Exploring the Death Spiral: A system dynamics model of the electricity network in Western Australia

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Abstract

Power networks worldwide are facing challenges from their own consumer base in the form of private, grid-connected solar photovoltaic systems, and emerging growth in accompanying energy storage. This paper reports the findings from a system dynamics model of the electricity system of Western Australia, used to explore plausible scenarios resulting from the impact of private solar and storage for the period 2015-2035.

The study finds the falling costs of solar PV systems will drive exponential growth that could result in a tenfold increase in private solar capacity by 2025 – a much higher capacity than that currently predicted by the Independent Market Operator who operates the system. Eventually the daytime export of excess solar energy to the network will be so great that base-load generation will be affected, the network disrupted and tariffs will rise in a so-called electricity death spiral. Despite this, economy-wide emissions and total energy costs will be lower, which are positive outcomes for society and should be embraced rather than resisted.

A coherent long term energy strategy is required to address the major implications for the network arising from the inevitable growth of private solar and storage, and for renewable energy at the network scale.

Keywords

Electricity, Solar energy, Energy storage, System dynamics, Death spiral, Greenhouse gas emissions, System costs.

Introduction

The electricity industry worldwide is talking about the so-called death spiral. Under this scenario conventional electricity networks are undermined by customers reducing their energy demand through energy efficiency measures and / or private generation, mainly rooftop solar photovoltaic panels (PV). Both processes reduce the quantum of electricity purchased from the network, thereby reducing revenue to the network. As many of the network costs are fixed, this necessarily implies increasing unit costs and therefore increasing tariff charges for electricity. The tariff increases merely exacerbate the problem – hence the “spiral” reference.

In this study these issues are considered in the context of Western Australia's south-west interconnected system (SWIS). The SWIS serves the south-west portion of the state, some 900,000 dwellings and 100,000 businesses. The effect of increasing rooftop solar PV and the potential in the future for private electrical storage are modelled using the system dynamics technique.

System dynamics has been used previously to simulate energy systems in general and electric power systems in particular, notably by Professor Andrew Ford of Washington State University (Ford 1997, 2007, 2008). The approach has also been used power industry policy and strategy (Dyner and Larsen 2001, Bunn 1993).

The SWIS

The system currently has a generation capacity of nearly 6,000 MW. In 2006, the previously integrated system was split into three components: generation; transmission and distribution; and retail. Synergy (a state owned business enterprise) owns around half of the generation capacity and has a retail monopoly on accounts of less than 50 megawatt hours (MWh) per year (essentially covering residential dwellings). Private generators provide the balance of the energy source while private retailers compete with Synergy for accounts of more than 50 MWh per year. Western Power (another state owned enterprise) operates the transmission and distribution elements of the system, operating as a regulated monopoly.

An independent market operator (IMOWA)[1] operates the Wholesale Electricity Market[2] (WEM). A key component of the WEM is the Reserve Capacity Mechanism (RCM). The RCM was designed to incentivise investment to ensure that there is adequate generation and Demand Side Management (DSM) capacity available each year to meet peak system requirements. Retail electricity prices are set by government for Synergy customers.

Despite a growing population and economy, both peak and average demand on the SWIS have plateaued in recent years (Figure 1 and Figure 2). Part of this change can be attributed to general reductions in energy intensity in the economy (i.e. energy consumed per $ Gross State Product).

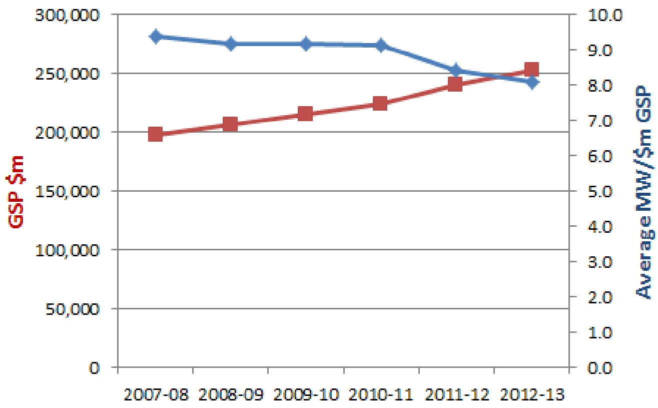

Figure 1 Gross State Product and Energy Intensity

[1] The explanation of the IMO role is taken directly from their website http://www.imowa.com.au

[2] A review of the WEM is underway at the time of writing.

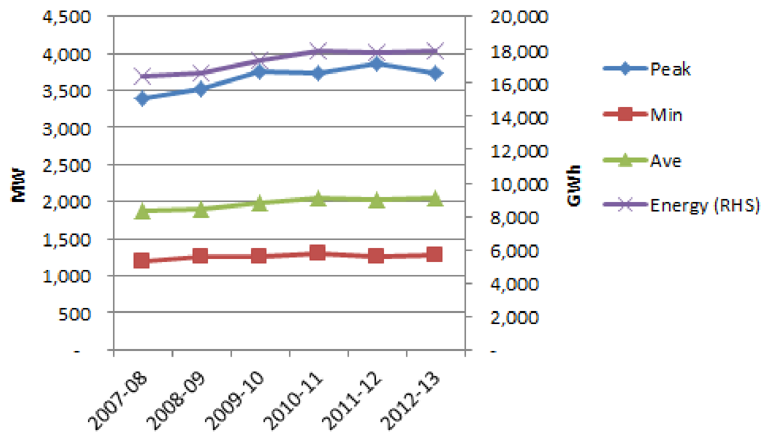

Figure 2 Recent Energy Demand

Rooftop Solar PV

Rooftop solar penetration has increased significantly in recent years on houses within the area served by the SWIS, and in Australia more generally (Table 1 and Figure 3).

