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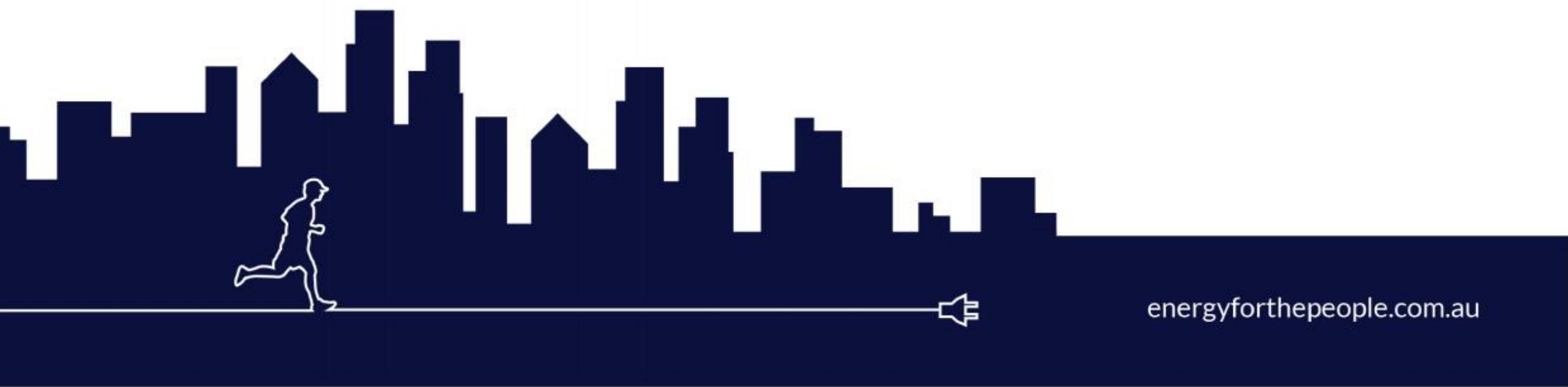
TITLE: What Happens When We Un-Plug?

Exploring the consumer and market implications of viable, off-grid energy supply

Research Phase 1: Identifying off-grid tipping points

Research project led by Energy for the People
with technical leadership by
the Alternative Technology Association

Contact authors for comment:
Tosh Szatow, Energy for the People – tosh@energyforthepeople.net
Damien Moyse, Alternative Technology Association – damien@ata.org.au



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Disclaimer

Background

The creation of this report was triggered by a series of prior studies and events, which pointed toward a period of rapid transition in the Australian energy market. Collectively they suggest that, should this transition not be proactively managed, there is a risk that Australian energy consumers will incur significant costs resulting from stranded network and generation assets.

In December 2009, the CSIRO released research titled "Intelligent Grid Report: a value proposition for distributed energy in Australia"[1]. The report suggested significant financial benefits associated with an efficient uptake of distributed energy (that is, collectively distributed generation, energy efficiency and demand management).

Specifically, the Intelligent Grid report highlighted the potential for as much as $130bn in savings to Australian energy consumers – this figure was a discounted future cash flow (at a 7% rate) and so represented savings in today's money. It detailed a myriad of policy, regulatory and market design issues that were limiting the efficient uptake of distributed energy.

It also suggested that, once solar photovoltaics (herein referred to as PV) hit retail price parity (then forecast to occur by approximately 2018), uptake of PV would accelerate significantly, marking a turning point for the growth of distributed generation and, by implication, for the energy market as a whole.

In September 2011, the Australian PV Association (APVA) took energy market observers by surprise, reporting that PV in Australia had hit "retail price parity"[2]. In other words, the levelised cost of PV was equivalent, or less than, the retail price of electricity for residential energy customers, some seven years ahead of the forecasts released by CSIRO just two years prior.

The APVA announcement was followed closely by a report published in November 2011 by Tosh Szatow for the Cape Paterson Ecovillage, titled: "Zero carbon study [3]" – suggesting that, even with conservative installation price assumptions, and before rebates, PV was at, or close to, retail price parity - making it an attractive financial proposition for households seeking to build net zero emission homes.

In June 2012, a working paper by Paul Simshauser and Tim Nelson, titled: "The Energy Market Death Spiral - Rethinking Customer Hardship[4]", highlighted the new reality of falling energy demand, driven by the rising cost of electricity, falling cost of PV and energy efficient products, and the threat this poses to the incumbent energy supply business model.

Against this backdrop, the Australian Energy Market Operator (AEMO) published a solar forecasting paper[5], noting that levels of PV in 2012 were "observable" in the energy market and would increasingly impact on investment in the National Electricity Market (NEM).

In 2012 AEMO also revised down its demand forecasts across the NEM from the previous year. It noted:

[1] See <http://www.csiro.au/Outcomes/Energy/Carbon-Footprint/IG-report.aspx>
[2] A detailed version of the study can be viewed online at < http://www.apva.org.au/sites/default/files/documents/APVA%20Reports/Residential%20Sector%20Modelling%20of%20PV%20and%20Electricity%20Prices%20-%20APVA%20Nov%202011.pdf>
[3] The report can be viewed online at <http://www.capepatersonecovillage.com.au/sustainability/zerocarbonstudy/>
[4] http://eraa.com.au/wp-content/uploads/No-31-Death-Spiral.pdf
[5] http://www.aemo.com.au/Reports-and-Documents/Information-Papers/Rooftop-PV-Information-Paper-National-Electricity-Forecasting

- "Across the NEM, annual energy for 2011-12 is projected to be 2.4 per cent lower than 2010-11 and 5.7 per cent lower than forecast in the 2011 Electricity Statement of Opportunities (ESOO) under a "medium" economic growth scenario;
- Forecast annual energy for 2012-13 is projected to remain flat (0.0% growth), which represents an 8.8 per cent reduction from the 2011 ESOO forecast[6].

AEMO twice again revised down forecast energy and peak demand in 2013[7], each time on the back of lower-than-expected demand, affirming the increased difficulty of predicting the future at a time of changing trends.

The revised forecasts by AEMO served to reinforce the risks highlighted by the Simshauser/Nelson paper. In addition to the change driven by negative economic conditions worldwide, it cited the rising costs of energy, falling costs of PV and a suite of policy and commercial drivers, which are improving energy efficiency and/or resulting in demand curtailment.

Since that time, an increasing number of industry observers and participants have continued to highlight risks to consumers entailed by Australia's energy market transition, specifically, the risk of stranded network and generation assets caused by falling energy demand.

A report of particular relevance to this research, and published prior to the Simshauser/Nelson paper, was produced by the Alternative Technology Association (ATA) in 2012[8]. It demonstrated that off-grid power supply was already cost-effective within certain market niches – in particular, in fringe-of-grid locations and as a response to network constraints or other safety and reliability imperatives (For example, bushfire response). The off-grid power systems that were the subject of the ATA research included a combination of PV and battery storage technology.

The findings highlighted the importance of the following question:

"What would happen to the energy market if battery technology followed the price trajectory of PV"?

In regard to this question, it is pertinent to note that:

1. The German feed-in-tariff for PV was effectively implemented in the year 2000. Just over ten years later, driven by a ramp-up in global manufacturing capacity and competition (primarily the arrival of China as a low-cost PV manufacturer) and the associated educational impact that comes with the scaling up of the production of any consumable, PV became competitive with the retail electricity price in Australia (and many other markets);
2. As a manufacturing challenge, battery technology has many similarities with PV technology, albeit currently in an earlier phase of its evolution for stationary energy applications. Specifically, in order to decrease production costs, both technologies

[6] Actual electricity consumed within in the NEM in 2013 was ultimately 2.8 per cent lower than in 2012 (recently released scheduled demand and generation data published by AEMO and provided through NEM-Review).

[7]See http://demobs.renegade.runs.mx/article/2013/11/18/energy-markets/who-pays-demand-drop-errors

[8] http://www.ata.org.au/projects-and-advocacy/the-economics-of-stand-alone-power-systems/

require high levels of automation, enabled by significant capital investment, which in turn depends on steady, growing consumer demand; and

3. Germany introduced a feed-in-tariff for battery storage in 2013, while China's current (twelfth) five-year plan highlights seven strategic emerging industries for priority investment, one of which is "new-energy vehicles", a subset being advanced batteries.

In summary, the experience of battery technology over the next decade looks set to closely replicate the experience of PV over the last decade, with government policies in Germany, Japan and China[9]leading the world, and established to ensure demand for battery storage technologies are secure and growing. Whether this results in the same dramatic reduction in technology costs, while improving performance, remains to be seen.

The following preliminary research paper is intended to lay the foundation for answering the question "what would happen to the energy market if battery technology followed the trajectory of PV?" It is intended to be useful for policy makers, industry participants, energy market institutions and industry observers. Specifically, it is designed to understand the timeframes over which stand-alone power solutions may become viable across a range of housing market contexts (that is, housing types and climate zones).

Subsequent papers are intended to build an understanding of:

- The viability of stand-alone power infrastructure across non-residential market segments and other climate zones across Australia;
- Key market planning and design processes, institutions and authorities that will influence the extent to which the stranded asset risk materialises, or is mitigated and managed. In this paper, we begin to map these issues, including the implications for energy customers; and
- The magnitude of the financial risk resulting from stranded assets in the energy market that materialise due to the financial viability, and reliability, of stand-alone energy solutions arriving in an un-planned way.

[9] We note that other jurisdictions around the world have incentives for energy storage technologies and that this will also play an important role.

Executive Summary

The research paper highlights that the National Energy Market (NEM) is in a state of profound transition, from a centrally planned and controlled market, to one where local generation, storage and local control of power is common-place. How far this transition goes, and how quickly, are important questions.

The research paper suggests the transition may be quick and dramatic – a shift to cost-effective stand-alone power solutions appears highly plausible by 2020, in a wide range of market segments. In some contexts, stand-alone power is viable today, particularly when assessed over a 25-year period.

The story of this transition is still being written, but the history of the energy market is worth remembering. When today's energy infrastructure was planned and built, it was far easier to transport electricity overland, than coal. Generating power close to where it was consumed caused air-pollution and associated health impacts. For over 100 years, large power stations, located near to coal mines, connected to businesses and homes across the country via power lines, has had a compelling and practical rationale.

Today, new technologies - specifically solar power and energy storage - have created a vastly different rationale for energy market design. They are factory built, and modular. Increasing or decreasing their installation size has a minimal impact on their installed cost. They can be located close to where energy is consumed, with no impact on air quality or health.

These new technologies, combined with complimentary advances in energy metering, data management and communications, are the building blocks for a very different energy market. The potential for a more customer-centric, resilient energy system is now very real.

Stand-alone power infrastructure can be locally owned and locally managed, with positive flow-on affects for local economies, particularly in regional areas that may suffer from poor power quality or unreliable supply. The risk of high energy prices for regional customers, which can be the result of more cost-reflective tariff structures, can also be proactively managed by transitioning to stand-alone power solutions or micro-grids. This will also help un-wind historical cross-subsidies from city to regional customers, reducing upward pressure on power prices for all.

Readers will note that in the scenarios we present, we consider households remaining connected to natural gas for space heating, while switching to stand-alone power (electricity) infrastructure. However, this should not be read as an advocacy position. The purpose of this research paper is to simply explore economic trigger points for moving away from reticulated electricity use across a variety of climate zone, housing type and fuel mix scenarios, and discusses the flow on effects.

Readers will also note we consider the use of wood fuel for space heating. Again, it should be noted we are not advocating for wood fuel as a replacement for space-heating for all households.

We note that in Victoria, the overwhelming infrastructure cost when switching to stand-alone power, where solar panels provide the bulk of energy, is determined by the winter space heating (and to a lesser extent water heating) electricity load, even after we assume household retrofits take place. Using wood fuel for space heating results in a significant stand-alone power infrastructure saving, such that it becomes viable. In this way, where wood heating can be made compatible with customer preferences, is burned with high efficiency and low emissions, and is sourced from renewable sources, we believe it can have an important role to play as part of a sustainable renewable energy system.

The research explored the viability of stand-alone power solutions across a range of Victorian climate zones and household scenarios. The twelve scenarios are described and labeled in the table below:

Scenario location and description	Scenario Names	
	Gas and electricity available	No gas available
1. *Bendigo* – 500+ homes, regional retrofit of homes and grid	a) Regional, 500, gas	b) Regional, 500, no gas
2. *Bendigo* – Retrofit of existing regional house	a) Regional, single, gas	b) Regional, single, no gas
3. *Werribee* – 500+ homes, urban fringe greenfield development	a) Greenfield, 500, gas	b) Greenfield, 500, no gas
4. *Werribee* – Urban fringe, new-build house	a) Greenfield, single, gas	b) Greenfield, single, no gas
5. *Melbourne* – Retrofit of existing inner-suburban house	a) City, single, gas	b) Not considered
6. *Melbourne* – 500+ home, inner-suburban retrofit of homes and grid	a) City, 500, gas	b) Not considered

The following table details when stand-alone power solutions will be viable across the scenarios considered. In each scenario, a range of energy efficiency measures were implemented in parallel with the stand-alone power solution. Excluding scenarios that considered the use of wood for space heating, it was assumed no behaviour change or compromise of amenity was required.

