ROAM CONSULTING
ENERGY MODELLING EXPERTISE

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Report (CEC00003) to

Clean Energy Council

The true costs and benefits of the enhanced RET

25 May 2010

VERSION HISTORY

Version History					
Revision	**Date Issued**	**Prepared By**	**Approved By**	**Date Approved**	**Revision Type**
1	2010-05-14	Jenny Riesz Joel Gilmore	Ian Rose	2010-05-13	Draft Report
1.1	2010-05-19	Jenny Riesz Joel Gilmore	Ian Rose	2010-05-19	Revised Report
1.2	2010-05-21	Jenny Riesz Joel Gilmore	Ian Rose	2010-05-19	Revised Report
1.3	2010-05-25	Jenny Riesz Joel Gilmore	Ian Rose	2010-05-25	Revised Report

EXECUTIVE SUMMARY

The LRET has various benefits and costs to consumers, only a subset of which are captured by analysis of RECs liability and the increase in renewable generation capacity. There are likely to be other more subtle "hidden" benefits and costs of the LRET through its interaction with the electricity market as a whole. This work therefore seeks to analyse the LRET holistically in the context of the electricity market, to identify and quantify any foreseeable "hidden" benefits or costs to the LRET that may not have been previously captured. The actual total costs of the LRET to consumers can then be quantified by taking all foreseeable factors into account.

A variety of potential hidden benefits and costs of the scheme have been identified, as listed in Table 1.1. Quantification of the relative materiality of these shows that all identified "hidden" costs are negligible in size, whereas identified hidden benefits produce significant savings to consumers. The only substantial cost of the LRET is the increased capital expenditure on renewable generation ($11.73 /MWh) which is considered to be a readily apparent cost (not hidden) that is typically quantified in many studies. This increased capital expenditure with the LRET is offset significantly by the various identified LRET benefits (-$4.63 to -$5.28 /MWh) producing a total cost of the LRET of $7.09 /MWh to $7.75 /MWh.

Table 1.1 – Summary of total benefits and costs of LRET in 2020
(Real 2010 dollars)

	Description	**Materiality** ($/MWh)
Benefits	***Reduced capital expenditure on gas-fired plant*** - Renewable generation provides a large quantity of energy to the system which allows cost effective installation of a higher proportion of low capacity factor open cycle gas turbine (OCGT) plant, and a smaller quantity of high capacity factor combined cycle gas turbine (CCGT) plant. OCGTs have significantly lower capital costs than CCGTs, providing a saving to consumers.	- $1.02 to - $1.66
	Reduced fuel costs and variable operations and maintenance (VOM) costs - Renewable generation provides large quantities of energy to the system at a very low short run marginal cost. This renewable plant displaces the operation of more expensive (short run cost) gas-fired and coal-fired plant, providing a saving to consumers in the form of reduced fuel costs and reduced VOM.	- $3.61
	Reduced greenhouse gas emissions (if carbon price is applied) - Renewable generation displaces emissions intensive fossil fuel fired generation. Greenhouse emissions will represent a direct cost to consumers in the event that a carbon pricing mechanism is introduced. The LRET reduces these costs to consumers through reduced greenhouse emissions (costs based upon carbon price of $38 /t$CO_2$-e in 2020).	- $3.06

Costs	***Renewable capital costs -*** Renewable technologies are currently more expensive than fossil-fuel fired generation. In addition, intermittent renewable technologies do not contribute their full capacity to system capacity for reliability, and so cannot fully displace thermal generation. Therefore a larger total capacity of plant must be installed to meet the RET with required system reliability levels. The cost listed here quantifies total capital expenditure and fixed operations and maintenance (FOM) on renewable generation under the LRET.	$11.73
	Transmission network infrastructure - Renewable resources are typically located in different places from the fossil fuel resources currently in use. Therefore the existing transmission network infrastructure may be inadequate for utilising large quantities of renewable generation, requiring augmentation. ROAM's modelling indicates that some new transmission is required to support the LRET, but comparable new transmission is cost effective even in the absence of the LRET to support load growth. The cost of transmission associated with the LRET is therefore calculated to be negligible.	$0
	Frequency Control Ancillary Services (FCAS) - These services maintain the frequency of the electricity system within required limits by ensuring that total supply (generation) matches total demand (load) in real time. The installation of a large quantity of intermittent generation under the LRET is likely to increase the variability required to be managed by FCAS. In the NEM FCAS (and particularly the regulation service) can be provided at very low cost, so the increase in cost (even with significant new wind generation) is calculated to be very small.	$0.03
Possible costs or benefits	***Network (Voltage) Control Ancillary Services*** - These services maintain the voltage of the electricity system within required limits. Depending upon the type of renewable energy installed, the LRET may assist with voltage control, or may require additional infrastructure. The calculated value to the right is an extreme upper bound on cost. The total impact may be $0.00 or negative (an overall benefit of the LRET) depending upon the type and location of renewable technologies that are installed.	$0.29
	Distribution network infrastructure - The distribution network connects customers (loads) to the higher voltage transmission network. The interaction of the LRET with the distribution network is complex and difficult to predict. Renewable generators are incentivised to locate in places where the network will be sufficient to meet their needs, but in some circumstances renewable development require network augmentation. On the other hand, installation of embedded generation may assist with meeting local loads, resulting in an overall reduction in strain on the distribution network, and allowing delayed augmentation of the network. Direct connection costs for new generation are listed to the right.	$0.32 - $0.34 (new connection costs)

	Some further possible distribution costs are captured through NCAS (above). Benefits are difficult to quantify with available data.	

These factors and the modelling used to quantify them are explained further below.

ROAM modelling to quantify benefits and costs

ROAM conducted an Integrated Resource Planning study to determine the quantity and type of generation that would be installed in the NEM to meet future load growth under a least cost assumption.

A certain amount of generating capacity is required to ensure sufficient system reliability (sufficient generating capacity is installed to meet expected demand). Intermittent generators cannot guarantee availability of the full capacity of their generator, so the contribution of capacity of these generators must be less than 100% of their installed capacity. This means that a larger total capacity of generation must be installed in order to ensure sufficient installed capacity for reliability. At the moment, wind generators are assumed to contribute a negligible amount of capacity to system reserve in the NEM. However, recent modelling by a number of parties suggests that due to the way reliability is specified under the current market rules, wind generation should be able to contribute a proportion of their capacity equivalent to their capacity factor (~30% for most wind farms in the NEM). ROAM has therefore modelled both possibilities in this study, to determine the implications of each in terms of costs.

System load is forecast to continue to grow, which will need to be met by a substantial quantity of new generation, even in the absence of the LRET. It is therefore necessary to compare generation investment required in the absence of the LRET to that required with the LRET. Three scenarios were calculated:

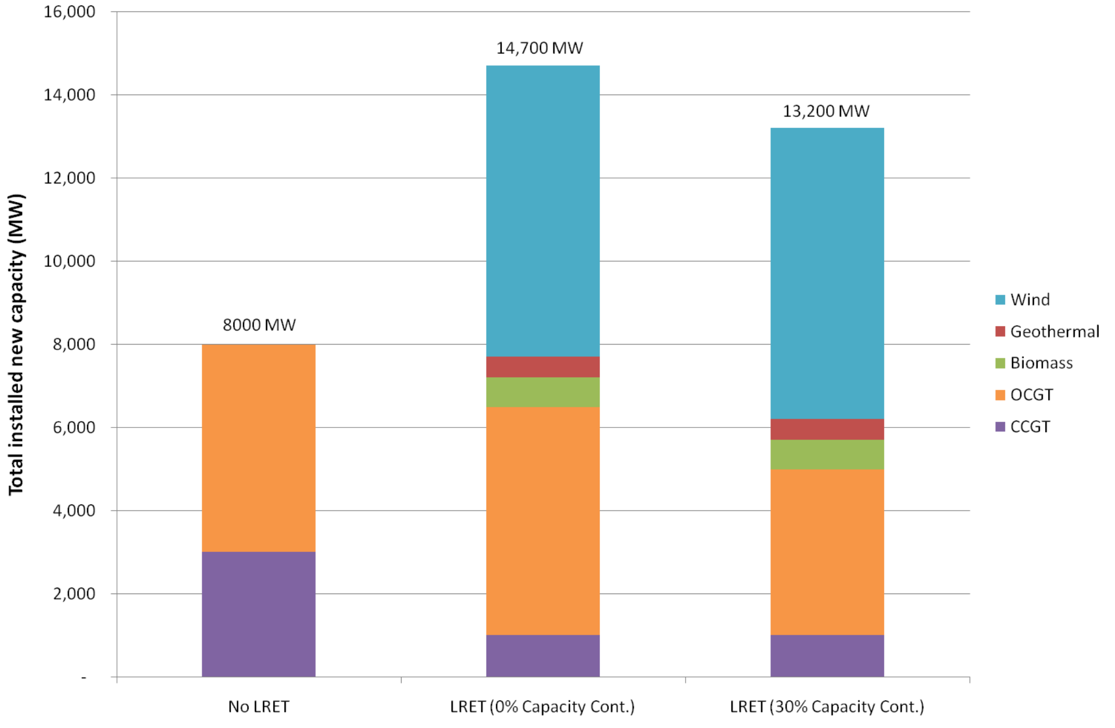
- ***No LRET*** - generation required to meet future load growth, with no requirement to meet renewable energy targets
- ***LRET (0% Capacity Cont.)*** - LRET targets must be met, and wind generation is assumed to make no contribution to system reserve
- ***LRET (30% Capacity Cont.)*** - LRET targets must be met, and wind generation is assumed to make a 30% contribution of installed capacity to system reserve

The plant installed in each scenario to meet the requirements at least cost are illustrated in Figure 1.1. When wind is assumed to make a 30% contribution to reserve, the LRET displaces some of the new gas fired plant (open cycle gas turbine - OCGT, and combined cycle gas turbine - CCGT). Biomass and geothermal plant are assumed to contribute 100% of their installed capacity to system reserve in all cases, and so can directly displace gas-fired generation. In the LRET (30% Capacity Cont.) scenario some of the wind capacity is also able to displace gas-fired generation, allowing a significantly smaller quantity of gas-fired capacity to be installed.

In the LRET (0% Capacity Cont.) scenario, geothermal and biomass plant displace gas-fired generation directly. Figure 1.1 illustrates that the combined capacity of gas, biomass and geothermal generation is slightly less than that installed in the No LRET scenario, even though wind is not considered to contribute any capacity directly. This is due to the blocked nature of the installations; gas-fired generation must be installed in 500 MW blocks, whereas biomass capacity can be installed in much smaller blocks (100 MW). This allows a slightly smaller total capacity to be installed to meet the minimum reserve requirements, even though wind is not contributing to system reserve.

In the LRET scenarios a higher proportion of OCGT plant can be installed due to provision of large quantities of energy from wind (Figure 1.1). This allows savings in capital expenditure on gas-fired capacity, because OCGT plant has a significantly lower capital cost than CCGT plant.

Figure 1.1 – Installed new capacity in NEM[1] (2020)



The costs of the various components of each scenario are illustrated in Figure 1.2. Capital costs and FOM (fixed operations and maintenance) costs of renewables are higher in scenarios with the LRET. However, this is offset by significant reductions in:

- Capital expenditure and FOM on new gas-fired plant (since lower capital cost OCGT plant can be installed in preference to higher capital cost CCGT plant)
- VOM (variable operations and maintenance) costs of both new and existing plant, through reduced usage of fossil fuel (displaced by the operation of wind and other renewable energy generation)

These factors mean that the increased cost of the LRET scenarios is relatively small compared with the No LRET scenario.

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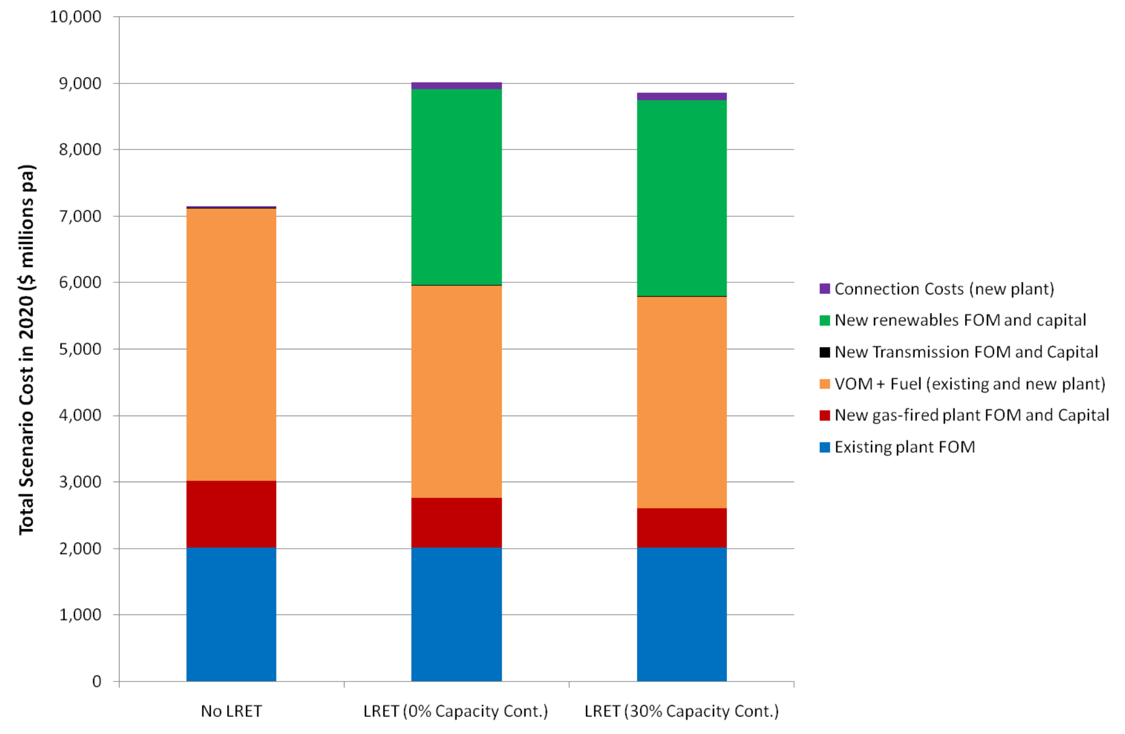
[1] It has been assumed that some of the LRET is met by renewable generation installed outside of the NEM, in proportion to the national load that is located outside of the NEM. The modelling illustrated here shows only results relating to the NEM, which includes the majority of the national electricity supply/demand.

New transmission capital and FOM is found to be very small by comparison to other costs, as is the cost of connection for new plants.

This data captures the "hidden costs" of system reserve requirements, transmission expenditure and new connection costs. These costs are largely offset by "hidden benefits" of the LRET, which are often not taken into account in many studies.

Figure 1.2 – Costs of scenarios (annualised cost in 2020)[2]



Transmission network infrastructure

ROAM's IRP[3] model chooses to install the same transmission augmentation in all three scenarios (with and without the LRET). Under a least cost condition it chooses to install a new 400 MW line from SA to VIC. In the scenarios with the LRET this new line supports export of substantial renewable investment in South Australia. In the scenarios without the LRET this new line is justified by lower cost supply to South Australia from generation in Victoria.

