IES/ROAM Modelling of Future Congestion Patterns:

Due Diligence review

Prepared for the

AEMC

by

E Grant Read

Version 2.3

29 June 2009

EGR Consulting Ltd.

Executive Summary

1. The AEMC has been directed by the Ministerial Council on Energy (MCE) to review the impacts on energy markets of the introduction of the proposed CPRS and expanded RET. In that context, the AEMC engaged both ROAM Consulting and Intelligent Energy Systems (IES) to assist with a study intended to:

   Investigate the relative economic costs of different models of locational entry and exit of generation and network investment response in the National Electricity Market (NEM) following the introduction of the Carbon Pollution Reduction Scheme (CPRS) and the expanded national Renewable Energy Target (expanded RET); and

2. Each consultant has addressed essentially the same questions, but using a different approach, and reported their conclusions in:

   - *Future Congestion Patterns and Network Augmentation. Report on Assignment A: Transmission Development Framework Scenarios.* IES final report to the AEMC on 25 June, 2009

   - *Network Augmentation and Congestion Modelling*. ROAM final report to the AEMC on 25 June 2009

3. EGR Consulting Ltd was subsequently engaged to undertake a peer review of both reports, and this report summarises our conclusions, based on a review of documents provided, and discussions with the AEMC, and with both consultants.

4. We conclude that the modelling has been based on reasonable assumptions, undertaken in a theoretically acceptable manner, and reported appropriately, by both consultants.

5. We do note, though, that the consultants have not only employed different methodologies, but also made significantly different assumptions, in areas which have a material bearing on the results. By and large this variation should be seen as providing useful sensitivities, and underlining the overall state of uncertainty with respect to future developments.

6. Accordingly, we have provided an extensive table comparing, and commenting on, the way in which ROAM and IES have treated various issues in their reports. This is intended to provide a basis on which the AEMC, and other parties, can compare and contrast the studies, and plan any future work.

7. We conclude by making some suggestions with respect to areas which might be further investigated to yield more insight with into the issues studied here. Specifically we comment on the kind of future studies that might best be performed using each of the models developed in the current study, based on the strengths of each approach.

Table of Contents

1. Introduction 4

2. Outline 5

3. Suitability of approach 5

4. Comparison and future directions 7

APPENDIX:
Key Comparisons between IES and ROAM approaches 10

Due Diligence Review of IES/ROAM Modelling of Future Congestion Patterns

1. Introduction

We understand that the AEMC has been directed by the Ministerial Council on Energy (MCE) to review the impacts on energy markets of the introduction of the proposed CPRS and expanded RET. The purpose of that review is to advise the MCE on whether changes to energy market frameworks are warranted, on the basis that they will better promote the market objectives.

In that context, the AEMC initiated a study intended to:

(1) *Investigate the relative economic costs of different models of locational entry and exit of generation and network investment response in the National Electricity Market (NEM) following the introduction of the Carbon Pollution Reduction Scheme (CPRS) and the expanded national Renewable Energy Target (expanded RET); and*

(2) *Undertake case studies of network augmentations responding to congestion arising from generation locational decisions.*

The AEMC engaged two consultants to assist with that study, namely:

- ROAM Consulting Pty ltd (ROAM); and
- Intelligent Energy Systems Pty ltd (IES).

Each consultant was to address essentially the same questions, but using a different approach. EGR Consulting Ltd was subsequently engaged to undertake a peer review of both reports, to engage with both consultants with a view to improving the final outcomes, and to report to the AEMC.

In the course of this assignment, we have attended presentations by both consultants, reviewed their initial draft reports, and discussed with them how those reports should be modified so as to best meet the AEMC's objectives. Much of that discussion related to presentational issues, and is no longer relevant at this point in time. But we also provided a draft of the current report, relating to more substantive issues, and have subsequently discussed and reviewed each consultant's response to that draft. Finally we reviewed the final reports submitted by each consultant.

2. Outline

This review document relates to the following versions of the reports provided by each consultant:

- *Future Congestion Patterns and Network Augmentation. Report on Assignment A*: *Transmission Development Framework Scenarios.* IES final report to the AEMC on 25 June, 2009

- *Network Augmentation and Congestion Modelling*. ROAM final report to the AEMC on 25 June 2009

It will be noted that, as this project has evolved, it has essentially focused only on Task (a). Thus both reports relate only to assessing *the relative economic costs of different models of locational entry and exit of generation and network investment response.*

The purpose of this review has been two-fold:

- First, to ensure that the modelling has been based on reasonable assumptions, undertaken in a theoretically acceptable manner, and reported appropriately.

- Second, to provide a basis on which the AEMC, and other parties, can compare and contrast the studies, and plan any future work.

We make some brief comment on these issues below, but note that our report consists largely of a table comparing, and commenting on, the way in which ROAM and IES have treated various issues in their reports. Thus it largely relates to the second goal above, that of providing basis for the AEMC, and readers to understand, and assess the significance of, the way in which these reports agree, and the reasons why their conclusions may differ. The aim is to assist with building an understanding of the issues, based on the strengths of each approach, and provide some pointers to future development.

3. Suitability of Approach

Both consultants were asked to address the following three scenarios:

*(a) "**Non-responsive transmission**" – generators make profit-maximising entry and exit decisions in the knowledge that transmission investment will be limited to the bare minimum consistent with meeting mandatory obligations. The level of transmission investment in this case would reflect the bare minimum required to continue meeting NEM demand and the expanded RET targets….*

*(b) "**Current regime working effectively**" – generators make profit-maximising entry and exit decisions in the knowledge that transmission investment will respond consistent with delivering mandatory and discretionary investment consistent with the National Electricity Rules (NER). The level of transmission investment in this case would reflect both reliability and market benefits driven investments to*

continue meeting NEM demand and the expanded RET targets. This case reflects the investment decisions that can be made under the current framework; and

(c) "**Co-optimising central planner"** *– a "socially optimal" generation and network investment case that reflects co-optimised investment decisions by generation and transmission businesses from a central-planning perspective. The decision to locate takes account of excess network capacity and the supply-demand balance. This would assume perfect foresight by the central planner and the objective of minimising the total costs of delivering energy services to customers over the analysis period…*

It was requested that the modelling should:

- *Determine the likely congestion patterns and network flow outcomes arising under the range of scenarios; and*
- *Measure and compare the change in dispatch costs and network investment costs under the different scenarios.*

Each consultant was asked to provide a report that:

- *Develops a range of credible scenarios of future generation and demand for each region under the CPRS during the period July 2010 to July 2020. …*
- *Advises on the likely changes in the location of generation in each region resulting from the changing generation mix under the CPRS;*
- *Advises on the likely location decisions of renewable generation under the expanded RET;*
- *Discusses how the operation and dispatch of increased renewable generation (under the expanded RET) and the changing generation plant mix (under CPRS) influences the patterns of congestion compared to the current patterns;*
- *Models the likely inter-regional and intra-regional network flows under each credible scenario;*
- *Identifies and measures the resulting congestion under each scenario (covering both inter-regional and intra-regional constraints). The measures of congestion must reflect both the duration and economic cost of the constraint binding;*
- *Identifies areas where congestion could be persistent and material, if efficient network developments cannot be achieved; and*
- *Provides commentary and observations about how to improve the current incentives that inform generation entry and exit decisions and network investment decisions, where the dispatch and network investment costs under the different scenarios differ substantively.*

In our view, both consultants have fulfilled these requirements.

