seed

Seed Advisory

The case for a Demand Response Mechanism in the NEM: an assessment

Report for the Energy Retailers Association of Australia, the Private Generators Group and the National Generators Forum

16 December 2013

Contents

1. Executive Summary

We have been asked to consider the benefits and costs of the Demand Response Mechanism (DRM) proposed by the Australian Energy Market Commission (AEMC) in the Power of Choice review for introduction into the National Electricity Market.[1] The DRM is to be the subject of a Rule Change Request from the Australian Energy Market Operator (AEMO) to the AEMC in December 2013.

Demand response has benefits to offer to the energy market and consumers more broadly. This report does not contradict this view, but focusses on the benefits and costs of the proposed DRM.

Our analysis highlights there are negative net benefits between -$22 million to -$72 million from the DRM (Section 1.3). This is based on our analysis of the Frontier Economic (Frontier) modelling of the wholesale market benefits published in October 2012 for the Power of Choice review[2] attributable to the DRM (Section 1.1) combined with the lower estimate of retailer and AEMO costs of implementation (Section 1.2). The material published by Frontier provided limited insight into the benefits associated with the DRM project, so our estimate is necessarily high level.

In our view, considering the merits of the DRM, a detailed benefit cost analysis looking appropriately at the issues raised in this report is required.

The proposed DRM involves a significant and complex change to the operation of the wholesale electricity market, paying end users (demand response providers) for reducing or shifting demand when spot prices are high[3]. Under the DRM, estimated baseline energy for an end user is compared with the end user's actual energy consumption to determine the level of demand response. The end user pays its retailer for its baseline energy and receives the prevailing spot price based on the level of its demand response. The proposed DRM introduces a new class of market participant, a demand response aggregator. The DRM also requires all retailers and AEMO to materially amend their systems to provide the capacity to service end users choosing to participate in the DRM.

The AEMC Power of Choice review estimated the benefits from the complete range of demand response programs it considered to be in the range of $2.8 billion to $4.3 billion over a 10 year period from 2013.[4] This estimated benefit was calculated at a high level only and combined avoided network costs and energy cost (wholesale market) savings. The AEMC's Final Report did not separately identify the estimated benefits of these two categories.

---

[1] Australian Energy Market Commission, *Power of Choice Review –Giving customers options in the way they use electricity,* 2012

[2] Frontier Economics, *Benefits of Reduced Peak Demand*, AEMC Power of Choice Public Forum, 3 October 2012, p 17; (hereafter referred to as Frontier, 2012a).

[3] The initial scope of the DRM is intended to include commercial and industrial customers consuming over 100MWh per annum. We understand the demand response envisaged in the DRM is in addition to demand response currently offered by the market.

[4] AEMC, 2012, Table 10.2, p 269

The AEMC acknowledged that "[t]he majority of these savings occur in the network sector given the current over supply of wholesale generation and relatively conservative view of baseline demand growth".[5]

The DRM benefits relate to a portion of the modelled energy cost (wholesale market) savings, that is, those savings from reductions in peak demand from commercial and industrial (C&I) customers who participate in the DRM. The remaining savings identified from other programs by the AEMC, for example residential customer programs and avoided network cost related savings, are complementary to, but separate from, the benefits of the DRM. This report does not consider the benefits or costs associated with the other programs or from avoided network costs more broadly.

1.1. The Benefits of the DRM

Based on Frontier's estimates of energy cost savings (Appendix B) and relevant adjustments discussed below, we estimate that the benefits attributable to the DRM over the period from 2013/14 to 2022/23 range from around $48 million in the Lower Case to just over $100 million in the Upper Case. This is prior to any allowance for the costs discussed in Section 1.2 and any further adjustments to the estimated benefits for a range of factors discussed in Sections 2.2.1 and 3.1 to 3.4.

Figure 1.1 shows the basis for our calculations of the Lower Case estimate of benefits. The comparable build-up of the estimate for the Upper Case can be found at Figure 2.2, on page 14 of this report.

Our estimate of the benefits is based on:

- a 7.1 per cent rate of discount for a 10 year period to 2022/23, consistent with period used by the AEMC and advice received from the AEMC on the discount rate used by Frontier;
- an adjustment to remove the benefits associated with reductions in residential peak load. Frontier modelled the energy cost savings from a reduction in both residential and C&I peak load. The current scope of the DRM only applies to C&I customers, so we adjusted the benefits calculated in line with the reductions in maximum demand achieved in each category over the period modelled; and
- an adjustment for the net present value of the full carbon cost offsets calculated by Frontier to reflect changes in government policy relating to the mechanism for reducing carbon emissions.

Recent developments are likely to have significantly reduced the originally estimated $48m - $100m benefit of the proposed DRM. Since the publication of the initial material in 2012 there have been:

- changes to the quantity of DRM modelled (Section 2.2.1), and
- significant reductions in AEMO's projections of demand growth (Section 3.1).

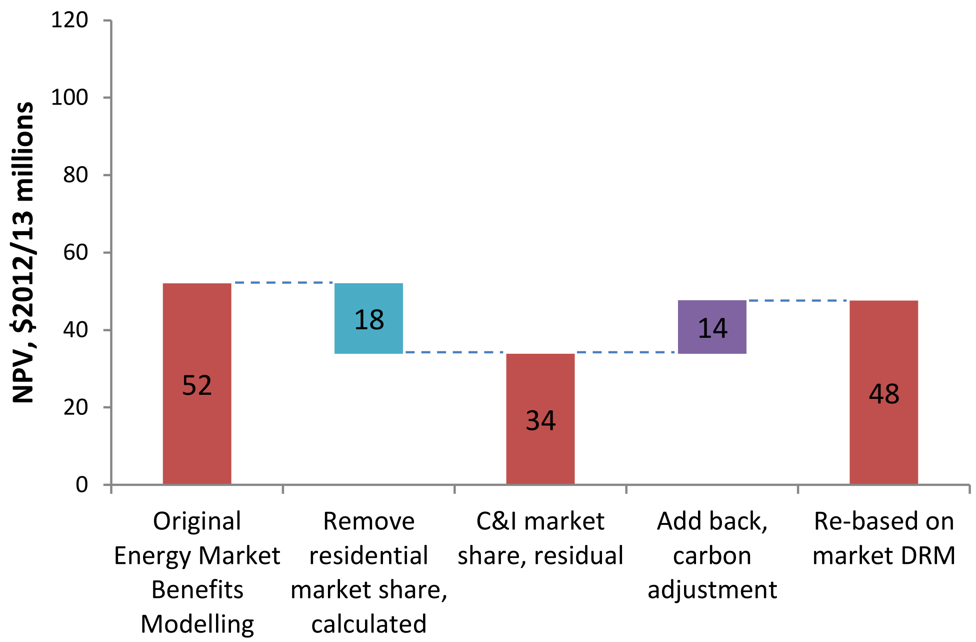
The modelling approach taken in preparing the estimated benefit for the Power of Choice was necessarily high level and raises a number of issues. In our judgment, many of these issues, if considered appropriately in the context of a detailed benefit cost analysis, would

[5] AEMC, 2012, p vi

have the effect of further reducing the original benefits modelled of the proposed DRM (See Sections 3.2 to 3.4).

For these reasons, we have focused on the estimated benefits of the Lower Case over the period from 2013/14 to 2022/23 (referred to as the Preferred Estimate).

Figure 1.1 Wholesale Market Benefits: Demand Response Mechanism, Lower Case, 2013/14 to 2022/23, estimated NPV, $2012/13 million



Source: Frontier Economics, 2012a; Seed estimates

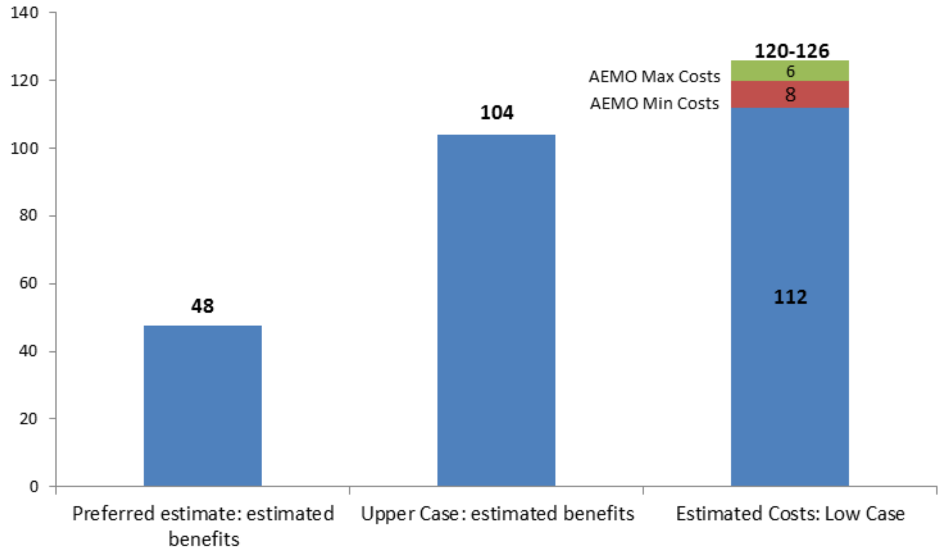
1.2. The costs of introducing the DRM

The ERAA collated 'order of magnitude' costing information from its members based on the AEMO costing request used as part of the DRM rule change development process. Using this information as well as our understanding of AEMO's expected costs associated with the DRM, we have estimated a low case total cost of $120 - $126 million. Our approach to calculating the cost estimates is discussed in further detail in Appendix D.

Figure 1.2 compares our Preferred Estimate of the benefits of the DRM with the present value of the low end of the estimated costs of its implementation and management over the 10 year period to 2022/23. For completeness, we have also included the estimated benefits of the Upper Case benefits.

Considering the Preferred Estimate and the lower bound of the costs ($120 million, based on $112 million retailer costs plus $8 million AEMO costs) gives a net negative benefit of -$72 million, well short of the level required for justification of the proposal, considering society's benefits and the costs. Considering the higher benefit estimate of $104 million and the higher cost estimate of $126 million, this gives a net negative benefit of -$22 million.

Figure 1.2 Estimated Benefits and Low Case Costs, DRM: 2013/14 to 2022/23, Present Value, $ million



Source: Frontier Economics, 2012a; ERAA Member Survey estimates; AEMO estimates; Seed estimates

1.3. Other adjustments to the DRM benefit estimate

Considering the Preferred Estimate and the lower bound of the estimated costs ($120 million), the benefits fall well short of the amount required to justify the introduction of the DRM, considering either the NEM or societal benefits more broadly.

The adjustments we identify to the Preferred Estimate from changes to the modelling approach, reductions in projected Maximum Demand and methodological issues are likely to further reduce the estimated benefits of the DRM.

- The modelling on which our Preferred Estimate is based overestimated the size of the program, increasing the benefits by between $6m and 12m NPV ($2012/13) compared with the appropriately sized program (Section 2.2.1).
- Projected Maximum Demand across the NEM has been significantly reduced, likely changing spot market outcomes and reducing the benefits from the DRM (Section 3.1).
  - In addition, the reductions in projected Maximum Demand largely eliminate the benefits from generation investment deferral (Sections 3.1, 3.3 and 3.4).
- The DRM program size assumed in the modelling is a stretch target, considering the timeline for its introduction and current levels of demand response identified by the AEMC's consultants and the ERAA's member survey. The benefits may not be achievable, particularly on the timeline underlying the modelling (Section 3.2).
- The modelling, which looks at wholesale market benefits, before participants' costs and payments to end users (demand response providers), falls short of the requirements of a benefits case as part of any benefit cost analysis (Section 3.3). A detailed benefit cost analysis is required.

1.4. Further observations

The DRM and demand response more broadly competes with existing generators, and the income stream earned by an end user participating in the DRM (or wholesale market) is neither guaranteed nor risk free (Section 4.1). Participants in the DRM could be seen as substitute providers of wholesale market hedge products similar to $300/MWh strike caps. Unlike cap products, however, demand response providers may have physical restrictions on their ability to respond to high price events. Many end users, for example, require a minimum notice period to respond and others have a maximum number of hours in total that they can respond.

Payments to DRM providers in the wholesale market are dependent on the frequency and duration of high spot price outcomes and the provider's ability to respond and, therefore, highly uncertain. For example, in Q1 2013 in NSW there were no prices in excess of $300/MWh. Over the same period in South Australia there were 14 periods, none of them longer than half an hour in duration.

Further, the benefits of network demand response and the DRM do not depend on each other (Section 4.2). Under certain circumstances – where an end user providing demand response rations the amount of demand response it is willing to provide, for example – the programs may even compete. Even if a more detailed review of the benefits and costs of the DRM program is unfavourable, this would not of itself detract from the potential benefits of any network demand response program, which account for more than 95 per cent of the AEMC's estimate of the benefits of demand response in total.

2. The benefits of a Demand Response Mechanism in the NEM

In reviewing the benefits likely to be realised through the introduction of the DRM as proposed in the AEMC's Power of Choice Final Report and AEMO's final design[6], we have been asked to consider a range of the work undertaken by the AEMC and its consultants during the Power of Choice review. Appendix A outlines our use of "demand response", "Demand Response Mechanism" and other terms throughout this report, while Appendix E details the work we were asked to consider.[7]

In reviewing these analyses, we were asked to consider:

- The range of benefits which can be directly attributed to the operation of the DRM;
- The extent to which stated benefits may also rely on other drivers;
- The additionality of stated benefits beyond what can already be realised through current off-market demand response programs, and also above and beyond the DRM;
- The likelihood of these benefits being realised;
- The validity of claims about the magnitude of benefits to be realised;
- The allocation of benefits to various roles across the electricity supply chain; and
- The expected timeframe for valid benefits to be realised by the market.

The AEMC Power of Choice review estimated the benefits from demand response to be in the range of $2.8 billion to $4.3 billion over a 10 year period from 2013.[8] This estimated benefit was calculated at a high level only and was a combination of avoided network costs and energy cost savings. The benefits of the DRM relate only to energy cost savings attributable to spot market participation by C&I customers or end users, not avoided network costs. Our analysis in the remainder of this report therefore focusses on this element of the benefit case.

We have considered the AEMC's benefits estimates in Chapter 10 of its Final Report and Frontier's work together. The AEMC's analysis in Chapter 10 of the benefits of the energy cost savings (wholesale market component) of demand response is based substantially on Frontier's modelling of wholesale spot market outcomes. The Frontier presentation from October 2012 is the only publicly available information on the benefits resulting from the DRM.

[6] Australian Energy Market Operator, *Demand Response Mechanism and Ancillary Services Unbundling - Detailed Design,* 15 November 2013

[7] The discussion that follows focusses on the AEMC's and Frontier's work. Futura's analysis, while providing a high level estimate of the existing and potential dispatchable peak demand response in the National Electricity Market – broadly equivalent to the potential participation in the DRM program we have been asked to consider – reflects activity in Australia to date in wider demand side participation programs and trials, the larger part of which have been focused on residential customers and are therefore less relevant to our review. Futura's discussion in Section 5 of its report about the outcome of those trials that have included small commercial and industrial customers suggests that those trials that have sought to include smaller commercial and industrial customers have had relatively little success enlisting this customer class.