These results mean that in either case (LRET or No LRET), the transmission augmentation is justified (albeit for different reasons in each case). Transmission

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[2] Real 2010 dollars, no discounting applied

[3] Integrated Resource Planning Model – this model computes the grid performance of a large number of alternative development plans that all meet the same reliability of supply criteria, choosing the appropriate combination of new generation and transmission plant that delivers the lowest aggregate cost of supply, including capital, fuel, operations and maintenance, and carbon taxes.

augmentation of a similar scale is required even in the absence of the LRET, to supply energy and reliability at the lowest cost to consumers.

Even if significant quantities of new transmission were required under the LRET, the costs of transmission augmentation are generally relatively small by comparison to other factors. The new line installed in this case comes at a cost of $15.3 million pa, which is equivalent to $0.06 /MWh.

Frequency Control Ancillary Services

Frequency control ancillary services (FCAS) maintain the frequency of the electricity system within required limits by ensuring that total supply (generation) matches total demand (load) in real time. This is termed "regulation". The installation of a large quantity of intermittent generation under the LRET (for example, wind generation) is likely to increase the variability required to be managed by FCAS.

Regulation is required even in the absence of renewable generation to meet the variability of system loads and scheduled generators who do not meet their dispatch targets exactly, so costs of regulation are split between customers and generators in a "causer pays" model. With 1557 MW of wind installed, generators currently pay a total of $1.52 million pa for the regulation service. With a significant increase in installed wind generation (of 7000 MW to a total of 8557 MW) this could be expected to increase to $8.3 million pa. This would increase the total cost of all ancillary services provided by AEMO from $174.4 million pa to $181.2 million pa (an increase of $0.03 /MWh from $0.89 /MWh to $0.92 /MWh).

Voltage Control Ancillary Service

Voltage control service is required to maintain the voltage on the electrical network to within specified tolerances. This can be achieved through the dispatch of generators that can absorb or generate reactive power from or onto the electricity grid and control the local voltage.

Wind generation could have significant implications for the voltage control ancillary service. Conventional generators are an important source of reactive power and contribute significantly in maintaining voltage stability. The increasing penetration of wind farms is likely to displace some of the conventional generators and their capacity to supply reactive power may need to be replaced. Wind farms can provide voltage support, but this is heavily dependent upon the type of wind technology installed. Older design fixed-speed induction machines usually have a negative impact on dynamic voltage stability unless they are fitted with additional reactive power equipment. However, more modern variable speed wind generators (Double Fed Induction Generators, DFIGs) are able to provide voltage control capability, as are synchronous wind generators.

Therefore, in some circumstances, wind generation may avoid the necessity of installing expensive reactive power devices that would otherwise be required. Voltages at the end of long radial networks (typical of the distribution network) are often poor. Wind plants installed at the end of long radial lines that have a reactive power control system can therefore benefit the system by supporting the local voltage.

In the worst case, the introduction of 7000 MW of new wind farms could require substantial new voltage control infrastructure. To provide an estimate of the upper bounds of the possible cost, ROAM assumed that every new wind farm was of the least helpful possible technology type, installed in the most disruptive possible location. In this worst possible case, around 7000 MVAr of SVC equipment may be required to support 7000 MW of installed wind capacity. This would have an annualised cost of $73 million pa, which equates to $0.29 /MWh.

Distribution network infrastructure

The distribution network connects customers (loads) to the higher voltage transmission network. The interaction of the LRET with the distribution network will be complex and is difficult to predict. Small to medium sized renewable generators may connect directly to the distribution network. These renewable generators are incentivised to locate in places where the network will be sufficient to meet their needs, but in some circumstances renewable development may place strain on the distribution network, requiring augumentation (particularly around voltage stability and other network control issues). Voltage control costs have been addressed directly above.

On the other hand, installation of embedded generation may assist with meeting local loads, resulting in an overall reduction in strain on the distribution network, and allowing delayed augmentation of the network. It is predicted by many parties that loads will continue to become "peakier" in nature, requiring distribution networks to be sufficient to meet higher peak demands (particularly due to air conditioning loads). This will require substantial investment in distribution network augmentation that is unrelated to the LRET. The LRET may actually delay the requirement for distribution network augmentation by meeting or offsetting local loads.

ROAM has accounted for connection costs of new renewable generators directly in the IRP (results outlined above), and for voltage control costs directly in the previous section.

Quantification of total costs

The costs and benefits of the LRET are quantified in the following table. These include the identified "hidden" costs and benefits, as well as costs that would be covered by the sale of Renewable Energy Certificates (RECs).

Table 1.2 – Summary of total cost of LRET in 2020
(Real 2010 dollars, annualised costs)

	Cost in scenario with LRET minus Cost in scenario without LRET			
	Wind assumed to contribute zero capacity to reliability ($m)	**Wind assumed to contribute 30% of capacity to reliability ($m)**	**Wind assumed to contribute zero capacity to reliability ($/MWh)**	**Wind assumed to contribute 30% of capacity to reliability ($/MWh)**
New Renewable Plant FOM and Capital	2,946	2,946	$11.73	$11.73
New Gas-fired Plant FOM and Capital	-256	-418	-$1.02	-$1.66
Connection Costs (new plant)	85	81	$0.34	$0.32
Existing plant FOM	0	0	$0.00	$0.00
VOM + Fuel (existing and new plant)	-908	-908	-$3.61	-$3.61
New Transmission FOM and Capital	0	0	$0.00	$0.00
Ancillary services (AEMO) - includes regulation (FCAS)	7	7	$0.03	$0.03
Additional SVC equipment to support wind (NCAS) - extreme upper bound estimate	73	73	$0.29	$0.29
Total (no carbon cost)	**1,974**	**1,781**	**$7.75**	**$7.09**
Carbon Cost ($38/tCO$_2$-e)	-769	-769	-$3.06	-$3.06
Total (with carbon cost)	1,178	1,012	$4.69	$4.03

The total cost of the LRET in 2020 is calculated to be between $7.09 and $7.75 /MWh, depending upon the assumed contribution of wind farms to system reserve (ranging from zero to 30%). This includes all capital expenditure on renewable generators, and takes account of benefits in terms of reduced fossil fuel expenditure. The increase in capital and FOM costs from new renewable plant ($11.73) is offset by the decreased capital and FOM from new gas-fired plant (-$1.02 to -$1.66), and decreased costs in VOM and fuel for new and existing plants (-$3.61). These savings are found to be substantial.

Increases in other "hidden" costs of the LRET are found to be very small, including:

- Expansion of transmission infrastructure
- Connection costs of new plants

- Ancillary services (FCAS)
- Voltage control (NCAS)

If a carbon price is applied by 2020 there are additional savings from reduced greenhouse emissions (renewable generation displaces more emissions intensive generation). With a carbon price of \$38/tCO$_2$-e in 2020 the reduction in emissions from the LRET produces a saving to consumers of \$3.06 /MWh. This further reduces the total cost of the LRET to between \$4.69 and \$4.03 /MWh in 2020.

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1) BACKGROUND

A number of players and the media are suggesting that the Renewable Energy Target and in particular the proposed LRET (Large-scale Renewable Energy Target) will involve substantial "hidden" costs to consumers. The claim is that these "hidden costs" will put a large additional cost on consumers, far in excess of those accounted for by determining the likely costs of Renewable Energy Certificates (RECs) alone.

One of the "hidden costs" that is referred to is the requirement for investment in "backup" generation to account for the variability of wind generation. Another is the costs of maintaining required reserves to meet reliability requirements, particularly relating to the contribution of intermittent generators at time of peak demand. Required investment in transmission infrastructure is also frequently mentioned. These are separate issues that are managed independently in the electricity sector, but in the public media these concepts are often confused.

Against these "hidden costs", there are likely to be "hidden benefits" to the LRET that are not being accounted for in analysis of the impacts of the LRET. The materiality of various benefits of the LRET should be quantified and offset against any costs that the scheme might involve.

There is a need for a clear outline of the various issues involved, the ways that they can be effectively managed, and an estimation of the likely costs of each to consumers.

2) SCOPE

This work seeks to clearly outline the various possible "hidden" benefits and costs of the LRET, and to provide quantification of their likely costs to consumers. It is intended to inform the debate during the lead-up to the vote in the senate to pass the upcoming revisions to the LRET legislation.

3) METHODOLOGY

ROAM has approached this study in two parts:

1. Identifying the hidden benefits and costs of the LRET
2. Quantifying the hidden benefits and costs of the LRET

Identifying the hidden benefits and costs of the LRET

Through careful holistic examination of the electricity sector ROAM has identified possible foreseen hidden benefits and costs of the LRET.

Quantifying the hidden benefits and costs of the LRET

Quantification of the benefits and costs of the LRET can be best achieved through comparison of the generation installed in a future system with the LRET, to that without the LRET. This allows analysis of only the factors that are due to the LRET scheme.

ROAM has used a proprietary integrated resource planning (IRP) model to construct the likely mix of generation in the NEM in 2020 for three scenarios:

1. No LRET
2. LRET with wind contributing 0% to capacity
3. LRET with wind contributing capacity factor equivalents to capacity (30%)

The IRP model selects the optimal least cost mixture of installed plant for each scenario. It will therefore quantify any hidden benefits in the installation of OCGT plant instead of CCGT plant, reducing costs from the more expensive capital of CCGTs. The total amount of plant required in each case will be quantified, in addition to the associated costs.

The IRP model also installs transmission upgrades where required[4]. This is a least cost outcome that meets the LRET, and addresses reliability issues. This allows quantification of the costs of transmission associated with the LRET.

The IRP is a very powerful model which utilises extensive computational resources. In order to maintain computational time within reasonable limits, ROAM has modelled the year 2020 only. Results are found to be consistent in the year 2020 with much more extensive modelling studies conducted over the period 2010 to 2030, alleviating concerns about 'end effects'.

4) ROAM MODELLING - INTEGRATED RESOURCE PLANNING

4.1) WIND CONTRIBUTION TO SYSTEM RESERVE

The Australian Energy Market Operator (AEMO) is responsible for maintaining the NEM system in a reliable operating state. This includes managing the system "reserve". Having sufficient installed reliable capacity is important to maintain the reliability of the system and avoid excessive load shedding (blackouts). Minimum reserve levels are calculated for each state annually, and AEMO is responsible for ensuring that sufficient capacity is installed to meet them. A shortfall in reserve indicates an opportunity for new generation to profitably enter the market.

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[4] To maintain manageable computational times only a small selection of the most likely transmission augmentations are made available to the model. Based upon previous modelling experience these are thought to be the only likely augmentations that can be justified on a cost minimisation basis.

Wind contributes energy (GWh), but it is often claimed cannot contribute reliable capacity (MW) to the electricity system. If wind cannot contribute reliable capacity, then sufficient capacity in another form must be installed (typically gas fired peaking plant).

Definition of reliability criteria

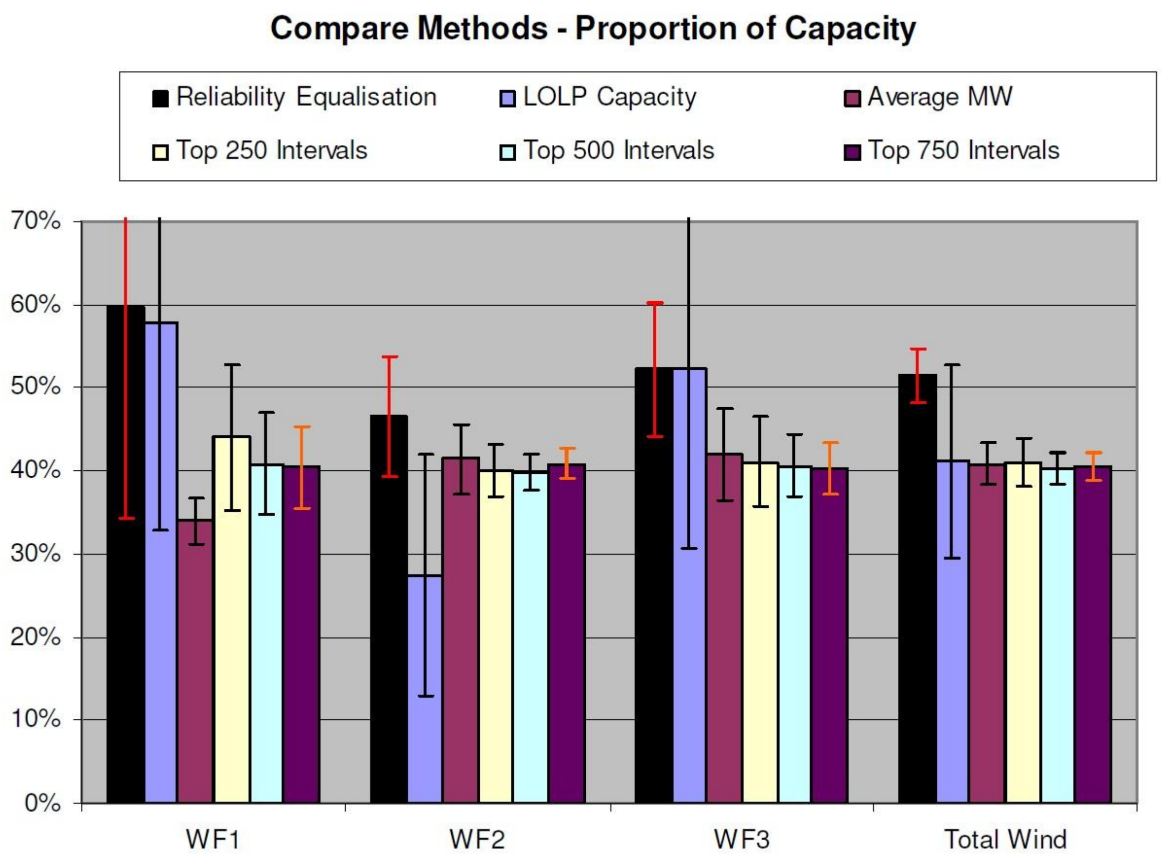
Importantly, the required reliability level in the NEM (National Electricity Market) is defined in the Rules to be a level that gives rise to less than 0.002% unserved energy averaged over a ten year period. This means that some level of load shedding is consistent with the required level of reliability, and this load shedding can occur at time of peak demand (as long as the system is reliably supplied at other times). This means that the system can be considered reliable even if there is insufficient installed capacity to meet the system peak demand (or if installed wind is considered unlikely to be operating at this time).

A similar reliability requirement is applied in the Western Australia market (the South-West Interconnected System, SWIS). In this market the contribution of capacity (MW) is recognised explicitly through a direct capacity market, where generators are paid on the basis of capacity that they make available. Under the current rules, wind generation is considered to contribute capacity in proportion to its average capacity factor (approximately 40% of capacity for most Western Australian wind farms).