ROAM has used a Dynamic Programming (DP) methodology, while IES has used a Linear Programming (LP) methodology. Both are sound and robust optimization methodologies in their own right, with a well established academic and professional pedigree. Both will give the same result, if applied to a problem with identical formulation. Each is also broadly suitable for the task at hand, although subject to specific limitations, as noted at various points in the table.

ROAM and IES have each employed their own models, implementing their respective methodologies. We have not attempted to check those models, but have no reason to suspect that they have not been correctly implemented. In particular, there is nothing in the reported results to suggest any problems with the underlying models.

We have made some comment on particular points in the table below but, so far as we can see, both consultants have reported and interpreted their results in an appropriate fashion, noting caveats where required.

We have not been asked to check the underlying data, which has been supplied from various sources, and agreed with the AEMC. So far as we can see, the data is generally plausible, and consistent, for the technologies and transmission development options under consideration here. Some instances are noted, though, where the two consultants have made significantly different assumptions and, as a result, come to significantly different conclusions. Readers, and the AEMC, will have to come to their own conclusions to how realistic those assumptions, or conclusions, might be. We suggest that some assumptions should probably be reconsidered, and refined, in any future studies.

4. Comparison and Future Directions

Although LP and DP may be broadly comparable, in abstract theoretical terms, each methodology has its own strengths and weaknesses. So, in practice, problems often have to be formulated somewhat differently in order to be efficiently addressed by one, vs the other. This is the case, here, and the formulations employed by ROAM and IES do differ in various respects.

This also means that the consultants have had to approach particular scenarios and questions in differing ways. By and large, these differences allow each consultant to explore different aspects of the same situation, as discussed in the table below. Similarly, with respect to the different assumptions made about technology cost and availability. On that topic, we note that IES seem more optimistic than ROAM with respect to prospects for:

- Early economic entry by a range of renewable technologies, other than wind; and
- Retirement of existing high emission plant.

It is not our role to comment on which assessment is more realistic, but it seems reasonable to regard these two studies as representing sensitivities with respect to the feasible rate of change in the sector.

It is not our role to interpret the results of these studies, or suggest any conclusions to the AEMC, either. But perhaps the most remarkable result from all this modelling is that both studies agree that the cost differences between the three main scenarios modelled are really quite small, at least when analysed at this aggregate level. It is also salutary to note that the impact on GHG emissions is not great either. Some reduction is achieved, but it is really not much more than holding the line, as loads increase. Basically, this reflects the fact that replacement of conventional plant with renewable alternatives is not really an attractive option, economically, or technically.

This suggests two profitable directions for further study:

- First, consideration of more extreme scenarios, in which targets and/or prices are set to levels high enough to induce electricity sector emissions to fall in proportion to the reductions being sought across the economy as a whole.[1]

- Second, finer grained examination of how the retirement of conventional generation, and development of renewable generation might interact with transmission system development in a particular region of the NEM, or even perhaps is a hypothetical “model” region constructed so as to capture the key elements under study.[2] Such a study should also consider the impact of different approaches to transmission cost recovery, and to ancillary service provision and pricing, including firming/peaking services traditionally provided by energy plant as part of the energy market.

If such studies are to be pursued, it should be recognised that each model is best suited to particular kinds of investigation. As noted in the table:

- The IES methodology has allowed a finer gained optimisation of investment decision-making than ROAM’s, because it does not require investment decisions to be discretised into distinct states. It can also be more readily adapted to look at further variations on such issues. But, while re-configuration is easy, most sensitivities would require much of the modelling exercise to be repeated. Also, each optimisation must assume a single objective, so it is virtually impossible to model the interaction between a transmission planner trying to maximise system benefits, and generator investors, trying to maximise their own profit, for example.

- The ROAM approach allows modelling of different decisions being made by different decision-makers, with differing objectives. In our view, its potential in that respect could be significantly further developed, and exploited, than it has been in this study. Sensitivities involving changes to objectives or capital costs, for example, could also be performed very easily, using the pre-computations already performed for this study. New scenarios involving a more detailed representation and modelling of intra-regional transmission investment might involve a little more

---

1 With perhaps more account being taken of the possibility that other sectors might be planning to reduce direct GHG emissions by adopting more electricity-intensive technologies. Such a move would increase energy and demand growth in the electricity sector further, making emissions reductions more difficult in the sector.

2 As was perhaps originally envisaged for part (b) of the original assignment.

work, though, since new pre-computations would probably be required. Sensitivities involving changes to the merit order, load, or breakdown probabilities would probably require wholesale re-computation of the pre-computations, though. That is obviously possible, but a less attractive prospect.

APPENDIX: Key Comparisons between IES and ROAM approaches

Aspect	IES	ROAM	Comment
Optimisation Methodology	IES use standard LP/MILP optimisation, in well known models. A regional version of MARKAL is used to optimise (notional) interconnector development in a high level NEM model. A full network version of MARKAL is used to optimise intra-regional generation development. PROPHET is used to simulate system performance in more detail, using a more detailed intra-regional transmission model Manual heuristics are used to determine intra-regional transmission expansion, based on PROPHET results. PROPHET is then re-run to determine final system performance.	ROAM use their IRP model, employing a variant of Dynamic Programming (DP).[3] They develop a (deterministic) decision tree, where each node represents an annual "state" of the system, as defined by the generation/transmission investment pattern. A simulation is performed to pre-compute system performance for each of a large number of possible states, (using a number of parallel computers).[4] The decision tree is then processed to determine an optimal sequence of capital investment decisions. System performance can then be read off pre-computed system simulations for the chosen states.	Both methodologies are technically sound, but they have differing strengths and weaknesses. Because it does not require decisions to be discretised into distinct states, the IES methodology allows a finer gained optimisation of investment decision-making than ROAM's. But each optimisation must assume a single objective, and most sensitivities require much of the modelling exercise to be repeated, though. The ROAM approach allows modelling of different decisions being made by different decision-makers, with differing objectives. The pre-computation methodology makes it difficult to do any sensitivities that would require system simulations to be re-computed. This probably includes anything affecting the merit order, load, or breakdown probabilities. But other sensitivities, eg involving changes to objectives or capital costs, can be performed very easily. Variations involving a modest number of new transmission/ generation investment combinations could be handled with moderate ease, too. .