Scenario	Description	Viable by
1b) - Regional, 500, no gas	Community buys back the grid; solution is delivered by a specialist energy services company; bottled gas is displaced by wood for space heating.[10]	**Before 2020**
1b) - Regional, 500, no gas	Community buys back the grid; solution delivered by a specialist energy services company; natural gas connection or network augmentation cost of $6,000 per home is avoided[11]; switch from electric heating to wood heating.	**Before 2020**
1a) - Regional, 500, gas	Community buys back the grid; solution delivered by a specialist energy services company; network upgrade cost of $2,000 per home is avoided or weighted cost of capital reduced to 7.6%.[12]	**Today**
1a) - Regional, 500, gas	Community buys back the grid; solution delivered by a specialist energy services company.	**Before 2020**
2a) - Regional, single, gas	Communities organise bulk-buy and retrofit homes; sufficient roof space for 8kW solar PV per home.	**2020 or sooner where bottled gas or network cost can be avoided**
3a) - Greenfield, 500, gas	Solution delivered by specialist energy services company; Passive design optimised; reduce average home size by 1% (2.5sqm).	**Before 2020**
3a) - Greenfield, 500, gas	Solution delivered by specialist energy services company; Passive design optimised; Cost of capital 7% over first 10years.	**Before 2020**
3b) – Greenfield, 500, no gas	Solution delivered by specialist energy services company; Passive design optimised; wood fuel for space heating; centralised gas and electricity cost of $8,000 avoided.	**2020**
4a) - Greenfield, single, gas	Reduce average home size by 3.5% (9sqm); construction cost saving is used to reduce the cost of stand-alone power infrastructure.	**2020**

[10] We note that the switch to wood fuel may not be unanimously supported by energy customers, or by local communities, local councils and EPA (with regard to particulates), the CFA (fire risk) or environmental organisations (with regards to the use of a sustainably-sourced wood supply). In addition, we also note that from a practical perspective, the use of wood fuel is not a 'like for like' fuel substitute for space heating and would require additional behaviour changes, planning and effort from the householder.

[11] This scenario refers to a situation where a regional town may be considering connecting to the natural gas network, and instead, chooses to switch to wood fuel for space heating at the same time as implementing a stand-alone power solution.

[12] This scenario refers to a situation where an upgrade to the local network is being considered, and an alternative to the upgrade is to switch to stand-alone power supply.

Note: we found other scenarios considered were unlikely to be viable before 2020 and so have not been detailed in the table above.

More specifically the report's findings include:

- Stand-alone micro-grids for greenfield housing developments, delivered by a specialist energy service provider, are highly likely to be viable before 2020 where natural gas is available, and may be viable where wood fuel displaces natural gas[13].
    - Key variables, such as the avoided centralised infrastructure costs and the weighted cost of capital and energy services company overheads (including infrastructure maintenance costs) determine the difference between a commercial model that is viable[14] over 10 years, or not at all. Over 25 years, the model is clearly viable even at today's prices.
    - A short-term reduction in the energy services company's weighted cost of capital, from 8.6% to approximately 7%, is likely to be sufficient to make a stand-alone micro-grid viable over a 10 year period, after which the cost of capital could increase again without affecting the commercial viability. Alternatively, reducing the size of homes by as little as 1%, and using the construction cost savings to offset stand-alone power infrastructure costs, is likely to be sufficient to make the model viable by 2020.
- In regional areas with natural gas, stand-alone micro-grids delivered by an energy service provider are viable today when assessed over a 25 year period, and are highly likely to be viable by 2020, particularly where the short-term weighted cost of capital can be reduced.
    - Where natural gas is available and there is the potential to avoid an electricity network upgrade cost of approximately $2,000 per home[15] within the area serviced by that network, it is more cost-effective to switch to a stand-alone micro-grid based on current prices for a stand-alone micro grid solution.
    - Where natural gas is not yet available and electricity is currently used for heating, and heating is switched to wood fuel to displace a centralised gas connection cost, or network augmentation cost, of $6,000 per home, the stand-alone micro-grid model becomes viable by 2020.
    - Where wood displaces bottled gas, the model is as good as cost-effective[16] today based on current prices for stand-alone micro-grid infrastructure and energy, and clearly viable over a 25 year period based on 2020 prices.
- Stand-alone power solutions for individual homes in regional areas, with high winter and summer thermal loads[17], are likely to be viable before 2020 where communities can self-organise and realise cost-reductions on stand-alone power infrastructure. However, they are constrained by the size of the PV systems required (in the order

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[13] Stand-alone micro-grids utilising wood fuel for space heating are viable where the combined cost of upgrading or connecting new centralised electric and gas networks exceed $6,000.

[14] We defined "viable" as being cash-flow positive on a cumulative basis, over a given time period. We used a simple pre-tax cash flow model for assessing viability.

[15] Note: this very low threshold reflects the fact that when the winter electricity load is relatively low (supplied by gas or wood fuel), stand-alone power infrastructure is very competitive with the centralised grid.

[16] The increased cost of the stand-alone power solution compared to business as usual grid supplied energy, is immaterial over a ten year assessment period.

[17] The Bendigo climate was used for all our regional scenarios.

of 8kW was needed for a typical house, which will be difficult for many household roofs to accommodate). Where wood is used to displace natural gas as part of an appliance replacement cycle (For example, old gas heaters are replaced by wood-heating and gas cook-tops are replaced with electric), stand-alone power solutions may also be viable by 2020. Where bottle gas is displaced by wood, the viability improves substantially.

- Stand-alone power solutions for individual homes in greenfield developments are unlikely to be viable before 2020 without a significant step-change in stand-alone power infrastructure costs, or customers choosing to reduce the size of their home to save on construction costs and offset stand-alone power infrastructure costs. We found that reducing the size of a home by $9m^2$ (3.5% of the average new Victorian home) would be sufficient to make stand-alone power infrastructure viable by 2020.
- Stand-alone power solutions for suburban areas are significantly constrained by the availability of adequate space for solar PV, and the difficulty of using wood fuel in suburban areas

Stranded asset risks

Infrastructure planning for new housing developments must be carefully managed by local authorities. Business as usual grid connections to both electricity and gas networks are likely to already be sub-optimal today, given we find stand-alone power solutions are viable prior to 2020.

To manage stranded asset risk as part of greenfield and major brownfield developments, local authorities, developers and builders will need to work closely together during long-term infrastructure planning processes to develop the knowledge, policies and systems required to enable truly efficient energy infrastructure planning, and to avoid locking in inefficient centralised infrastructure.

Processes and controls for managing network investment are also critical, including pricing controls. Nodal pricing[18] has the potential to highlight opportunities where centralised network assets can be re-purposed to a more cost-effective stand-alone power solution. However nodal prices are highly likely to create "winners and losers" and pose risks to ensuring energy remains affordable for vulnerable customers.

The Australian Energy Regulator will need to be vigilant as part of five-year network investment reviews to ensure that network companies have fully investigated the potential for non-network solutions to grid-constrained areas, and where networks are in need of replacing. It will be critical that network companies are engaged in the efficient transition of their grid – if they lack incentive, or effective discipline, the risk of stranded network assets, and the related impacts on future energy prices, will only grow.

It is important to note that in none of the assessments has the report accounted for the real cost of supplying regional customers through the conventional grid – the results are based on current retail tariff structures only - this is likely to significantly under-value the transition

[18] Nodal pricing entails the true cost of network infrastructure at any given point of the energy network be priced relative to its true cost. For those not familiar with energy pricing, it is important to note that electricity and gas networks do not price their services strictly based on the cost of serving customers in specific locations, and that this masks the true cost of serving customers, particularly those in regional and fringe of grid locations.

to stand-alone power solutions. In fact in some fringe of grid locations, off-grid systems may already be viable, even at today's relatively high stand-alone energy infrastructure prices.

Further, the analysis considered Victoria only. In other areas of Australia, and in particular the NEM jurisdictions of New South Wales, Queensland and South Australia, milder climate zones, better solar radiation and higher-than-average electricity prices would make stand-alone power solutions more viable and sooner.

Implications for energy consumers

The report's findings have significant implications for consumer protection in the energy market and for efficient investment in centralised gas and electricity infrastructure more broadly.

The current energy market design is premised on the idea that customer choice, enabled by information and a disaggregated competitive market, will lead to the lowest possible prices for customers. However, our analysis shows that stand-alone power solutions, led by a specialist energy service company, is likely to offer the potential for lower, more certain energy prices, but at the expense of future retail choice.

Energy delivered by a service company, making use of stand-alone power infrastructure, is also likely to improve the incentive for designing and offering products and services that help customers reduce energy demand. Reduced energy demand translates more directly into local infrastructure savings, in particular reductions in back-up generator use and/or battery capacity and cycling demands. This contrasts to the current energy market where reduced energy demand in any given area does not necessarily translate into savings for customers in that location due to price smoothing across locations.

Importantly, stand-alone power solutions are likely to entail greater price certainty for customers, including the potential to proactively manage the risk of major price restructuring under a "utility death spiral[19]" scenario.

Greater price certainty occurs because the stand-alone power infrastructure model is far less exposed to variable fuel prices - energy supply is predominantly from solar power which utilises free fuel – the sun. Also, this model is resistant to fluctuations in asset utilisation because prices are set based on a combination of energy services delivered (space heating, hot water, etc) and energy used – not just energy used as per the incumbent energy supply model[20].

"Utility death spiral" risks would be managed by buying out local network infrastructure and re-purposing it to enable a new energy supply model that is less dependent on sales volumes to retain viability. That is, instead of a sub-optimal business model constantly re-pricing services to remain viable, the infrastructure could be bought out and the business model for energy supply reconfigured.

[19] The utility death spiral refers to a scenario where declining energy demand forces energy utilities to increase fixed charges to recover lost sales volume. This re-pricing further improves the viability of customers leaving the grid, and so exacerbates the dilemma faced by utility companies. See http://eraa.com.au/wp-content/uploads/No-31-Death-Spiral.pdf

[20] When prices are set to reflect the quality of energy services, such as provision of thermal comfort, reductions in energy use do not impact on the viability of the supply model. Customer payments are set to reflect the value of the service, and not just how much energy is consumed. In this way, enhancing energy efficiency does not undermine the viability of the service model, whereas where customer payments reflect energy use only, energy efficiency undermines asset utilisation and causes prices to increase – eroding the financial benefits of energy efficiency.

In the case of regional customers, the transition to stand-alone power solutions may also entail markedly improved power quality and reliability, including improved resilience to outages caused by extreme weather, such as storms and fires.

Collectively, the results suggest that the premise upon which the current energy market is designed should be challenged in the interest of all consumers. A future energy market in which customers are supplied by stand-alone power and micro-grids also implies new regulatory challenges and specifically, begs the following questions:

- What measures are appropriate to manage customer hardship? What processes should be followed for customers who cannot afford to pay for their energy requirements?
- How important is customer choice? It would not be possible for a customer to be disconnected from one retailer and re-allocated to another, in a market where stand-alone power solutions limit retailer choice;
- What would become the equivalent of a "retailer of last resort" in the event that an energy service company, delivering stand-alone power solutions, became insolvent? Prudential requirements for such infrastructure providers, including insurance policies, would need to be carefully designed and managed to ensure financial insolvency would not leave customers without power; and
- How would the discipline of price and service competition be maintained on stand-alone power infrastructure providers, given customers would not be able to switch retailers in the event they became dissatisfied with energy prices and/or customer service?

These questions point to the need for specific community service obligations on providers of stand-alone power infrastructure, and possibly tighter prudential requirements, to ensure the risks are effectively managed.

Implications for the National Electricity Market

A future in which stand-alone power infrastructure emerges at scale, and in an unplanned way, suggests the risk of significant network and generation infrastructure becoming stranded assets. This report suggests a number of measures, which could be implemented to mitigate and/or manage this risk:

- Coordinated trials of small-scale stand-alone power solutions, potentially through the distributors' demand management incentive scheme, to enable accelerated learning by energy market participants and regulatory authorities. We note that this funding should not be limited to network service businesses whose natural incentive is to use storage to support network infrastructure, as opposed to avoiding or deferring the need for it altogether. Given the scheme is paid for by customers, how it is spent should not be constrained by the preferences of incumbent businesses; and
- Facilitated purchase of centralised network assets, where they have been shown to be inefficient as part of a centralised supply model. Projects could be identified and flagged for action by the Australian Energy Regulator, as part of its network planning and regulatory investment test processes. State governments or other entities could then co-ordinate a targeted, localised response, using a network of energy market stakeholders; and

- The clear and transparent publication of network constraints, made available in easily accessible language and format to the public, organised by postcodes - this will allow community groups, councils and energy service providers easy access to the data needed to assess stand-alone power infrastructure models and may obviate the need for state government co-ordination; and
- Adjustment of the Regulatory Investment Test for distribution (RiT-D), with networks' threshold to be based on a cost-per-customer basis, as opposed to a capital cost figure alone. This report demonstrates that, even at $2,000 per customer, upgrading the electricity network and continuing its operation as part of the centralised energy market is highly likely to be inefficient where natural gas is available for space heating. The implication of this finding is that the RiT-D threshold could be set as low as $2,000 - $3,000 per customer served in the network to ensure there are no inefficient investments in network infrastructure; and
- Assessing network planning and investment decisions more stringently in areas where stand-alone power solutions are likely to be viable – specifically regional areas, and particularly either where bottled gas exists and/or in residential growth corridors where new network assets will be planned.

We recognise these points are necessarily brief, reflecting the early stage and scope of the research. Further work would be required to develop measures that can be implemented, with support from energy market stakeholders.

Research: Aims & assumptions

The research was designed to provide robust, valid insights into the probable financial viability of off-grid energy supply in a range of market contexts over time, within the budget constraints of the project.

The overarching aim was to understand the timeframes within which the risk of stranded assets in Australia's centralised energy market may materialise. Specifically, the research aimed to identify a plausible timeframe by which off-grid energy supply may be financially viable for the mass-market – the implicit assumption being that, if viable for the mass-market, significant stranded asset costs would be at risk of being realised.

A key determinant of whether a solution would work in the mass-market was the assumption that behaviour change would not occur – that is, technology alone would be needed to meet energy demand expectations.