[8] AEMC, 2012, Table 10.2, p 269

Chapter 5 of the AEMC's Final Report is a largely high level review of the design and benefits of the DRM and, at that level, we accept the AEMC's conclusions that on-market demand response has benefits to offer the wholesale market, customers and society. At a high level, the question we have been asked to answer is not whether the DRM provides benefits to society, but whether the proposed program will deliver the estimated benefits and whether these benefits will outweigh the costs of implementing the proposed design.

In this section, we:

- describe Frontier's approach to estimating the wholesale market cost savings (Section 2.1.1);
- estimate the total net energy market savings consistent with Frontier's presentation of the savings and also truncated in line with the AEMC's estimation of the benefits (Section 2.1.2);
- adjust the total net savings for the change in government policy in relation to carbon emission reduction costs (Section 2.1.3); and
- estimate the further adjustment necessary to reflect the changed quantity of the DRM between the initial October presentation and the AEMC's Final Report (Section 2.2.1).

Our estimates suggest that, consistent with AEMC's discussion of the distribution of the benefits of the Power of Choice across networks and wholesale markets, the majority of the benefits relate to network cost savings. The maximum share of the total benefits attributable to the DRM could be around 2.5 per cent of the total, comparing our estimate of the NPV of the benefits of the Upper Case with the AEMC's estimate of the Upper Case of the NPV of the total benefits from all the demand response programs that were modelled for its report.[9] If we compare our Preferred Estimate with the AEMC's estimate of the benefits of the Lower Case, then the DRM contributes around 1.7 per cent of the total benefits modelled.

Taking into account those adjustments that we outline in Section 3 would significantly reduce the net benefits, considered either on the basis of benefits to the wholesale market or, more appropriately, benefits to society.

2.1. Estimating the energy cost benefits

Frontier's work is not represented by Frontier or the AEMC as a benefit cost analysis, nor is it represented as a full analysis of the benefits case. However, it has been cited by the AEMC as representing the economic cost savings as a result of the introduction of the DRM: the AEMC describes Frontier's modelling as "look[ing] at the benefits associated

[9] The AEMC claims total benefits of $4.3 to $11.8 billion (NPV $2012/13) from all the programs considered over the first 10 years of the program (AEMC, p 256; 268). Of this result, between $2.8 and $4.3 billion (NPV $ 2012/13) are attributed to the combination of demand response programs – network, residential demand and the DRM. Our preferred (carbon adjusted) benefit calculation, before further adjustments is $48 - $104 million for the DRM project (see Section 2.1.3, below) and our calculation is based on our Preferred Estimate (Upper Case) as a share of the AEMC's Lower Case (Upper Case), giving a range of 1.7 to 2.4 per cent of the total identified benefits.

with ... introducing the Demand Response Mechanism in the wholesale electricity market."[10], using a long-term cost based model to calculate the energy benefit estimates.

Frontier's approach estimates the combined benefits of shifting demand from peak to other periods in the electricity wholesale market.

The benefits are categorised as:

- the reduction in generators' variable costs, relative to the benchmark, as load shifting moves load from more to less expensive generators;
- a reduction in the fixed costs of generation, resulting from load deferral; and
- offsetting these benefits, higher carbon costs as load is shifted from periods where average carbon emissions are lower to periods where average carbon emissions are higher.[11]

In Section 3.4 we discuss the appropriateness of the treatment of Frontier's approach as the benefits element of any benefit cost analysis.

2.1.1. Background

Frontier used its WHIRLYGIG model, designed to minimise the total cost of meeting the demand for electricity, including the fixed and variable costs of meeting electricity demand, subject to a number of constraints.[12] AEMO's 2012 medium projections (50% Probability of Exceedence or POE) for maximum demand, electricity sent out, were used as the Base Case.

Demand response in the wholesale market has been modelled as a reduction in Maximum Demand. The benefits of the reduction in demand were calculated by comparing energy market costs, both fixed and variable, before and after demand reduction. Frontier modelled the demand reduction for residential customers and C&I customers together. Frontier compared:

- the discounted total costs of meeting total demand under the Base Case, taking into account the long run marginal cost of generation and the requirement for new generation investment, with
- the discounted total costs of meeting total demand after allowing for projected demand reductions achieved across both residential and C&I Maximum Demand as the result of a range of demand response programs.

The demand reductions assumed for C&I Maximum Demand step up to 5 per cent ("Lower Case") and 10 per cent ("Upper Case") of total projected peak demand in 2017/18 and are maintained at those percentage shares of projected C&I demand until

---

[10] AEMC, p.256

[11] Frontier also includes as a benefit the reduction in Variable Deficit Energy relative to the Baseline. Variable Deficit Energy is a product of the modelling approach which allows for very short term periods where regional demand is greater than regional supply and the price of the resulting energy deficit is the Market Price Cap. In the modelling undertaken for the AEMC, we understand that Variable Deficit Energy arises in one region only and for such short periods of time that the introduction of new generation would be inappropriate. Frontier, 2012b, p 84; verbal communication.

[12] Frontier Economics, *Methodology Report – input assumptions and modelling: a Draft Report prepared for IPART,* November 2012, pps 79-86; hereafter, Frontier, 2012b. We are grateful to Frontier for responding to a number of queries relating to the WHIRLYGIG model and the modelling approach for the work undertaken for the AEMC.

2032/33.[13] Frontier assumes there is no loss of production – total demand is held constant through load shifting – and, in consequence, no economic costs to participants or the economy more broadly in achieving the savings identified.

Frontier's WHIRLYGIG model uses the long run marginal costs (LRMC) of the existing and required future generation to meet projected demand. LRMC models show increasing costs over time as the demand/supply balance tightens and more expensive generation is scheduled more frequently to meet demand. New entrants enter the market in the WHIRLYGIG model when the regional reserve margin is breached.[14] Models like WHIRLYGIG differ from models that make assumptions about generator bidding in that LRMC serves as a proxy for the outcome of generator bidding behaviours: in the short run, as in the long run, a generator earns LRMC. In the case of existing generators, a generator earns its estimated LRMC, while new entrant generation earns the LRMC associated with its specific class of generators.

2.1.2. Estimating the contribution of the DRM to the total benefits estimates

We estimate that the benefits attributable to the DRM over the period from 2013/14 to 2022/23 range from around $48 million ($2012/13) in the Lower Case to just over $100 million in the Upper Case. [15] Appendix B provides a more detailed description of our approach to estimating the benefits attributable to DRM from the information in the public domain.

Our estimate of the benefits is based on:

- a 7.1 per cent rate of discount for a 10 year period to 2022/23, consistent with period used by the AEMC and advice received from the AEMC on the discount rate used by Frontier;
  - The results over the total period to 2032/33 modelled are sensitive to the discount rate, while the truncated results are relatively insensitive to the discount rate.
- an adjustment removing the benefits associated with reductions in residential peak load. Frontier modelled the energy cost benefits from reductions in both residential and commercial and industrial (C&I) peak load. The current scope of the DRM only applies to C&I customers, so we prorated the benefits calculated in line with the reductions in maximum demand achieved in each category over the period modelled;
  - The DRM program reaches its target level sooner than the Demand Response Residential program, so that over the 10 year period for which benefits have been calculated, a disproportionate share of the benefits accrues to the DRM.
- an adjustment to add back the net present value of the full carbon cost offsets calculated by Frontier to reflect changes in government policy relating to the mechanism for reducing carbon emissions.

---

[13] However, see Section 2.2.1 about the quantum of DRM assumed in Frontier's original modelling, presented in October 2012, relative to the modelling assumptions outlined.

[14] Frontier recognises the conservatism of this assumption, particularly in the light of the historic performance of the 10% POE projections (Frontier, 2012b, p 85). For the purposes of this analysis, the approach has two impacts: compared with an alternative rule, for example a commercial rule relating to the minimum required generation for the entry of a new generator, the cost of meeting demand will be lower because the new entrant will enter the market sooner. On the other hand, the capital costs of new load will be incurred earlier than might otherwise be the case.

[15] Frontier Economics, 2012a, p 17.

This estimate is calculated from the total net system cost savings illustrated in Frontier's presentation.[16] Table 2.1 shows our estimates of Frontier's savings of energy cost savings in aggregate, as well as our estimate of the C&I share of these energy cost savings which relate to the DRM. Comparing the estimated benefits over the 10 year period used by the AEMC in its report with the estimated benefits over the total period modelled demonstrates that the benefits in the relatively short term are very small, compared with those over the longer term: the majority of any benefits arise in the period beyond 2022/23. However, the longer term benefits may be illusory, since they assume a level of growth in projected Maximum Demand that has since been significantly reduced (Section 3.1) and include benefits from deferred generation investment which, if still valid, should not, in our view, have been included in the evaluation (Section 3.3).

Table 2.1 Demand Response Mechanism: Total Net Wholesale Market Cost Savings, Estimated Net Present Value, $2012/13, millions*

Period	Lower Case	Upper Case
Total Estimated Benefits		
2013/14 – 2022/23	52	102
2013/14 – 2031/32	439	586
C&I Share of Estimated Benefits (Prorated)		
2013/14 – 2022/23	34	56
2013/14 – 2031/32	274	309

* Totals may not add due to rounding

Source: Frontier Economics, 2012(a); Seed Estimates

2.1.3. Adjusting the estimates for changes in the carbon pricing regime

In moving consumption from peak periods to lower consumption periods, Frontier has estimated the additional carbon liability associated with the substitution of coal for gas-fired generation and included the costs of the additional carbon liability as an offset to the estimated system wide cost savings.

Current government policy proposes the elimination of the carbon tax and carbon reduction liabilities in their current form. Given this, we have added back the net present value of the full carbon costs calculated by Frontier. If government policy was to change and an explicit carbon price was introduced in the future, some part of these additional benefits would be reversed. In this respect, our treatment of the carbon costs modelled by Frontier is conservative.

Adding back our estimate of the net present value of the full carbon cost offsets calculated by Frontier to the estimates in Table 2.1 above suggests savings ranging from just under $50 million to around $100 million over the 10 year period that the AEMC has used for estimating the benefits in Chapter 10. Our calculations are given in Table 2.2.

[16] Our numbers are necessarily estimates only, as they are based on our own estimate of Frontier's graphic representation of the system cost savings over time. Neither Frontier nor the AEMC provides a breakdown of the actual savings estimate or its components. See Appendix B.

Table 2.2 Demand Response Mechanism: Total Net Wholesale Market Cost Savings adjusted for Carbon Costs, Net Present Value, $2012/13, millions*

Period	Lower Case			Upper Case		
	Net of carbon	Carbon costs	Including carbon	Net of carbon	Carbon costs	Including carbon
Total DSR Benefits						
2013/14 – 2022/23	52	-22	74	102	-90	192
2013/14 – 2031/32	439	-225	664	586	-344	930
C&I Prorated Benefits						
2013/14 – 2022/23	34	--14	48	56	-48	104
2013/14 – 2031/32	274	-140	414	309	-180	489

* Totals may not add due to rounding

Source: Frontier Economics, 2012(a); Seed Estimates

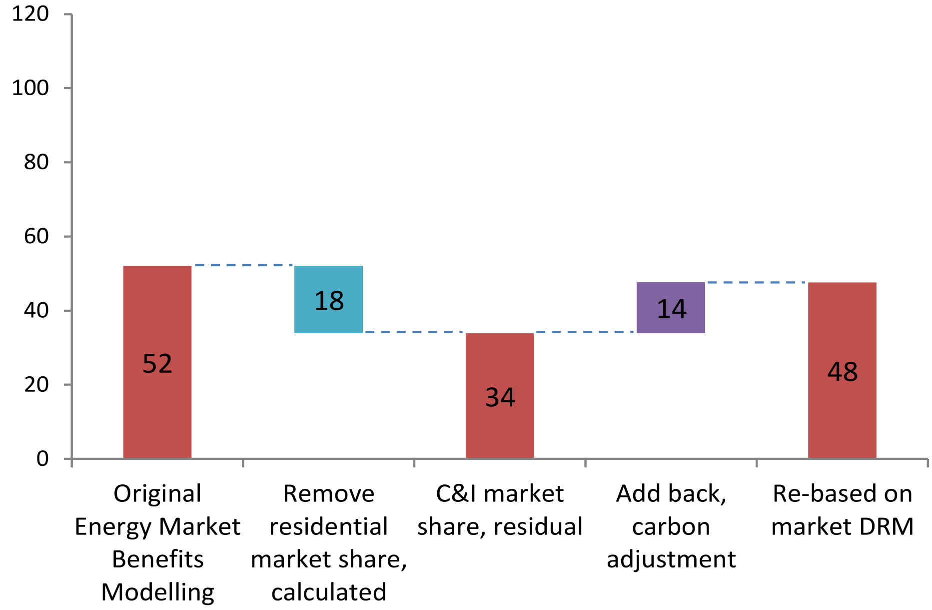
Frontier's modelling is based on full load shifting: there is no lost production (see Section 3.3) and no incremental use of existing or new embedded generation (Sections 3.2 and 3.3). To the extent that existing or new embedded generation is used in preference to load shifting, then the increase in carbon emissions as a result of the DRM may be higher than Frontier's estimates. We have made no allowance for potential additional costs or their effects on the benefits case.

2.2. The Adjusted Baseline: our Preferred Estimate

For the purposes of the subsequent analyses, our Preferred Estimate is the estimated C&I benefits under the Lower Case, calculated over the 10 years to 2022/23 and adjusted to remove the additional carbon costs calculated by Frontier. Figure 2.1, below, shows the build-up of our adjusted estimate, while Figure 2.2 provides the same build-up for the Upper Case.

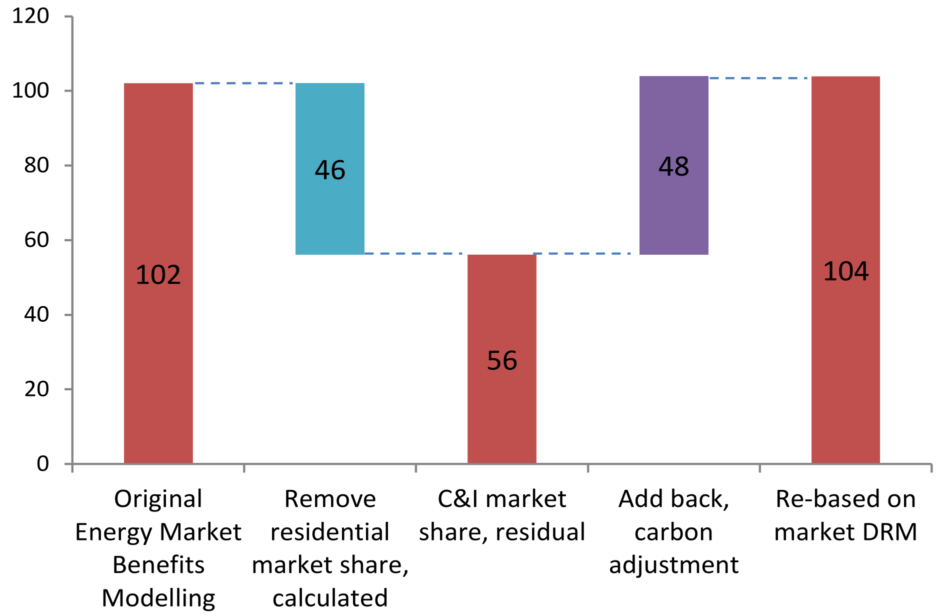
Depending on the implementation details of the Government's policy relating to carbon abatement, this adjustment may be subject to downwards revision. However, in our judgement, other unquantified adjustments discussed in Section 3 are likely to have a more material effect on the benefits estimates than changes to the treatment of carbon emissions. Given this, we prefer the Lower Case to the Upper Case as the estimate of the DRM benefit and the discussion in Section 3 focuses on our Preferred Estimate in discussing the benefits from the DRM.

