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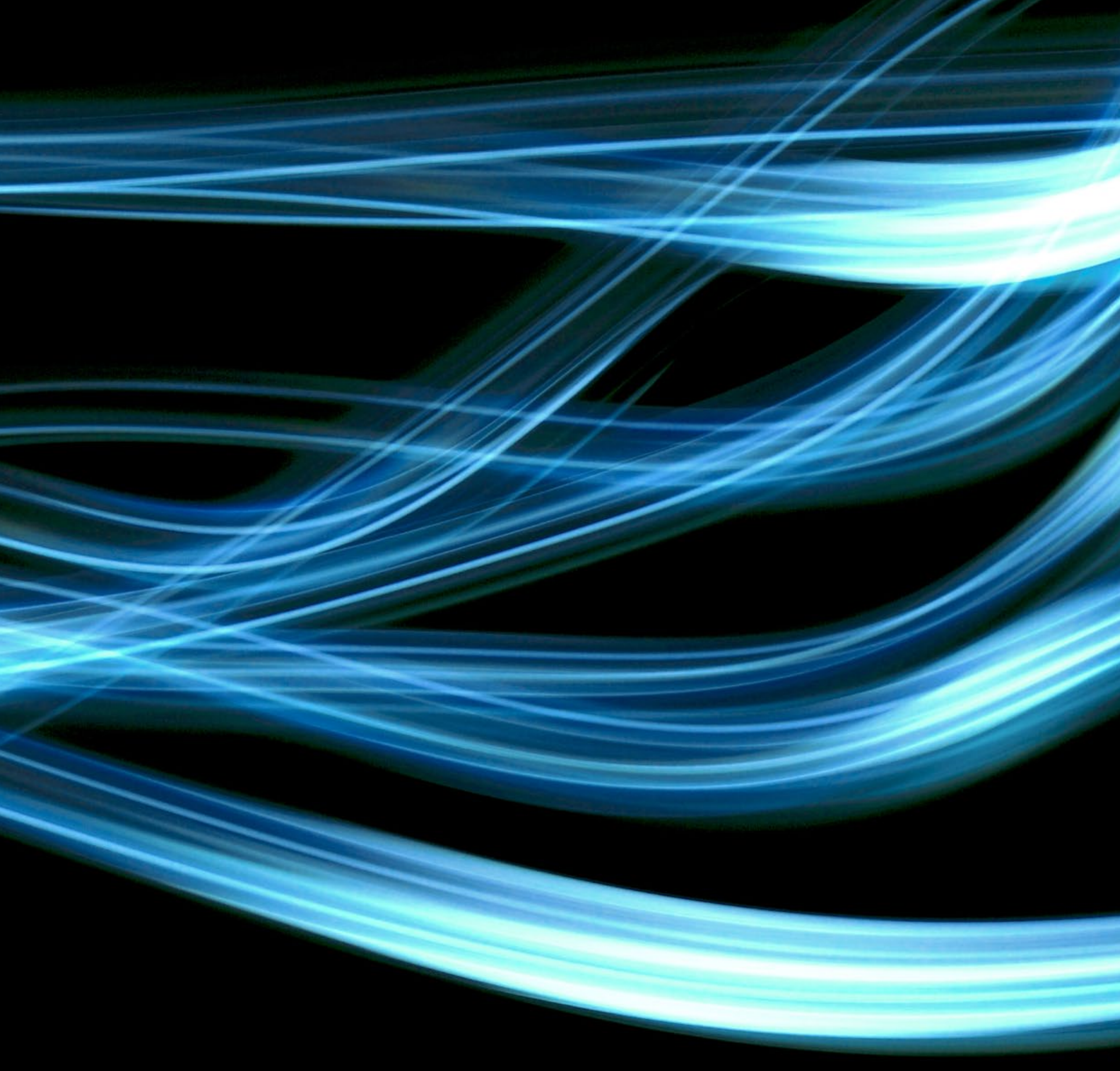
Change and choice

The Future Grid Forum's analysis of Australia's potential electricity pathways to 2050



ACKNOWLEDGEMENTS

The Future Grid Forum was jointly funded by the electricity industry participants. The Future Grid Forum extends its special thanks to platinum sponsors GE and CSIRO and gold sponsors Ausgrid and Grid Australia.

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Foreword

Australia's electricity system is at a significant crossroads. Historically high retail electricity prices, widespread deployment of solar panels, greenhouse gas emissions abatement, and declining aggregate peak demand and consumption in most states are some of the major issues that have put it at this crossroads, and there are several potential future directions. Each direction has far-reaching implications for the future electricity supply chain and would alter the electricity model in this country. While many of these challenges also confront electricity supply in other parts of the world, Australia has its own set of unique strengths and vulnerabilities around which it will need to tailor effective solutions.

Recognising the extraordinary circumstances of this time in the electricity sector's history, in 2012 CSIRO convened the Future Grid Forum, unique in composition (bringing together more than 120 representatives of every segment of the electricity industry, as well as government and community) and in approach (undertaking extensive whole-of-system quantitative modelling and customer social dimensions research to support its deliberations and findings).

Many studies and reviews have evaluated the drivers of change now affecting the electricity system, but most have focused on specific parts of the system or been from the perspective of particular stakeholders. Australia's electricity sector recognised that the system cannot be analysed and optimised by only examining its separate parts. A whole-of-system evaluation was essential.

Although there are many areas where the Future Grid Forum reached a high level of agreement, this report should not be interpreted as a consensus statement. Rather, it is a summary of the Forum's journey and its key conclusions. Our intent is to help inform public discussion and policy settings around the challenges and opportunities Australia will face in managing electricity needs to 2050.

Future Grid Forum participants
December 2013

Participants

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Executive summary

The electricity system is central to Australia's modern lifestyle and economy. It has served the nation very well and will continue to do so for some time, but it is now facing complex and unprecedented challenges. These challenges have the power to affect all links in the electricity supply chain and to encourage new market structures, actors, and business models to emerge. The future is likely to look vastly different from today.

The Future Grid Forum explored these challenges and extensively modelled four scenarios to ask these important questions:

- What might Australia's electricity system look like in 2050?
- What are the issues and options that might arise along the way?
- What can the electricity sector and its stakeholders do to most effectively plan and respond?

The Future Grid Forum offers its findings and invites a national conversation to decide the right answers for the sector, its stakeholders and, most importantly, all Australians.

What might Australia's electricity system look like in 2050?

Many drivers of future change already exist. Some events explored in the Forum's scenarios are a reaction to or an extrapolation of recent issues and developments in the electricity sector:

Electricity bills have risen	Since 2007 the average household electricity price has increased by two-thirds, from around 15 cents per kilowatt hour to over 25 cents per kilowatt hour in 2012. Reduced consumption and rising incomes for some consumers moderated the impact of this price increase on electricity bills; nevertheless, the scale of these price increases has represented a 'price shock' to Australian consumers. The causes are complex, various and differ by state, but investment in the electricity distribution system for asset replacement and refurbishment as well as compliance with reliability licence conditions and capacity to meet growing demand played the largest role. The carbon price and various state feed-in tariffs have also contributed.
Peak demand and consumption have reversed trend in most states since 2008–09	Coinciding with the 'price shock' in the market, peak demand and consumption both reversed trend and declined in most Australian states. Energy conservation, on-site generation (solar photovoltaic), weather conditions (La Nina), and industry evolution (growth of services businesses over manufacturing) drove this decline and the future trend in consumption and peak demand is now highly uncertain.
There is an oversupply of generation capacity	Decreasing consumption, past investments in coal and gas generation assets and, more recently, deployment of wind power (as the main renewable generation platform under the Renewable Energy Target) have led to an oversupply of generation capacity in the wholesale market. This economic reality has led to some generation capacity being mothballed or retired early and this comes at a cost to the owners of those assets.
Residential electricity prices are not well aligned with the costs of services	Given the prevalence of volume-based pricing, most residential consumers do not receive cost-reflective pricing signals from the electricity system. Residential consumers are engaging more with their electricity supply (as the adoption of on-site generation and energy efficiency indicates), but they remain unaware of the impact of peak power use on electricity system costs and have limited incentive to act to address it.
Australia's electricity supply has started to decarbonise, but a substantial task remains	Greenhouse gas emissions from electricity generation in Australia peaked in 2008 at 208 million tonnes of carbon dioxide equivalent, but had fallen by 8 per cent to 191 million tonnes of carbon dioxide equivalent by December 2012. Yet the electricity sector remains the largest single source of Australian emissions, and substantial further decarbonisation is required over coming decades if Australia is to contribute its fair share to the global greenhouse gas abatement task.
There is uncertainty around carbon policy in Australian politics	While Australia has a bipartisan greenhouse gas abatement target of a 5–15 per cent reduction on 2000 levels by 2020 (or a 25 per cent reduction if there is stronger international action), there is ongoing disagreement on the appropriate policy mechanisms to deliver these targets and on longer-term reduction targets. Given the long life of electricity system assets and the scale of greenhouse gas emissions from the electricity sector, this uncertainty presents a significant investment risk and has flow-on impacts to consumers.
Attitudes towards electricity system reliability and its cost are shifting	While reliability has become more important over time as Australia's lifestyle and industry have come to depend more on electricity, the contribution to the recent electricity price rises of infrastructure spending to meet reliability standards led many to question whether reliability standards are now set too high or too prescriptively in some jurisdictions.

Against this backdrop, the Forum believes Australia's electricity landscape will change significantly in the decades to 2050, and the greatest changes are likely to come from:

- **'megashifts'** brought on by the advent of low-cost electricity storage, sustained low demand for centrally-supplied electricity, and the need for significant greenhouse gas abatement
- **consumer choice** as an outcome of potential new business models, a greater degree of cost-reflectivity in pricing, and a higher overall level of consumer engagement.

Fuel prices, any carbon and energy policies and their specific targets and mechanisms, changes in the costs of other technologies, and any adaptation to a changing climate will also create significant uncertainties for the system.

If the electricity sector is to effectively plan and respond to these changes, it is important for it to fully understand how all of this might play out. But in exploring and presenting possibilities through its scenarios, the Forum notes:

- The actual future might include elements of each of the scenarios.
- For each scenario, every segment of the electricity supply chain would be affected differently.
- There is no future scenario that is universally advantageous to all stakeholders.
- The Forum does not endorse any particular scenario as being the most likely or the most desirable.

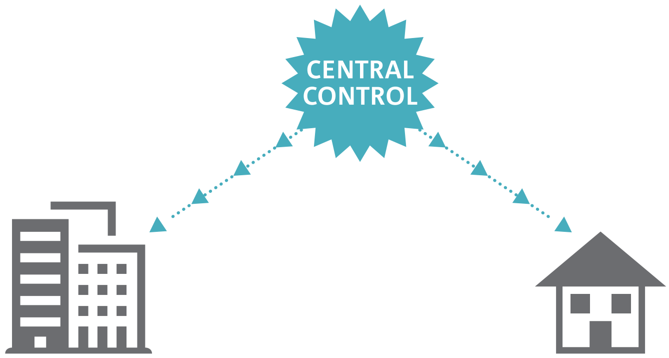
THE FUTURE GRID FORUM'S FUTURE SCENARIOS AND THEIR POTENTIAL IMPACTS ON THE SUPPLY CHAIN

Scenario 1: 'Set and forget'

Sustained high retail prices, heightened awareness about the issue of peak demand, and new business opportunities lead residential, commercial and industrial customers to adopt peak demand management.

But, recognising the busy lives of many customers, the demand management systems are designed to be on a 'set and forget' basis after customers have decided which level of demand management suits them.

Measures include building large-appliance control (air-conditioning, pumps), on-site storage, specialised industrial demand reduction markets, and electric vehicle charge management, as well as advanced metering and communication to enable these services.



Scenario 2: 'Rise of the prosumer'

Continued falling costs of solar photovoltaic panels and other on-site generation technologies, sustained high retail prices, and increasingly innovative financing and product packaging from energy services companies leads to the widespread adoption of on-site generation.

Residential consumers in particular are empowered by their choice to become more actively engaged in their electricity supply and call themselves 'prosumers'. Electric vehicle adoption is also popular.

The use of on-site generation is also strong in commercial and industrial customer sectors, but with a stronger preference for cogeneration or trigeneration technologies. By 2050, on-site generation supplies almost half of all consumption.

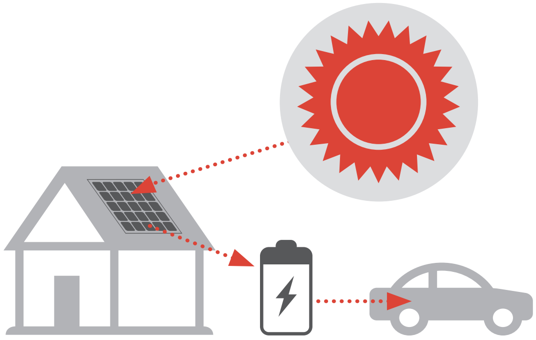
Customer-centric model
where customers consume, trade, generate and store electricity.

Scenario 3: 'Leaving the grid'

The continued dominance of volume-based pricing among residential and small commercial consumers encourages energy efficiency without accompanying reductions in peak demand growth. The subsequent declining network utilisation feeds increases in retail prices.

New energy service companies sensing a market opportunity invite consumers to leave the grid, offering an initially higher-cost solution but one that appeals to a sense of independence from the grid. Consumers have already become comfortable using small amounts of storage on-site and in their vehicles and a trickle of consumers takes up the offer.

By the late 2030s, with reduced storage costs, disconnection becomes a mainstream option and the rate of disconnection accelerates. Customers remaining on the system are those with poor access to capital and industrial customers whose loads can't be easily accommodated by on-site generation.



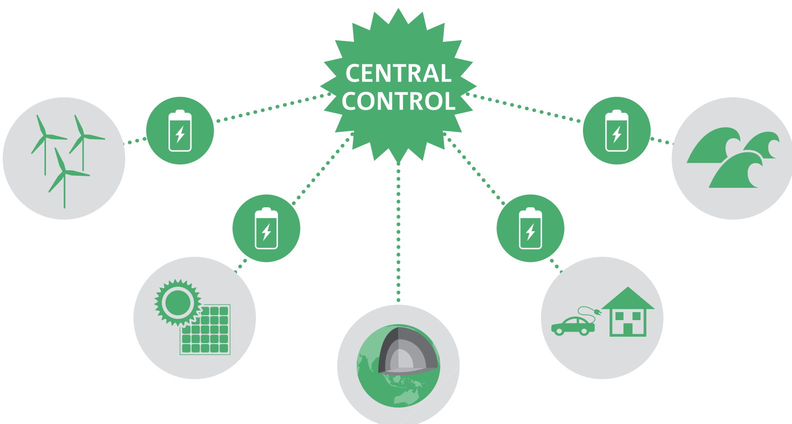
Scenario 4: 'Renewables thrive'

Confidence in the improving costs of renewable technologies, achieved by combined efforts from government and industry around the world, results in the introduction of a linearly phased 100 per cent renewable target by 2050 for *centralised* electricity generation.

To shift demand and meet renewable supply gaps, storage technology is enabled to achieve the target at utility, network and consumer sites.

Some customers maintain on-site back-up power (for example, diesel) for remote and uninterruptible power applications, offsetting their emissions by purchasing credits from other sectors, such as carbon forestry.

Overall, the renewable share, taken as a share of both centralised and on-site generation, is 86 per cent by 2050.



SUMMARY OF SUPPLY CHAIN SEGMENT IMPACTS BY SCENARIO

STAKEHOLDER	Scenario 1: 'Set and forget'	Scenario 2: 'Rise of the prosumer'	Scenario 3: 'Leaving the grid'	Scenario 4: 'Renewables on tap'
Residential consumer	◔	◕	●	◑
Commercial or industrial customer	◔	◕	●	◑
Retailer	◔	◕	●	◑
Distribution	◑	◕	●	◕
Transmission	◑	◕	◕	◕
Generation and transmission system operators	◑	◕	◕	●
Energy service companies	◔	●	●	◕
Metering services	◑	●	◕	●
Centralised generator – coal	◕	●	●	●
Centralised generator – gas	●	●	●	◔
Centralised generator – renewable	◔	◑	◑	●
On-site generators	◔	◕	●	◑
Storage technology providers	◑	◕	●	●
Electric vehicle providers	◑	◕	◕	●
Information and communication technology	◔	◕	◑	◑

KEY:

◔ = Modest change, manageable within existing structures and business models

◑ = Significant change; some new activities emerge but within existing structures

◕ = Substantial change where new business models and market structures are required

● = Vastly different from today; most existing activities and business models completely change

What are the issues and options that might arise along the way?

From the Forum's modelling, it became clear that Australia's electricity system will face significant issues during the decades to 2050 and each of these issues will bring its own challenges, risks and barriers. While the electricity sector cannot fully predict or control any changes these issues would bring—and the scale of the electricity system and its investments mean these changes could take decades to address—it could position the electricity market so that it is better able to respond and transition effectively.

The major issues identified through the Forum's modelling and some options for addressing them are presented here. These options are intended only to set out broad principles for consideration. Ongoing conversations among all stakeholders will be necessary to achieve detailed understanding and consensus within the Australian community. The options are not mutually exclusive; given it is not possible to predict which scenario events will occur and in what combination, the options could be combined or implemented in parallel.

THE FUTURE GRID FORUM'S SUMMARY OF MAJOR ISSUES AND OPTIONS FOR ADDRESSING THEM

ISSUE	CHALLENGES
Investment in new generation	Wholesale electricity generation prices are projected to remain below that which would be required to build new plant and recover a reasonable return on investment until the early 2020s. Wholesale prices need to increase from around $40/MWh (4 c/kWh) in 2013 (excluding the carbon price) to around $70/MWh (7 c/kWh)[1] (excluding any future carbon price or equivalent mechanism) to be viable for new plant.
Managing peak demand	Limiting growth in peak demand is projected to save 2 c/kWh each year on the costs of electricity distribution between 2020 and 2050. Peak demand has declined recently in some states and its future rate of growth is uncertain. If peak demand growth recovers in the future, it may contribute to declining network utilisation.
Increased on-site generation	On-site generation is projected to reach 18–45 per cent of total generation by 2050. This leads to a decline in network utilisation that is not driven by a lack of effort in managing peak demand, but rather a shift in the source of electricity generation from the grid to the user.
Disconnection from the grid	Disconnecting from the grid as a residential consumer is projected to be economically viable from around 2030 to 2040 when independent power systems are expected to be able to match retail prices of 35–40 c/kWh as battery costs fall. Current costs of disconnecting are estimated at 92–118 c/kWh (around four times 2013 retail prices).
Rising residential electricity bills, but stable as a share of income	As a result of increasing whole-of-system costs, by 2030 residential electricity bills are projected to be 2–9 per cent above 2013 levels. Some vulnerable residential consumers, for whom electricity is a large component of their overall expenses, could experience some hardship. However, the combined effect of adoption of energy efficiency, on-site generation, and general wages growth means, for the average wage earner, the electricity share of income is projected to be slightly lower than 2013 in 2030 and return to similar levels by 2050 (between 9 per cent below, and 14 per cent above, 2013 across the scenario range).

1 All prices and their percentage changes are in real terms.

RISKS AND BARRIERS	OPTIONS FOR MANAGING THE CURRENT TRANSITION
Investment may be slow to respond when new plant is needed after a long period of low prices.	**Government** Maintain existing generation market arrangements which will allow the wholesale electricity prices to rise once the market supply and demand balance tightens and in response to carbon policy. **Australian Energy Market Operator** Continue to monitor generation capacity needs and continuously improve demand forecasting to support its annual *Electricity statement of opportunities* report.
The majority of small commercial and residential consumers remain on volume-based price contracts, have limited knowledge of alternative options, and do not have access to more sophisticated metering. Therefore, there is limited infrastructure, knowledge or incentives to reduce peak demand at present in these states. Several peak demand reduction actions have already been highlighted in existing reviews, such as *Power of choice*. Reform is challenging in a multi-jurisdictional policy environment.	**Government and regulators** Remove remaining barriers to introducing cost-reflective pricing in the small commercial and residential sector so that consumers can receive the correct signal for the cost of peak power use. Accelerate the task of evaluating and implementing other appropriate responses to encourage peak demand reduction from existing reviews. **All stakeholders** Raise consumer awareness about the benefits of peak demand reduction and cost-reflective pricing. If adoption of cost-reflective tariffs is not widespread, then the system benefits may be minimal.
If on-site generation and demand response technologies reach a significant share, the model of regulating networks as monopoly suppliers of reliable electricity might require a different approach.	**Regulators** Encourage network businesses to investigate alternative network development and asset management strategies, including market transparency. Planning will need to be flexible to changes in future use and mitigate the potential for future reductions in network utilisation while maintaining agreed levels of performance. **Government** Establish processes to identify the changes, if any, that might be required to market frameworks in light of this issue and other megashifts examined in this report.
If there is a significant share of disconnected customers, this would challenge existing business models. The cost of small-scale generation and storage technologies are critical, but future cost projections are uncertain.	**Industry** Innovate to provide optimal business models for on-site generation and system operation. **Government** Consider how and where to apportion relevant costs. Expand the Australian Energy Technology Assessment process to include small-scale generation and storage technologies.
Some low peak demand-to-consumption ratio households may be cross-subsidising high peak demand-to-consumption ratio households under current tariff structures. Retail unit costs (expressed in cents per kilowatt hour) may be less relevant over time as a measure of expected costs due to use of on-site generation, energy-efficiency opportunities, alternative tariffs, and wages growth.	**Government** Review electricity bill assistance for low-income and vulnerable customers, including the state-based energy concession schemes. Move to greater retail deregulation to support efficient price signals for electricity system investment (for suppliers and consumers alike) and reduce the degree of consumer cross-subsidisation. Ensure market structures facilitate cost-effective energy efficiency adoption. **Residential consumers** Review any new tariff structures and government support schemes to minimise electricity bills. Manage both peak demand and consumption to offset any unit cost increases.

ISSUE	CHALLENGES
Large commercial and industrial customers' electricity costs	As a result of their relatively strong exposure to costs of generation, which are projected to increase to achieve greenhouse gas emission reduction (see next point), large commercial and industrial customers are expected to experience an increase in electricity bills, primarily after 2020. By 2030, large commercial customers who adopt energy-efficiency measures are projected to limit the increase in their electricity bills to 1.1–2.2 per cent a year. Industrial customers (assuming no change in electricity efficiency) could face an increase in electricity bills of 1.6–3.0 per cent a year to 2030 across the scenario range.
Electricity sector emissions	Across the scenarios, the electricity sector is projected to achieve greenhouse gas emission reduction of 55–89 per cent below 2000 levels by 2050. This is reasonably consistent with the currently legislated national greenhouse gas emission reduction target of 80 per cent below 2000 levels by 2050. To achieve this emission reduction, wholesale electricity unit costs increase from approximately \$60/MWh in 2013 to between \$113/MWh (11.3 c/kWh) and \$176/MWh (17.6 c/kWh) in 2050. Against this cost, the benefits of avoided climate change were not estimated (however, see 'Climate change adaptation' below).
Carbon policy uncertainty	The wholesale electricity price is projected to be 17 per cent (\$24/MWh or 2.4 c/kWh) higher by 2050 if long-term carbon policy uncertainty is not resolved.
Climate change adaptation	Where the risk of climate change results in networks building to a higher probability of extreme peak demand events, then unit electricity costs are projected to be 2.8 c/kWh higher on average each year between 2025 and 2050. Impacts of extreme weather generally and costs of other electricity sector climate change adaptations were not estimated, but are also very relevant.
Increasing natural gas prices	Wholesale electricity prices are projected to be \$11/MWh (1.1 c/kWh) higher and greenhouse gas emissions 34 per cent higher by 2050 relative to Scenario 1 if there is a higher rate of growth in gas prices.
The role of nuclear power	Wholesale electricity prices are projected to be \$34/MWh (4 c/kWh) lower and greenhouse gas emissions 72 per cent lower by 2050 relative to Scenario 1 if nuclear power is included in the electricity generation mix.