Contribution of intermittent generation to system reserve

Modelling based on historical operation of Western Australian wind farms suggests that wind farms contribute a proportion of their capacity to system reserve close to their capacity factor. This is illustrated in Figure 4.1, where the proportion of capacity that three individual wind farms contribute to reliability in the SWIS is shown, as calculated using various different methodologies and approaches. All methodologies agree to within the error bars, and the aggregate (total) wind is shown to contribute 40% of its capacity to system reserve.

Figure 4.1 – Modelling of WA wind farm contribution to reserve[5]



Reliability studies by ROAM indicate similar results for wind farms in the NEM. Under some circumstances some wind farms actually contribute more than their capacity factor, because the operation of the wind farm alleviates transmission constraints that would otherwise bind. This allows the wind farm to displace a comparatively larger quantity of thermal generation.

It is often stated that wind farms (and other intermittent generators) cannot be relied upon to provide capacity at time of peak demand, and that there may actually be a negative correlation (peak demand typically occurs on a very hot day associated with a high pressure system, which is likely to be associated with very low wind levels). This has been observed for South Australian wind generators, where a 95% availability criteria was applied to historical wind levels to determine the available "reliable" supply[6]. Based upon the recorded wind performance during the top 10% of demand periods it was found that 95% of the time wind generation in South Australia is producing at least 3% of its installed capacity. Based upon this result, a 3% contribution of wind to capacity in South Australia is assumed, because this is the quantity that can be relied upon to be producing at time of

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[5] Figure from MMA report to the WA Independent Market Operator, "Valuing the Capacity of Intermittent Generation in the South-west Interconnected System of Western Australia". 29 Jan 2010. Report available at: http://www.imowa.com.au/n139.html, Work Package 2. LOLP - "loss of load probability".

[6] ESIPC (Electricity Supply Industry Planning Council), Annual Planning Report, June 2009, p. 66.

peak demand with a 95% confidence level. Similarly low levels of capacity contribution are currently assumed for wind farms in other states (8% for Victoria, 5% for New South Wales, and 0% for Queensland and Tasmania)[7].

Based upon this alternative criteria of contribution at time of peak demand, wind contributes a much smaller (almost negligible) amount of capacity to system reserve. However, this criteria is not founded in the market rules, but is rather a highly conservative approach. Based upon the reliability criteria as defined in the market rules a low level of unserved energy is allowed, and this can occur at time of peak demand. This means that it is not necessary to ensure that wind capacity is available at time of peak demand with a 95% confidence level.

If a small amount of loss of load at time of peak demand in an exceptionally high peak demand year is considered unacceptable, then the reliability criteria need to be reviewed and changed to reflect the level and type of reliability that is desired.

These issues are complex, and are currently under review in both the NEM and the SWIS. For this reason ROAM has modelled two scenarios in this study, to capture the full range of possible outcomes and assess their implications in terms of costs to consumers.

- One scenario explores the implications of wind (and other intermittent generators) contributing capacity to system reserve equivalent to their capacity factors (based upon the existing reliability criteria specified in the NEM and SWIS rules).
- Another scenario explores the cost implications of wind and other intermittent generators contributing no capacity to system reserves.

Other factors for consideration

System reliability may be adversely affected by large quantities of intermittent generation if large thermal generators are increasingly shut down overnight during low load conditions (with the low load being met by a high proportion of renewable generation). Daily shut down and start up is stressful for large thermal generators (typically designed for continuous operation), and can greatly increase the rate of forced outages. Reliability modelling is based upon historical forced outage rates, and therefore becomes less accurate if forced outage rates are greatly increased. It is assumed for this study that generators are managed such that forced outage rates are maintained at close to historical levels, since much higher forced outage rates will be significantly detrimental to generator revenues.

4.2) IRP MODELLING - METHODOLOGY AND ASSUMPTIONS

ROAM conducted integrated resource planning (IRP) modelling to determine the least cost planting outcomes for three scenarios:

1. ***No LRET*** - No renewable energy target is implemented.

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[7] AEMO 2009 Electricity Statement of Opportunities (ESOO), Appendix B, B.6.6.

2. ***LRET (0% Capacity Cont.)*** - The renewable energy target is implemented, and intermittent technologies (wind generation) are considered to make no contribution to system capacity for reliability assessment.
3. ***LRET (30% Capacity Cont.)*** - The renewable energy target is implemented, and intermittent technologies are considered to make a contribution to system capacity for reliability equivalent to their average capacity factor (assumed to be 30% for wind).

For each of these scenarios, ROAM's IRP software calculates the two hourly dispatch outcomes for every possible combination of new plant installed (operating in conjunction with the existing plant mix), and determines the least cost planting outcome. This balances annualised capital expenditure against operational expenditure and other costs for each possible new entrant technology to determine the optimal least cost plant mix to meet the system peak demand and energy requirements. Market dispatch is done on the basis of plant's short run marginal costs (SRMC), which means the full capacity of the cheapest generators are dispatched before more expensive plant is brought online, thus ensuring the cheapest generation outcome to consumers.

Carbon price

A mild carbon price has been applied in all three scenarios. The application of a low carbon price prevents the entry of new coal-fired generation, and has a small effect on the dispatch merit order (there is some re-ordering of plant on the basis of emissions intensity). The price is insufficient to change the fundamental operation of the system, such that existing coal-fired generation continues to operate in a "base-load" fashion, with gas-fired generation continuing to play an intermediate and peaking role.

A carbon price of \$38 /tCO_2-e was assumed, based upon Treasury modelling for the Australia's Low Pollution Future study (carbon price outcome for 2020 under a CPRS -5% scenario). There is currently great uncertainty over the future of carbon pricing in Australia, but both the Government and the Opposition have committed to a 5% emissions reduction by 2020. It is assumed that this must have implications for the electricity sector, since it is responsible for a large proportion of Australia's emissions.

If an emissions price becomes unfavourable, similar planting outcomes to those illustrated here could be achieved via a combination of other policies and measures. These might include a moratorium on new coal-fired generation combined with the LRET and a gas incentive scheme (such as the Queensland Gas Scheme, implemented via Gas Electricity Certificates).

Even if an explicit carbon price is not applied externally through a tax, emissions trading scheme, or similar mechanism, greenhouse gas emissions can still be assumed to have a real cost for consumers for the following reasons:

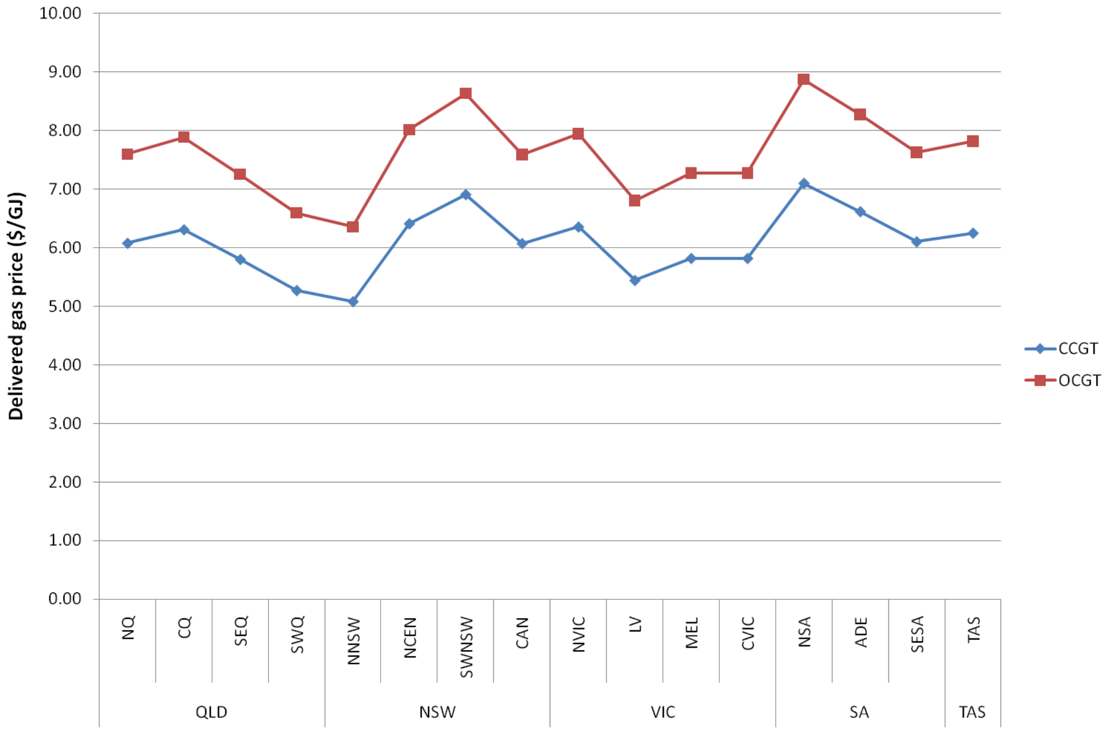
- Australia has ratified the Kyoto Protocol, which includes explicit national emissions targets for the first commitment period. It is assumed that international support for action on climate change will continue to grow, and Australia will take on more stringent targets for the second commitment period (and beyond), either under the Kyoto Protocol, or a new international mechanism. If these national emissions targets are not met domestically, Australia will need to purchase international credits to make up the difference. This carries a real cost for Australian consumers.

- In the long term, greenhouse gas emissions cause climate change which will have significant real costs to Australian consumers in terms of adaptation.

Gas price

Gas prices were assumed to be those proposed by ACIL Tasman for the 2010 National Transmission Network Development Plan[8]. Scenario 3 was selected as an appropriate "middle ground" scenario. Gas prices vary by location (since they include gas transport costs), and by technology (since CCGT plant should be able to negotiate better bulk prices due to higher consumption levels). Gas prices assumed in 2020 are illustrated in Figure 4.2.

Figure 4.2 – Delivered gas prices by location and technology



Capital cost

Capital costs for each plant type were assumed to be those proposed by ACIL Tasman for the 2010 National Transmission Network Development Plan[9]. Scenario 3 was selected as an appropriate "middle ground" scenario. All capital costs are annualised using a WACC of 9.79% and an assumed economic plant lifetime of 30 years. All costs listed in

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[8] http://www.aemo.com.au/planning/ntndp.html

[9] http://www.aemo.com.au/planning/ntndp.html

this report are the costs in the year 2020 only. The most competitive technologies are listed in Table 4.1.

Table 4.1 – Capital Costs (2020) - Real 2009-10, $/kW installed

	Capital costs	Annualised capital, FOM and tax costs
CCGT - Without CCS	1,302	155
OCGT - Without CCS	947	108
Supercritical PC - Black coal	2,587	332
Wind - Large scale (500 MW)	2,561	310
Biomass	5,000	574
Geothermal - Hot Sedimentary Aquifers (HSA) (installed in NSA zone)	5,267	743
Solar Thermal - Central Receiver w/out Storage (supported by Solar Flagships program)	2,056	280
Photovoltaic - PV Fixed Flat Plate (supported by Solar Flagships program)	2,685	318

Coal-fired generation was included as an option, but was uncompetitive with gas-fired generation due to the applied carbon price.

Dispatch

Dispatchable plant was assumed to bid into the market at short run marginal cost, with SRMC values assumed to be those proposed by ACIL Tasman for the 2010 National Transmission Network Development Plan (Scenario 3)[10]. This included geothermal, biomass, CCGT and OCGT plant. High forced outage rates were assumed for the renewable technologies, representative of their relatively lower maturity.

Short run marginal cost (SRMC) bidding typically produces low pool price outcomes, since it neglects the market power of participants. However, IRP studies are intended to determine least cost outcomes, and the dispatch produced by SRMC is the most useful in this regard.

Wind farms were operated on traces calculated from historical wind data from the Bureau of Meteorology, scaled to match capacity factors by location and adjusted by time of day and for park effects based upon the actual operation of several wind farms compared with BOM data. Capacity factors were assumed to be those proposed by ACIL Tasman for the 2010 National Transmission Network Development Plan (Scenario 3)[11]. This methodology captures correlations between wind farms, allowing analysis of the true

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[10] http://www.aemo.com.au/planning/ntndp.html

[11] http://www.aemo.com.au/planning/ntndp.html

value of transmission augmentation as dependent upon likely correlation between wind farm output in different regions.

Demand

Demand and energy targets were taken from the AEMO Electricity Statement of Opportunities 2009 (ESOO). The medium growth trajectories were used.

The 10% POE (probability of exceedance) demands in conjunction with minimum reserve levels (MRLs) were used for determining the necessary installation level of plant, since the MRLs are determined based upon 10% POE demands. However, 50% POE demands were used for the actual simulation, to represent a "likely" or "average" year. These are peak demand levels that would be exceeded one year in two. This is representative of the actual process that it used in the NEM (10% POE levels are used to determine the necessary level of installation for reliability, but an average year would have peak demands closer to 50% POE).

Table 4.2 – Demand targets (Medium 10% POE peak demands for summer 2019-20)

QLD	NSW	SA	VIC	TAS
14,353	19,123	4,282	12,797	2,200

These energy and demand targets were used to calculate a two-hourly demand trace for the simulations based upon the actual historical demand trace from 2008-09.

End effects

IRP studies are typically run over a range of years (for example, from 2010 to 2030) in order to avoid "end effects". These are effects where the model may choose to install a generator or transmission line (or not) in the late years of the study because it is least cost for that short duration, but if costs are calculated over a longer period another alternative becomes lower cost.

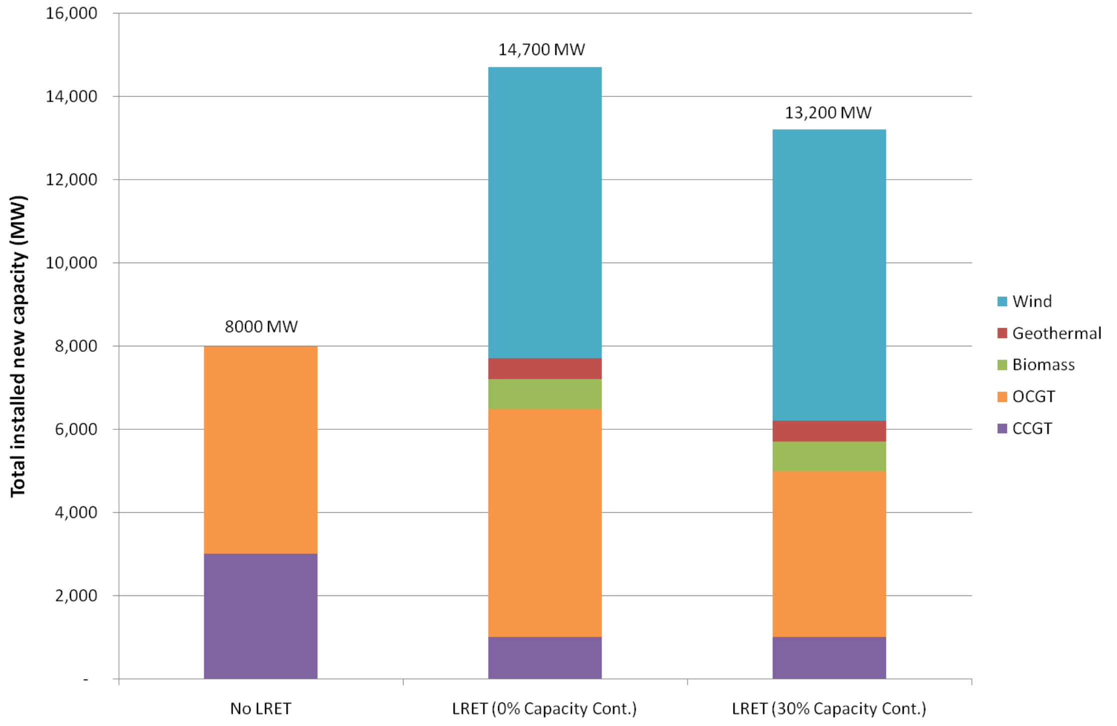
For this study, ROAM has only run the IRP for a single year (2020), and this is vulnerable to end effects. However, ROAM has previously conducted extensive IRP modelling with very similar input assumptions over an extended time period around 2020 (2010 to 2030). This provides a strong benchmark against which to compare this study. Very similar results were obtained, which is a strong indication that end effects are not distorting the IRP results in this case.

