CLOSE TO HOME: Potential Benefits of Decentralised Energy for NSW Electricity Consumers

Prepared by

Institute for Sustainable Futures

for

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Executive Summary

The electricity sector is responsible for 37 per cent of Australia's total greenhouse gas emissions.[1] In the City of Sydney however, around 80 per cent of greenhouse gas emissions are due to coal fired electricity.

The City of Sydney has proposed the installation of 360 megawatts (MW)[2] of "trigeneration" by 2030, in order to reduce greenhouse gas emissions by 18 to 26 per cent from 2006 levels. Trigeneration systems are highly efficient small power plants that can be located in or on buildings. They not only generate electricity but also use waste heat to produce hot water for heating, and cold water (through "absorption chillers") for air-conditioning. The rest of the City's energy needs are proposed to come from renewable energy and energy efficiency measures in order to reduce overall emissions by 70 per cent by 2030 for the local government area, which includes the Central Business District (CBD). This equates to 50 per cent below 1990 levels.

Over the period 2010-2015, electricity network businesses in Australia are proposing to spend over $46 billion – or $9 billion per year – on upgrading and extending the electricity network. This expenditure is more than that proposed for the National Broadband Network, and is the main driver for the current sharp rise in electricity prices.

The traditional approach of investing in new power cables and substations to service increasing electricity demand reinforces the reliance on large-scale, centralised electricity supply which has been responsible for the high and rising levels of greenhouse gas pollution from the power sector. Following this path will make it more difficult for Australia to meet its 2020 greenhouse reduction target of 5 to 25 per cent put forward at international climate treaty negotiations.[3] Alternatively, if electricity regulators provided better support for electricity networks to redirect more of this network expenditure towards energy efficiency, peak load management and decentralised generation, then energy cost pressures and greenhouse gas emissions could be significantly reduced.

In NSW, electricity networks are undertaking capital expenditure of $17.4 billion over the five years to 2013/14. This represents $2,400 per person and an 80 per cent increase on the previous five-year period. **Average Energy Australia electricity prices are expected to rise by as much as 83 per cent during this period with the proportion of power bills that goes to pay network charges estimated to rise from 40 per cent to almost 60 per cent[4]**. Network charges reflect the costs of transporting electricity from where it is produced (mostly by coal fired power stations in regional areas like the Hunter Valley) to consumers in cities like Sydney, via the long distance network of wires, poles, cables and electrical substations. Amid the current intense public debate about power price rises, it is important to recognise that increased electricity network investment is main cause of the price increases (about 86 per cent

[1] See Department of Climate Change and Energy Efficiency, 2010. *Quarterly Update of Australia's National Greenhouse Gas Inventor. March Quarter 2010*, p.5.
[2] Megawatts electrical generation capacity, often denoted at MWe.
[3] Note: commitment higher than 5 per cent is conditional upon coordinated international action.
[4] See Section 4. Impact of network expenditure on electricity prices, p. 24

of the regulated power price rises for Energy Australia customers between 2009/10 and 2012/13).[5]

As much as $7.6 billion of this new capital expenditure on networks in NSW is **'growth-related',** including $3.3 billion to be spent by Energy Australia, whose service territory includes the Sydney CBD. This report suggests that **much of this new investment could potentially be deferred or avoided if peak demand growth was slowed through measures such as energy efficiency, peak load management and decentralised or local energy generation.** This has the potential to moderate future energy costs for all NSW electricity consumers, avoid the need for large new power stations and significantly reduce greenhouse gas emissions.

It is estimated that the City of Sydney's plans to supply 70 per cent of the local government area's electricity needs from a network of trigeneration plants by 2030 could achieve savings in deferred electricity network costs of over $200 million by 2020, or upwards of $1 billion by 2030. When the avoided costs of new fossil fuel power stations of around $0.5 billion of installed capacity are added, the City's proposed 360 MW of trigeneration capacity could potentially avoid in the order of $1.5 billion in electricity generation and networks by 2030.[6] While the City's trigeneration development program would also entail major costs, the above estimated cost savings highlights that the scale of benefits is potentially very large.

In NSW, annual energy consumption is forecast to increase by 21 per cent or about 15,500 gigawatt hours (GWh) of electricity between 2009/10 and 2019/20. There are currently many proposals to meet this additional energy demand, including coal-fired and natural gas-fired power stations, renewable energy generators, energy efficiency and load management. If NSW installed its proportional share of the Federal government's Renewable Energy Target of 20 per cent by 2020, this would equate to 13,200 GWh p.a. of renewable energy production. This means that in 2020 there would remain a notional electricity supply "gap" of 2,300 GWh in NSW, or about three per cent of current energy demand.

The City of Sydney's energy infrastructure plans can play a role in helping to overcome this notional energy 'gap' between forecast demand and supply in NSW to 2020. It is estimated that with 155 MW of the City of Sydney's planned 360 MW of trigeneration capacity in place by 2020, approximately 1,000 to 1,450 GWh per year of grid electricity could be displaced, which represents 44 to 63 per cent of the NSW energy "gap". When combined with energy efficiency and distributed generation, this could contribute significantly to filling this potential energy demand/supply gap.

However, despite this relatively small energy gap in the planning horizon to 2020, two NSW Government owned generators, Macquarie Generation and Delta Electricity, have proposed major expansions of 4,000 MW (combined) of coal or gas baseload power stations at an estimated cost of between $4.6 and $7 billion dollars.[7]

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[5] IPART, *Review of regulated retail tariffs and charges for electricity 2010-2013, Electricity — Final Report*, March 2010, Table 1.2.

[6] This estimate is conservative as it excludes the electrical load avoided due to the heating/cooling load being met by trigeneration using waste heat.

[7] NSW Department of Planning, *Major Project Assessment, Bayswater B Power Station, Director General's Environmental Assessment Report*, December 2009 and NSW Department of Planning,

If coal-fired, these two new large power stations (at Bayswater in the Hunter Valley and Mt Piper near Lithgow) would emit over 23 million tonnes of carbon dioxide per annum.[7] This would be equivalent to over 4 per cent of Australia's greenhouse gas emission in 2015[8] or up to 15 per cent of total NSW emissions.[9]

When combined with the additional network infrastructure required to deliver their power to consumers, these big new centralised power stations are likely to be significantly more expensive and more polluting than a prudent combination of decentralised generation, load management and energy efficiency. A previous report by the Institute for Sustainable Futures[10] found that "Distributed Energy" options including distributed generation, peak load management and energy efficiency measures were, as a response to peak and energy shortfalls, likely to be both cheaper and produce less carbon emissions than either coal or gas fired power stations. These Distributed Energy options were estimated to be able to cut total power bills by as much as $600 million per year by 2020 – equivalent to about $60 per household per year.

Moreover, if the recently recommended target of the Prime Minister's Task Group on Energy Efficiency to improve nationwide energy efficiency by 30 per cent by 2020 is enacted, there would be little if any need for new fossil fuel based electricity generation, as the reduction in energy consumption would be bring 2020 consumption to below that of 2010.

There are, however, numerous impediments to electricity network businesses investing in 'demand management' to support the use of distributed energy to defer generation and network infrastructure). Consequently, the scale of funds spent on demand management in Australia remains relatively small. In total, the aggregated level of annual expenditure on demand management is likely to represent significantly less than 1 per cent of total annual expenditure on electricity supply in Australia. This report outlines six key regulatory and other changes that would help unlock the potential of demand management to deliver greenhouse gas emission reductions and limit price increases for NSW electricity consumers:

1. Changing the form of regulation to reward, instead of penalising, electricity network businesses that help consumers save energy;
2. Better reporting and assessment of *actual* demand management performance;
3. Better assessment of the *potential* for demand management to reduce energy bills;
4. Putting a significant price on carbon emissions;

Major Project Assessment, Mt Piper Power Station Extension, Director General's Environmental Assessment Report, December 2009.

[8] Arup, 2009. *Independent Review of Greenhouse Gas Assessments*; *Bayswater B EA Concept Plan*, Oct 2009, p. 20; Arup, 2009. *Independent Review of Greenhouse Gas Assessments*; Mt Piper Power Station Extension, Oct 2009, p.21.

[9] Aecom, 2009. *Bayswater B Submissions Report*, Report prepared for Macquarie Generation, November 2009, p.32. Uses AeCom citation of NSW Government reported emissions of 158 million tonnes in 2005.

[10] Jay Rutovitz & Chris Dunstan, 2009. *Meeting New South Wales Electricity Needs in a Carbon Constrained World*. Report prepared by the Institute for Sustainable Futures, University of Technology, Sydney.

5. Setting targets for demand management (and measuring progress towards them);
6. Establish a dedicated fund, or scheme, to support demand management by network businesses, and others.

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1. Background

Introduction to Trigeneration and Electricity Networks

Trigeneration energy systems are highly efficient mini-power plants that run on natural gas or renewable gases to produce electricity, heating and cooling. These three distinct outputs are where *tri*generation derives its name. They can be up to three times more efficient than coal fired power stations because they capture the waste heat from producing electricity and use it to heat buildings and, through absorption chillers, to cool them. They are able to do this due to their 'distributed' location within the electricity network, close to the point of building heating and cooling loads. This is distinct from the centralised coal-fired power stations that produce 80 per cent of NSW's electricity, in which two-thirds of the energy content of coal is lost as steam and waste heat through the cooling system. Distributed power generators also reduce transmission and distribution losses, which make up around 7 per cent of electricity produced, by avoiding the need to transport power from distant power plants into the city.

Trigeneration has the potential to reduce electricity demand at peak times because not only is electricity produced, but the waste heat can be used to replace electrical air-conditioning or heating, which are major contributors to peak electricity demand. Trigeneration in the CBD could not only reduce the need for increased capacity in local electricity distribution wires and substations but also in the long-distance electricity transmission and sub-transmission networks servicing the CBD. Thus the City of Sydney's trigeneration plans offer a key opportunity to defer or eliminate a portion of the $7.6 billion being invested in wires, poles and substations over the next five years due to growth in electricity demand in NSW.

Significantly reducing demand on the electricity network in the CBD could also result in the deferral or avoidance of large centralised power stations.

Earlier work by the Institute for Sustainable Futures (ISF)[11] found that "Distributed Energy" options including distributed generation, peak load management and energy efficiency measures were both cheaper and produced less carbon emissions than either coal or gas fired power plants as a response to peak and energy shortfalls. These Distributed Energy options were estimated to be able to cut total power bills by as much as $600 million per year by 2020 - equivalent to about $60 per household per year.

This report builds on the previous analysis specifically in relation to the City of Sydney's decentralised energy plans.

Trigeneration Master Plan and Sustainable Sydney 2030

The City of Sydney ('the City') has set a target to supply 70 per cent of the local government area electricity needs from a network of trigeneration plants by 2030, which is estimated to reduce greenhouse gas emissions by 18 to 26 per cent from

[11] Jay Rutovitz & Chris Dunstan, 2009. *Meeting New South Wales Electricity needs in a Carbon Constrained World*. Report prepared by the Institute for Sustainable Futures, University of Technology, Sydney.

2006 levels.[12] The remainder of the City's energy needs will come from renewable energy and energy efficiency measures to reach an overall emissions reduction target of 70 per cent for the local government area, including the CBD, by 2030 (this equates to 50 per cent below 1990 levels).

To map out this strategy, the City of Sydney commissioned a Trigeneration Master Plan for the CBD to assess a number of technical factors for the establishment of a trigeneration network such as the distribution of electrical and gas loads, the size and location of electrical cables and gas mains, and what capacities could be connected to them and where. This plan, due to be launched in December, outlines the installation of at least 360 MW of trigeneration capacity by 2030.[13]

Last year the City of Sydney also called for expressions of interest to design, install and operate a network of trigeneration plants in the CBD based firstly around council properties but with the potential to expand by connecting to other city buildings. After receiving responses from major national and international energy players, a tender, which closes in January 2011, was sent to a shortlist of companies. The City's tender also seeks expressions of interest in participating in a public/private joint venture with the Sydney Energy Services Company to roll out the 360 megawatts of trigeneration as set out in the Master Plan.

According to a 2009 study prepared for City of Sydney,[14] a broader rollout of the plans similar to Sydney's Sustainable Sydney 2030 in other Australian cities could achieve 50 per cent cuts in greenhouse gas emissions over the next 20 years. This study suggested that a coordinated strategy of this nature could reduce emissions by a cumulative 540 million tonnes between 2010 and 2030, contributing 41 per cent of the national 5 per cent target and almost one quarter towards a 25 per cent national reduction target.

Trigeneration in Australia

Australia employs a relatively small amount of cogeneration (which produces electricity and heating) and trigeneration technologies relative to other parts of the world such as Europe, North Asia and the United States. In 2006, Australia ranked 34th out of 40 countries surveyed for decentralised energy generation, with around 5 per cent of total generation coming from decentralised sources (mostly in large industrial applications) compared to 40 per cent in the Netherlands and 55 per cent in Denmark.[15]

There are a small number of trigeneration plants operating in Australian cities including the Stockland property group building in Sydney, Macquarie University and Canberra Airport. Others are planned for Qantas at Sydney airport and the National Australia Bank's data centre in Melbourne. However, the City of Sydney's plans represent a dramatic change in how the technology is currently used in Australia. It plans to install large-scale plants to supply networks of nearby buildings or "precincts". For example, a trigeneration plant planned for Sydney Town Hall could

[12] Kinesis, Cogent Energy, Origin. 2010, *City of Sydney Decentralised Energy Master Plan 2010-2030.*
[13] Modelling by City of Sydney consultants, Kinesis, October 2010.
[14] Kinesis, 2009. *Examining the Abatement Potential of Australia's Capital Cities by 2030*, Report prepared http://www.cityofsydney.nsw.gov.au/2030/documents/CCLMKinesisReport.pdf
[15] World Alliance for Decentralised Energy, 2006. *World Survey of Decentralised Energy,* Fig. 9 http://www.localpower.org/documents/report_worldsurvey06.pdf

supply the Queen Victoria Building, St Andrews School, Woolworths and other nearby buildings. The City believes that its plan has the potential to increase significantly the energy efficiency of the system compared to the single building operation, and that greenhouse gas emissions in connected buildings can be reduced by between 39 to 56 per cent depending on how the plants are used.[16]

Background to and structure of this report

In early 2009 the City of Sydney made a submission to the Australian Energy Regulator (AER) outlining the significance of the issue of avoidable electricity network costs to the business case of its planned Trigeneration Master Plan (then called "Green Transformers"). The submission stressed the importance of the AER's regulatory decision in assisting the transition to a regulatory environment in which distributed generators are allowed to capture some of these avoided costs, resulting in an outcome that is both lower in cost and lower in carbon emissions.

This report reviews electricity demand forecasts, generation planning figures and network expenditure information that has changed since the City's submission, to provide an up-to-date assessment of network investment and the potential environmental and consumer benefits achievable through decentralised energy options. It should be stressed that while this report primarily refers to supporting the development of trigeneration, the arguments presented here apply equally to improving outcomes through energy efficiency or other peak load management approaches.