[3] The documentation describes DP in a way which may seem unfamiliar to some readers. Often DP is applied to problems having a compact "state space", with the same number of states in each period, and the diagrams may give the impression that the same is true here. In this case, though, ROAM makes it clear that the state space truly is very large, and does grow over time "*from hundreds in earlier stages, to hundreds of thousands in later stages*". This produces a "decision tree" structure, such as is more commonly drawn to represent a "Decision Analysis" problem, or perhaps a repeated game "in extensive form". It does create a valid DP, though.

ROAM also use a "forward recursion" algorithm, ending with a backward pass to trace out the optimal path. DP models more often employ a "backward recursion" algorithm, because it can readily be generalised to stochastic problems. Thus many textbooks only describe the backward recursion algorithm. However ROAM's forward recursion will produce the optimal solution for the deterministic problem addressed here.

Treatment of Scenario A **(minimal network development)**	Full network version of MARKAL run to determine least system cost generator development, while meeting a RET target, assuming no (non-committed) transmission development. PROPHET then used to simulate performance. No further transmission development modelled, irrespective of PROPHET outcomes. (In principle, developments could have been considered to meet RET targets, but we understand that no additional expansion was thought necessary)	ROAM states that interconnector entry was kept to the bare minimum required to meet NEM demand, and RET targets. We understand that routine development was assumed to occur as in the ANTS projections, but that no additional expansion was thought necessary to meet RET[5]. Generator entry optimised so as to maximise profits for a hypothetical investor determining the entire new investment portfolio (renewable or not),[6] assuming a REC price of $40.[7] (Also see ROAM's sensitivity on Scenario C, where no transmission upgrades are allowed, but system costs are minimised).	For IES, entry location is optimised to the level of transmission system detail modelled in the full network version of MARKAL. Thus this scenario can reasonably be characterised as "generation following transmission". But it is also somewhat unrealistic, because (implicitly) generator entry will be modelled as responding to prices calculated for each node in that network representation, rather than to a Regional Reference Price. The fact that ROAM and IES have taken different approaches with respect to entry incentives may be regarded as a useful sensitivity. But although ROAM uses the ANTS constraints to model network detail, they model entry as responding to a Regional Reference Price, after allowing for constrained-off probabilities. This probably means that location "follows transmission" less than in the IES model. But that may be more realistic for the NEM.

---

4 This pre-computation approach is not common, but it is quite valid, and has been used for many years in a DP-based operational/planning model of the New Zealand power system. See: E.G. Read, J.G. Culy, T.S. Halliburton, and N.L. Winter: "A Simulation Model for Long-term Planning of the New Zealand Power System". In G.K. Rand (ed.) *Operational Research 1987*, North Holland, p.493-507.

5 This is fortunate, because it is not obvious how the transmission planning regime could, would, or should, choose which transmission expansion to pursue in order to meet the RET requirement at least cost.

6 This hypothetical decision-maker must compare profits in different pre-computed states, and thus implicitly does account for the price differences between them in assessing profitability, implying some kind of market power with respect to entry optimisation, which is unrealistic. Since entry will tend to depress market prices, accounting for this may discourage (modelled) entry, relative to the IES model. This criterion could probably be changed, within the ROAM DA/DP framework, to model decisions being made on the basis of the apparent profitability of each investment, at the prices determined by the (sequence of) state(s) in which the investment does not yet appear. This would more nearly model the basis on which individual project investors are likely to operate. Given the large block-size, though, blocks of plant entering on this basis would most likely find themselves operating unprofitably, at least initially, because their entry depresses prices. But that effect could be offset by setting a slightly higher profitability hurdle for entry.

7 We understand that this value was chosen after some experimentation to determine what price level might be required to make enough REC based entry economic to meet the RET. The use of a REC price as well as a RET target may seem like double-counting, but see discussion in Footnote 24 below.

Treatment of Scenario B **(status quo transmission expansion regime working as intended)**	Regional version of MARKAL run to determine least system cost interconnector and generator development, while meeting a RET target, and ignoring intra-regional constraints. PROPHET then used to simulate performance, modelling flows on intra-regional lines, but ignoring flow bounds. Intra-regional transmission upgraded where PROPHET results indicate congestion for more than 20 hours. PROPHET then used to simulate performance, with expanded intra-regional transmission.	Section 8.2 outlines an iterative process by which entry timing of the SA-VIC interconnector was optimised on a total system cost basis. Based on Scenario C results, the only other transmission development that seemed worth considering was QNI, which was not economic.[8] Intra-regional transmission limits, and development options other than intra-regional implications of interconnector developments, were ignored. Generator entry was optimised, within a band of options meeting the RET, so as to maximise profits for a hypothetical investor determining the entire new investment portfolio (renewable or not), assuming a REC price of $40 and interconnector entry determined as above.	The level of congestion allowed before intra-regional transmission upgrade occurs is a critical factor in the IES approach, and a whole range of scenarios could usefully be constructed by varying that parameter. If the level of congestion considered acceptable is small enough, the strategy can reasonably be characterised as "transmission following generation". If that level is large, this scenario is similar to Scenario A, above, inasmuch as no intra-regional transmission development will be deemed necessary. The location of development will be impacted, though, by using the full network version of MARKAL. Since the ROAM model only considers interconnector development, it really models "interconnector development following generation", although the interconnector development chosen may derive much of its value from relieving intra-regional constraints. Of itself, that may not be a problem, but it implies that the cost of intra-regional transmission development has been ignored, making NPV comparisons suspect.[9] On the other hand the simulation presumably reflects the cost imposed by un-expanded intra-regional transmission, which should be greater than in the IES model, if the ANTS constraints are an accurate and adequate representation. On balance, though reported costs will be understated, if the IES assumptions are realistic, and imply over-expansion, from an economic perspective, as has been suggested.

8 That is ROAM did a series of DP runs, each assuming a particular interconnector expansion timing, and employing a standard DP recursion to optimise generation investment with the single objective of maximising profit for entrant generators. The best interconnector development scenario was then chosen so as to maximise nett NPV benefit, from a system perspective.