Research: Methodology

Housing locations and types

Three locations where chosen for the analysis - Werribee, Bendigo and an inner-Melbourne suburb. Locations were chosen to reflect a range of climate and property types across Victoria, and to highlight particular challenges and opportunities likely to be faced by a potential shift to off-grid energy supply.

Whilst not an exhaustive list of locations, they represent a substantial and important range of Victorian climate zones and property types, with Bendigo being indicative of Victoria's regional growth areas; Werribee indicative of suburban fringe growth and suburban Melbourne being indicative of existing housing stock.

An important omission was medium to high-density housing. It was felt this would be the last residential market in which stand-alone power solutions would be viable due to the relative energy density of this housing typology. That is, in comparison with the available roof area, per household, for solar electricity generation, there is relatively far more energy demand than a typical free-standing or attached single/double story dwelling.

In this way, we have taken the view that, should stand-alone power solutions emerge as a viable mass-market option, they are likely to be concentrated, and have most impact on the energy market, in suburban and regional/rural areas, noting it is already the most cost-effective option for many remote and fringe-of-grid locations. This view naturally implies a future where, despite stand-alone power being common for many households, cities and commercial/industrial zones would remain largely dependent on centralised grid infrastructure.

It is important to note this is not a prediction of the future. Rather, it is a scenario designed to help us explore the probability, and consequences, of stand-alone power becoming a financially viable option for a significant number of residential energy customers.

It is also important to note that with Victoria's relatively harsh climate, poor solar resource and low energy costs compared to other states and NEM jurisdictions, the locations chosen represent close to a "worst-case" scenario for the viability of off-grid energy supply in Australia.

Scenarios explored

The following table summarises the scenarios explored and their labels used throughout the report.

Scenario location and description	Scenario Names	
	Gas and electricity available	**No gas available**
7. *Bendigo* – 500+ homes, regional retrofit of homes and grid	c) Regional, 500, gas	d) Regional, 500, no gas
8. *Bendigo* – Retrofit of existing regional house	b) Regional, single, gas	c) Regional, single, no gas
9. *Werribee* – 500+ homes, urban fringe greenfield development	b) Greenfield, 500, gas	c) Greenfield, 500, no gas
10. *Werribee* – Urban fringe, new-build house	b) Greenfield, single, gas	c) Greenfield, single, no gas
11. *Melbourne* – Retrofit of existing inner-suburban house	b) City, single, gas	c) Not considered
12. *Melbourne* – 500+ home, inner-suburban retrofit of homes and grid	b) City, 500, gas	c) Not considered

Figure 1: Summary of scenarios considered

Energy demand assumptions

In each scenario, a housing type was developed in line with the predominant housing types of the three locations, and a baseline energy load profile was developed for each home and scenario. The key characteristics considered were:

- Size of the home;
- Star-rating of the home; and
- The type and efficiency of appliances/systems used inside the home for space heating and cooling, water heating, lighting, refrigeration and washing.

For each scenario, we considered a range of possible measures aimed at reducing energy demand cost-effectively, before sizing and pricing stand-alone power infrastructure.

Through previous research[21], ATA have found that investing $1 in energy efficiency to reduce residential load requirements saves somewhere in the range of $3 to $6 of stand-alone power system (SAPS) capex. Given this significant relationship between demand assumptions and stand-alone power costs, we used conservative demand assumptions, including no behaviour change, to ensure the assessment would not distort the potential viability of SAPS infrastructure.

A financial hurdle rate of return of 10% was chosen for retrofit measures – this hurdle rate was chosen due to the premise that such a hurdle rate, at a minimum, would be required to make stand-alone power infrastructure financially attractive and, by default, such a hurdle rate should be applied to assess measures that reduce energy demand.

In this way, the retrofit measures we selected for implementation did not unduly influence the viability of the stand-alone power solution assessed.

In each location, assumptions were made about what percentage of the thermal load would be used for heating or cooling, including the fuel type and efficiency by which heating and cooling demand would be met, before and after retrofit measures were implemented.

Summary tables of the energy savings attributed to retrofit measures, including the costs and the thermal load assumptions that underpin them, are detailed in Appendix A. It is important to note that:

- In upgrading new homes from 6 to 7.5-star, we rely on a number of zero cost and/or cost-saving design measures being implemented - primarily the reduction of window glazing surface area and its appropriate positioning (concentrated to the north, with almost no glazing to the south).
- In assuming upgrades to Bendigo (160sqm) and Melbourne (140sqm) properties, we rely on a combination of draught-proofing ($1,000), ceiling insulation ($1,500), wall insulation ($4,000), upgrades to curtains/pelmets ($1,000) and floor insulation ($1,200). In this way, the $6,600 budget we have allocated for upgrades does not pay for all retrofit measures, but should be sufficient in most circumstances to realise a change from 2 to 4-stars, or an equivalent energy saving. The figures are based on our direct experience of assessing the cost of upgrading existing properties, and work published by the Moreland Energy Foundation[22] that confirms, across most property types, the retrofit measures we have specified are sufficient to lift star-ratings by around 2-stars, and additionally are the most cost-effective;

[21] http://www.ata.org.au/projects-and-advocacy/the-economics-of-stand-alone-power-systems/
[22] See < http://www.mefl.com.au/what-we-do/energy-efficiency/item/363-energy-efficiency-potential-of-victorian-homes.html> for an overview of this work and links to more detailed results

- In assuming appliance upgrades realise the energy savings specified, we assume that in the greenfield scenario the household would otherwise pay for the “business as usual” appliance. In this way, the appliance premium only reflects the cost of upgrading from “business as usual”, not the full cost of the appliance. In the retrofit scenarios (Bendigo and Melbourne) we assume the household pays for the full cost of the appliance upgrade and that, depending on the specific household need, the appliance selection is optimised. That is, not all appliance upgrades are assumed to occur for any given home – only the most cost-effective options for that specific home are implemented. In this way, the appliance upgrades are paid for out of energy savings only, implying the appliance itself is not paid for by the customer; and
- Our heating/cooling load assumptions, including how they are met, are designed to be conservative and, as such, will appear too high for many people that are accustomed to using energy more efficiently. The relatively high winter heating loads and lower system efficiency we have assumed, present a more challenging load profile for SAPS design, and so help ensure our results remain conservative.

In the ‘no gas’ new home scenario, it is assumed that:

- A wood heater is used instead of a gas heater, and this switch is capital cost-neutral to implement;
- An electric heat pump is used instead of gas boosted solar and this is cost-neutral to implement; and
- An electric cooktop is used instead of gas and this is cost-neutral to implement.

Note: These assumptions are very conservative, given a house being built without gas is likely to save on build-costs because it will avoid costs for gas plumbing.

In the ‘no gas’ retrofit scenario, it is assumed that:

- A wood heater displaces a gas heater at a cost of $3,000. In the 500-home cluster scenario, we assumed 30% of gas heaters would be in need of replacing, and so a new wood heater becomes cost-neutral for those 30% of homes.
- We assume an existing gas water heater is replaced with an electric heat pump at a cost of $3000. In the 500-home cluster scenario, we assumed 30% of hot water systems would be in need of replacing, and so retrofitting with a heat pump becomes a cost of $1000 for those homes, instead of $3000.
- Gas cooking is replaced by electric cooking at a cost of $1000. In the 500-home cluster scenario, we assumed 30% of cooking systems are in need of replacing, and so this becomes cost-neutral for those homes.

Business as usual thermal loads, including how they are met, remain the same as the dual-fuel scenario. Appliance upgrade options and their benefits also remain the same. The additional capital costs of switching to wood and supplying wood fuel are factored into the energy services company cost model, while the additional electrical load resulting from switching to heat pumps and electric cooking are factored into the SAPS design and cost assumptions.

It is important to note that, house by house, the type of measures assumed for reducing energy demand, and their relative costs and benefits, may vary substantially. Our assumptions are not intended to be precise for every house - an unrealistic aim. Rather, they were intended to give us a measure of what reduction in energy demand could be considered plausible and conservative across the range of scenarios considered.

Energy supply solution design assumptions

Once a load profile was developed, based on plausible energy demand, a stand-alone power system was sized and priced, before the viability of the stand-alone energy package (demand reductions and power infrastructure) was modeled. In this modeling process, we made the following judgments:

- That the stand-alone energy package would be delivered by a professional energy services company;
- That systems would be designed to minimise the need for back-up generation (to avoid local particulate emissions and exposure to fuel price risk) – all systems were designed for solar to supply 92-96% of all energy needs;
- That the professional energy services company would be purchasing infrastructure at wholesale prices and recovering the profit margin on that infrastructure, plus labour for installation and their corporate overheads, over the lifetime of said infrastructure. The assumption naturally implies a lower installed capital cost than if a household was purchasing infrastructure at retail prices. Discount factors applied to retail costs were in the order of 35-40% for all components, other than PV, which had an assumed retail discount of 10%[23]. Centralised diesel generators for the 500 home solutions, were assumed to be purchased at retail price from a suitability qualified supplier and placed on a service contract with that supplier for ongoing maintenance.
- The energy services company would take on warranty risk, implying a 16.5% premium on wholesale costs – the entity importing becomes responsible for the enactment of any warranty.

A detailed list of product and price assumptions are provided in Appendix B.

These judgments were based on our direct experience and a belief that stand-alone energy solutions for the “mass-market” will need to be delivered by a professional energy services company, which manages risk and complexity on behalf of the household.

That is, if left to individual households to implement, stand-alone energy solutions are unlikely to spread beyond a niche of committed early adopters due to the relative complexity of designing and delivering an integrated, optimised, stand-alone energy solution, and the associated transaction costs for the householder.

We examined the business case for delivering the stand-alone energy solution from the perspective of the energy services company, with the assumption that, if this can be done for the equivalent price of energy incurred by the household, regardless, it will be attractive to the mass market.

It is important to note that where a householder uses gas for space heating, financial benefits from reduced heating needs are realised by the customer, due to building fabric upgrades as opposed to stand-alone power infrastructure. Our hypothetical energy services model accounts for this value and ensures it is considered in the business case for a stand-alone energy package.

23 The rationale for not discounting PV and PV-related materials was that, in reality, 2013 panel prices are currently likely to be somewhat depressed, given the global oversupply of Chinese panels and panel manufacturers, and that potentially a small increase may be experienced in the market over the next few years as the global PV industry adjusts to a more stable, long term economic future.

Once we developed our energy services company financial model, we then examined a range of plausible future scenarios for energy and stand-alone power infrastructure prices, and used this to assess the viability of a stand-alone power solution.

Using an iterative process - primarily adjusting gas price and battery price variables[24] - we identified plausible timeframes by which the energy services company, providing an integrated stand-alone energy package, could be viable. We also adjusted assumed cost of capital and debt for the energy services company, as well as overhead costs incurred by the service company. Where we have varied these assumptions, they are detailed in the scenario findings.

Stand-Alone Power Supply (SAPS) design

The SAPS chosen for the purposes of all scenarios were based on the most cost-effective, proven and currently available technology in the Australian energy market – that is:

- a solar photovoltaic (PV) array;
- batteries and battery management system;
- inverter-charger/s and regulator/s; and
- backed up by a small petrol generator, for the individual home scenarios; or
- large-scale diesel (potentially fuelled by bio-diesel) generators for the clustered scenarios

For the clustered 500 home scenarios, both the PV and the battery banks were distributed, with not every home needing to house all or part of the stand-alone system.

Storage

Lithium-iron phosphate batteries were chosen for all modeling scenarios, primarily due to their ability to handle more regular deeper discharges over many cycles, as well as their tolerance of higher discharge rate than lead-acid batteries. Both of these factors lead to higher economic performance than their lead acid, or similar, counterparts. They also typically have longer asset life due to in-built smart charging.

Smaller (48 volt, 48 kWh) banks were used for the individual home scenarios. The additional annual (and particularly winter) loads of the all-electric scenarios meant that these smaller battery banks led to a significant PV requirement – to the extent that it was questionable whether some households would be able to cater for the level of required PV.

Larger (120 volt, 120 kWh) banks were also considered for the individual home scenarios, in order to reduce the PV requirement - however this led to a significant increase in system capex.

The larger banks were also used for the clustered 500 home scenarios - however, not every home required batteries or PV on-site. Economies of scale were found in the design of these clustered scenarios, with only somewhere between one in seven and one in five homes needing to house battery banks.

[24] We deemed that these two variables would be the primary source of variation affecting the viability of stand-alone power systems.

It is important to note that we expect battery technology will continue to evolve, and that by 2020, lithium-ion may not be the most appropriate or cost-effective storage technology available. To avoid speculation on technology evolution, we have assumed lithium-ion is used.

Solar

In 500 home cluster scenarios, typically nine out of ten homes required PV, with only those houses with both PV and batteries (approximately one in five) requiring the more expensive inverter-chargers. Houses with PV, but no battery banks, only required traditional grid connect DC-AC inverters.

The level of solar contribution to the overall electricity supply from the system was set in the range of 92% – 96% for each of the scenarios modeled in order to minimise generator run-time, and any associated air-quality impacts.

Generator Back-up

Petrol generators were chosen for the individual home scenarios as these typically involve quieter units, with less particulate emissions. As generator use is only occasional, petrol gensets are also more cost-effective than diesel for this type of application.

Multiple, centrally located, 350 kVA diesel generator units were selected for the 500 home clustered scenarios, as these offered economies of scale and meant that generator back-up would not be required at individual household premises.

The potential for bio-diesel to be utilised for these generators exists, in order to completely eliminate operational emissions from the project, albeit at a slightly higher opex (fuel) costs than for traditional diesel based generators. The capex requirements to run these generators using bio-diesel was included within the model, and we simply note here that in the future, these cost assumptions may change.

In addition, these generators could also be co-located with centralised PV, in order to accommodate any excess PV required that could not be located on household roofs due to orientation or shading issues or due to non-participant homes.