RISKS AND BARRIERS	OPTIONS FOR MANAGING THE CURRENT TRANSITION
The manufacturing sector (comprising food, beverages, textiles, wood, paper, printing, petroleum and chemical products, iron and steel, and non-ferrous metals, such as aluminium) is the most exposed to increasing electricity prices in its costs of production. Australian industries are competing against countries that have different greenhouse gas reduction policies.	**Government** Review arrangements to support the competitiveness of Australian export-exposed energy-intensive industries. Ensure market structures facilitate cost-effective energy efficiency adoption. **Commercial and industrial customers** Implement cost-effective peak demand and consumption management opportunities to offset any unit cost increases.
The cost of flexible generation (such as gas), various types of storage, or demand management to support the variable output of some renewables will be an important determinant of costs of abatement.	**Government** Continue to support programs for assessing, researching, developing and demonstrating low-emission electricity generation technologies.
Uncertain carbon policy means that plant investment is delayed and is dominated by a narrower range of electricity plant types which are able to partially mitigate against carbon policy risks to projected rates of return.	**Government** Develop bipartisan carbon policy relating to the targets for each decade to 2050 and the policy mechanisms that will be implemented to achieve them. (While not specifically modelled, similar investment risks and policy remedies apply to the Renewable Energy Target.)
The electricity sector is particularly vulnerable to changes in climate because climate affects every aspect of its operation, from the efficiency of generation and transmission through to the profile of demand.	**Industry and regulators** To support efficient investment choices, develop consistent guidelines and methodologies for estimating the impact of changes in the climate on the electricity system. Implement and periodically review adaptation plans. **Government** Continue to work with the global community, through international agreements for greenhouse gas emission reduction, to reduce the risk of climate change impacts.
Under the BREE (2012) cost assumptions, gas combined cycle (that is, baseload) plants are one of the lowest-cost forms of electricity generation. Further, gas peaking plants may play an important role in supporting variable renewables.	**Government** Although markets and costs of production will determine prices, governments can continue to support efficient and transparent markets for gas exploration, production, generation, trade and consumption. Expand the Australian Energy Technology Assessment process to include large-scale storage technologies, which are a potential substitute for gas in supporting variable renewable generation.
The BREE (2012) cost assumptions, on which this projection is based, do not include decommissioning. There would be considerable delay (assumed to be after 2025 in this study) before nuclear plant could contribute to electricity generation in Australia because of long construction times, skill shortages, and necessary development of regulations and policy changes. Non-cost factors are important in technology adoption. Nuclear power consistently rates at the lower end of the scale of social acceptance relative to other electricity generation technologies (for example, Ashworth et al 2012).	**Industry and government** Continue to monitor and evaluate the social acceptability of nuclear power and other barriers to its uptake not explored in this report.

What can the electricity sector and its stakeholders do to most effectively plan and respond?

Many of the options the Forum offers in this summary table are not new, but rather support existing processes or market arrangements. However, the Forum believes that mechanisms to accelerate these processes should be investigated given that electricity markets have shown the tendency to undergo major and rapid shifts that are able to outpace the reform processes' ability to implement change. In addition, the Forum suggests expanding the scope of the Australian Energy Technology Assessment to include on-site generation and storage technologies because of their potential to shape the future of the electricity system.

Of the options presented in the summary table, there are four that are not already established but could be considered as potential approaches to addressing the issues identified in the scenarios:

1. Implement a sustained long-term program to increase consumer awareness of the benefits and mechanisms of cost-reflective pricing and demand management.
2. Develop bipartisan agreement on the long-term (2050) greenhouse gas emission target and implementation mechanism for Australia.
3. Review Australia's electricity consumer social safety net.
4. Establish processes to identify the changes, if any, that might be required to market frameworks in light of the megashifts examined in this report.

EVALUATING OUTCOMES

The Forum developed a framework of five key performance indicators for evaluating electricity sector outcomes for Australia, based on the recognition that how much any of these issues and their outcomes matters is directly linked to how much value people place on them. This framework helped to focus the Forum's deliberations and could be a useful tool for other electricity sector analysis in future.

SUMMARY OF THE FUTURE GRID FORUM'S PROPOSED KEY PERFORMANCE INDICATORS

KEY PERFORMANCE INDICATOR	DEFINITION
Whole-of-system cost	*The total cost of electricity consumed by end-users, inclusive of generation, distribution, transmission, retail and any on-site costs that the end-user incurs, in order to obtain the desired services that electricity enables*
Reliability	*The extent to which the supply and quality of electricity is maintained at a given level*
Greenhouse gas emissions	*Emissions from the electricity sector contributing to climate change*
Service and price customisation	*The degree to which customers can access an electricity contract that matches the electricity supply and other services they need and want, and the degree to which the price they pay for this contract matches the actual cost the services impose on the system*
Resilience	*The ability of the electricity system to recover from and adapt to shocks such as those from technological, market, social, and environmental changes*

The Forum recognises that while each of these key performance indicators is desirable, they do not perfectly align and this makes setting goals and objectives for the electricity system challenging. Trade-offs among potential outcomes will be necessary. The Forum did not seek to determine the best trade off of the key performance indicators, but rather to highlight these trade-offs and potential alternative outcomes under different future scenarios.

The conversation must continue

The Future Grid Forum believes the nation has to continue this crucial conversation about the future of electricity in Australia. It presents its findings as a starting point so that the electricity industry, its stakeholders, and the community can fully understand, manage, and benefit from the many changes and choices now emerging.

The companion report, *Modelling the Future Grid Forum scenarios*, presents the quantitative modelling of the Future Grid Forum's scenarios and sensitivity cases.


h.
Go Green

Section 1: Future Grid Forum principles, processes and scenarios

The Future Grid Forum examined the future of electricity in Australia across all links in the electricity supply chain, and discussed and (where possible) agreed on the existing and emerging issues facing the system. From there, the Forum formulated some options for transitioning the electricity system through the period of great change to 2050. The Forum hopes that sharing its findings will inform and inspire an ongoing conversation about Australia's energy future and support the electricity system to most effectively manage the risks and opportunities to 2050.

Over 15 months, the Future Grid Forum:

1. analysed the existing and future issues facing Australia's electricity system
2. envisioned four 'electricity future' scenarios for Australia and used these as a framework for extensive quantitative modelling, analysis and social dimensions research
3. developed an evaluation framework for defining a high-performing electricity system for Australia and for evaluating the outcomes and trade-offs that the changes occurring in the sector might bring about
4. identified a set of options for positioning the electricity system to most effectively plan and respond to its challenges to 2050.

The four scenarios

Each of the Future Grid Forum's four scenarios is a potential pathway for electricity in Australia. The scenarios are presented here for context and are referred to throughout the report. The Forum does not endorse any particular scenario as being the most likely or the most desirable. For each scenario, every stakeholder in the electricity system would be affected differently. There is no scenario that is universally advantageous to all stakeholders. The scenarios explore some topics and exclude others and, in reality, the actual future might include elements of each scenario.

To better understand the effects of the assumptions within each scenario, the Forum explored some sensitivity cases. The companion report, *Modelling the Future Grid Forum scenarios*, presents details of the quantitative modelling of the scenarios and the sensitivity cases.

Scenario 1: 'Set and forget'

Following continued retail price rises to 2015 and clear messages to customers that peak demand growth is a significant cause, residential, commercial and industrial customers become open to taking up demand management.

Tariff deregulation makes available a wider variety of management options. The level of customer engagement is light, however, and customers prefer to rely on their utility company for the solutions for contracting, integrating, and operating demand response.

Customers lead busy lives and want to 'set and forget' their demand management once they've worked out which level of demand control suits them. For example, most pool owners switch to off-peak filtration and time-of-use pricing.

In time, nearly all household and commercial air-conditioning systems are central-control enabled. Smart meters are ubiquitous, providing the infrastructure for pricing arrangements, inclusion of other large appliances in demand management schemes, and efficient operation of on-site storage to shift demand when it is not practical to ramp down appliances.

Specialised markets for industrial demand reduction are streamlined. Customers take up on-site generation and electric vehicles, but, overall, centralised power and liquid-fuelled transport remain dominant because they are still cost-competitive and meet customer needs in most applications.

Scenario 2: 'Rise of the prosumer'

Over several decades, lowering costs of solar photovoltaic panels and inverters has meant that eventually nearly every residential consumer with a usable roof space takes up solar power. Not owning a home does not prevent uptake because panels become no more difficult to move between rental properties than a refrigerator, and apartments allocate available roof space or use solar photovoltaic cladding.

The domestic consumer interest in on-site generation spreads to other technologies, such as gas-powered systems, and commercial and industrial customers take up cogeneration and trigeneration systems, both supported by gas price increases that were less than anticipated.

Distribution service providers, retailers, and energy service companies embrace prosumers' needs and compete to provide them with financing arrangements where needed and the best opportunities for trading power or using it on site through storage systems. The network provides the platform for transactions, while a variety of companies compete to carry out the integration and facilitation roles.

Consumers choose the level of control they require from a wide variety of plans. A popular plan involves using batteries from electric vehicles as storage at the end of their vehicle life. Electric vehicles come to dominate passenger and light commercial vehicle transport, substantially reducing the demand for oil in Australia.

Scenario 3: 'Leaving the grid'

The continued dominance of residential volume-based pricing encourages energy efficiency without accompanying peak demand reduction. Poor export prices and other price signals encourage residential and commercial customers who have on-site generation to seriously explore using storage more substantially to maximise the value of their on-site generation. Large-scale uptake of electrification for light vehicles reinforces customers' increasing comfort with operating storage systems.

New energy service companies sensing a market opportunity make available building control systems and interfaces that take care of most of the details for the customer.

As battery costs decline, an increasing number of customers begin to wonder whether there is sufficient benefit in staying connected (much like they did with landlines during the rapid uptake of mobile phones). A trickle of disconnections becomes an avalanche because, in a self-reinforcing cycle, all other things being equal, retail prices must continue to rise as the system becomes more and more underutilised with each disconnection. Customers remaining on the system are those with poor access to capital and industrial customers whose loads can't be easily accommodated by on-site generation.

Scenario 4: 'Renewables thrive'

By 2025, renewable electricity generating technologies are found to cost less than expected, largely as a result of deliberate programs and targets introduced in countries across the world to deploy them and bring down their costs. While a moderate carbon pricing scheme is maintained for the remainder of the economy, the success of these renewable target policies results in the introduction of a linearly phased 100 per cent renewable target by 2050 for the *centralised* electricity generation sector.

Besides emission reduction, the renewable target is also seen as an opportunity for Australia to build new technology supply industries and to develop regions expected to be the focus of renewable deployments. Accompanying this policy are deliberate incentives to adopt storage in place of natural gas as the primary back-up system for managing peak demand and renewable energy supply variability.

Storage is deployed both at utility-scale and network locations as well as on-site with customers, shifting demand and storage charging loads to the middle of the day to take advantage of high large-scale solar and decentralised rooftop solar output. The network is tasked with integrating these processes. Some customers maintain on-site back-up power (for example, diesel) for remote and uninterruptible power applications, offsetting these emissions by purchasing credits from other sectors, such as carbon forestry. Residential, commercial and industrial customers all participate in peak demand management.

Overall, the renewable share, taken as a share of both centralised and on-site generation, is 86 per cent by 2050.

Section 2: The existing issues for electricity in Australia

Complex and unprecedented issues are confronting Australia's electricity system. They span climate change, changing energy consumption patterns, fuel source diversity, rising costs, social inequity, and accommodating new technologies and the digital age. Some of these issues have been at play over the past five years; some are more recent and continue to evolve. Taken together, a clearer picture of the current landscape for electricity in Australia emerges.

'Price shock' in electricity supply

In the second half of last century, real Australian electricity prices had been declining or fairly stable, with the exception of the early 1980s (Figure 1); however, since 2007 the average regulated household electricity price has increased by two-thirds, from around 15 cents per kilowatt hour to over 25 cents per kilowatt hour in 2012 (all currency in this report is expressed in real 2013 Australia dollars). This is around the levels experienced in the 1950s (adjusted to today's dollars), but household electricity use has increased considerably since that time. The causes of this price increase are complex, various and differ by state, but investment in the electricity distribution system played the largest role.

As an example, a breakdown of changes in the components of retail costs for New South Wales' regulated residential price is presented in Figure 2. Note that the cost components in each state vary somewhat from the New South Wales trend as a result of variations in each state's circumstances (Figure 3). Also, market prices can be significantly below the regulated prices shown in both Figures 2 and 3.

In New South Wales, total network costs (comprising 77 per cent distribution and 23 per cent transmission costs in 2012–13) increased by 7.1 cents per kilowatt hour between 2007–08 and 2012–13, accounting for 60 per cent of the total increase in retail prices.

The carbon price has added 2.1 cents per kilowatt hour, but only since its introduction in July 2012; other factors have increased incrementally throughout the period. Tax changes for low-income groups[2] and partial exemptions for export-exposed industries have offset the effect of the carbon price to some extent. The Commonwealth Government's Renewable Energy Target (RET) and state government schemes, such as solar feed-in tariffs, have also contributed to higher electricity prices, adding around 1 cent per kilowatt hour (Figure 3) (although the RET has had the counteracting effect of lowering wholesale prices, as discussed below).

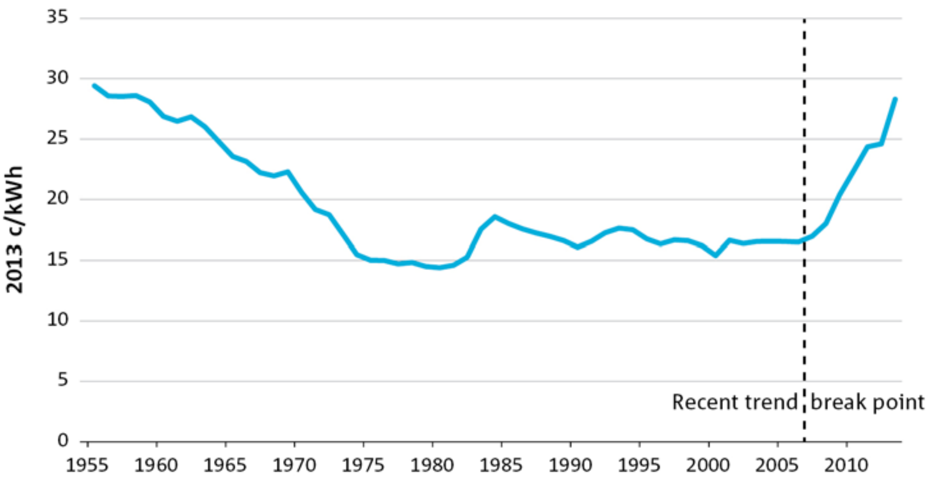


Figure 1: Historical average national electricity retail prices (2013 dollars)

Source: ESAA (various); ABS (2013a)

2 Called the Government Household Assistance Package.

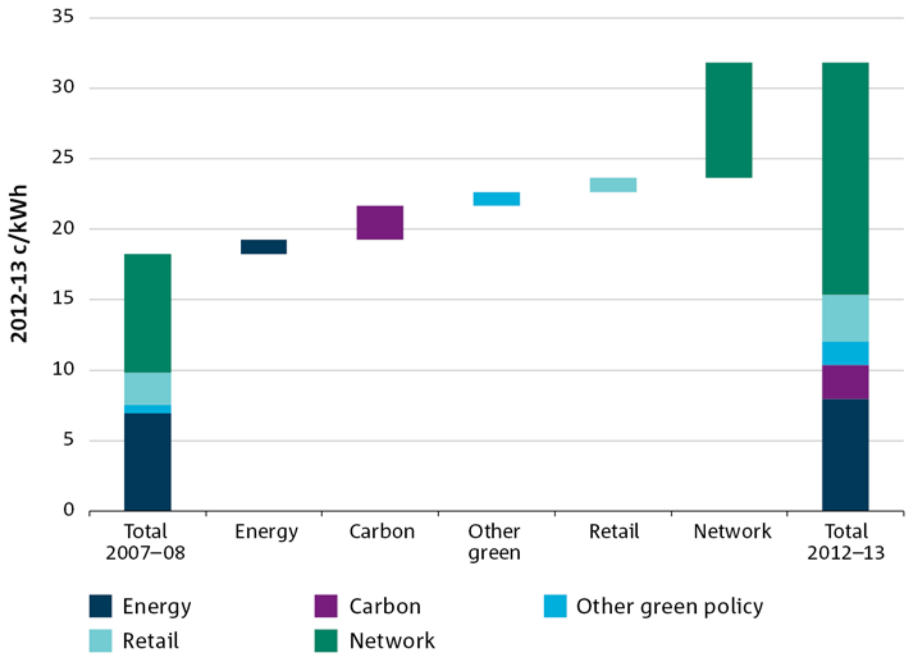


Figure 2: Changes in real regulated residential retail electricity price components (New South Wales, 2012–13 dollars)

Source: IPART (2013); AEMC (2013a)

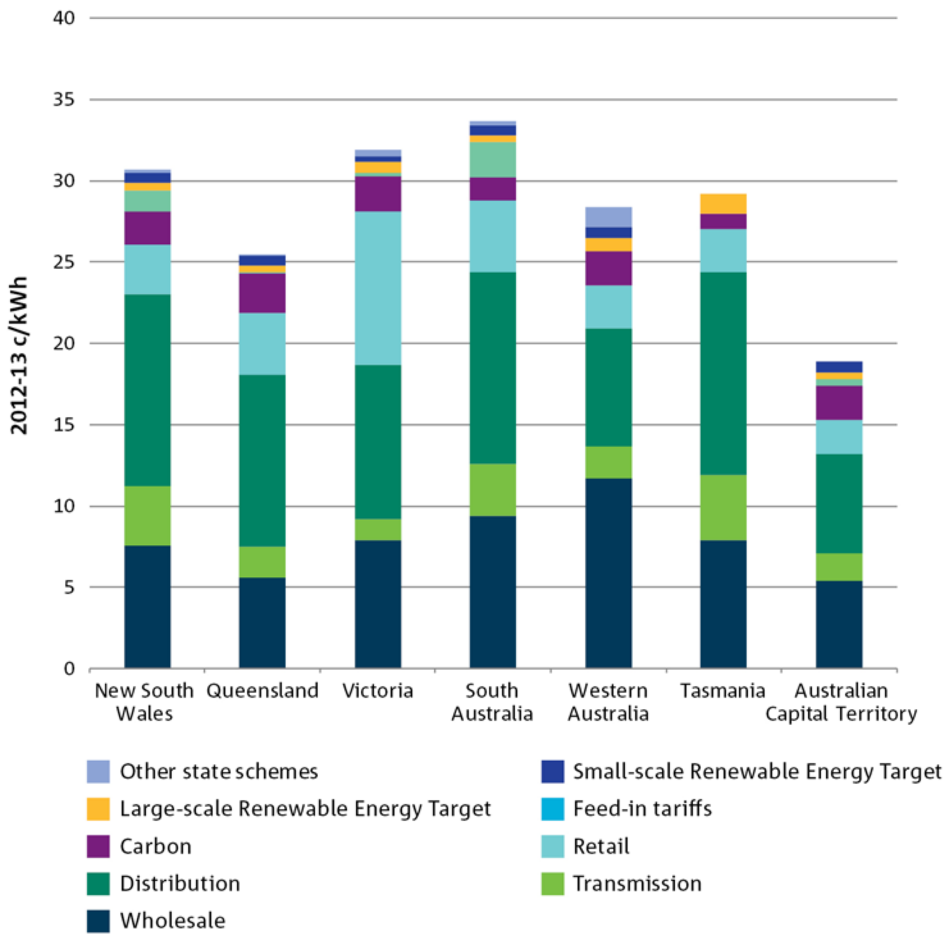


Figure 3: Components of state regulated retail electricity prices in 2012–13[3]

Source: AEMC (2013a)

3 It is important to note that these prices should be discounted. Market offers were lower than these regulated prices and remain so; however, no other source provides a consistent breakdown for all states. The roll-out of advanced metering in Victoria is included in the retail component and is unique to that state. Prices are exclusive of good and services tax (GST).

One factor that actually reduced pressure on retail prices during the past five years, but not enough to offset the increases in other factors, was lower generation costs. A recent unexpected decline in electricity consumption together with greater renewable generation has led to excess supply in the generation market, depressing wholesale prices. Several generation plants have been mothballed or retired as a result.

The reality of the depressed wholesale market is in conflict with the information in Figure 2, which suggests that wholesale costs have risen; however, the wholesale costs in Figure 2 refer to the costs of building new plant[4] not actual wholesale market prices, which have been significantly below plant replacement costs. Only investment in renewable generation capacity required by the RET is proceeding under these market conditions. When and if additional generation capacity investment is needed above that required to meet the RET, wholesale prices will need to increase. Indeed, with the risk of a low/zero carbon price in the period to 2020, there are concerns that the wholesale price may not be sufficient to even allow the RET to be met, despite the extra payments the scheme affords renewable plant.

Several factors drove the increase in the distribution component of retail electricity prices in Australia, but the pressures were not the same in each jurisdiction. Some states raised their reliability standards in an effort to meet assumed customer demand for lower incidence and duration of interruptions, and this required system expansion, while in other jurisdictions, aged network infrastructure, which was rapidly built in the household modernisation era of the 1950s and 1960s, had to be replaced. The global financial crisis increased the financing costs for these activities.

There was also additional network expenditure to ensure there was sufficient capacity to meet peak demand.[5] Expectations of rising peak demand were partly driven by increasing air-conditioner ownership among Australians, which doubled from around 35 per cent in 2000 to over 70 per cent in 2012 (Figure 4). Network capacity has been sized to provide power on days when air-conditioner usage is high because of weather extremes—and these same extremes lower the effective capacity of the network. Peak demand increased significantly in most states up to 2008–09, but expectations of further increases were not realised in the period 2008–09 to 2012–13 (Figure 6).

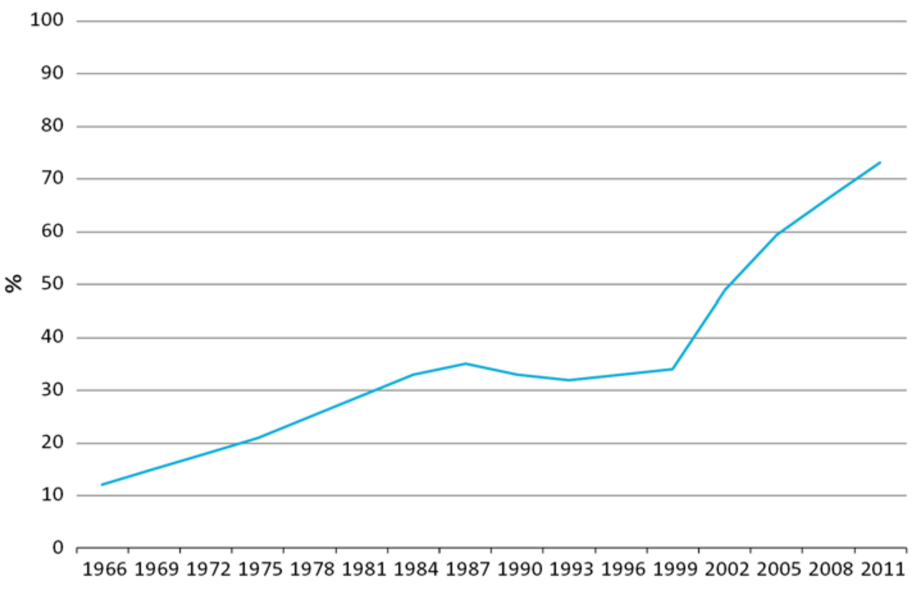


Figure 4: Historical residential air-conditioner adoption

Source: DEWHA (2008); ABS (2011)

4 This was the preferred calculation method for wholesale costs in New South Wales' regulated retail prices.

5 'Peak demand' is the highest instantaneous level of demand experienced in a given period, expressed in watts, whereas 'consumption' refers to the total volume of electricity consumed over a given period expressed in watt-hours.

Decline in peak demand and consumption

Usually climbing inexorably with economic growth, in most Australian states aggregate peak demand and consumption have both reversed trend and declined since around 2008–09[6] (Figures 5 and 6). There are no state-level baseline studies on energy customer behaviour to accurately determine the relative strengths of the various causes of the aggregate changes, but these factors played a role:

- Some consumers responded to the price shock by adopting energy efficiency and energy conservation measures and changed usage patterns in an effort to reduce their electricity bills.
- State and federal government incentives and falling costs of on-site generation systems supported customers' adoption of solar hot water and rooftop solar photovoltaic power systems, reducing their need for electricity from the centralised network.
- Manufacturing and minerals processing activity (including electricity-intensive aluminium refining and steel production) declined as a result of a range of factors, including lower commodity prices and the historically high Australian dollar through 2011 and 2012 (although it has eased in 2013).
- A prevailing La Nina weather pattern from 2010 to 2011 described as the 'strongest in living memory'[7] resulted in cooler summers and consequently less use of residential and commercial air-conditioning.

Lack of connection between consumer prices and costs of services delivered

While faster growth in peak demand relative to consumption was a partial cause of electricity price increases, it could be said that the much deeper cause is the lack of connection between consumer prices and the costs of services delivered to small consumers who largely remain on volume-based tariffs (larger customers are charged on the basis of both volume and peak demand). Lack of cost-reflective pricing means there is no signal to small consumers that greater use of high instantaneous power-demanding appliances will increase the per unit cost of consumption for the system as a whole. The dominance of volume-based electricity contracts for small consumers has effectively meant that consumers with high peak demand are subsidised by those with low peak demand but similar consumption levels.