9 Similarly for the cost of transmission system "extension", which is ignored in both studies, as discussed below.

Treatment of Scenario C **(centralised optimisation of generation/ transmission development)**	Regional version of MARKAL run to determine least system cost interconnector and (preliminary) generator development, to meet LDC and RET target, and ignoring intra-regional constraints. (As for B) Full network version of MARKAL run to refine least system cost generator development to meet LDC and RET target, assuming interconnector development as above. PROPHET then used to simulate performance, modelling flows on intra-regional lines, but ignoring flow bounds. (As for B) Intra-regional transmission upgraded where PROPHET results indicate congestion for more than 20 hours. (As for B) PROPHET then used to simulate performance, with expanded intra-regional transmission. (As for B)	IRP run with a least cost (NPV) central planning objective, and allowed to install any generation block and/or any of the (limited set of) network augmentations at any time. A sensitivity has also been included, where no transmission upgrades are allowed, but system costs are minimised. This case can be compared with Scenario A as calculated by IES, from a central planning, cost minimisation perspective. This sensitivity indicates the positive value provided by the SA-VIC upgrade but, according to Section 6.1, induces very little change to the optimal generation investment pattern.	ROAM's treatment of this scenario differs from that of Scenario B in that a different objective function is assumed. The modelling of the transmission system, and of transmission system development, is as above, so the same comments apply. The insensitivity of generator investment to interconnector development may be partly due to the lumpiness of the generation investment blocks. We understand that IES developed a true co-optimisation model, but abandoned it, for lack of credible data on intra-regional transmission costs. The iterative process used in the study is really more one of "interaction" between transmission and generation planning. The only difference from Scenario B is the refinement of the (regional balance of) generator development after interconnector development has been determined. The solution could probably be refined by continuing the iteration, to re-optimise interconnector development, given generator development, and so on, until convergence (hopefully occurs). Alternatively, iteration could proceed on an annual basis, with generator development being optimised, each year, assuming the transmission system development plan optimised for the year before.[10] This would be computationally intensive, though.
Chronological detail in simulation	MARKAL uses an annual LDC, with 54 blocks. But final results represent a single one-year pass, running PROPHET for each half-hour, for each system (investment) state.	A single one-year pass over an hourly load trace, for each system (investment) state.	This level of detail seems adequate, for the purpose, assuming that variation in hydro conditions is not a significant issue in Australia. (This may be an issue for Tasmania, though, and a more detailed study may be appropriate.)

[10] We understand that IES have previously performed a study of transmission/generation development in Queensland, using this kind of iteration, but using a heuristic approach to optimize entry from a market (price) driven perspective, rather than from a system cost/benefit perspective.

Coverage	NEM -wide	NEM -wide	This seems appropriate at this stage of the investigation. Closer focus on a particular region may be more appropriate for future studies, though.
Transmission system detail	NEM regions modelled in regional MARKAL model. More detail, with 93 nodes, 140 lines, and an explicit "DC" power flow to represent intra-regional detail in full network MARKAL model, and PROPHET.	Regional NEM model, but using 16 ANTS zones, and c.250 ANTS constraints to represent intra-regional detail. (ANTS constraints are modelled as changing once interconnector investment occurs.)	A more detailed representation should be considered for a regional case study, but this level of detail is probably adequate for the broad-brush studies done so far. Differences between the models could be explored further, because transmission system congestion is a critical issue here. We have not attempted any serious comparison, or attempted to interpret the ROAM results, which relate to ANTS constraints being binding, in terms of congestion on lines, at the level of detail reported by IES.
Notional interconnector investment	Assumed to be "centrally optimised", with a total system benefit objective, in MARKAL	Assumed to be "centrally optimised", with a total system benefit objective	Interconnector investment costs and characteristics were given, and assumed to be the same by both studies. Each notional interconnector upgrade would in fact be implemented by building a series of intra-regional components, though.

Intra-regional transmission investment	Intra-regional components of (notional) interconnector investments assumed as per MARKAL solution. But other intra-regional components upgraded if desired flows exceed capacity by more than 10,000 MWh for more than two years running, in initial PROPHET run.	Intra-regional components implicit in (notional) interconnector investments accounted for via changes to ANTS constraints, but upgrade of other intra-regional components not considered. (We understand that data only exists to determine the impact of intra-regional transmission investment on ANTS constraints for those developments considered during the ANTS process. This may not include some of the developments that might be considered in the alternative futures considered here.)	This is an important area, central to the issues under study, and needs further consideration. The results suggest that the ROAM model has upgraded the SA-VIC interconnector, in particular, mainly because that upgrade implies upgrades to intra-regional components that would relieve congestion within South Australia.[11] This implication may already be clear enough from the results, but consideration should be given to having ROAM undertake a more detailed study of South Australia, where the intra-regional assets are explicitly modelled, and corresponding investment states generated. On the other hand, while the IES upgrade rule aims to emulate real decision-making, it is not necessarily "optimal". This sensitivity could be explored, although we note that while a looser criterion may seem optimal, based on the results from these studies, a tighter rule may actually be more realistic, given that these studies both understate congestion by assuming only system normal states.
Cost of transmission "extension"	Ignored, but defined as relating to transmission assets required between the existing transmission system and the "connection" assets for particular generation developments. Perhaps distinguished from "deep connection" reinforcements to the existing transmission system, although the distinction is not entirely clear, in theory or in practice.	Ignored. (But a sensitivity could be easily performed on this, without performing any new pre-computations, by re-processing the decision tree, with transmission extension cots included as part of generator capital costs, if data were available.)	This seems like a significant issue, made more complex by the question of who will pay for transmission "extension". In order to get a system-wide optimum, "extension" costs should be accounted for as part of the capital cost of projects requiring such extension, either individually or jointly. But this would only be valid for simulation of market scenarios if participants actually faced the extension cost. Alternatively one might model "extension" as part of the transmission expansion process, but restrict generation development to occur close to the extended transmission system. This seems like something which should be studied in the context of a regional case study. Even a conceptual study, using stylised data, could yield useful insights.

[11] ROAM also reports that the SA-NSW interconnector projector nearly becomes viable within the planning horizon, but possibly only for the same reason. This suggests that we should consider choosing either the SA-VIC, or SA-NSW, interconnectors for upgrade, but not both. Actually, though, the optimum may be just to upgrade intra-regional assets within South Australia, rather than proceeding with either "interconnector", as such.