Supply-side cost assumptions

Establishing valid future price estimates for electricity, gas and stand-alone power infrastructure was required to determine potential timeframes for stand-alone power viability.

Electricity and gas prices

There were two methodological challenges to address in establishing forward energy prices:

1. Establishing a forward estimate of energy price that can be de-coupled from a real, or implicit, emissions price, given the uncertainty over domestic policy; and
2. Establishing a forward estimate for energy prices, including tariff structures, given uncertainty over the pace and scope of market reform.

To deal with these issues within the scope of our work, this assessment establishes a forward price for energy that is plausible without a price on emissions. That is, it could be driven by fundamentals such as changes in gas prices, coal prices, or network costs.

It is important to acknowledge that establishing a reliable forward price curve is extremely difficult given the many variables that influence energy prices, including:

- Fuel cost (gas, coal) - uncertainty over the future price of gas and whether the predicted risk of domestic prices trending upwards (towards the value of export LNG internationally) materialises;
- Uncertainty over an emissions price, and the cost of other policy measures, which are subject to change over time;
- Changes to network prices, including the influence of declining energy volumes on tariff structures, the potential for new tariff structures, as well as their implicit value. To an extent, the complete de-coupling from the electrical network negates the impact of changes in tariff structures, as the total billed amounts are likely to reflect the cost to supply; and
- Water scarcity[25].

On balance, we consider an assumed increase of electricity prices, of 3% per annum, at or slightly above the rate of inflation (less than 1% in real terms), to be a reasonable and conservative assumption for the purposes of this paper.

We have assumed gas price rises of 5% per annum for five years and then plateau, rising at the cost of inflation. We note that publicly available forecasts tend to suggest the forward price curve for gas will be a different shape – with sharper rises in the short-term that decline over time. This helps reinforce the conservative nature of our assessment.

We assume rising electricity and gas prices are distributed evenly across peak, off peak and standing charges. However it is more likely that changing tariffs will be weighted towards shifting price rises onto fixed charges, particularly in the energy market, where electricity volume has been declining. Such price restructuring would favour stand-alone power solutions and so reinforce the conservative nature of our assumptions.

A fuller discussion of our approach is available in Appendix K.

Starting prices for electricity and gas, including GST, were assumed to be:

- Peak electricity – 35c/kWh
- Off peak electricity – 15c/kWh
- Daily electricity connection charge – 80c
- Gas use – 6.3c/kWh (2.3c/MJ)
- Bottled gas - 16.2c/kWh (4.5c/MJ incl bottle delivery)
- Daily gas connection charge – 60c

By 2020, based on the assumptions listed in the previous paragraphs, these become:

- Peak electricity – 43c/kWh
- Off peak electricity – 18c/kWh
- Daily electricity connection charge – 85c
- Gas use – 10c/kWh (3.7c/MJ)
- Bottled gas – 23c/kWh (8.4c/MJ)
- Daily gas connection charge – 85c

[25] Note: toward the end of the last drought cycle in Australia (2008-2009), water scarcity drove up the price of energy generation substantially (around 50%) as water is a major resource input to many power stations.

Future price of stand-alone power infrastructure

The future price of PV and battery storage is naturally contested. We have taken the view that the primary driver of cost reductions in stand-alone power systems will be changes to battery storage prices.

While further drops in solar panel costs are certainly possible, we have taken the view that system price reductions of the last two to three years in Australia will slow down and plateau. This reinforces the conservative nature of our method.

To inform our future battery price assumption, we considered a range of publicly available research into forward battery price curves with a focus on lithium-iron technology. While lithium-iron will be challenged by other technologies, we have made the assumption that as it is the dominant storage technology currently being developed for transport energy applications and small-scale stationary energy storage applications, is a sensible proxy for future energy storage costs.

Forecasts for lithium-ion battery storage tend to converge at, or slightly above, a retail price of $200/kWh[26] by 2020. The figure below presents a consolidated view of battery price forecasts from a range of sources.

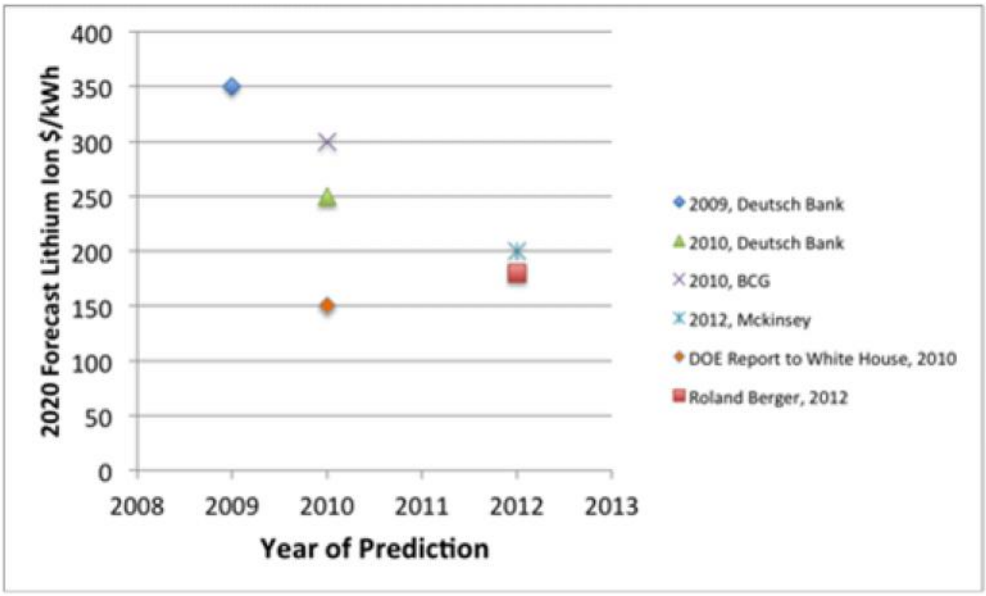

Figure 2: consolidated lithium Iron cost projections, viewed online at <http://static.cdn-seekingalpha.com/uploads/2012/7/30/1131950-13436713894081504-Nick-Butcher.png> or at <http://seekingalpha.com/article/793241-ev-myths-and-realities-part-3b-evconomics-its-the-stupid-battery>

This implies a 7.5%pa drop from today's retail price of around $350/kWh[27] and depending on assumed margins across the retail supply chain, a production cost of approximately $145/kWh. The experience of PV, which dropped in price by approximately 80% over three to four years suggests a price reduction of this order is plausible and conservative for batteries.

[26] Note, this $/kWh figure represents usable storage – that is, it accounts for depth of discharge constraint of 80%.

[27] Note, this $/kWh figure may appear low as it does not include system integration costs. Costs for inverter, battery housing and wiring are considered separately.

Given we assume batteries will be purchased wholesale, and effectively leased to customers as part of a contracted service, we assumed a wholesale purchase price of $175/kWh including warranty risk.

Across different scenarios, we varied the assumed reduction in balance-of-system costs, including the inverter, solar panels, wiring, back-up generator and labour from 0%-2%. This was done to test the sensitivity of the analyses to these assumptions, and identify future price points at which stand-alone power systems could become viable.

Load profiles

In determining the seasonal generation requirements of the various stand-alone power infrastructure systems required for each scenario, a typical, half-hourly, annual load profile was used for a dual-fuel household in Melbourne, acquired from meter data under the Victorian Advanced Metering Infrastructure (AMI) program[28.]

The profile was scaled to meet the annual and daily demand requirements of each of the dual-fuel scenarios, accounting for seasonal variations.

Given the substantial capex required to design a SAPS, to provide winter space heating load[29], we chose to reduce the SAPS capex by considering wood as an alternative fuel source for space heating in the all-electric scenarios.

Given the efficiency and environmental performance of modern wood burners when used correctly with quality wood fuel, and their ability to act as (non-electric) back-up water heating, these are likely to be an excellent space heating alternative in many circumstances where a SAPS may be considered. In addition, wood can be a renewable biomass resource, harvested in a way that reduces fire-load, and is potentially carbon neutral over the longer term.

We note that some locations may have geographies that are not suited to high penetrations of wood fuel, as they may accumulate wood smoke. Discretion is therefore required to ensure wood fuel is only used where appropriate and does not impose health costs on communities. We also note that wood fuel would not be needed for all winter heating needs, although this was modeled in our scenarios. In practice, it would only be needed to complement the battery storage and back up generation stem during the most severe periods of winter.

The wood burner choice resulted in the SAPS design for the all-electric scenarios needing to meet the load requirements for the existing electrical load, as per their dual-fuel scenario equivalents, as well as for cooking and water heating only.

Water heating for these scenarios was assumed to be carried out using a high efficiency electric heat pump system, with a standard electric oven/cooktop plus microwave dealing with household cooking needs[30]. A small electrical load to drive a fan for the wood heater was allowed for (0.66 megawatt hours was allowed per annum).

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[28] http://www.dpi.vic.gov.au/smart-meters/resources/reports-and-consultations/advanced-metering-infrastructure-customer-impacts-study-volume-1

[29] A typical Victorian dual-fuel home requires in the order of 40,000 megajoules of gas for space heating for the six coldest months of the year. This equates to approximately 4.5 megawatt hours of electricity at a co-efficient of electrical performance (CoP) of 2.5.

[30] We considered induction cooktops, but found that whilst the energy savings and the potential connection and cookware upgrades required may be economic in some circumstances, the use of electric resistance cookers meant that model results remained conservative. In reality, some homes may choose induction cooktops for these scenarios.

In the absence of indicative data, the same AMI load shape was used for the all-electric scenarios. However, an additional scaling 'factor' to account for the likely increase in peak electricity consumption was applied, associated with water heating and space heating (electric fan only) in winter. This was additional to annual load requirements for cooking and water heating year round.

The factor comprised a 56% increase in the winter peak load in the coldest months of June, July, August and September. The remainder of the year was subject to the peak load scaling factor outlined in the table below:

Month	January	February	March	April	May	June
Peak Load Factor	1.18	1.18	1.18	1.37	1.37	1.56

Month	July	August	September	October	November	December
Peak Load Factor	1.56	1.56	1.56	1.37	1.37	1.18

Figure 3: Scaled Peak Load Factor – All Electric Scenarios

Climate data

Relevant climatic data was also used for each of the specific locations (that is, Werribee, Bendigo and Preston) to guide SAPS design - this included NASA coordinate solar insolation data[31] and monthly-average temperature data for the nearest BoM weather station[32].

Stand-alone power – energy service model

As detailed previously, we have assumed that, should stand-alone power systems emerge as a mainstream energy supply option, it would be facilitated by an energy service provider that procures, designs, installs and maintains the infrastructure on behalf of customers.

For the purposes of this research, we have assumed that such a business model is likely to work through an initial period of demonstration pilots, before scaling up to provide a mass-market service solution. In all financial modeling, we have assumed the energy service business operates with efficient internal costs and is able to purchase and finance stand-alone power infrastructure at scale.

ESCo cost assumption	Assumption value
Equity investment portion	20%
Cost of equity	15%[33]
Debt investment portion	80%
Cost of debt	7%

[31] https://eosweb.larc.nasa.gov/cgi-bin/sse/sse.cgi?skip@larc.nasa.gov+s02#s02

[32] http://www.weatherzone.com.au/climate/station.jsp?lt=site&lc=87031

[33] This is the rate of return paid to equity investors in the ESCo.

Implied weighted cost of capital, 20% equity, 80% debt	8.6%
Infrastructure insurance cost	Captured in wholesale price premium assumption for stand-alone power infrastructure
Customer acquisition cost (per customer)	Varied across scenarios to test sensitivity, with default value being $500
Customer service cost (including business overheads) – single home solution (per customer)	$700 – this is on top of the opex costs included in the SAPS model for System Monitoring, comms and on-site maintenance
Customer service cost (including business overheads) – 500 home cluster solution	Varied across scenarios to test sensitivity, with default value being $400
Service fee (start price for the stand-alone power service)	Equal to the "business as usual" household energy cost, increasing at 3%pa
Service fee and service overhead cost - annual escalation	2.5%
Year 12 appliance replacement cost	1% cost reduction per annum reduction in real terms from year 1
Year 15 inverter replacement cost	1% cost reduction per annum reduction in real terms from year 1
Year 15 battery replacement cost	1% cost reduction per annum reduction in real terms from year 1
Value of centralised infrastructure offset – single home, dual-fuel, greenfield scenario	$2500 per customer to reflect avoided network infrastructure costs
Value of centralised infrastructure offset – single home, all electric, greenfield scenario	$2500 for avoided electricity network, $2200 for avoided gas network[34]
Value of centralised infrastructure offset – 500 home, dual-fuel, greenfield scenario	N/A – it is assumed the cost of building the islanded network required to support a stand-alone power solution is equivalent to a business as usual network, excluding additional cost for system monitoring and smart control[35]
Value of infrastructure offset – 500 home, dual-fuel, retrofit scenarios	Built into SAPS capital cost assumption – electricity network valued at 20% of its raw cost of $2500 per home, with grid O&M costs set at 5% of full capital value ($50,000 per annum).

[34] Note, in a typical subdivision, gas network costs are often fully subsidised by the network provider and/or the state government. The $2200 avoided gas network assumption was derived by taking the current daily gas connection charge and multiplying it by 10 years as a conservative estimate of the capital cost.

[35] Note, in practice this may underestimate the value of a stand-alone power solution as in a typical greenfield development where the property developer contributes towards the infrastructure cost.

	A range of avoided gas network cost assumptions are used as part of a sensitivity analysis

Using these business model assumptions, a simple (pre-tax) cash-flow model was developed to reflect the business case for providing a stand-alone energy solution. The cash-flow model included dividend payments to equity investors and debt financiers reflecting their respective financing costs.