4.3) IRP MODELLING RESULTS

The optimal (least cost) planting outcomes for each of the three scenarios are illustrated in Figure 4.3 for the year 2020.

In the No LRET case, 8000 MW of new plant is required to meet the growing system demand and energy requirements. This is divided between higher capital cost, more efficient combined cycle gas turbine (CCGT) plant (38%), and lower capital cost, less efficient open cycle gas turbine (OCGT) plant (62%). CCGT plant operates at high capacity factors, providing "base-load" power, whereas OCGT plant operates only at times of very high demand, providing generating capacity to the system, but very little energy (due to very high operating costs). Without the LRET, no renewable energy is installed.

Figure 4.3 – Installed new capacity in NEM[12] (2020)



When the LRET is introduced, 8200 MW of renewable energy capacity is installed. This is mostly wind capacity (7000 MW), with some biomass (700 MW) and geothermal (500 MW). The geothermal and biomass technologies are assumed to be dispatchable, and therefore displace OCGT/CCGT capacity. In the case where wind is assumed to contribute capacity equivalent to their average capacity factors, some wind capacity also displaces further OCGT/CCGT capacity.

The combined capacity of OCGT, CCGT, Biomass and Geothermal in the LRET (0% Capacity Cont.) case is slightly less than that in the No LRET case due to the smaller size of renewable plant. Biomass plant can be installed in 100 MW blocks, whereas

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[12] It has been assumed that some of the LRET is met by renewable generation installed outside of the NEM, in proportion to the national load that is located outside of the NEM. The modelling illustrated here shows only results relating to the NEM, which includes the majority of the national electricity supply/demand.

CCGT/OCGT plant is installed in larger 500 MW blocks. This allows a slightly smaller capacity of dispatchable plant to be installed in the LRET (0% Capacity Cont.) case, even though wind generation is assumed to not contribute to system capacity.

In addition to reducing the overall quantity of CCGT/OCGT plant installed, the LRET also changes the proportion of CCGT and OCGT plant required. Because wind generation supplies large quantities of energy, a much lower proportion of CCGT plant is installed, and lower capital cost OCGT plant is preferred. With the LRET providing energy, only 1000 MW of CCGT plant is required, compared with 3000 MW in the absence of the LRET.

4.3.1) Costs of scenarios

The total costs in each scenario can be calculated by summing the following components:

1. Fixed operations and maintenance (FOM) for existing plants
2. Capital cost of new installed gas-fired plant (annualised over a 30 year lifetime)
3. Capital cost of new installed renewable plant (annualised over a 30 year lifetime)
4. Fixed operations and maintenance for new installed plant
5. Connection costs for new installed plant
6. Variable operations and maintenance (VOM) for all installed plant, including fuel costs
7. Capital cost and FOM of new interconnector (transmission) developments
8. Carbon costs (if a carbon price is applied)

The resulting total costs for each scenario are illustrated in Figure 4.4, and tabulated in Table 4.3.

FOM costs for existing plants are identical across all three scenarios, because no retirements occur in any scenario prior to 2020.

Capital expenditure on new renewable technologies under the LRET is substantial. There is an increased cost (above that in the No LRET case) of $2,946 million associated with capital and FOM of new plant in 2020. This is offset somewhat by a reduction in capital expenditure and FOM of new gas-fired plant when the LRET is introduced, because some renewable capacity displaces gas-fired generation. Capital expenditure and FOM on new gas-fired plant is reduced by $256 million even when wind is considered to make no contribution to system capacity for reliability. If wind is assumed to contribute 30% of capacity to reliability the reduction in gas-fired capital expenditure and FOM is even larger, at $418 million in 2020.

Connection costs increase when the LRET is introduced due to the connection of remote wind farms. However, connection costs are a very small proportion of total costs (0.6 - 0.7% in the cases with the LRET).

Variable operations and maintenance costs (VOM) and fuel costs are reduced in the scenarios with the LRET. They reduce from $4,092 million in the absence of the LRET to $3,184 in scenarios with the LRET. This is a saving of $908 million (Table 4.3). VOM and fuel costs reduce with the implementation of the LRET because of reduced gas and coal usage with the installation of large quantities of wind and other renewable technologies.

The magnitude of savings in VOM and fuel costs are likely to be heavily dependent upon the gas price, because the renewable generation under the LRET is likely to be displacing mostly gas-fired generation. In this scenario assumed gas prices were low to medium compared with most market estimates (this scenario assumed prices from $5-7 /GJ delivered for CCGTs and $6-9 /GJ for OCGTs, depending upon location). Many estimates of future gas prices are far in excess of these, which would likely increase the savings from reduced fuel costs, potentially by a large amount.

Figure 4.4 – Costs of scenarios (annualised cost in 2020)
Real 2010 dollars

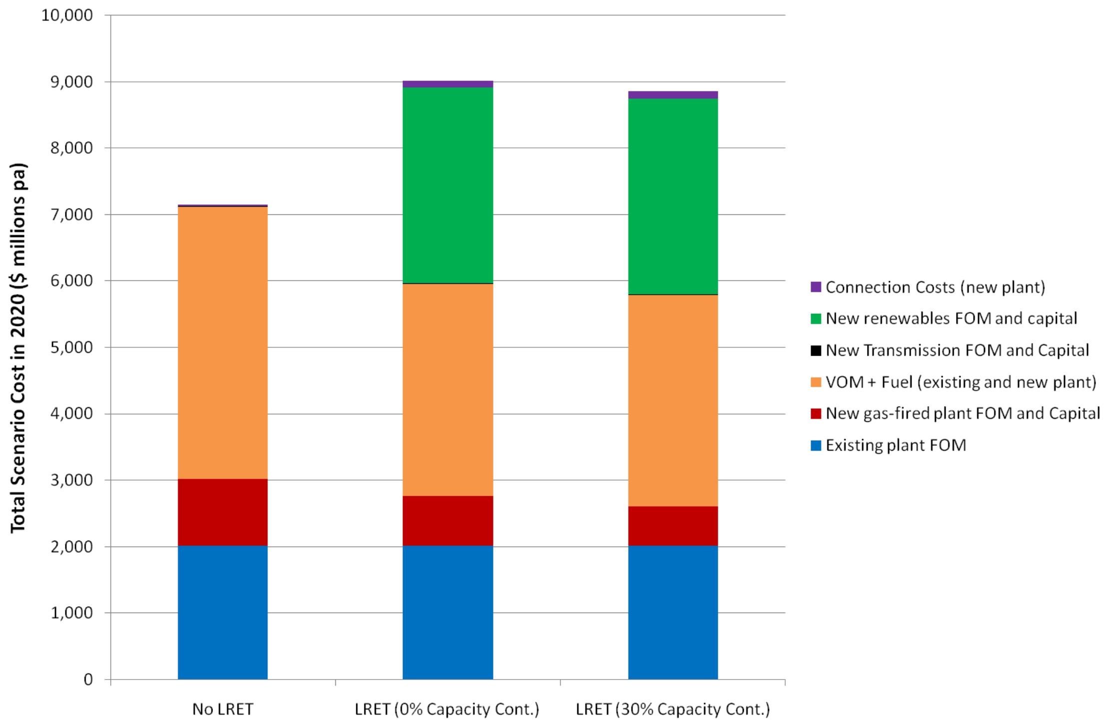


Table 4.3 – Costs of scenarios (annualised cost in 2020) ($ millions)
Real 2010 dollars

	No LRET	LRET (0% Capacity Cont.)	LRET (30% Capacity Cont.)
New Renewable Plant FOM & Capital	0	2,946	2,946
New Gas-fired Plant FOM & Capital	1,004	748	586
Connection Costs	21	106	102
Existing plant FOM	2,019	2,019	2,019
VOM + Fuel	4,092	3,184	3,184

New transmission FOM & Capital	15	15	15
Total (no carbon cost)	7,151	9,018	8,852

Table 4.4 – Summary of total cost of LRET (difference with LRET) **(Real 2010 dollars, annualised costs in 2020)**				
	LRET (0% Capacity Cont.) minus **No LRET** ($m)	**LRET (30% Capacity Cont.)** minus **No LRET** ($m)	**LRET (0% Capacity Cont.)** minus **No LRET** ($/MWh)	**LRET (30% Capacity Cont.)** minus **No LRET** ($/MWh)
New Renewable Plant FOM and Capital	2,946	2,946	$11.73	$11.73
New Gas-fired Plant FOM and Capital	-256	-418	-$1.02	-$1.66
Connection Costs (new plant)	85	81	$0.34	$0.32
Existing plant FOM	0	0	$0.00	$0.00
VOM + Fuel (existing and new plant)	-908	-908	-$3.61	-$3.61
New Transmission FOM and Capital	0	0	$0.00	$0.00
Total (no carbon cost)	**1,867**	**1,701**	**$7.43**	**$6.77**

When the savings on fuel, VOM and gas-fired capital and FOM are taken into account, the difference in the total cost of the scenarios is significantly reduced. Despite extra spending on renewable generation capital and FOM of $2,946 million with the LRET, the total additional cost is only between $1,701 million and $1,867 million, due to savings from reduced gas-fired capital expenditure and FOM, reduced VOM, and reduced fossil fuel usage (Table 4.4).

These costs are illustrated in Table 4.4 in terms of dollars per MWh of demand, based on a total energy usage of 251,300 GWh pa in 2020. Additional costs of the LRET in renewable generation capital and FOM sum are calculated to be $11.73 /MWh (calculated per MWh of demand). There is a saving of $1.02 /MWh to $1.66 /MWh on reduced gas-fired generation capital expenditure and FOM, a saving of $3.61 /MWh on reduced fuel and VOM costs. The total increase in cost due to the LRET amounts to $7.43 /MWh if wind is considered to contribute zero capacity to reliability, or a total cost of $6.77 /MWh if wind is considered to contribute 30% of capacity to reliability.

Note that these costs give the total cost of implementing the LRET, and are inclusive of costs that would be covered by RECs.

Optimal development to produce a least cost outcome has been assumed, and costs may vary (in either direction) if a sub-optimal development plan is implemented that deviates significantly from this.

4.3.2) Greenhouse emissions

As described in the assumptions section, a carbon price has been applied to this modelling consistent with a 5% reduction in emissions by 2020. This means that operation of emissions intensive generation has an associated carbon cost which has been taken into account in the planting decisions, and the dispatch merit order. The minimal carbon price that has been applied ($38 /tCO$_2$-e) is sufficient to prevent the entry of new coal-fired generation, and produces a small shift in the dispatch merit order towards less emissions intensive plant. If a carbon price does not eventuate by 2020, similar outcomes could be produced through alternative policies and measures, such as a moratorium on new coal-fired generation, and gas incentives schemes (similar in nature to the Queensland Gas Scheme).

The LRET is found to reduce emissions, as illustrated in Table 4.5. Emissions from gas-fired generation are reduced by 8 million tCO$_2$-e, and emissions from coal-fired generation are reduced by almost 12 million tCO$_2$-e in 2020. Renewable generation primarily displaces the most marginal generator type, which in this case (with a minimal carbon price) is gas-fired generation. Under a higher carbon price the LRET would likely reduce emissions much more since the marginal generator type would become much more emissions intensive coal-fired generation.

Table 4.5 – Greenhouse gas emissions (tCO2-e) (2020)

	No LRET	LRET	LRET minus No LRET
Gas generation	17,015,068	8,441,813	-8,573,255
Coal generation	205,279,624	193,540,882	-11,738,743
Other (biomass)	0	103,637	103,637
Total	222,294,693	202,086,332	-20,208,361

Due to the emissions reductions with the LRET, carbon costs are reduced when the LRET is implemented. Carbon costs are reduced by $769 million when the LRET is implemented (Table 4.6). This equates to a saving of $3.06 /MWh. If the carbon price were higher than $38 /tCO$_2$-e in 2020 then this saving is likely to be larger.

Table 4.6 – Summary of total cost of LRET (difference with LRET) - Carbon costs
(Real 2010 dollars, annualised costs in 2020)

	LRET (0% Capacity Cont.) minus **No LRET** ($m)	**LRET (30% Capacity Cont.)** minus **No LRET** ($m)	**LRET (0% Capacity Cont.)** minus **No LRET** ($/MWh)	**LRET (30% Capacity Cont.)** minus **No LRET** ($/MWh)
Total (no carbon cost)	1,867	1,701	$7.43	$6.77
Carbon cost ($38/tCO$_2$-e)	-769	-769	-$3.06	-$3.06
Total (with carbon cost)	1,099	933	$4.37	$3.71

Projecting emissions savings to life of scheme

Emissions savings from the LRET will vary year to year as the plant available in the market changes, and with shifts in other external drivers. Emissions reductions from the LRET over its entire life could be ideally assessed with an annual dispatch model, comparing each year to an identical scenario without the LRET scheme implemented. This would allow determination of the plant displaced by renewable generation in each half hour individually, allowing quantification of emissions saved. However, by making some simple assumptions a rough estimate of emissions savings over the life of the scheme can be achieved.

Since the LRET targets are constant from 2020 to 2030, it could be assumed that the amount of renewable energy entering the market driven by the scheme remains constant. The emissions savings from displacing emissions intensive plant are therefore likely to remain relatively constant over this period. Prior to 2020, a linear ramp up in emissions savings could be assumed, in line with linearly increasing annual LRET targets. Based upon these rough assumptions, the emissions savings from the LRET could be estimated to be of the order of 313 million tCO$_2$-e over the life of the scheme (from 2010 to 2030).

The SRES consists of contributions of RECs from small generating units (SGUs) and solar water heating (SWH). ROAM has previously estimated projections of possible installation levels of SWH and SGUs. ROAM's "medium" projection for the SRES exceeds the SRES targets in early years (due to the recent bubble in SWH and SGU installations), and settles to a long term equilibrium slightly above the SRES minimum target. Based upon this "medium" projection, and assuming:

- SWH installations replace electric water heaters on overnight tariffs, meaning that SWH installations mostly displace coal-fired generation (average emissions factor assumed to be 1.2 tCO$_2$-e/MWh sent out)
- SGU installations are assumed to be dominated by solar rooftop installations, which would typically displace peaking/intermediate gas-fired generation (OCGTs and CCGTs) (average emissions factor assumed to be 0.6 tCO$_2$-e/MWh sent out).