Transmission outage	Assumes contingency ratings, but in system normal state, as agreed by AEMC.	ANTS data assumes (seasonal) contingency ratings, but in system normal state, as agreed by AEMC.	As noted by IES, the system normal assumption excludes consideration of the states when the transmission system will be under most pressure, due to planned or unplanned transmission system outage, particularly high temperatures, etc. Since these states tend to involve compounding difficulties, this may imply significant understatement of transmission congestion. Consideration could be given to performing a case study making more realistic assumptions about transmission system availability, in order to estimate some relationship between congestion/ non-supply probabilities, and market impacts, as calculated by these models, and as they might occur in reality. On the other hand, reliability standards are presumably set to take these effects into account. So application of those standards in these studies may serve as a reasonable proxy.
Load	30 block LDC in MARKAL and half hourly load trace in PROPHET. But all modelling used median (50% PoE) loads, as agreed by AEMC.	Hourly load trace, also representing median loads. (50% PoE), as agreed by AEMC.	IES comments that the median assumption may understate extremes, and hence congestion/transmission upgrade consequences. Sensitivity to that issue could be explored, along with consideration of the impact of states other than "system normal" in the transmission system. However, possible changes to the LDC are not really the focus of this study. The extent to which peaking requirements might be driven by increased wind penetration would be more relevant. We would also query whether a "business as usual" load forecast for electricity is compatible with scenarios in which national GHG emissions are projected to fall significantly. It seems possible that some other sectors (eg transport) might be planning to substitute electricity for technologies that emit GHGs directly.
Regional reserve margins	Ignored, on the ground that there is not sufficient basis for a meaningful calculation	Updated to reflect interconnector changes, when investment occurs. The minimum reserve margin constraint does become binding after 2017-18, and is the driver for entry of thermal plant in the final few years of the study.	Given ROAM's comments, the imposition of this constraint may explain why ROAM predicts greater investment in conventional thermal technologies towards the end of the horizon. In part this may be seen as reflecting a perception that renewable technologies may not be good at providing traditional "ancillary services", or maintain traditional reliability levels.

Ancillary services	Can be modelled in PROPHET, but not in this case.	Ignored.	As above, ancillary services provision may become a more important issue, both because intermittent technologies like wind may require greater ancillary service support, and because plant that has traditionally supplied such services may be retired and/or replaced by alternatives at different network locations. Thus more consideration should perhaps be given this aspect, along with the possible need for greater locational signalling in ancillary service pricing.
Generator investment	Assumed to be "centrally optimised", with a total system benefit objective, throughout.	Assumed to be "centrally optimised", with a collective investor objective under Scenarios A and B, but with a total system benefit objective, under Scenario C. (This includes the sensitivity on Scenario C where no transmission upgrades were allowed, and which thus may be compared with Scenario A as calculated by IES)	The joint investor objective in the ROAM model implicitly assumes some degree of market power in the investment market. Thus solutions may be preferred because they shift prices sufficiently to make the whole investment programme collectively more profitable. This is a bit extreme, but it does provide an alternative perspective to Scenario C, and to the IES study, which uses centralised optimisation throughout. The real aim would be achieved if participants were modelled as each pursuing their own profit maximisation objective. But that is tricky, for several reasons, and the results reported here should at least place upper/lower bounds on the outcome.[12]

[12] Modelling of individual investment incentives that differ from those of a centralised decision-maker is difficult in the LP/MILP framework used by IES, because it requires models to be altered so as to form some kind of decomposition/equilibrium framework, with respect to long term investment. Still, we understand that IES have done this in previous studies, using PROPHET. In principle, we believe the ROAM model could be modified to do this, but that would require each investment decision-maker to be modelled as acting in turn. Accurate modelling of individual investment incentives would also need to take account of the fact that entrants may also have incumbent plant, which will change their incentives.

Investment Block Size	Unrestricted (Investments treated on a project by project basis.)	500 or 1000 MW blocks. e note the implication that, when a block is committed, as being economic on average, the marginal MW in that block will generally not be economic. This may partially explain why developments are committed, eg in Northern South Australia, even when they will be partially constrained off by transmission limits. Conversely, there will be infra-marginal developments on other blocks which are not committed, even though they would have been economic.	ROAM must limit itself to discrete block sizes in order to keep the number of pre-computation states reasonable.[13] This may partially explain why the IES model forecasts a more gradual introduction of several technologies, with a correspondingly wider geographical spread. If so, the ROAM results may be partially a result of an artificial modelling constraint, rather than a reflection of (differing assumptions about) reality. Also, since investment must equal or exceed the RET target in each year, using 1000MW blocks implies that investment will exceed the target, by 500MW, on average. This should be borne in mind when comparing results between IES and ROAM.
Discount Rate	8% discount rate/for NPV, but 9.2% WACC for capital cost calculations	10% discount rate/WACC for both NPV and capital cost calculations	This difference makes it inappropriate to compare NPVs between the two studies. The difference in WACC is smaller, but may help to explain why IES forecasts more aggressive development of both renewable and non-renewable replacements for existing plant.
Capital costs (for new transmission or generation)	Annualised, assuming a 30 year plant life for generation, and 40 years for transmission	Annualised, assuming a 30 year plant life for generation, and the same for transmission[14]	This is a common assumption because it simplifies treatment of many end of horizon effects b y avoiding the question of salvage values etc. It is valid, if restrictions are imposed to ensure that plant can not retire after an unnaturally short working life, or if the logic of the pattern of load growth and system development ensures that this will not happen.[15].

---

[13] Actually, ROAM could probably use smaller investment block sizes by interpolating between these pre-computed states in the DP tree, as in the New Zealand DP models referred to earlier. This might produce development paths that are "smoother", but not necessarily more balanced, because the incremental benefit of each transmission/generation development type will be constant, across the original blocks, so long as the interpolation is linear.

[14] In Appendix B, ROAM shows annualised costs being associated with arcs, rather than vertices. DP models of this kind more normally show a lump sum (lifetime) investment cost on any arc where new investment is involved. As ROAM points out, though, all the arcs leading into each vertex show the same annual cost, and that cost is consistently followed though to all successor arcs. In other words, the costs are really associated with the vertices, which is correct, no matter how they are drawn on the diagrams.

Plant Retirement	Only for existing plant. IES assumes that many existing plant would retire rather than continue operating in a backup/ peak support role. Retirement has been "optimised", in the sense that plant is retired if its operating profit becomes negative, after accounting for costs of maintenance etc, which are assumed to continue at a fixed rate.[16] The retired plant appears to be replaced by CCGT investment, after 2014.	No retirements are modelled after Munmorah in 2014-15. Section 5.5.3 notes that renewable technologies have not yet been developed to fulfil many roles now filled by thermal plant, and argues that existing plant, or "equivalent" replacements, will have to continue operating in a peak support/backup role throughout the planning horizon, and the market mechanisms will have to be found to support this, even if the CPRS regime makes regular operation in the energy market uneconomic.[17]	This is a tricky area and, while the assumptions employed here are simplified, a full scale optimisation could probably not be attempted. There seems a significant difference between the IES and ROAM assumptions, and hence results. Since retirement of existing plant is a critical issue, though, and may deserve more investigation. One issue is whether existing plant really could or would operate in the more intermittent modes envisaged here. Another is whether the market would support, or find a mechanism to support, existing plant operating in a support/backup role. If not, we must ask what kind of plant would replace it in providing ancillary services, both explicit and implicit (eg inertia or reactive /voltage support). The location of such replacement plant is also important, and may have significant implications for intra-regional transmission requirements.