Research findings

Here we detail findings from the different climate zones and scenarios, including a brief repeat summary of key assumptions detailed in the methodology section.

Werribee (greenfield)

A brief summary of key Werribee greenfield scenario assumptions is produced below:

Assumption	Value	Unit	Comments
Gross Annual Load	5.5	MWh/yr	Typical annual load of Victorian dual-fuel household[36]
Efficiency Saving	0.5	MWh/yr	Achieved via increasing building performance from 6.0 Star (Vic mandated) to 7.5 Star[37]
Efficiency Saving	1.5	MWh/yr	Achieved via a combination of upgrading lights, tv, washing machine, fridge, dish washer & a/c.
Net Annual Load	3.5	MWh/yr	
Net Daily Load	9.6	kWh/day	Average per day, for 365 days

The detailed design specifications for the SAPS system are provided in Appendix C.

Greenfield, Single Home, Gas

Our analysis of the single home, dual-fuel, greenfield home scenario quickly identified that a solution driven by an energy services company is unlikely to be viable within a decade due to the high capital cost and service overheads incurred.

Give this scenario, we performed a series of analyses based on an individual home purchasing SAPS infrastructure at or close to wholesale rates, and financing the purchase through their home-loan. The assumption implies a bulk-buy driven model, potentially

[36] Table 5 in: http://www.dpi.vic.gov.au/smart-meters/resources/reports-and-consultations/advanced-metering-infrastructure-customer-impacts-study-volume-1/4-data-characteristics

[37] Based on annual end use energy saving of 56 MJ/m^2 for Climate Zone 60 (Tullamarine) under NATHers: http://nathers.gov.au/about/pubs/starbands.20121129.pdf

organized through a developer, or community group local to the greenfield development. We allowed a $500, per home, brokering fee for this model.

Our analyses focused on determining the price assumptions that would need to hold true in order for the SAPS solution to become cost-effective.

The following table details findings from our analysis of this scenario:

Scenario description	Summary of key assumptions	Assumption values	Household cash position – year 10	Household cash position – year 25
Current prices	Current SAPS Capex	$29,900	-$13,279	-$33,920
	Fuel Opex (starting)	$320		
	Balance of system maintenance Opex	$690		
	Debt payments (6.5%)[38]	$3,516		
Battery prices drop to $200/kWh retail and balance of system costs drop 2%pa, maintenance costs near zero	SAPS Capex	$25,956	-$1038[39]	$13,012
	Fuel Opex	$320		
	Maintenance Opex	$60		
	Debt payments (6.5%)	$3,100		
Batteries and balance of system prices drop a further 30% than assumed above	SAPS Capex	18,170	$685	$7,936
	Fuel Opex	$320		
	Maintenance Opex	$690		
	Debt payments (6.5%)	2170		

We find that based on a "no-compromises" stand-alone power solution for an individual home, using conservative forecasts for battery technology and balance of system costs, is unlikely to be cost-effective by 2020. Maintenance costs need to be set close to zero in order for the solution to be near break-even over 10 years, and cash-flow positive over 25 years.

Alternatively, the net cost of the solution (stand-alone power infrastructure plus household upgrade) needs to fall a further 30% from our conservative 2020 price, with fuel and

[38] Note in all tables, debt payments are calculated on the SAPS + retrofit cost, and not just the SAPS cost.

[39] Note that due to avoiding the need for a network connection, the household is actually "cash flow positive" for most of the first four years.

maintenance costs remaining uncompromised, for the proposition to appear financially attractive.

On balance, it is reasonable to assume that, for the mass-market (that is excluding remote and fringe of grid locations where stand-alone power has been cost-effective for many years), by 2020, stand-alone power infrastructure for single dwellings may not be a viable option unless:

- House sizes are reduced by approximately 9sqm or 3% (the average new Victorian home being 250sqm), in order to save on net home ownership costs – around $9,000 of construction costs need to be saved in order for the cost of building + energy infrastructure package, to become viable by 2020;
- Home occupants are willing to make behavioural adjustments, specifically constraining consumption for five to 10 days of the year in winter, when solar output is at its lowest, and energy demand is likely to be at its highest; or
- A technology breakthrough results in a lower than expected costs for stand-alone power infrastructure and/or lower maintenance costs. This would most likely be:
    - A step change in battery cost and/or performance; or
    - Building integrated PV and/or third generation PV realising a step change in PV cost and/or performance, noting that improvements to winter output/low light conditions would have most value.

Given the relatively marginal nature of the solution, we determined that switching natural gas to wood, a more expensive fuel, would further erode the viability of the solution. However where bottled gas would otherwise be used, wood is a significantly cheaper heating fuel, and so would improve the viability of the solution.

It is important to note that for greenfield developments staged over many years, even if stand-alone power infrastructure is not viable today, it will be more cost-effective to establish this infrastructure now, so that it doesn't have to be retrofitted at a later time – this also avoids the potential for inefficient sunk investments (stranded centralised electricity and gas network assets). A real-options analysis would be needed to assess the costs and benefits of this approach project by project.

Greenfield, 500-home, Gas

The clustered scenarios, and their aggregated load requirements, allowed for efficiencies to be realised in the design of the overall SAPS and energy supply system. In particular, not every home required PV or batteries and centralised diesel generation could be utilised for back-up, with the overall system maintaining reliability requirements.

However, a land-take for PV is likely to be needed, based on the assumption that it may not be possible for every home to have good quality solar access. We have estimated this to be 4600sqm based on a 230kW system (five acres per MW). This site could also be used for housing the required centralised diesel generation.

Our analysis of the 500-home, dual-fuel, greenfield scenario quickly identified that a solution driven by an energy services company is almost viable, being cash flow positive over 25 years, even at today's prices for stand-alone power infrastructure.

Given this, our analyses focused on determining the price assumptions that would need to hold true in order for the SAPS solution to become cost-effective. The following table details findings from our analysis of this scenario:

Scenario description	Summary of key assumptions	Assumption values	ESCO cash position per customer[40] – year 10	ESCO cash position – year 25
Current prices	SAPS Capex	$15,197	-$5,290	$3,571
	Fuel Opex	$78		
	Balance of system maintenance Opex	$263		
	Debt, equity and service overhead (WACC -8.6%)	$2,429		
Battery prices drop to $200/kWh retail and balance of system costs drop 1%pa	SAPS Capex	$12,394	-$2,168	$12,007
	Fuel and maintenance Opex	$342		
	Customer service and corporate overhead per customer	$350		
	Debt, equity and service overhead (WACC -8.6%)	$2,200		

We find that based on a "no-compromises" stand-alone power solution, using conservative forecasts for battery technology and balance-of-system costs, a 500-home cluster solution is viable today over a 25 year period, but not over 10 years. Key assumptions, such as the weighted cost of capital, the cost of servicing customers, and the cost of maintaining stand-alone power infrastructure determine the difference between a service model that is profitable over a 10 year period, or not.

It is important to note that for greenfield developments staged over many years, even if stand-alone power infrastructure is not viable today, it will be more cost-effective to establish this infrastructure now, so that it doesn't have to be retrofitted at a later time. A real-options analysis would be needed to assess the costs and benefits of this approach project by project.

[40] Cash position is after equity dividends are paid, and so where positive, indicates profit over and above payments to shareholders, debt payments and all operating costs. Our ESCo model does not consider the impacts of tax and depreciation on profitability.

Greenfield, 500-home, no gas

Our analysis of the 500-home, no gas, greenfield scenario identified that a solution driven by an energy services company would not be profitable at today's prices for stand-alone power infrastructure and our conservative 2020 prices for energy. We determined one of the primary determining factors, and unknowns, to be the cost of centralised gas infrastructure.

Given this, our analyses focused on assessing a conservative 2020 price for SAPS infrastructure and determining what other assumptions would have to hold true for the model to be viable, including the assumed avoided cost of centralised gas infrastructure.

The following table details findings from our analysis of this scenario:

Scenario description	Summary of key assumptions	Assumption values	ESCo cash position – year 10	ESCo cash position – year 25
2020 prices for SAPS, 2020 prices for energy, avoided gas and electric infrastructure - $8,000	SAPS Capex	$24,005	-$2,930	$2,320
	Operating and fuel costs	$855		
	Debt, equity and service overhead (WACC -8%)	$2,798		
2020 prices for SAPS, 2020 prices for energy, service overheads increase 2% pa (BAU is 3%), avoided gas and electric infrastructure - $9,500	SAPS Capex	$24,005	$263	$12,030
	Operating and fuel costs	$855		
	Debt, equity and service overhead (WACC -7.6%)	$2,695		

We find that based on a "no-compromises" stand-alone power solution for a 500-home greenfield development, where wood heating displaces natural gas, may be viable over a 25 year period before 2020, and depends on key assumptions including the cost of avoided electricity and gas infrastructure, cost of capital, and service overheads.

The primary determinant of viability is the assumed cost of avoided gas and electricity infrastructure. With a combined avoided gas and electricity network cost of $8,000, the stand-alone power infrastructure model is viable over a 25 year period. Alternatively, where avoided gas and electricity infrastructure is $9,500, the model is viable over a 10 year period, and definitively profitable over a 25 year period, with a small reduction in cost of capital and service overheads.

It is important to note that for greenfield developments staged over many years, even if stand-alone power infrastructure is not viable today, it will be more cost-effective to establish this infrastructure now, so that it doesn’t have to be retrofitted at a later time – this also avoids the potential for inefficient sunk investments (stranded centralised electricity and gas network assets). A real-options analysis would be needed to assess the costs and benefits of this approach project by project.

Bendigo retrofit

A brief summary of the Bendigo retrofit demand assumptions is produced below:

	Value	Unit	Comments
Gross Annual Load	7.5	MWh/yr	Higher end of typical annual electrical loads of households in the Great City of Bendigo[41]
Efficiency Saving	1.7	MWh/yr	Achieved via increasing building performance from 2.0 to 4.0 stars through improved building fabric[42]
Efficiency Saving	1.3	MWh/yr	Achieved via a combination of upgrading lights, tv, washing machine, fridge, dish washer & a/c.
Net Annual Load	4.5	MWh/yr	
Net Daily Load	12.3	kWh/day	Average per day, for 365 days

Regional, Single Home, Gas

Our analysis of the single home, dual-fuel, Bendigo retrofit home scenario quickly identified that a solution driven by an energy services company is unlikely to be viable within a decade due to the high capital cost and service overheads incurred by the ESCo.

Give this scenario, we performed a series of analyses based on an individual home purchasing SAPS infrastructure at or close to wholesale rates, and financing the purchase through their home-loan; this implies a bulk-buy driven model, potentially organised through a community group or council. We allowed a $500 per home brokering fee for this model.

Our analyses focused on determining the price assumptions that would need to hold true in order for the SAPS solution to become cost-effective.

The following table details findings from our analysis of this scenario:

Scenario description	Summary of key assumptions	Assumption values	Household cash position – year 10	Household cash position – year 25
Current prices	Current Capex	$31,190	-$1992	$12,400
	Fuel Opex (starting)	$370		

[41] http://www.climatechange.vic.gov.au/__data/assets/pdf_file/0005/73355/25-GreaterBendigo_C_.pdf

[42] Based on annual end use energy saving of 280 MJ/m^2 for Climate Zone 66 (Ballarat) under NATHers: http://nathers.gov.au/about/pubs/starbands.20121129.pdf

	Balance of system maintenance Opex	$745		
	Debt payments (6.5%)	$3,656		
Battery prices drop to $200/kWh retail and balance of system costs remain static.	SAPS Capex	$27,990	$912	$21,919
	Fuel Opex	$370		
	Maintenance Opex	$745		
	Debt payments (6.5%)	$3,366		

We find that based on a "no-compromises" stand-alone power solution for a Bendigo house retrofit, using conservative forecasts for battery technology and balance of system costs, is likely to be cost-effective by 2020, assuming sufficient space is available for the PV installation, and it has clear access to winter sun.

One of the primary differences between the Werribee greenfield and Bendigo retrofit scenarios is the benefits of upgrading the thermal performance of the home from 2 to4-stars in Bendigo, compared from 6 to7.5-star in Werribee, are significantly higher due to the nature of the Bendigo climate.

It is important to note that in practice, these modeled financial benefits may not be realised in terms of financial gains, but may be realised in terms of improved comfort and health outcomes in the home, arguably of higher value than the financial savings.

It is also important to note that a stand-alone power solution for a Bendigo retrofit would not be viable without the right home retrofit measures. This highlights the importance of the business model for deploying stand-alone power solutions, as well as some of the market constraints on its viability – for example, if house upgrades have already been undertaken, or if a house is tenanted and the split-incentive with landlords cannot be overcome, a solution may not be possible to implement.

On balance, it is reasonable to assume that, for the mass-market[43], by 2020, stand-alone power infrastructure for single dwellings will emerge as a viable energy solution for many households across regional Victoria without the need for any technological breakthrough. In particular, viability will improve where:

- Houses begin with a low-base of energy performance, meaning cost-effective upgrades to building fabric and appliances can be made at the same time as a stand-alone power infrastructure solution is installed;
- Communities are able to self-organise, to arrange bulk buy and installation of infrastructure;
- Power quality or reliability issues are a motivating factor in switching to a stand-alone power solution;

[43] That is, excluding remote and fringe of grid locations where stand-alone power has been cost-effective for many years.

- Customers are willing to change their behaviour, particularly throughout winter, in order to reduce the size and cost of their stand-alone power infrastructure;
- For lower consumption households, if there is a move to higher fixed charges; and/or
- Where taking homes off-grid with SAPS is more cost-effective than network upgrades.