The structure of this report is as follows:

Section 2 reviews the demand forecasts made by Energy Australia and other sources since the 2009 AER network pricing Final Determination (the City's submission was in response to the *Draft* Determination) to determine whether the previous forecasts remain an accurate picture of current trends driving network investment.

Section 3 reviews the network investment approved in the AER's pricing determination, and considers what proportion of this investment may be avoidable through energy efficiency, trigeneration and other decentralised energy options.

Section 4 looks at the consumer implications of this network investment, in terms of the resulting tariff increases.

Section 5 discusses regulatory and other changes that are needed to allow trigeneration and other decentralised energy options to compete on a more level playing field with traditional centralised coal-fired power. It also suggests strategic approaches the City of Sydney can take in pursuing this agenda.

The **Appendix** contains an analysis of the AER's responses to the recommendations contained in the City's submission, as background to the suggested strategy seen in Section 5.

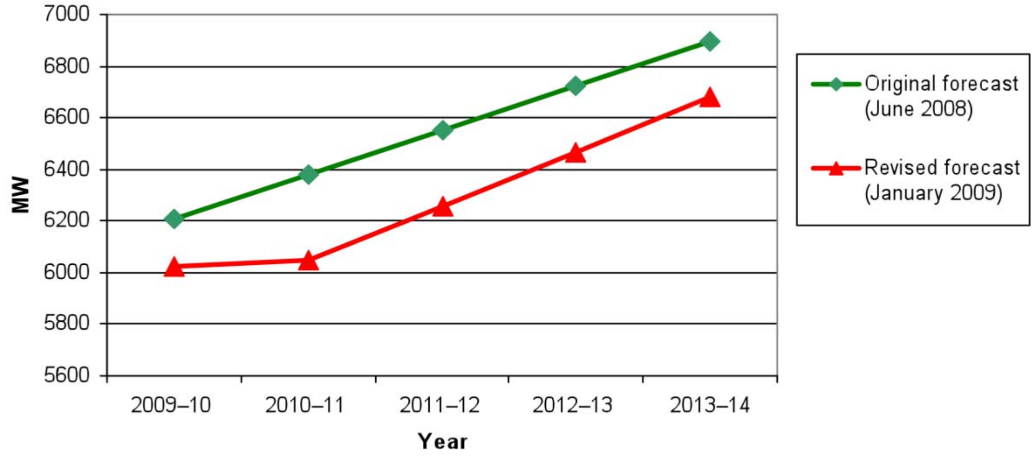
[16] Kinesis et al 2010, above n12.

2. Demand forecasts and generation planning

Demand Forecasts

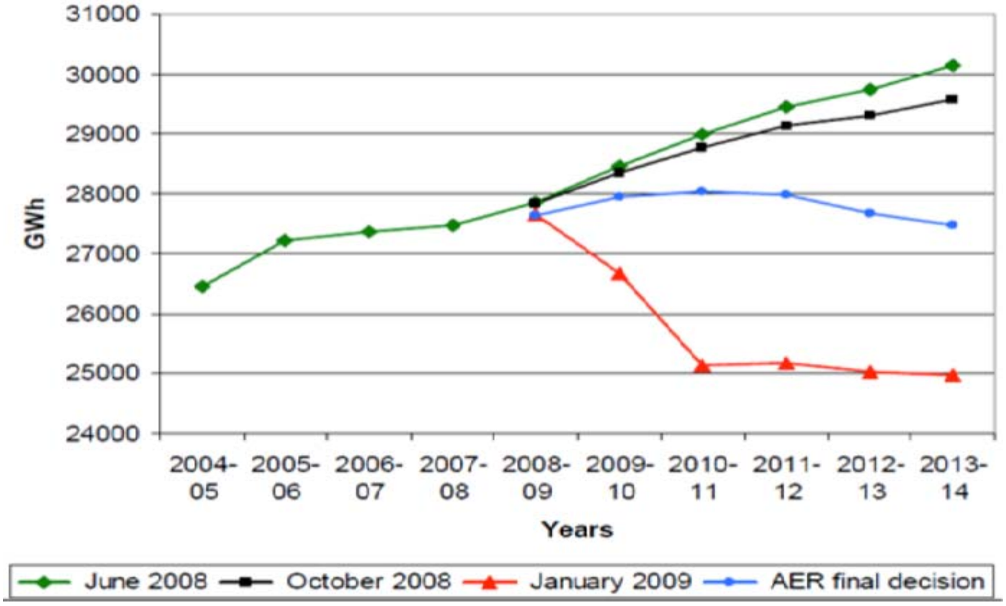
The Australian Energy Regulator's NSW distribution network pricing determination took place during worst impacts of the Global Financial Crisis (GFC) on global financial markets. Energy Australia's (EA) peak demand forecasts at the time reflected the impact of the GFC on economic growth, as illustrated by the January 2009 forecasts shown in Figure 1 and Figure 2 below.

Figure 1 – Energy Australia forecast peak demand as at January 2009[17]



[17] Data source: AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, Table 6.4 p.86.

Figure 2 – Comparison of energy forecasts for Energy Australia's network[18]



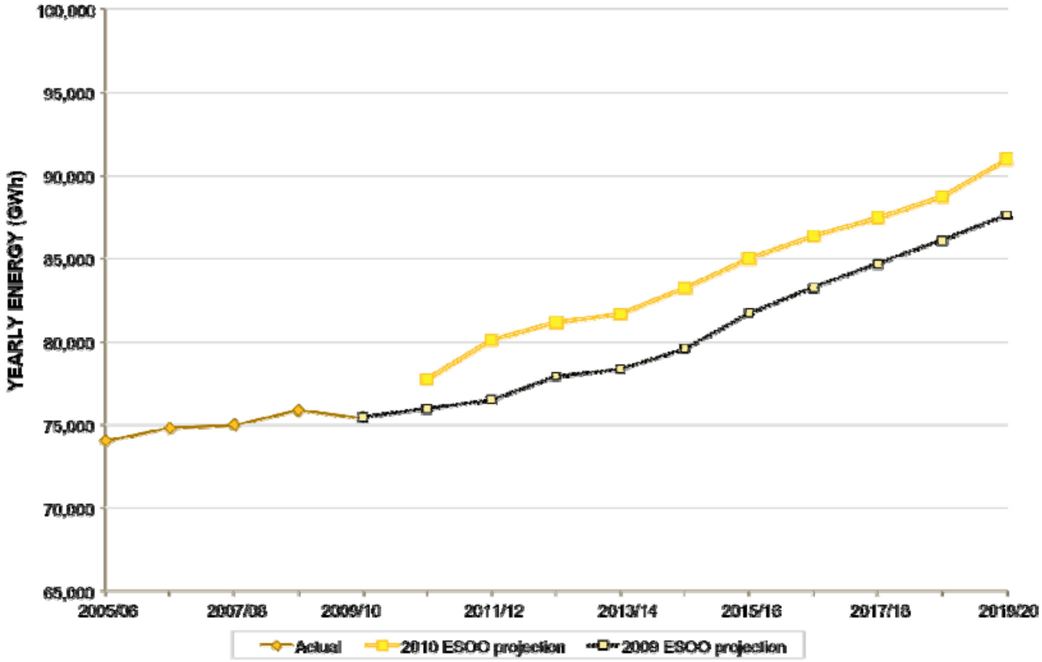
As can be seen from Figure 1 and Figure 2, the reduction between June 2008 and January 2009 in forecast peak demand (which drives network capital expenditure and EA *costs*) was estimated to be much less than the impact on energy consumption (which mainly drives EA *revenue*). This major reduction in EA's forecast of consumption was probably also influenced by the expected impact of rapid increases in customers electricity bills due to increases in electricity network charges. Consequently, EA argued for a higher price increase to compensate for these impacts.

It is pertinent to consider how actual data since compares with these projections. While public data is unavailable for EA's network specifically, the recently released 2010 Australian Energy Market Operator (AEMO) Electricity Statement of Opportunities shows that energy consumption in NSW in 2009/10 did in fact fall slightly compared to 2008/09 (from 75,857 gigawatt hours (GWh) to 75,421 GWh) as shown in Figure 3. If reflective of EA's demand pattern, this would place the actual demand between the forecast of AER and EA. (Note that since the AER's regulation closely ties revenue to sales volume, it is in the financial interest of EA if actual sales exceed the forecast adopted by the AER.)

The 2010 AEMO projections are substantially higher than the 2009 projections due to a quicker than anticipated economic rebound from the GFC. However, it is worth noting the large safety margin applied to the AEMO energy forecast for NSW, in that even in the *lowest* growth scenario of the three considered by AEMO a growth rate of 1.5 per cent is used, which is substantially higher than the observed average annual energy growth from 2004-2009, of just 1 per cent.

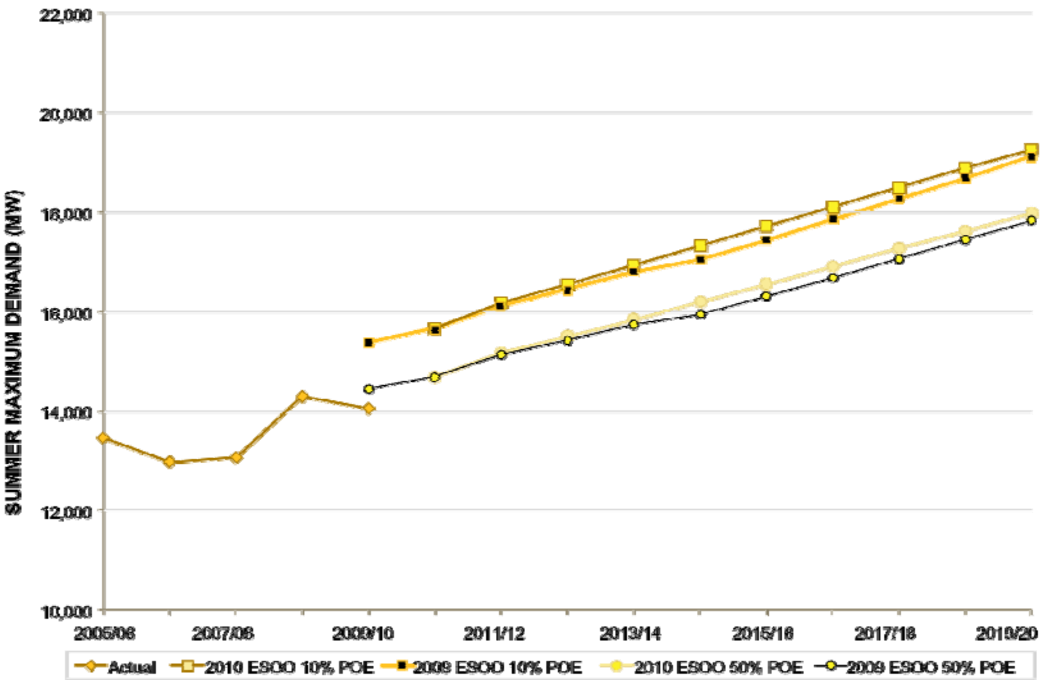
[18] Figure source: AER, above n17, Fig. 6.2, p.114.

Figure 3 - Comparison of NSW medium growth energy projections (AEMO 2010),[19] GWh p.a.



According to AEMO, both summer and winter peak demand for NSW also fell in 2009/10 compared to 2008/09, by around 230MW and 1,300MW respectively. (The AEMO summer actual and forecast demand is shown in Figure 4). It should be noted that peak demand is much more weather dependent than total energy consumption, and is therefore more variable and harder to accurately forecast.

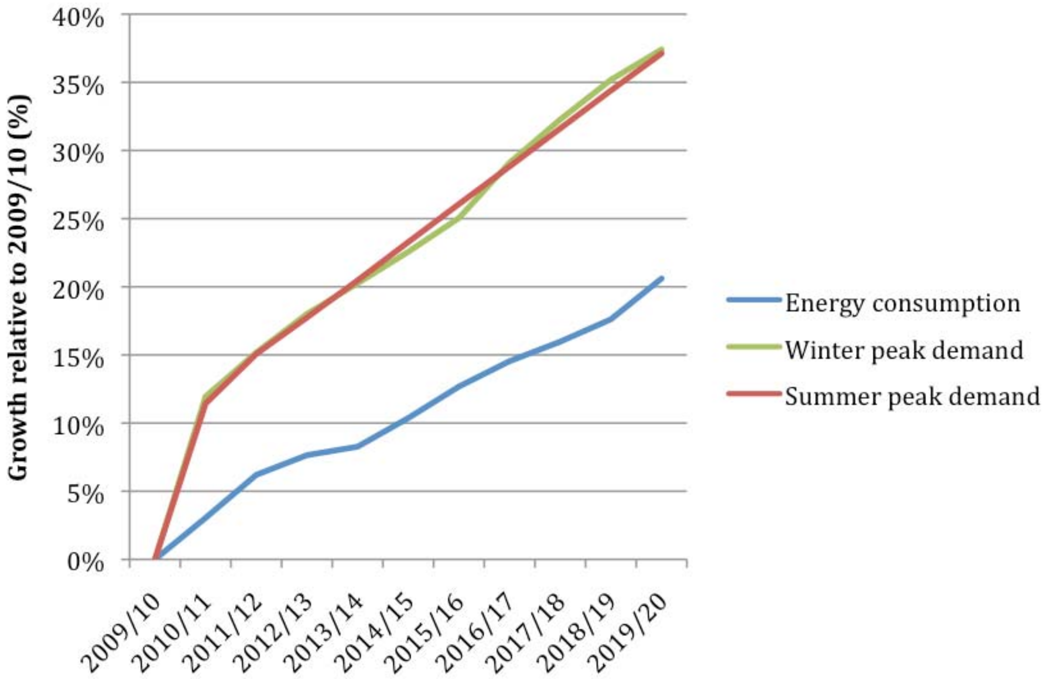
Figure 4 - Comparison of NSW medium growth summer maximum demand projections[20]



[19] AEMO, 2010. *Electricity Statement of Opportunities.* Fig 4-9, p.45.
[20] AEMO, 2010. *Electricity Statement of Opportunities.* Fig 4-10, p.47.

Bringing the above AEMO peak and energy forecasts together as shown in Figure 5, over the 10-year period from 2009/10 to 2019/20 the AEMO medium growth scenario projections suggest that energy consumption is forecast to grow by 21 per cent, while both summer and winter peak demand are forecast to grow by 37 per cent.

Figure 5 – Growth in NSW energy consumption and peak demand relative to 2009/10[21]



In summary, the actual peak and energy data one year into the AER's network pricing determination period are broadly in line with peak and energy forecasts adopted by the AER.

Looking further out to 2014 the forecasts have changed significantly from the 2008 Draft Determination, but are broadly in line with those adopted by AER for the Final Determination. On this basis, it seems reasonable to conclude that changing economic and energy forecasts have neither improved nor diminished the potential for trigeneration and DM or the likely financial impact on Energy Australia of supporting these options compared to when the AER decision was made.