---

15 The potential problem with using annuities is that it may seem economic for lines, or plant, to be installed for just a few years, and so only pay the annuity for a few years, to cover a gap prior to an interconnector being expanded, or a new technology being ready, for example. It can be shown that this will never happen in a world with monotone increasing loads, continuous expansion, and no lead-time restrictions, but that is not the case here. So "path restrictions" (or equivalent MILP constraints), disallowing plant retirement before x years, must be employed to prevent it happening. As we understand it, the "path restriction" employed in both ROAM and IES formulations is that, once introduced, new investments can not be retired at all.

16 The problem here is that a fully optimised formulation would have to go beyond a simple "path restrictions". In order to optimize retirement times, we need to ask why plant would ever be retired, once the capital investment has been sunk. This is where the annuity approach becomes problematic, because retiring plant does not (at least from a system perspective) eliminate the requirement to pay the annuity covering its sunk capital cost. And, that being the case, the plant should only be retired if its operating profit can not cover its ongoing annual operating costs. But the problem is that most models, including these ones, model operating costs (and availability) as being independent of age. In reality, operating costs ate expected to rise (and availability to fall), as a function of both chronological age and cumulative generation. But modelling this would require more data, and a great many more variables, in either model.

17 We understand that "similar" plant could mean plant of a similar capacity and location, not necessarily using the same fuel, or technology. ROAM comments that: *The minimum reserve level creates a lower bound on installed capacity in each region. Thus if a large plant retires, it is likely that it will be replaced by a similar capacity plant or combination of plant (probably gas-fired) located in the same region…(but) at the carbon prices modelled in this study, retiring and replacing existing plant is not cost effective before 2020.*

Non-renewable generation investment	CCGT and OCGT investment possible, with large CCGT investment occurring later in the planning horizon, presumably to replace less flexible/ higher carbon conventional plant retired by the IES model, when its operation becomes uneconomic.	CCGT and OCGT investment is possible, where necessary to meet minimum reserve requirements in each region. This is achieved by applying a "thermal upper bound" in Appendix B, and such entry does occur, towards the end of the horizon, to balance out the large wind/geothermal component in these scenarios.	It seems realistic to assume that conventional plant will be required, with the principal need being for more flexible plant, at least until schedulable renewable technologies are developed further. It is interesting to note that the ROAM model still builds such plant, and also replaces existing plant with "similar", but possibly more flexible, new plant. We understand that these investments may be driven by regional reserve margins, though, particularly in the high-banking scenario, where early developments are dominated by wind, creating a need for more firming/peaking support towards the end of the planning horizon.
Wind	Assumed to be widely available throughout the planning horizon, with developments treated individually. But, at nearly $125/MWh, costs are assumed to be 30-50% higher than assumed by ROAM, despite a lower discount rate	Assumed to be widely available throughout the planning horizon. Developments are modelled as being in particular ANTS zones, but for decision-making purpose are grouped into 2-3 tiers, with progressively poorer capacity factors, in each region.[18]	Both consultants rate wind as being more expensive than biomass or geothermal, and hence presumably only attractive because those options are not freely available. But the difference in assumed wind costs is really quite marked, with IES assuming wind to be significantly more expensive than ROAM's estimate, and also much more expensive than most other renewable technologies. We understand that these estimates reflect Australian field experience with wind, but suggest that the estimated cost of other technologies may well rise, too, as more experience is gained.
Simulation of wind	Artificial manipulation of data from a limited number of representative sites, to create synthetic data with appropriate characteristics and correlations. (A detailed generation trace from a single wind farm was used, but scaled to match the size and capacity factor of each other wind farm, and shifted to create appropriate correlations between developments in neighbouring regions.)	Detailed correlation of wind regimes at each site with BOM data, and hence with each other, and with the load trace. We understand that this simulation tends to predict worse performance than that suggested by the IES database.	We understand that capacity factors for wind plant were agreed with AEMC. The IES model is able to choose particular projects which promise superior performance to the average of the projects in the much larger investment blocks assumed by ROAM. To some extent, the IES assumption of superior performance tends to offset its assumption of higher costs.

18 For the purpose of grouping projects, regions are normally NEM regions, except in South Australia, where the NSA and ADE regions are treated as separate regions. Each entry development block is located within an individual ANTS zone for the purpose of assessing congestion.

Solar	PV assumed to be available, but more expensive than wind, and so presumably uneconomic throughout planning horizon. Some other solar projects are listed in table 7-3 as having a levelised cost of $86/MWh, similar to that of geothermal, and much cheaper than wind at $125/Mwh. These projects are assumed to be available, and built, early in the horizon, but no further projects are modelled after that. Thus renewable entry is increasingly dominated by wind, later in the horizon, even though it is much more expensive in Table 7-3.	Thermal solar considered to be "schedulable". But it is not costed, as it is assumed to be unavailable/ uneconomic throughout the planning horizon, on the scale required for bulk electricity supply, i.e. 500MW to 1000MW by 2020). PV assumed to be available, but uneconomic throughout the planning horizon.	It may seem surprising that a technology that one consultant believes to be unavailable/uneconomic, appears at a fairly early date, and low cost in the results reported by another. The discrepancy is less than it appears, though, because the IES assumptions relate to what are essentially demonstration projects that would be too small to form an investment block in the ROAM model, and neither consultant assumes these technologies to be widely available later in the horizon.. A realistic interpretation is probably to say that the economic viability of solar is simply unknown. The technology seems unlikely to be site specific. So if the initial projects assumed by IES turn out to be as economic as Table 7-3 suggests, one might expect solar to spread widely and rapidly. But it could equally turn out to be unavailable/uneconomic as both ROAM and IES actually assume for the latter part of the horizon. This seems like a significant sensitivity, that could be explored in any future study
Biofuels	Table 7-3 suggests an LRMC cost of around $80-90/Mwh, significantly cheaper than wind, and some projects are assumed to be available, and built.	Assumed to be carbon neutral, and available after 2014/15. This plant is treated as "schedulable", with no energy limit. Table 6-1 suggests an LRMC cost of around $70/Mwh, again much less than wind	The issue here seems to relate to availability, rather than cost. If market prices are high enough to support sustained entry by wind, at the prices assumed by IES, or even ROAM, we speculate that there might be more biofuels projects that become economic, particularly given that, being truly schedulable, this plant should get a significant premium over wind.
Geothermal	Costed at $83/MWh in Table 7-3, but does not appear before 2015, and dominated by supposedly more expensive wind projects later. So presumably not available earlier in the planning horizon, and only in limited quantities thereafter.	Costed at $87/MWh, falling to $83/MWh in Table 6-1. Assumed to be available after 2016/17. This plant is actually treated as "schedulable", with a small non-zero SRMC offer. Thus it can be displaced by wind, which has zero SRMC.	There may be not much significant difference here, in absolute terms, but the cost advantage of geothermal over wind is much greater for IES than for ROAM. Thus the reason it is not more heavily used is due to assumed limits on availability. To some extent the same comments apply as for solar, except that geothermal will be more site specific, so genuine limits can be expected in the long term.