Figure 2.1 Demand Response Mechanism: Total Net Wholesale Market Cost Savings adjusted for Carbon Costs, Lower Case, 2013/14 to 2022/23, Estimated NPV, $2012/13 million



Source: Frontier Economics, 2012a; Seed estimates

Figure 2.2 Demand Response Mechanism: Total Net Wholesale Market Cost Savings adjusted for Carbon Costs, Upper Case, 2013/14 to 2022/23, Estimated NPV, $2012/13 million



Source: Frontier Economics, 2012a; Seed estimates

2.2.1. The quantity of demand response participating in the DRM

The assumptions used as a basis for modelling the DRM program include an assumption that 5 per cent of C&I peak demand is shifted from peak periods in the Lower Case and 10 per cent in the Upper Case. The reference year used for the DRM program – the year in which the program first reaches the target level – is 2017/18.[17]

The initial modelling, on which our analysis and calculation of the Preferred Estimate and Table 2.1, Table 2.2, Figure 2.1 and Figure 2.2 are based, assumed that the quantity of the demand response participating in the DRM program increases by a fixed amount annually, so that by 2022/23 just under 10 per cent of C&I maximum demand was included in the program (Lower Case) and just under 20 per cent in the Upper Case. The corresponding numbers for the total period modelled were around 17 per cent of C&I maximum demand in the Lower Case and around 35 per cent in the Upper Case. This was rectified and the assumption was amended prior to the AEMC's Final Report, as illustrated by a comparison with the charts on slides 10 and 11 in the Frontier presentation of October 2012 with the equivalent AEMC Figures 10.2 and 10.3.[18]

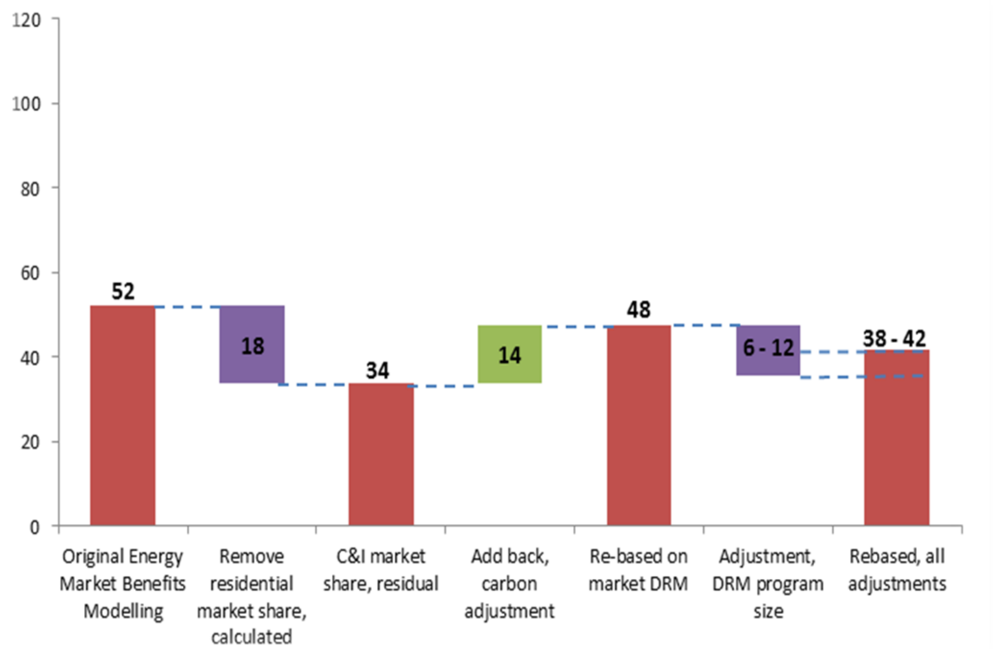
Our estimates of the energy market benefits are based on Frontier's presentation and, as a result, will be higher than the benefits that have been included in the total benefit estimate for all demand response programs included in the AEMC's Final Report. The extent of the over-estimate is likely to be material in relation to our Preferred Estimate of $48 million ($2012/13). We have calculated an estimate of the impact of changing this assumption as a negative adjustment of between $6 and $12 million ($2012/13) to the Preferred Estimate.

- There is around twice as much demand response in the DRM program by the end of 2022/23 as was originally assumed. The difference between the design intention and the DRM modelled occurs between 2017/18 and 2022/23, when the period over which the benefits are calculated ends. The contribution of the additional volume to the NPV in our Preferred Estimate is discounted because it occurs so late in the period over which the benefits are calculated: the reduction in the estimated benefits is likely to be lower than that resulting from prorating the estimated benefits.
- Further, Frontier notes that expansions to the program are subject to declining marginal returns, so adjusting the Preferred Estimate is not a straightforward as pro-rating our Preferred Estimate to reflect the lower volume.
- If we assume the last 50 per cent of the volume of DRM earns between 12.5 and 25 per cent of the first 50 per cent – a conservative estimate – then, we can assume that the NPV of the Preferred Estimate could be reduced by between $6 and $12 million ($2012/13), to between $36 and $42 million ($2012/13). In comparison, pro-rating the benefit suggests a reduction of around $14 million ($2012/13) in the NPV.

Figure 2.3 summarises the effect of the adjustments for the size of the DRM program on our Preferred Estimate, which, in addition to the other previously discussed adjustments would reduce the benefits of the Lower Case to between $38 and $42 million, $2012/13.

[17] Frontier, 2012a, p7.
[18] AEMC, pps 262-263

Figure 2.3 Demand Response Mechanism: Total Net Wholesale Market Cost Savings adjusted for Carbon Costs and Program Size, Lower Case, 2013/14 to 2022/23, Estimated NPV, $2012/13 million



Source: AEMO, 2012 National Electricity Forecasting Report (NEFR); Frontier Economics, 2012a; Seed estimates

Frontier estimates that over the longer period modelled the operation of the DRM program enables generation investment to be deferred. While not a component of our Preferred Estimate or the AEMC's, both of which consider only the 10 year period to 2022/23, the benefits of deferral represent a significant element of the longer term benefit case.

- Our view is that, in including the benefits of deferred investments, there is an element of double counting in Frontier's benefits estimate (Section 3.4.). But, notwithstanding this, the amended quantity of DRM is unlikely to supply the same benefits in deferring generation investment, always assuming that generation investment is required (Sections 3.1.1 and 3.2).
- Further, given the very low growth in the contribution of projected C&I DRM to the wholesale market from 2017/18 resulting from the revised calculation methodology, the deferred generation benefit is, by its nature, one-off. Low projected growth in C&I DRM means that this benefit is unlikely to be repeated: deferred investment provides only a transitory benefit, not one that continues to grow over time.

3. Recalibrating the benefits of the DRM

What value does the DRM provide to the wholesale market? The DRM can provide additional capacity at periods when demand is high relative to available supply and, as a result, prices are high. High price periods typically characterise the summer period across the NEM and can also occur when binding constraints arise, islanding regional or sub-regional markets and increasing spot prices. The returns to the DRM, therefore, are driven by:

- the relationship between demand and capacity throughout a day and across the year in a given regional market that gives rise to time variant and seasonal wholesale price variability;
- the frequency of other high price events that occur randomly throughout the year;[19] and,
- the level reached by prices during periods of high hourly, daily or seasonal demand.

Section 2 discussed the benefits of the DRM prior to any further adjustments. In the material that follows we discuss a range of changes that, relative to the modelling undertaken of the benefits of the DRM are likely to reduce the estimated benefits of the DRM. We expect these changes, working through changes in the supply/demand balance in NEM regional markets, to result in additional surplus capacity relative to previous projections, reducing the frequency of high price periods and reducing the market clearing price during high price periods. Working together, these changes are expected to reduce the value of the DRM relative to the estimated value.

In this section, we discuss a range of further adjustments to our Preferred Estimate that in our view would be required to reflect:

- the significant changes to the Baseline as a result of reduced demand projections in the 2013 National Electricity Forecasting Report (NEFR) relative to the 2012 report relied on by Frontier and the AEMC, which, all other things being equal, could be expected to reduce the benefits estimate; and,
- other adjustments required if the analysis was to be used as an estimate of the net benefits of the DRM.

We then discuss the AEMO's estimates of its implementation costs and participant costs identified in the ERAA's member survey in relation to the adjusted Preferred Estimate.

3.1. Changes to projected maximum demand: impact on the benefits

3.1.1. Reductions in projected Maximum Demand: impact of 2013 ESOO projections

The 2013 Electricity Statement of Opportunities and the accompanying National Electricity Forecast Review significantly revise projections for Maximum Demand growth served by the wholesale electricity market over both the truncated and total period over

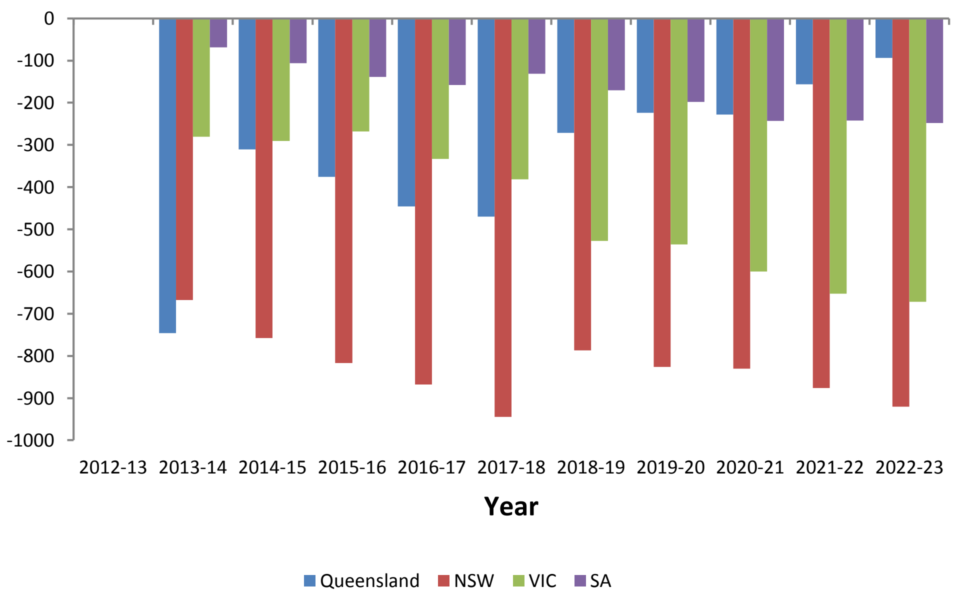
[19] Frontier's WHIRLYGIG model will not capture these effects and, to the extent they are important in determining average spot prices, will underestimate the contribution of DRM to wholesale electricity costs.

which the benefits of the DRM have been calculated. Figure 3.1 below, shows the difference in MW between the 2012 and 2013 Planning (50 per cent POE) projections for Maximum Demand, electricity sent out, by jurisdiction.

Compared with earlier projections, the current projections show very significant and persistent reductions in projected Maximum Demand served by the wholesale electricity market across the NEM. In South Australia, the revisions to the projections are such that the absolute level of Maximum Demand projected to be served by the wholesale electricity market falls relative to the 2011/12 level across the period to 2031/32. Other states, while showing demand growth over the period, show significantly less demand growth than projected in 2012.

As a result of the projected slowing in demand growth, only Queensland is projected to have a requirement for additional capacity over the period to 2022/23. Queensland breaches the Reserve margin in 2019/20 on the Medium Scenario, requiring 159 MW additional installed capacity at that point to meet the Reserve margin.

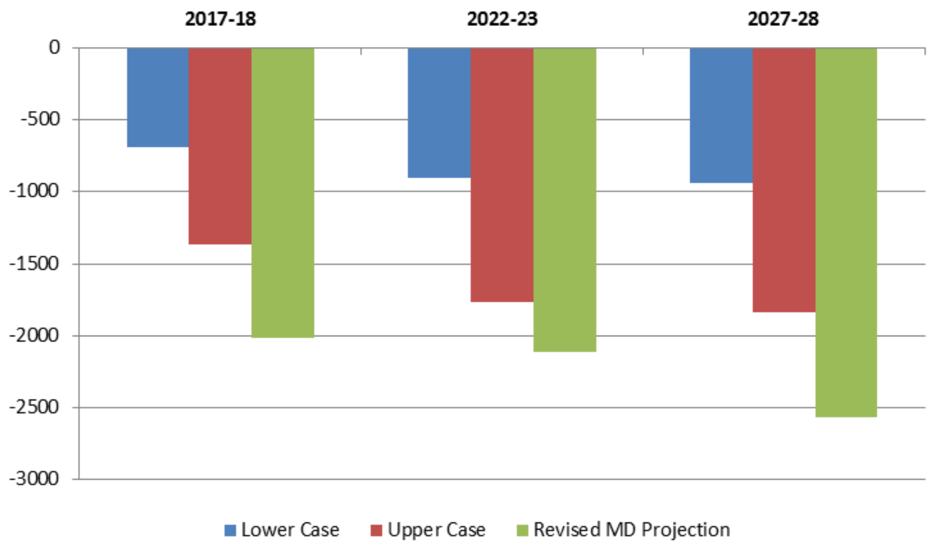
Figure 3.1 Change in projected Maximum Demand by Jurisdiction, 2013 NEFR compared with 2012, Summer MD, Planning Scenario, 50% POE, MW



Source: AEMO, National Electricity Forecasting Report, 2013; Seed calculations

Putting the changed projections for Maximum Demand and the DRM program modelled into perspective, NEM wide the reductions in projected Maximum Demand are between 2.3 and 2.9 times the size of the assumed reduction in peak demand achieved by the Lower Case DRM program modelled. They are also between 1.2 and 1.4 times the size of the assumed reduction in peak demand achieved by the Upper Case DRM program modelled. Figure 3.2 demonstrates these relationships for the Reference Year (2017/18), 2022/23 – the end of the AEMC's analysis period – and 2027/28, the 10 year mark for the full program.