There will also be limitations on mass-market uptake – financial viability won't be the sole driver. Limitations include:

- Customers taking comfort in being connected to the main grids;
- Concerns about re-sale value of homes that have stand-alone power; and/or
- Tenanted properties finding it difficult to implement SAPS solutions.

Regional, Single Home, No Gas

Our analysis of the single home, no gas, Bendigo retrofit scenario quickly identified that a solution driven by an energy services company is unlikely to be viable within a decade due to the high capital cost and service overheads incurred by the ESCo.

Give this, we performed a series of analyses based on an individual home purchasing SAPS infrastructure at, or close to, wholesale rates, and financing the purchase through their home-loan. The assumption implies a bulk-buy driven model, potentially organized through a community group or council. We allowed a $500 per home brokering fee for this model.

Our analyses focused on determining the price assumptions that would need to hold true in order for the SAPS solution to become cost-effective.

The following table details findings from our analysis of this scenario:

Scenario description	Summary of key assumptions	Assumption values	Household cash position – year 10	Household cash position – year 25
2020 SAPS and energy prices, centralised gas offset of $20,000,	Capex	$33,132	-$1,118	-$10,438
	Fuel Opex including wood (starting cost)	$1420		
	Balance of system maintenance Opex	$800		
	Debt payments (6.5%)	$4,413		
2020 SAPS and	SAPS Capex	$33,132	-$5,372	$19,637

energy prices, bottled gas offset	Fuel Opex	$1420		
	Maintenance Opex	$800		
	Debt payments (6.5%)	$4,413		

We find that based on a “no-compromises” stand-alone power solution for a Bendigo house retrofit, where bottled gas is displaced by wood, is close to a viable proposition by 2020 when implemented by single households, assuming sufficient space is available for the PV installation, and it has clear access to winter sun.

The main caveat is that it is only likely to be cost-effective over a 10 year period where appliances, such as a hot water service or gas heater, are in need of replacing, thereby offsetting the capital cost of an appliance upgrade package. Over a 25 year period, it is clearly a cost-effective option. Again, this highlights the risk of stranded assets should a centralised, network solution to a local grid constraint, or a new natural gas network, be installed instead of transitioning to a stand-alone power solution.

Regional, 500-Home, Gas

Our analysis of the 500-home, dual-fuel Bendigo retrofit home scenario identified that a solution driven by an energy services company is not viable at today’s prices for stand-alone power infrastructure over 10 years, but is over 25 years where the weighted cost of capital can be reduced slightly from 8.6% to 7.6%.

The following table details findings from our analysis of this scenario:

Scenario description	Summary of key assumptions	Assumption values	ESCO cash position per customer – year 10	ESCO cash position – year 25
Current prices, WACC reduced to 7.6%[44]	Current Capex	$18,450	-$7,191	$9,267
	Fuel and maintenance costs	$411		
	Debt, equity and service overhead (WACC -7.6%)	$3,100		
2020 prices for stand-alone power and	Stand-alone power capex	$16,086	$2,825	$41,202
	Fuel and maintenance	$411		

[44] Note, a similar result is produced by introducing an avoided electricity network upgrade cost of$2,000 per home

energy	costs		
	Debt, equity and service overhead (WACC -8.6%)	$3,112	

We find that, based on a “no-compromises” stand-alone power solution, using conservative estimates for current infrastructure and service business costs, a 500-home cluster solution is likely to be viable today where the weighted cost of capital can be kept below 7.6% or when an electricity upgrade cost of $2,000 per home can be avoided. Given this is below borrowing costs for households and councils, and only a short-term reduction in the cost of capital is required to make the solution viable, we can say it may be viable today and will certainly be viable before 2020.

By 2020, the stand-alone micro-grid is clearly profitable over a 10 year period, which implies it will be viable before 2020 without compromising our conservative weighted cost of capital of 8.6%.

It should be noted here again that the above analysis takes into account Victoria only, and significantly better value propositions will be achieved throughout South Australia, New South Wales, Queensland and the Australian Capital Territory. Again, this highlights the risk of stranded assets should a centralised, network solution to a local grid constraint, or a new natural gas network, be installed instead of transitioning to a stand-alone power solution.

Regional, 500-Home, No Gas

Our analysis of the 500-home, dual-fuel Bendigo retrofit home scenario identified that a solution driven by an energy services company is not viable over a 10 year assessment period at today’s prices for stand-alone power infrastructure and energy, where natural gas is not available.

However, where bottled gas is used for space heating, cooking and hot water and can be substituted with wood and electricity, the energy service model appears viable over a 25 year period at today’s prices for stand-alone power infrastructure, including when we discount the assumed bottled gas consumption by 20%[45].

The viability naturally improves when we assume a natural gas connection or electricity network upgrade can be avoided. The following table details findings from our analysis of this scenario:

[45] Note, this was done to reflect that customers are likely to compromise their comfort in winter by constraining energy consumption to manage costs.

Scenario description	Key assumptions	Assumption values	ESCo cash position – year 10	ESCo cash position – year 25
Current prices for stand-alone power and energy – bottled gas displaced (avoided energy value discounted by 20%)	Current Capex	$25,638	-$12,258	$8,562
	Fuel and maintenance opex	$1,311		
	Debt, equity and service overhead (WACC -8.6%)	$4,681		
Current prices for stand-alone power and 2020 prices for energy – combined gas and electricity network connection cost avoided $6,000	SAPS Capex	$25,638	$50.21	$34,625
	Fuel and maintenance opex	$1,311		
	Debt, equity and service overhead (WACC -8.6%)	$4,681		

We find that based on a “no-compromises” stand-alone power solution for a 500-home cluster in a climate zone such as Bendigo, where bottled gas is displaced by wood, is viable today when assessed over a 25-year period. When assessed over 10-years, it viable by 2020 (cash flow is only marginally negative over the 10-year assessment period). We note that a cluster of 500 homes using bottle gas is unlikely to occur in Bendigo, however this may be the case in other regional Victorian towns.

Further, we find that where the combined cost of upgrading a local electricity network and a new connection to the centralised gas network is $6,000, a stand-alone power solution using wood instead of natural gas for space heating, and electricity for all other energy demand, is likely to be viable by 2020.

Again, this highlights the risk of stranded assets should a centralised, network solution to a local grid constraint, or a new natural gas network, be installed instead of transitioning to a stand-alone power solution.

Melbourne retrofit

A brief summary of the Melbourne retrofit demand assumptions is produced below:

Assumption	Value	Unit	Comments
Gross Annual Load	5.5	MWh/yr	Higher end of typical annual electrical loads of households in the Greater City of Melbourne[46]
Efficiency Saving	1	MWh/yr	Achieved via increasing building performance from 2.0 to 4.0 stars through improved building fabric[47]
Efficiency Saving	1	MWh/yr	Achieved via a combination of upgrading lights, tv, washing machine, fridge, dish washer & a/c.
Net Annual Load	3.5	MWh/yr	
Net Daily Load	9.58	kWh/day	Average per day, for 365 days

City, Single Home, Gas

Our analysis of the single home, dual- fuel, Preston retrofit home scenario quickly identified that a solution driven by an energy services company is unlikely to be viable within a decade due to the high capital cost and service overheads incurred by the ESCo.

Given this scenario, we performed a series of analyses based on an individual home purchasing SAPS infrastructure at or close to wholesale rates, and financing the purchase through their home-loan. The assumption implies a bulk-buy driven model, potentially organised through a community group or council local. We allowed a $500 per home brokering fee for this model.

Our analyses focused on determining the price assumptions that would need to hold true in order for the SAPS solution to become cost-effective. The following table details findings from our analysis of this scenario:

Scenario description	Summary of key assumptions	Assumption values	Household cash position – year 10	Household cash position – year 25
Current prices	Current Capex	$30,095	-$14,315	-$26,153
	Fuel Opex (starting)	$380		

46 http://www.climatechange.vic.gov.au/__data/assets/pdf_file/0005/73355/25-GreaterBendigo_C_.pdf

47 Based on annual end use energy saving of 280 MJ/m^2 for Climate Zone 66 (Ballarat) under NATHers: http://nathers.gov.au/about/pubs/starbands.20121129.pdf

	Balance of system maintenance Opex	$745		
	Debt payments (6.5%)	$3,534		
Battery prices drop to $200/kWh retail and balance of system costs drop 2%.	SAPS Capex	$24,179	-$8,946	-$11,016
	Fuel Opex	$370		
	Maintenance Opex	$745		
	Debt payments (6.5%)	$3,366		

We find that based on a “no-compromises” stand-alone power solution for a Preston house retrofit, using conservative forecasts for battery technology and balance of system costs, is unlikely to be cost-effective by 2020, even assuming sufficient space is available for the PV installation, and it has clear access to winter sun.

Net retrofit + SAPS cost needs to drop by a further 15% on our 2020 conservative estimate, with fuel and maintenance opex dropping to $750 a year, before it becomes a break-even proposition over 10 years. Given these assumptions, the household cash position becomes $-266 in year 10 and $11,283 in year 25.

On balance, it is reasonable to assume that by 2020, stand-alone power infrastructure for single dwellings is unlikely to emerge as a viable energy solution for the mass market across inner-city and suburban Melbourne, without a step-change in technology cost and/or customers willing to make behavioral adjustments.

Based on the analysis above, and the potential impacts on air quality from switching to wood fuel, we quickly assessed that a no-gas solution for Melbourne would not be viable.

We also assessed that due to space constraints, a 500-home cluster solution would not be viable without a step change breakthrough such as building-integrated PV, which could be easily integrated into roofing systems and/or streetscapes.

Implications for customers

The report's findings have significant implications for consumer protections in the energy market and for efficient investment in centralised gas and electricity infrastructure more broadly.

The current energy market design is premised on the idea that customer choice, enabled by information and a disaggregated competitive market, will lead to the lowest possible prices for customers. However, our analysis shows that stand-alone power solutions, led by a specialist energy services company, is likely to entail no choice of retailer yet offer the potential for lower energy prices for the scenarios assessed.

Energy delivered by a service company, making use of stand-alone power infrastructure, is also likely to improve the incentive for designing and offering products and services that help customers reduce energy demand, as reduced energy demand translates more directly into local infrastructure savings, in particular reductions in back-up generator use and/or battery capacity and cycling demands. The predicted situation contrasts to the current energy market where reduced energy demand in any given location does not necessarily translate into savings for customers in that location due to price smoothing across locations.

Achieving the same incentive is possible through the use of pricing that more accurately reflects costs of serving local customers. However, such pricing relies on customers being able to effectively respond, and would significantly penalise and disadvantage certain customers, particularly rural and regional customers living in areas where the true cost of energy supply is significantly greater than those customers currently experience. The proactive transition to stand-alone power as envisaged in our research, would actively support customers in adopting more energy efficient technology and behaviour, and avoids the need for regressive pricing.

Lastly, stand-alone power solutions are likely to entail greater price certainty for customers, including the potential to proactively manage the risk of major price restructuring under a "utility death spiral" scenario.

Greater price certainty occurs because the stand-alone power infrastructure model is far less exposed to variable fuel prices (energy supply is predominantly from solar power which utilises free fuel – the sun) and fluctuations in asset utilisation because prices are based on a combination of energy services delivered (space heating, hot water, etc) and energy used – not just energy used as per the incumbent energy supply model[48].

"Utility death spiral" risks would be managed by buying out local network infrastructure and re-purposing it to enable a new energy supply model that is less dependent on sales volumes to retain viability – that is, instead of the current network business model which constantly needs to re-price services to remain viable as energy demand contracts, network infrastructure could be bought out and the business model for energy supply reconfigured. This would also enable network service providers to offer cheaper energy to customers where grid-supplied energy remains more cost-effective than stand-alone power, as tariff smoothing would no longer be needed to cross-subsidise customers that are more expensive to service.

[48] When prices are set to reflect the quality of energy services, such as provision of thermal comfort, reductions in energy use do not impact on the viability of the supply model – customer payments are set to reflect the value of the service, and not just how much energy is consumed. In this way, enhancing energy efficiency does not undermine the viability of the service model, whereas where customer payments reflect energy use only, energy efficiency undermines asset utilisation and causes prices to increase – eroding the financial benefits of energy efficiency.

In the case of regional customers, the transition to stand-alone power solutions may also entail improved power quality and reliability, including improved resilience to outages caused by extreme weather, such as storms and fires.

Collectively, the results suggest that the premise upon which the current energy market is designed should be challenged in the interest of all consumers. A future energy market in which customers are supplied by stand-alone power and micro-grids also implies new regulatory challenges and specifically, begs the following questions:

- What processes should be followed for customers who cannot afford to pay for their energy requirements? It would not be possible for a customer to be disconnected from one retailer and re-allocated to another, in a market where stand-alone power solutions limit retailer choice;
- What would become the equivalent of a "retailer of last resort" in the event that an energy services company, delivering stand-alone power solutions, became insolvent? Prudential requirements for such infrastructure providers, including insurance policies, would need to be carefully designed and managed to ensure financial insolvency would not leave customers without power; and
- How would the discipline of price and service competition be maintained on stand-alone power infrastructure providers, given customers would not be able to switch retailers in the event they became dissatisfied with energy prices and/or customer service?

These questions point to the need for specific community service obligations on providers of stand-alone power infrastructure, and possibly tighter prudential requirements, to ensure the risks are effectively managed.