Generation forecasts (energy)

According to the AEMO Electricity Statement of Opportunities (2010), energy consumption in the National Electricity Market (NEM) states is forecast to rise by about 48,000 GWh p.a. between 2009/10 and 2019/20 (medium economic growth scenario). During this period, renewable energy generation is due to increase by at least 33,000 GWh due to the mandatory Renewable Energy Target (RET). This situation is shown in Figure 6 below.

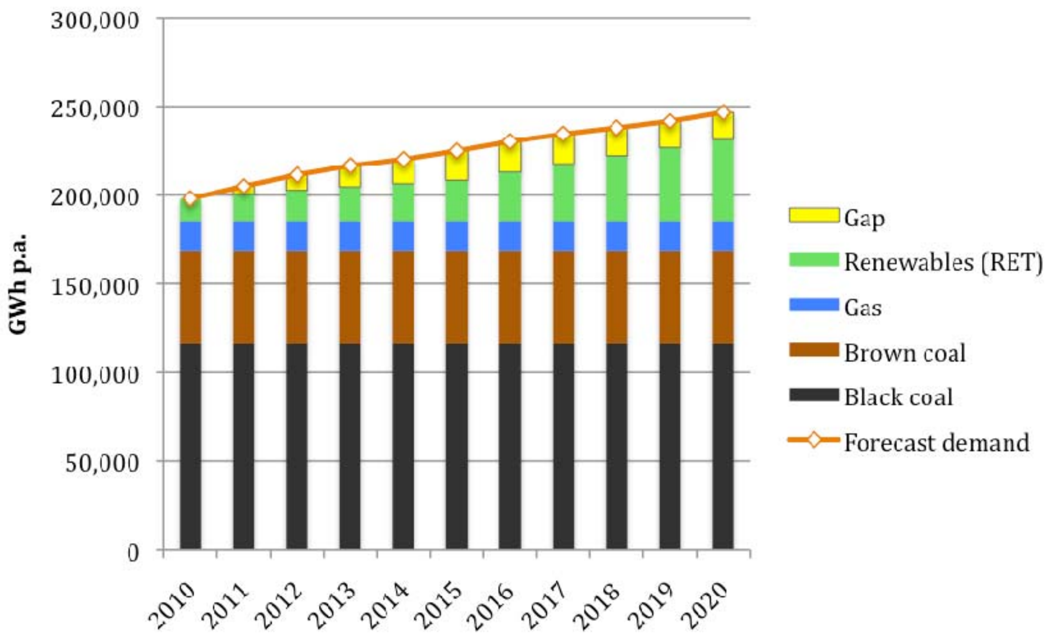
[21] Data Source: AEMO, 2010. *Electricity Statement of Opportunities*. Tables 4-10, 4-11, 4-12. For winter projections the year 2009 was aligned with 2009/10 summer forecasts.

This leaves a gap of about 15,000 GWh to be met by other sources (shown as a notional "gap" in yellow in Figure 6). Note that this is only a notional "gap" as there are a number of existing and proposed options to meet this gap, which are likely to emerge well in advance of any real supply shortfall occurring.

Options to meet the "gap" include:

1. increased output by existing gas- and coal-fired power stations;
2. new gas-fired power stations;
3. new coal-fired power stations;
4. additional renewables beyond that required to meet the national renewable energy target (RET);
5. cogeneration/trigeneration; and
6. improved energy efficiency.

Figure 6 – Energy supply/demand situation in the National Electricity Market, 2010-2020,[22] GWh p.a.



[22] Data Sources: Forecast demand from AEMO, 2010. *Electricity Statement of Opportunities.* Fig 4-3; Breakdown of non-renewable components of existing generation according to AER, 2009. *State of the Energy Market,* Fig 1.5b; Renewables from Renewable Energy (Electricity) Act 2000 (Cth), Act No. 174 of 2000 as amended (compilation prepared on 1 February 2010 taking into account amendments up to Act No. 78 of 2009), s.40. Note that this older version of the Act was used to illustrate gross renewable energy additions, as the Act was subsequently amended to create complementary Small (SRET) and Large (LRET) target schemes, ultimately intended to lead to the same outcome in terms of total renewable energy provision (but the new Act does not contain an overall combined target table totalling 45,000GWh by 2020). In fact, it is currently estimate that the SRET will 'overdeliver' and it is expected that the total resulting installed capacity of renewables in 2020 will be 52,000 GWh, and thus the numbers used in this report are conservative. See: MMA (McLennan Magasanik Associates), 2010. *Impacts of Changes to the Design of the Expanded Renewable Energy Target*, Report to Department of Climate Change and Energy Efficiency.

The approach shown above for the National Electricity Market is now applied to NSW, as shown in Figure 7 below. In NSW energy consumption is forecast by AEMO to increase by about 15,500 GWh or 21 per cent between 2009-10 and 2019/20. This is shown by the black dotted lines in Figure 7. If NSW were to get its proportional share of renewable energy through the RET, or about 40 per cent of total capacity,[23] this would equate to 13,200 GWh of renewable energy supply (the green component of the column in Figure 7). Shown in yellow is the additional energy required to meet the deficit, which is 2,300 GWh, or about 3 per cent of current energy demand. This is equivalent to about 900 MW of wind power (operating at a typical 30 per cent capacity factor).

The two right hand columns of Figure 7 provide a picture of how the City of Sydney and its local government area could contribute to this 2,300 GWh "gap" in 2020. While the City's energy demand only makes up around 5 per cent of total 2020 NSW consumption (shown in orange as the "City's share" in Figure 7),[24] the City has the potential to play a more significant role in addressing an energy deficit. The City is looking at several possible low emission energy options, which could contribute to meeting this forecast energy supply gap, including:

- energy efficiency;
- distributed renewable energy (e.g. solar power, solar hot water); and
- distributed generation, including cogeneration and trigeneration (from renewable and non-renewable fuels).

The relative impact that each of these measures could have is also shown as dotted boxes in Figure 7.

It is estimated that under the City's medium growth trigeneration scenario, in 2020 with 155 MW of trigeneration in operation, approximately 1,000 to 1,450 GWh per annum[25] of grid electricity would be being displaced by providing low carbon electricity and displacing electrical heating and cooling by utilising waste heat. This equates to about 10 times the City's proportional contribution to a notional NSW energy supply gap, or 44 to 63 per cent of the *total* NSW gap of 2,300 GWh p.a.[26] Using standard industry figures derived from Acil Tasman[27] for proposed new fossil fuel generation costs, deferring investment in coal or gas fired power stations is estimated to result in an avoidable cost of around $1.5 million per MW of installed capacity. Given the City's proposed 360 MW of generating capacity, this translates to over $0.5 billion in avoided fossil fuel generation infrastructure.[28]

In addition, if the City was to improve energy efficiency by 30 per cent in line with the recommendation of the Prime Minister's Task Group on Energy Efficiency this

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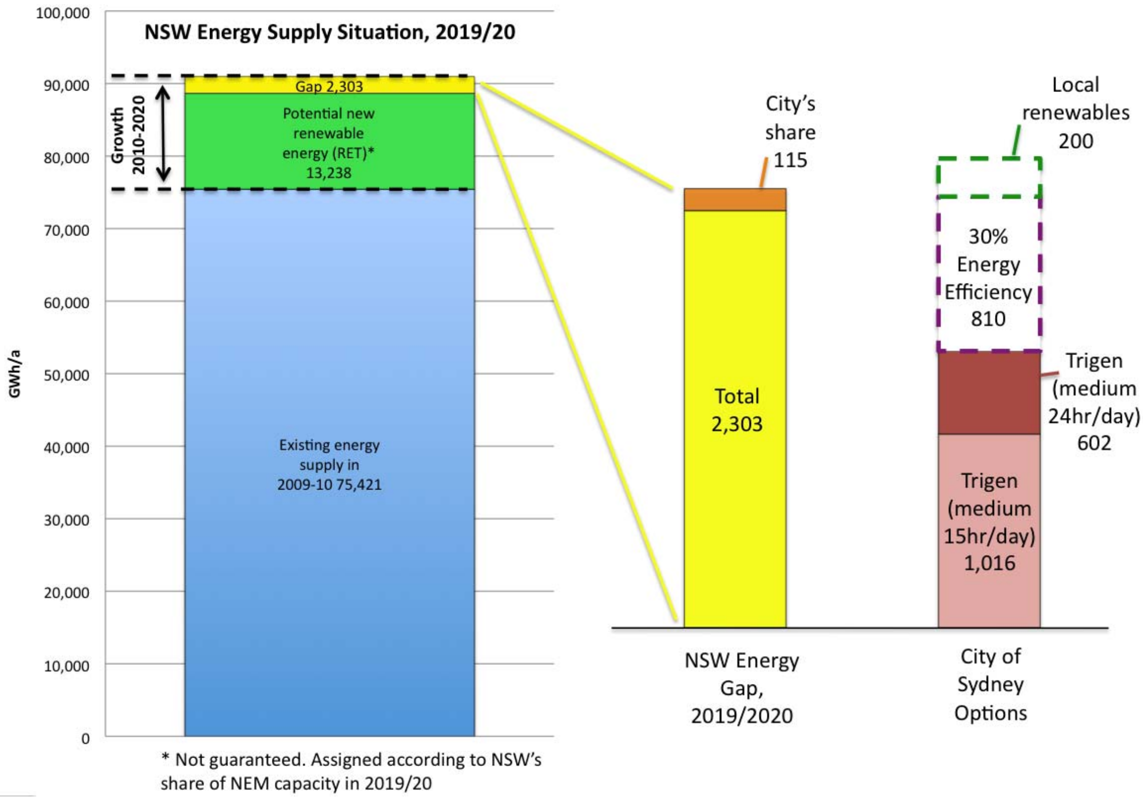
[23] NSW's share of projected peak demand on the National Electricity Market in 2019/20 according to AEMO 2010.
[24] Based on a 2020 demand of 4,874 GWh (Kinesis modelling data from 2009).
[25] Depending on whether the trigeneration is operation for 15 or 24 hours per day.
[26] Furthermore, under the medium growth scenario there is also sufficient potentially dispatchable trigeneration capacity installed prior to a notional *peak demand* 'gap' being observed on the network (69MW of trigeneration is installed by 2016/17 when a 27 MW peak capacity gap is predicted).
[27] ACIL Tasman, 2008, *Impacts of the Carbon Pollution Reduction Scheme and RET: Modelling of impacts on generator profitability*, Department of Climate Change.
[28] Figure is conservative as the heating/cooling load offset from waste heat is not included.

could contribute an estimated additional 810 GWh p.a. (35% of the gap) in savings,[29] while local renewables under the (yet to be finalised) Renewable Energy Master Plan could make up a further 200 GWh p.a. (9%).[30]

Figure 7 – Indicative potential contribution of the City of Sydney to NSW energy supply in 2019/20[31]



Despite this relatively small notional energy gap in the planning horizon to 2020, two NSW Government owned electricity generators, Macquarie Generation and Delta Electricity, have proposed major expansions of 2,000 MW each of coal or gas baseload power stations at an estimated cost of between $4.6 and $7.0 billion dollars.[32] (Note that these costs are reflective of the $1.5 million per MW mentioned above.) These two new power stations (at Bayswater in the Hunter Valley and Mt Piper near Lithgow) would produce in the order of 28,000 GWh per year (if operating at a typical 80 per cent of capacity) and, if coal-fired, would emit over 23 million tonnes of carbon dioxide per annum.[33] This would be equivalent to over 4 per cent of

[29] This accounts for 10% of the 14% efficiency gains factored into Sustainable Sydney 2030 having already been counted in the 'baseline'.
[30] The City's 2030 target is 1,300 GWh from direct investment in renewables. About half of this would be within the LGA and it is assumed that approximately 30% of this half would be installed locally by 2020. An additional margin has also been subtracted to account for some overlap counted under the national Small Renewable Energy Target (SRET).
[31] NSW forecasts obtained from AEMO *2010*, Table. 4-10, medium growth scenario.
[32] NSW Department of Planning, *Major Project Assessment, Bayswater B Power Station, Director General's Environmental Assessment Report*, December 2009 and NSW Department of Planning, *Major Project Assessment, Mt Piper Power Station Extension, Director General's Environmental Assessment Report*, December 2009.
[33] Ibid.

Australia's greenhouse gas emissions in 2015[34] or up to 15 per cent of total NSW emissions.[35]

To further compound the apparent imprudence of proposing new baseload power stations, the Prime Minster's Task Group on Energy Efficiency recently released a recommendation to adopt a nationwide target of 30 per cent energy efficiency improvement by 2020.[36] Should this recommendation be enacted, there would very likely be no need for new fossil fuel based electricity at all, as the reduction in energy consumption would bring 2020 demand below that of 2010. Such a decision would dramatically shift the goalposts in terms of planning for all energy generation projects.

Generation forecasts (peak capacity)

While thus far this report has focussed on "energy" or "GWh" shortfalls, the availability of electricity generation at peak times (i.e. "peak capacity" in MW) will now be reviewed briefly.

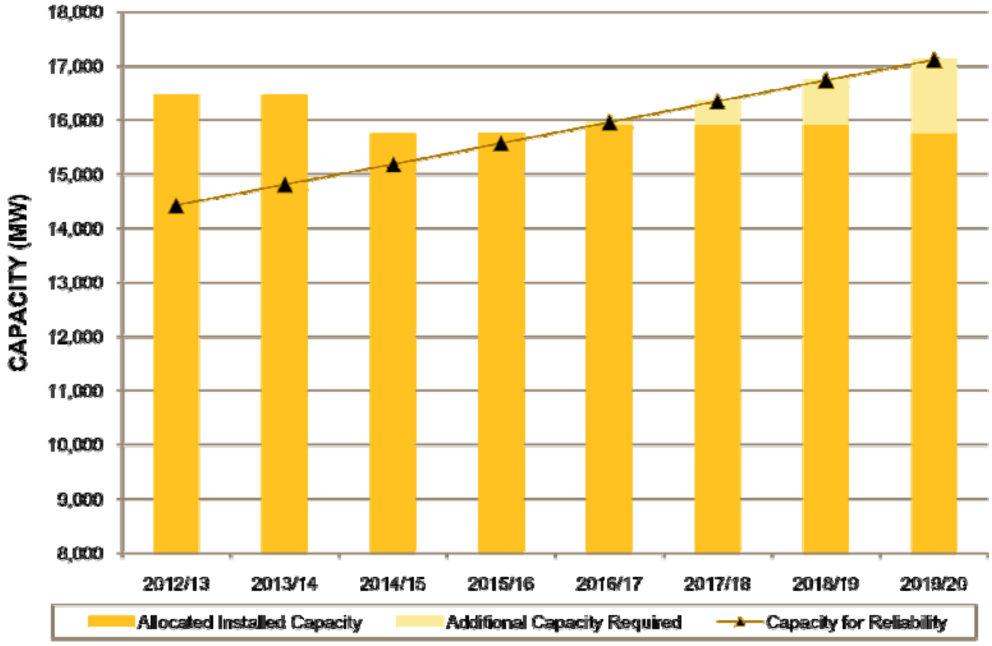
Under the medium growth scenario NSW currently has sufficient generation capacity to meet the State's projected peak electricity demand until 2016/17, at which point the projected deficit is 27 MW (Table 1), or 0.2 per cent of installed capacity in NSW. This projected (notional) "gap" in peak energy capacity occurs one year later than was predicted in last year's (2009) Electricity Statement of Opportunities, which was in turn one year later than the year before. Such a trend of continually pushing out the projected requirement date for new generation infrastructure is to be expected in a well functioning electricity market. Nevertheless, the projected gap in peak capacity quickly increases, to around 1,200-1,300 MW in 2020, as shown in Figure 8.