Figure 3.2 Projected Reduction in Maximum Demand in the NEM: Lower and Upper DRM and changes in ESOO projections, MW



Source: Frontier, 2012a; National Electricity Forecasting Report, 2013; Seed calculations

As Figure 3.3 and Figure 3.4 show, rebasing the Lower and Upper cases for the DRM program to take account of the more recent projections for electricity demand materially affects the size of the program, as well as likely reducing its value. In Figure 3.3 and Figure 3.4, the broken lines represent the Baseline, Lower and Upper cases for the DRM program, based on the 2012 ESOO projections. The solid lines represent the same program, but rebased on the 2013 ESOO projections. Figure 3.3 and Figure 3.4 do not correspond to the comparable figures included in Frontier's presentation and the AEMC's Final Report, as we understand that the figures used by Frontier and the AEMC were based on the 10 per cent POE ESOO projections, rather than the 50 per cent POE projections included in the modelling assumptions.[20]

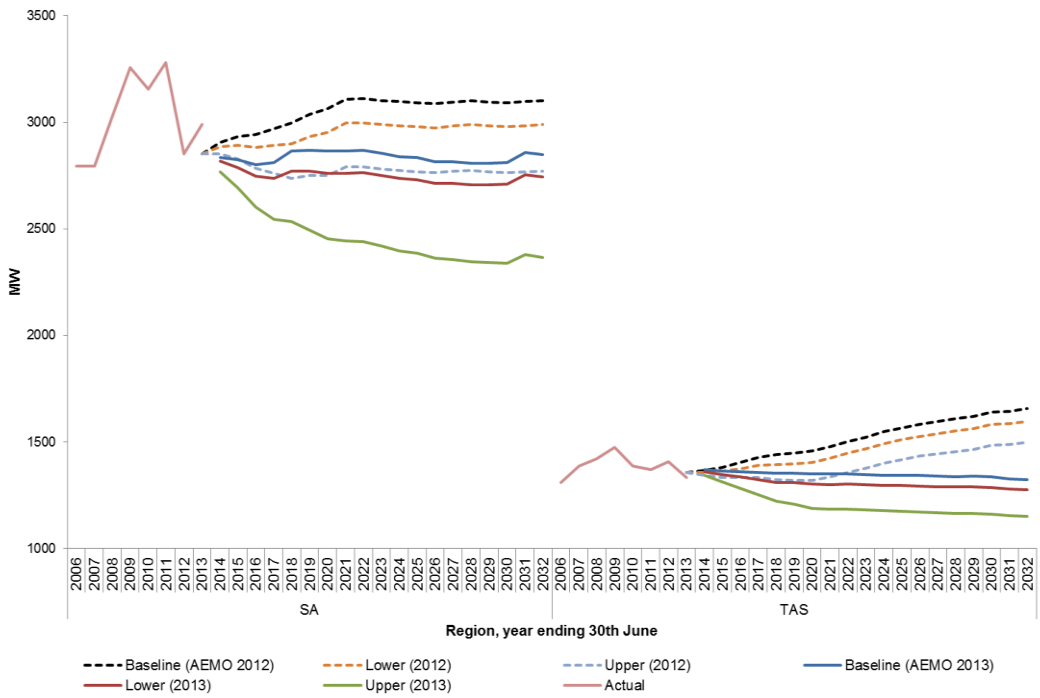
With the exception of Queensland, the 2013 Baseline projection for electricity demand is below the level expected to have been achieved in the DRM Lower Case and the 2013 Lower Case is around the level of demand projected to have been achieved by a combination of more aggressive energy efficiency measures and the Upper Case DRM program when based on the 2012 ESOO projections.

[20] Frontier Economics, verbal communication. Relying on the 10 per cent POE would have raised further issues for the results: the differences between the 50 per cent and 10 per cent POE estimates are significant and have a material effect on both the load duration curve used to generate the LRMC estimates in the WHIRLYGIG model and on the size of the DRM program. Further, as both Frontier and AEMO have recognised, the 10 per cent POE estimates are highly conservative and, used to model the contributions of the DRM program, would result in a material increase in the estimated benefits relative to the likely achievable level.

Figure 3.3 DRM Program Projections: Lower and Upper Cases by region and year, Seed assumptions, 2012 ESOO and 2013 ESOO, NSW, Qld and VIC, 50% POE, MW sent out

Source: AEMO, 2013 NEFR; AEMC, Power of Choice; Seed calculations

Figure 3.4 DRM Program Projections: Lower and Upper Cases by region and year, Seed assumptions, 2012 ESOO and 2013 ESOO, SA and Tasmania, 50 % POE, MW sent out



Source: AEMO, 2013 NEFR; AEMC, Power of Choice; Seed calculations

In applying the same approach to evaluating the potential contribution of the DRM as the AEMC applied in defining the Lower and Upper Cases, changes to the ESOO Maximum Demand projections could be expected to reduce the assumed size of the program. In 2017/18 rebasing the DRM Lower and Upper Cases to reflect the changes between the 2012 and 2013 ESOO projections reduces the NEM wide DRM in the wholesale market by between 46 and 127 MW, or a reduction of between 5 and 7.5 per cent in the size of the program.

Estimating the effects of this reduction on the benefits of the program is more difficult.

- A reduction in the size of the program would not be expected to reduce the benefits case proportionally, as each marginal increment to the program attracts a lower value. Reductions in the size of the program, therefore, are likely to reduce the benefits by less than the estimated average value represented by a MW in the program. Further, while a reduction of 5 per cent on its own may not materially affect the marginal value of the every MW of DRM, the reduction occurs in addition to a significant reduction relating to the initial overestimate of the potential DRM in the program (Section 2.2.1).
- Frontier's total benefits case over the total period to 2032/33 was significantly increased by the contribution of the DRM program to deferring generation in South Australia and Queensland. The longer term benefits case will be reduced as a result of the reduction in the benefits from deferred investment.
  - With South Australia's Maximum Demand for electricity sent out expected to marginally fall in absolute terms over the period to 2032/33, a substantial share of the benefits case associated with investment deferral is removed. Queensland's growth profile has been shifted to a later period, making a smaller contribution to the total benefits case.
  - However, we are concerned that there may be elements of double counting in the current approach to including the benefits of deferred generation: see the discussion in Section 3.4.
- Finally, if recent experience of the effects of solar PV on peak prices during the summer period, particularly in NSW, is repeated and lower peak demand is associated with lower peak prices, then the benefits from the program as a whole will fall, as the average peak wholesale price will fall, reducing returns to DRM.
  - Growing contributions from energy efficiency and solar PV contribute significantly to the total projected reduction in Maximum Demand over the period to 2022/23 and could be expected to have a dampening effect on peak demand prices, particularly during the summer period. Figure 4.2 illustrates the effect on the load on a Queensland residential feeder of increasing solar PV penetration over the period 2009 to 2013. It shows a significant reduction in load during daylight hours. As solar PV penetration increases, this effect could be expected to significantly change daily and seasonal peak demand in the wholesale market, affecting pricing.
  - Quoted market prices for $300 caps have already declined in response to the experiences of recent summers, where high price periods have been both infrequent and, outside Queensland, of relatively short duration compared with historic experience in the NEM (Section 4.1).
  - The ERAA's survey of retailers' current C&I demand response programs suggests that current C&I contracts for participants in demand response programs are

structured similarly to option contracts, with a strike price (the price at which the customer's demand response is triggered) of $300/MWh, high fixed charges similar to an option premium and benefit sharing typically giving customers between 50 and 60 per cent of benefits received in excess of the strike price (see Appendix B for further details).[21] The willingness of customers and retailers to enter into contracts like this is a function of expectations of the frequency of spot prices exceeding $300/MWh: the lower the number of expected high price events, the lower the demand for and the supply of demand response (see also Section 4.1).

- However, by treating the contributions of energy efficiency and solar PV as determined by forces unrelated to the cost of wholesale electricity, the future contribution of these programs to reducing Maximum Demand for electricity sent out may be overestimated. If peak price levels and volatility were to be significantly modified as a result of lower expected growth, then the impetus for energy efficiency in particular may fall.[22]
  - In the same way, we expect that the impact of the reductions in projected Maximum Demand, electricity sent out, will affect the returns to the total DRM program and, in consequence, the likely participation of DRM providers in the wholesale market. Comparing the ERAA's Survey results with reported cap prices, existing C&I demand response program participants already appear to be expensive relative to substitute products in the marketplace with fewer specialised characteristics (Section 4.1).[23]

3.1.2. Impact on the benefits: qualitative and directional impacts

Table 3.1 summarises the likely effects on the value of the DRM program in adjusting for changes to projected electricity demand as a result of changes to AEMO's projections between 2012 and 2013.

- Our Preferred Estimate is the estimated C&I benefits under the Lower Case, calculated over the 10 years to 2022/23 and adjusted to remove the additional carbon costs calculated by Frontier. We estimate that the benefits amount to around $48 million ($2012/13).
- This estimate should be reduced by between $6 and $12 million ($2012/13), resulting in an adjusted Preferred Estimate of between $36 and $42 million ($2012/13), to

[21] Where the regional reference price is higher than $300/MWh during a period when the customer is providing demand response, then the customer would receive, in addition to the original option premium, 50 to 60 per cent of the difference between the strike price and the regional reference price. At an RRP of $400/MWh, the customer would receive between $50 to $60/MWh for every hour in which it provides demand response in addition to the fixed payment.

[22] The assumed growth in projections of energy efficiency is a significant element in the reduction in projected Maximum Demand, electricity sent out, for the NEM. In 2022/23, the last year included in the truncated benefits analysis, the increase in energy efficiency at summer peak demand periods across the NEM is 1,295 MW, or just over 3 per cent of residual demand for electricity sent out and explains around 60 per cent of the total reduction in projected Maximum Demand in the NEM in that year relative to the 2012 projections. If, however, rather than being treated as exogenous to other drivers of electricity demand, energy efficiency was assumed to be related to (previous) electricity prices, then other drivers of decreasing Maximum Demand – particularly lower economic activity and increased solar PV penetration – might be expected to reduce prices and, with a lag, energy efficiency savings.

[23] Quoted options have the advantage over DRM of having no ramp rates and standardised contract characteristics which, among other advantages, make them fungible (Section 4.1).

allow conservatively for the reduction in the size of the DRM program between the Frontier presentation and the AEMC's Final Report.
- An additional downwards reduction should be made to the estimate to allow for the effect of reductions to projected electricity demand working directly through a proportional reduction in the size of the DRM program and indirectly, through the expected effect on spot prices and the returns to DRM.

Given the relatively small benefits and the size and nature of the adjustments identified, in our view there is a strong case for the benefits to be re-estimated, taking into account more recent information. In Sections 3.2, 3.3 and 3.4, we consider other issues that, in our view, should be taken into account in re-estimating the benefits of DRM.

Table 3.1 Quantitative and qualitative effects, estimated NPV, Demand Response Mechanism, Lower Case, 2013/14 to 2022/23, Seed Estimates

Adjustment / Issue	Direction	Explanation
Reductions in projected Maximum Demand and Maximum Demand growth. **Changes between the 2012 and 2013 AEMO demand forecasts contained in the National Electricity Forecasting Report (NEFR) in projected demand growth, electricity sent out have significantly reduced projected Maximum Demand growth and, in SA, expected Maximum Demand levels.**	Reduces benefits: reduces need for generation investment as supply exceeds demand, therefore reducing size of any deferred generation benefit.	• Significant revisions to expected Maximum Demand levels in SA remove benefits from capital deferral from around 2026/27. – These benefits, while outside the period for the NPV calculations included in the AEMC's Report, are a significant contributor to the large longer term benefit estimates.
	Reduces benefits: excess of supply over demand is expected to reduce average peak prices and volatility, reducing payoff to demand response, DRM suppliers.	• In the absence of further withdrawals of generating capacity from the market, there is likely to be significant excess supply. This will most likely reduce peak prices and peak price volatility, reducing benefits attributable to DRM and demand response. • This effect is compounded by a modelling approach that currently treats demand response, residential and the DRM as happening simultaneously. – However, demand response, like Energy Efficiency (and increasing solar PV penetration), reduces Maximum Demand for electricity sent out, reducing wholesale peak prices and peak price volatility and reducing payoff to the DRM, with possible effects on program participation. • Further, if modelling approached demand response and energy efficiency as price sensitive, reduced peak prices and peak price volatility could be expected to reduce the pay-off to demand response, DRM and Energy Efficiency, reducing the quantity delivered below AEMO's projections, further reducing the benefits.
	May bring forward some benefits in Queensland where there is a small amount of additional new generating capacity required.	• 2013 ESOO suggests that small additional capacity required in Qld from 2019/20 to meet AEMO planning standards (Reserve margin). If demand response and the DRM sufficiently robust and investment was expected to proceed to meet Reserve Margin, demand response could defer indefinitely, given requirement for additional generation is only small. – However, significant questions remain: reserve margin requirement highly conservative and investment is unlikely to occur solely on the basis of AEMO's estimate; arguably, deferred investment should not be included as benefit. See Section 3.4.

3.2. Is the contribution modelled achievable?

Table 3.2 below contains the revised estimates for the quantity of DRM participating in the wholesale market, consistent with the 2013 ESOO projections and assuming the Lower Case represents a maximum of 5 per cent of assumed C&I demand from 2017/18, the Reference Year, and the Upper Case, 10 per cent.

Table 3.2 Projected DRM program size, 2013/14 to 2022/23, MW

Year	Lower Case	Upper Case
2013-14	173	341
2014-15	345	681
2015-16	518	1,022
2016-17	690	1,362
2017-18	863	1,703
2018-19	871	1,715
2019-20	881	1,731
2020-21	893	1,754
2021-22	901	1,769
2022-23	906	1,777

Source: AEMO, 2012; Seed calculations

Futura estimates that there is around 340 MW dispatchable C&I peak demand response deriving from curtailable loads and standby generation in the NEM, although Futura also cites evidence from one-off events associated with very high prices in the Victorian and Tasmanian markets of up to 300 and 108 MW respectively.[24] The ERAA's survey of demand response programs reports around 215 MW of contracted load, not including smelters (Appendix C).

Relative to the evidence discussed by Futura, the projected DRM participation in the Reference Year is between 2.5 and 5 times larger than participation to date and relative to the ERAA's results, an increase of between 4 and 8.5 times. Regardless of the base, the projections represent a significant increase. Is this increase in participation achievable? Further, is it achievable over the time frame modelled?