The solar multiplier was not applied, since RECs from the solar multiplier are not representative of real generation.

ROAM used these assumptions to make a rough estimate of the emissions avoided by the SRES. SWH under the SRES is estimated to contribute emissions savings on the order of 57 million tCO_2-e over the life of the SRES scheme, complemented by SGUs contributing emissions reductions on the order of 11 million tCO_2-e over the life of the scheme. This makes the total emissions savings of the SRES of the order of 68 million tCO_2-e over the life of the scheme (2020 to 2030).

This can be compared to similar assumptions regarding emissions savings from the MRET/RET to date. Data was extracted from the RECs registry to determine the number of valid RECs of each type that have been surrendered. SWH RECs were assumed to have displaced coal-fired generation, SGU RECs were assumed to have displaced peaking/intermediate generation, and all other RECs were assumed to have displaced a combination of the two (average emissions factor of $0.9tCO_2/MWh$). Based on these assumptions, the MRET/RET to date can be calculated to have produced an emissions saving on the order of 46 million tCO2-e, from the beginning of the scheme (2001) to 2009 (the RECs registry takes some time to update and include new RECs).

RECs under the SRES (and the MRET for SWH and SGUs) are deemed for the life of the installation, and all surrendered when the generator is first installed. This means that in this calculation SGUs and SWHs installed towards the end of the scheme contribute the full amount of their lifetime RECs to these estimates (even though the scheme will soon be ended). This was not assumed in the LRET calculations; for the LRET only the emissions savings included within the duration of the scheme were included as emissions savings. In reality, the renewable generation infrastructure installed under the LRET will continue to displace more emissions intensive generation beyond the life of the LRET scheme, reducing emissions further.

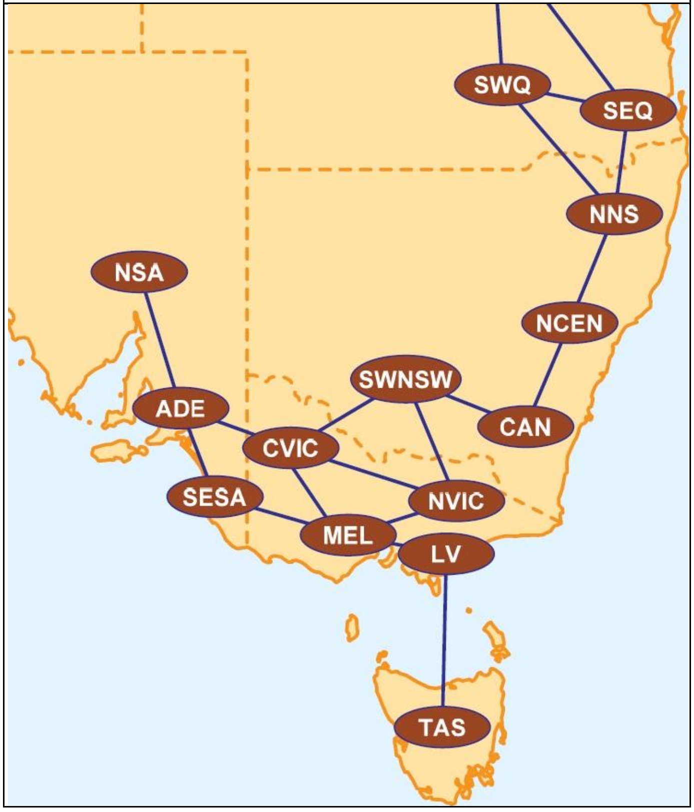
Table 4.7 – Greenhouse gas emissions savings

Scheme	Greenhouse gas emissions savings over life of scheme (tCO_2-e)
LRET (2010 to 2030)	313 million
SRES (2010 to 2030)	68 million
MRET/RET (2001 to 2009)	46 million

4.3.3) Transmission augmentation to support the LRET

The IRP chooses to install the same transmission augmentation in all three scenarios. Under a least cost condition it chooses to install a new 400 MW line from SA to VIC, running from NSA-ADE-SESA-MEL (refer to Figure 4.5).

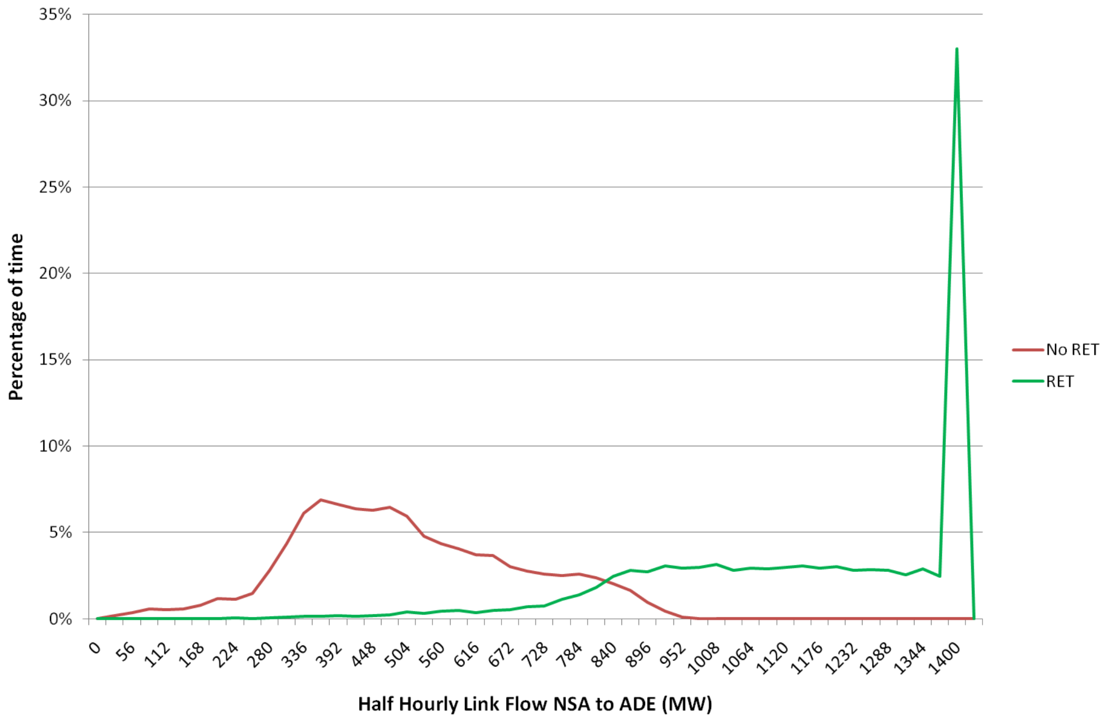
Figure 4.5 – Transmission augmentation flow path



In the scenarios with the LRET, NSA (Northern South Australia) is an appealing location for new wind generation and geothermal generation. 1000 MW of wind is installed in NSA, with a further 1000 MW installed in SESA. This is due to the excellent wind resource located in these areas. A 500 MW geothermal power station is also installed in SA, in addition to 100 MW of biomass capacity.

This abundance of renewable energy in South Australia drives strong export of low short run marginal cost renewable energy from South Australia to Victoria. Even with the new line installed, link flows are constrained at the upper limit flowing from NSA to ADE almost 35% of the time (Figure 4.6). This indicates strong utilisation of this new transmission line for export of renewable energy from SA to VIC.

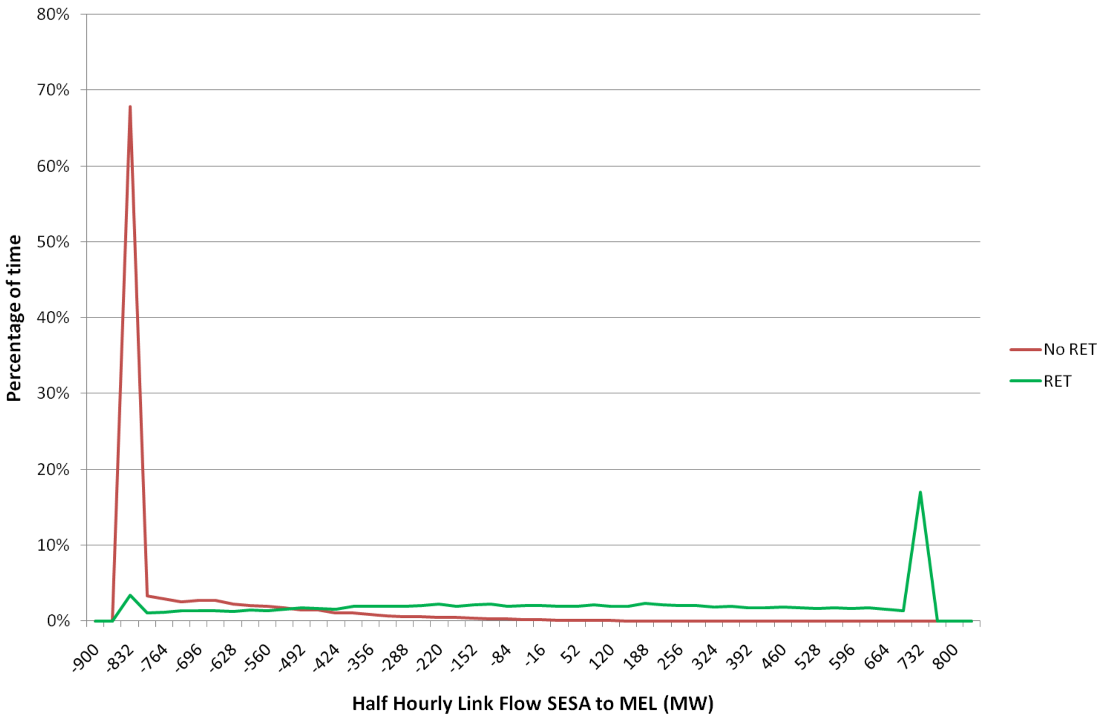
Figure 4.6 – Transmission link flow duration (NSA to ADE)



In the absence of the LRET, load growth in South Australia is not met by an increase in low cost local generation. Instead, 1000 MW of high short run marginal cost OCGT (open cycle gas turbine) plant is installed in ADE. This means that South Australia can be supplied at lower cost via import of energy from Victoria. This drives heavy imports into South Australia on the SESA-MEL line (Figure 4.7). Flows are constrained at the limit almost 70% of the time into South Australia.

These results mean that in either case (LRET or No LRET), the transmission augmentation is justified (albeit for different reasons in each case). Transmission augmentation of a similar scale is required even in the absence of the LRET, to supply energy and reliability at the lowest cost to consumers.

Figure 4.7 – Transmission link flow duration (SESA to MEL)



Even if further transmission were required, the cost of transmission augmentation is relatively small by comparison to other factors. The SA-VIC augmentation installed in these scenarios comes at a cost of $15.3 million pa. This includes annual capital repayments of $13.7 million, in addition to FOM of $1.6 million pa. Spread over the total energy consumed in 2020 (251,300 GWh) this translates to a total cost of $0.06 /MWh.

This analysis only considers a single scenario, and under other assumptions further transmission augmentation may be justified. However, this provides an indication that transmission augmentation is unlikely to be a significant cost associated with the LRET.

5) ANCILLARY SERVICES

Ancillary services are various services in addition to the supply of energy that are required for proper operation of the electricity system. They include:

1. Frequency Control Ancillary Services (FCAS)
2. Network Control Ancillary Services (NCAS)
3. System Restart Ancillary Services (SRAS)

The NEM has separate markets for each of these. Market participants bid into these various markets to provide the various ancillary services.

These ancillary services are different to each other in nature, and will be affected differently by the introduction of larger quantities of intermittent generation under the LRET. We will analyse each of these in turn in the sections below.

5.1) FREQUENCY CONTROL ANCILLARY SERVICES

Frequency Control Ancillary Services ensure that the system frequency is maintained close to 50 Hz, as required by the Market Rules. This is achieved by ensuring that supply (generation) always exactly matches the demand (load) in the system. This involves managing two types of events:

1. ***Normal operation (Regulation)*** - During normal operation the demand constantly varies (as loads in the system of various sizes turn on and off). This must be managed minute to minute via the use of one or several generators ramping generation up or down as required to match total system generation with total system load. The service is called "regulation". This can also be used to manage the normal variability in the operation of intermittent generators, and circumstances where scheduled generators do not exactly meet their dispatch targets.
2. ***Contingency Events*** - A contingency event is something outside the normal operation of the system. For example, if a generator in the system suddenly experiences an unexpected forced outage, the system frequency will rapidly fall. This fall must be quickly arrested via the replacement of that lost generating capacity.

It is expected that the introduction of a large quantity of intermittent generation will increase the requirement for regulation (FCAS under normal operation), potentially substantially. Wind generation is by nature intermittent and exhibits variability on various timescales. This variability is analogous to demand variability (demand constantly ramps up and down, and can be unpredictable on various timescales), and variability caused when scheduled generation does not exactly meeting dispatch targets. As the amount of installed wind capacity increases, the amount of plant providing this load following service will need to be increased. ROAM's previous analysis in the SWIS indicates that approximately 14% of the capacity of each new installed wind farm needs to be added to the load following requirement[13]. This may be lower in the NEM, where a larger amount of geographical smoothing of wind farm output is possible.

The introduction of larger quantities of intermittent generation is not expected to greatly affect FCAS contingency services. These are mostly concerned with sudden outages of large single units. Intermittent generators are typically composed of many small units, which are unlikely to go offline simultaneously (within one minute). Shifts in generation of these units over longer timeframes would be considered to fall within normal operation (rather than contingency events), and so would contribute to the regulation requirement (rather than the contingency requirement).

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[13] ROAM Consulting modelling for IMO WA, April 2010, Assessment of Frequency Control Services for high levels of intermittent generation. Presentation of results available at http://www.imowa.com.au/n139.html under Meeting 11 Papers (21 April 2010).

5.1.1) Cost of Regulation Ancillary Service

AEMO publishes data about the costs of ancillary services[14]. From late 2007 to April 2010 total ancillary services in the NEM cost an average of $3.35 million per week ($174 million per annum). This cost is spread across market participants according to who has created the need for the service.

Generators are responsible for the costs of contingency "Raise" services, since these are typically required if a large generator experiences an unexpected forced outage. Contingency "Raise" services comprise an average of 46% of total costs of ancillary services.

Similarly, customers are responsible for the costs of contingency "Lower" services, since these are typically required if a large load experiences an unexpected forced outage. Contingency "Lower" services comprise an average of 7% of the total costs of ancillary services.

Regulation services are among the least expensive of ancillary services, comprising only 2.9% of the total ancillary services cost on average. Regulation services are required by both loads (with typically variable demand) and intermittent generators, and the costs are divided on a "causer pays" basis. Based on historical data, loads are typically responsible for 70% of the costs of regulation, and generators are responsible for 30% of the costs of regulation.