There are some longstanding partial exceptions in each state where volume-based price signals also include some incentive to small consumers to shift peak demand. For example, many states have traditionally had strong off-peak tariff schemes for hot water. More recently, Queensland was successful in attracting 59 per cent of Energex consumers to off-peak hot water, pool filtration and air-conditioning. Victoria increased its smart meter penetration to almost 90 per cent in 2013 and has introduced flexible tariffs that reflect the electricity price at time of use. Some examples of alternative tariff models and their advantages and disadvantages for consumers are explored later in this report (Table 1).

Another issue relating to cost of services is a fair payment for consumers' exports of household roof-top solar photovoltaic electricity. Feed-in tariffs implemented in 2008 and 2009 across Australia initially set the price to encourage investment rather than to reflect their value in the market. Since governments pulled back feed-in tariffs in 2010 and 2011 for new contracts signed, feed-in tariffs have decreased considerably (down from as high as 60 cents per kilowatt hour in New South Wales to 5–10 cents per kilowatt hour in different states), and this has opened a debate about what payment is reflective of their value. For the consumer receiving the exported solar panel output, the electricity is at least as valuable as the retail electricity price they would otherwise pay; however, the feed-in tariff should be less than the retail price because consumers exporting solar panel electricity use the distribution system for exporting and therefore they should provide some payment for this use (net of any benefits they might provide to the system). Ultimately, these charges and payments will be established over time between the various parties. This market is relatively new and still innovating.

6 Although within each state, specific regions of peak demand growth driven by new developments have remained.

7 Bureau of Meteorology 2011, 'La Nina reaches its end', media release, BOM, Canberra, <http://www.bom.gov.au/social/2011/07/lanina-ends/>.

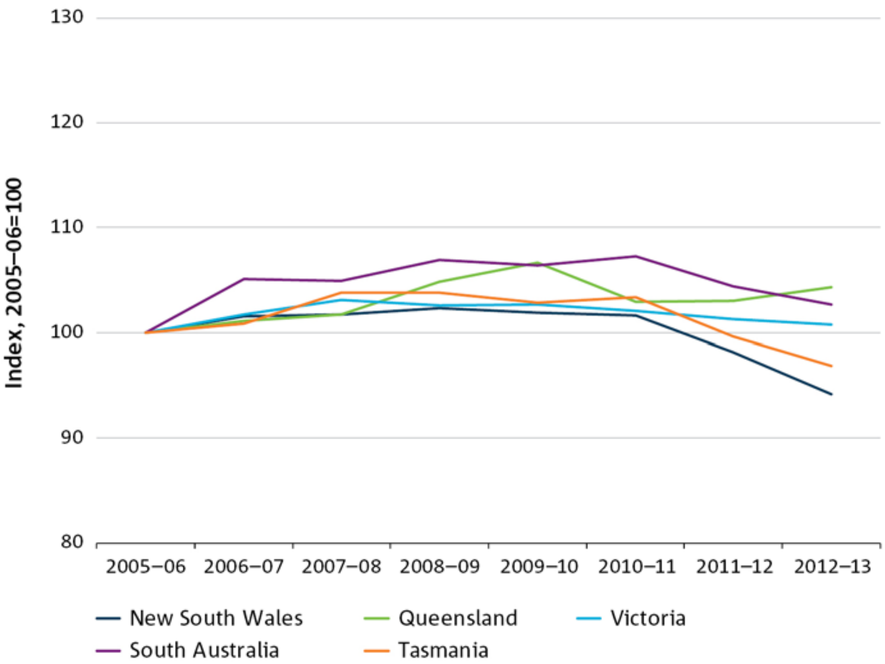


Figure 5: Index (2005–06=100) of historical consumption (TWh) in NEM states

Source: AEMO (2013b)

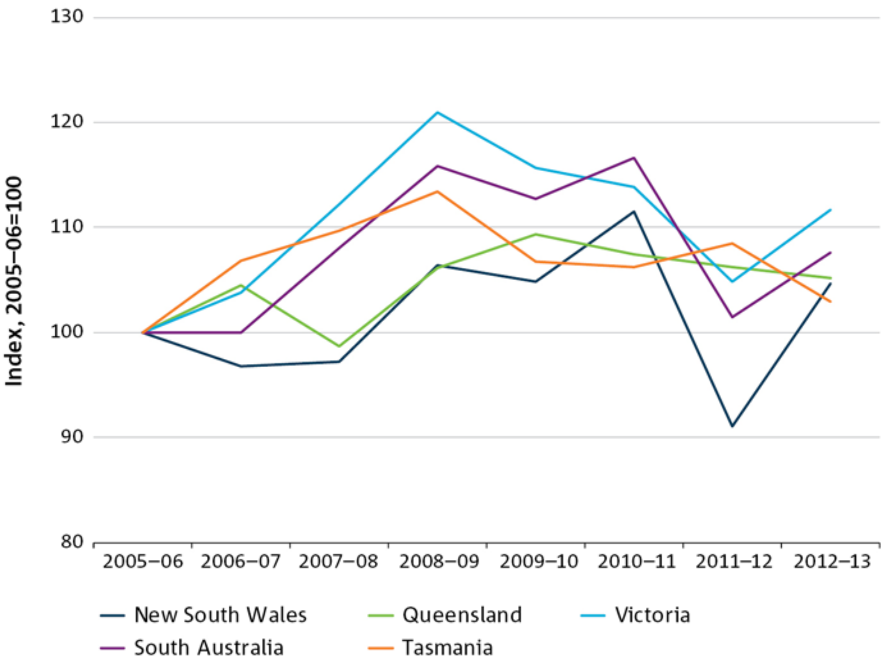


Figure 6: Index (2005–06=100) of historical peak demand (GW) in NEM states

Source: AEMO (2013b)

Greenhouse gas emissions, carbon policy and climate change vulnerability

DECARBONISING AUSTRALIA'S ELECTRICITY SUPPLY

Greenhouse gas emissions from electricity generation in Australia peaked in 2008 at 208 million tonnes of carbon dioxide equivalent and were reported at 191 million tonnes of carbon dioxide equivalent in December 2012. A combination of factors led to this outcome. From a policy perspective, state-based solar feed-in tariffs, energy-efficiency schemes, the RET and the Clean Energy Future carbon pricing policy were in place. Forced outages at coal plants, lower electricity demand contributing to the closure or mothballing of some coal-fired plants, and strong hydroelectricity supply are also thought to have played a part (Figure 7). Because these multiple factors occurred together, there is some uncertainty and debate about their individual level of impact.

Despite this recent reduction in emissions, the electricity sector remains the largest single source of Australian emissions, and further decarbonisation is required over coming decades if Australia is to contribute its fair share to the global greenhouse gas abatement task.

CARBON POLICY UNCERTAINTY

In Australian politics there is bipartisan support for a 2020 national greenhouse gas emission reduction target of 5–15[8] per cent below 2000 levels (or 25 per cent below 2000 levels, if the world agrees to a deal capable of stabilising levels of greenhouse gases in the atmosphere at 450 parts per million carbon dioxide equivalent or lower), but there is no bipartisan view on the best set of policy mechanisms to achieve this target or on the longer-term emission trajectory beyond 2020. Current legislation requires emissions be 80 per cent below 2000 levels by 2050.

Carbon policy targets the generation end of the electricity supply chain where it provides a financial incentive for investors to change the technology mix to favour lower-carbon generation technologies. It can also affect the retail price and consequently drive behavioural change in customers. Further, carbon policy can affect transmission costs in cases where it is necessary to have different generation locations in order to access or support the operation of lower-emission resources.

Uncertainty about carbon policy can delay or lead to sub-optimal investment decisions for electricity generation (Nelson et al 2011). At present, the Large-scale Renewable Energy Target, rather than the carbon price, primarily drives development of new electricity generation

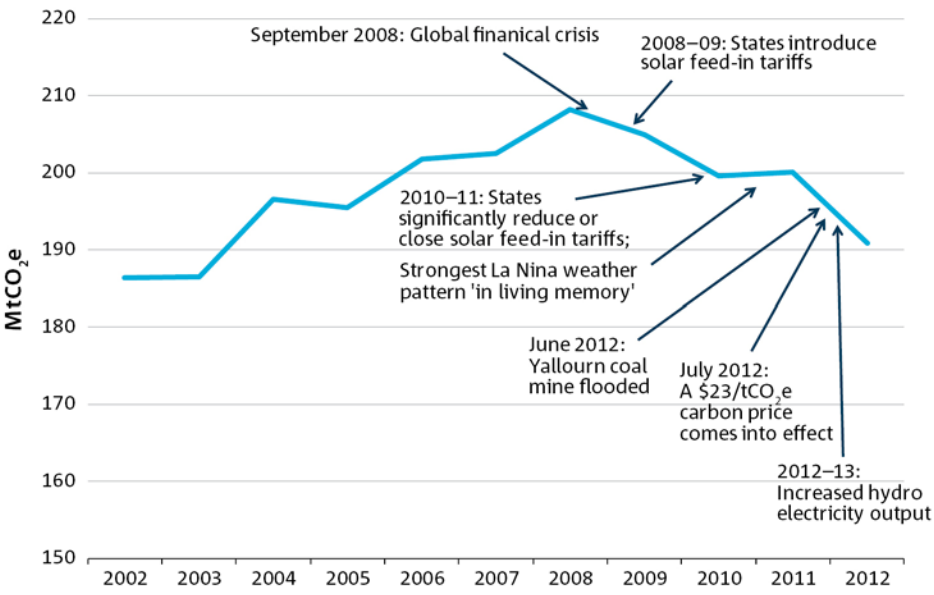


Figure 7: Historical electricity sector greenhouse gas emissions

Source: DIICCSTRE (2013)

8 Australia will unconditionally reduce its emissions by 5 per cent compared with 2000 levels by 2020 and by up to 15 per cent by 2020 if there is a global agreement that falls short of securing atmospheric stabilisation at 450 parts per million carbon dioxide equivalent under which major developing economies commit to substantially restraining their emissions and advanced economies take on commitments comparable to Australia's.

capacity, but expectations around carbon policy beyond 2020 will increasingly become material to investment. Given the electricity sector is the largest single source of greenhouse gas emissions in Australia, the lack of an explicit, stable, long-term decarbonisation signal increases the risk to investors of substantial changes in carbon policy during the asset's lifetime or even during its construction.

VULNERABILITY TO CLIMATE CHANGE

The strong impact of weather conditions on the operations of the electricity system leaves it especially vulnerable to climate change. Climate affects the electricity industry at every stage of the supply chain. It heavily influences the daily and seasonal profile of demand, the efficiency of generation, the availability of cooling water or hydropower resources, capacity of the network, and expenditure on maintenance and storm event damage, among many other factors. The reduction in capacity of transmission and distribution assets under high ambient temperature conditions is particularly challenging because it occurs when demand is likely to be high as a result of air-conditioner load. The potential for more frequent extreme climate events in the future, and the inability to predict these, is a concern for system reliability and cost.

Shifting attitudes to reliability and its cost

Reliability of supply has always been a goal in the development of the electricity system and because of the historically prohibitive cost of storing electricity, the focus has been on the network being able to meet supply during credible contingencies. To ensure satisfactory levels of reliability, the system must have a level of built-in redundancy to allow for failure and outages of parts of the system from external factors, such as extreme weather.

Reliability has become more important over time as Australia's lifestyle and industry have become more dependent on electricity (notwithstanding the recent uptake of more battery-powered personal computing devices). In 2005, New South Wales and Queensland increased their reliability standards for electricity distribution following extreme weather events. These increased standards triggered additional network investment to achieve compliance. After the electricity price rises that occurred between 2007 and 2012 (Figure 1) many have questioned whether reliability standards are now set too high or too prescriptively in these jurisdictions (Wood 2012).

Analysis by the Australian Energy Market Commission (2012b) surveyed 1,300 New South Wales customers and confirmed that, based on their valuation of reliability, there would be some benefits if the level of distribution reliability were to be reduced. The benefits of reduced investment in reliability would be realised in the longer term since expenditure to meet the 2005 New South Wales reliability standards is already committed. New South Wales customers are estimated to save between $3 and $15 a year in exchange for an additional 2–15 minutes of outages a year on average.[9]

To address the concerns about reliability standards, the state and Commonwealth governments agreed in principle to implement a national framework for transmission and distribution reliability and commissioned the Australian Energy Market Commission to report on the proposed framework (AEMC 2013b), which it completed in late 2013 (AEMC 2013c). The report provides a set of broad principles which state jurisdictions and network service providers will consider and further develop.

9 Individual experiences of outages will vary significantly depending on location and network.

Section 3: Future Grid Forum scenario origins and assumptions

In developing the four scenarios it was clear to the Forum that:

- There are some factors that create significant uncertainties for the system, but do not alone require it to fundamentally change, such as fuel price volatility and changes in technology costs.
- There are some changes that are so significant they carry the potential to cause a 'megashift' in the electricity system. A 'megashift' occurs when, either incrementally or suddenly, an industry and its businesses must be substantially restructured to accommodate a new reality. Three potential megashifts for Australia's electricity sector are the advent of low-cost electricity storage, sustained low demand for centrally-supplied electricity, and the need for significant greenhouse gas abatement. These megashifts are factored into the four scenarios to varying degrees.
- Consumer engagement with their electricity supply has recently increased, but it is uncertain how much consumers will want to engage in the future. The extent to which consumers engage is an important variable in each scenario, ranging from passive to highly engaged.

General uncertainties

The list of general uncertainties is naturally a long one given the complexity of the electricity system, but the key uncertainties the Forum chose to include in scenarios or sensitivity cases are:

- fuel prices
- carbon and energy policies (targets and implementation mechanisms)
- technology costs
- climate change impacts.

FUEL PRICES

Fuel prices can have a large impact on electricity generation costs, potentially affecting the wholesale electricity price by \$20 to \$40[10] per megawatt hour over the long run (Graham et al 2013a). In particular, there has been significant discussion within the electricity sector about the uncertainty around future gas prices in Australia owing to a wide variety of influences, including challenges in the social acceptance of accessing coal seam

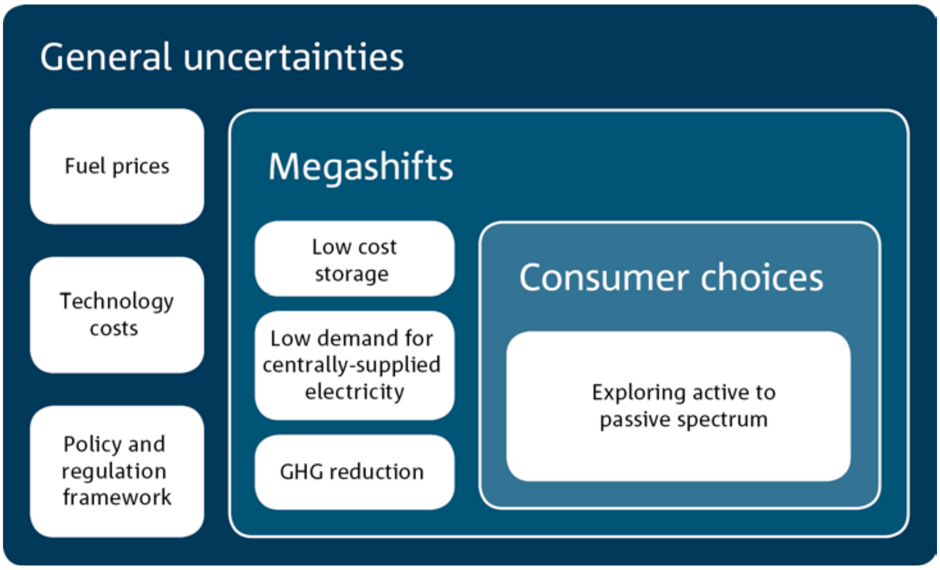


Figure 8: Future Grid Forum scenario development framework

10 All projections in this report are in real 2013 Australian dollars.

gas resources where there are existing land use activities, the potential for greater east coast export price parity in Australia as a result of the development of export terminals, and the potential global market impact of increased shale gas supply in the United States (Wood & Carter 2013).

The fuel cost ranges applied in this report are based on ACIL Tasman (2012) and are presented in Figure 9 for the east coast of Australia. The projections assume that price movements for gas are far more uncertain than those for coal. It is assumed natural gas prices will rise as a result of the east coast being exposed to international competition; the main uncertainty is in the degree of the increase.

The medium fuel price paths have been applied in Scenario 1: 'Set and forget' and Scenario 4: 'Renewables thrive'. The low fuel price path has been applied in Scenario 2: 'Rise of the prosumer' and Scenario 3: 'Leaving the grid' to support the economic plausibility of the high use of gas in on-site generation expected in those scenarios. A sensitivity test was conducted on Scenario 1 to understand the impact if the high fuel price path had been applied. It found that wholesale electricity prices would be around $10 per megawatt hour higher and greenhouse gas emissions 40 million tonnes of carbon dioxide equivalent higher by 2050 under higher fuel prices. This reflects greater use of coal, which is more competitive under high gas prices.

Renewables deployment is lower when gas prices are high because high gas prices increase the cost of managing the variability of some renewable supply (unless other options, such as demand management, peaking direct-injection coal engines, or storage are able to fulfil that role at low cost). Use of storage is explored in Scenario 4; direct-injection coal engines are included in the modelling technology set, but demand management is generally targeted at peak demand reduction rather than supporting renewables when it is implemented in Scenarios 1, 2 and 4.
The projected impact of high gas prices on renewables is specific to this study, which has assumed gas-fired plants are a low-cost source of generation based on BREE (2012) (see technology cost assumptions below). Were other technologies (perhaps even other renewables) able to support variable renewables at a similar cost to gas plant, then the price of gas would not have such an impact on renewable deployment.

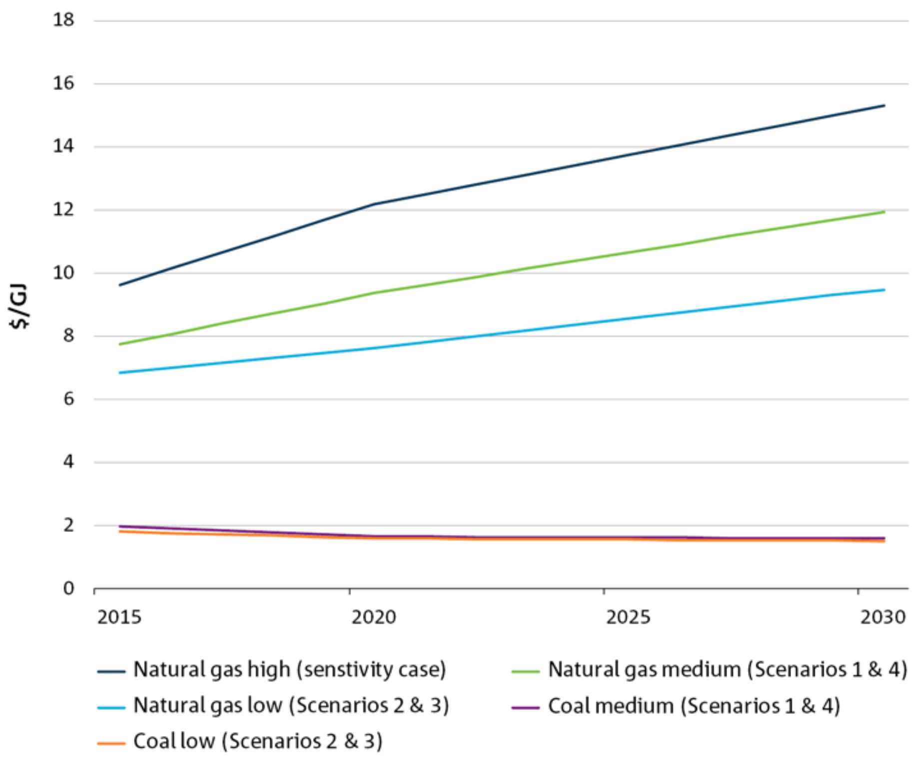


Figure 9: East coast coal and natural gas price projections

Source: ACIL Tasman (2012)

CARBON AND ENERGY POLICIES

Australia's current national emission reduction targets are to achieve 5–15[8] per cent below 2000 levels by 2020 (or a 25 per cent reduction if global action is stronger) and 80 per cent below 2000 levels by 2050. The legislated 2050 target is described by Treasury (2011) as Australia's fair share of abatement in contributing to the global goal of limiting average temperature increases to 2 degrees Celsius. Stabilisation of atmospheric concentrations at 450 parts per million carbon dioxide equivalent is estimated to provide a 50 per cent chance of avoiding exceeding 2 degrees Celsius and the aggregate global emission abatement paths are derived on that basis. Stabilisation of atmospheric concentrations at 550 parts per million carbon dioxide equivalent is estimated to provide a 50 per cent chance of avoiding exceeding 3 degrees Celsius.

In determining Australia's fair contribution to global greenhouse gas abatement efforts, there are many ways in which it could be assigned: capability (wealth and access to abatement options), responsibility (contribution to historical emissions), equality (recognising an equal right to emit greenhouse gases), or access to sustainable development (supporting the development needs of poorer countries) (Climate Change Authority 2013). Although there are many issues of contention, it was not a priority for this Forum to challenge any of these concepts or to analyse them further. This report therefore relies on reinterpreting the existing analysis to understand the possible range of carbon prices that the electricity sector may have to respond to in the future.

The mechanism for meeting the national emission target in Australia is not settled. A fixed carbon price was introduced in July 2012 and was designed to move to a free-floating carbon price determined by the market for emission permits within a few years. As at the end of 2013, the in-coming government has planned to move to a policy called 'Direct Action' which includes an abatement auction system.[11] The Forum does not seek to model and evaluate these alternative mechanisms in this report, although they would have different impacts. Instead, as a necessary simplifying assumption, the Forum uses a generic carbon price throughout the modelling as a proxy for a range of mechanisms that governments might implement to send signals to the market to reduce emissions.

The carbon prices presented by Treasury (2011) were the most current, with the exception that since that work was published it has been acknowledged that international carbon prices are weaker than expected

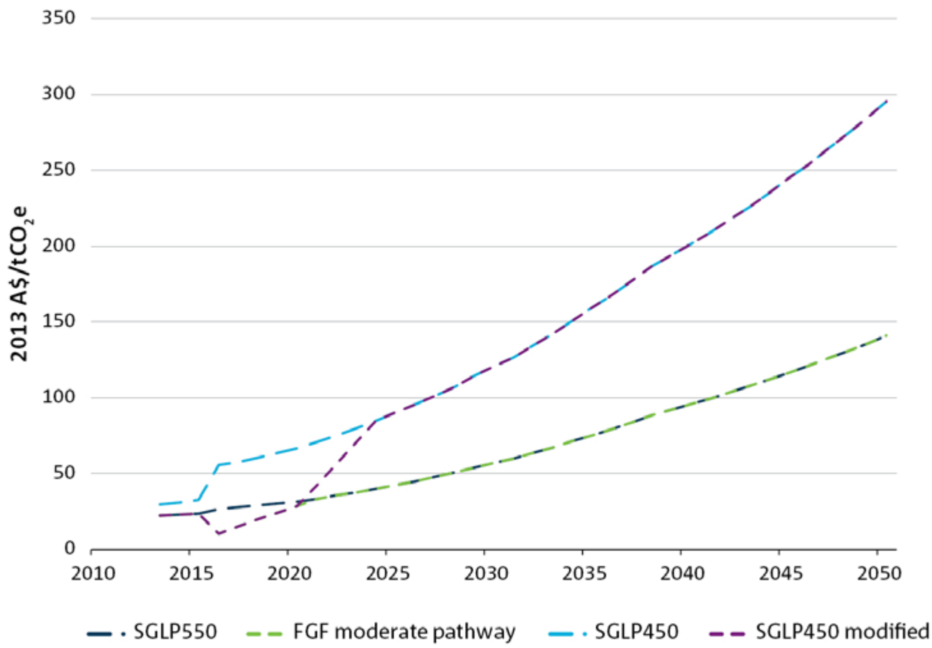


Figure 10: Treasury (2011) and modified Future Grid Forum carbon price trajectories

11 The government purchases bids for emission abatement up to a given budget or target as opposed to the situation under emission trading where the government sets the target and sells permits that sum up to that target. The 'Direct Action' policy also excludes using abatement that occurs outside Australia, but expands the allowable domestic abatement to include soil carbon.

in the short term, particularly in Europe where Australia would first link to international carbon prices. To this end, the May 2013 Commonwealth Government budget papers updated the series to 2018–19 to take into account the weaker carbon price market. Therefore, the Forum developed two modified carbon price paths. All four scenarios adopt a modified version of Treasury's (2011) 550 parts per million scenario (Figure 10). A high carbon price sensitivity case is also adapted from the Treasury's (2011) 450 parts per million price path. In both cases, the carbon price recovers to its previous path.