Implications for the National Electricity Market

A future in which stand-alone power infrastructure emerges at some scale, in an un-planned way, entails significant stranded asset risk. A number of measures can be used to help mitigate and manage this risk:

- Co-ordinated trials of small-scale stand-alone power solutions, potentially through the distributors' demand management incentive scheme, to enable accelerated learning by energy market participants and regulatory authorities. We note that this funding should not be limited to network service businesses whose natural incentive is to use storage to support network infrastructure, as opposed to avoiding the need for it altogether. Given the scheme is paid for by customers, how it is spent should not be constrained by the incumbent monopolies risk preferences;
- Facilitated purchase of centralised network assets where they have been shown to be inefficient as part of a centralised supply model. Projects could be identified and flagged for action by the Australian Energy Regulator (AER), to state governments, as part of its network investment review processes. State governments could then co-ordinate a targeted, localised response using a network of energy market stakeholders. The thresholds for stand-alone power infrastructure viability identified in this report begin to articulate how this could be done by the AER;
- The clear and transparent publication of network constraints, made available in easily accessible language and format to the public, organised by post codes. This will allow community groups, councils and energy service providers easy access to the data needed to asses stand-alone power infrastructure models and may obviate the need for state government co-ordination of this;
- Adjustment of the Regulatory Investment Test for distribution (RiT – D), with networks' threshold to be based on a cost-per-customer basis, as opposed to a capital cost figure alone. The report demonstrates that, even at $2,000 per customer, upgrading the electricity network and continuing its operation as part of the centralised energy market is highly likely to be inefficient where natural gas is available for space heating. The implication of this finding is that the RiT – D threshold could be set as low as $2,000 - $3,000 per customer served in the network;
- Assessing network planning and investment requirements more stringently in areas where stand-alone power solutions are likely to be viable – specifically regional areas, and particularly either where bottled gas exists and/or in residential growth corridors where new network assets will be planned; and
- The implications of a move to virtual net metering, where generation of energy at one location could be offset against the retail bill of a customer located nearby, but on a separate land title, needs to be carefully considered. Such metering arrangements would create a strong incentive to maximise generation of energy at any given location, and reduce the incentive for energy storage, as storage would not be necessary for avoiding local network costs.

We recognise these network measures are necessarily brief, reflecting the early stage and scope of the research. Further work would be required to develop measures that can be implemented, with support from energy market stakeholders.

Conclusion

The National Energy Market is in a state of profound transition, from a centrally planned and controlled market, to one where local generation, storage and control of power is commonplace. How far this transition goes, and how quickly, are the only questions that remain unanswered. This research paper strongly suggests the transition may be quick and dramatic – a shift to cost-effective stand-alone power solutions appears very plausible, by 2020.

Investment decisions are being made every day in the energy market, resulting in capital-intensive energy assets being built. Communities are considering building their own, community-owned power generation assets. In this time of profound change, a clear view of what our energy market will look like, based on fundamental shifts in technology costs, in five, 10 and 20 years, is critical to have in mind. An incremental transition, where new technologies are integrated within the incumbent energy system is possible. However a more dramatic transition, where new technologies shape an entirely new energy market, appears financially compelling - in the long-run, economic fundamentals will be hard to withstand.

Appendices

A. Energy savings and costs of retrofit measures

		Star-rating (implied heating and cooling load) assumptions				"Appliance pack" upgrade[49]		
House location	Net conditioned m^2	BAU	After redesign /retrofit	Cost of increase	MJ gas / kWhe saved	Cost of upgrade	kWh saved per annum	Net MJ / kWh saved per annum
Werribee (dual-fuel new build)	200sqm	6-star	7.5-star	$4,000	5333 / 290	$1,900	1698	~ 5330 / 2000
Bendigo (dual-fuel retrofit)	160sqm	2-star	4-star	$6,600	12500 / 1700	$2,500	1300	~12500 / 3000
Melbourne (dual-fuel retrofit)	140sqm	2-star	4-star	$6,600	6468 / 993	$2,250	1000	~ 6468 / 2000

Figure 4: summary of assumed energy retrofit savings – dual-fuel

[49] An appliance pack upgrade incorporates a mix of upgrades to lighting, refrigeration, heating/cooling systems, washing machines and dish washers.

House location	% thermal load as heating	% heating load gas	% cooling electricity	Gas efficiency	Weighted electric space heating efficiency[50]	Electric cooling efficiency
All	84%	80%	100%	80%	200%	300%

Figure 5: Summary of assumed BAU heating / cooling loads and supply efficiency

Appliance	Capital cost	kWh/pa saving	% peak	peak saving	off peak saving
lighting	$800	584	80%	467.2	116.8
tv	$800	328.5	80%	262.8	65.7
fridge	$600	300	60%	180.0	120.0
washing machine	$600	300	20%	60.0	240.0
dish washer	$600	300	20%	60.0	240.0
air conditioner after insulation	$1500	173.0	80%	138.4	34.6
TOTAL potential savings (kWh)		1985.5			
Total peak-time savings		1168.4			

Figure 6: summary of appliance measures, their costs and benefits

[50] Note, it is assumed some electric heating is resistance heating, which is common particularly in existing homes where bedrooms are difficult to heat any other way.

B. SAPS Product and Price List

In ATA's experience with SAPS design and operation, a number of the modelling parameters are likely to remain relatively constant into the future, or decline. As such, and in line with the Capex and Opex principles outlined above, the following parameters were fixed for all modelling scenarios:

Product	Assumed wholesale price	Retail Price (2013 $)	Unit
PV - pre STC capex (modules only)	$0.85	$0.94	per watt
STC Price	$30.00		per certificate
Capex - framing/mounts/connections/wiring	$0.41	$0.45	per watt
PV maintenance Opex	$50.00		per system, per year
Inverter/charger Capex - 5.0kW @ 48V	$0.90	$1.50	per watt
Inverter/charger Capex - 7.5kW @ 48V	$0.74	$1.23	per watt
Inverter/charger Capex - 10.0kW @ 120V	$0.72	$1.20	per watt
Inverter/charger maintenance Opex	$50.00		per unit, per year
Regulator Capex - 4.0kW @ 48V	$0.17	$0.28	per watt
Regulator Capex - 2 x 5.0kW @ 120V	$0.53	$0.88	per watt
Petrol genset – Capex (for single home)	$4,200	$7,000	Up to 12 kVA capacity
Diesel generator – Capex (for clustered scenarios)	$72,500		per 350 kVA unit
Petrol generator maintenance cost, excluding fuel	$6.00		per hour
Diesel generator maintenance cost, exc. fuel	$2,800		per unit, per year
Petrol generator fuel cost	3.5		litres per hour, per unit
Diesel generator fuel cost	72		litres per hour, per unit
Diesel price	$1.60		per litre
Petrol price	$1.60		per litre
Battery Capex (nameplate capacity, 48V system)	$198	$330	per kWh
Battery Capex (nameplate capacity, 120V)	$209	$348	per kWh
Battery maintenance Opex	$50.00		per bank, per year
Installation & Commissioning (labour)	$0.98	$1.50	per watt
Warranty risk	16.5%		of component

		costs
Asset Life – PV	25	years
Asset Life – Batteries, Inv/Charger, Regulator	15	years
Asset Life – petrol / diesel generators	15	years

Figure 7: product and price list

C. SAPS design –Greenfield, single home, gas available

Component	Value	Unit	Capex ($)	Opex p.a. ($)	Comments
PV - pre Small-scale technology certificates (STC)	3.6	kW	3,060	50	Optimised for winter insolation, 52^0 tilt.
STC Value			(1,890)		1.185 x 3.6 x 15yrs x $30
PV materials			1,460		Frame, mounts, wiring, connections
Inverter / Charger	5	kW	4,500	50	48 V unit
Regulator	4	kW	660		48 V unit
Petrol Generator	6.0	kVA	3,600	342	Maintenance @ $6/hr x 57 hrs
				318	Fuel cost @ 3.5L/hr x $1.60/L
Generator Run-Time	45	hrs			57 hrs /yr including an additional 12 hrs allowed for contingency
Battery Bank	48	kWh	9,500	50	15 x 3.2V, 1000 AH Lith-ion cells
Storage Capacity	70%	Min			33.6 kWh @ 5000 lifetime cycles
	80%	Max			38.4 kWh @ 3000 lifetime cycles
Containment			2,000		Battery, generator containment
Warranty Risk			3,500		16.5% of component costs
Install & Commissioning			3,510		Labour cost
System Monitoring				200	Done by ESCO, off-site
System Voltage	48	volts			
Total			**$29,900**	**$1,010**	

D. SAPS design – Werribee, single home, no gas

Component	Value	Units	Capex ($)	Opex p.a. ($)	Comments
PV - pre STCs	8.2	kW	6,970	50	Optimised for winter insolation, 52^0 tilt.
STC Value			(4,350)		1.185 x 8.2 x 15yrs x $30
PV materials			3,320		Frame, mounts, wiring, connections
Inverter / Charger	7.5	kW	5,520	50	48V unit
Regulator	8	kW	1,320		2 x 4kW, 48V units
Petrol Generator	12.0	kVA	4,200	450	Maintenance @ $6/hr x 75 hrs
				420	Fuel cost @ 3.5L/hr x $1.60/L
Generator Run-Time	63	hrs			75 hrs /yr including an additional 12 hrs allowed for insolation shortfall contingency
Battery Bank	48	kWh	9,500	50	15 x 3.2V, 1000 AH Lith-ion cells
Storage Capacity	70%	Min			33.6 kWh @ 5000 lifetime cycles
	80%	Max			38.4 kWh @ 3000 lifetime cycles
Containment			2,000		Battery, genset containment
Warranty Risk			4,540		16.5% of component costs
Install & Commissioning			5,265		Labour cost
System Monitoring				200	Done by ESCO, off-site
System Voltage	48	volts			
Total			**$38,285**	**$1,220**	

E. SAPS design – Werribee, 500-home, gas available

ATA optimised the level of required storage and PV, taking into account a realistic estimation of how much PV could be optimally installed across 500 homes, and still ensuring that diesel generator run time was still in a target range of 100 – 200 hours per year[51].

In optimising overall system design for Werribee 3, ATA found that:

- only 68 of the 500 homes would require 40 x 1,000 AH (3.2V) lithium battery cells;
- each of these 68 homes would require high quality inverter/chargers, and be able to support an average of 2.5 kW of PV per home;
- only four out of five of the remaining homes (that is, 360 homes in total) required 5.0 kW of PV and a traditional grid-connect, PV-only inverter. This allowed for the fact that, in reality, approximately 10% of homes would be unsuitable for PV due to likely shading, orientation and/or roof design issues; and
- the final 230kW of required PV would be centrally located, in conjunction with the centralised diesel generation.

The third Werribee scenario assumes that a new electricity network would be established that exclusively services the new 500 home cluster. The situation involves poles/wires/connection points/smart meters/associated communication and controls infrastructure. The approach outlined above led to the following design parameters for the third Werribee scenario:

Component	Value	Units	No. Homes	Total	Comments
PV	5.0	kW	360	1,800 kW	Optimised for winter insolation, 52^0 tilt
PV	2.5	kW	68	170 kW	Homes with battery banks only
PV	230	kW		230 kW	Located with diesel generators
Inverter / Charger	10.0	kW	68		Homes with battery banks only
Inverter (PV only)	5.0	kW	360		Traditional grid connect PV-only Inverter
Diesel Generators	350	kVA	2	700 kVA	Centrally located, nearby but off-site
Generators Run-Time	170	Hours			Total generator run-time per year
Battery Bank	128	kWh	68	8.7 MWh	40 x 3.2V, 1000 AH Lith-ion cells x 68 banks

[51] Compared with the individual home scenarios, ATA were comfortable with a small increase in generator run time for the 500 home scenarios, as the diesel generators would be centrally located and away from any individual residences.

Storage Capacity	70%	Min			89.6 kWh @ 5000 lifetime cycles per bank
	80%	Max			102.4 kWh @ 3000 lifetime cycles per bank
System Voltage	120	Volts			

ATA then translated the required design parameters outlined above into the following capital and annual operational costs, in 2013 dollars:

Component	Capex ($)	Opex p.a. ($)	Comments
PV – pre STCs	1,870,000	21,400	Optimised for winter insolation, 52^0 tilt
STC value	(1,173,150)		1.185 x 2,200 x 15yrs x $30 (each PV system below 100kW so eligible for deemed STCs)
PV materials	891,000		Frame, mounts, wiring, connections
Inverter / Charger	486,560	3,400	10.0 kW @ 120V
Inverter (PV only)	566,350	9,000	
Communications infrastructure	214,000		
Diesel Generators	145,000	5,600	Maintenance @ $6/hr x 170hrs
		39,170	Fuel cost @ 3.5L/hr x $1.60/L
Battery Bank	1,819,680	6,800	
Containment	136,000		Battery, genset containment
Warranty Risk	473,980		16.5% of component costs
Install & Commission	715,000		Labour cost - PV only
Install & Commission	204,000		Labour cost - Inverter/Charger + Batteries
Grid Costs	1,250,000		
System Monitoring		85,800	Done by ESCO, off-site
Total	***$7,598,420***	***$171,170***	
Per Home	**$15,197**	**$342.34**	

F. SAPS design – Bendigo, single home, gas available

Component	Value	Units	Capex ($)	Opex p.a. ($)	Comments
PV - pre STCs	4.3	kW	3,655	50	Optimised for winter insolation, 52^0 tilt.
STC Value			(2,280)		1.185 x 4.3 x 15yrs x $30
PV materials			1,745		Frame, mounts, wiring, connections
Inverter / Charger	5	kW	4,500	50	48 V unit
Regulator	4	kW	660		48 V unit
Petrol Generator	6.0	kVA	3,600	396	Maintenance @ $6/hr x 66 hrs
				369	Fuel cost @ 3.5L/hr x $1.60/L
Generator Run-Time	54	hrs			66 hrs /yr including an additional 12 hrs allowed for contingency
Battery Bank	48	kWh	9,500	50	15 x 3.2V, 1000 AH Lith-ion cells
Storage Capacity	70%	Min			33.6 kWh @ 5000 lifetime cycles
	80%	Max			38.4 kWh @ 3000 lifetime cycles
Containment			2,000		Battery, genset containment
Warranty Risk			3,620		16.5% of component costs
Install & Commissioning			4,190		Labour cost
System Monitoring				200	Done by ESCO, off-site
System Voltage	48	volts			
Total			**$31,190**	**$1,115**	

G. SAPS design – Bendigo, single home, no gas

Component	Value	Units	Capex ($)	Opex p.a. ($)	Comments
PV - pre STCs	7.0	kW	5,950	50	Optimised for winter insolation, 52^{0} tilt.
STC Value			(3,720)		1.185 x 7.0 x 15yrs x $30
PV materials			2,835		Frame, mounts, wiring, connections
Inverter / Charger	7.5	kW	5,520	50	48V unit
Regulator	8	kW	1,320		2 x 4kW, 48V units
Petrol Generator	12.0	kVA	4,200	438	Maintenance @ $6/hr x 73 hrs
				408	Fuel cost @ 3.5L/hr x $1.60/L
Generator Run-Time	61	hrs			73hrs /yr including an additional 12 hrs allowed for contingency
Battery Bank	48	kWh	9,500	50	15 x 3.2V, 1000 AH Lith-ion cells
Storage Capacity	70%	Min			33.6 kWh @ 5000 lifetime cycles
	80%	Max			38.4 kWh @ 3000 lifetime cycles
Containment			2,000		Battery, generator containment
Warranty Risk			4,375		16.5% of component costs
Install & Commissioning			4,560		Labour cost
System Monitoring				200	Done by ESCO, off-site
System Voltage	48	volts			
Total			**$36,540**	**$1,196**	

H. SAPS design – Bendigo, 500-home

The clustered scenarios, and their aggregated load requirements, allowed for efficiencies to be realised in the design of the overall SAPS and energy supply system. As with the other 500-home scenarios, not every home was required to have batteries and PV.