Ancillary services costs in the NEM are shown in Figure 5.1, as paid by customers and generators. Costs are shown per MWh of demand. In most weeks, costs are very low, being on average $0.41 /MWh for customers, and $0.48 /MWh for generators ($0.89 /MWh in total).

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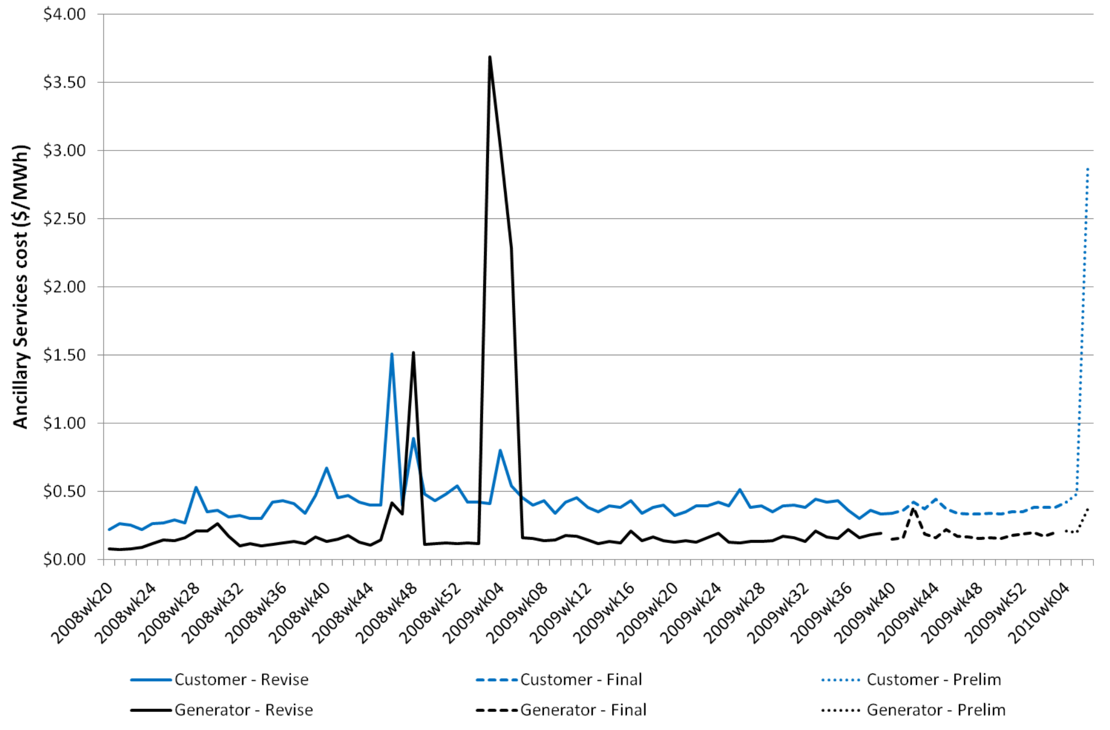
[14] http://www.aemo.com.au/electricityops/883.html

Figure 5.1 – Historical Ancillary Services Costs in the NEM



Projection of costs of ancillary services with LRET

There is currently 1557 MW of wind generation installed in the NEM. If we make the conservative assumption that all regulation costs paid by generators are paid by these wind farms, we can draw some insight into the likely future costs of the regulation service as the quantity of installed wind capacity increases. Under this assumption, these wind farms currently face a regulation cost of $1.5 million per annum, which amounts to $975 pa per MW installed. Assuming an average capacity factor of 30% this equates to $0.37 /MWh. This can be considered to be a cost that these wind farms are already experiencing, and thus including in their cost assumptions in decision making.

Modelling by ROAM shows that the correlation in output between installed wind farms is critical in determining the amount of increase in the regulation requirement due to their introduction to the system[15]. If new wind farms are geographically dispersed, as the installed capacity of wind increases, the marginal increase in the regulation requirement will decrease. The first large wind farm installed may increase the system variability a great deal, but a second equally large wind farm located in a geographically separate area (such that the output of the two wind farms is uncorrelated in time) is unlikely to substantially increase the regulation requirement. However, if the second wind farm is co-located with the first wind farm such that their output is highly correlated, the regulation requirement will increase substantially with the introduction of the second wind farm.

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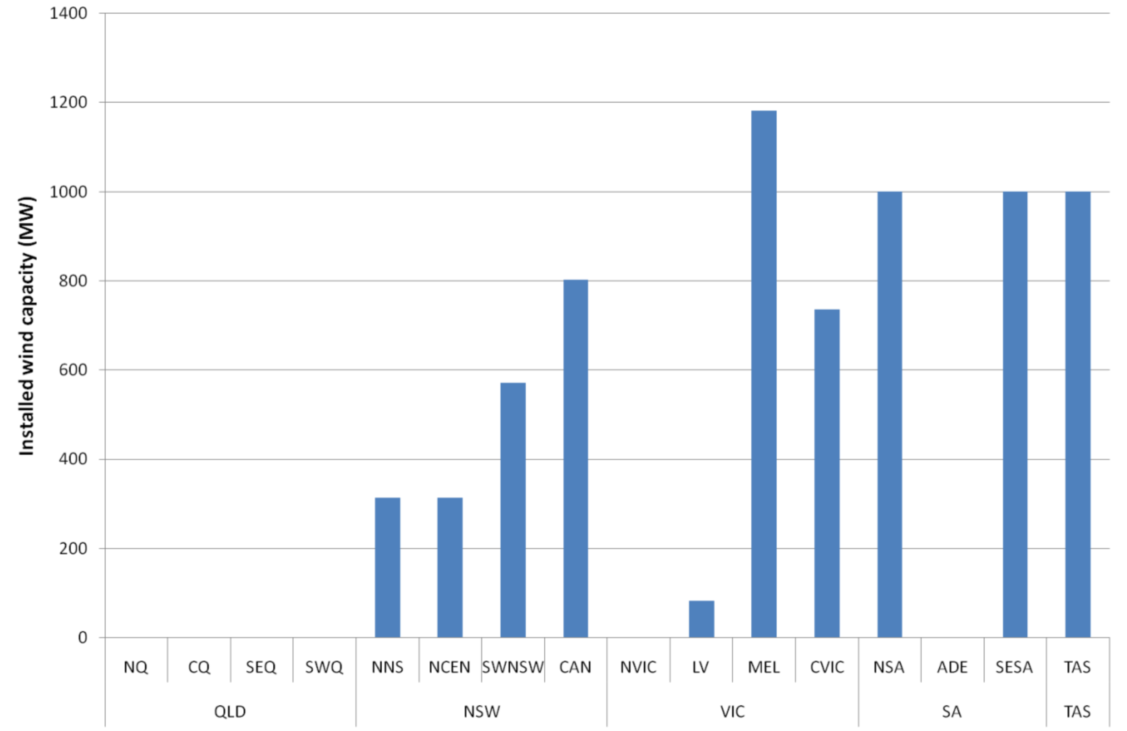
[15] ROAM Consulting modelling for IMO WA, April 2010, Assessment of Frequency Control Services for high levels of intermittent generation. Presentation of results available at http://www.imowa.com.au/n139.html under Meeting 11 Papers (21 April 2010).

The existing wind farms are moderately geographically dispersed, with 870 MW installed in South Australia, 490 MW installed in Victoria, and relatively smaller quantities in Tasmania, New South Wales and Queensland. Some level of correlation between the existing wind farms would be expected, increasing the existing regulation requirement.

The IRP results show a similar geographical distribution of wind farms projected forwards (Figure 5.2). The distribution of wind farms in the IRP is based upon a tiered approach; wind farms are grouped into blocks with the highest capacity factor wind farms in the first tier (installed first), and lower capacity factor wind farms in each state installed sequentially in later blocks. The IRP selects the lowest cost order in which to install each block, based upon the operation of the individual wind farms in each block.

Figure 5.2 – Distribution of installed wind in NEM (2020, IRP results)



Based upon these results we can assume that a similar degree of correlation in output is likely to exist between future wind farms as does between existing wind farms. This suggests that the cost per megawatt of wind installed for the regulation service should remain relatively constant into the future, as more wind is installed (the cost of regulation to generators grows linearly as the capacity of wind installed increases).

On this basis, with a total installed wind capacity[16] of 8557 in 2020, the regulation ancillary service would cost generators $8.3 million per annum. As before, this equates to $975 /MW per annum, or $0.37 /MWh (assuming a 30% capacity factor).

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[16] 1557 MW existing capacity in addition to 7000 MW of new installed capacity.

Other ancillary service costs are expected to remain unaffected, giving a total ancillary services cost to generators of $102.5 million with the increased 7000 MW of wind generation capacity (compared with $95.6 million with the existing 1557 MW of installed wind). Comparing this with the MWh of demand shows that the total ancillary service cost to all generators increases from $0.48 /MWh of demand to $0.53 /MWh of demand. Ancillary services costs directly to consumers are expected to remain unchanged at $0.41 /MWh of demand, given a total cost of ancillary services of $0.92 /MWh of demand. This is an increase of 3c per MWh of demand, which can be considered to be negligible.

These costs are summarised in Table 5.1.

Table 5.1 – Ancillary Services Costs (AEMO)

		2010 (existing)	**2020 (projected)**
Installed wind capacity	Total in NEM	1557 MW	8557 MW
Cost of Regulation Ancillary Services	Total	$1.52 million pa	$8.3 million pa
	As paid by wind generators	$975 /MW pa	$975 /MW pa
	As paid by wind generators, 30% capacity factor	$0.37 / MWh	$0.37 / MWh
Total cost of ancillary services to generators (AEMO)	$ million pa	$95.6 million pa	$106.4 million pa
	$ /MWh of demand	$0.48 /MWh	$0.53 /MWh
Total cost of ancillary services to customers (AEMO)	$ million pa	$78.7 million pa	$78.7 million pa
	$ /MWh of demand	$0.41 /MWh	$0.41 /MWh
Total cost of ancillary services (AEMO)	$ million pa	$174.4 million pa	$181.2 million pa
	$ /MWh of demand	$0.89 /MWh	$0.92 /MWh

5.2) NETWORK CONTROL ANCILLARY SERVICES

Network Control Ancillary Services (NCAS) fall into two categories:

1. ***Voltage control*** - this service is required to maintain the voltage on the electrical network to within specified tolerances. This can be achieved through the dispatch of generators that can absorb or generate reactive power from or onto the electricity grid and control the local voltage. Reactive power cannot be transmitted long distances, and therefore must be provided on a local basis.
2. ***Network loading control*** - Network loading ancillary services are used to control the flow on interconnectors to within short term limits. This is achieved by adjusting the dispatch of generation on either side of the interconnector.

Voltage control in the NEM is the responsibility of various different parties:

- Transmission network service providers (TNSPs) are responsible for providing sufficient voltage control in the transmission network to support peak demand under normal conditions
- AEMO is responsible for providing sufficient voltage control in the transmission network under contingency conditions
- Distribution network service providers (DNSPs) are responsible for voltage control in the distribution network

The costs of providing voltage control ancillary services therefore are split between these parties.

Voltage control can be provided in various ways. Different generators have different reactive power supply and absorption capabilities, and are often contracted to provide the balance of positive and negative reactive power required in their local area. If no local generation is available or capable of providing the required voltage support, a Static VAR Compensator (SVC) can be installed. These provide effective fast-acting reactive power, but are relatively expensive devices.

Wind generation could have significant implications for the voltage control ancillary service. Conventional generators are an important source of reactive power and contribute significantly in maintaining voltage stability. The increasing penetration of wind farms is likely to displace some of the conventional generators and their capacity to supply reactive power may need to be replaced[17]. In addition, the reactive power demand of the system varies with system loading. By introducing a large amount of intermittent generation into the system reactive demand patterns are modified, and the VAr demand/supply volatility will also be increased.

Wind farms can provide (dynamic) voltage support, but this is heavily dependent upon the type of wind technology installed. Older design fixed-speed induction machines usually have a negative impact on dynamic voltage stability unless they are fitted with additional reactive power equipment[18]. However, more modern variable speed wind generators (Double Fed Induction Generators, DFIGs) are able to provide voltage control capability, as are synchronous wind generators.

Therefore, in some circumstances, wind generation may avoid the necessity of installing expensive reactive power devices that would otherwise be required. Voltages at the end of long radial networks (typical of the distribution network) are often poor. Wind plants installed at the end of long radial lines that have a reactive power control system can therefore benefit the system by supporting the local voltage,[19] and improving the overall system voltage profile[20] [21].

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[17] Econnect, "South West Interconnected System (SWIS) - Maximising the Penetration of Intermittent Generation in the SWIS". Econnect Project No: 1465. Prepared for Office of Energy, Western Australia. 2005.

[18] Impact of Large Scale Wind Power on Power System Stability. Ch. Eping, J. Stenzel, M. Poller, H. Muller. DIgSILENT Consulting.

[19] European Wind Energy Association.

[20] A. P. Agalogaonkar, S. V. Kulkarni, S. A. Khaparde, "Impact of Wind Generation on Losses and Voltage Profile in a Distribution System", Conference on Convergent Technologies for Asia-Pacific REgion, TENCON 2003, Vol. 2, pp. 775-779.

The relative locations of wind farms is also important in determining whether they have a positive or negative impact on voltage profiles. Dispersion of wind farms typically minimises voltage impacts and the corresponding reactive power requirement[22].

Many international grid codes have implemented standardised minimum requirements for wind farms regarding reactive power, but there are concerns that these may be unnecessarily stringent, placing additional cost burdens on wind farm developers. In the NEM no capability is required of new generation to supply or absorb reactive power at the connection point, under the minimum access standard[23], with the exception of South Australia. In South Australia the regulator (ESCOSA) has imposed a licence condition requiring wind farms to be capable of generating and absorbing reactive power similar to the Automatic access standard.

It may become appropriate for wind farms in the NEM generally to take responsibility for managing a certain level of reactive power capability on a case by case site specific approach[24]. This could help to provide incentives for wind farm developers to make choices that minimise impacts on reactive power requirements.

These factors suggest that voltage control could be significantly affected by the integration of large quantities of intermittent generation, but that strategies to minimise this impact are available. Appropriate incentives to wind farm developers may assist in minimising NCAS cost increases.

5.2.1) Costs of Voltage Control

Potential increases in cost in the Voltage Control ancillary service have not been included in the previous analysis (NCAS costs were assumed to remain constant). This is because voltage control services are only partially the responsibility of AEMO; transmission network service providers and distribution network service providers are likely to bear substantial proportions of the cost if increased penetration of intermittent generation requires additional voltage control infrastructure.

As discussed above, the amount of additional voltage control infrastructure required could vary substantially depending upon the type of wind turbines installed, and the locations of those wind farms.

In the best case, wind farms could contribute positively to voltage control, reducing NCAS costs.

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[21] K. C. Divya, P. S. Nagendra Rao, "Models for Wind Turbine Generating Systems and their Application in Load Flow Studies". ELSEVIER, Electric Power Systems Research Vol. 76, 2006, pp.844-856.

[22] K. Yang, A. Garba, C. Tan, K. Lo, "The impact of the wind generation on reactive power requirement and voltage profile". IEEE, DRPT2008, 6-9 April 2008, Nanjing China.