Table 1 - National supply-demand outlook, 2012/13-2019/20 (AEMO 2010)[37]

Region	Low economic growth		Medium economic growth		High economic growth	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
Queensland	2015/16	184	2013/14	726	2012/13	716
New South Wales	2017/18	91	2016/17	27	2016/17	285
Victoria	2017/18	135	2015/16[f]	249	2014/15	222
South Australia	2017/18	11	2015/16[f]	50	2012/13	85
Tasmania (summer)	>2019/20	N/A	>2019/20	N/A	>2019/20	N/A
Tasmania (winter)	>2020	N/A	>2020	N/A	>2020	N/A

[34] Arup, 2009, above n8.
[35] AeCom, 2009, above n9.
[36] Full report downloadable from: http://www.climatechange.gov.au/publications/energy-efficiency/report-prime-ministers-taskforce-energy-efficiency.aspx
[37] Table source: AEMO, 2010. *Electricity Statement of Opportunities*, Table 1, p.3.

Figure 8 - NSW summer supply-demand outlook for peak capacity (AEMO 2010)[38]



It is useful to provide a comparison to the scale of the City's Trigeneration Master Plan in relation to meeting peak electrical demand. If 80 per cent of installed trigeneration under the medium uptake scenario was considered to be "firm capacity" – that is, could be called upon when required to meet critical peak loads – this would provide an offset of approximately 170 MW in 2020, or 400 MW in 2030.[39] (Note that this is higher than the 360 MW installed capacity in 2030 as it also accounts for offsetting electrical air conditioning load using waste heat from trigeneration.)

It is apparent therefore that while the City's plans for trigeneration may be sufficient to meet a notional gap in NSW energy supply in tandem with new renewable generation under the RET in 2020, they are highly unlikely to be sufficient to meet the peak demand growth requirements for the entire state. However, if combined with additional energy efficiency and peak load management (or "Demand Side Response"), these resources could make a significant contribution to meeting NSW's current projected peak demand capacity shortfall.

It should be emphasised that these comparisons are for illustrative purposes only, in order to highlight the significant scale of the City's plans. There is, of course, no reason to suggest that the developments in the City of Sydney alone should be expected to meet the entire State's emerging energy needs. Nevertheless, these comparisons highlight the degree to which distributed energy options, even in one small geographic area, could contribute to meeting the community's future energy needs.

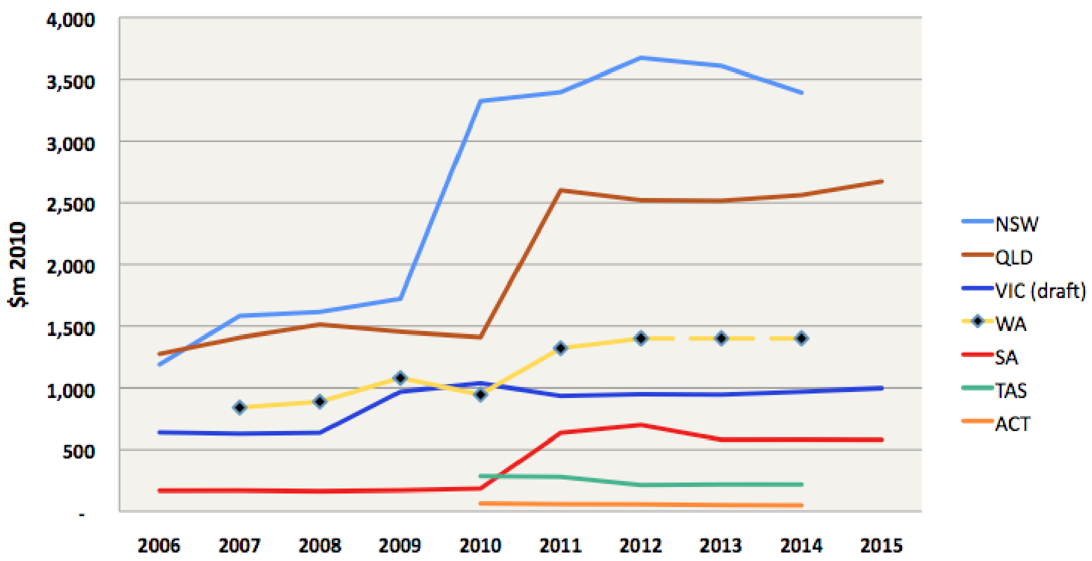
[38] Figure source: AEMO, 2010. *Electricity Statement of Opportunities*, Fig. 7-3 p.150.
[39] Based on modelling data from Kinesis, October 2010.

3. Network expenditure review & potential savings

Capital Expenditure on Electricity Networks

The network expenditure approved for investment in the City of Sydney's LGA is part of a larger and unprecedented nationwide trend of increasing capital expenditure on electricity network infrastructure for both transmission and distribution. This national growth trend is illustrated in Figure 9, which shows the regulator-approved network capital expenditure by jurisdiction. All of the major states shown demonstrate a significant jump in this expenditure from 2009-2010 onwards.[40] Over the period 2009-2015 this dramatic increase in investment totals more than $46 billion (in $2010), or more than $9 billion per annum. This level of expenditure is larger than that of the proposed National Broadband Network and occurs over a shorter period of time.

Figure 9 – Electricity Network Capital Expenditure (Transmission & Distribution) by Jurisdiction, 2006-2015[41]



Of this $46 billion, NSW accounts for $17.4 billion, or approximately 38 per cent of the total national expenditure. To place this value in context, $17.4 billion value represents:

- an 80 per cent increase on the previous five years;
- $2,400 per person in NSW; or
- $9.3 million per day.

Table 2 shows the breakdown of the $17.4 billion of approved spend for NSW by utility (converted to $2010) from 2010-2014.

[40] Where a dashed line is shown, this indicates a basic extrapolation by the authors, to better align the regulatory periods.
[41] Data sources: AER decisions and network business regulatory proposals (see sources for Table 2); Insufficient data available for Northern Territory.

Table 2 - NSW Final Approved Capital Expenditure by Electricity Network Businesses, 2010-14 (converted to $2010 millions)[42]

Utility	Type	2010	2011	2012	2013	2014	TOTAL
Energy Australia	Distribution	1,168	1,322	1,467	1,420	1,468	**6,846**
	Transmission	272	180	253	330	203	**1,238**
	Sub-total	1,440	1,502	1,720	1,751	1,671	**8,084**
Integral Energy	Distribution	589	638	568	517	495	**2,807**
Country Energy	Distribution	738	781	801	803	822	**3,946**
TransGrid	Transmission	557	476	585	537	404	**2,558**
TOTAL	**T&D**	**3,323**	**3,397**	**3,674**	**3,608**	**3,393**	**17,394**

The City's submission to the Australian Energy Regulator (AER), quoted figures from the AER Draft Determination, citing Energy Australia's plans for $7.38 billion capital expenditure for *distribution* infrastructure during the 2009-2014 regulatory period. The figures presented in Table 2 represent a reduction in allowed expenditure between AER's draft and final decisions of 8 per cent for Energy Australia, or 5 per cent for NSW as a whole.

Avoidable "Growth-Related" Investment

The key component of this figure is the proportion that is potentially avoidable through a different approach to electricity system planning. To estimate this sub-component of total network spend, it is necessary to define what is considered "avoidable". The three major drivers of electricity network investment are:

1. Replacing aging network infrastructure;
2. Growth in electricity demand at peak times due in large part to growth in the use of electrical services such as air conditioning; and
3. Increased reliability standards imposed by governments on electricity utilities (refer to box on next page entitled "What is the cost of an hour of power?").

It is the second (and perhaps to a lesser extent the third)[43] point that efforts to reduce electricity demand – particularly at peak times – can avoid investment in network infrastructure. ISF has defined avoidable network capital expenditure firstly as only the component of total approved capital expenditure that relates to the network (as opposed to other capital expenditure items such as vehicles and IT), and secondly only that network expenditure which is related to demand growth. Implicit in this definition is that reducing demand on existing electricity infrastructure will not yield any cost savings unless capacity constraints are observed and *new* infrastructure is avoided.[44]

[42] Data Sources: AER, above n17, Tables 7.16, 7.17 & 7.18; AER, *Transgrid Final Transmission determination 2009–10 to 2013–14* (28 April 2009), Table 2. An average annual inflation rate of 3.13% has been applied based on 2005-06 to 2008-09 Consumer Price Index Figures for the Weighted Avg of 8 Capital Cities (ABS, *Consumer Price Index*, December Quarter 2009, p.10).

[43] While the *driver* of this investment is not strictly "growth-related", it is considered avoidable in that reducing peak demand could prevent the new lower investment thresholds from being triggered.

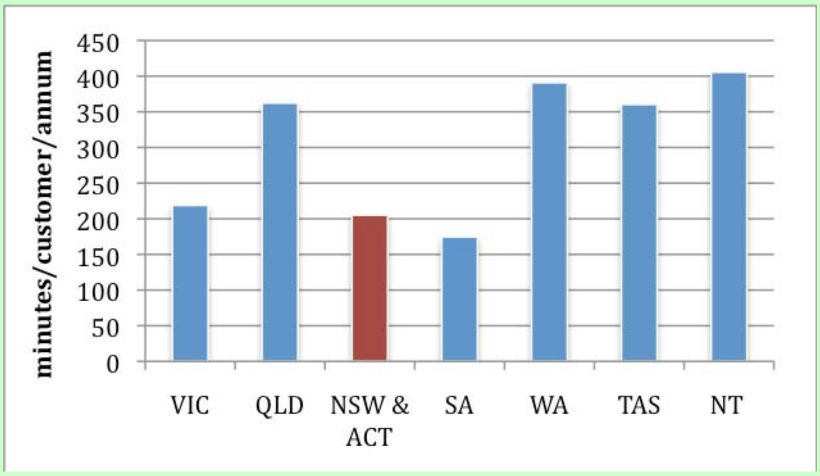
[44] Note it is generally considered that the replacement of ageing infrastructure cannot be classed as avoidable. It should be noted that reducing demand on energy infrastructure can be expected to extend the life of assets and therefore reduce the need to replace infrastructure. However, due to the difficulty in quantifying this impact, these cost savings have *not* been considered here.

What is the cost of an hour of power?

How much do electricity consumers value a 0.01 per cent improvement in reliability of electricity supply? The answer is implied by Government regulations and is perhaps in the order of several hundred million dollars. This figure reflects the often unrecognised cost of improving electricity reliability, which demonstrates rapidly increasing cost and rapidly diminishing returns on investment as the electricity system approaches 100 per cent reliability.

For the past 10 years the reliability of the NSW electricity system has remained around 99.97 per cent. To put this reliability level in perspective, in 2009 NSW had the second *best* electricity reliability of all States and Territories, behind only South Australia. This is illustrated in the SAIDI[45] outage figures shown in Figure 10 (noting that a lower figure represents less power outages per customer).

Figure 10 – SAIDI (power outages) by jurisdiction, 2009[46]



While NSW's average reliability level might sound impressive, very high reliability is appropriate, particularly in an area such as Sydney, a global city with a high concentration of high value adding businesses, government, hospitals, transport hubs, and telecommunications. Loss of electrical supply to the Sydney CBD, as occurred for over two hours in March 2009, can be extremely disruptive and expensive.

So while there can be no debate that high reliability is desirable, there can and should be debate about the means of ensuring this reliability and the cost of doing so.

The NSW State Plan contains a target to "achieve average electricity reliability for NSW of 99.98 per cent by 2016",[47] representing an improvement of 0.01 per cent

(continued on next page)

[45] System Average Interruption Duration Index (SAIDI)
[46] Data source: Energy Supply Association of Australia. 2010. *Electricity Gas Australia*. Table 1.4, p.8.
[47] NSW State Government, *NSW State Plan: Investing in a Better Future*, pp. 22, 65.

(continued from last page)

reliability. This translates to 30 per cent shorter total blackout periods during year, or around 53 minutes less blackout time per annum for the average customer. While the cost of achieving such an incremental improvement in *an unreliable electricity system* would be relatively small, the cost of raising reliability criteria by this level in NSW has significant implications for required works and associated energy prices. Amongst other requirements, this commitment requires Energy Australia to raise reliability criteria in the Sydney CBD from *'n-1' to 'n-2'* by 2014.[48] This new *n-2* criteria means that power must remain on even if the largest two power supply lines or transformers to the CBD fail at the same time (as opposed to one for *n-1*). Other areas are also required to upgrade from "*n*" to "*n-1*". Along with peak demand growth and replacement of aging infrastructure, this is one of the major drivers behind Energy Australia's record investment in the Sydney CBD electricity network, which is costing at least $800 million (in the form of the CityGrid project) or up to $2.2 billion when counting other projects in the Sydney east and inner city area.

Without detailed information and analysis, it is impossible to provide a precise estimate of how much meeting the higher reliability standards is costing. However, it is possible to make an indicative estimate based on some reasonable assumptions. Taking an average EA demand of about 3,200 MW and a cost of say $1 billion (13 per cent of EA's approved capital expenditure) to reduce outages by one hour per year, this equates to about $300,000 per MWh. If this investment were to ensure this improvement in reliability for say 10 years, then the cost of this reliability improvement is about $30,000 per MWh or $30/kWh. This is more than 150 times the current average cost of electricity of about $0.18/kWh.

This raises two obvious questions:

1. Are customers willing and able to pay 150 times the average price of power for an extra hour of reliable electricity supply each year?
2. Are there less expensive means of delivering an equivalent improvement in reliability (for example, a combination of local generation, energy efficiency and peak load management)?

While answering these questions is outside the scope of this report, they are crucial questions that need to be examined. In particular, it is crucial to understand better the potential and the costs of trigeneration, energy efficiency and load management in improving reliability of electricity supply and to compare this with network infrastructure solutions.