The Lower Case represents between 3 and 6 per cent of estimated maximum demand, depending on the load factor assumed, based on the recent Australian Bureau of Statistics of electricity consumption by industry,[25] adjusted to: allow for off-grid

---

[24] Futura, pps 8-9

[25] Australian Bureau of Statistics, *Cat No 4660.0 Energy Use, Electricity Generation and Environmental Management, Australia, 2011-12*, 31 Jul 2013. The ABS' figures provide significant additional coverage of generation outside the Electricity, Gas, Water and Waste Services Sector compared with the KPMG Survey for AEMO, *Stage 3 Report: Semi-scheduled, Non-scheduled and Exempted Generation by Fuel Source, 2010-11 to 2034-35*, 2011, although the ABS provides information on production only, not capacity. The ABS gives

generation[26]; sectors where electricity consumption is, on average, less than 100 MWh/year at the enterprise level[27]; and to remove the Electricity, Gas, Water and Waste Services Sector.[28]

On the face of it, the projected participation is achievable, even if the short term growth assumed is aggressive. However, if participation in the DRM is assumed to come primarily from the manufacturing sector, the projections are more of a "stretch target". The projected Lower Case program represents between 6 and 11 per cent of manufacturing sector coincident maximum demand[29] in the Reference Year and the Upper Case would represent between 11 and 22 per cent of estimated coincident manufacturing sector maximum demand.[30]

- Why restrict participation to the manufacturing sector?
  - Frontier assumes that all electricity consumption moved from the peak is shifted to some other time period, without loss of production. Larger manufacturing enterprises may have this ability[31] while substantial elements of the services sector – Health Care, Arts and Recreation, and Retail Trade, for example – are likely to have less flexibility in the timing of production. Alternatives to Frontier's assumption are more problematic: where the output of the DRM provider is more valuable than the value of its electricity, reducing production to reduce electricity consumption or shifting production at some cost to the producer (or its customers) represents an economic loss, potentially larger than the gains to the electricity wholesale market.
  - The ERAA's survey suggests that around 50 per cent of existing demand response from C&I customers comes from on-site generation, 35 per cent from load shifting and 15 per cent from shutting down operations. Combining the ERAA's experience with the ABS survey results suggests that the potential expansion of demand response in the short term may be limited. There is insufficient embedded generation to provide the required flexibility without significant additional investment, particularly in the services sector.

---

annual consumption. The lower capacity estimate is based on a coincident load factor (peak to average) of 50 per cent; the higher capacity estimate is based on a coincident 100 per cent load factor.

[26] All mining sector consumption and generation has been excluded, as the survey provides no basis for distinguishing between on- and off-grid, or allocating generation to a state. While conservative, this treatment of the ABS's results is preferable to including off-grid generation, particularly in the light of the Bureau of Resources and Energy Economics' findings that off-grid generation has significantly increased in recent years. Bureau of Resources and Energy Economics, *2013 Australian Energy Statistics*, 2013, p 10.

[27] This calculation simply divides total electricity consumption by enterprise numbers at the sector level. The ABS Survey provides very limited detail on the distribution of consumption by enterprise size and none on enterprise size by sector. ABS, *Cat No 4660.0*

[28] So as to remove own use production. The sectoral breakdown provided by the ABS does not allow electricity generation by electricity generators to be separated from electricity generated by, for example, water utilities.

[29] That is, this calculation assumes that peak manufacturing sector demand occurs at the same time as peak NEM demand, which is not necessarily the case.

[30] Calculated from ABS *Cat No 4660.0.* The lower estimate is based on a coincident load factor (peak to average) of 50 per cent; the higher estimate is based on a coincident 100 per cent load factor.

[31] We are aware of NEM participants who adjust their production in response to high spot prices, temporarily reducing production during high spot price periods and, presumably, either sharing the benefits in the form of lower prices or imposing some small incremental costs on their customers in the form of longer production times as a result.

- The ABS survey suggests that Australia-wide, there are around 18,000 enterprises with some generation, excluding the Electricity, Gas, Water and Waste Services sector. While around 90 per cent of the enterprises with generation are in the services sector, the services sector accounts for only around 5 per cent of generation, while the manufacturing sector accounts for just under 50 per cent of total. The balance is mining sector generation.
- The manufacturing sector is also responsible for over 90 per cent of all cogeneration: around two thirds of total manufacturing sector electricity generation is the result of cogeneration. The contribution of cogeneration can be a limiting factor to manufacturing sector DRM: cogeneration typically is sized to production requirements, providing limited flexibility outside defined technical limits and therefore restricting both reductions and increases in electricity production and consumption, particularly at limited notice. [32]
- Finally, if continuing energy efficiency measures and increased solar PV capacity result in material changes to wholesale market demand profile, will the manufacturing sector continue to be a potential provider of a significant DRM response? At the limit, if solar PV installations shifted the temperature sensitive peak in the wholesale market to, say, from 4pm to 7pm, would we need to consider those manufacturing enterprises with continuous processes only and exclude manufacturing enterprises with production restricted to normal working hours?

3.2.1. Demand response: international experience

How relevant is the international experience in estimating the potential contribution to a NEM wide DRM program? International experience has been cited by the AEMC, drawing on Futura and Oakley Greenwood's work for the AEMC to suggest that international – primarily US – evidence suggests the projected levels of participation, at 5 to 10 per cent of the attributed peak demand, are achievable.[33]

- However, the comparisons with the US evidence may not be on a like-with-like basis.
  - Federal Energy Regulatory Commission (FERC) surveys of Demand Response programs across the US suggest that the majority of programs take the form of emergency response or ancillary services, rather than dispatchable demand response, as proposed by the AEMC.[34]
  - Among other differences, the US programs typically provide for limited and infrequent demand response, often accompanied by a high fixed payment. These programs have similar characteristics to those existing demand response programs captured by the ERAA's survey. The ERAA's survey suggests that existing C&I demand response program participants look for payments – like option premiums – fixed in advance, some (relatively short) notice before being

[32] ABS, *Cat No 4660.0*
[33] AEMC, pps 121-122
[34] Federal Energy Regulatory Commission, *2013 Assessment of Demand Response and Advanced Metering: Staff Report,* October 2013; also, the 2012 Survey, which contains a more detailed discussion of US program survey results. The AEMC acknowledges that this issue was raised in its consultation (AEMC, p, 121-122 and Footnote 205) but does not explore the implications of the differences between the objectives of the programs for the level of program participation and, in particular, the number of times that a program participant would be prepared to participate over a given period and at what price.

called and benefit sharing, effectively restricting the competitiveness of their offering to periods where prices exceed $300/MWh for several hours.
  - The US programs and the current demand response programs are unlike the DRM program proposed by the AEMC, which is price based but not otherwise restricted in the number of occasions called, or the alternative non-scheduled generation program being considered by AEMO, where the provider receives the Regional Reference Price at the time of dispatch.

In our view, the growth in demand response participation by C&I customers required to meet the Reference Year assumptions relative to known participation and own generation resources is ambitious. At the least, the speed of the ramp up in participation is required to meet the projections is very rapid and it is unclear whether, given that some demand response programs currently exist, the introduction of a further class of specialist market participants in Demand Response Aggregators, is a sufficient condition to achieving this rapid increase. Given this, the adjusted preferred benefits case may still be on the high side, even if, in the longer term, the projected participation can be realised.

3.3. Is DRM as modelled appropriately specified?

In Frontier's description of its modelling, both the Demand Response: Residential and the DRM programs have been modelled as peak shaving programs. However, in taking this approach, the modelling is likely to have overestimated the benefits calculated, for several reasons.

- The residential demand response program occurs outside the wholesale market and is experienced by market participants as a reduction in demand at peak periods, reducing the spot market price in these periods relative to the Baseline. In contrast, the DRM program is the equivalent of adding additional lower cost generation at peak periods. The effect of the DRM program on market prices is critically dependent on the difference between the average price required by an end user and that required by the marginal generator.
- Sequencing matters.
  - As the residential demand response program grows, effectively withdrawing demand at peak periods, the frequency, duration and average price of high price events in the wholesale market should fall relative to the Baseline, in the same way that solar PV installations appear to be affecting wholesale market prices and volatility (see Figure 4.2. and the related discussion in Section 4.1.)
  - The altered wholesale market dynamics – that is, taking account of the effects of residential peak shaving outside the wholesale market – should be the basis for the Baseline comparison with the wholesale market including the DRM. The effects of the residential program should be taken into account before the DRM program benefits are calculated.
- Finally, by modelling the DRM in this way, effectively demand response through the DRM has been bid in at zero price: the benefits as calculated take no account of the price at which end users would be willing to make capacity available.

If we assume, however, that an end user or DRM provider requires a positive return for participation, then, provided the price is lower than the marginal generator's required price, the DRM program will continue to provide benefits to electricity customers in the form of lower costs. The extent of the benefits will be lower than the current estimate and critically dependent on the price required by the end user or DRM provider relative to the marginal generator.

- If end users price up to the level consistent with desired dispatch, but only fractionally below the marginal generator, the benefits to customers as a whole will be small. The larger part of the current benefits will take the form of a transfer from generation to end users, rather than a benefit to customers as a whole. The end user only realises a benefit to the extent that its returns from the DRM exceed the losses from deferred or reduced production.
  - Alternatively, if end users require very high prices to participate – higher than those required by peaking generators, for example – the extent of their participation and the resulting benefits will be significantly lower than estimated by Frontier, because the frequency with which the DRM is dispatched will be lower.
  - The evidence of the ERAA's survey of existing demand response programs suggests that existing C&I demand response program participants currently require a minimum price of at least $300/MWh for participation and, given that the survey indicates ramp rates of between 30 and 60 minutes, requires these conditions to persist for the minimum of an hour for dispatch to pay off. (See the discussion in Section 4.1 about current demand response contract characteristics.) As benefit sharing is also a common characteristic of existing contracts, end users participating in demand response programs currently have an incentive to price up to the marginal generator's bid: the higher the price, the higher the pay-off.
- Finally, AEMO's program design differs from the AEMC's design and Frontier's model, including participation in the DRM as non-scheduled dispatch, not setting the Regional Reference Price.
  - We would expect that this design would reduce the average price received by participants because of the lower level of certainty that the DRM provider will be dispatched as bid.
  - As a result, it is also likely to reduce the benefits of the DRM relative to Frontier's model. Not all participating load in the DRM will be dispatched at high price periods, unlike the peak shaving representation of the program. Further, lower prices received by providers are likely to reduce participation, reducing the benefits of the program.

3.4. Are the estimates of the benefits of DRM equivalent to a benefits case?

Neither Frontier nor the AEMC represents the benefits estimate as part of a benefit cost analysis. Considering what a benefits estimate as part of a benefit cost analysis should include suggests a number of elements in the current calculation would need to be revised or omitted.

- DRM represents a benefit to society as a whole only if the electricity saved is more valuable than the production value lost as a result of the deferral or reduction in production.

  - If we assume that DRM providers are rational and are only willing to provide DRM when this condition is met, then we can assume that there is no lost value to society as a whole.
  - However, in making this assumption, we need to rule out assumptions that are inconsistent with this – for example, assuming that services industries could radically change their hours or conditions of service so as to avoid high price electricity events without taking into consideration the potential cost to customers in loss of convenience or amenity or the potential loss to the sector in the form of production or sales foregone.
  - In ruling out this assumption, then the indications we have from the ERAA survey (Appendix C) about the incidence of existing on-site generation and current C&I demand response program participants' reliance on on-site generation to provide demand response suggest that the achievable program size may be lower than is envisaged in the AEMC's modelling.
- As we have argued in Section 3.3 above, if end users receive a price for the capacity made available, then the income received by end users represents a transfer from existing generators and, on the usual principles applying to societal benefit cost analyses, should be excluded from any societal benefits case. Only the residual benefit represented by the difference between DRM providers' prices and the marginal generator's price should be considered as a benefit to society as a whole. The size of this residual depends on end users' costs and behaviour in pricing their offer in the market.
  - The ERAA's survey suggests that under current circumstances, given end users' preferences, there is unlikely to be any material societal benefit. Existing demand response contract prices are high relative to cap prices and demand response contracts typically have characteristics that make caps a preferable risk mitigation mechanism (Section 4.1). The price and other characteristics limit the competitiveness of demand response contracts, while current market conditions limit the expected frequency with which demand response contracts would operate. In the first three months of 2013, for example, participants offering demand response services in the NSW region of the NEM would not have been called, while in South Australia over the same period, there were 14 periods, none of them longer than half an hour, when prices exceeded $300/MWh and demand response would have been called.
- Perhaps more significantly over the longer term, when it comes to considering the benefits of DRM, what is the appropriate treatment of the benefits of deferred generation investment?
  - FERC argues that in evaluating the cost-effectiveness of demand response offered through organised wholesale electricity markets, including benefits from capital investment deferred represents a form of double counting.[35] Wholesale prices

[35] FERC, *A Framework for Evaluating the Cost-Effectiveness of Demand Response: prepared for the National Forum on the National Action Plan on Demand Response: Cost Effectiveness Working Group,* February 2013, which, for substantive discussion of this issue refers to the discussion and submissions considered in FERC Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, 2011. Although the FERC Framework Paper considers demand response cost effectiveness only in markets other than markets where demand response is made available through an organised wholesale market and is, therefore, not directly applicable to the NEM, it also contains a useful discussion of the

signal the requirement for new capacity. In including the benefits of DRM in the form of lower prices relative to the Baseline over the period prior to the entry of new capacity and as a deferred benefit, the same value is effectively being counted twice. The LRMC methodology used in the Frontier model approaches a form of pure long term economic pricing – generators recover their LRMC – and, arguably, is double counting.

- Leaving aside the question of the relationship between LRMC and market prices, generation investment is funded by private risk capital. The NEM provides no guarantees of an economic return and has no levers to regulate the extent of generation investment. The NEM is unable to compel investment, even in the event of a breach of the Reserve margin. In this respect the NEM differs from a number of electricity markets where the Market Operator or overseeing regulatory authority has a role in the forward procurement of generation capacity and customers or rate payers are responsible for the costs of the investment. In these markets, the benefits of deferral are relevant to the societal benefits case. What is the case in the NEM for considering the benefit that accrues to private investors from deferring investment as part of the benefits case in these circumstances?[36]

3.5. The Costs of Demand Response Mechanism in the NEM

In comparing our Preferred Estimate of the benefits of the DRM with the estimated costs of implementation, we have relied on the cost estimates developed by AEMO and the ERAA in the course of the work undertaken in developing the forthcoming Rule Change Proposal to support the introduction of DRM.

3.5.1. Market Operator's costs

We understand from AEMO that it estimates its costs over 10 years for implementation and ongoing support at between $8 million and $14 million in $2013.[37]

3.5.2. Market Participants' Costs

The estimates of Market Participants' costs were based on information collated by the ERAA from its members. The ERAA collated 'order of magnitude' costing information from nine (9) members, comprising all three first tier retailers and six second tier

---

components of the Participant Cost, Ratepayer Impact Measure, Program Administrator Cost, Total Resource Cost and Societal Cost tests, some combination of which is used by US regulators, depending on the requirements of the jurisdiction, to evaluate proposals.

[36] From the private investor's perspective, the nature of the benefit is unclear if we assume that the investment in electricity generation is expected to earn the risk-adjusted rate of return. Several years of not earning this return? Lower investment risk? Considering this private benefit as part of a wider benefits case is even more perverse when you consider the asymmetric treatment of the losses incurred by private investors when, for example, average generation prices fall below LRMC or SRMC. Private losses are not considered as part of an evaluation of the benefits in these circumstances, although the cases are parallel. From society's perspective, if we regard this premature investment as a dead weight loss without simultaneously identifying market design characteristics that give rise to this behaviour, then the question becomes one of the incidence of the loss. If the market for generation is regarded as competitive, customers do not bear the loss, capitalists do.