[23] National Electricity Rules Version 35, Chapter 5, Network Connection, page 435. S5.2.5.1 b).

[24] G. Marzio, J. Eek, J. Tande, O. Fosso, "Implication of Grid Code Requirements on Reactive Power Contribution and Voltage Control Strategies for Wind Power Integration". IEEE, 2007.

In the worst case, the introduction of 7000 MW of new wind farms could require substantial new voltage control infrastructure. To provide an estimate of the upper bounds of the possible cost, ROAM has made the following assumptions:

- 7000 MW of new wind farms are installed in the NEM (as per the IRP results in the LRET scenarios).
- All of the new installed wind farms are older design fixed-speed induction machines that do not contribute to voltage support
- All of the new installed wind farms are located in very weak parts of the grid where there is insufficient local voltage support
- All of the new installed wind farms therefore require associated Static VAR Compensator (SVC) infrastructure of a sufficient size to support the local voltage.

It should be noted that these are extreme assumptions intended to provide an upper bound on cost. It is very likely that many wind farms will be located in areas where the local voltage support is sufficient, or that some of the installed wind farms will be newer designs that provide some local voltage support. In addition, where increased voltage support is required, much cheaper capacitor banks may be sufficient in many cases (rather than the much more sophisticated and expensive SVC equipment).

A 350 MVAr SVC installation costs approximately $35 million[25], giving a cost of $0.1 million per MVAr of reactive power. In the worst case, it could be assumed that 1 MVAr of reactive power is required to support each installed MW of wind capacity (active power). This would mean that in the worst case 7000 MVAr of SVC equipment would be required to support 7000 MW of installed wind capacity. This would have a total cost of $700 million. With an expected equipment lifetime of 30 years and a WACC of 9.79%, this gives an annualised cost of $73 million pa. Spread over the annual energy consumed in 2020 this equates to $0.29 / MWh.

This data is summarised in Table 5.2. Note that this cost is likely to be divided between distribution and transmission network providers.

Table 5.2 – Estimate of upper bound on NCAS cost increases
(Real 2010 dollars)

Cost of SVC infrastructure	$0.1 million / MVAr
Reactive power requirement	1 MVAr / MW
Installed wind capacity	7000 MW
Total reactive power requirement	7000 MVAr
Total cost of SVC equipment	$700 million

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[25] Australian Energy Regulator (AER) Draft Decision - Queensland transmission network revenue cap 2007-08 to 2011-12. Dec 2006. p.197. Value of $25 million has been increased to account for inflation. Similar costs are listed in Powerlink Final Report, "Augmenting the transmission network in South Eastern Queensland", 22 June 2007. Also in NEMMCO 2008 Statement of Opportunities.

Lifetime of SVC equipment	30 years
WACC	9.79 %
Annualised cost of SVC equipment	$73 million pa
Cost of SVC equipment per MWh of demand in 2020	$0.29 / MWh

5.3) SYSTEM RESTART ANCILLARY SERVICES

System Restart Ancillary Services are required to enable the system to be restarted following a complete or partial system blackout. Only certain generators are capable of restarting without any external source of supply. On the assumption that system reliability and security will be maintained as specified in the Market Rules, this service is not expected to be substantially affected by the introduction of intermittent generation.

6) DISTRIBUTION NETWORK INFRASTRUCTURE

Distribution costs already form a substantial component of the cost of electricity to consumers. Distribution costs are expected to rise as demand grows, but the contribution of renewable energy is unclear. There are likely to be competing factors.

Renewable development may contribute to distribution network costs via the following:

- ***New network connections*** - New renewable installations require new network connections, and smaller generators are often connected to the distribution network. However, renewable generators are often considered to be responsible for these costs, which would therefore be reflected in the LRET cost (costs are accounted for under the REC price). This has been the assumption in the modelling included in this report (all new connection costs are included in the capital costs of renewable projects).
- ***Voltage stability*** - Where medium scale renewable generation is installed and connected to the distribution network (for example an embedded 10 MW wind farm) this may have additional impacts of the LRET on distribution networks related to voltage stability requirements and other local electronics required. This is discussed further in the chapter on Ancillary Services.

These costs have been included explicitly in the IRP model (new network connections) and in the chapter on ancillary services (voltage stability infrastructure).

Renewable development may reduce distribution network costs via the following:

- ***Reducing load with embedded generation*** - There is substantial interest in household embedded generation under the enhanced RET (through the SRES), such as rooftop solar photovoltaics. These technologies supply electricity directly at the point where it is required, reducing use of the distribution network. Larger embedded generators (such as small wind farms and solar installations) that are appropriately sized for the local network can also serve to reduce local loads, reducing strain on the distribution network.

- ***Offsetting growing 'peakiness' of demand*** - Much of the increase in distribution costs is likely to be due to increasing "peakiness" of demand, driven by factors such as air-conditioning loads (which increase demand in peak periods, but relatively little in off-peak periods). A large proportion of the investment in distribution networks is aimed at meeting this peak demand. This suggests that embedded intermittent generators that operate during or close to peak periods (such as solar technologies) could effectively reduce peak demands, allowing postponement of augmentation of the distribution network.

The extent of these possible positive impacts is unclear at this stage, so they have not been quantified in this report.

Distribution Loss Factors (DLFs)

Distribution Loss Factors (DLFs) describe the average electrical energy losses for electricity transmitted on a distribution network between a distribution network connection point and a transmission network connection point. The price of electricity paid by loads (and paid to generators) in a particular area is multiplied by the DLF calculated at that point. A DLF greater than one indicates an excess of load in an area, such that electricity usually flows into that area from generators located in another part of the network. Since distribution networks typically supply loads, and do not contain a large quantity of generation, DLFs are typically greater than one. This indicates that any generation located in these areas reduces average losses in the distribution network, and therefore has a positive incentive to locate there.

When a generator connects to the distribution network the DLF at that node will be adjusted to reflect the impact of that new generator. If the generator is very large, supplying the local load and also supplying additional energy that must be exported through the distribution network, the DLF will be reduced to below one. In areas where the distribution network is particularly weak (and would therefore require significant augmentation to accommodate the new generation) this effect will be particularly strong. Where the network is stronger, the adjustment to the DLF will be smaller. This penalty provides a significant disincentive for larger generators to locate in areas where the grid is insufficient to support their size. This will tend to minimise potential negative impacts of renewable generation on the distribution network.

7) CONCLUSIONS

ROAM has identified a wide variety of costs and benefits of the LRET, outlined and quantified in the following tables.

Table 7.1 – Summary of total cost of LRET (scenarios with and without LRET)
(Real 2010 dollars, annualised costs in 2020)

	No LRET ($m)	**LRET (0% Capacity Cont.)** ($m)	**LRET (30% Capacity Cont.)** ($m)
New Renewable Plant FOM and Capital	0	2,946	2,946

New Gas-fired Plant FOM and Capital	1,004	748	586
Connection Costs (new plant)	21	106	102
Existing plant FOM	2,019	2,019	2,019
VOM + Fuel (existing and new plant)	4,092	3,184	3,184
New Transmission FOM and Capital	15	15	15
Ancillary services (AEMO) - includes regulation (FCAS)	174.4	181.1	181.1
Additional SVC equipment to support wind (NCAS) - extreme upper bound estimate	0	73	73
Total (no carbon cost)	**7,325**	**9,272**	**9,106**
Carbon cost ($38 /tCO$_2$-e)	8,456	7,687	7,687
Total (with carbon cost)	15,781	16,960	16,794

Table 7.2 – Summary of total cost of LRET (difference with LRET)
(Real 2010 dollars, annualised costs in 2020)

	LRET (0% Capacity Cont.) minus **No LRET** ($m)	**LRET (30% Capacity Cont.)** minus **No LRET** ($m)	**LRET (0% Capacity Cont.)** minus **No LRET** ($/MWh)	**LRET (30% Capacity Cont.)** minus **No LRET** ($/MWh)
New Renewable Plant FOM and Capital	2,946	2,946	$11.73	$11.73
New Gas-fired Plant FOM and Capital	-256	-418	-$1.02	-$1.66
Connection Costs (new plant)	85	81	$0.34	$0.32
Existing plant FOM	0	0	$0.00	$0.00
VOM + Fuel (existing and new plant)	-908	-908	-$3.61	-$3.61
New Transmission FOM and Capital	0	0	$0.00	$0.00
Ancillary services (AEMO) - includes regulation (FCAS)	7	7	$0.03	$0.03

Additional SVC equipment to support wind (NCAS) - extreme upper bound estimate	73	73	$0.29	$0.29
Total (no carbon cost)	**1,947**	**1,781**	**$7.75**	**$7.09**
Carbon cost ($38 /tCO$_2$-e)	-769	-769	-$3.06	-$3.06
Total (with carbon cost)	1,178	1,012	$4.69	$4.03

Only the changes in transmission and distribution system costs have been included here. Transmission and distribution network service providers have ongoing FOM costs for their existing networks, which will be the same in all three scenarios. Since this analysis is interested in the differences between scenarios, these existing ongoing costs have not been included.

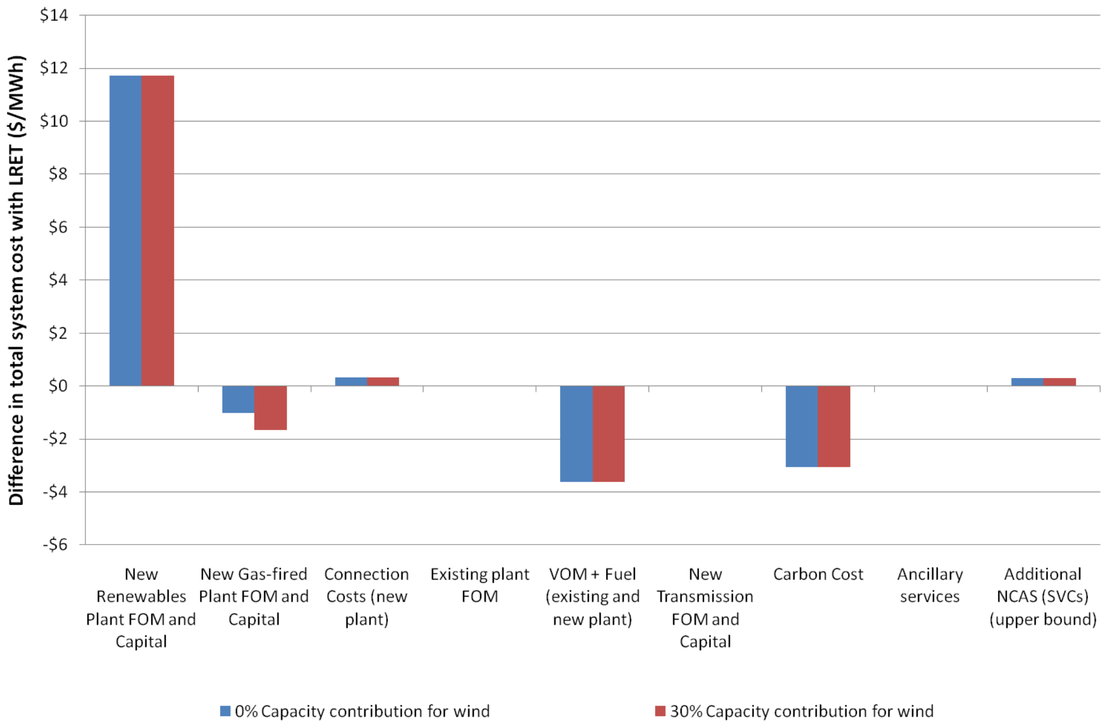
Consumers will also be exposed to retailer margins. These are similarly assumed to be identical in all three scenarios (unaffected by the LRET), and have therefore not been explicitly listed.

The costs listed here represent actual underlying costs, and do not take account of market gaming strategies, or any market power that individual market participants may have to inflate the price in various markets (for wholesale electricity in the pool, or for FCAS, for example).

LRET costs to retailers are not included in this cost calculation, since the LRET scheme simply provides monetary redistribution within the energy sector to support the capital expenditure on renewable generation via REC payments from retailers and consumers. Inclusion of the actual costs of the LRET to the system therefore requires calculation of the actual capital repayments (as has been done in this study), rather than the “costs” of RECs to retailers.

Figure 7.1 illustrates the various cost components that have been identified, comparing the scenarios with the LRET to the scenario without the LRET. The increase in capital and FOM costs from new renewable plant ($11.73) is offset by the decreased capital and FOM from new gas-fired plant (-$1.02 to -$1.66), and decreased costs in VOM and fuel for new and existing plants (-$3.61). These components are found to be substantial.

Figure 7.1 – Summary of total cost of LRET (difference from No LRET case)
(Real 2010 dollars, annualised costs in 2020)



Increases in other "hidden" costs of the LRET are found to be very small, including:

- Expansion of transmission infrastructure
- Connection costs of new plants
- Ancillary services (FCAS)
- Voltage control (NCAS)

Comparison to previously calculated costs

In an earlier report to the Clean Energy Council[26], ROAM calculated the costs of the LRET and SRES to consumers. Depending upon the LRET price and the amount of SWH and SGU installations the total cost to consumers of the LRET in 2020 was found to range between $10.40 /MWh and $16 /MWh. The cost of the SRES ranged between $0.30 /MWh and $1.10 /MWh. At the high end, this study included extreme projections of possible high REC prices, in order to capture the full range of possible costs to consumers of the LRET.

These previously calculated costs are indicative of the costs that consumers will incur as a direct result of liability for RECs, assuming a range of REC prices. They do not take account of savings from reduced capital investment in gas-fired plant, reduced VOM and reduced fuel costs. These are genuine savings that in an efficient market should be passed onto consumers via lower wholesale electricity prices.

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[26] ROAM Consulting report to Clean Energy Council, "Implications of the LRET and SRES modifications to the LRET". 18th March 2010.

These previously calculated costs based upon REC liability could be compared to the increase in capital cost and FOM of new renewable plant entering under the LRET. This study indicates this to be $11.73 /MWh. This is comparable to the previously calculated values, which do not take account of the "hidden benefits" that have been quantified in this study.