Recognising that Australia's carbon price policy is not settled, the Forum also explored two additional sensitivity cases. The first is no carbon price. This is useful as a way of understanding the costs of greenhouse gas mitigation and the underlying trend in wholesale electricity price absent a carbon price signal. The second sensitivity case examines an uncertain carbon price case which does not assume a single carbon price projection, but rather examines how ongoing uncertainty across the entire future possible carbon price range impacts on the electricity sector.[12]

TECHNOLOGY COSTS

The Australian Government conducted the first Australian Energy Technology Assessment (AETA) in 2012, coordinated by the Bureau of Resource and Energy Economics (2012). AETA projects the cost and performance characteristics (for example, capacity factor, efficiency, and carbon capture rate) of most large centralised electricity generation technologies to 2050. The AETA technology capital cost projections[13] were developed on the basis of a Treasury (2011) 550 parts per million world in terms of global greenhouse gas reduction effort. Therefore, they provide a reasonably consistent technology cost assumption for the Forum's scenarios. For Scenario 4, however, the Forum wished to include the possibility of an accelerated rate of reduction in the cost of renewable energy

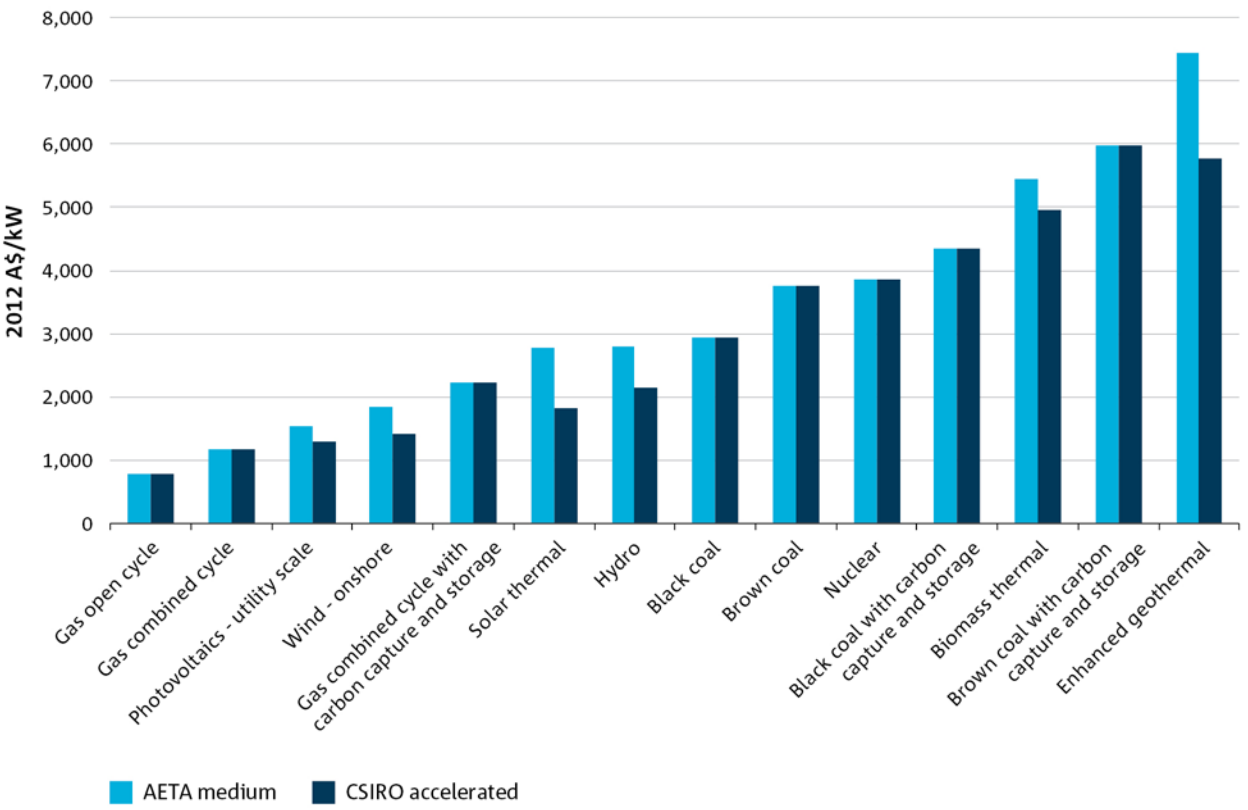


Figure 11: Alternative 2050 capital cost assumptions for large-scale centralised electricity generation technologies

12 See Graham et al (2013b) for details of how this sensitivity case is implemented.

13 The capital cost of carbon capture and storage technologies shown in Figure 10 does not include the cost of carbon dioxide storage, but this cost is included in all modelling.

technologies. The Forum sourced an accelerated renewable energy technology cost projection from Hayward and Graham (2012) who developed their projection for the Australian Energy Market Operator's *100 per cent renewables study*.[14] Both projections are shown in Figure 11 for the year 2050. Most cost reduction occurs before 2030, after which the rate of cost reduction slows as technologies mature.

The AETA does not address on-site generation and so the Forum derived its on-site generation cost assumptions from the Intelligent Grid Research Program, a CSIRO study analysing the value proposition for on-site energy in Australia (CSIRO 2009). The Forum updated the data where new information had become available and indeed developed two cases: 'medium' and 'accelerated' (Figure 12). The 'medium' case is applied in Scenario 1, while the 'accelerated' case is applied in Scenarios 2 to 4 to drive the greater adoption of on-site generation envisaged in those scenarios. The Forum does not impose any specific on-site generation targets in the modelling, but rather allows the cost assumptions to drive uptake. However, the modelling does include some recognition of limits to the size of different customer segments.

Given the scenarios use different cost assumptions, it is important to recognise that this means the financial metrics of each scenario are not directly comparable. It is not possible to say, for example, that a given scenario is preferable to the others because it appears to have lower costs; this may be simply a function of the different input assumptions.

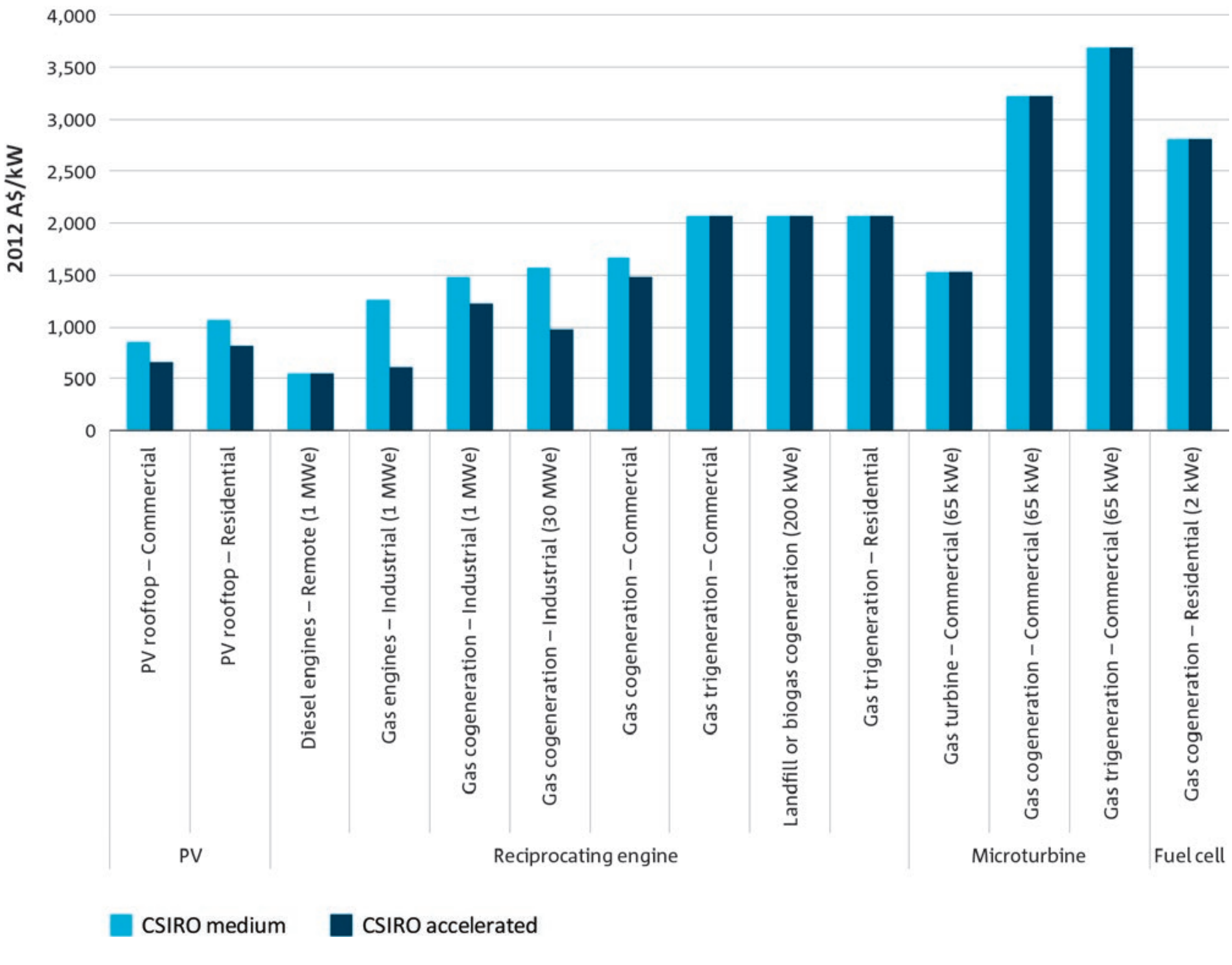


Figure 12: Alternative 2050 capital cost assumptions for on-site electricity generation technologies

14 Department of Industry, Innovation, Climate Change, Science, Research and Tertiary Education 2013, *100 per cent renewables study*, Commonwealth of Australia, Canberra, <http://www.climatechange.gov.au/reducing-carbon/aemo-report-100-renewable-electricity-scenarios>.

CLIMATE CHANGE IMPACTS

The scenario development process acknowledged that there is a significant risk that the climate will change with or without successful global greenhouse gas abatement efforts. The electricity system is particularly vulnerable to climate change because the weather impacts nearly every aspect of its operation, but the technical ability to downscale climate changes to changes in annual weather outcomes at specific locations remains limited, as does the capacity to estimate and collate all of the ways in which the electricity system may be affected. Consequently, the Forum did not specifically include climate impacts in any of its scenarios.

To begin to get a handle on the possible impacts using a simplified approach, however, the Forum conducted a sensitivity case to provide an indication of how climate change might have changed the scenarios if it were included. The simplified approach examines the cost of building generation and network plant to meet a higher peak demand, but does not link the peak demand forecast to any specific climate change scenario and excludes many other climate change adaptations that might be required.

Megashifts

ELECTRICITY STORAGE

Although currently regarded as too expensive for large-scale applications, sustained investment in materials manufacture and technological development could mean electricity storage plays a future game-changing role in many aspects of the electricity system. For example, it could:

- support uptake of renewable electricity generation by smoothing or shifting the timing of generation export to the grid
- manage distribution system peaks and troughs
- give customers a measure of independence from the electricity system if they desire it
- give service providers a cost-effective alternative to grid connection for some edge-of-grid customers
- support uptake of electric vehicles
- manage integration of all of these.

New business models and ways of operating the system could be required for these roles.

The modelling focuses on battery storage because batteries suit most applications envisaged in the scenarios, but there are many other storage technologies that could be viable. The current high levels of investment in battery technology for various applications, such as electric vehicles, makes it reasonable to assume that electricity storage will cost less in future, but how much less is uncertain. The International Energy Agency (2012) projects the cost of batteries for electricity vehicles will halve by 2020. Marchment Hill Consulting (MHC) (2012) provides a medium, optimistic and pessimistic case (Figure 13). The pessimistic case recognises the potential for some raw materials (such as rare earths) in storage devices to become more expensive. The optimistic case includes a greater than 50 per cent reduction by 2020 and the medium case lies between the two extremes. James and Hayward (2012) applied a modelling approach that assumed battery costs would be linked to deployment and improvements in the costs of intermittent renewable electricity generation technologies, such as wind and solar photovoltaics. In this case, a 50 per cent reduction is not projected to be reached until 2030. Based on these studies, the Forum's modelling assumed the cost reduction trajectory shown in Figure 13.

LOW GROWTH OR DECLINING DEMAND FOR CENTRALLY-SUPPLIED ELECTRICITY

Over the past century, Australia's electricity system was geared to manage increasing supply to meet growing electricity consumption. Switching focus to managing slow-growing or declining consumption would require a major paradigm shift for the system. In particular, lower apparent grid consumption caused by greater use of on-site generation has significant implications because it means there would be less energy required from central sources, but it may not significantly reduce the peak demand that the system is called on to supply.

Some Australian states have already experienced several years of declining centrally-supplied consumption. While this coincided with the global financial crisis and might be temporary, there are other drivers that suggest that load growth is becoming less strongly influenced by economic growth:

- On-site generation, such as solar photovoltaic panels, is becoming cheaper (as discussed, this reduces the consumption that is visible to the centralised electricity supply chain, but may not reduce peak demand or total consumption).

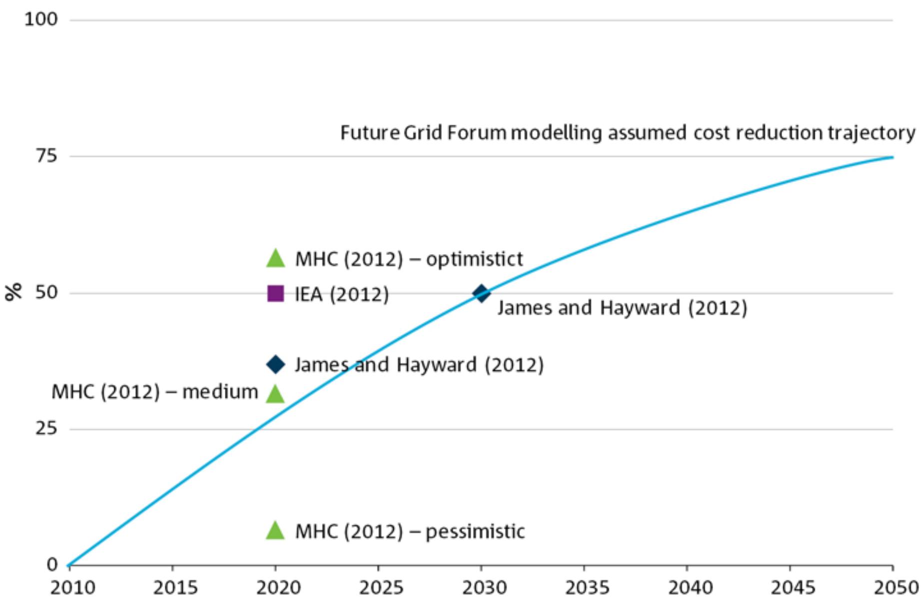


Figure 13: Projected percentage reductions in storage costs and the Future Grid Forum assumed cost reduction trajectory

- Sustained high retail electricity prices are driving more energy-efficient customer behaviour.
- There are structural shifts in the economy towards low energy-intensive service industries and experiences rather than material-based production and consumption of goods and services.
- Energy-efficient appliances and building stock are becoming more commonplace.

Lower centrally-supplied electricity consumption has the potential to strand some existing electricity generation assets or at the very least force a greater focus on utilisation of the existing asset base. This is a challenge for current business and regulatory models. On the other hand, improved energy efficiency is also important in limiting increases in electricity bills over time, particularly given the need for the generation component of electricity tariffs to rise as Australia decarbonises its electricity system.

GREENHOUSE GAS ABATEMENT

Despite recent progress in reducing greenhouse gas emissions from the electricity sector (an 8 per cent reduction from 2008 to 2012), the scale of decarbonisation required to meet long-term greenhouse gas emission targets will demand much greater transformation. Australia's currently legislated 2050 national emission reduction target is 80 per cent below 2000 levels.

The starting point for Australia's electricity sector in contributing to an 80 per cent reduction in greenhouse gas emissions is that coal and gas fuel 69 per cent and 19 per cent of Australia's electricity generation respectively, resulting in a highly emissions-intensive power supply. Although emissions have been declining since 2008, annual greenhouse gas emissions in the electricity sector were 8 per cent above 2000 levels in 2012 and represent 35 per cent of total national emissions. The transition to a low-carbon electricity system will require substantial upgrades to and replacements of existing infrastructure, supported by sustained investment in research, development, commercialisation, and deployment of low-carbon technology solutions.

Consumer choices

CSIRO conducted a literature review to ascertain consumers' interest in exploring new contract arrangements and making accompanying behavioural changes (Boughen et al 2013). There were three key findings. These findings are not concrete; consumer attitudes may change in future, but for now they are a useful guide to how to manage future adoption of emerging electricity technologies and relationships.

First, up until recent price events and solar uptake, electricity use was invisible to the residential consumer, resulting in a lack of awareness, knowledge and incentive to participate.

Evidence suggests household knowledge of energy use is low, particularly about which appliances contribute most to bills. This might be a challenge since many of the technologies proposed for the future electricity grid require residential consumers to be much more aware and involved in their energy consumption and, in some cases, production.

Despite this low knowledge base, research shows some residential consumers are willing to investigate and even try technologies and initiatives once the concepts are explained in detail. Residential consumers are already expressing interest in becoming more aware and taking control of how they consume and produce their electricity. While many emerging electricity technologies (such as smart meters, dynamic pricing, and direct load control) initially receive mixed reactions, often negative reactions are overcome once the consumer's knowledge of the technology increases and their key concerns (such as the health and privacy concerns about smart meters, and the impact of dynamic pricing on vulnerable households) are addressed. That said, residential consumers are sceptical that the proposed benefits will be realised and that key concerns will be adequately addressed.

Second, despite saying they are willing to change their behaviour to reduce their energy bills, many residential consumers continue to behave in ways that are contradictory to their intent (for example, they increase their use of energy-intensive appliances). Research suggests that motivations (for example, to help the environment) do not necessarily translate into behaviour (such as turning off lights or installing solar panels) and other factors also come into play (for example, social norms, ingrained habits, and the extent to which the person believes it is easy or difficult to take action). The research showed that cost is top-of-mind and is therefore acting as both a primary motivator for, and a key barrier to, uptake of alternative tariffs and technologies.

Some studies in the literature review suggest that consumers do consider other complementary decision factors, including reliability, quality, safety, control, and environment, and that in some instances these factors can be more influential than cost. As an example, early adopters of a technology often rate other features as more important than cost. It is important to note that evidence suggests that an individual's socioeconomic profile is not a consistent predictor of attitudes, values and beliefs, but it may be an indicator of their capacity to take action in the absence of financial support or incentives.

Finally, the literature review suggests that residential consumers need information to help them make decisions and the quality of information matters. Information and feedback need to be clear, accessible, appealing, relevant and timely. What made implementation programs (explored in the literature review) successful includes consumer involvement through engagement, education, consumption feedback, and supporting technology.

One of the most vital components of effective engagement is trust. Currently, many utilities in Australia are not commanding strong public trust and so this will be a challenge to overcome.

To explore the role of consumer choice, the Forum's scenarios represent different types of consumer attitudes and industry response. In Scenario 1: 'Set and forget', consumers are passive and industry responds by providing demand management and tariff regimes that require some decisions up front but very little engagement afterwards. In Scenario 2: 'Rise of the prosumers', consumers are much more active and push service providers to provide them with a wide range of active and ongoing choices, including diverse on-site generation options (that is, the regulatory environment is much the same as in Scenario 1, but consumers want more engagement in Scenario 2 and are encouraged by lower on-site generation costs). In Scenario 3: 'Leaving the grid', there is no change from current residential tariff structures and so poor price signals remain, leading to inefficient use of the grid. Increasing unit costs and other factors conspire to push consumers towards the greatest form of engagement, which is sole reliance on their own off-grid supply, with the assistance of service producers specialising in those systems. Consumer attitudes in Scenario 4: 'Renewables thrive' lie somewhere between the extremes of Scenarios 1 and 2, with good consumer engagement and significant uptake of on-site generation and demand management, but a stronger reliance on the centralised grid because of its high renewable content which has strong community support.

OUTCOME OF CONSUMER CHOICES ON CONSUMPTION, PEAK DEMAND AND ADOPTION OF ON-SITE GENERATION

The result of these consumer choice assumptions is the following consumption and peak demand profiles for each scenario:

- The scenario consumer behavioural assumptions were partly imposed by and partly projected as changes on the existing Australian Energy Market Operator's *National electricity forecasting report* demand projections AEMO (2013b).
- The imposed assumptions were uptake of demand response activities of residential, commercial and industrial customers, including air-conditioning optimisation for peak reduction, battery storage, controlled electric vehicle recharging, and extension of industrial peak reduction markets. These activities reduce peak demand and were applied in Scenarios 1, 2 and 4.
- To determine the impact of these measures, the Forum also examined a sensitivity case in the form of a 'counterfactual': what would be the outcome if demand response was not deployed across the scenarios?

The Forum modelling projected uptake of on-site generation based on applying the technology costs discussed in this section. Uptake of on-site generation reduces the amount of consumption that must be supplied by centralised electricity generation (Figure 14). In scenarios where on-site generation uptake is high (see Figure 16), this significantly reduces the consumption required from centralised electricity generation (Figure 15).

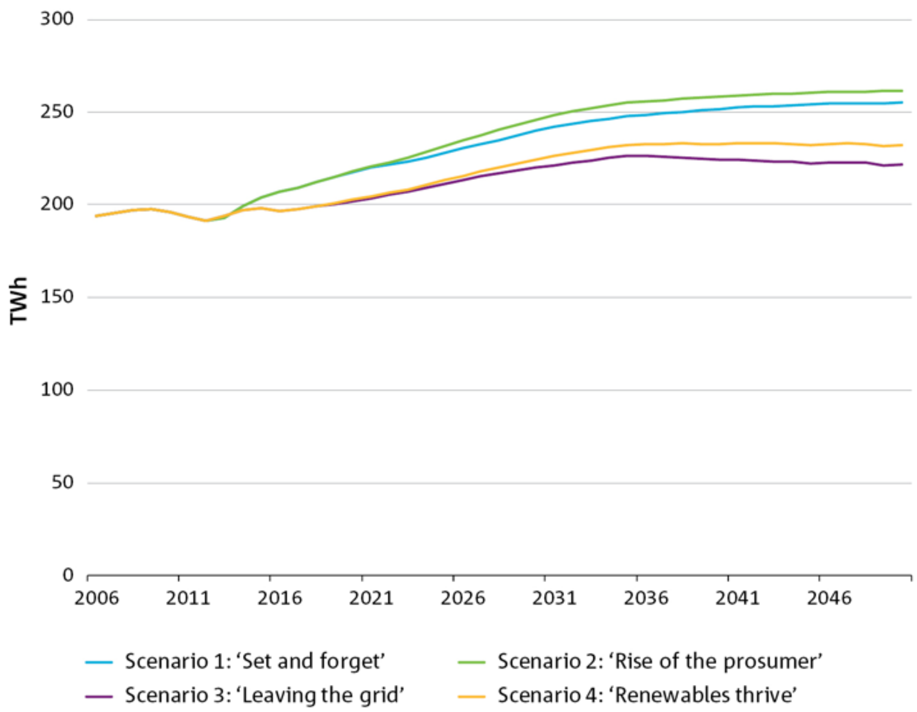


Figure 14: Projected electricity consumption supplied by the grid and on-site generation (NEM total)

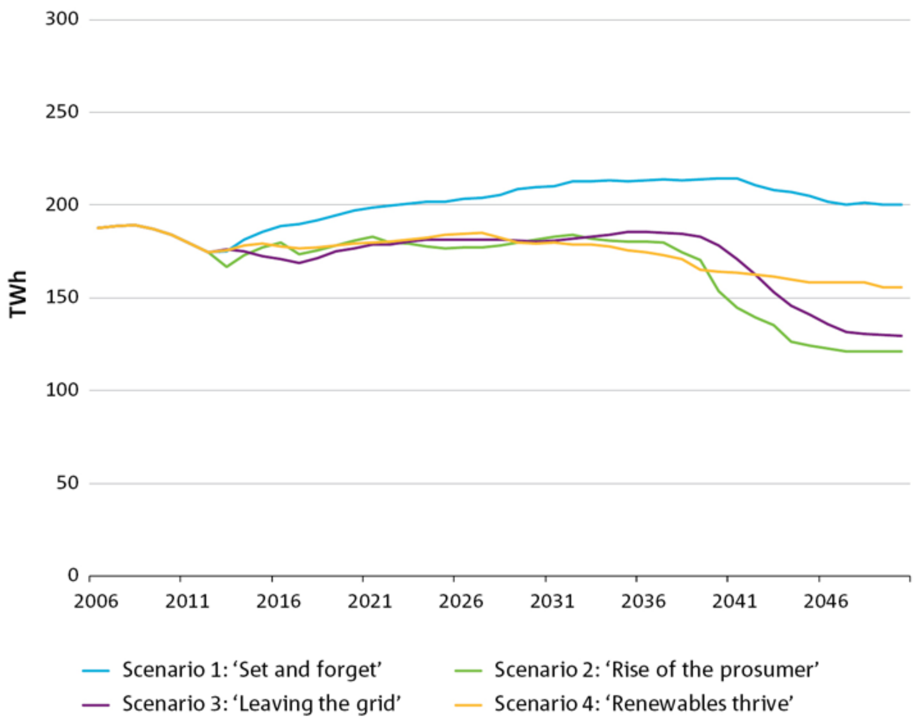


Figure 15: Projected electricity consumption supplied by the grid (NEM total)

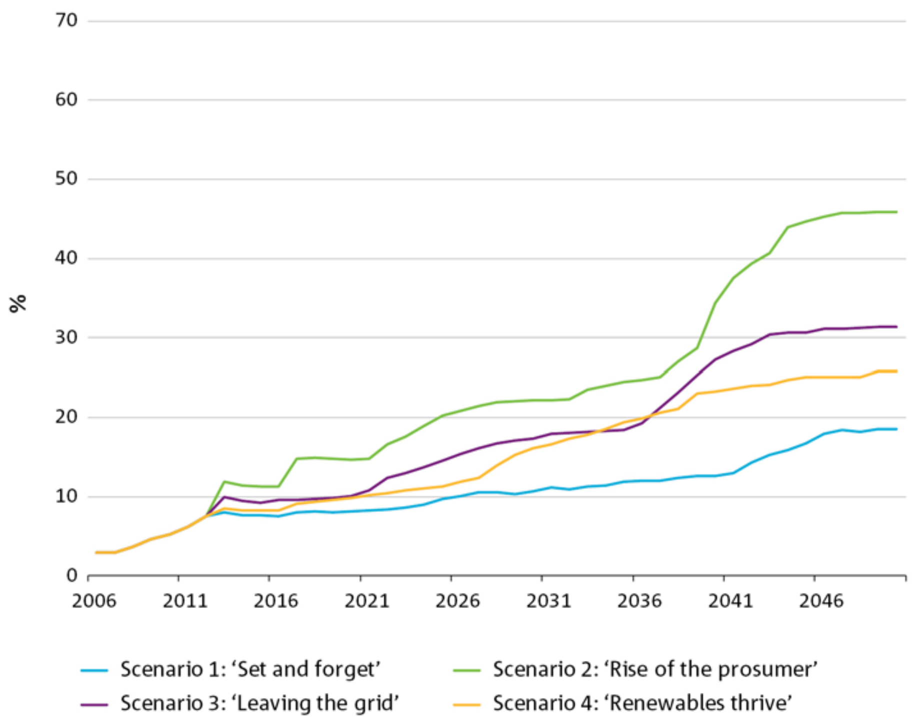


Figure 16: Projected share of on-site generation (all states)

Up to around 2020, Scenario 3 demonstrates projected peak demand without any significant adoption of consumer peak demand reduction measures; however, Scenarios 1, 2 and 4 do include peak reduction measures in their consumer choice assumptions. From around 2020, in Scenario 3, a small number of consumers begin disconnecting from the grid, accelerating rapidly from 2035. This does not represent peak demand reduction measures, but rather that the peak demand from these consumers is removed altogether from the grid. Instead, their on-site systems are managing demand and supply balance.