Other renewables	We understand that, even though wave power appears to be cheaper than wind in Table 7-3, only small demonstration plant were assumed to be available. Thus the IES results, for "other renewables", presumably refer primarily to biofuels.	Wave power etc assumed to be unavailable/ uneconomic throughout planning horizon, on the scale required for bulk electricity supply, i.e. 500MW to 1000MW by 2020.	Even if proponents forecast costs to be low, in the long term, it would be fair to say that none of these other technologies has reached the point where anything other than experimental plant should realistically be included in projections for this horizon.
Demand side participation	Solar water heating subtracted from RET, but otherwise ignored, except inasmuch as it impacts on the assumed load forecast.	Solar water heating subtracted from RET, but otherwise ignored, except inasmuch as it impacts on the assumed load forecast.	In principle one would expect supply side changes to affect prices, and thus demand side participation. Ignoring this flexibility tends to overstate the requirement for supply side developments, but the effect is probably not large. We understand that this was one reason for using median demand, since DSM is not likely to apply for more than 50% of the time.
Generator outage	Scheduled and random outages modelled in single annual simulation for each year.	Scheduled and random outage modelled in single annual simulation for each annual investment state modelled. .	This level of detail seems adequate, for the purpose, although any failure to model outage states will tend to under-estimate cost, prices, and potential congestion.
Generator bidding	SRMC bidding assumed in MARKAL. [19] "Realistic" bidding assumed in PROPHET	SRMC bidding assumed throughout.	Real bidding will presumably be "realistic", so the IES study provides a useful sensitivity, even if the base/common assumption between the two studies must be SRMC bidding. But note that bidding strategy is not re-optimised as the transmission system changes, for example. So the IES study does not purport to measure the impact of such development in terms of "competition benefits", or the impact that renewables might have on incumbent bidding strategy.

19 We understand that MARKAL also takes account of a capacity constraint, when optimising entry. Implicitly, this is like assuming a capacity component in market prices. So the assumption of "SRMC bidding" should not be taken to imply a forecast of SRMC-based market prices, or of entry based on such prices.

USE **(Unserved Energy)**	USE has been calculated, costed at $12500/MWh, and included in NPV. IES has commented that its estimates are necessarily inaccurate, particularly because of the system normal assumption.	USE has been calculated, costed at $12500/MWh, and included in NPV. ROAM comments that: *To accurately estimate USE, around 100 Monte Carlo simulations are required. In this study, one simulation of each state was performed. Hence the cost of USE may be dramatically different to this estimate.*	While acknowledging the points made by ROAM and IES, USE is an important measure, and omitting it from the NPV comparisons could make the non-optimised scenarios look artificially attractive. Consideration could be given to performing a case study making more realistic assumptions about transmission system availability, in order to estimate some relationship between USE, as calculated by these models, and as it might occur in reality. But that is not really the focus of this study.
RET banking	Discussed, but not considered as a sensitivity, as agreed with AEMC.	Banking is not optimised, but a high banking scenario is treated as a sensitivity. That is, the optimisation model is forced to meet an exogenously determined profile which sets the RET target higher, earlier in the planning horizon.[20] The effect is to install more wind, earlier, but this actually has a negative long run impact, because it crowds out investment in more effective renewable technologies that are not available until near the end of the horizon.	According to the ROAM results this is an important issue. But their high banking profile is not optimised[21], and a detailed study has not been done to determine whether the implied price of RECs in this scenario is realistic, or not.[22] Thus this sensitivity should probably be seen as highlighting the importance of assumptions in this area, and perhaps forming a starting point for studies on that topic.

---

[20] According to the ROAM results this creates more variation in the results than other sensitivities studied, and far more than the differences between scenarios A, B, and C. The reason is that, under the high banking profile, far more wind enters early in the planning horizon when (according to ROAM's assumptions) other technologies are unavailable. This then reduces the need and/or scope for more efficient/economic renewable technologies to enter later. This has a negative impact on performance toward the end of the planning horizon, and could be expected to have a significantly greater negative impact over the decade following.

[21] We understand that ROAM has developed a DP model in which the level of banking can be optimized, but has not employed it in the study.

[22] Normally, one would think that, under discounting, spending money to meet a target earlier than is necessary could not be optimal, from a system perspective, and ROAM comments that this "high banking" scenario is, indeed, more `expensive in NPV cost terms. But we understand that various parties are finding it attractive to build early, and bank RECs, in the current market. We have not investigated the dynamics of this market, but presumably early building tends to depress REC prices, while banking allows that effect to be somewhat mitigated. In part, this may reflect the fact that the REC market is assumed to disappear in 2030, so that each year in which investment is "brought forward" actually represents an extra year in which RECs can be generated.

RET impact on bidding	No explicit impact is considered, but if the LP model in MARKAL is constrained to meet RET targets with generation (rather than just investment), then it will implicitly subtract the shadow price on the RET constraint from offers for all renewable plant. PROPHET will not do this, and gives no specific priority to dispatching renewables. We understand, though, that while the RET shadow price may not have been subtracted from offers in PROPHET, offers were set so that renewables were always dispatched ahead of non-renewable generation. .	No impact is considered, on the grounds that renewable plant is "energy limited" so that, once built it will generate the same amount of energy within the year, and hence the same number of RECs, irrespective of when it is dispatched.[23] Since the pre-computations, like PROPHET, do not model the RET constraint, no specific priority is given to dispatching renewables. And, unlike MARKAL, the DP methodology will not naturally determine a shadow price that could be subtracted from relevant offers, if desired.	Negative offers are legitimate in the market, but we understand that they have not been modelled in either study. This has been justified on the basis that the relative merit order position of geothermal and wind will not change if both subtract the REC price from their offers. Their merit order position would change, though, relative to other plant that may make negative offers (eg inflexible brown coal, overnight), and that may change dispatch patterns. This may not be a significant issue, though, unless wind and/or geothermal would be competing with such inflexible plant, on the margin, overnight. The projected situation seems more one of wind forcing geothermal, and more flexible thermal, out of the dispatch, particularly in South Australia. Negative offers may also have a significant impact on prices in some periods, and hence on commercial incentives to enter the market in particular regions. This could impact on ROAM's modelling of the interaction between commercially driven wind and geothermal investment, particularly in South Australia. Thus the issue should be re-considered if a more detailed study is done of that region.