The AER determination breaks down network expenditure from other capital expenditure for each utility, and then generally reports the growth related component as either 'augmentations' or 'growth-related' expenditure. 'Augmentations' are driven by demand growth and are considered avoidable, by reducing consumption or locating "embedded generators" within the network close to the point of electricity

[48] EnergyAustralia, *EnergyAustralia Regulatory Proposal 2008*, p.36.

consumption. 'Growth-related' expenditure generally includes 'augmentations' *plus* the cost of new customer connections, which is generally not considered avoidable as this relates to providing new access to electricity (e.g. new meters and low voltage lines to premises).

The NSW AER determination primarily presents 'growth-related' capital expenditure and not the sub-category of augmentations, which is shown in Table 3 below.[49] For Energy Australia, new customer connections appear to account for around 16 per cent of growth-related capital expenditure,[50] while reported Integral Energy and TransGrid figures already exclude customer connections. Country Energy's customer metering costs appear to be less than 2 per cent of growth-related capital expenditure,[51] but there is insufficient information available to say conclusively.

Thus while the figures in Table 3 include slightly more than augmentations alone, there is additional planned capital expenditure to meet more stringent service requirements (classed separately as in the determination as 'reliability', 'service enhancement' or 'compliance obligations') that are considered avoidable similar to augmentations. These categories add up to an additional $2.5 billion over five years. Thus even if a small fraction of this category was avoidable this would outweigh the customer connections component discussed above, suggesting the figures shown in Table 3 are reasonably conservative.[52]

Table 3 – NSW growth-related network capital expenditure (converted to $2010), peak demand growth and calculated "Avoidable cost per MW"[53]

Network business	Avoidable "growth-related" capital expenditure ($m 2009-10)		Peak demand growth (MW)		Avoidable cost per MW	Notes
	5yr Reg. Period	Per annum	5yr Reg. Period	Per annum	($m/MW)	
Country Energy	$1,461	$292	323	81	$3.62	1
Energy Australia	$3,281	$656	689	172	$3.81	2
Integral Energy	$1,388	$278	643	161	$1.73	3
Distribution Total	$6,130	$1,226	1655	414	$3.05	
TransGrid (transmission)	$2,075	$415	1740	435	$0.95	4
Total	**$7,589**	**$1,518**			**$4.01**	5

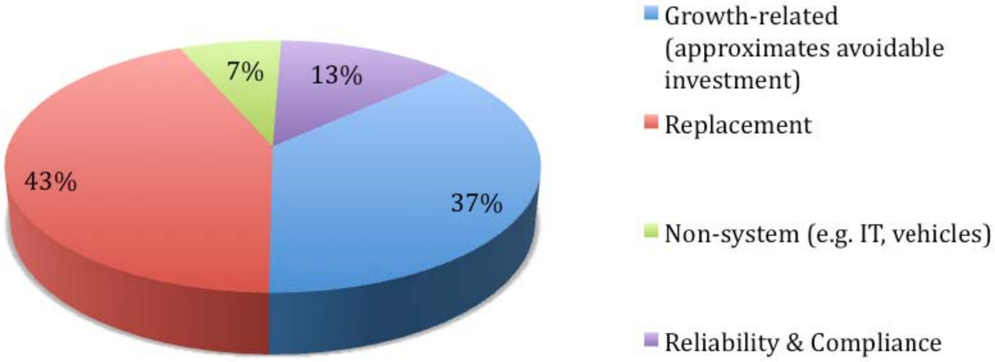
1. AER, NSW Draft distribution determination 2009–10 to 2013–14. p.135, p.85
2. AER, NSW Draft distribution determination 2009–10 to 2013–14, p. 136, p.88.
3. AER, NSW Draft distribution determination 2009–10 to 2013–14. p.137, p. 91. This figure does not include customer connections.
4. AER, Transgrid Draft Transmission determination 2009–10 to 2013–14, p. 16, p.34 (10% POE). This figure does not include customer connections.

[49] The draft determination was used for these figures as the breakdown of growth-related expenditure was not presented in the AER Final Determination.
[50] AER, New South Wales Draft distribution determination 2009–10 to 2013–14, p. 136.
[51] Country Energy's Regulatory Proposal 2009-2014, p.91.
[52] These figures also do not account for the potential to reduce planned investment in areas where network infrastructure is being retired and replaced with new equipment, by reducing the future load on the system in that location after replacement (i.e. replacement with smaller capacity equipment).
[53] Table adapted from: Jay Rutovitz & Chris Dunstan. 2009. *Meeting New South Wales Electricity Needs in a Carbon Constrained World*, Institute for Sustainable Futures, University of Technology, Sydney, p.21.

5. Peak demand cannot be totalled as Transgrid's peak load includes that of the distributors

As shown in Table 3, it is estimated that in **NSW there is up to $7.6 billion of approved network capital investment that is 'growth-related',** including $3.3 billion to be spent by Energy Australia. **Much of this new investment could potentially be deferred or avoided if peak demand growth was slowed through measures such as energy efficiency, peak load management and decentralised or local energy generation.** When this $7.6 billion growth-related capital spend is divided by the amount of peak demand growth driving this investment as shown in Table 3, this equates to an incremental avoided network cost of $4 million for each MW of growth in peak capacity avoided (i.e. $4 million per MW).

Figure 11 – Approximate breakdown of Energy Australia $8.1b network capital expenditure, 2010-2014[54]



As a strategically placed network of distributed generation (or energy efficiency) has the ability to reduce or eliminate growth in peak demand, it can thereby be utilised to delay or "defer" planned growth-related network investment. To determine the value of this contribution to the electricity network, we need to calculate the annual value of "deferral" of the construction of network infrastructure by one year. This was done using the following three steps:

- **Step 1:** take the "Avoidable cost per MW" of $4.0 million per MW (Table 3) and multiply this by the real weighted average cost of capital (WACC) of 6.31 per cent per annum.[55] This gives an annualised capital cost of $0.26 million per MW for each year of deferral achieved; then
- **Step 2:** Calculate the avoided cost of depreciation by assuming a uniform depreciation over a 40-year lifespan of network infrastructure (i.e. 2.5% per annum), yielding a figure of $0.10 million per MW per annum.
- **Step 3:** Add these two values together to give a total annualised cost of growth-related network investment of $0.36 million per MW per annum.[56] However, in recognition of the fact that network costs are location dependent,

[54] Data source: approximated from AER, above n50, Figure 7.4 and pp.135-7. Note that the Final Determination was not used as this did not break down expenditures to an adequate level of detail.
[55] 8.78% nominal WACC less 2.47% inflation from AER, above n17, p. 237.
[56] The WACC represents the opportunity cost of *not* investing capital in infrastructure, and depreciation is included as this is considered as an "avoided loss".

the analysis adopts a lower, more conservative value of **$0.3 million per MW per year** as the annual value of deferring network investment.

In other words, if distributed generators or energy efficiency service providers were allowed to "capture the value" of this deferred investment, it could be worth up to $0.3 million per MW per annum (or $300 per kW per annum). Where appropriate, there is a strong argument that this value of avoided network cost (or an appropriate portion of) should either be directly invested by network business in their own distributed energy assets, or be passed on to distributed energy service providers, allowing this value to be factored into the business case of these technologies.

Electricity network expenditure in the City's LGA

Of Energy Australia's total $8.1 billion planned capital expenditure (Table 2), a significant proportion is being invested in the Sydney CBD to meet load growth and enhanced reliability of supply requirements. The status and value of these projects, totalling approximately $2.2 billion, are shown in Table 4 below. Based on limited publicly available information it appears that approximately $0.5 billion of these funds have been spent or committed, and over $1.5 billion remains to be spent under the CityGrid project over the next decade.

According to Energy Australia's Managing Director, it is likely that *another* $8 billion of investment in its network will be required from 2014 to 2019,[57] similar to the $8.1 billion being invested from 2010-2014. This would essentially mean that the level of increases in network charges currently being felt by consumers are likely to continue for the remainder of the decade. Yet this assumes that the business-as-usual electricity demand growth continues, and thus reducing this growth through demand management (energy efficiency, distributed generation and load management) remains the only promising way to slow these price increases.

If we were to assume that just 10 per cent of the remaining $1.5 billion investment was deferrable through demand management, and given that Energy Australia assumes a summer peak growth of the CBD of around 15 MW per annum,[58] this equates to an incremental avoidable network work cost of $10 million per MW, or more than double the NSW average of $4 million per MW calculated earlier. Thus, even if a small fraction of this remaining $1.5 billion investment in the City's local government area is deferrable, then using the average NSW deferral value could be considered conservative. The NSW average figure is used later in this report to calculate avoidable network costs attributable to the City's trigeneration plans.

[57] Australian Financial Review, *EnergyAustralia has its own hefty bill to pay*, 1 September 2010.

[58] EnergyAustralia, 2008. *Sydney CityGrid Project Concept Environmental Assessment Report*, Vol 1, Section 2.4. Avail from http://www.energyaustralia.com.au/Common/Network-Supply-and-Services/Network-projects/Sydney-CBD-and-East/Sydney-CityGrid-Project/~/media/Files/Network/Network%20Projects/Sydney%20CBD/SCGvol1ch2.ashx

Table 4 – Energy Australia and TransGrid Projects Underway or Planned in (or servicing) the City's Local Government Area

<table>
<tr><th>Region</th><th>Project</th><th>Value ($m)</th><th>Driver</th><th>Timeframe</th><th>Deferral possibility</th><th>Summer pk growth rate</th></tr>
<tr><td rowspan="12">CBD</td><td>City North zone substation</td><td>83</td><td>Demand; Reliability</td><td>Completion end 2009</td><td>No (sunk)</td><td rowspan="12">11-15 MVA/yr</td></tr>
<tr><td>City West Cable Tunnel</td><td>180</td><td>Demand; Reliability</td><td>Completion end 2009</td><td>No (sunk)</td></tr>
<tr><td>Sydney CityGrid</td><td>~800</td><td>Demand; Reliability; Replacement</td><td>2008-2018</td><td>Varied</td></tr>
<tr><td>- Belmore Park zone substation</td><td>180</td><td>Demand; Reliability</td><td>Completion in 2012</td><td>Limited (committed)</td></tr>
<tr><td>- City East zone substation</td><td>22</td><td>Demand; Replacement</td><td>Completion mid 2010</td><td>Limited (committed)</td></tr>
<tr><td>- Surry Hills switching station</td><td rowspan="7">499</td><td rowspan="7">Demand; Reliability</td><td rowspan="7">No information</td><td rowspan="7">Some potential</td></tr>
<tr><td>- City South and Dalley Street substation upgrades</td></tr>
<tr><td>- City South Cable Tunnel extension</td></tr>
<tr><td>- 11kV network upgrades</td></tr>
<tr><td>- Rozelle to Pyrmont cable project</td></tr>
<tr><td>- Other components</td></tr>
<tr style="display:none"><td></td></tr>
<tr><td rowspan="4">Inner City</td><td>Camperdown zone substation Refurbishment</td><td>12</td><td>Demand; Replacement</td><td>2010-2012</td><td>Limited (committed)</td><td></td></tr>
<tr><td>Surry Hills subtransmission substation equipment replacement</td><td>5</td><td>Replacement</td><td>Planned for 2011</td><td>No (replacement)</td><td></td></tr>
<tr><td>Botany Bay Cable Project</td><td>110</td><td rowspan="2">Demand; Replacement</td><td>Completion late 2010</td><td>No (sunk)</td><td>100 MVA/yr</td></tr>
<tr><td>Other unaccounted for projects</td><td>1012</td><td>No information</td><td>No information</td><td>No information</td></tr>
<tr><td rowspan="2">Trans Grid</td><td>Beaconsfield West Substation Upgrade</td><td>144</td><td>Demand</td><td>Commence mid-2010</td><td>Some potential</td><td>37.5 MVA/yr</td></tr>
<tr><td>Sydney South Substation Upgrade</td><td>15</td><td>No information</td><td>No information</td><td>No information</td><td>No information</td></tr>
<tr><td>TOTAL</td><td></td><td>2261</td><td></td><td></td><td></td><td></td></tr>
</table>

Notes: Table constructed by ISF based on information on or inferred from http://www.energyaustralia.com.au/Common/Network-Supply-and-Services/Network-projects/Sydney-CBD-and-East.aspx and http://www.transgrid.com.au/projects/projects/Pages/default.aspx . Available information was limited and as such these figures are only intended to provide a broad estimation of the status of network projects in the City's LGA.

Potential network savings through trigeneration

The methodology for costing of network deferral value discussed above can be applied to the City's planned Trigeneration Master Plan, to compute the potential value of avoidable network investment. This does not reflect a cost benefit analysis from the network perspective as only the network *benefits* are represented here, while the *costs* associated with connecting distributed generators to the electricity network are not included.

Using the conservative value of $0.3 million per MW (or $300 per kW) developed above, Table 5 calculates the potential avoidable network cost per year of deferral in 50MW increments from 50 to 500MW.

Table 5 – Annual avoidable investment through trigeneration ($m p.a. for each year of deferral)

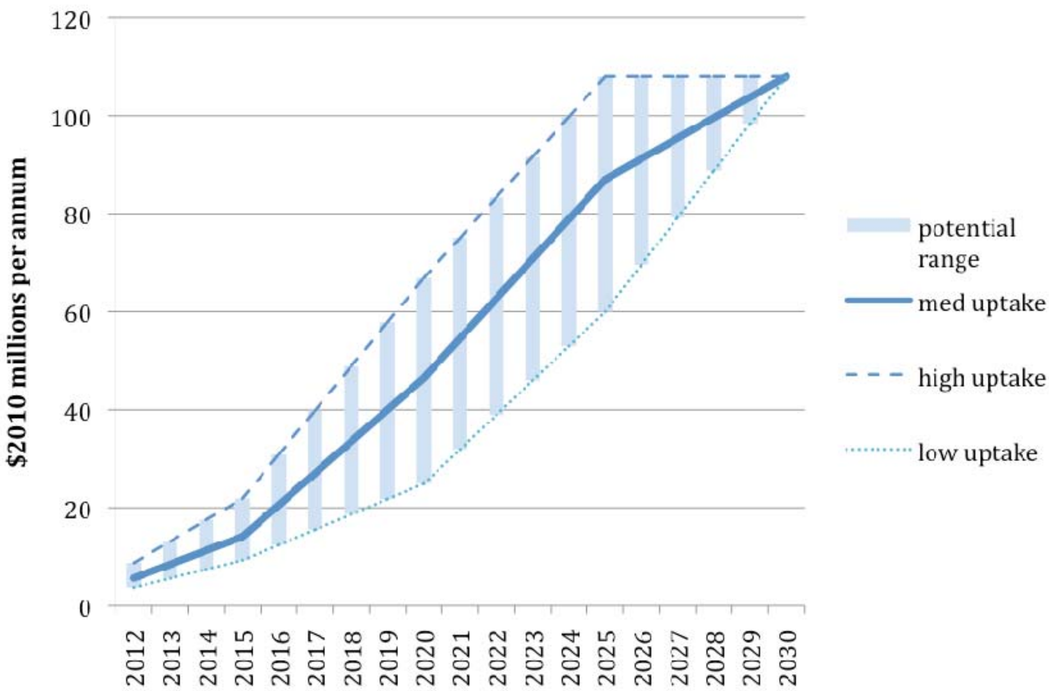
Trigen Capacity (MWe) [59]	Avoidable network investment ($2010 m p.a.)	Planned timeframe (med uptake)
50	15	2016
100	30	2018
150	45	2020
200	60	2023
250	75	2024
300	90	2026
350	105	2030
360	108	2030
400	120	-
450	135	-
500	150	-

Taking the information from Table 5 and applying it over the planned development timeframe of the City's low, medium and high trigeneration uptake scenarios then allows the visualisation of the annual avoided network cost that would be achieved through the City's trigeneration network, as shown in Figure 12. This is a value that the City (or private trigeneration operators) could argue should be contributed by the network operator for network support services. The dark blue line represents the medium trigeneration uptake scenario, which is bounded by the dashed low and high uptake scenarios.