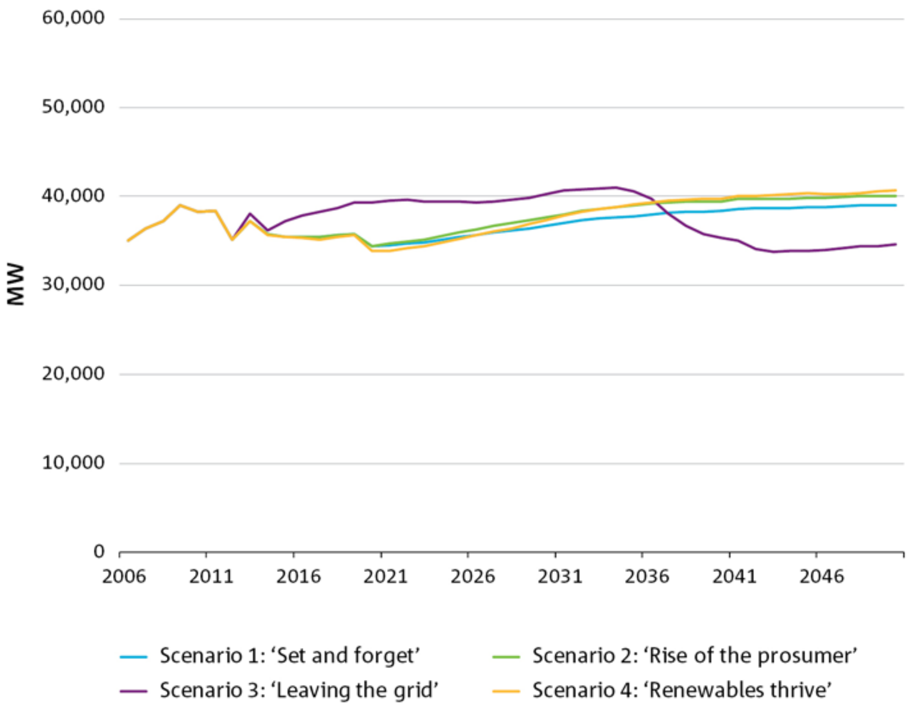


Figure 17: Projected aggregate peak demand to be met by centrally-supplied electricity (NEM total)


POWER SLEEP
TIMER RUN

Section 4: The emerging issues for electricity in Australia

Implications of shifting attitudes to reliability and the potential for customer disconnection

As noted, customers have increased the value they place on reliability, but at the same time questioned whether reliability standards are too high or too prescriptive. Part of deploying demand response measures to reduce peak demand would necessarily also open up the opportunity for customers to opt into a more tailored level of reliability. The option to participate in demand response effectively allows customers to trade off their cost of electricity against making their load available for different types of curtailment or load shifting during times of network stress (for example, off-peak water heating).

The Forum's proposed Scenario 3: 'Leaving the grid' imagines a large number of customers taking full responsibility for reliably meeting their own electricity demand through complete disconnection, and deploying on-site generation and electricity management systems. Those disconnected would not be able to maintain a link to the grid in case of back-up because they would have to pay for that link, which would void their motivation (independence and cost reduction) for being disconnected.

BUT HOW ECONOMICALLY VIABLE IS FULL DISCONNECTION?

For commercial or industrial customers with sufficient roof space, solar panels with batteries might be feasible; otherwise micro or cogeneration systems utilising gas, biomass, diesel or coal (depending on cost and distribution constraints) would also allow disconnection. Small-scale engines or turbines are well suited to load-following and are a complete technical solution, but there are some limitations. First, these customers essentially become reliant on another type of grid (fuel distribution grids). Second, costs may be prohibitive depending on their load profile. They would need to size their plant to their peak demand. If the difference in their peak-to-minimum demand is very large then the plant will achieve a low utilisation of capital, which may result in a prohibitively high unit cost of electricity. Third, given fossil fuel and carbon prices are expected to rise over time, plant running costs would be expected to increase (for those that are liable for greenhouse gas emissions in any given future scheme).

Microgeneration systems also would be technically viable options for residential and small commercial consumers, but they are generally more expensive at smaller scale and would be subject to the same limitations.

For Scenario 3: 'Leaving the grid', the Forum considered solar photovoltaic panels for the main on-site electricity source because they are most in keeping with the scenario theme of independence, particularly for households. The major challenge with solar panels would be to manage electricity supply from the panels with battery storage to cover general variability, non-daylight load and temporary cloudy periods.

The battery system would need to be sized for all of the demand that is non-coincident with solar output and also take into account round-trip efficiency of 70 per cent and 80 per cent useful charge range. Hot water heating would be relatively straightforward to arrange during the day given it has built-in thermal storage, but a more sophisticated demand control system would be required to shift the loads of other appliances. Ultimately, there would be a limit to what can be shifted and any demand control systems would need to be included in total system costs.

The battery and solar systems would need to be sized to meet daily energy consumption and peak load (when most appliances are switched on). Households that have large air-conditioning systems, pool pumps or other large power devices would need larger systems.

During extended solar panel outages or unfavourable weather, it would be cost-prohibitive to rely solely on battery storage capacity. Instead, it would make sense to rely on some sort of generator using petrol, diesel or gas. Households with high power needs might factor in being able to use their generator for occasional periods where the demand is very high. Biodiesel would be a potential solution to maintain the environmental values of the installation. Local council regulations, however, might prohibit generators if they produce significant noise and local air pollution.

If the consumer also wants to charge an electric vehicle, they would need a system capable of storing and charging typically an extra 6 kilowatt hours a day or have access to public recharging. This does not increase the unit cost of electricity for the installation but might, if it's not already doing so, press the limits of roof space. For the purposes of Scenario 3, modelling allows for the potential development of alternative organic or structural photovoltaic panels which would increase the surface of the house available for electricity generation.

Sensitivity testing of different levels of household consumption (Graham et al 2013b) estimates the current cost of household disconnection to be 92–118 cents per kilowatt hour. Based on a number of studies discussed earlier, the Forum assumed a 50 per cent reduction in storage costs by 2030. As a result, disconnection is projected to cost 42–53 cents per kilowatt hour by 2030. Assuming a 75 per cent reduction in costs relative to 2013, by 2050, the cost of disconnection is projected to be 20–24 cents per kilowatt hour.[15] On the basis of these assumptions, disconnection will not be economically viable until after 2030, but would be before 2050 under retail cost projections (discussed in the following section).

15 Detailed assumptions are provided in Graham et al (2013b).

Implications for costs and electricity bills

NETWORK UTILISATION

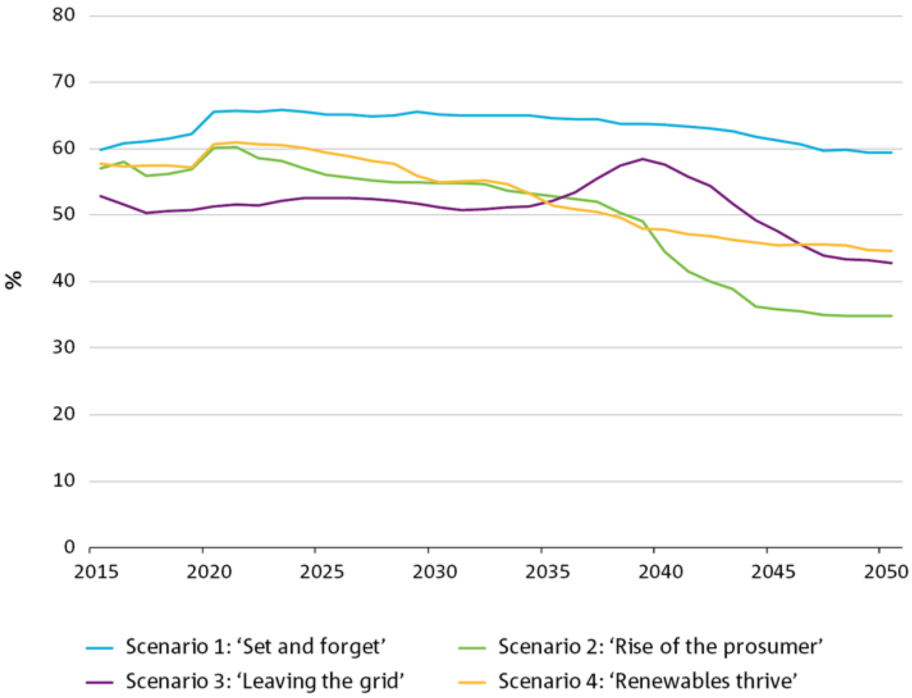


Figure 18: Projected distribution network aggregate load factor under the Future Grid Forum scenarios

Falling network utilisation as measured by the aggregate load factor of the system[16] will be a major challenge to containing further increases in electricity unit costs. Figure 18 shows the trend in distribution network aggregate load factor for each of the Forum's scenarios. The main drivers of utilisation across the scenarios are the underlying rate of growth in consumption and peak demand, whether peak demand is managed, the rate of adoption of on-site generation, and consumer disconnection.

In Scenarios 1, 2 and 4, distribution network utilisation initially improves because peak demand is reduced at the same time as consumption is growing. Electricity consumption is growing in all scenarios, at an average rate of 0.6, 0.7, 0.3 and 0.4 per cent a year in Scenarios 1 to 4 respectively between 2015 and 2050.

From the 2020s, the utilisation rate begins to decline as a result of the uptake of on-site generation (Figure 16), which decreases the amount of consumption that needs to be supplied by the grid.[17]

The incidence of declining network utilisation begins earliest and the rate is strongest in Scenarios 2 and 4 because they have stronger uptake of on-site generation. Beyond adoption of the peak demand response measures already included in Scenarios 1, 2 and 4, the Forum scenarios do not assume any other specific responses to this issue by network owners.

Scenario 3 does not include any peak demand reduction measures and this is the major reason for the lower utilisation through to 2035. On-site generation also plays a role, but its impact is different to the other scenarios. When customers in Scenario 3 adopt on-site generation they leave the grid entirely so the system loses responsibility for both their consumption and their peak demand. When the disconnection rate is strongest, around 2035, the loss of these customers temporarily improves utilisation because those leaving the grid tend to be smaller residential and commercial consumers who have a higher contribution to peak demand. However, as the level of disconnection stabilises, the declining trend reasserts itself.

16 This is a simplification of the modelling approach. These are related but different concepts. Network utilisation is the ratio of energy supplied to the maximum energy that could have been supplied by the network capacity. The load factor is the ratio of energy consumption to the maximum potential energy throughput implied by peak demand. Also, below system-level, utilisation rates will vary considerably by location.

17 On-site generation could also make a contribution to peak reduction through the use of storage technologies or other load-following capability; however, the distribution network will still need to build capacity that is capable of providing for events where on-site generation is not able to respond (for example, on-site generation is at maximum output or electricity storage is drained).

DISTRIBUTION UNIT COSTS

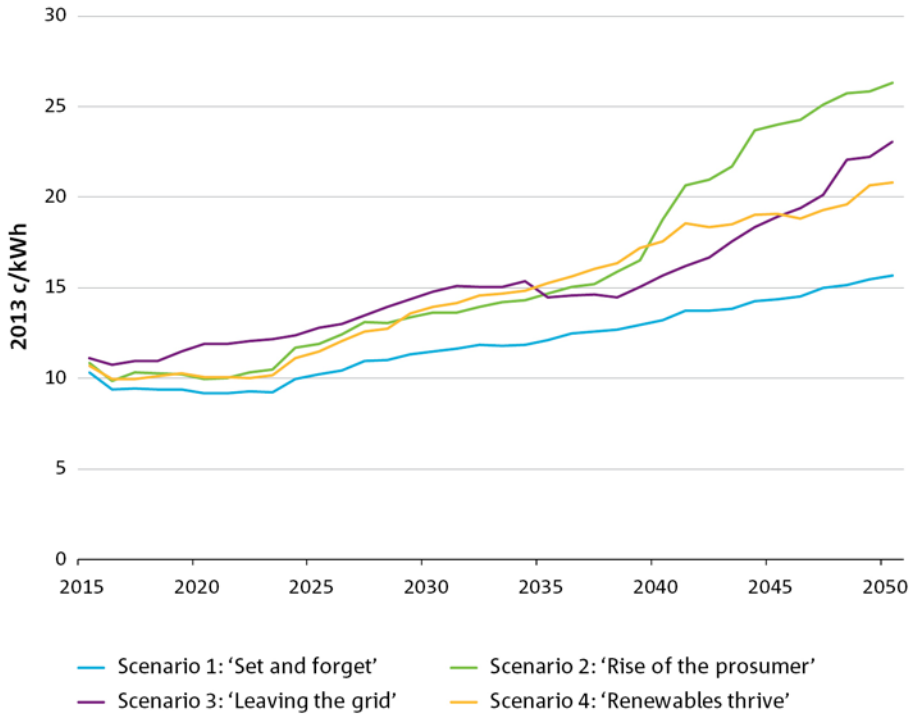


Figure 19: Projected distribution system unit costs (real 2013 Australian dollars)

Figure 19 shows the outcome of the outlook for distribution network utilisation on distribution unit costs. For simplicity, the analysis here shows distribution charges on a per unit of consumption (kWh) basis; however, customers will face a mix of different tariff structures depending on their load.

Up to around 2025, distribution unit costs are stable or declining in three of the four scenarios, reflecting the assumed peak demand, on-site generation and energy-efficiency customer behaviours, and subsequent impacts on network utilisation.

The improving network utilisation up to 2025 does not lead to a major reduction in distribution costs because investments in network expansion and reliability are long-term investments that are paid off through regulated returns to network owners over many decades. Operating and maintenance expenses during the life of the asset add to the costs. Therefore, even if future peak demand growth is contained or reduced, under current regulatory arrangements previous investments in network expansion and reliability will place a floor on unit distribution costs for a considerable time to come. This is not to say, however, that peak reduction activities have no benefit under current regulatory arrangements. The modelling finds that distribution unit costs would be 2 cents per kilowatt hour higher on average in Scenario 1 if peak reduction measures had not been implemented.

The potential for declining utilisation due to the combined impact of energy efficiency and increased use of on-site generation seems reasonably plausible and to some extent self-fulfilling under current market arrangements. High electricity prices encourage uptake of energy-efficiency measures and on-site generation, which leads to lower consumption. As is clear from the Forum modelling, lower consumption increases the per unit cost of distribution that would be passed through to all users under current volume-based tariffs and encourages the further adoption of energy-efficiency and on-site generation. The decreasing cost of on-site generation technologies increases the likelihood of these outcomes.

GENERATION SECTOR COSTS AND GREENHOUSE GAS EMISSIONS

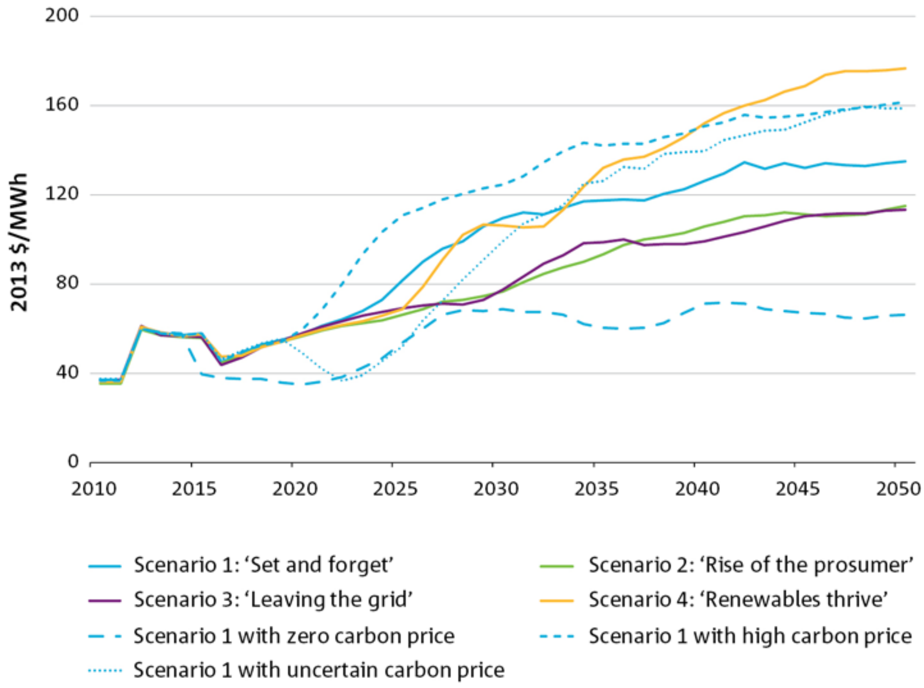


Figure 20: Projected average wholesale electricity unit costs by scenario and a zero, high and uncertain carbon price sensitivity on Scenario 1

Fuel costs, technology costs, carbon policy and the rate of consumption growth will influence future wholesale electricity generation prices. The Forum scenarios all include a carbon price consistent with Australia participating in global action to achieve greenhouse gas reductions that would result in a global concentration target of 550 parts per million carbon dioxide equivalent. The variation in projected wholesale prices that is evident in Figure 20 is therefore a function of other factors within the scenarios, with the exception of three sensitivity cases on Scenario 1: a zero carbon price, a high carbon price, and an uncertain carbon price.

The zero carbon price sensitivity case shows the projected wholesale electricity price if the carbon price were removed from Scenario 1 in 2014. In that case, the wholesale electricity price would revert back to the level before carbon pricing was introduced, just below $40 per megawatt hour and remain at that level for several years. The wholesale price level of $40 per megawatt hour is not high enough to cover the full cost, including returns to investors, of any type of electricity generation that could currently be built (BREE 2012). Wholesale prices can only remain below the cost of new plant while the market is in excess supply, which is projected to remain a feature of the market until after 2020. After 2020, the wholesale price increases to cover the level of replacement cost of new plant, which is around $70 per megawatt hour; this is above the 2013 wholesale price inclusive of a carbon price.

Under the uncertain carbon price sensitivity case, a carbon price signal is maintained to 2020 given this is the period in which there is bipartisan support for an emission target, but thereafter the investor faces the prospect of a wide range of carbon prices. Under these circumstances, the investor must narrow its choice of technologies to those that will achieve reasonable returns across a number of scenarios, rather than to those that will optimise returns for a single given carbon price scenario. The result is that the wholesale electricity price is projected to be 17 per cent ($24 per megawatt hour) higher by 2050.[18]

18 Nelson et al (2010) find an $8.60 per megawatt hour additional cost, but their study was focused on 2020.

Turning to the scenarios that do include a single positive carbon price, the initial dip in the wholesale electricity price in 2016[19] in Scenarios 1 to 4 reflects the assumption of the shift to internationally linked emission trading and the expected initially lower carbon price, particularly in Europe which would be an early linking partner. The lower trajectory of Scenarios 2 and 3 reflects that energy consumption supplied by the centralised grid is flat or declining in those scenarios (owing to high on-site generation), which tends to keep prices lower.

The wholesale electricity price increases the most in Scenario 4 where, in addition to a carbon price, there is a policy of achieving a 100 per cent renewable share in centralised electricity generation (resulting in an 86 per cent share of renewable when on-site generation is taken into account in total generation). Under this policy, the set of allowable technologies in centralised electricity generation is gradually narrowed over time to only renewables by 2050 as an extension of the existing 20 per cent by 2020 target. Natural gas is also ruled out in on-site generation, but diesel remains permissible because of its flexibility in remote and uninterruptible power applications. The assumption of cost-effective electricity storage supports the high renewable share. Schedulable renewables, such as enhanced geothermal systems and biomass, also play a role in supporting other variable renewable sources, such as wind and solar photovoltaic systems. This is similar to the results of other studies, such as AEMO (2013a).

The cost of limiting the centralised generation technology set to only renewables is a wholesale electricity price that is 31 per cent higher than Scenario 1 by 2050.[20] It is also higher than the Scenario 1 high carbon price sensitivity case. The high carbon price sensitivity case imposes a carbon price that is consistent with global action to achieve a 450 part per million carbon dioxide equivalent concentration target, but does not restrict the technology available to do that. Under that sensitivity case, the centralised electricity system, given the choice, adopts a significant amount of natural gas and coal-fired generation with carbon capture and storage. These technologies are not emission-free like renewables, but have emission factors that are quite low, around 0.1–0.2 tonnes of carbon dioxide equivalent per megawatt hour compared with the 2013 system average of around 1 tonne of carbon dioxide equivalent per megawatt hour.

The national emissions target for Australia by 2050 is an 80 per cent reduction in the 2000 level of emissions. In a national emission trading scheme there is no obligation that each industry sector contributes exactly their proportional share of emission abatement towards that target. Rather, contribution should be on the basis of marshalling the most reductions from the sectors with the lowest cost of abatement. The Treasury (2011) found that under the 550 parts per million carbon dioxide equivalent concentration carbon price path, the electricity sector makes a slightly less than proportionate contribution (a 77 per cent reduction) to the national target. Under the 450 parts per million carbon dioxide equivalent price path, the electricity sector makes a greater than proportionate contribution (an 87 per cent reduction).

The modelling here finds much the same result (Figure 21). Under the 550 parts per million consistent carbon price, Scenarios 1 to 3 achieve abatement of between 55 per cent and 70 per cent below 2000 levels by 2050. If a 450 parts per million consistent carbon price is imposed on Scenario 1, it delivers an 89 per cent reduction by 2050 relative to 2000 levels. If, as in Scenario 4, a 550 parts per million carbon price and a 100 per cent renewable target emission are combined, abatement also of 89 per cent below 2000 levels by 2050 is achieved.

19 At the time the modelling was conducted, the government had flagged an earlier shift to emission trading, but had not implemented it.

20 This projection is higher than that found in the AEMO (2013a) study; however, AEMO (2013a) is lower for three reasons. The first is it assumed all renewable technology could be purchased at the price prevailing in the modelled year. In reality, most plant would have been purchased in previous years at higher cost. Second, AEMO (2013a) does not include the cost of transforming from the present system, which would involve implementing a price signal for any fossil units built before 2050 to shut down. This price signal may need to be reasonably high given it is likely the capital costs of any fossil plant would be regarded as sunk once constructed. Finally, AEMO (2013a) used biomass converted to biogas in peaking plant as back-up to variable renewables, but Forum modelling finds any available bio-energy resources would be purchased by the transport industry.