Appendix A) Glossary

General:

AEMO	Australian Energy Market Operator
CCGT	Combined Cycle Gas Turbine
CPRS	Carbon Pollution Reduction Scheme
CPT	Carbon Price Trajectory
DFIG	Doubly-Fed Induction Generator (type of wind turbine)
DLF	Distribution Loss Factor
DNSP	Distribution Network Service Provider
FCAS	Frequency Control Ancillary Service
FOM	Fixed operations and maintenance
IRP	Integrated Resource Planning (ROAM Software)
LOLP	Loss of Load Probability
LRET	Large-scale Renewable Energy Target
MLF	Marginal Loss Factor (losses in transmission network)
NCAS	Network Control Ancillary Service
NEM	National Electricity Market
OCGT	Open Cycle Gas Turbine
REC	Renewable Energy Certificate
RET	Renewable Energy Target
ROAM	ROAM Consulting
SRAS	System Restart Ancillary Service
SRES	Small-scale Renewable Energy Scheme
SVC	Static VAR Compensator (Voltage Control equipment)
SWIS	South West Interconnected System (WA electricity grid)
TNSP	Transmission Network Service Provider
VOM	Variable operations and maintenance

Zones in the National Electricity Market:

ADE	Adelaide
CAN	Canberra
CQ	Central Queensland
CVIC	Country Victoria
LV	Latrobe Valley
MEL	Melbourne
NCEN	Central New South Wales

NNS	Northern New South Wales
NQ	North Queensland
NSA	Northern South Australia
NVIC	Northern Victoria
SEQ	South East Queensland
SESA	South East South Australia
SWNSW	South West New South Wales
SWQ	South West Queensland
TAS	Tasmania

Appendix B) Overview of the IRP Model

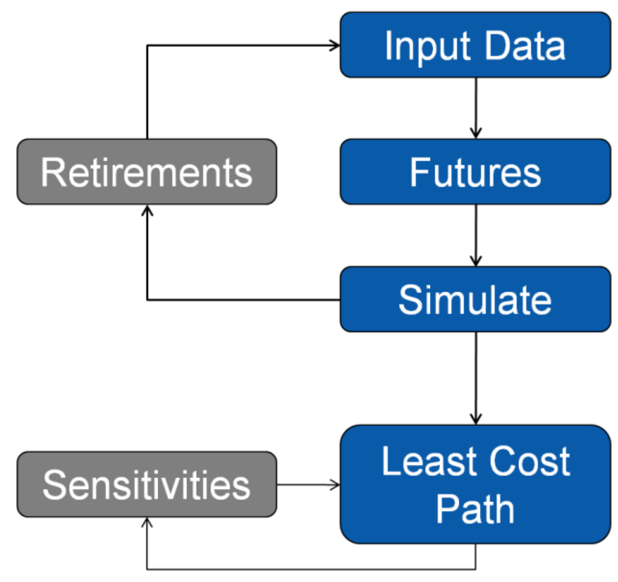
The least cost planning outcomes for each scenario and system were developed using ROAM's Integrated Resource Planning Suite (IRP). IRP can be used to find least cost generation and transmission expansion plans for any power system, given client-specified parameters and constraints. It takes into account existing supply, forecast demand, and financial and regulatory considerations, to produce an optimal new entry generation development, retirement, and transmission upgrade schedule over the duration of the study.

The IRP methodology is in accordance with world's best practice, and applies an underlying model and solution algorithm similar to that employed by the Wien Automatic System Planning (WASP) program developed by the International Atomic Energy Agency. WASP is currently one of the most widely used models for power system planning.

The IRP method follows the flow chart shown in Figure B.1. The broad methodology involves:

1. **Input Data.** Input data is determined, including new entrant options, network upgrade options, demand and costs. Basic long run marginal cost (LRMC) analysis is performed on new entrant technologies in each location to determine potential least cost candidates.
2. **Futures.** Possible "states" are determined subject to constraints such as the Renewable Energy Target, minimum reserve levels and technology build rate limits, as well as network upgrade combinations.
3. **Simulate.** Each state is simulated using ROAM's 2-4-C dispatch engine to determine the production cost. This is done on a time sequential basis, and captures both network constraints and the operation of intermittent generation.
4. **Retirements.** Plant revenue is assessed and plant that is no longer profitable is retired.
5. **Iterate.** The above procedure is iterated for future years of the study.
6. **Least cost path.** Finally, ROAM employs a dynamic programming algorithm to find the least cost path over the entire study period, taking into account production costs, fixed and variable operating costs and capital repayments for new entrant generation and transmission options.
7. **Sensitivities.** Common sensitivities conducted by ROAM include investigating the impact of locking in or out various options (e.g., forcing the construction of an interconnector), or varying capital costs to find the required effective cost for entry of a specific technology.

Figure B.1 – IRP methodology



B.1) *Futures - Creating possible planting schedules*

In the NEM, the IRP considers the construction of new plant in blocks subject to system constraints such as:

- Regional capacity contributions at least meet peak demand plus the minimum reserve level (MRL) in each region[27]
- Renewable generation to meet the annual Renewable Energy Target and GreenPower take-up
- Earliest entry dates for technology types (e.g., CCS or geothermal)
- Annual build limits (by zone or aggregate)
- Capacity limits (by zone)

New entrant plant sizes are set at the 'typical new entrant size' specified for each plant type.

The IRP then constructs possible planting options that would satisfy all these constraints within the given year, which will form the search space for a least cost solution.

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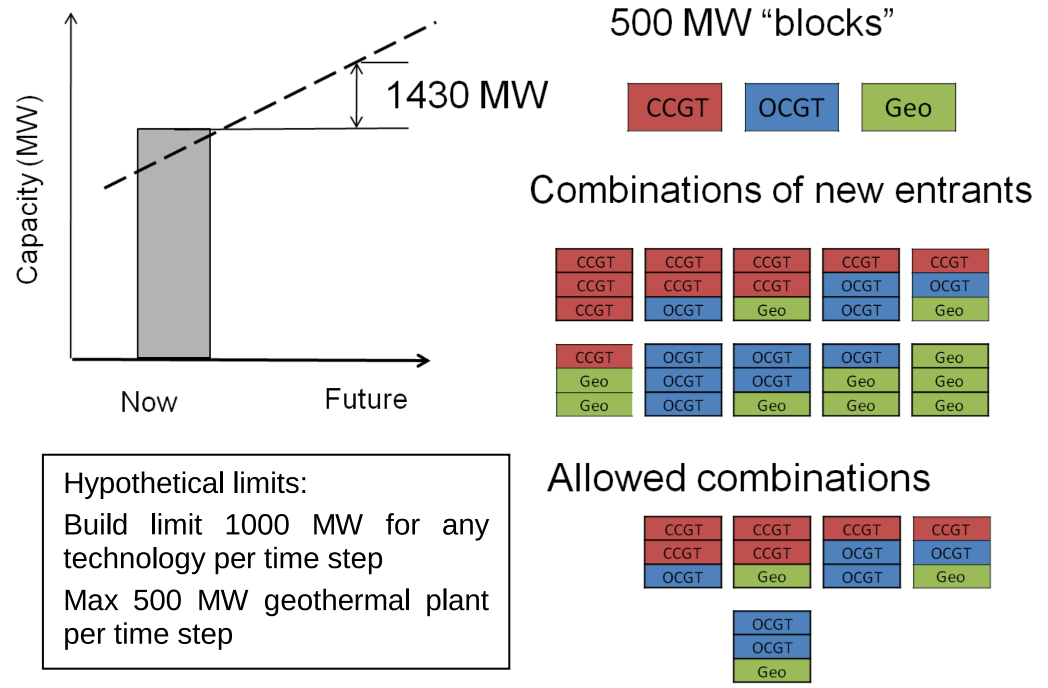
[27] Current (2006) minimum reserve levels for each region were used for the entire study period.

Thermal plant, biomass plant and geothermal plant were assumed to have 100% of their capacity available at times of peak demand.
Wind farms are assumed to have a 15% contribution to peak, representative of the large capacities being installed and the (presumably) diverse siting, which will increase reliability. The exception is in South Australia where wind farms are assumed to have only 3% contribution based on specific available data. Solar thermal plant is assumed to have a 90% contribution to peak demand.

A sample IRP calculation step is shown in Figure B.2 for a hypothetical scenario where an increase in demand of 1430 MW is required to be met. The IRP is given the option to install 500 MW blocks of either CCGT, OCGT or geothermal plant. To at least meet the MRL, this would require the construction of three blocks, leading to 10 possible planting options.

In practice, however, some of these options do not need to be considered. For example, build rates might limit the construction of any one type of technology. In Figure B.2, a build rate of 1000 MW per time step for CCGT and OCGT plant and 500 MW for geothermal has been applied, resulting in only five states that need to be considered (these limits are for demonstrative purposes only).

Figure B.2 – IRP methodology



Hypothetical limits:

Build limit 1000 MW for any technology per time step

Max 500 MW geothermal plant per time step

This procedure is applied to each region of the system producing many system-wide combinations of new entry planting. Any global constraints (such as the LRET) are then applied to produce a final set of viable "states".

Network upgrades are also considered as options and applied in a similar fashion. In this work, no modifications to regional minimum reserve level constraints were applied when an interconnector was upgraded.

Renewable options

Wind farms in each state were planted by the IRP in 1000 MW blocks. Each 1000 MW block is made up of the best available wind, potentially across multiple zones, and is planted in order by the IRP such that each subsequent block of installed wind within a zone is at a lower capacity factor, capturing the decreasing quality of sites available.

Simulate – Obtaining production costs

Generator maintenance plans (unique to each generator) are included, in addition to partial and full forced outages. Generator forced outages are included in the model via Monte Carlo seeding (including hydro generators).

The same seed is used for each generator in each set of states in each year, and each generator has a unique seed, to ensure equitable comparison across all potential planting schedules considered.

Each IRP state is then simulated at two-hourly time sequential dispatch intervals. The variable annual energy production of each individual generator is recorded. The production cost of each state is then calculated as the sum over all generators of their annual generation multiplied by their sent-out SRMC.[28]

B.2) *Retirements*

Swanbank B and Munmorah were assumed to be retired by 2020 for this study, based upon announcements. It was assumed that no further plant would retire before 2020 based on proposed carbon price trajectory transitional compensation payments made to generators to maintain capacity for reliability.

B.3) *Iterate – Developing whole of study planting schedules*

In studies where multiple years are considered, the IRP repeats the above sequence for each subsequent year, developing planting schedules based on each state in the previous year. This typically results in an exponential growth in the number of states at each time step, as shown in Figure B.3.

Typically, there are between 100,000 and 300,000 possible states to be simulated in 2030. Some states will “converge” in each year, corresponding to two different pathways to reach the same outcome (e.g., building an OCGT then a CCGT or vice versa, both of which result in a state with one OCGT and one CCGT) provided that the merit order is not affected by different build years. The learning curve in capital costs (such that the cost of a state depends on the year in which a station is built) is accounted for in the next step of the IRP.

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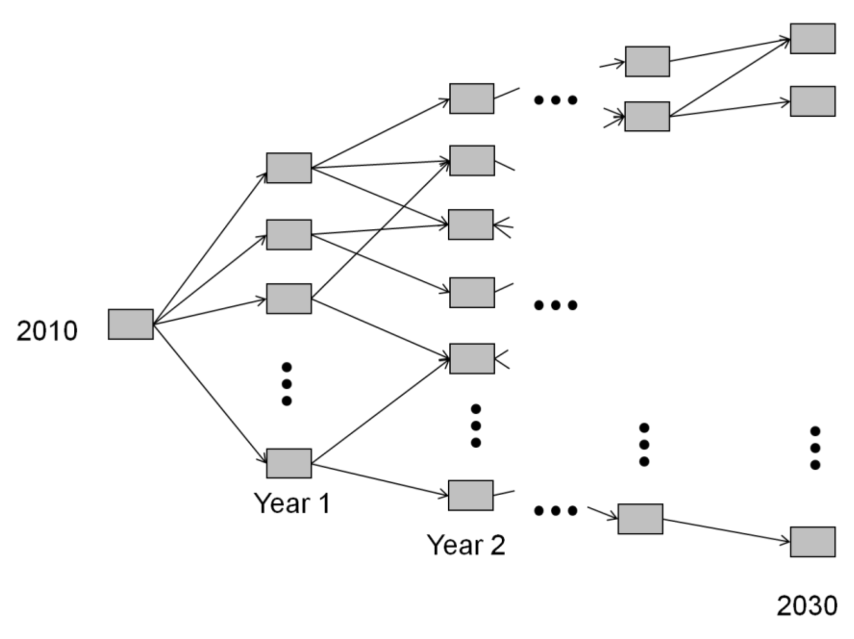
[28] As discussed in Section **Error! Reference source not found.** a generator’s sent-out SRMC includes fuel costs, variable O&M and carbon costs (emission and /or storage costs).

Figure B.3 – IRP methodology



B.4) *Least Cost Path*

To determine the least cost outcome, ROAM applies a Dynamic Programming (DP) algorithm that searches for the least cost outcome over the entire study period. This methodology allows millions of possible paths to be evaluated.

The optimization is over the entire study period, such that the least cost outcome may include plant or interconnector upgrades that are unfavourable when viewed in a single year but provide long term benefits. For an interconnector option to be installed by the IRP, the cost of the upgrade must be outweighed by the reduction in generation capital, fuel, O&M and emissions costs elsewhere in the system.

End effects were addressed by considering annualised costs for all generator and network options. In this way, costs are applied continuously over the life of the plant (which extends beyond the study period) and helps eliminate the incentive for low capital cost plant in the final year of the study.

B.5) *Calculation of costs*

To determine the minimum cost planting outcome, full scenario costs were calculated.

Discounting

All costs are expressed in real 2010 dollars, discounted where appropriate using a real, pre-tax discount rate (9.79%). Capital costs for both generation and transmission options are annualised over their economic lifetime, using the weighted average cost of capital (WACC) provided for each scenario.

Cost components

Costs were calculated in the components as follows:

1. Total production cost, which includes:
    - Variable O&M
    - Fuel costs
    - Emissions costs
    - Carbon transport and sequestration costs (where applicable)
2. Capital repayments
    - Annual net present value repayments for all new plant (does not include existing plant, or committed plant)
    - This includes capital repayments on transmission augmentations
3. Fixed O&M
    - Annual net present value O&M for all generators
    - Annual net present value O&M for transmission augmentations (assumed to be 1% of total capital cost)

Existing plant capital costs were assumed to be sunk and the recovery costs for retired plant to be sufficient only to cover decommissioning.

Run costs were calculated on a two hourly basis, determined by the two hourly dispatch of each plant. These were discounted to net present values for determination of the total scenario cost.

Start up and shut down costs were not included, and could be significant given that many plants which currently operate as 'base-load' may adopt mid-merit order, cycling behaviour if a sufficiently high price is applied to carbon emissions.

Inclusion of a carbon price trajectory and the LRET

The cost of carbon is directly included in the short run marginal cost for all emitting generators. Any transitional compensation payments are assumed to not impact generator behaviour, except to incentivise generators to remain available until at least 2020, despite declining generation volumes. The payments under such a scheme are independent of ongoing operation (only requiring plant to be available), and will therefore not affect short run marginal costs.

The cost of the LRET scheme is directly included through inclusion of the capital repayments for renewable generators. LRET costs to retailers are not included in the cost calculation, since the LRET scheme simply provides monetary redistribution within the energy sector to support the capital expenditure on renewable generation via REC payments from retailers and consumers. Accurate inclusion of the actual costs of the

LRET to the system therefore requires calculation of the actual capital repayments, rather than the “costs” of RECs to retailers.

Dynamic programming and the IRP optimisation

Dynamic programming is a mathematical method for fast computation of an optimal policy for a multistage decision process. In principle, each of the several million pathways could be costed and compared separately, and the lowest cost path selected. However this would be time consuming. Instead, the problem can be broken down into multiple stages and the solutions to each stage constructed into an optimal solution for the original problem. ROAM employs a highly optimised version of this algorithm.