[37] We assume that this is in $2013 and represents the NPV of AEMO's costs. However, we understand from AEMO that implementation (systems) costs are the dominant component of their costs, so even if not discounted, the strictly comparable number would not be expected to be materially different.

retailers, based on the AEMO costing request used as part of the DRM rule change development process. Appendix D details the costing methodology used by AEMO in collecting the costs and the ERAA in compiling the cost estimates.

We calculated a 'low case' cost estimate to compare with the low case estimate of the benefits. Our approach in calculating the low case estimate applied a degree of conservatism. Based on the approach outlined in Appendix C, our low case cost estimate was $112 million ($2013) over a 10 year period.[38]

3.5.3. End Users' Costs and Aggregators' Costs

In assuming that end users and Demand Response Aggregators are rational, we have, in effect, assumed that end users' costs to participate and Demand Response Aggregators' costs are covered by the income earned in providing DRM into the market. Given this, we have not separately allowed for their costs in the comparison of costs and benefits.

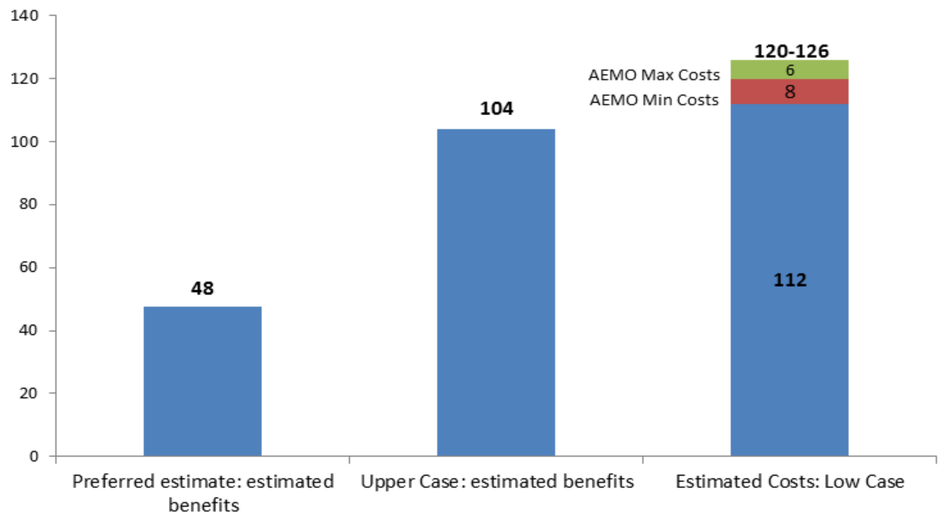
3.5.4. Comparing the energy benefits and the costs

Figure 3.5 compares our Preferred Estimate of the benefits of DRM – the Lower Case, adjusted for carbon – and the benefits of the Upper Case with the estimated present value of the low end costs of its implementation and management over the 10 year period to 2022/23. At the lower bound of the costs ($120 million), the costs exceed the benefits of our Preferred Estimate by around $70 million and exceed the Upper Case, which we believe is not achievable given the reductions in projected future maximum demand, by $16 million.

Considering the Preferred Estimate and the lower bound of the costs ($120 million, based on $112 million retailer costs plus $8 million AEMO costs) gives a net negative benefit of -$72 million, well short of the level required for justification of the proposal, considering society's benefits and the costs. Considering the higher benefit estimate of $104 million and the higher cost estimate of $126 million, this gives a net negative benefit of -$22 million[39].

[38] Again, these numbers are not strictly comparable with the benefits estimate, which is given in $2012/13, but in our judgement the difference is unlikely to be material.
[39] These net negative benefits could also be expressed as a ratio of costs to benefits. The ratio is 0.4:1 for the lower end and 0.9:1 at the higher end, both of which are less than 1.

Figure 3.5 DRM: Estimated Benefits and Low End Costs, 2013/14 to 2022/23, Present Value, $ million



Source: Frontier Economics, 2012a; Seed estimates; ERAA Member Survey estimates; AEMO estimates

3.6. Adjusting the energy costs benefits: directional and qualitative changes

Adjustments to our Preferred Estimate to reflect the issues discussed throughout this section of the report would further reduce the benefits to cost ratio, potentially materially.

Table 3.3 summarises the rationale and direction and of the issues discussed throughout this section of the report.

Table 3.3 Summary quantitative and qualitative effects, estimated NPV, Demand Response Mechanism, Lower Case, 2013/14 to 2022/23, Seed Estimates

Adjustment / Issue	Direction	Explanation
Reductions in projected Maximum Demand and Maximum Demand growth. **Changes between the 2012 and 2013 AEMO demand forecasts contained in the National Electricity Forecasting Report (NEFR) have significantly reduced projected Maximum Demand growth and, in SA, expected Maximum Demand levels.**	Reduces benefits: reduces need for deferred generation investment as there is further excess supply over demand.	• Significant revisions to expected Maximum Demand levels in SA remove benefits from capital deferral from around 2026/27. – These benefits, while outside the period for the NPV calculations included in the AEMC's Report, are a significant contributor to the large longer term benefit estimates.
	Reduces benefits: excess supply over demand is expected to reduce average peak prices and volatility, reducing payoff to demand response, DRM suppliers.	• Material reduction in projected Maximum Demand growth across the NEM. In the absence of further withdrawals of generating capacity from the market, there is still likely to be significant excess supply over demand. This will most likely reduce peak prices and peak price volatility, reducing benefits attributable to DRM and demand response. – This effect is compounded by a modelling approach that currently treats demand response, residential and the DRM as happening simultaneously. • However, demand response, like Energy Efficiency (and increasing solar PV penetration), reduces Maximum Demand for electricity sent out, reducing wholesale peak prices and peak price volatility and reducing payoff to the DRM, with possible effects on program participation. • Further, if modelling approached demand response and energy efficiency as price sensitive, reduced peak prices and peak price volatility could be expected to reduce the pay-off to demand response, DRM and Energy Efficiency, reducing the quantity delivered below AEMO's projections, further reducing the benefits.
	May bring forward some benefits in some states where there is a small amount of additional new generating capacity required.	• 2013 ESOO suggests that small additional capacity required in Qld from 2019/20 to meet AEMO planning standards (Reserve margin). If demand response and the DRM sufficiently robust and investment was expected to proceed to meet Reserve Margin, demand response could defer the investment indefinitely, given requirement for additional generation is only small. – However, significant questions remain: reserve margin requirement highly conservative and investment is unlikely to occur solely on the basis of AEMO's estimate; arguably, deferred investment should not be included as benefit. See Section 3.4.

Adjustment / Issue	Direction	Explanation
The assumed level of DRM participation may not be achievable, at least on the timeline assumed in the modelling	Reduces benefits: the size of the program is smaller than expected	• Existing on-site generation insufficient to support significant expansion projected. Alternatives, in particular reduction in production, inconsistent with the assumption of no economic cost.
Considered as a benefits case, there are elements of double counting and mis-specification.	Reduces benefits: societal benefits lower than electricity market benefits	• Appropriately accounting for benefits to end users (DRM providers) as transfers significantly reduces benefits in the form lower wholesale market price outcomes, as does allowing for customers' preferences for the price required for participation. • Benefits from investment deferral should be excluded: no basis for inclusion given NEM design and arguably double counting existing benefits captured in price effects.
Cost indications from AEMO, market participants suggest costs could be very high relative to benefits	When considered as part of benefit cost analysis, significantly reduces and may eliminate any potential benefit.	• AEMO estimates its costs of implementation as between $8 and $14 million, $2013, NPV. • The ERAA survey results of participants' costs suggest costs of around $112 million ($2013, NPV).

4. The Case for Demand Response: Further Observations

4.1. The competitiveness of demand response programs: prices, expected frequency of dispatch and income

The ERAA's survey of current demand response program characteristics (Appendix C) suggests that current customer contracts are similar to cap contracts with a generator with specific physical characteristics. The contracts covered in the survey:

- Have a typical strike price of $300/MWh, consistent with current traded cap strike prices.
- Pay a fixed payment to the provider over the agreed contract period, comparable to the option premium provided to the cap provider. The contract term may be coincident with the length of the customer's contract, but is unlikely to be longer. Large customer contracts typically have 3 year terms.
- Have specific characteristics – notice periods, response/ramp times and, in some cases, limits on the frequency that the customer can be called on to provide a response – similar to the characteristics of some peaking generators.

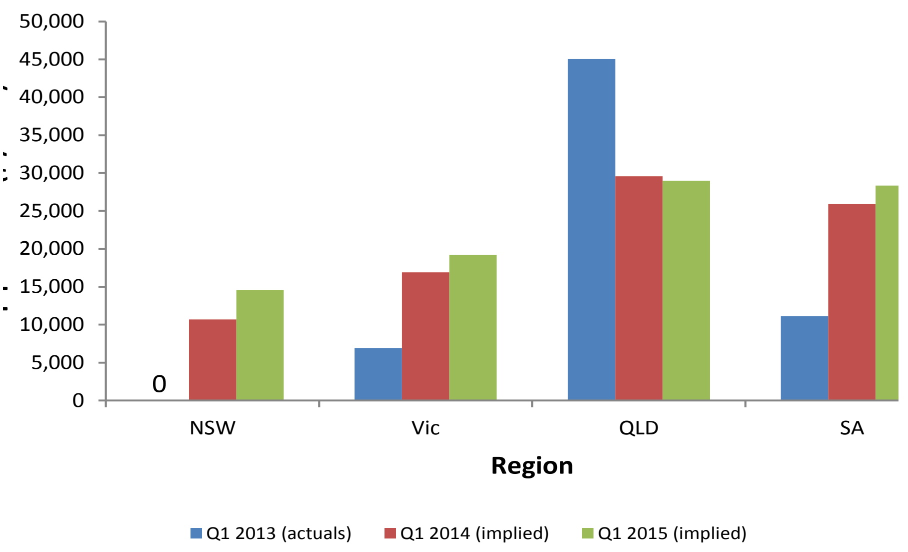
Thought about in this way, the demand response provider – the end user – is competing with caps offered as a financial product: the two offer similar levels of protection to a retailer in the event of high prices. However, relative to the physical product the financial derivative has a number of advantages: the financial derivative is tradable, whereas an end user is restricted to providing its service to its retailer; and, the financial derivative is also fungible with any other cap contract, having no provider-specific characteristics (ramp rate, notice periods, etc.) that could have the effect of limiting its value.

Given these differences, we expect that participants in wholesale market demand response programs would receive similar, but lower payments than the market price for caps. We have tested this relationship by looking at current cap prices and comparing the payments (cap premiums) received with those from the ERAA's survey of current demand response arrangements. Our results, shown in Figure 4.1, suggest that on current market prices for caps, depending on the region, demand response contracts in the ERAA's survey are expensive for retailers in comparison to caps. The survey suggests demand response premiums of between $12,000 and $50,000/MW, in addition to profit sharing where the price at the time of participation exceeds $300/MWh.

Figure 4.1 shows actual break-even premiums for Q1 2013 and implied cap premiums based on quoted prices for Q1 2014 and Q1 2015 traded caps. Prices for Q1 have been used because, reflecting typical spot prices over the summer, cap prices are highest in these quarters. Recently, however, the combination of mild weather and reduced peak demand has modified spot price experience. In NSW, in Q1 2013 $300 caps had no value evaluated after the event: the price never reached $300/MWh in the course of the quarter. Looking forward, the lower bound of the demand response prices in the survey – $12,000/MW – is expensive relative to caps in NSW in Q1 2014, while the upper bound

– $50,000/MW – is expensive relative to cap prices in all regions for Q1 2014 and Q1 2015.

Figure 4.1 Q1 Cap Premiums by region and year, actual and implied, $ per MW



Source: AEMO (spot prices), Australian Stock Exchange (futures prices); Seed estimates

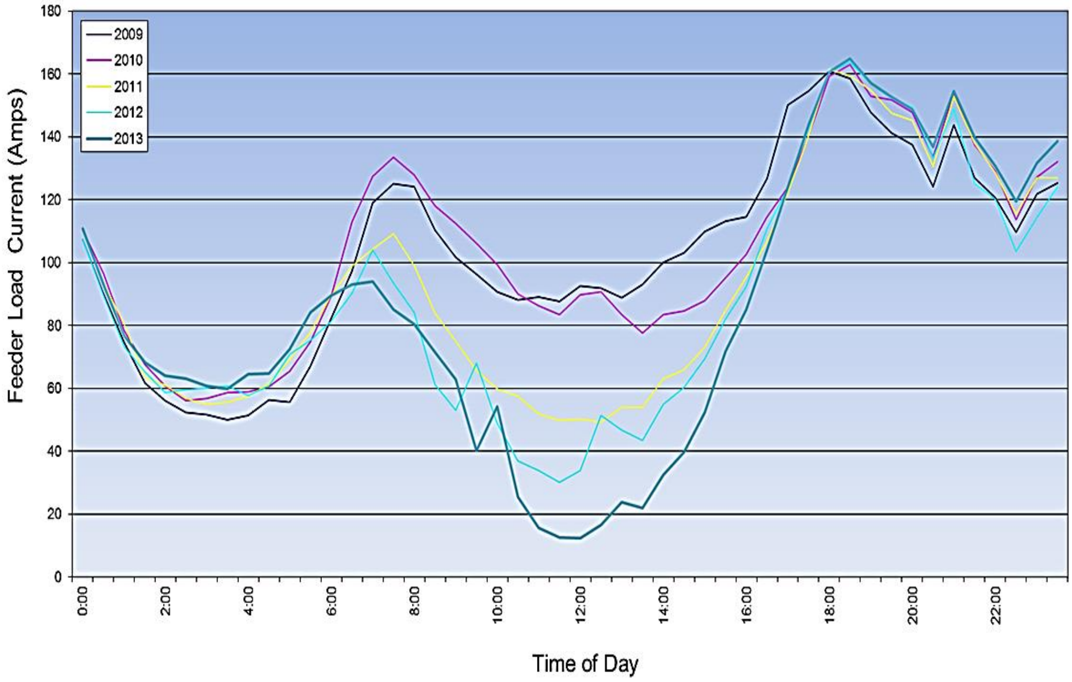
The cap market provides some certainty of income to a demand response program participant as cap premiums are payable in advance to the cap provider. However, the income (premium received) is both subject to competition from other cap providers and, over time, will adjust to reflect expectations of spot price volatility. In the current market, where projected Maximum Demand has been significantly reduced in all regions other than Queensland, cap prices could be expected to remain low for some time.