In the year 2015 – the beginning of the next regulatory period – an installed trigeneration capacity of 47 MW (under the medium uptake scenario) would equate to an allocation for trigeneration-related network support services of $14 million.

[59] megawatts electrical

Figure 12 – *Annual* avoided network costs at different trigeneration uptake rates[60]



As shown in Table 6, increasing *annual* network deferral payments commensurate with installed trigeneration capacity would result in a *cumulative* total of $39 million in 2015 (medium uptake scenario), $207 million in 2020, or upwards of $1 billion by 2030.

Table 6 – Total potential allocation for trigeneration network support (cumulative $m 2010)

Year	Cumulative trigen capacity (MW)	Total allocation for network support ($m 2010) (medium trigen scenario)
2015	47	39
2020	155	207
2025	290	561
2030	360	1,059

Key peak periods for distributed generation

The peak demand in the Sydney Inner Metropolitan Area typically occurs on hot summer working weekdays between midday and 6pm, which includes the period from mid November to mid March, but excluding the holiday period from 24 December to mid January.[61]

[60] Based on trigen uptake data provided by the City of Sydney.
[61] *EnergyAustralia & TransGrid, Demand Management Investigation Report, Sydney Inner Metropolitan Area, November 2009, p.4;* TransGrid, *Request for Proposal Number: 105 /09, Non-Network Alternatives in the Sydney Inner Metropolitan Area, Technical and Commercial Requirements*, December 2009, p.16.

Energy Australia states that if demand management options such as trigeneration, load management, standby generation or energy efficiency are to be successful in relieving a network constraint and thereby defer network investment, they are required to be available on call on any given day during the aforementioned peak summer period to effectively reduce load on the system:

- for a maximum of *3.5 continuous hours* (this figure is for the first year of constraint – 2012/13 – and increases to a period of 6.5 hours by 2014/15).
- and for a maximum of *21 hours in total,* which would be spread across different days during the full summer period (this figure is also for 2012/13, and increases to a maximum period of 78 hours in 2014/15).[62]

These “maximum” figures above are given due to the unpredictable timing of peak demand and constraints on the electricity network, which generally occur on high temperature days when air conditioning demand is greatest.

In other words, if a trigeneration facility was to be paid for deferring a network investment, it could enter into contract with Energy Australia to supply power according to the conditions described above. From Energy Australia’s perspective the provider would thus only need to guarantee to operate for up to 21 hours in total across the summer of 2012/13. However, from a business perspective, for such a facility to be financially viable it would be more likely to operate for as many hours as possible.

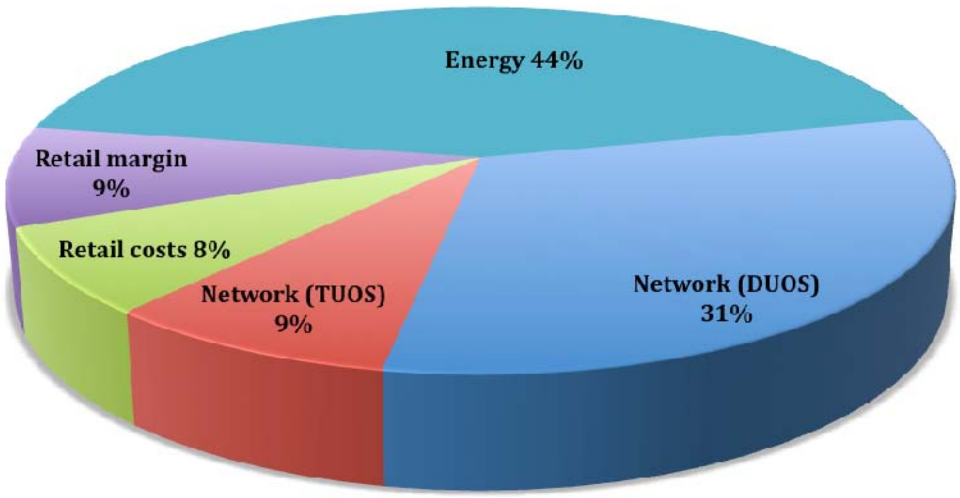
[62] TransGrid, above n61, p.17.

4. Impact of network expenditure on electricity prices

The AER determines how much network businesses are able to charge in order to recover the cost of spending on infrastructure and other expenses. In NSW, the Independent Pricing and Regulatory Tribunal (IPART) also currently sets regulated retail tariffs that incorporate these regulated network charges. Although the NSW Government (along with other Australian governments) has committed to phasing out retail electricity price regulation completely where "effective competition exists", in March 2010 the IPART issued its determination for the (optional) regulated retail electricity tariffs which will be in place for consumer protection until at least 2013.[63] This determination gives an indication of the breakdown of customer tariff components and outlines the price impacts of the AER's final determination for NSW.

Using IPART and AER data as a starting point, Figure 13 provides an indication of the breakdown of a typical low voltage customer tariff such as a household or small business. It suggests that transmission (TUOS) and distribution (DUOS) network charges make up around 40 per cent of each unit of electricity delivered to the customer, the actual energy component is 44 per cent and the remainder retails costs and profit margin. Note that the "capacity charge" component of network charges (charged per kilovolt ampere [kVA] of demand instead of per kilowatt hour [kWh] of energy used) is not explicitly shown in Figure 13. However, as an indication, these costs are in the order of 20 per cent of the total network charges for large business consumers, while residential customers using under 40 MWh/a are generally not subject to capacity charges.

Figure 13 – Indicative breakdown of typical household customer tariff in 2008-09 before the impact of the AER's Final Determination[64]



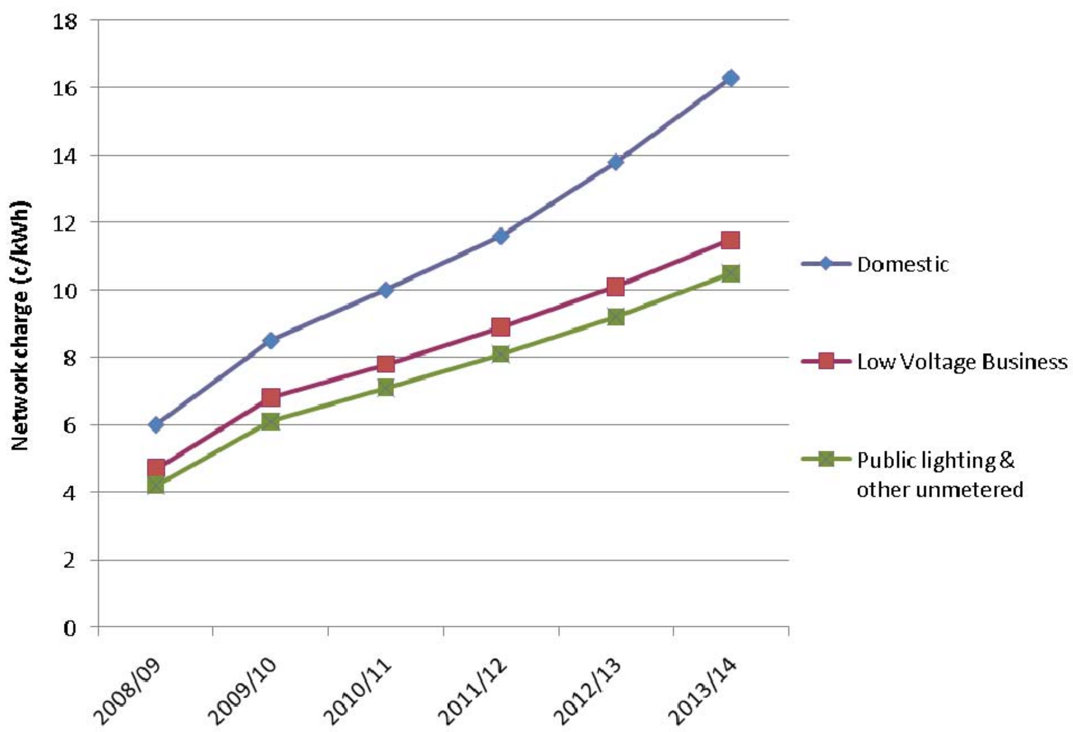
[63] IPART, *Review of regulated retail tariffs and charges for electricity 2010-2013, Electricity — Final Report*, March 2010.

[64] Data source: Modified from IPART, above n63. Effect of carbon price removed; DUOS/TUOS division added based on expected revenues of distribution vs. transmission businesses as found in AER Final Determinations (78/22 split); relative proportion of each component back-calculated to 2010 based on EnergyAustralia price component increases contained in IPART Table 1.1; and 18c/kWh rate assumed to approximate typical regulated low voltage customer tariff.

The AER's Final Determination results in a nominal increase in Energy Australia's average network charges (the navy and red components in Figure 13 above) of almost 100 per cent over the next five years and up to 172 per cent for domestic customers.[65]

Figure 14 provides an indication of the magnitude of increase of network charges. Transgrid's price path for its transmission charges is also following an upward trajectory, with 25 per cent increases over the same period.[66]

Figure 14 – Energy Australia Indicative Network Charges by Customer Type[67]



According to IPART, this increase in network charges (along with much smaller contributions in energy and retail components)[68] will result in average increases in the regulated Energy Australia retail tariffs of 22 per cent in 2009/10 and around 10-11 per cent per annum in subsequent years, as shown in Figure 15. While the IPART determination does not extend beyond 2012/13, the AER's 5-year determination suggests similar price increases of roughly 10-11 per cent would also occur in 2013/14, as indicated by the dashed lines shown in Figure 15. This increase would bring the total nominal rise in average Energy Australia electricity prices to around 83 per cent across the 5-year period of the AER determination, as shown by the red line.

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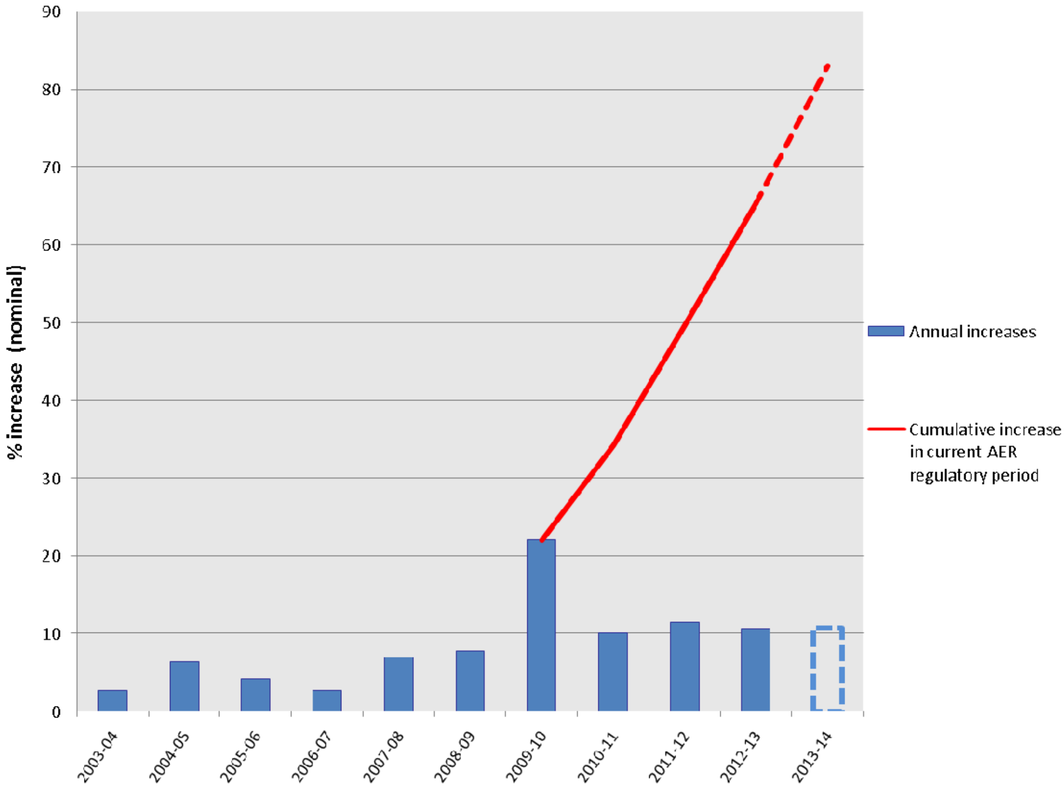
[65] AER Final Determination, p. xlviii

[66] AER, *TransGrid transmission determination 2009–10 to 2013–14*, 28 April 2009, p.125.

[67] Data source: EnergyAustralia, *Revised Regulatory Proposal and Interim Submission*, January 2009, p. 190.

[68] Increases in network charges account for 86% of EnergyAustralia price rises in the IPART 2010-13 determination (IPART, above n63, Table 1.2).