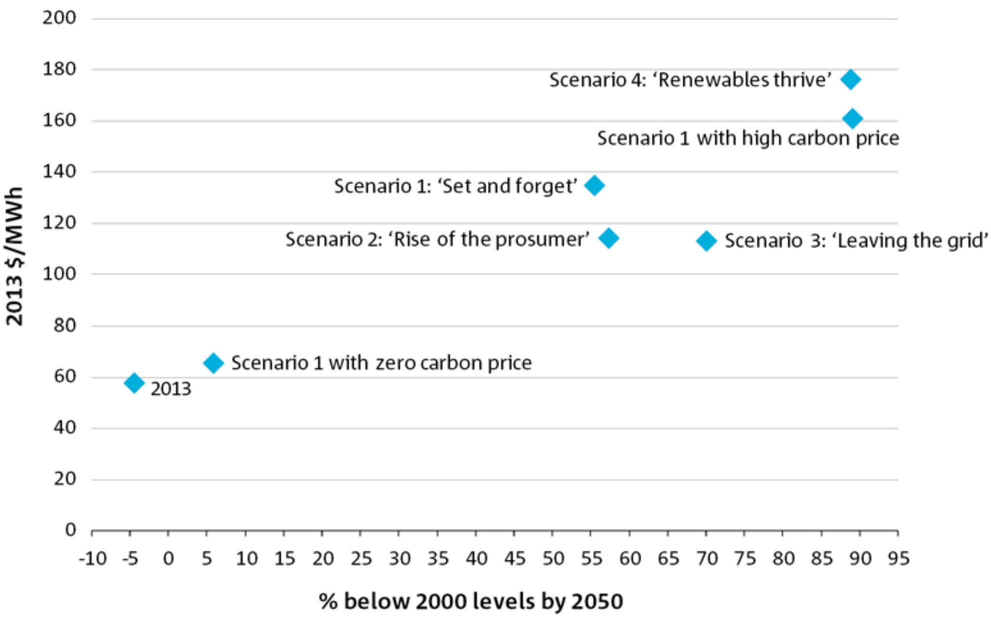


Figure 21: Projected average wholesale electricity unit costs and per cent below 2000 greenhouse gas emission levels in 2050 by scenario and a zero and high carbon price sensitivity on Scenario 1 compared to 2013

WHOLE-OF-SYSTEM COSTS

The increasing per unit of consumption cost pressures from decreasing network utilisation in the distribution and transmission sectors, together with carbon policy and higher generation plant replacement costs following weak market conditions in the next decade in the generation sector, mean that in total the retail unit costs of electricity are projected to rise under the Forum's scenarios (Figure 22). All scenarios are remarkably similar up to 2030 because those with higher transmission and distribution costs (due to weak consumption growth causing low utilisation) receive an offsetting reduction in generation costs which are low under these conditions (a greater number of assets with sunk costs generate at below long-run marginal cost). The reverse occurs under higher utilisation in Scenario 1.

By 2050, however, Scenario 1 has the lowest increase in unit costs because its lower growth in distribution and transmission costs eventually more than offsets the higher cost of generation. Scenario 4 has the higher unit retail costs by 2050 as a result of its high generation costs. Unit costs, however, are not necessarily the most valid indicator of costs. Unit costs ignore volume and scale. An alternative measure is cumulative system expenditure (Figure 23). This includes all expenditure on capital, operations and fuel in the generation, distribution and transmission sectors.[21] It also includes a cost for off-grid expenditure, such as on-costs for 'smart'-enabled appliances, smart meters or other equivalent control and communication devices and on-site storage. On-site generation appears in 'generation' if it is connected and in the 'off-grid' category if it is disconnected.

21 The calculations ignore the retail sector for this analysis because it is assumed to be a fairly constant value across scenarios. Even in Scenario 3: 'Leaving the grid', retail costs would potentially be substituted with other costs from energy service companies.

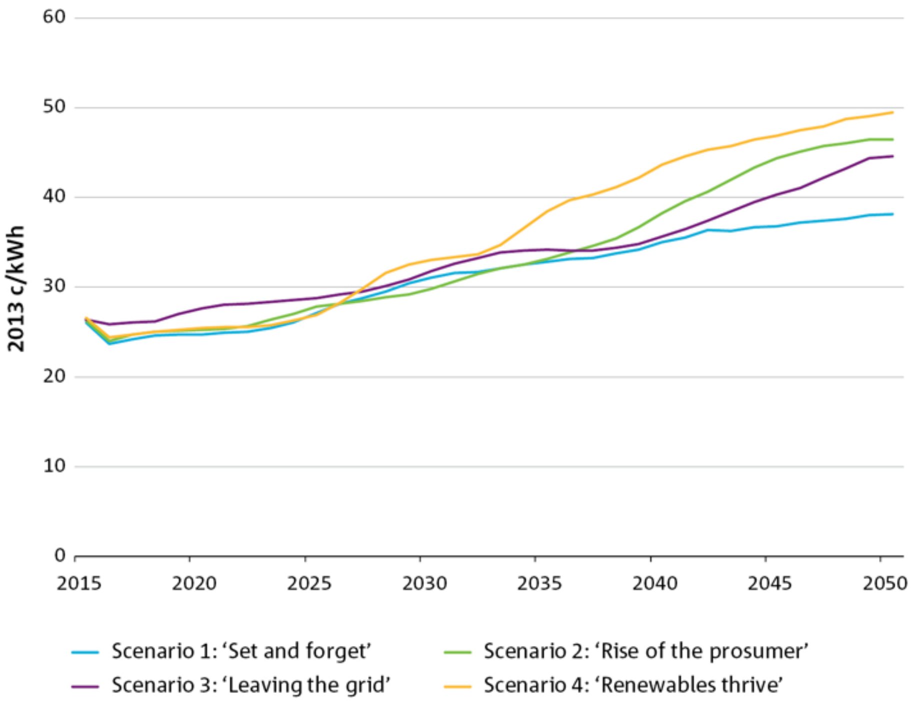


Figure 22: Projected unit cost of retail electricity supply from the centralised grid by scenario

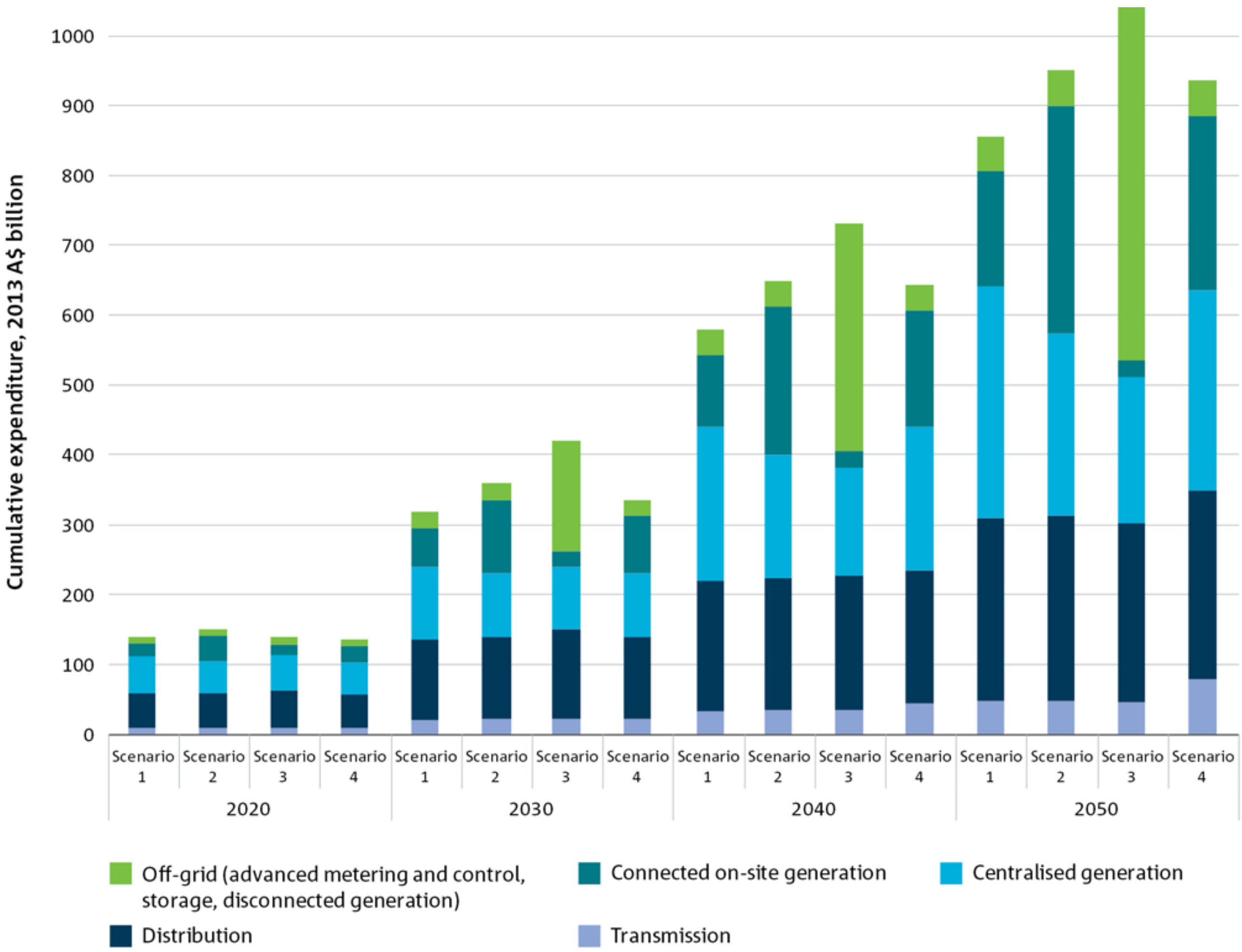


Figure 23: Projected cumulative system cost by scenario to 2050

From a cumulative system expenditure point of view, Scenario 1 is the lowest cost scenario from 2030 to 2050. Management of growth in peak demand has been important in achieving this result. Scenarios 2 and 3 result in the highest system cost outcomes. In Scenario 2 this reflects that while uptake of on-site generation has been optimal for individuals, it has caused some duplication in the system since generation, transmission and distribution capacity must still be developed and maintained for when on-site generation needs to be backed up.

In Scenario 3 the high cost outcome reflects the off-grid cost of disconnecting and the high growth in peak demand for the remaining connected customers, which means the system is not significantly downscaled even after the significant loss of customers.

Looking at system costs for Scenario 4 reveals it is the lowest-cost scenario during the 2020s and remains second lowest for the remainder of the projection period. This reflects that Scenario 4 includes both significant peak reduction and energy efficiency, which means that system investment is kept to a minimum. Costs under that scenario only rise above Scenario 1 from 2030 due to generation investment to meet the 100 per cent renewable target for centrally-supplied electricity.

CUSTOMER IMPACTS

Residential

This analysis highlights the importance of considering both unit and total system costs, but to break it down further and to understand consumer impacts, the Forum considered a residential electricity bill since that encapsulates paying a unit price, a given volume of electricity consumption, and the opportunity to consider on-site generation (Figure 24). It is assumed on-site generation, if connected, is sold back to the electricity grid at a price consistent with the retail unit cost minus retail and distribution cost components (and this reduces annual electricity costs). Scenarios 3 and 4 include their existing assumption of 0.7 per cent a year lower electricity consumption per household, while Scenarios 1 and 2 have a slower 0.3 per cent a year improvement over the current average rate of electricity consumption of 6,000 kilowatt hours a year.[22]

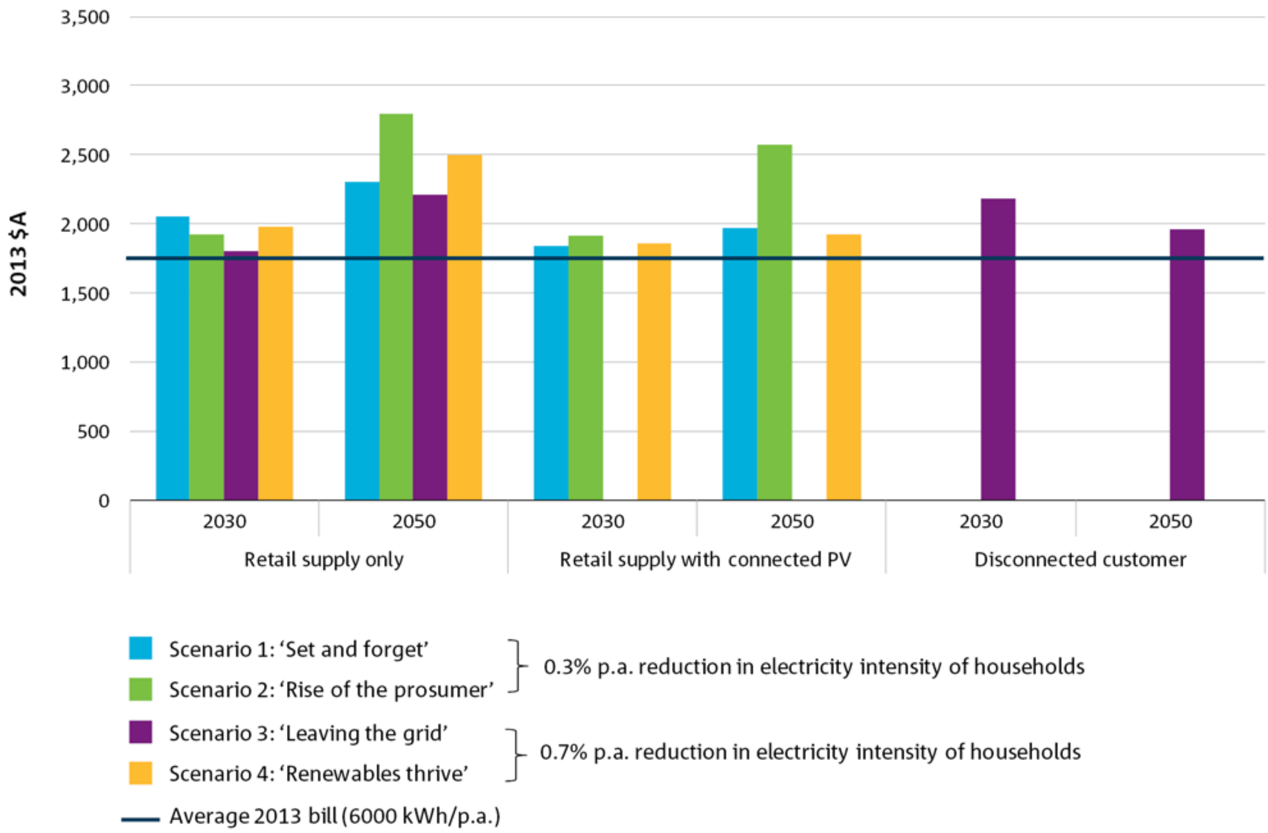


Figure 24: Projected net annual electricity cost (retail bill minus PV export payments plus amortised on-site costs where relevant) under alternative scenarios and household types

22 These were based on AEMO (2013). As a guide to potential household electricity consumption, ClimateWorks (2013) recommends 0.7 per cent a year as a central estimate within a high energy efficiency scenario of 2.2 per cent a year improvement and a low scenario of 0.8 per cent growth in electricity consumption.

The analysis shows that by 2030, the best outcome for the residential consumer is to have a reduced rate of electricity consumption and either contract all of their electricity supply from the grid or adopt solar panels if the retail electricity price is higher, as is the case under Scenario 4. Under all scenarios, there is almost no increase in the household electricity bill by 2030 compared with today. However, if the residential consumer is unable to achieve a high rate of electricity efficiency improvement (as in Scenarios 1 and 2), the best option for the household is to adopt solar panels because this will result in a modest reduction in costs relative to retail supply only. Note, the difference in owning and not owning connected solar panels is not large in 2030 and would depend on specific feed-in tariffs secured and the profile of household electricity use (as it does now).

By 2050, the projections indicate it is financially preferable for all residential consumers to have some type of on-site generation rather than grid supply only. The lowest cost outcome for grid-connected households with on-site generation occurs under Scenario 1 followed by Scenario 4; however, if more households choose on-site generation to reduce net electricity bills then the assumptions of these scenarios are violated and consumers shift into the world of Scenario 2: 'Rise of the prosumer' where there is much broader uptake of on-site generation and subsequent higher unit retail costs due to lower network utilisation.

If, however, the assumed 75 per cent reduction in battery costs by 2050 emerges, then complete disconnection will potentially be a preferable option than remaining connected as in Scenario 3: 'Leaving the grid'. If, however, those circumstances do not arise then, again, remaining connected with some on-site generation is the preferred outcome. From a big picture point of view, there is a sense that, over time, circumstances will tend to push customers towards adoption of on-site generation and potentially into disconnection, with the plausibility of this latter step highly depending on costs of storage systems relative to any changes in the cost of network connection charges.

Of course, all of the scenarios represent an increase in electricity bills by 2050, but does this mean electricity is a greater share of our household budget? To determine that, the Forum needed to consider whether there were compensating increases in income. The most appropriate projections of future increases in real wages are from the Treasury (2011), which considered how the economy grows under a carbon price. In that analysis, real wages increased by around 37 per cent to 2050 under a 550 parts per million consistent carbon price.[23]

The current share of the electricity bill in an average wage is 2.5 per cent. This share slightly improves (declines) or is maintained by 2030; however, the projected 37 per cent increase in real wages from 2013 to 2050 is not enough to offset the increases in electricity bills to 2050 across all scenarios (Figure 25). The future share of the electricity bill in the real wage is projected to be 2.3–2.9 per cent depending on the scenario (Figure 25).

While the average wage earner is not likely to experience significant financial stress as a result of increased electricity prices, vulnerable groups for whom electricity is a greater share of their expenditure and whose income may not keep pace with real wages would be more significantly impacted. The most vulnerable will be those dependent on unemployment programs such as Newstart and single parents and pensioners who do not own their own home. For Newstart recipients, the current share of electricity in their income would be around 14 per cent at average electricity consumption.

In Figure 25 the Forum examines the pensioner's share of electricity in their income since the future indexing arrangements for pensions are more settled. For a pensioner, the current share of an electricity bill in the pension payment (assuming average consumption) is 9 per cent and this is projected to be between 8 and 10 per cent across the scenarios. Welfare recipients with large households to support will be worse off, while those with lower electricity consumption and the capacity and knowledge to invest in energy efficiency will fare better. Governments will need to consider whether the current form and level of social safety net payments is adequate for managing the general cost of living, including electricity costs, for those at risk of experiencing hardship.

23 Technically, the wages growth projection is an over-estimate because the economic growth modelled by Treasury under a carbon price takes into account the cost to the economy of reducing emissions, but not the cost of climate change impacts. Climate change impacts will be partially mitigated by the abatement activity, but not reduced to zero, due to the inertia in the climate system and continued emissions along the global abatement path.

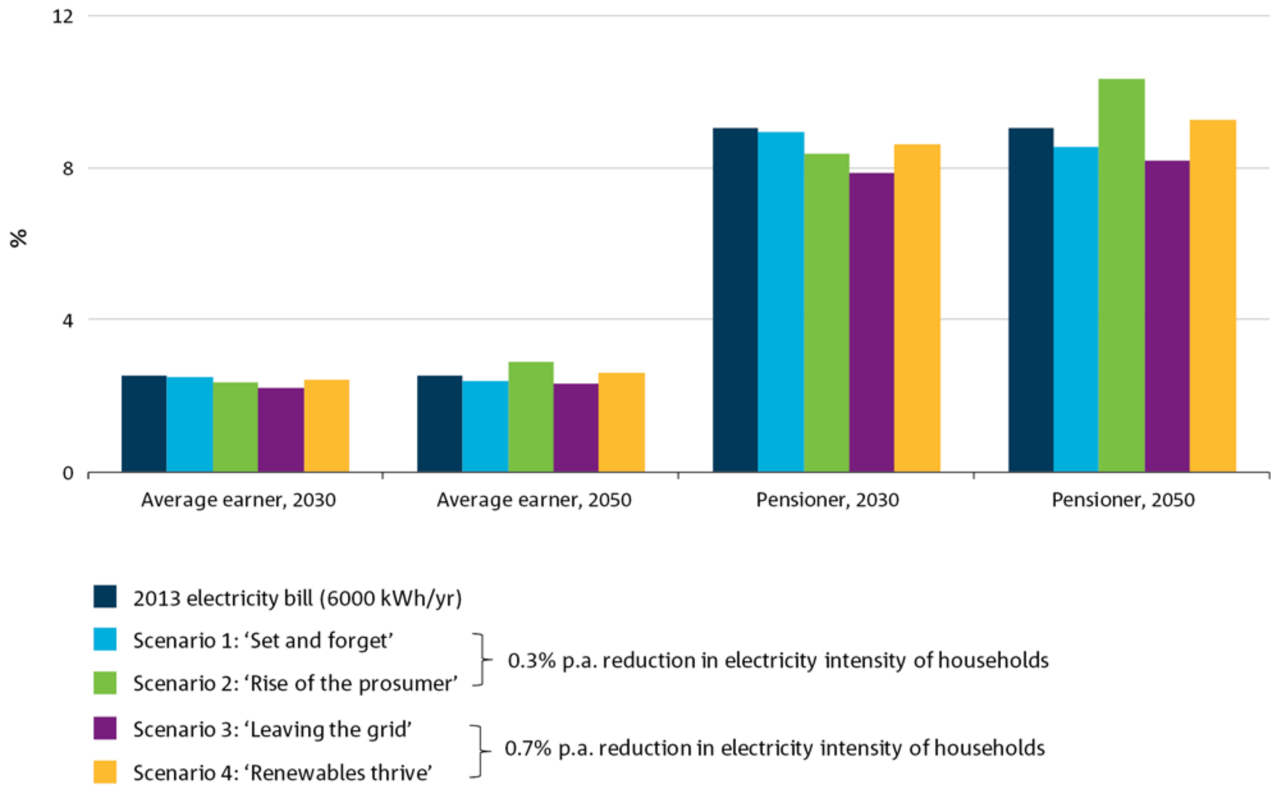


Figure 25: Residential electricity share of income in 2030 and 2050 by scenario

Commercial and industrial

Electricity price increases will not uniformly impact each industrial and commercial sector of the economy, but rather will impact the cost of production the greatest for those industries with the highest electricity intensity. Figure 26 shows how this varies across key industry and commercial sectors. Manufacturing, which is the most electricity-intensive sector, includes food, beverages, textiles, wood, paper, printing, petroleum and chemical products, iron and steel, and non-ferrous metals, such as aluminium.

Each scenario assumes the commercial sector reduces the intensity of its electricity consumption through building and equipment energy efficiency. In Scenarios 1 and 2, electricity intensity is reduced by 6 per cent and 12 per cent by 2030 and 2050 respectively. In Scenarios 3 and 4, the improvement is 14 per cent and 26 per cent by 2030 and 2050 respectively, based on AEMO (2013b). The projections on which the Forum's scenarios were based did not assume any specific industrial energy-efficiency measures (AEMO 2013c); however, ClimateWorks (2013) has observed that industrial energy efficiency has been improving at 1.1 per cent a year and there are sufficient opportunities to continue the trend until 2020, after which the potential is less certain. Continuation of the current trend would imply a 20 per cent and 26 per cent reduction in industrial electricity intensity by 2030 and 2050 respectively.

Small commercial customers have similar cost components in their electricity bill as residential consumers, but with some differences in network and retail costs depending on the supplier. As such, changes in residential bills are a reasonable proxy for the expected proportion of change in their electricity bills. For larger commercial and industrial customers, however, their electricity charges are structured differently. They have significantly lower retail and network costs (per kilowatt hour) in recognition that there are significant economies of scale in being able to service a single customer who consumes several hundred (large commercial) to many thousand (industrial) times the volume of a residential or small

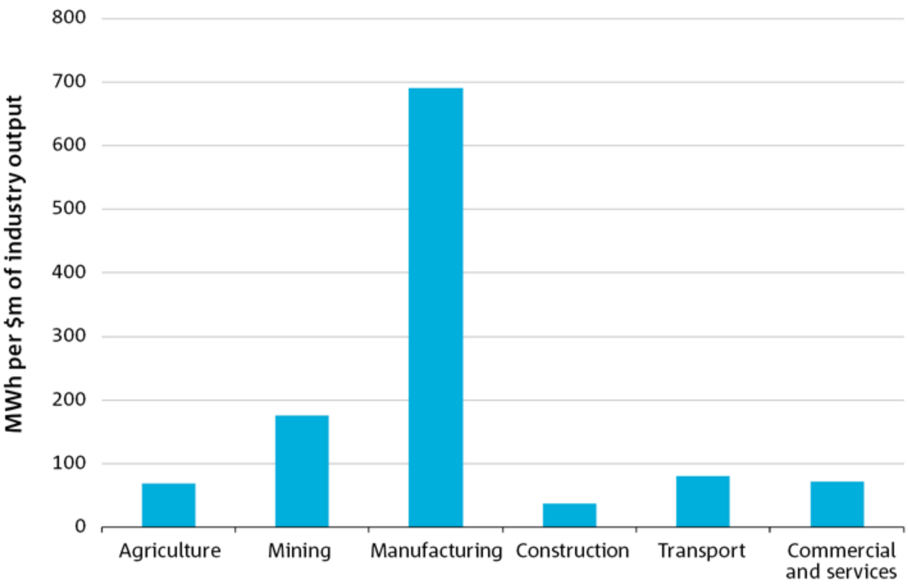


Figure 26: Megawatt hours of electricity required per million dollars of output by industry category

Source: ABS (2013b)

commercial consumer. This means that the costs of generation (rather than network and retail) are a much stronger determinant of impact on commercial and industrial electricity bills—industrial customers even more so than large commercial customers.