- Given the level of capacity relative to projected demand, there are more participants in the cap market than before, as mid and base load generators sell caps as an alternative source of income, reducing prices.
- Recent experience influences future cap prices. The low break-even premiums for regions other than Queensland resulting from the Q1 2013 experience can be expected to affect future cap premiums. Figure 4.1 suggests this is occurring.
- The increasing penetration of solar PV is structurally affecting wholesale market peak prices, with the expectation that future peaks in demand will not be as high as previously projected. There is likely to be a corresponding impact on the frequency of high spot peak prices and the value of cap products.
  – Figure 4.2 illustrates the potential for solar PV to affect wholesale prices.[40] It shows the load on the second Tuesday in October by time of day for a residential area feeder in the Energex area over the 5 years from 2009 to 2013. Since 2010, residential demand during daylight hours prior to the evening peak has fallen

[40] The absence of any apparent systematic reduction in consumption in the period from 18.00 hours to 7.00 hours suggests that the driver of the changes in load observed is neither a significant improvement in energy efficiency nor a significant change in household composition.

annually and in 2013, between midday and 2pm demand was between 20 to 25 per cent of the 2009 level.

Figure 4.2 Solar PV penetration: feeder load by time of day, Queensland residential feeder, 2009 – 2013, Amps



Source: Energex

Participants in wholesale market demand response programs are not, of course, restricted to the cap market for their returns, but can participate in the spot market. However:

- Spot market returns are not guaranteed, representing a higher level of risk to the participant in targeting the desired return from demand response participation.
- Successful participation requires high and prompt response: outside Queensland in Q1 2013 there were no periods in any region of the NEM where prices exceeded $300/MWh for more than 3 consecutive half hourly periods.
- Participants whose response is restricted to business hours – say, from 7am to 7pm – will be unable to benefit from providing a response to high price events occurring outside these times. In Q1 2013, high price events between 7pm and 7am made up 30 per cent of the high price half hours in Queensland and around 7 per cent of the events in the South Australian market.

Successful participation in the market requires demand response program participants to compete with substitute products, some of which may have preferable characteristics. With competitors' prices low and falling, the current structure and pricing of demand response contracts is not guaranteed, while participating in the wholesale spot market provides no guarantee of high returns.

4.2. The relationship between the DRM and the network program

In the preceding sections, we have analysed the proposed DRM program without reference to the network support program investigated in parallel with the DRM by the AEMC and separately modelled by Frontier. The AEMC states that the network benefits make up the larger part of the total benefits claimed for demand response. On our estimates, the network benefits account for over 95 per cent of the total benefits estimated for the AEMC by Frontier. Of the remaining benefits, over the 10 year period, the DRM accounts for between half and two thirds.[41]

In treating the two markets for which demand response programs are proposed separately, we argue that the programs are separate and, under some circumstances, may compete with each other.

- Not all customers will be located in areas where network support programs are offered. Regardless of location, however, provided that the customer is connected to the distribution network, a customer will be able to participate in the relevant wholesale market program.
  - In these circumstances, the success or otherwise of the DRM program has no relationship to the performance of the network demand response program: the two can be considered separately.
- It has been suggested to us that the relationship between the two programs is complementary, based on the income stream from participation in the DRM program. Under this view, the income stream offered by participation in the DRM program would allow a provider to finance required changes in its network connection to offer network support services, enhancing the participation in network support programs.
  - However, as we have discussed above, the income stream from demand response in the wholesale market in current market conditions is not guaranteed and may fall from the levels currently offered by providers, in the same way that cap prices have fallen over recent periods.
  - In addition, not all customers will be located in areas where network support programs are offered or required.
- Wholesale market and network peak periods typically occur at different times of the day. A customer providing demand response to the wholesale market may be able to simultaneously provide network support services on extreme days, but in a program aimed at providing more frequent network support would not generally do so.
  - On extreme days, there is some evidence cited by Futura[42] that suggests that the two periods approach each other: the network peak shifts to an earlier time, coinciding with the wholesale market early afternoon peak in demand. However,

[41] The AEMC claims total benefits of $4.3 to $11.8 billion (NPV $2012/13 real) from all the programs considered over the first 10 years of the program (AEMC, p 256; 268). Of this result, between $2.8 and $4.3 billion (NPV $ 2012/13) are attributed to the combination of demand response programs – network, residential demand and the DRM. The calculation above represents the total estimated benefits less that share we estimate is attributable to the energy cost benefits of demand response, including residential demand response and the DRM. We estimate the total value of the two programs combined as between $74 and $192 million (NPV $2012/13) – see Table 2.2 and Section 2.1.

[42] For example, in the discussion of the Energex Cool Change Trial Impacts, p 61, 125 and Endeavour Energy's PeakSaver Residential Demand Management Program, p 144.

  in general, network peaks occur later than wholesale market peaks, reflecting the pick-up in residential demand as consumers return home.
  - Although the same customer may enroll in both network support and the DRM programs, generally participation in one would not mean simultaneous participation in the other.
- If the customer is willing only to interrupt or delay its consumption for a limited number of times in a given period – say, as for the lowest number of interruptions given in the ERAA's survey results, limited to 28 hours over a year – then, a customer able to provide both network demand response and wholesale market DRM services may find its participation in one program limited by the requirements of the other.
  - Where the customer rations the availability of its demand response, rather than being a joint service where the offering to one program entails the offering to another, the programs compete.

Given these characteristics of the two programs, even if a more detailed review of the benefits and costs of the DRM program is unfavourable, this would not of itself detract from the potential benefits of the network demand response program, which account for the larger part of the AEMC's estimate of the benefits.

A. The relationship between Demand Response, Demand Response Mechanism and Energy Efficiency

Throughout this report, we have used the following terminology:

C&I Demand Response: Network programs using demand reduction by customers/aggregated by Demand Response Aggregators providing demand reduction at peak network periods as an alternative to network investment.

These programs are expected to allow networks to defer investment that would otherwise be required in additional network capacity and, with some lag and depending on the level of firmness, to result in network investment remaining below the level that would otherwise have been required to accommodate growing customer demand.

These programs may affect wholesale electricity prices by changing electricity demand at network peak periods relative to other periods (load shifting), and/or by reducing demand for electricity (either by reduction in consumption or an increased use in small, non-scheduled generation or co-generation).

The effect on wholesale prices depends on customers' behaviour – in particular, the extent to which load shifting and load reduction occur – and customers' relative sensitivity to wholesale electricity prices and network prices. A higher level of sensitivity to network peak prices, for example, might suggest a lower wholesale market effect, as the two peak periods are typically not co-incident.

Demand Response Aggregator An intermediary providing demand response from a number of customers to the wholesale market.

Demand Response Mechanism (DRM): The wholesale market program proposed by the Power of Choice in which C&I customers comsuming more than 100 MWh/year are able to offer demand reduction as an alternative to peaking generation. The proposed service will allow customers to contract separately, if preferred, with Demand Response Aggregators for the provision of Demand Response services and retailers for the purchase of wholesale electricity.

The reductions in load by customers under the DRM occur *inside* the wholesale market, in response to the customer's or the demand side aggregator's offer to provide a reduction in demand as a cheaper alternative to dispatching the marginal generator to meet demand. The benefits of the program include: a return to the C&I customer offering the reduction in consumption at least sufficient to meet the customer's costs of load shifting; and a lower price for wholesale electricity for all customers than would otherwise have been the case in the

	absence of the DRM. The extent of the reduction in wholesale electricity prices depends on the difference between the marginal price offered by the DRM participant and the marginal price offered by the marginal generator. From the perspective of the wholesale electricity market, customers' behaviour will be experienced as an increase in available generation at peak periods as well as either an increase in demand outside peak periods (load shifting) or a reduction in aggregate demand.
Demand Response Provider (DRM Provider), *or* an end user	This term is used to in this report to refer to the C&I customer reducing its consumption to provide the demand response. When we refer to the aggregator, who may provide demand response from a number of customers to the wholesale market, we refer to a Demand Response Aggregator.
Demand Response:	The combination of programs – both Residential and Commercial & Industrial (C&I) – that are recommended in the Power of Choice Review as likely to improve the efficiency of the wholesale electricity market and electricity infrastructure usage. These programs include: more efficient pricing for Residential and small Commercial customers, with greater cost reflexivity, shifting consumption outside wholesale and network peak periods; the introduction of a wholesale market program in which C&I customers are able to offer demand reduction as an alternative to peaking generation; and a significant expansion of network programs using demand reduction by customers as an alternative to network investment.
Energy efficiency	Changes in customers' electricity consumption behaviour that results in a reduction in electricity consumption, with no net loss of amenity or production. In theory, energy efficiency is the result of some combination of changes in technology and relative energy prices and could be expected to be at least partly endogenous to a model of electricity consumption that allowed for changing relative prices. In practice, following the AEMC, AEMO and Frontier Economics, we have treated Energy Efficiency as exogenous to other changes being considered in the electricity market. By treating Energy Efficiency in this way in particular in the Upper Case, where the contribution of Energy Efficiency is significantly increased relative to AEMO's 2012 projections and additional Demand Response is projected, there is a risk that the available short term responses to changing relative prices have be overestimated. The exogenous nature of the Energy Efficiency contribution to wholesale and network prices is particularly

problematic where the effect of other Demand Response programs is to reduce prices: if Energy Efficiency was endogenous, then, in these circumstances, the rate of Energy Efficiency gains could be expected to fall, rather than to remain static.

Residential demand response:	Load shifting or load reduction by Residential and small Commercial customers in response to a higher level of cost reflectivity in total electricity prices (network and wholesale prices), increasing prices at peak periods relative to other periods and/or programs offered by retailers and NSPs to encourage load shifting at particular times.

These reductions occur *outside* the wholesale market: customers respond to price signals delivered on their bills and programs run by retailers and distributors to change their consumption behaviour.

From the perspective of the wholesale electricity market, the outcome of customers' behaviour is expected to be experienced as a reduction in peak demand relative to demand outside peak periods, and/or a reduction in peak demand flowing through to a reduction in aggregate demand.

With some lag, network investment will respond to customers' signals, falling below the level that would otherwise have been required to accommodate growing customer demand.

The balance of these influences on wholesale electricity prices depends on customers' behaviour – in particular, the extent to which load shifting and load reduction occur – and customers' relative sensitivity to wholesale electricity prices and network prices. A higher level of sensitivity to network peak prices, for example, might suggest a lower wholesale market effect, as the two peak periods are typically not co-incident.

B. Estimating the Wholesale Market Benefits of the DRM

Frontier Economics was engaged by the AEMC to estimate the wholesale market benefits of long term reductions in peak demand and the impact on consumers. Their work focussed on estimating two areas of benefits:

- Savings from avoided network costs; and
- Savings in wholesale electricity market costs.

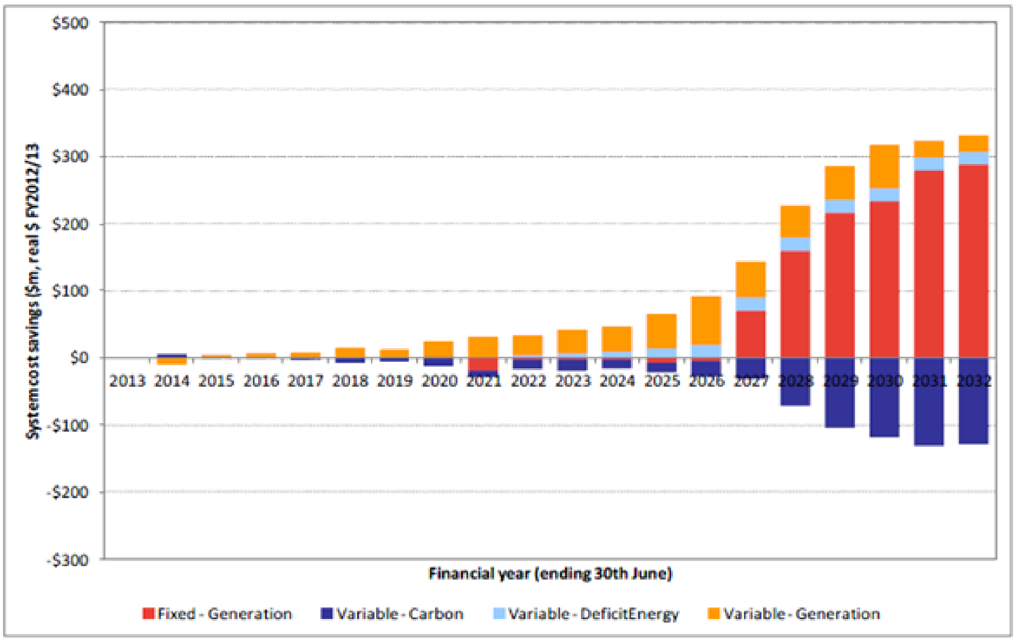
The Final AEMC Report estimated the total benefits from the network, residential and C&I demand response programs as $2.8 - $4.3 billion (real $2012/13). However, the report did not separately identify the benefits from the network demand response program and estimated energy cost savings.

We estimated the benefits directly attributable to the DRM proposal from the material originally presented by Frontier Economics (Frontier) in October 2012 as part of the AEMC Power of Choice review. The material published by Frontier provided limited insight into the benefits associated with the DRM project, so our estimate is necessarily high level.

The following section details the results of the modelling by Frontier Economics outlined on page 17 of their presentation and our approach to analysing these results.

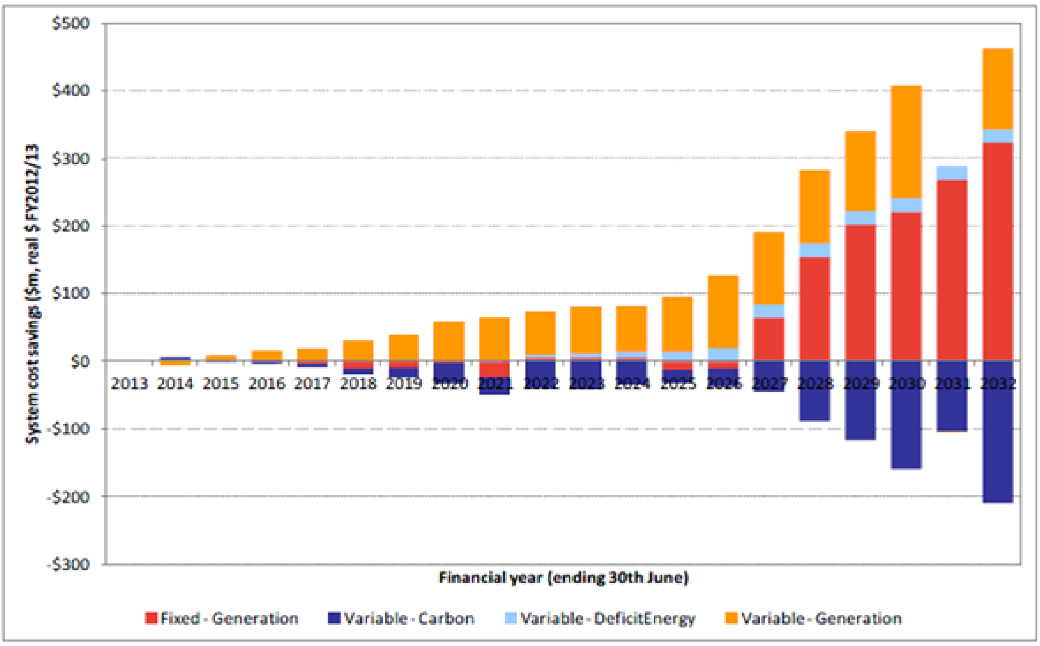
Figure B. 1 and Figure B. 2 below are the Lower Case and Upper Case estimates of the total energy market benefits published by Frontier in October 2012, considering both the benefits from the residential demand response program and those from the DRM.