[23] According to our understanding of the way in which the term is used elsewhere, only storage-based hydro and bio-fuel plant is in fact "energy limited". Other renewables (solar, geothermal, wind, and wave/tidal) are more akin to 'run-of-river" hydro, where foregone generation opportunities (and hence REC generating opportunities) are lost forever. Thus bidders should logically deduct the price of RECs from their offers. Subtracting a REC price from offers would imply a negative offer price for technologies with a zero/low SRMC base offer price level.

RET impact on investment	The optimisation is forced to meet a target constraint in each year (with no discretion allowed with respect to inter-year banking). In an LP/MILP optimisation this means that a REC price profile will be generated endogenously.	The optimisation is forced to meet (or exceed) a target constraint in each year, with no discretion allowed with respect to inter-year banking, in either banking scenario. On the other hand, a constant REC price profile was assumed for investment purposes.[24]	The ROAM results suggest that the assumed RET profile has a major impact on outcomes. Thus it is important to understand the interaction between RET constraints and REC prices. In principle, we would argue that one should either have a RET target, or a REC price, but not both. However, ROAM's discussion suggests that the REC price has not actually been set at such a high level as to over-ride the RET constraint, and this suggests that the results are valid. .
Treatment of REC Price in NPV	Ignored	The REC price is only used to drive the choice of generator investments, and is ignored in NPV calculations. It should be recognised, though, that the size of the investment blocks used means that ROAM solutions will systematically tend to exceed the RET target, and thus deliver more of this "good", even in the "low-banking" case. And, by design, they deliver much more in the "high-banking" case.	For base-case comparisons, it seems conceptually correct to ignore the REC price because, irrespective of whether meeting the REC impacts on national welfare, these scenarios have all been constructed so as to meet the same RET targets. The real economic value of the excess RECs produced by the ROAM solutions is debatable, but the fact that some runs exceed the RET by more than others means that the results are not strictly comparable.

[24] Since the REC contribution can be calculated for each pre-computed investment state, and since no banking flexibility is modelled, the ROAM model can simply exclude consideration of states that do not meet the assumed target. Thus investment schedules will automatically meet the RET requirement, and sufficient renewable investment should occur, even with a REC price of zero. Conversely, there could be a problem in assuming a REC price, as well as a RET constraint, since if the REC price is set too high, investment could be modelled well in excess of the RET. We understand that the $40-$60 values chosen lie within the range indicated by studies undertaken by ROAM to determine the REC price level required to induce enough entry to meet the RET target. But ROAM states that using a $60 REC price, instead of $40, did not induce any greater entry. That result may be taken to imply that the REC price necessary to meet the RET constraint is actually in excess of $60. If so the assumed prices should not have had any untoward impact on the overall entry level, possibly because any potential effects was less than the size of the investment blocks modelled. Arguably, the REC price could be dropped, but we understand that a positive REC price has been assumed so as to differentiate between alternative renewable investment strategies, according to the number of RECs generated. That does seem desirable, although we expect that the effectiveness of the mechanism as a way of achieving a subtle trade-off in this respect will also be limited by the size of the investment blocks modelled.

CPRS	Assumes Treasury's 5% price path until 2014-15, then switching to 15% path, as agreed by AEMC.	Assumes Treasury's 5% price path until 2014-15, then switching to 15% path, as agreed by AEMC. (CPRS is included in generator offers.)	This switch may account for some of the apparent regime change around 2014-15, with CPRS only becoming a significant driver after that date. This effect is valid if there is reason to think the regime will actually change at that time.25 And much of the change around that date may be driven by changes in assumed technology availability, and in the REC banking profile, (at least in ROAM's case).
Interconnector expansion results	Robust conclusion that QNI should expand, with SA-VIC possibly being economic with substantial renewable investment in South Australia, perhaps due to increased carbon prices, or reduced development costs.	Robust conclusion that only SA-VIC should expand.[26] But this may in fact be triggered by the intra-regional situation in South Australia, which ROAM suggests should be modelled more explicitly in future studies	The reasons for this difference should be explored, but it does not necessarily imply anything with respect to the purpose of this study, except to illustrate that there is considerable uncertainty about the nature and location of investment in renewable generation.
Sensitivities	A number of sensitivities are reported with respect to the economics of interconnectors, and support the robustness of the conclusions about interconnector investment.	The sensitivities reported in Table 6.2 suggest that the results are largely insensitive to a fairly wide range (+/- 20%) of variation in capital costs, for OCGT, CCGT and wind. Only minor changes were recommended to generator investment decisions, depending on whether or not the SA-VIC interconnector was expanded, even though that expansion was robustly recommended by the modelling.	The insensitivity reported by ROAM might be interpreted as indicating that the solution is largely being driven by constraints, including the RET, rather than by economic trade-offs. And/or it may suggest a low degree of competition in the market for generator entry, which may be concerning. This latter interpretation is consistent with the significant differences between costs for differing plant types in the ACIL Tasman data.

[25] Although, if banking of carbon permits is allowed, we might expect permit prices to trend towards their expected post regime-change level, over the years prior to the change.

[26] Sensitivities suggest that QNI and/or SA-NSW upgrades may become worthwhile around the end of the planning horizon. But see Footnote 11 above.

Carbon reduction results	Not reported on in any detail, but IES and ROAM results are probably not too different in this regard.	All scenarios show GHG emissions more or less constant and far above the proportional reduction sought by the Government, across all sectors.	Basically, it would seem that renewables investment in these scenarios does little more than hold the line, so that GHG emission does not increase as loads increase. This may be a cause of concern, unless one is confident that other sectors will be more responsive and/or that on credits can be imported at the specified price. A sensitivity in which electricity sector emissions were forced down to the proportional reduction sought across the economy, would doubtless reveal a much higher marginal cost of reduction, corresponding to a much higher emission permit price, and more radical changes to investment patterns. Commentary on the implications of that lie outside the present scope. But such a sensitivity may be relevant if it is thought possible that permit prices will rise to the point where the electricity sector actually does provide the kind of proportional adjustment implied by the Government targets. If so, the transmission system impact implied by the pattern of generation investment and retirement must differ significantly from that in the current studies, which may be found to significantly understate the degree of disruption to the sector, and hence the need for transmission system re-configuration.