Figure 27 shows the projected change in commercial and industrial electricity bills, inclusive of commercial sector electricity intensity improvements.[24]

Overall, the projections indicate commercial and industrial electricity bills will increase in real terms; more so in the period after 2030, in a similar outcome to that for residential consumers. The Forum cannot know, without examining each of the relevant markets (which is outside the scope of this study), whether these commercial and industrial customers are able to absorb these cost increases.

Industrial customers who were assumed to make no changes in electricity intensity of consumption, and are the most exposed to generation cost increases of approximately 100 to 200 per cent across the scenarios, are projected to experience the strongest increase in electricity bills. For both large commercial and industrial customers, Scenarios 1 and 4 result in the highest electricity bills because these have the greatest increases in wholesale electricity generation costs in 2030 and 2050.

In the immediate decades, these customers might be eligible for schemes that partially exempt them from carbon price components of electricity generation unit costs if they are competing with countries that have not yet made the same commitment to greenhouse gas reduction.[25] Also, as discussed, the present estimates do not include actions to reduce industrial electricity intensity of output, for which there is significant potential.

Addressing the risk of declining network utilisation

The Forum scenarios have highlighted the risk that network utilisation might decline if consumption of centrally-supplied energy is flat or declining while peak demand is increasing. Together with the debate about reliability standards (discussed earlier) and general uncertainty in future demand highlighted by the Forum's scenarios, there is a case for considering the future of network investment regulation.

For peak demand, a number of reviews, such as the Australian Energy Market Commission's *Power of choice* in 2012 and the Productivity Commission's *Electricity network regulatory frameworks* in 2013, have recommended measures to reduce the aggregate peak demands at the generation, transmission and distribution levels. These measures include:

- ensuring there is a competitively neutral environment for investment and innovation in demand response (including storage, smart appliances, advanced metering and various types of energy management systems) in order

24 See Graham et al (2013b) for assumed tariff and electricity consumption.

25 The current policy is called the Emission-intensive Trade-exposed Industry Assistance Package.

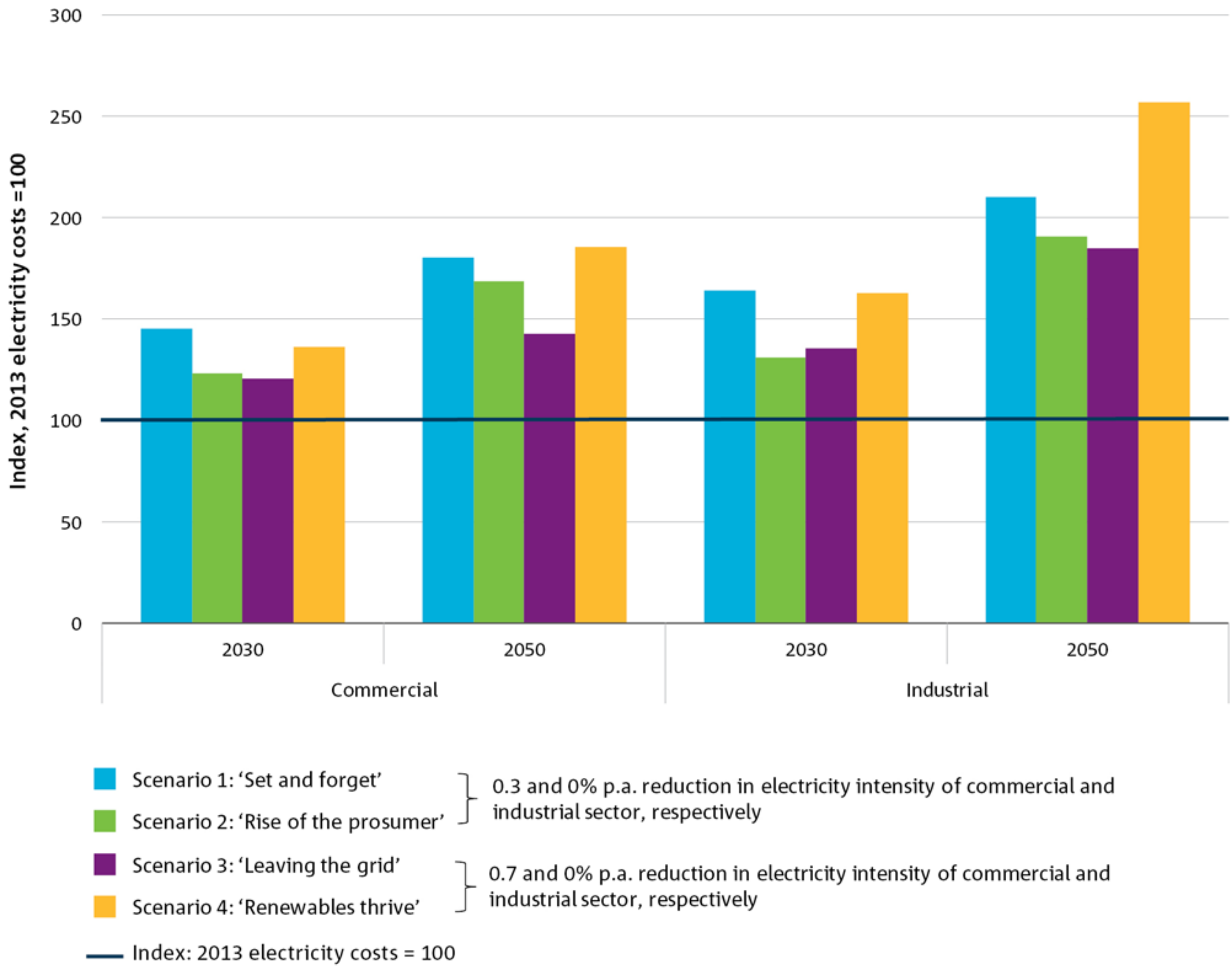


Figure 27: Index (2013=100) of projected changes in commercial and industrial electricity bills

to address concerns that current regulations may provide unbalanced incentives towards building additional network capacity to meet demand

- implementing strategies to allow more cost-reflective pricing
- developing standards and regulations that allow the relevant technologies to be integrated
- expanding delivery of information which supports market choices.

The forum scenarios highlight the need to accelerate the evaluation and, if appropriate, implementation of reforms such as these to support peak demand reduction. However, electricity market reform in Australia is necessarily slow because of the multiple jurisdictions involved in decision-making and the need for robust information and consultation processes.

There is a risk that some future potential market developments could outpace the market reform process, which can only be fully implemented at the end of the five-year pricing periods under which the current regulation operates. As such, benefits of reform can take a long time to flow through.

Besides reducing peak demand, one could also consider whether Australia's system of regulating networks may need to change. As regulated monopolies, customers in most normal circumstances share the risk of under- or over-investment in network capacity with the network companies. Under the current National Electricity Law and Rules, the risk of financial stranding is constrained to circumstances where capital expenditure is undertaken above regulatory allowances. Network investors receive a regulated rate of return on existing capital assets.

However, given a fundamental assumption of existing arrangements—monopoly supply—is potentially challenged by increasingly sophisticated on-site generation and demand response, a process may need to be established to identify changes, if any, that might be required to market frameworks.

Some potential options that would moderate declining utilisation are:

- even greater reductions in peak demand than those already included in the Forum scenarios (which were around 10 per cent)
- giving greater consideration to on-site generation, which has a lower risk of underutilisation as an alternative to network capacity augmentation
- identifying new markets for electricity consumption that would support increased throughput.

Electrification of road transport is one potential new market that would also contribute to delivering more efficient, low-emission transport as the emission intensity of electricity declines relative to petroleum fuels. The Forum scenarios already include additional demand from this sector of 25–45 terawatt hours, representing 19–37 per cent of road kilometres by 2050 (Figure 28); however, even greater adoption of road transport electrification could be economically viable depending mostly on electric vehicle costs and oil prices. It might also be appropriate to reconsider under what circumstances electric hot water heating should be allowed or discouraged. For example, as wind penetration increases, its output tends to contribute a greater proportion of total overnight generation, which could mean electric systems approach the environmental credentials of alternative water heating systems.

Finally, to address consumption, it will also be important that price signals for energy efficiency and the cost of connecting, and payments for exporting from on-site generation, are both cost- and benefit-reflective so that tariff arrangements do not play a distorting role in their rate of adoption.

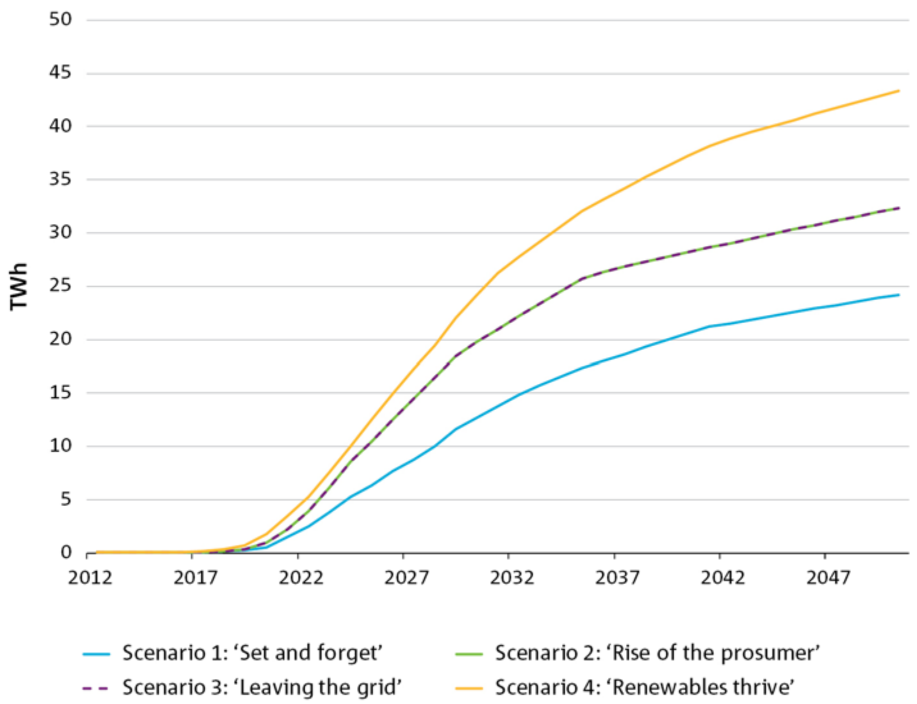


Figure 28: Projected electricity consumption from road electrification by scenario

Implications of the lack of connection between consumer prices and service costs

The Forum believes more cost-reflective pricing would provide a number of benefits to the system and there is wide scope for change in the residential sector where it has primarily been lacking, provided consumers are given the information and tools to make choices. Table 1 describes four tariff options that represent the general range of options available: fixed volume, seasonal time-of-use, critical peak, and combined capacity and volume. These are not the only options, but even this small list highlights that moving away from the dominant volume-based contract for small consumers would require significant education and engagement with consumers, including decision-making tools and assistance from utilities and intermediaries, such as energy service companies. Compared with fixed volume-based tariffs, most alternatives offer the consumer better price signals of the cost of generation and network capacity development, which would ultimately benefit consumers through more efficient utility investment.

Table 1: Four general tariff options for consideration

TARIFF TYPE	PRO (INDIVIDUAL)	CON (INDIVIDUAL)	PRO (SYSTEM)	CON (SYSTEM)
Fixed volume-based tariff A single annual cents per kilowatt hour fee	Consumer can install devices with large power (watt) rating without major (short-term) penalties.	Generation capacity and networks are built to accommodate power needs without an accurate view of individual consumer's willingness to pay, but all consumers ultimately foot the bill in future years.	It gives a direct price signal to manage volume. It supports signals for lowering greenhouse gas emissions, which are volume-related.	It gives a poor price signal for managing network capacity growth. There can be overuse of power at peak times during the day, leading to poor network utilisation.
Seasonal time-of-use volume-based tariff[26] Three prices in cents per kilowatt hour applying per day: peak, shoulder, and off-peak, varied with each season	Consumers who use most of their power at off-peak times can pay less than the average price.	Consumers, particularly low-income groups, may lack the resources to manage their load and pay more or experience discomfort by curtailing the basic services they require at peak times.	It gives a moderate price signal to reduce energy consumption at peak times during the day, reducing the requirement for peaking plant and network capacity.	Seasonal peak, shoulder, and off-peak pricing signals remain only a proxy for the actual daily volatility. The price signal will only partially reflect the true level of congestion. The price deterrent may not be enough to reduce peak on extreme days.

26 A less extreme version of this is the current peak and off-peak tariff arrangements in many states. In those cases, the peak and off-peak rates do not vary with the season.

TARIFF TYPE	PRO (INDIVIDUAL)	CON (INDIVIDUAL)	PRO (SYSTEM)	CON (SYSTEM)
Critical peak tariff Two prices in cents per kilowatt hour: one for most hours of the year and another for designated critical peak periods nominated via a trigger point (e.g. temperature)	The consumer only needs to consciously manage their load for a small number of days a year.	Design of the tariff can be confusing. Low-income groups may lack resources to manage their exposure to higher prices at extreme times or experience discomfort by avoiding costs. There is potential for bill shock if communication of the critical day trigger point is unclear.	It gives a strong price signal for reducing loads on peak days.	It may lead to a relatively volatile revenue stream for network businesses because the number of peak days cannot be reliably predicted each year. Requires a communication system to advise of critical days.
Combined capacity and volume tariff[27] Part of tariff based on power capacity used (cents per kilowatt) and remainder based on volume (cents per kilowatt hour)	It offers lower costs for those with fewer appliances using high levels of power and smaller occupancy households.	It offers higher costs for those with multiple appliances using high levels of power. Many consumers will be initially unaware of the 'power capacity' concept and fail to manage their exposure to high prices unless they have access to appropriate tools and information.	It gives a good price signal for both volume and capacity.	There may be transaction costs in setting up capacity rates and in education to inform consumers so they can avoid bill shock.

The Forum believes the electricity sector will develop new business models in order to adapt to the scale and scope of customer requirements envisaged in the scenarios. Currently, the paradigm of Australia's electricity system is a predominant one-way flow of power from generation through transmission to distribution and finally to the customer. Mid-last century, each segment was structured as a vertically integrated single entity. To some extent, the present trend of a more segmented supply chain has eroded (for example, retailers and distributers own some generation; some generators contract directly with customers), but the model of a one-way flow remains dominant.

On-site generation systems, such as rooftop solar, which has experienced strong growth in its uptake, as well as large discrete on-site generation, present a major shift to this paradigm. On-site generation systems make the customer the generator and can create time-variant, two-way power flows.

If the number of customers using rooftop solar or other on-site generation systems continues to grow, and these customers remain connected to the centralised system only for back-up or for opportunities to export their own power back to the grid, the current distribution system would need to change its focus and become a platform and marketplace for local power trading.

27 Most large commercial and industrial customers are on a tariff of this type.

1950s business model

- Government-owned
- All services centrally planned and implemented by one utility
- Customers consume only

Immediate past model

- Mix of corporatised government and private sector utilities
- Generation and retail most competitive. Transmission and distribution most regulated
- Customers mostly consume only

Possible future customer-centric model

- Multiple private parties
- Current roles changed in scope and scale
- Customers consume, trade, generate, store and charge

Figure 29: Evolution of business models: what's possible?

Integrating a large number of solar systems with the grid may not require significant coordination or regulation if there are contracts that recognise the value to all parties and appropriate and consistent standards for voltage control and communication.[28] Electricity distributors face significant technical challenges from large commercial and industrial-scale on-site generation units and clusters of generation units because it is much more likely that their net supply to the distribution network could at times exceed local demand. These circumstances could push beyond the tolerances of the current management systems.

If on-site generation becomes the norm (as is considered in some of the Forum's scenarios), retailers might compete to provide the best export price for customers' generation exports. Given the reductions in legislated feed-in tariffs of the past three years, solar power might initially struggle to live up to expectations that it will reduce net energy bills. Feed-in payments to customers will vary over time according to market and policy changes.

Customers will have strong incentives to use as much of their own locally produced power as possible so as to avoid exposure to the retail

28 Standard 4777 provides for various network management protocols and advanced power quality functions. While increasing voltage is a concern for solar photovoltaic panels, the standard also envisages that management of electric vehicles will require similar coordination and management of under-voltage as a result of their charging.

electricity price, which is currently five times greater than the solar panel export price in some states.[29] This incentive will strengthen if:

- export prices are unattractive for new connections
- solar panels continue to come down in price
- residential- and commercial-scale storage becomes more economically viable
- demand management systems are available to shift power use to better match solar panel or other on-site generation output
- lower-cost, non-solar on-site generation options, such as fuel cells, become available.

The electricity sector can learn a valuable lesson in tailoring contracts from the telecommunications industry. The path from a one-size-fits-all landline telephone system to a smorgasbord of mobile and associated data and entertainment services was (and to some extent remains) challenging. There were bill shocks from a lack of communication when customers exceeded their agreed limits on mobile and data plans. Infrastructure development couldn't keep pace with adoption of mobile and data services, resulting in poor quality services to some customers (ACMA 2011). Some retailers' reputations were damaged, and some hardware providers lost significant market share when they failed to anticipate the importance of data services, accessible interfaces and the merging of social and commercial functionality (Rushe 2013).

In learning from other sectors, electricity providers will need to accurately predict which services other than electricity might become essential to provide to customers. It will be crucial to determine an appropriate rate of smart meter (or an alternative, more advanced customer interface) roll-out, matching the pace, scale and model in which consumer segments will want to transition from a standard electricity service to the kinds of alternative tariff structures, demand management, and local generation options that are becoming increasingly feasible. Those retailers who go several steps beyond providing basic electricity are typically referred to as 'energy service companies'. These companies provide the services that electricity enables, such as air-conditioning, lighting, cooking, heating, and entertainment and management services like metering, load control, and aggregation and data analytics. Some electricity retailers in Australia are evolving to provide energy services, but will face competition from new entrants and other business models in the future.

A major cautionary note in this discussion about service and price customisation is that any new tariff system will likely create 'winners' and 'losers'. For retailers and energy service companies to offer a new deal to customers there must be benefits to both parties. The structural inertia in the electricity system means there are currently no major actions customers can take to receive a large discount on their electricity costs other than to reduce their consumption volume. Reducing their peak load will benefit the system the most if it is in a location where peak loads are currently constraining the system. With recent investment in system capacity and reduced peak demand, those opportunities and locations are fewer.

Taking into account this system inertia, the Forum's modelling showed that a major peak reduction program would reduce system costs in the long term by an average of 2 cents per kilowatt hour (Graham et al 2013b). This represents the value spread across all customers, but those directly contributing could be allocated greater discounts and indeed would expect such a discount in exchange for their participation.

Price deregulation offers the best opportunity for customers who place least demand on the system to be rewarded with lower costs. Under deregulation, retailers and energy service companies can realign electricity tariffs to better reflect the costs of meeting each customer's needs. So customers who demand less pay less. Customers who place greater demands on the system (by using very large air-conditioning systems or other equipment at peak times, for example) may still be cross-subsidised to some extent depending on whether cost-reflective pricing is voluntary or not. An adjustment and education process would assist in deriving the most benefit from deregulation so that customers have time and opportunity to understand how their power use affects the system, when they use their power, and the available options for managing their power use.

There is a significant risk that not all customers will equally engage and capture the available benefits.

29 Solar panel feed-in prices applicable in 2013 by state compared with an average national retail electricity price of 25 cents per kilowatt hour in 2012–13: QLD and Victoria 8 cents per kilowatt hour, South Australia 9.8 cents per kilowatt hour, Western Australian (based on Synergy) 8.85 cents per kilowatt hour, New South Wales voluntary retailer payments 5–8 cents per kilowatt hour based on advice to government published at <http://www.myenergyoffers.nsw.gov.au/useful-information/solar-feed-in-tariffs.aspx>.

Customers will need to have the time and motivation to engage, and become better informed and sufficiently energy literate to navigate and understand all of the options that might emerge. Those who don't will miss benefits. While industry must lead the engagement process, government will have a role in addressing equity issues for vulnerable groups.

In a similar way to how Australians think about the road network, electricity customers have grown up with the idea that electricity is an essential service and should largely be provided to all at a similar price, particularly at the residential level. But this notion is no longer relevant. While changing the tariff system will bring about 'winners' and 'losers', the current one-size-fits-all system is already doing just that by offering an ever-increasing amount of opportunities for individual customers to use the electricity system in radically different ways from each other. In fact, the current system could deepen inequity over time. Therefore, concerns about future 'winners' and 'losers' should not halt the transition to more cost-reflective tariff structures, particularly if education and measures for protecting vulnerable customers are well planned and executed.

Implications of greenhouse gas abatement and carbon policy uncertainty

Achieving long-term clarity on the electricity system's greenhouse gas abatement task will be important for efficient electricity generation investment decision-making. The life of a power plant is between 20 and 60 years or seven to 20 election cycles. Once the plant is built, if market conditions change for the worse, there is no way to recoup losses; the plant cannot be moved to a more favourable market or scrapped for a reasonable return. Carbon policy therefore represents a huge risk for investors in electricity generation. The effects of this risk are that finance will cost more and investors will choose whichever technology offers the best return across the widest range of possible policy outcomes rather than the least-cost technology—and both of these effects manifest as higher electricity prices to customers.

The Forum's modelling has estimated that the sub-optimal investment resulting from ongoing carbon policy uncertainty, while having limited impact in the short term while investment requirements are low, could result in wholesale electricity prices by 2050 that are $24 per megawatt hour higher than they would be in an environment of policy certainty. While this discussion has focused on new plant investment, upgrades to and maintenance of existing plant would also be expected to be delayed under carbon policy uncertainty.

Implications of the electricity system's vulnerability to climate change

The carbon prices applied in the quantitative modelling for the Forum are broadly consistent with those that would be required to achieve stabilisation at 550 parts per million carbon dioxide equivalent. This global greenhouse gas concentration target most closely matches the current level of commitment expressed by various countries, but is inadequate to limit global average temperatures rising no more than 2 degrees Celsius. Instead, it is estimated that it will deliver a 50 per cent chance of limiting average global warming to around 3 degrees Celsius above pre-industrial levels. Under this outcome, there are significant risks to species and ecosystems. More pertinent to the electricity sector, coastal infrastructure would face significant risks, including frequent or permanent coastal inundation for parts of the Australian coastline. There would also be a substantial increase in extreme weather across the nation (Treasury 2011; Climate Change Authority 2013).

In this context, the electricity sector is becoming increasingly interested in climate change impact and resilience planning. Understanding these climate impacts is still in its infancy, but preliminary modelling indicates it could cost an additional 2.8 cents per kilowatt hour by 2050 to adapt the current electricity supply chain to climate change.

Section 5: A potential path forward

The Forum's proposed framework for evaluating outcomes

How much any of these issues and their outcomes matters is directly linked to how much value people place on them.

The Forum therefore found it useful to develop a framework of five key performance indicators for evaluating electricity sector outcomes for Australia. This framework focused the Forum's deliberations and could be a useful tool for future electricity sector analysis.

Table 2: Future Grid Forum's proposed key performance indicators

KEY PERFORMANCE INDICATOR	DEFINITION AND EXPLANATION
Whole-of-system cost	*The total cost of electricity consumed by end-users, inclusive of generation, distribution, transmission, retail and any on-site costs that the end-user incurs, in order to obtain the desired services that electricity enables* For this indicator, 'cost' is used instead of 'price' because prices are not always cost-reflective and users can adopt energy-efficiency measures to reduce their exposure to prices (sometimes at a cost) to achieve the same level of services. This indicator emphasises 'efficiency', but the Forum also considered whether 'affordability' might be a better higher level indicator for the system. 'Affordability' is a more accurate measure of customer welfare because incomes of some groups could rise to offset any cost increases. The Forum concluded, however, that the electricity system could not be designed to achieve affordability. The electricity sector cannot control incomes, income distribution, and assistance to vulnerable groups; these are government responsibilities in managing the economy as a whole. The electricity sector can only make the whole-of-system costs as low as possible to support affordability.
Reliability	*The extent to which the supply and quality of electricity is maintained at a given level* At the macro level, Australia's electricity supply is generally reliable and Australians organise their commerce and lifestyles based on this reliability. At a technical level, there are standards for reliability which the different parts of the electricity supply chain are responsible for achieving. Importantly, in addition, customers in Australia have always been proactive in tailoring their own level of reliability, using methods as simple as keeping a stock of candles or as sophisticated as maintaining their own on-site uninterruptible power supply system.