Figure B. 1 Wholesale Market Cost Savings: Lower Case, $ real, FY2012/13, million



Source: Frontier Economics, 2012a

Figure B. 2 Wholesale Market cost savings: Upper case, $ real, FY2012/13, million



Source: Frontier Economics, 2012a

Table B. 1 and Table B. 2 contain our estimates of the values underpinning the lower and upper case charts. Our estimate of the NPV of benefits used in this report is based on these values; uses a 7.1 per cent rate of discount for a 10 year period to 2022/23, consistent with period used by the AEMC and advice received from the AEMC on the discount rate used by Frontier. Our estimates also pro-rate the total wholesale market benefits between the residential demand response program and the DRM on the basis of the share of each program in the level of demand reduction achieved in each year.

Table B. 1 Wholesale Market Savings: Lower Case, estimated value, $ real, FY2012/13, million

Year	Fixed-Generation	Variable Carbon	Variable Deficit Energy	Variable Generation	Net Result
2013-14	0	5	0	-10	-5
2014-15	0	0	0	5	5
2015-16	0	0	0	7	7
2016-17	0	0	0	9	9
2017-18	0	-5	0	15	10
2018-19	0	-2	0	10	8
2019-20	0	-10	0	25	15
2020-21	0	-5	0	5	0
2021-22	0	-10	2	23	15
2022-23	0	-15	5	30	20
2023-24	0	-10	5	35	30
2024-25	0	-10	10	45	45
2025-26	0	-20	15	70	65
2026-27	70	-30	15	60	115
2027-28	160	-75	15	50	150
2028-29	220	-105	15	45	175
2029-30	230	-120	15	70	195
2030-31	280	-135	15	30	160
2031-32	290	-130	15	25	200

Source: Frontier Economics, 2012a; Seed estimates

Table B. 2 Wholesale Market Savings: Upper Case, estimated value, $real, FY2012/13, million

Year	Fixed-Generation	Variable Carbon	Variable Deficit Energy	Variable Generation	Net Result
2013-14	0	5	0	-10	5
2014-15	0	0	0	10	10
2015-16	0	-5	0	15	10
2016-17	0	-5	0	15	10
2017-18	0	-5	0	20	15
2018-19	0	-10	0	30	20
2019-20	0	-25	0	55	30
2020-21	0	-25	0	40	15
2021-22	0	-45	2	68	25
2022-23	0	-45	5	75	35
2023-24	0	-30	5	75	50
2024-25	0	-15	10	70	65
2025-26	0	-25	15	95	85
2026-27	70	-40	15	105	150
2027-28	160	-90	15	105	190
2028-29	200	-115	15	125	225
2029-30	225	-160	15	165	245
2030-31	275	-105	15	-5	180
2031-32	320	-210	15	125	230

Source: Frontier Economics, 2012a; Seed estimates

C. Characteristics of the Demand Response Market: results of the ERAA's Member Survey

The ERAA assisted us in undertaking a simple member survey in relation to the typical characteristics of demand response contracts in the NEM. In addition we were provided with an estimate of the currently contracted level of demand response in the NEM and a breakdown by type of demand response. The purpose of the survey was to assist in understanding some of the practical considerations in contracting for demand response and the impacts that these practical considerations may have on the assessment of benefits of the DRM.

We did not verify the accuracy of the data collected by the ERAA.

The following tables provide a summary of the results provided by the ERAA.

Table C. 1 Typical Demand Response Contract Parameters, ERAA Member Survey, summary results

Parameter	Result
Typical strike price required ($/MWh)	$300/MWh
Typical fixed payments required in demand response contracts ($ pa)	Range from $120,000 fixed payment p.a. to $12,000 - $50,000/MW p.a. (dependent on the strike price/cap value)
Maximum number of days demand response is allowed to be called per year based on typical contract terms	365
Maximum number of hours demand response is allowed to be called per year based on typical contract terms	Multiple scenarios – ranging from 60 hours per supply period, 28 hours to 8760 hours or unlimited.
Minimum notice period required before demand response can be called based on typical contract terms	Within the contract the demand reduction must be activated within 24 hours; typically customers' equipment will take 30 mins to ramp up, plus approximately 30 mins for notification response depending upon demand reduction technology. Warnings the day before and on the morning of the demand response event day will improve response times. The most common response was 30 - 60 minutes' required notice.
Other comments	Customers share in benefits (some examples cited include 58% - 85% of the benefit accrued to the end user). In addition, some retailers offer a lower tariff in return for demand response.

Table C. 2 Contracted demand response, ERAA Member Survey, summary results, quantity and type, MW (% of total)

Item	Result
Level of currently contracted demand response (MW)	~215 MW. Some responses noted that they have additional customers on pool price pass through and progressive hedging style products which have some similar characteristics to demand response without the need for a baseline consumption calculation.
Demand response expected to be provided by onsite generation, % of total	~50%
Demand response expected to be provided by shutdowns, % of total	~15%
Demand response expected to be provided by demand shifting, % of total	~35%

D. The costs of implementing the Demand Side Mechanism: AEMO's costs and the results of the ERAA's Member Survey

The cost estimates were based on information collated by the ERAA from its members. We did not verify the accuracy of the data collected by the ERAA.

The ERAA collated 'order of magnitude' costing information from nine (9) members, comprising all three first tier retailers and six second tier retailers, based on the AEMO costing request used as part of the DRM rule change development process.

The costs were compiled by AEMO/ERAA on the following basis:

- each retailer completed a self-assessment of the order of magnitude of their costs covering the following major areas:
  - Registrations;
  - Metering and data management;
  - Settlements and prudentials;
  - Reporting; and
  - Retail customer billing.
- The costs were then further subdivided into two categories:
  - Upfront costs – split between business process / FTE requirements and system change requirements; and
  - Ongoing costs.
- any costs associated with operating as a Demand Response Aggregator were excluded.

An example of the order of magnitude table completed by the retailers is provided below.

Table D. 1 Retailer Costs, order of magnitude, by category and cost, $

Order of Magnitude	Range
Small	Up to $100k
Medium	Greater than $100k, up to $500k
Large	Greater than $500k, up to $2m
Very Large	Greater than $2m, up to $5m
Very, Very Large	Greater than $5m

When assessing the costs we calculated a 'low case' cost estimate to compare with the low case estimate of the benefits. Our approach in calculating the low case estimate applied a degree of conservatism.

The development of the low case cost estimate involved the following steps:

- Assigning a cost value for each cost based on the lower bound of the relevant order of magnitude, for example:
  - If a retailer estimated their retail billing system costs were 'very large', we assigned a value of $2m to this cost based on the low end of the very large range.

– For those costs that were identified as 'small' we applied a notional $20,000 value.

The table below is an example of the order of magnitude costing used:

Table D. 2 Retailer Costs, example calculation

Order of Magnitude	Range	Low case cost used
Small	Up to $100k	$20k
Medium	Greater than $100k, up to $500k	$100k
Large	Greater than $500k, up to $2m	$500k
Very Large	Greater than $2m, up to $5m	$2m
Very, Very Large	Greater than $5m	$5m

- We aggregated the costs across all categories and retailers – separating upfront costs from ongoing costs.
- We calculated the NPV of the costs over a 10 year period discounted at 7.1%, the same discount rate used in assessing the benefits.

Based on this approach, our low case cost estimate was around $112 million over a 10 year period.

In addition, we understand AEMO's cost estimates for the DRM are in the range of $8m - $14m over a similar 10 year period.

E. Terms of Reference: Assessment of the case for a Demand Response Mechanism in the NEM

Introduction

The Energy Retailers Association of Australia (ERAA), National Generator Forum and the Private Generators Group seek to engage Seed Advisory to produce a report analysing the case for the implementation of the Demand Response Mechanism (DRM) in the National Electricity Market (NEM).

The ERAA represents the organisations providing electricity and gas to almost 10 million Australian households and businesses. Our member organisations are mostly privately owned, vary in size and operate in all areas within the NEM.

Objective

The objective of this engagement is to produce a report assessing the case for establishing the DRM in the NEM. This should have regard to the level of Demand Response available to be delivered from large electricity users through the DRM, and the reasonable participant and AEMO costs and benefits expected to be realised by both the electricity industry and consumers over time which are attributable to the DRM.

Background

The Australian Energy Market Commission (AEMC) undertook a review of demand side participation in the NEM during 2011 and 2012, titled *Power of Choice - giving consumers options in the way they use electricity*. Key recommendations of the review included to establish a new Demand Response Mechanism in the wholesale market, and a new category of market participant that will allow for the unbundling of non-energy services from the sale and supply of electricity.

In December 2012, the Standing Council of Energy and Resources provided in-principle support for these recommendations and directed the Australian Energy Market Operator (AEMO) to establish an advisory stakeholder working group to assist in developing a potential rule change proposal for a new wholesale market demand side participation option (known as the Demand Response Mechanism), and a new category of market participant, for the AEMC's consideration and final decision.

With the work of the advisory stakeholder working group now well progressed, AEMO has advised that it will be drafting a rule change proposal for the implementation of the DRM.

Scope of Work

A report is to be developed that assesses whether or not there is a compelling case to implement the DRM, in light of the costs and benefits and how these meet the criteria within the NEO.

The assessment of the case for the DRM should specifically consider the:

- value of valid benefits which can be attributed to the operation of the DRM, and additional to the benefits that could be achieved through current off-market Demand Response programs;

- costs incurred in the initial implementation and ongoing operation of the DRM as provided by the ERAA; and
- timeframes over which costs and benefits are likely to be realised.

The table below is an example of how the costs and benefits may be summarised.

Demand Response Mechanism	Year preceding DRM start	Year 1	Year 2	Year 3	Year 4	...
Cost Incurred						
Benefits Realised						

This engagement requires three broad inputs, as described below. Of these inputs, Input 2 is expected to be the principal focus for Seed Advisory.

The report should detail methodologies, assumptions and findings associated with the inputs below, and Seed Advisory's approach to making a value assessment of the DRM.

Assumptions should include:

- DRM participation will be restricted to NEM customers with annual electricity consumption of 100MWh or greater;
- the operation of the DRM will be as per AEMO's *Demand Response Mechanism and Ancillary Services Unbundling – High Level Design* as released on 1 July 2013;
- Demand Response Aggregators will consist of both energy retailers and third party service providers; and
- the DRM will commence operation on 1 January 2015.

A note on demand-side participation and Demand Response

Demand side participation is a broad term which can describe any activity undertaken at the consumer end of the electricity supply chain to reduce consumption. This may include embedded generation, distribution network enhancements, metering replacement and energy efficiency measures.

Demand Response, as discussed in this Terms of Reference document, refers to an agreement to reduce electricity consumption for a discreet period of time, in return for some incentive. The DRM as recommended by the AEMC is one example of Demand Response, and it is unique from other Demand Response programs operating across the NEM in that it facilitates Demand Response through the NEM wholesale trading market.

For this engagement, the AEMC's DRM should be considered distinct and separate from Demand Response programs which operate independently of the NEM wholesale trading market ("off-market" Demand Response), such as those currently offered by electricity retailers. It is expected that many of these off-market Demand Response programs would continue to operate regardless of the presence of the DRM. Therefore this assessment of the case for the DRM should assess only the additional costs and benefits realised due to the DRM, and not those associated with off-market measures.

Input 1: Estimation of the volume of Demand Response available in the NEM

A survey of members of the ERAA, National Generator's Forum and Private Generators Group, will be undertaken by the ERAA. This survey will aim to determine in aggregate form the:

- volume of Demand Response currently contracted;
- scheduled or firm nature of contracted Demand Response;
- trigger for Demand Response dispatch (whether spot price, or some other trigger); and
- volume of contracted Demand Response that would meet criteria for participation in the DRM.

The survey will provide a strict definition of Demand Response, and set criteria that would make this Demand Response suitable for participation in the DRM. The survey will also try to capture in aggregate form the amount of Demand Response currently contracted to market participants. Outcomes of this survey will be provided to Seed Advisory. Seed Advisory will not be required to verify the accuracy of data collected, but rather should assume its integrity.

In assessing this input, consideration should be given to the:

- current volume of Demand Response contracted through off-market Demand Response programs by electricity retailers;
- volume not currently contracted that is likely to become available following the establishment of the DRM;
- volume of Demand Response currently contracted likely to switch from an off-market Demand Response program to the DRM, once established;
- potential fluctuations of the above volumes over time; and
- development of external factors that may impact on the actual uptake of demand response and the use of the DRM. This may include such things as the impact on demand from the uptake of distributed generation or initiatives such as the introduction of flexible pricing.

Input 2: Review of benefits case associated with the operation of the DRM

Undertake a review of the benefits realised through the establishment of the DRM as canvassed in the following sources:

(i) AEMC, *Power of choice review - giving consumers options in the way they use electricity*, Final Report, November 2012, with particular focus on Chapters 5 and 10;

(ii) Frontier Economics, *Benefits of reduced peak demand*, presentation, AEMC Public Forum, October 2012; and

(iii) Futura Consulting, Investigation of existing and plausible future demand side participation in the national Electricity market, December 2011.

This review should consider the:

- range of benefits which can be directly attributed to the operation of the DRM;
- extent to which stated benefits may also rely on other drivers;
- additionality of stated benefits beyond what can already be realised through current off-market Demand Response programs, and also above and beyond the DRM;
- likelihood of these benefits being realised;
- validity of claims about the magnitude of benefits to be realised;
- allocation of benefits to various roles across the electricity supply chain; and
- expected timeframe for valid benefits to be realised by the market.

Input 3: Costs associated with the implementation and ongoing operation of the DRM

The ERAA will collate costing information from members based on the AEMO costing request (the AEMO costing template has been included in Attachment 1). Costs will be compiled by the ERAA on the following basis:

- self-assessment of each electricity retailer's costs;
- all electricity retail business impacts to be costed;
- any costs associated with operating as a Demand Response Aggregator will be excluded;
- costs to be defined as implementation costs or ongoing costs; and
- order of magnitude costing only.

The ERAA will provide costing results in a consolidated view, the exact format of which will be determined once data has been assessed and in discussion with Seed Advisory. The table below is an example of the order of magnitude costing:

Order of Magnitude	Range
Small	Up to $100k
Medium	Greater than $100k, up to $500k
Large	Greater than $500k, up to $2m
Very Large	Greater than $2m, up to $5m
Very, Very Large	Greater than $5m

Seed Advisory will not be required to verify the accuracy of data collected, but rather should assume data integrity.

In addition to these costs Seed Advisory should consider costs external to member organisations required to facilitate the DRM. This would include such things as AEMO cost estimations for implementation.

seed