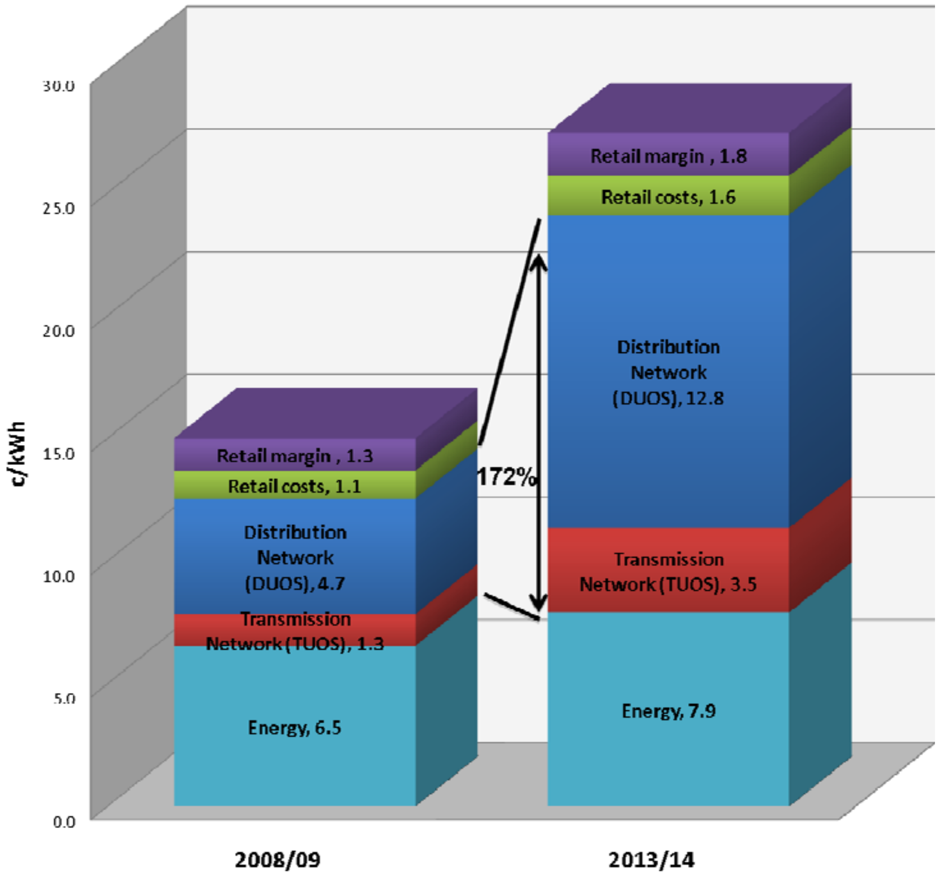
Figure 15 – Nominal increases in Energy Australia average regulated retail tariffs, 2003/04-2013/14[69] (dashed line indicates projection)



As a result of proportionally greater increases in network investment, in 2013/14 the proportion of consumer bills made up by network charges becomes far more significant, surging from 40 per cent to almost 60 per cent of the total average bill.[70] This impact is demonstrated in Figure 16 below, which shows the different components making up a typical residential household tariff in cents per kWh before and after the 5-year period relating to the AER determination. Note the relatively small increase in retail and energy costs, while network charges increase by 172 per cent and make up the vast majority of the 12.5c/kWh increase from 15c/kWh up to around 27.5c/kWh. (The numbers in Figure 16 represent the total 83 per cent cumulative nominal increase over the 5-year period flowing on from the AER's Final Determination shown in Figure 15.)

[69] Data source: IPART, above n5, p.167. 2013/14 is authors' simple projection of continued investment trend of preceding three years based on data from AER Final Determination, above n17, p.144.
[70] in the absence of a carbon price.

Figure 16 – Indicative breakdown of Energy Australia regulated household tariff in 2008/09 & 2013/14, showing significant increase in network charge components[71]



To show full extent effect of resulting from the AER Final Determination on consumer bills, we need to track prices for the full 5-year period of AER approved capital spending. That is, from 2008/09 before the price increases took effect, to the final year of the determination, 2013/14. To do this we extend the analysis in the IPART 2010 determination forward by one year to 2013/14 (in the same way as Figure 15 and Figure 16) and take account of the 22 per cent price increase from IPART's previous determination. This suggests that the nominal increase in electricity bills for a typical Energy Australia household customer consuming 5.6 MWh p.a. would increase by $760 p.a. by 2013/14, (from $916 to $1,677 p.a). For business customers consuming 20 MWh p.a. this would represent an increase of $3,022 p.a., (from $3,638 to $6,660), or if consuming 80 MWh p.a. would represent an increase of $13,225 p.a. from $15,918 to $29,143 p.a. Figure 17 and Figure 18 below illustrate these price increases by typical customer type.

[71] Data source: Modified based on data from IPART, above n63. Effect of carbon price removed; DUOS/TUOS division added based on expected revenues of distribution vs. transmission businesses as found in AER Final Determinations (78/22 split); relative proportion of each component back-calculated to 2008/09 based on EnergyAustralia price component increases contained in IPART Table 1.2 adjusted for 6c/kWh network charge in 2008/09 (EnergyAustralia, above n67, p. 190); 15c/kWh rate assumed to approximate typical 2008-09 residential tariff.

Figure 17 - Indicative annual bills for typical Energy Australia residential customers in 2008-09 & 2013-14 ($nominal, incl. GST)[72]

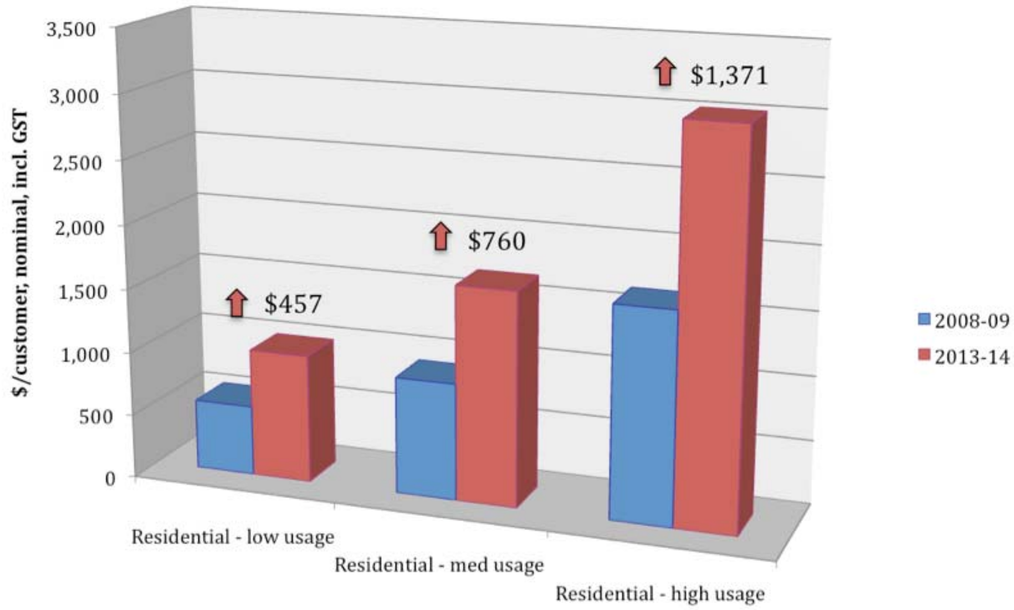
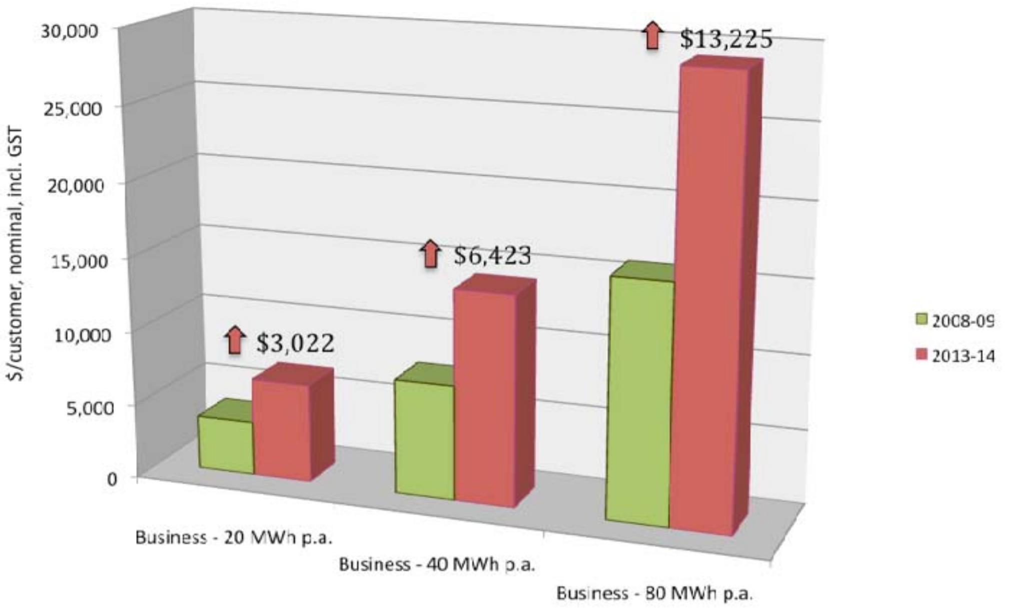


Figure 18 - Indicative annual bills for typical Energy Australia business customers in 2008-09 & 2013-14 ($nominal, incl. GST)[72]



[72] Data source: Modified from IPART, above n63, Table 11.4, p.172 (2008-09 back calculated from 2009-10 using stated 22% increase; 2013-14 projected from 2012-13 applying average annual increase of 10.67%).

5. Required regulatory changes & the role of the City

Engaging with regulatory reform is an essential component in fulfilling the City of Sydney's vision for a greener, more climate-friendly, more resilient and more self-sufficient energy future.

The City has joined other stakeholders in advocating for regulatory reform to encourage networks to support alternatives to network investment, such as decentralised generation, energy efficiency and peak load management (collectively described as "non-network alternatives" or "demand management"- DM). Regulators and policy makers have recognised and responded to this advocacy through measures such as:

The Australian Energy Regulator (AER) has established a Demand Management Incentive Scheme (DMIS) in NSW, albeit it small at $2 million per annum in addition to retaining the Demand Management Factor (D-Factor), which aims to counter regulatory disincentives to DM.

The AER has stated that DM should occur wherever it is economically efficient.

The AER has stated that investment in DM is permitted *in advance of* network capacity constraints occurring.

The AER has acknowledged that the transparency and reporting processes to ensure efficient DM is adopted are currently inadequate and has indicated that it intends to improve them through Regulatory Information Orders.

The AER has recognised that the absence of specific targets or policy objectives for DM has reduced its capacity to encourage investment in DM (particularly in comparison to other policy objectives for which specific standards have been established, such as for improved reliability).

- The Australian Energy Market Commission (AEMC) has made a series of recommendations (through its proposed national framework for electricity distribution network planning) to improve processes for distribution network business to support non-network alternatives such as trigeneration and demand management generally[73]. These recommendations include:
    - Stipulating a national annual reporting process on network planning to improve consistency;
    - Requiring distributors to develop a Demand Side Engagement Strategy; and
    - Developing a Regulatory Investment Test for Distribution (RIT-D) process which aims to facilitate efficient DM.

[73] AEMC, Review of National Framework for Electricity Distribution Network Planning and Expansion Sept 2009

http://www.aemc.gov.au/Market-Reviews/Completed/Review-of-National-Framework-for-Electricity-Distribution-Network-Planning-and-Expansion.html

The Ministerial Council on Energy (MCE) has endorsed the AEMC's recommendations and requested that the AEMC proceed to institute them as part of the National Electricity Rules.[74]

However, this regulatory reform has been modest and has yet to achieve a major increase in the adoption of DM in NSW. To achieve this, it is crucial that the City of Sydney, and other advocates for demand management and distributed energy continue to push for faster and wider reform of the electricity sector. Some of these areas of reform are outlined briefly below.

It should also be recognised that where network businesses face strong regulatory, governance and business capacity incentives to continue business as usual, simply removing barriers to DM may not be sufficient to stimulate rapid adoption of cost effective DM.

AER related reform

1. Form of Regulation

The form of price regulation for NSW electricity distribution networks for the period July 2014 to June 2019 is due to be decided by the AER by June 2012. This review process is therefore likely to begin within 12 months. The current "weighted average price cap" form of regulation rewards the distributors if consumers use more electricity from the main grid and penalises distributor if consumers use less electricity. It therefore is a significant barrier to the adoption of trigeneration and energy efficiency.

2. Monitoring and Reporting of DM performance

There is currently no consistent and comprehensive reporting of DM performance including outcomes, cost and benefits. The AER has undertaken to address this through a Regulatory Information Order (which as of October 2010 had yet to be developed). Follow through on this by the AER is important.

3. Assessment of potential for and relative economic efficiency of DM proposals

To date the AER has not effectively considered the potential scope for or relative cost effectiveness of DM in the context on network proposed expenditure. It is crucial that this shortcoming be addressed well in advance of the next regulatory determination (2015-2019).

[74] Ministerial Council on Energy Standing Committee of Officials - Bulletin No. 184, MCE Response: AEMC Review of a National Framework for Electricity Distribution Network Planning and Expansion 8 Oct 2010 http://www.ret.gov.au/Documents/mce/_documents/2010%20bulletins/Bulletin%20No.%20184%20-%20MCE%20Response%20to%20AEMC%20Review%20Oct%202010.pdf

Other regulatory and policy reform

4. Putting a price on carbon

The uncertainty and inefficiency created by the absence of an effective and adequate national market price on greenhouse gas emissions is now very widely appreciated. The NSW Government has created a modest price on carbon through the innovative Greenhouse Gas Abatement Scheme (GGAS). A higher, more cost reflective carbon price is essential to provide a level playing field for trigeneration, demand management (DM) and other clean energy options. However, the transition to a fully cost reflective carbon price is likely to take many years. Until this occurs other regulatory and policy mechanism will be required to compensate for this distortion.

5. Setting a DM target (and measuring progress against it)

The Prime Minister's Task Group on Energy Efficiency has recognised the importance of targets in driving a national "step change" in energy efficiency.[75] The AER has also noted that the absence of policy or regulatory targets for DM have limited its capacity to encourage DM.

Such targets need not be legislated but must be backed by clear government commitment. DM targets can be mandatory and based on the "stick" of penalties for non-compliance, voluntary and based on the "carrot" of incentives, or some combination of the two. It is crucial to recognise that DM can deliver benefits not just to consumers and for the environment, but also enhance the operational and financial performance of the distributors themselves. Incentives to assist the distributors to identify, capture and highlight these benefits of DM, could be very effective in stimulating greater adoption of DM. In order to accelerate the adoption of DM and to demonstrate clearly its commitment to meeting DM targets, Government could offer additional financial incentives to distributors that perform well in approaching such targets. Such an approach may be described as a "collaborative target" that lies somewhere between the extremes of "voluntary" and "mandatory" targets.

A good example of setting targets in this context is the approach adopted in Ontario, Canada. Through its "Energy Conservation and Demand Management Program" which sets overall targets of peak demand reduction of 1,330 MW and energy savings of 6,000 GWh per annum between 2011 and 2014.[76] The individual targets for each distributor will be developed in consultation with the distributors themselves.
The Queensland "Energy Conservation and Demand Management Program" described below also includes specific DM performance targets[77].

[75] Australian Government, 'Report of the Prime Ministers Task Group on Energy Efficiency, July 2010, www.climatechange.gov.au/~/media/submissions/pm-taskforce/report-prime-minister-task-group-energy-efficiency.ashx

[76] Ontario Executive Council, *Decree No. 437/2010* March 2010, http://www.powerauthority.on.ca/Storage/118/16586_minister_directive_20100423.pdf

[77] Queensland Government, *ClimateQ: toward a greener Queensland Fact Sheet Energy Conservation and Demand Management Program*, 2009. http://www.climatechange.qld.gov.au/pdf/factsheets/1energy-b1.pdf

6. Establish a DM Fund

Until the above reforms are fully implemented, a dedicated fund to support DM and Trigeneration can be an effective tool. Such a fund must be secure, well targeted and managed, extend over a period of at least several years and include transparent performance reporting. Such a fund should be made available to as wide a range of parties as possible, including distribution businesses, and be allocated on the basis of expected and actual performance and cost effectiveness in delivering DM.