ATA optimised the level of required storage and PV, taking into account a realistic estimation of how much PV could be optimally installed across 500 homes, and still ensuring that diesel generator run time was in a target range of 100 – 200 hours per year[52].

In optimising overall system design for Bendigo 3, ATA found that:

- only 98 of the 500 homes would require 40 x 1,000 AH (3.2V) lithium battery cells;
- each of these 98 homes would require high quality inverter/chargers, and an average of 3.0 kW of PV per home; and
- only five out of six of the remaining homes (that is, 350 homes in total) required 5.0 kW of PV and a traditional grid-connect, PV-only inverter; this allowed for the fact that, in reality, up to 10% of homes would be unsuitable for PV due to likely shading, orientation and/or roof design issues; and
- an additional 456kW of centrally located PV would be required, in conjunction with the centralised diesel generation. This has a land-take of approximately two acres.

In addition, given that, on average, approximately one in seven Australian homes now have PV, and this is likely to be higher in locations with good levels of solar insolation (such as Bendigo), ATA considers it likely that an existing installed capacity of PV will exist, which a project such as this could tap into.

For the purposes of the model, ATA therefore assumed that 20% of Bendigo homes would currently have typically sized PV arrays (2.2 kW), that could be purchased cost-effectively by the ESCo[53].

The third Bendigo scenario also assumes that a new electricity network would be established that exclusively services the new 500 home cluster; this involves poles/wires/connection points/smart meters and so on.

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[52] Compared with the individual home scenarios, ATA were comfortable with a small increase in generator run time for the 500 home scenarios, as the diesel generators would be centrally located and away from any individual residences.

[53] It was assumed that the ESCO could purchase these existing systems for $1.50/watt for the fully installed system (that is, PV + grid-connect inverter + all other system components).

The approach outlined above led to the following design parameters for the third Bendigo scenario:

Component	Value	Units	No. Homes	Total	Comments
PV	5.0	kW	350	1,750 kW	Optimised for winter gen, 52^0 tilt
PV	3.0	kW	98	294 kW	Homes with battery banks only
PV	456	kW		456 kW	Centrally located with diesel generators
Inverter / Charger	10.0	kW	98		Homes with battery banks only
Inverter (PV only)	5.0	kW	350		Traditional grid connect PV-only Inverter
Diesel Generators	350	kVA	3	1050 kVA	Centrally located, nearby but off-site
Generator Run-Time	179	Hours			Total generator run-time per year
Battery Bank	128	kWh	98	12.5MWh	40 x 3.2V, 1000 AH Lith-ion cells x 98 banks
Storage Capacity	70%	Min			89.6 kWh @ 5000 lifetime cycles per bank
	80%	Max			102.4 kWh @ 3000 lifetime cycles per bank
System Voltage	120	Volts			

ATA then translated the required efficiency investments and SAPS design parameters outlined above into the following capital and annual operational costs, in 2013 dollars:

Component	Capex ($)	Opex p.a. ($)	Comments
PV – pre STCs	2,232,250	22,375	Optimised for winter generation, 52^0 tilt
STC value	(1,245,120)		1.185 x 2,335 x 15yrs x $30 (each PV system below 100kW so eligible for deemed STCs).
PV materials	945,675		Frame, mounts, wiring, connections
Inverter / Charger	697,640	3,625	10.0 kW @ 120V
Inverter (PV only)	432,630	10,000	
System Smarts	223,750		
Diesel Generators	217,500	8,400	Maintenance @ $6/hr x 179hrs
		61,860	Fuel cost @ 3.5L/hr x $1.60/L

Battery Bank	2,609,100	9,750	
Containment	195,000		Battery, generator containment
Warranty Risk	617,000		16.5% of component costs
Install & Commission	758,875		Labour cost - PV only
Install & Commission	292,500		Labour cost - Inverter/Charger + Batteries
Grid Costs	1,250,000		
System Monitoring		89,700	Done by ESCO, off-site
Total	***$9,226,800***	***$205,710***	
Per Home	**$18,450**	**$411.42**	

I. *SAPS design – Preston, single home*

The net annual load and load profile, after investment in energy efficiency, resulted in the following design, capital and annual operational costs, in 2013 dollars:

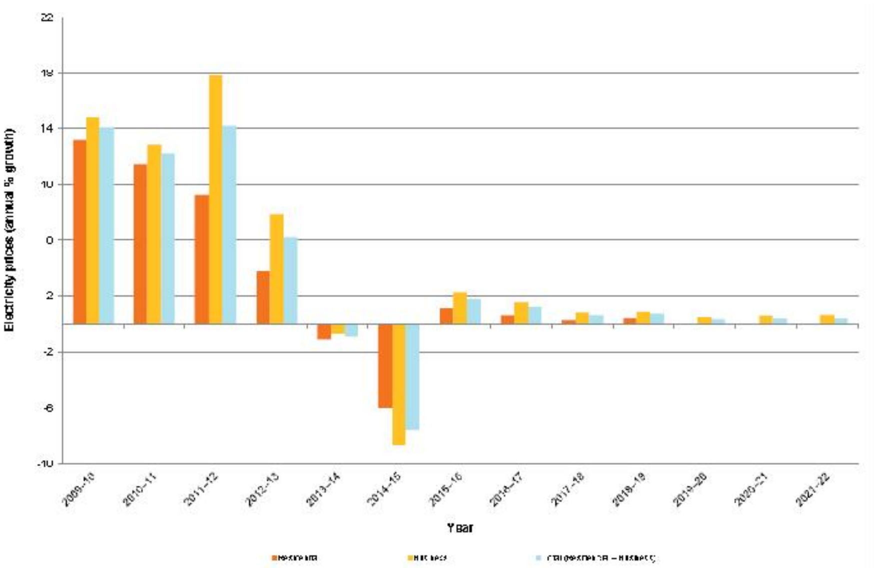
Component	Value	Units	Capex ($)	Opex p.a. ($)	Comments
PV - pre STCs	3.2	kW	2,720	50	Optimised for winter gen, 52^0 tilt.
STC Value			(1,680)		1.185 x 3.2 x 15yrs x $30
PV materials			1,300		Frame, mounts, wiring, connections
Inverter / Charger	5	kW	4,500	50	48 V unit
Regulator	4	kW	660		48 V unit
Petrol Generator	6.0	kVA	3,600	336	Maintenance @ $6/hr x 56 hrs
				314	Fuel cost @ 3.5L/hr x $1.60/L
Generator Run-Time	45	hrs			56 hrs /yr including an additional 12 hrs allowed for contingency
Battery Bank	48	kWh	9,500	50	15 x 3.2V, 1000 AH Lith-ion cells
Storage Capacity	70%	Min			33.6 kWh @ 5000 lifetime cycles
	80%	Max			38.4 kWh @ 3000 lifetime cycles
Containment			2,000		Battery, genset containment
Warranty Risk			3,460		16.5% of component costs
Install & Commissioning			3,120		Labour cost
System Monitoring				200	Done by ESCO, off-site
System Voltage	48	volts			
Total			**$29,180**	**$1,000**	

J. Establishing energy prices

Starting points for energy prices were simply derived from published (online) tariffs by major energy retailers. We note that prices structure and value varies substantially across the competitive retail market.

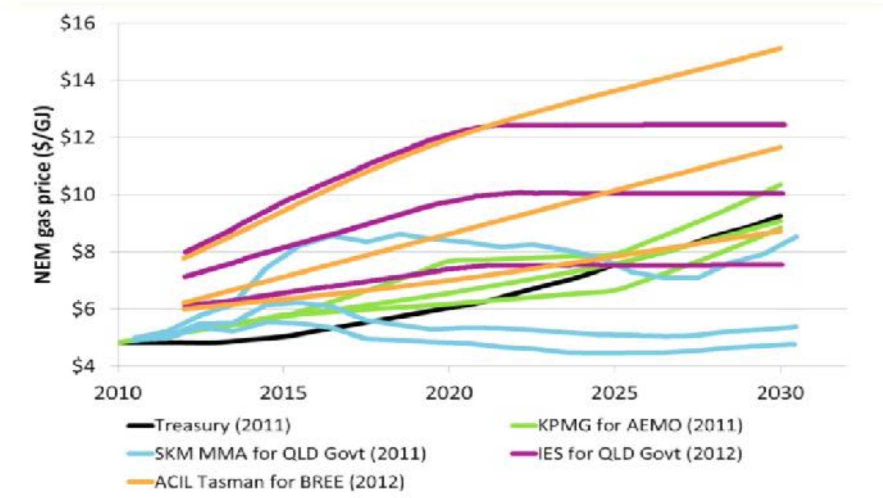
Publicly available forecasts for energy are available from the Australian Energy Market Operator (AEMO) and suggest, in the short-run, that retail prices may decline, before trending at close to the rate of inflation, the net result being a decline in prices in real terms over the next 10 years. The forecast is provided below, noting forecasts are in real terms - that is, adjusted for inflation.

It is worth noting these forecasts suggest domestic and global economic conditions continue their recovery from the global financial crises and remain firm in to the future (this implies a growing demand for energy), but the risk of domestic gas prices trending towards international parity with LNG prices does not appear to be considered. A carbon price has been assumed, but the impact of declining energy volumes on network tariffs and tariff structures does not appear to be considered.



On balance, we believe the forecast is likely to underestimate the future price of electricity and, potentially, significantly underestimate the future price of electricity, even if we do not account for a carbon price.

The risk of domestic gas prices increasing by a factor of two or more over the next decade is real. The following graphic (public estimates of future gas prices, AECOM, 2012) summarises a range of public forecasts made over the last two years, with more recent forecasts significantly increasing the upper-end of future prices considered plausible.



The view that gas prices may increase more rapidly than previously thought was recently highlighted in the Australian Financial Review[54] (22nd February 2013), with wholesale gas prices purportedly on track to reach $6-9GJ in 2013. With wholesale prices approximately one-third of the retail price, a doubling of wholesale costs implies an increase in retail prices of approximately 30%.

Combined with a trend of declining energy demand[55], which does not appear to be short-term (that is, it appears to be driven primarily by fundamentals associated with the low cost of PV and more efficient energy technologies being deployed across customer segments as they have become more cost-effective), significant cost-pressures on the centralised energy market are likely to emerge over the next decade.

Our assessment is reinforced by further work produced by AGL economists Paul Simshauser and Tim Nelson[56]. They note that future prices of energy can be contained and reduced, in real terms, but only if policy and market reforms proceed in an efficient and effective way to enable implementation and management of demand side measures – specifically, measures that ensure better utilisation of market assets. They also identify changes to gas, coal and network prices as being likely to have a greater influence on future energy prices than renewables.

On balance, we consider an assumed increase of electricity prices of 2% per annum for five years, and 3% per annum subsequently, at, or slightly above, the rate of inflation, to be a reasonable and conservative assumption for the purposes of this paper. We have assumed gas prices rise at 5% per annum for five years, then 7% and 9% in sequential five year blocks, reflecting forecasts on the price of gas and its nature as a diminishing, finite resource. We note that in reality, these price rises are likely to be "front-loaded", with sharper increased in the short-term and potentially periods where prices increases plateau.

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[54] See http://www.afr.com/p/national/power_price_hikes_from_gas_boom_hxTOyltdZNB18GAP4S20FJ

[55] Declining energy demand will reduce asset utilisation across the energy market and create upward pressure on fixed and variable charges, which perpetuates further price increases. This is commonly referred to the "the utilities death spiral", coined by AGL economists, Paul Simshauser and Tim Nelson.

[56] See http://www.ceda.com.au/media/290387/epofinal%202013.pdf for details.

Authors and contact details

Tosh Szatow, Director

Energy for the People

tosh@energyforthepeople.com.au

0414 155 547

Alex Houlston, Director

Energy for the People

alex@energyforthepeople.com.au

0431 073 556

Damien Moyse

Energy Policy Manager

Alternative Technology Association

damien@ata.org.au

Craig Memery

Renewable Energy Specialist

Alternative Technology Association

craig@ata.org.au

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