KEY PERFORMANCE INDICATOR	DEFINITION AND EXPLANATION
Greenhouse gas emissions	*Emissions from the electricity sector contributing to climate change* The electricity sector produces more greenhouse gas emissions than any other sector in Australia's economy. As such, the sector recognises that while it is not solely responsible for greenhouse gas emission reduction, it does have a key role to play in any national greenhouse gas abatement effort. Existing national emission targets are one measure of the level of abatement the electricity sector may be set to achieve; however, to achieve emissions reduction in a cost-effective manner, the sector might deliver more or less than its proportional share of abatement depending on the sector's relative abatement costs. Greenhouse gas reduction presents a specific challenge to how the electricity sector operates. Other environmental impacts of its operations are also important, but are dealt with by working within other existing environmental management legislation, which applies to all sectors. Greenhouse gas emissions are typically measured as tonnes of carbon dioxide equivalent (tCO_2e).
Service and price customisation	*The degree to which customers can access an electricity contract that matches the electricity supply and other services they need and want, and the degree to which the price they pay for this contract matches the actual cost the services impose on the system* Australia currently has limited service and price customisation in electricity contracting: there are different contract offerings for each of the residential, commercial, rural and industrial customer segments and further choice within those offerings, but consumers' needs are becoming increasingly sophisticated. Many now require a contract that includes terms of supply to obtain electricity from their retailer as well as terms to export their own generated electricity. Customisation could go further, but for a variety of reasons the price charged for the service is not always reflective of the cost of supplying the service. Pricing in the electricity system is currently regulated in all states except South Australia and Victoria. With other states now considering price deregulation, the scope for electricity sector utilities to tailor services and prices may expand, but customer desires will ultimately drive this.
Resilience	*The ability of the electricity system to recover from and adapt to shocks such as those from technological, market, social, and environmental changes* During the second half of the twentieth century, price and electricity mix were relatively stable within the Australian electricity system because of a strong reliance on abundant, low-cost coal resources and centralised electricity generation technologies. These circumstances contributed to the economic competitiveness of Australia's industrial sector and the lifestyles of Australians. In the first half of the twenty-first century, changing circumstances, such as the need to reduce greenhouse gas emissions, higher centralised electricity prices, and the emergence of on-site electricity generation technologies, have meant that some characteristics of Australia's electricity system that were formerly strengths have become vulnerabilities. Current disruptors to the system could potentially strengthen resilience because they create greater diversity of supplies if well managed. Valuing resilience and flexibility in the electricity system would mean avoiding 'technology lock-in' and having transition paths available when events challenge the incumbent business model.

APPLYING THE FRAMEWORK

The Forum recognised that while each of these key performance indicators is desirable, they do not perfectly align and this makes setting goals and objectives for the electricity system challenging. Trade-offs among potential outcomes will be necessary. For example, to achieve greater reliability, resilience and greenhouse gas reduction, customers would need to incur higher costs. That said, some performance areas will partially achieve or reinforce others. For example, greater customisation of the services customers receive and the prices they pay would improve whole-of-system costs per user by better matching system investment to willingness to pay (although this process would necessarily result in some customers paying more if they are currently being cross-subsidised under existing arrangements), while greater system redundancy would partially achieve both system reliability and resilience.

The Future Grid Forum did not seek to determine the best trade off of the key performance indicators. The best balance and how to achieve it will be different for each stakeholder in the sector depending on their individual perspectives and resources. The Forum's purpose was to highlight these trade-offs and potential alternative outcomes under four future scenarios.

Impacts by segment and scenario

The degree to which each of the existing and future segments of the electricity supply and end-use chain will need to change is not equal across the segments or scenarios. Scenario 1: 'Set and forget' represents the least amount of change across the scenario set. Customers increase their level of engagement when selecting new tariffs, but largely disengage afterwards. Retailers and distributers extend the variety of tariff structures they offer and administer. Increased metering services are required to implement some new tariffs and demand management schemes; however, continuous communication with the customer via interfaces is generally not required. Storage becomes prevalent in household energy management and electric vehicles emerge as a genuine alternative to internal combustion engines, but only where convenient. The biggest generation changes are for gas-fired power, which expands substantially in centralised and on-site generation, reducing coal-fired power. Renewables also expand.

In Scenario 2: 'Rise of the prosumer', metering and energy service companies play a much bigger role in facilitating higher levels of consumer engagement and on-site generation. This scenario would have the greatest need for information and communication technologies because of the high degree of connected customers engaging in demand management and on-site generation systems. Electric vehicles are also more prevalent. Distribution and transmission companies are heavily affected because they see a substantial decline in system utilisation via reduced grid-supplied consumption without a fully compensating drop in peak demand. The market operator faces long periods of managing systems in excess supply. Gas and renewable generators, both centralised and on-site, are again achieving higher market shares.

In Scenario 3: 'Leaving the grid', there are very few segments of the electricity sector that are not heavily affected either by new opportunities or challenging changes to established business models. Distribution and transmission companies would face similar utilisation problems to those in Scenario 2. Customers disconnecting from the grid will experience significant change as they more closely manage all aspects of their supply and energy use, as will the service companies offering their services to support them. Disconnected customers require very helpful interfaces to manage their system, but there is less need for communication systems on the grid. Storage is a key enabler of disconnection.

In Scenario 4: 'Renewables thrive', distribution and transmission companies will still face the lower utilisation issues of Scenarios 2 and 3, but to a slightly lesser extent because centralised power plays a stronger role. Under this scenario, the transmission system in particular may need to undergo the largest spatial development in order to accommodate the connection of many more renewables. Natural gas generation does not undergo the large increase seen in other scenarios because it is being phased out in centralised supply (along with coal). Regulators may need to consider and implement changes to the market rules in order to accommodate a high penetration of renewables. This scenario represents the biggest growth for electric vehicles and storage, which becomes a dominant technology throughout the system. Information and communication systems are required to support customers and to coordinate on-site generation, but to a lesser extent than in Scenario 2.

These impacts are summarised in Table 3.

Table 3: Summary of current and future supply chain segment impacts by scenario

STAKEHOLDER	Scenario 1: 'Set and forget'	Scenario 2: 'Rise of the prosumer'	Scenario 3: 'Leaving the grid'	Scenario 4: 'Renewables on tap'
Residential consumer	◔	◕	●	◑
Commercial or industrial customer	◔	◕	●	◑
Retailer	◔	◕	●	◑
Distribution	◑	◕	●	◕
Transmission	◑	◕	◕	◕
Generation and transmission system operators	◑	◕	◕	●
Energy service companies	◔	●	●	◕
Metering services	◑	●	◕	●
Centralised generator – coal	◕	●	●	●
Centralised generator – gas	●	●	●	◔
Centralised generator – renewable	◔	◑	◑	●
On-site generators	◔	◕	●	◑
Storage technology providers	◑	◕	●	●
Electric vehicle providers	◑	◕	◕	●
Information and communication technology	◔	◕	◑	◑

KEY:

◔ = Modest change, manageable within existing structures and business models

◑ = Significant change; some new activities emerge but within existing structures

◕ = Substantial change where new business models and market structures are required

● = Vastly different from today; most existing activities and business models completely change

Proposed options for addressing the issues identified in the scenario modelling

The Forum identified options for positioning the electricity sector to most effectively plan and respond to the issues explored in the scenario modelling (Table 4).

The proposed options are intended only to set out broad principles for consideration. Further conversations among all stakeholders will be necessary to achieve detailed understanding and consensus within the Australian community. The options are not mutually exclusive; given it is not possible to predict which scenario events will occur and in what combination, the options could be combined or implemented in parallel.

Table 4: Summary of proposed options for addressing the major issues identified in the Future Grid Forum's modelling

ISSUE	CHALLENGES	RISKS AND BARRIERS	OPTIONS FOR MANAGING THE CURRENT TRANSITION
Investment in new generation	Wholesale electricity generation prices are projected to remain below that which would be required to build new plant and recover a reasonable return on investment until the early 2020s. Wholesale prices need to increase from around \$40/MWh (4 c/kWh) in 2013 (excluding the carbon price) to around \$70/MWh (7 c/kWh)[30] (excluding any future carbon price or equivalent mechanism) to be viable for new plant.	Investment may be slow to respond when new plant is needed after a long period of low prices.	**Government** Maintain existing generation market arrangements which will allow the wholesale electricity prices to rise once the market supply and demand balance tightens and in response to carbon policy. **Australian Energy Market Operator** Continue to monitor generation capacity needs and continuously improve demand forecasting to support its annual *Electricity statement of opportunities* report.
Managing peak demand	Limiting growth in peak demand is projected to save 2 c/kWh each year on the costs of electricity distribution between 2020 and 2050. Peak demand has declined recently in some states and its future rate of growth is uncertain. If peak demand growth recovers in the future, it may contribute to declining network utilisation.	The majority of small commercial and residential consumers remain on volume-based price contracts, have limited knowledge of alternative options, and do not have access to more sophisticated metering. Therefore, there is limited infrastructure, knowledge or incentives to reduce peak demand at present in these states. Several peak demand reduction actions have already been highlighted in existing reviews, such as *Power of choice*. Reform is challenging in a multi-jurisdictional policy environment.	**Government and regulators** Remove remaining barriers to introducing cost-reflective pricing in the small commercial and residential sector so that consumers can receive the correct signal for the cost of peak power use. Accelerate the task of evaluating and implementing other appropriate responses to encourage peak demand reduction from existing reviews. **All stakeholders** Raise consumer awareness about the benefits of peak demand reduction and cost-reflective pricing. If adoption of cost-reflective tariffs is not widespread, then the system benefits may be minimal.

30 All prices and their percentage changes are in real terms.

ISSUE	CHALLENGES	RISKS AND BARRIERS	OPTIONS FOR MANAGING THE CURRENT TRANSITION
Increased on-site generation	On-site generation is projected to reach 18–45 per cent of total generation by 2050. This leads to a decline in network utilisation that is not driven by a lack of effort in managing peak demand, but rather a shift in the source of electricity generation from the grid to the user.	If on-site generation and demand response technologies reach a significant share, the model of regulating networks as monopoly suppliers of reliable electricity might require a different approach.	**Regulators** Encourage network businesses to investigate alternative network development and asset management strategies, including market transparency. Planning will need to be flexible to changes in future use and mitigate the potential for future reductions in network utilisation while maintaining agreed levels of performance. **Government** Establish processes to identify the changes, if any, that might be required to market frameworks in light of this issue and other megashifts examined in this report.
Disconnection from the grid	Disconnecting from the grid as a residential consumer is projected to be economically viable from around 2030 to 2040 when independent power systems are expected to be able to match retail prices of 35–40 c/kWh as battery costs fall. Current costs of disconnecting are estimated at 92–118 c/kWh (around four times 2013 retail prices).	If there is a significant share of disconnected customers, this would challenge existing business models. The cost of small-scale generation and storage technologies are critical, but future cost projections are uncertain.	**Industry** Innovate to provide optimal business models for on-site generation and system operation. **Government** Consider how and where to apportion relevant costs. Expand the Australian Energy Technology Assessment process to include small-scale generation and storage technologies.

ISSUE	CHALLENGES	RISKS AND BARRIERS	OPTIONS FOR MANAGING THE CURRENT TRANSITION
Rising residential electricity bills, but stable as a share of income	As a result of increasing whole-of-system costs, by 2030 residential electricity bills are projected to be 2–9 per cent above 2013 levels. Some vulnerable residential consumers, for whom electricity is a large component of their overall expenses, could experience some hardship. However, the combined effect of adoption of energy efficiency, on-site generation, and general wages growth means, for the average wage earner, the electricity share of income is projected to be slightly lower than 2013 in 2030 and return to similar levels by 2050 (between 9 per cent below, and 6 per cent above, 2013 across the scenario range).	Some low peak demand-to-consumption ratio households may be cross-subsidising high peak demand-to-consumption ratio households under current tariff structures. Retail unit costs (expressed in cents per kilowatt hour) may be less relevant over time as a measure of expected costs due to use of on-site generation, energy-efficiency opportunities, alternative tariffs, and wages growth.	**Government** Review electricity bill assistance for low-income and vulnerable customers, including the state-based energy concession schemes. Move to greater retail deregulation to support efficient price signals for electricity system investment (for suppliers and consumers alike) and reduce the degree of consumer cross-subsidisation. Ensure market structures facilitate cost-effective energy efficiency adoption. **Residential consumers** Review any new tariff structures and government support schemes to minimise electricity bills. Manage both peak demand and consumption to offset any unit cost increases.
Large commercial and industrial customers' electricity costs	As a result of their relatively strong exposure to costs of generation, which are projected to increase to achieve greenhouse gas emission reduction (see next point), large commercial and industrial customers are expected to experience an increase in electricity bills, primarily after 2020. By 2030, large commercial customers who adopt energy-efficiency measures are projected to limit the increase in their electricity bills to 1.1–2.2 per cent a year. Industrial customers (assuming no change in electricity efficiency) could face an increase in electricity bills of between 1.6–3.0 per cent a year to 2030 across the scenario range.	The manufacturing sector (comprising food, beverages, textiles, wood, paper, printing, petroleum and chemical products, iron and steel, and non-ferrous metals, such as aluminium) is the most exposed to increasing electricity prices in its costs of production. Australian industries are competing against countries that have different greenhouse gas reduction policies.	**Government** Review arrangements to support the competitiveness of Australian export-exposed energy-intensive industries. Ensure market structures facilitate cost-effective energy efficiency adoption. **Commercial and industrial customers** Implement cost-effective peak demand and consumption management opportunities to offset any unit cost increases.

ISSUE	CHALLENGES	RISKS AND BARRIERS	OPTIONS FOR MANAGING THE CURRENT TRANSITION
Electricity sector emissions	Across the scenarios, the electricity sector is projected to achieve greenhouse gas emission reduction of 55–89 per cent below 2000 levels by 2050. This is reasonably consistent with the currently legislated national greenhouse gas emission reduction target of 80 per cent below 2000 levels by 2050. To achieve this emission reduction, wholesale electricity unit costs increase from approximately \$60/MWh in 2013 to between \$113/MWh (11.3 c/kWh) and \$176/MWh (17.6 c/kWh) in 2050. Against this cost, the benefits of avoided climate change were not estimated (however, see 'Climate change adaptation' below).	The cost of flexible generation (such as gas), various types of storage, or demand management to support the variable output of some renewables will be an important determinant of costs of abatement.	**Government** Continue to support programs for assessing, researching, developing and demonstrating low-emission electricity generation technologies.
Carbon policy uncertainty	The wholesale electricity price is projected to be 17 per cent (\$24/MWh or 2.4 c/kWh) higher by 2050 if long-term carbon policy uncertainty is not resolved.	Uncertain carbon policy means that plant investment is delayed and is dominated by a narrower range of electricity plant types which are able to partially mitigate against carbon policy risks to projected rates of return.	**Government** Develop bipartisan carbon policy relating to the targets for each decade to 2050 and the policy mechanisms that will be implemented to achieve them. (While not specifically modelled, similar investment risks and policy remedies apply to the Renewable Energy Target.)
Climate change adaptation	Where the risk of climate change results in networks building to a higher probability of extreme peak demand events, then unit electricity costs are projected to be 2.8 c/kWh higher on average each year between 2025 and 2050. Impacts of extreme weather generally and costs of other electricity sector climate change adaptations were not estimated, but are also very relevant.	The electricity sector is particularly vulnerable to changes in climate because climate affects every aspect of its operation, from the efficiency of generation and transmission through to the profile of demand.	**Industry and regulators** To support efficient investment choices, develop consistent guidelines and methodologies for estimating the impact of changes in the climate on the electricity system. Implement and periodically review adaptation plans. **Government** Continue to work with the global community, through international agreements for greenhouse gas emission reduction, to reduce the risk of climate change impacts.

ISSUE	CHALLENGES	RISKS AND BARRIERS	OPTIONS FOR MANAGING THE CURRENT TRANSITION
Increasing natural gas prices	Wholesale electricity prices are projected to be $11/MWh (1.1 c/kWh) higher and greenhouse gas emissions 34 per cent higher by 2050 relative to Scenario 1 if there is a higher rate of growth in gas prices.	Under the BREE (2012) cost assumptions, gas combined cycle (that is, baseload) plants are one of the lowest-cost forms of electricity generation. Further, gas peaking plants may play an important role in supporting variable renewables.	**Government** Although markets and costs of production will determine prices, governments can continue to support efficient and transparent markets for gas exploration, production, generation, trade and consumption. Expand the Australian Energy Technology Assessment process to include large-scale storage technologies, which are a potential substitute for gas in supporting variable renewable generation.
The role of nuclear power	Wholesale electricity prices are projected to be $34/MWh (4 c/kWh) lower and greenhouse gas emissions 72 per cent lower by 2050 relative to Scenario 1 if nuclear power is included in the electricity generation mix.	The BREE (2012) cost assumptions, on which this projection is based, do not include decommissioning. There would be considerable delay (assumed to be after 2025 in this study) before nuclear plant could contribute to electricity generation in Australia because of long construction times, skill shortages, and necessary development of regulations and policy changes. Non-cost factors are important in technology adoption. Nuclear power consistently rates at the lower end of the scale of social acceptance relative to other electricity generation technologies (for example, Ashworth et al 2012).	**Industry and government** Continue to monitor and evaluate the social acceptability of nuclear power and other barriers to its uptake not explored in this report.

Many of the options in Table 4 are not new, but rather support existing processes or market arrangements. For example, the Forum considers that the existing market arrangements in the National Electricity Market and the existing market information provision functions of the Australian Energy Market Operator are already providing clear signals to market participants. This report highlights the need to accelerate the evaluation and, if appropriate, the implementation of existing recommendations to support peak demand reduction, but recognises that electricity market reform in Australia is necessarily time-consuming because of the multiple jurisdictions involved in decision-making and the need for robust information and consultation processes. The Forum believes that mechanisms to accelerate these processes should be investigated given that electricity markets have shown the tendency to undergo major and rapid shifts that are able to outpace the reform processes' ability to implement change.

Rapid uptake of roof-top solar photovoltaics has occurred in two years, which is approximately the timeframe for minor rule changes. (More than five years is generally required for major structural reform, such as the establishment of the National Electricity Market, and fixed five-year regulatory reset cycles are used for new rules relating to network expenditure.)

In 2012, the Australian Government commenced an Australian Energy Technology Assessment focusing on centralised electricity generation technologies. In light of the Future Grid Forum scenarios, expanding the scope of the AETA to include on-site generation and storage technologies would be appropriate given their potential to shape the future of the electricity system.

Of the options presented in Table 4, there are four that are not already established but could be considered as potential approaches to addressing the issues identified in the scenarios. These four are expanded here:

1. *Implement a sustained long-term program to increase consumer awareness of the benefits and mechanisms of cost-reflective pricing and demand management.*

As part of addressing a potential decline in network utilisation through various reform measures, readying consumers for cost-reflective pricing might require more than deregulation. Information campaigns over several years, perhaps similar in scale to those implemented to increase awareness of energy-efficiency measures for households and businesses, might be warranted.

Cost-reflective pricing (that is, pricing that accurately reflects the cost of delivering a particular service that could include more than just electricity) empowers consumers to make informed decisions that lead to more optimal long-term outcomes because the system provides the services that consumers are willing to pay for at the price they cost. But as the Forum's social research indicates, consumer knowledge is low, particularly about which appliances most affect their electricity use. Consumers can also be cynical about new technologies, such as smart meters, particularly if the technology is mandated rather than actively chosen. Change could be politically challenging, but for consumers to access many of the benefits of demand response, on-site generation, and energy efficiency that were included in the Forum's scenarios, a change to cost-reflective pricing and an ability to adopt and respond to those price signals is a prerequisite. The *Power of choice* (AEMC 2012a) review makes recommendations for implementing cost-reflective pricing, and New South Wales and Queensland are considering price deregulation, which will enable it in those states (following the lead of South Australia and Victoria).

2. *Develop bipartisan agreement on the long-term (2050) greenhouse gas emission target and implementation mechanism for Australia.*

Australia's carbon policy continues to substantially change during and following each change of government or political leader. Failure to reach a bipartisan position on the implementation mechanism and emission target beyond 2020 is preventing the electricity sector from responding in the most efficient way possible and outcomes will only get worse the longer uncertainty continues. No industry can or should expect policy to remain constant throughout the life of its investments, but given that the electricity supply chain involves very long-lived investments in what can be described as one of the most complex systems on the planet, a non-political approach leading to some form of predictability is warranted.

Specifically, the electricity sector and its customers would benefit from bipartisan support for a long-term abatement target and implementation mechanisms to 2050, including interim targets for each decade. While the sector would expect some changes over time, a credible long-term abatement target and implementation mechanisms would provide much-needed guidance on the emissions outcomes expected of the next fleet of electricity plants. The implementation mechanisms should heed other electricity system performance indicators, such as minimising whole-of system cost and maximising reliability and resilience through flexibility, but there will be a need to trade off some of these objectives against each other and against the needs of other sectors subject to the carbon policy.

These conclusions about carbon policy would likely also apply to renewable energy targets and policies, although the Forum did not specifically model the impact of uncertainty on renewable policy.

3. *Review Australia's electricity consumer social safety net.*

Unfortunately, the Forum's scenarios have not been able to rule out further electricity bill increases, but the Forum does expect more options for managing consumers' exposure to cost increases to become available to consumers. Examples are further energy-efficiency opportunities, greater potential for use of on-site generation, and implementation of cost-reflective pricing to reduce cross-subsidisation of heavy system users and to support efficient investments throughout the system.

To provide further support to this option, governments could consider:

- developing a national consumer protection framework for deregulated markets that considers the need for any protections for new tariff types and other demand-side participation options, including guidelines on consumer rights in phasing out older tariffs
- developing a nationally consistent framework for energy concessions and emergency assistance that ensures the most vulnerable consumers can afford to remain connected to electricity supplies
- regularly reviewing the impact of carbon pricing relative to the tax offsets provided to low-income wage earners
- more targeted, flexible and innovative packages of social safety net measures, including, for example, energy-efficiency standards for rental properties and incentives for landlords to invest in energy efficiency and on-site generation; energy-efficiency retrofits and on-site generation for social housing stock; low-interest microfinance schemes for improving low-income households' electricity cost resilience; direct engagement to address information barriers to energy efficiency and new tariff options.

A major challenge in addressing this issue is for governments to find the balance between meeting community expectations of protection for the most vulnerable consumers and not stifling innovation in deregulated electricity retail markets. Governments will need to consult with industry to determine whether the market can develop satisfactory solutions, particularly to issues such as financing.

4. *Establish processes to identify the changes, if any, that might be required to market frameworks in light of the megashifts examined in this report.*

The Future Grid Forum has developed scenarios to 2050 focusing on the potential megashifts of low-cost electricity storage, sustained low demand for centrally-supplied electricity, and the need for significant greenhouse gas abatement. The scenarios highlight the potential, in some cases, for dramatic changes in the way electricity is transacted, and in the roles of various parties, particularly customers.

The Forum process has delivered scenarios that provide a 'technical' view of potential futures and provide some insight into the changes that may occur in each of the industry sectors, but other processes may need to be established to consider whether the current market and regulatory frameworks will be consistent with these futures, and whether or not there are some changes that need to be considered to facilitate the transition to the future arrangements.

Given the nature of the megashifts identified, it would not be surprising if some changes were required and it would be sensible to start considering these now, at least at a high level. There may be some common issues where it is worth developing an early understanding of the feasibility of the alternative options available.

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Glossary

ITEM	DEFINITION
$/MWh	dollars per megawatt hour
c/kWh	cents per kilowatt hour
consumption	the total volume of electricity consumed over a given period measured in watt-hours
cost	the expenditure required to deliver a service (in contrast to 'price')
kW	kilo (a thousand) watts
MW	million watts
on-site generation	generation that occurs at the site of the electricity consumption as opposed to remotely and supplied through the transmission and distribution network. Also known as distributed generation or embedded generation
peak demand	the highest instantaneous level of demand experienced in a given period, measured in watts
ppm	parts per million
price	the fee charged for a service (in contrast to 'cost')
$MtCO_2e$	million tonnes of carbon dioxide equivalent
NEM	the National Electricity Market comprising the southern and eastern states of Australia and excluding Western Australia and the Northern Territory
RET	Renewable Energy Target
TWh	a thousand billion watt hours

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