There are many precedents for such a fund both in Australia and overseas. For example, the State Electricity Commission of Victoria's $55 million three-year Demand Management Action Plan announced in December 1989 (SECV, 1991), remains one of Australia's biggest DM programs.

The $200 million NSW Energy Savings Fund was established in 2005 with an explicit focus on DM, partly in response the 2002 IPART *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services***.** The primary recommendation of this inquiry was the establishment of a "Demand Management Fund" (IPART 2002). However, the DM focus of the Energy Savings Fund has since been blurred with its merging into the Climate Change Fund.

More recently, in its 2009/10 State Budget, the Queensland Government committed to provide $47.7 million to its two distribution network businesses, Ergon Energy and Energex "to initiate a range of energy conservation and demand management measures designed to reduce peak electricity demand in Queensland" (Queensland Government, 2009a). This *Energy Conservation and Demand Management Program* was planned to cease after 2009-10 when it is expected that the measures are to be continued by the distributors as part of their regulated activities (Queensland Government, 2009b). The AER subsequently included proposed DM expenditure of about $221 million by Energex and Ergon Energy as part of its regulatory determination for the period 2010/11 - 2014/15[78],[79]. This represents the largest commitment to DM in Australia to date.

Beyond this, the AER has also made modest provisions for some DM with the continuation of the "D-Factor" scheme in NSW, and the "DM Innovation Allowances" (DMIAs) established in NSW & ACT ($11.5 million over five years),[80] South Australia ($3 million over five years),[81] Queensland ($10 million over five

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[78] Australian Energy Regulator, *Queensland distribution determination 2010–11 to 2014–15 Final decision*. May 2010, p. 292 http://www.aer.gov.au/content/item.phtml?itemId=736403&nodeId=371a320444f322cb7b9e3f01d8212690&fn=Queensland%20distribution%20decision.pdf

[79] Energex, *Regulatory Proposal for the period July 2010 – June 2015*, July 2009, http://www.aer.gov.au/content/item.phtml?itemId=729492&nodeId=d389e8d1cfd43fe80a60287c29bc209c&fn=Energex's%20Regulatory%20Proposal%202010-15.pdf

[80] Australian Energy Regulator, *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations: Demand management innovation allowance scheme*, November 2008, http://www.aer.gov.au/content/item.phtml?itemId=723848&nodeId=73bf57627acf693dd91c48caa4d70b0a&fn=Guideline%20-%20Replacement%20DMIA%20for%20ACT-NSW%20(28%20November%202008).pdf

[81] Australian Energy Regulator, S*outh Australia distribution determination 2010–11 to 2014–15 Final decision* May 2010 http://www.aer.gov.au/content/item.phtml?itemId=736345&nodeId=3554008b804b9019e53df0ac3f8b2313&fn=South%20Australian%20decision.pdf

years),[82] and proposed for Victoria ($10 million over five years).[83] Western Australia has also established a D-Factor mechanism.

However, the scale of such funds in Australia remains relatively small. In total, the aggregated level of annual expenditure on DM is likely to represent significantly less than 1 per cent of total annual expenditure on electricity supply in Australia.

[82] Australian Energy Regulator, *Queensland distribution determination 2010–11 to 2014–15 Final decision.* May 2010, p. 292 http://www.aer.gov.au/content/item.phtml?itemId=736403&nodeId=371a320444f322cb7b9e3f01d8212690&fn=Queensland%20distribution%20decision.pdf

[83] Australian Energy Regulator (AER 2010c), *Victorian electricity distribution network service providers Distribution determination 2011 - 2015 Draft Decision,* June 2010 http://www.aer.gov.au/content/item.phtml?itemId=736991&nodeId=1822051ac603ac047389b47cc147e492&fn=Victorian%20distribution%20draft%20decision%202011-2015.pdf

Appendix:

AER response to City of Sydney's Regulatory Proposals

The Australian Energy Regulator (AER) is responsible for regulating electricity network charges, including reviewing the prudence of networks' proposed capital expenditure. In its submission dated 16 February 2009, based on the Institute for Sustainable Futures' research, the City made some overarching and ten specific recommendations to the AER for consideration in its Final Determination for network price regulation for NSW and ACT for the period 2009/10 to 2013/14.[84] The AER response to each of the City's proposals is summarised in Table 7, followed by a brief summary of each recommendation, the full wording of the AER response and a brief comment.

Table 7 – AER Responses to City of Sydney recommendations in its Final Determination[85]

City's Recommendation		AER Response
General	Facilitate major investment in demand management (DM)	Under current environment, investment in DM should occur wherever it is economically efficient; Demand Management Innovation Allowance (DMIA) in Draft Decision is sufficient DM incentive.
1	Explicitly encourage distributors to invest in cost effective DM	Networks are already required to consider DM & DNSP's have operational independence to best manage their network spending
2	Report on greenhouse emissions implications	Outside AER responsibility
3	Support open, competitive transparent processes	AER is developing Regulatory Information Order (RIO).[86] See also 5 below.
4	Set targets for demand management outcomes	Beyond AER responsibilities (but have advocated to NSW Govt)
5	Require reporting on DM	DMIA and D–factor schemes already require DNSPs to report on the outcomes of DM projects, but may be improved though RIO being developed.
6	Allow early investment in demand management	This is allowed.
7	Assess DM potential	AER will consider more general discussion and engagement; see also AEMC Review.
8	Remove barriers for re-assigning customers to tariff classes, esp. with respect to Time-of-Use tariffs	Current wording does not create barriers.

[84] Recommendation 11 related to other SSROC raise issues regarding public lighting.
[85] AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14,* 28 April 2009.
[86] As of October 2010 this process was not yet complete (AER pers comm., email, 12 October 2010).

City's Recommendation		AER Response
9	Ensure distributed generators receive full benefit of avoided TUOS and distributors are not disadvantaged in this process	Not explicitly addressed.
10	Report on the full network & retail price implications of its determination	AER does not make judgements on the overall 'reasonableness' of prices that result from its decisions.

General recommendation – Facilitate major investment in demand management

AER Responses: "The AER is an economic regulator, limited in its role to applying and enforcing the NER. The NER provides some scope for the AER to develop and apply incentives for DNSPs to consider demand management, however only where demand management is the most economically efficient response to a network constraint" (p.262)

"The AER considers that the allowance provided under the DMIA will provide a sufficient incentive for each DNSP to further develop their demand management initiatives and capabilities over the next regulatory control period." (p.258)

"In determining the appropriate amount of capex and opex for each of the NSW DNSPs over the next regulatory control period, the AER has considered the extent that the NSW DNSPs have considered and made provision for, efficient non-network alternatives, as required by clauses 6.5.6(e)(10) and 6.5.7(e)(10) of the transitional chapter 6 rules." (p.263)

Comment: Essentially the AER suggests that it is only empowered to require utilities to investigate DM where it is economically efficient, which it believes already occurs under the current regulatory environment. Further, it restated that it ruled that the allowable value of direct support published in the draft decision ($1m p.a. for Energy Australia) was sufficient. Hence no further support for DM can be seen in the Final decision relative to the Draft decision. This is a disappointing response, which equates to the suggestion that the current arrangement for DM is performing adequately.

Recommendation 1. Explicitly encourage distributors to invest in cost effective DM

AER Response: "The NER [already] requires that DNSPs consider alternatives to network augmentation, including demand management, when determining potential responses to network constraints…AER's approval of capex and opex does not limit a DNSP's operational independence to best manage their network, including in making decisions to trade network augmentation for efficient demand management." (p.264-5)

Comment: This suggests that the AER sees its role as not to *encourage* demand management *per se*, but to ensure that it occurs where it is economically efficient. The AER considers this objective to be met by Chapter 6 of NER.

Recommendation 2. Report on Greenhouse emissions implications

AER Response: "While it takes into account the policy environment in which its decisions are made, including environmental policies and debates, the NER requires that the AER creates incentives for the DNSPs to make economically efficient business decisions, rather than decisions which preference environmentally efficient outcomes." (p.262)

Comment: The AER sees greenhouse reporting as external to its mandate and a matter for other parts of government. Its role, as stated in the NER, is strictly to deliver economically efficient outcomes. There is thus scope through a Rule Change Proposal to broaden the mandate of the AER.

Recommendation 3. Support open, competitive transparent processes

AER Responses: "the AER is currently developing a [Regulatory Information Order] RIO for DNSPs, which is proposed to include public reporting on demand management programs and expenditures" (p.265)

"The AER is in the process of developing regulatory information notices (RINs) for the NSW DNSPs to report on their incentive schemes (such as demand management) for 2009-10. Following collection of the regulatory information, the AER expects to be in a position to develop a report that publishes relevant regulatory information/performance for the NSW DNSPs. For regulatory reporting arrangements from 2010-11 onwards, the AER expects to issue RINs to the DNSPs to collect the regulatory information (accounts and schemes)."[87]

Comment: There is hope that the RIO being developed by the AER will require better information disclosure and attention to DM issues by utilities.

Recommendation 4. Set targets for demand management outcomes

AER Responses: "The AER has previously considered the differences between its role and the role of the California Public Utilities Commission in relation to demand management.[88] The recommendations made by the City of Sydney in relation to California refer to broader policy decisions which go beyond the AER's responsibilities in respect of applying chapter 6 of the NER to the NSW DNSPs." (p.265)

Comment: This issue is perceived by the AER to be outside its responsibilities, however the AER has advocated to the NSW Government in support of this concept.[89]

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[87] AER, pers comm., email, 12 October 2010.

[88] The AER also stated in relation to the issue of target setting similar to California, that it has previously considered the differences between its role and the role of the California Public Utilities Commission in relation to demand management in the documents AER, *Explanatory statement and proposed demand management incentive scheme to apply to Energex, Ergon Energy and ETSA Utilities over the 2010–15 regulatory control period*, June 2008, pp. 19-20 and AER, *Final decision—demand management incentive scheme—Energex, Ergon Energy and ETSA Utilities, 2010–15,* October 2008, p. 16.

[89] AER, pers. comm. 2009.

Recommendation 5. Require reporting on DM

AER Responses: "The AER's DMIS for NSW DNSPs, consisting of the DMIA and D-factor schemes, requires DNSPs to report on the outcomes of demand management projects in order to be eligible for demand management cost recovery under those schemes." (p.264). See also comment under Recommendation 3 on RIO development above.

Comment: The AER suggests that there is a level of reporting on DM already required, but indicates that this may be improved in future through the RIO.

Recommendation 6. Allow early investment in demand management

AER Response: This was responded to directly in the Final Determination but the implication of the existing arrangements is that there is no restriction on when utilities invest in demand management.

Comment: While in principle there may be no regulatory impediment, there is anecdotal evidence that distribution businesses are reluctant to invest in DM early in advance of network constraints due to concerns that such expenditure may be deemed imprudent by the AER. Further clarification and dialogue between distributors, the AER and DM service providers on this issue would be valuable.

Recommendation 7. Assess DM Potential

AER Response: This was not specifically responded to in the Final Determination. However, during a meeting between ISF and the AER it was noted that the AER would consider more general discussion and engagement on this issue.

Comment: There was some level of acknowledgement that there is a need to a make a high level assessment of where DM could be efficiently adopted for the purposes of cross-referencing the effectiveness of the current regulatory environment around DM.

Recommendation 8. Remove barriers for re-assigning customers to tariff classes, especially with respect to Time-of-Use (TOU) tariffs

AER Response: "Section 5 of the AER's proposed procedures set out in appendix A of the draft decision was not intended to apply a restriction on the circumstances in which a reassignment can take place. The AER considers that it is not necessary to make any changes to the section because the language of the section does not impose any limits, or state that it sets out the only circumstances, in which a reassignment can occur." (p.23)

Comment: The AER reviewed draft wording in response to this comment and considered that it does not impose such restrictions.

Recommendation 9. Ensure distributed generators receive full benefit of avoided TUOS and distributors are not disadvantaged in this process

AER Response: This issue was not addressed.

Recommendation 10. Report on the full network & retail price implications of its determination

AER Response: "Regarding the comments…on the various other issues affecting users' energy costs, the AER does not have any explicit powers to consider or make judgements on the overall 'reasonableness' of prices that result from its decision, nor to make associated adjustments to regulated revenues. The AER has assessed each element of the NSW DNSPs' regulatory proposals and revised regulatory proposals without any preconceived notion of what might be regarded as acceptable price increases." (p.310)

Comment: The AER believes that this issue is beyond the scope of AER's final decision. This represents a flaw in the current system, as once the AER makes this decision, State based regulators such as NSW's Independent Pricing and Regulatory Tribunal (IPART) whose job *does* involve determining reasonableness, have no power to overturn or amend a decision made by the AER. This is an issue (in addition to environmental considerations) on which the City could campaign for amendment to the scope of AER's mandate.

Summary

In summary, the AER Final Determination document contains little in the way of direct support for demand management outside the elements of the Demand Management Incentive Scheme (DMIS).

The biggest concern is that the general position of the AER in response to the City's requests is that the AER believes that the framework for promoting economically efficient DM is *already in place*. This is despite the fact that mandated investigations of DM seldom actually result in DM being undertaken,[90] and there is no systematic mechanism to assess the overall effectiveness of the regulatory framework. If the regulatory framework is assumed to function effectively, then this would suggest that there is in fact very little to no cost-effective DM that can be used to defer or avoid network capital expenditure. This is contrary to international experience such as that of California, and local research findings by ISF and others.[91] This could represent either or both a failure of procedural enforcement of effective undertaking of DM studies by networks, or an issue associated with the design of the assessment process itself, such as inadequate lead time of assessments to deliver DM of sufficient scale to avoid large network investment.

Nonetheless, there are also positive elements that can be drawn from the AER's Final Determination, which include:

1. That network businesses, such as Energy Australia, may choose how to spend its revenue and does not have to spend it all on network expansion. Any savings made through DM are retained by the network businesses, giving some incentive to act;

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[90] In only 5 out of 80 cases where DM has been considered to address network constraints has a project been authorised. See http://www.energyaustralia.com.au/Common/Network-Supply-and-Services/Demand-Management/Program-progress-tracking.aspx

[91] See for example, Langham, E., Dunstan, C., Walgenwitz, G., Denvir, P., Lederwasch, A., and Landler, J. 2010, *Reduced Infrastructure Costs from Improving Building Energy Efficiency*. Prepared for the Department of Climate Change and Energy Efficiency by the Institute for Sustainable Futures, University of Technology Sydney and Energetics.

2. That network businesses can recover both DM program costs and forgone revenue through the continuation of the “D Factor” mechanism; and
3. The $1 million per annum Demand Management Innovation Scheme (DMIS) to support less proven DM approaches.