Table 1 Solar PV in Australia 2013 [3]

State	#systems	Capacity (MW)	Proportion of dwellings with Solar Power
ACT	14,000	38	10%
NSW	252,000	633	10%
NT	3,000	11	4%
QLD	360,000	986	22%
SA	160,000	450	25%
TAS	18,000	55	9%
VIC	201,000	532	10%
WA	149,000	334	18%
National	1,157,000	3,039	14%

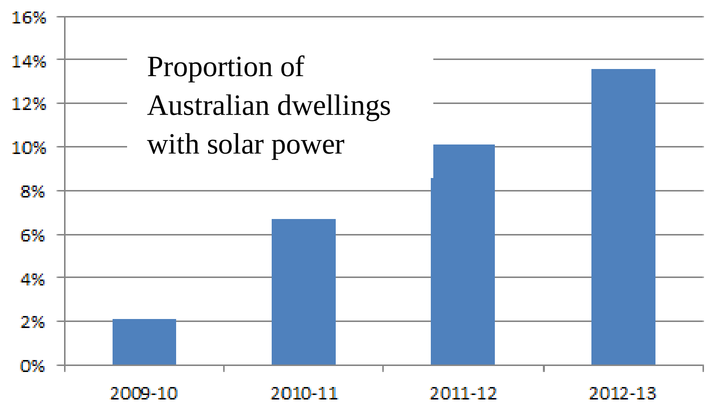

Figure 3 Rooftop solar PV on the SWIS[4]

[3] Source: http://www.sunwiz.com.au/index.php/australian-solar-pv-market-forecast.html

Households and businesses that export energy to the SWIS (at times when solar generation exceeds electrical demand) are paid in accordance with the Renewable Energy Buyback Scheme (REBS) which has just been reduced from 8.85 to 7.13 c/kWh, about one-third of the household tariff. The government briefly introduced an additional feed-in tariff of 40c/kWh but this was withdrawn (due to high subscription) in 2011.

The increase in take-up of private solar PV installations coincides with a significant drop in unit price in recent years.[5]

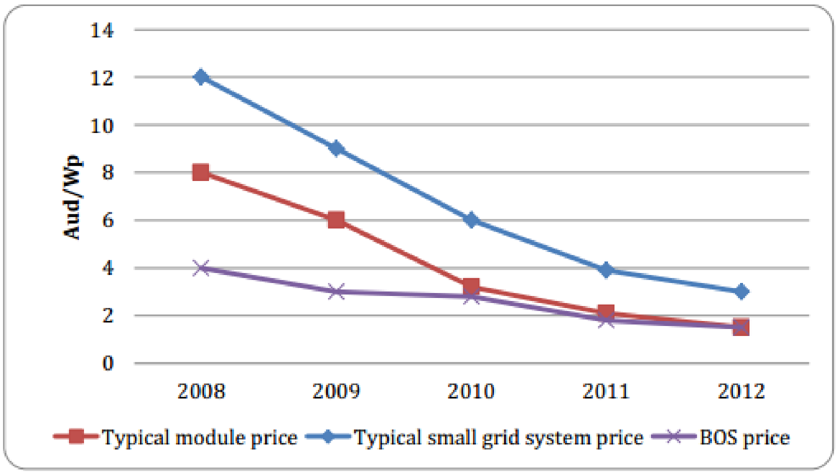

Figure 4 Cost of solar PV in Australia ($/W)

Electrical Energy Storage

The other innovation that is likely to follow the rapid take-up of household solar energy is energy storage. In the short term this will probably be battery storage and lithium-ion batteries appear most likely to lead the market. Development of lithium-ion batteries is being driven by both domestic scale renewable energy and the electric vehicle industry (Figure 5)[6].

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[4] Source: IMOWA

[5] Source: cleantechnica.com

[6] There several factors associated with the large range in costs for existing lithium-ion batteries, including battery size, required power demand / duration and geographical variations in manufacturing unit costs.

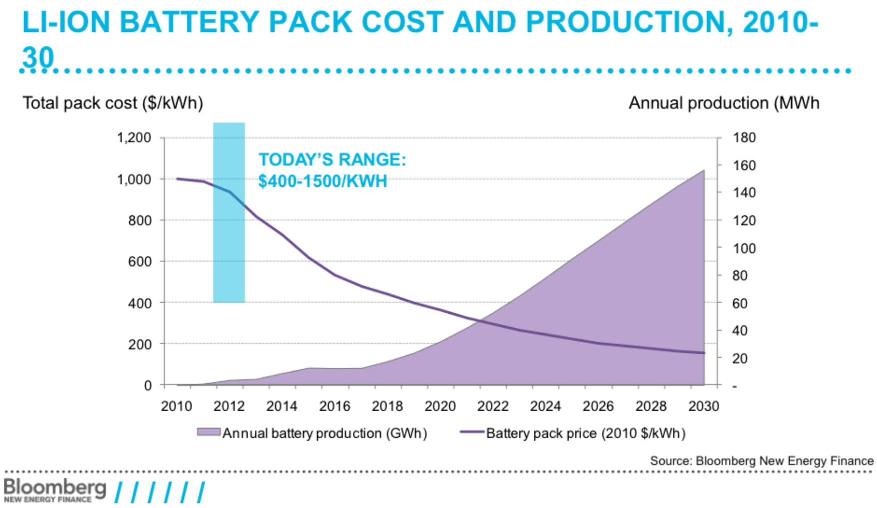

Figure 5 Projected Cost and Production of Li-ion storage[7]

The Model

Model Structure

The purpose of the model is to explore the influence of growing solar penetration on the SWIS network. The essential structure of the model is depicted in the causal loop diagram below.

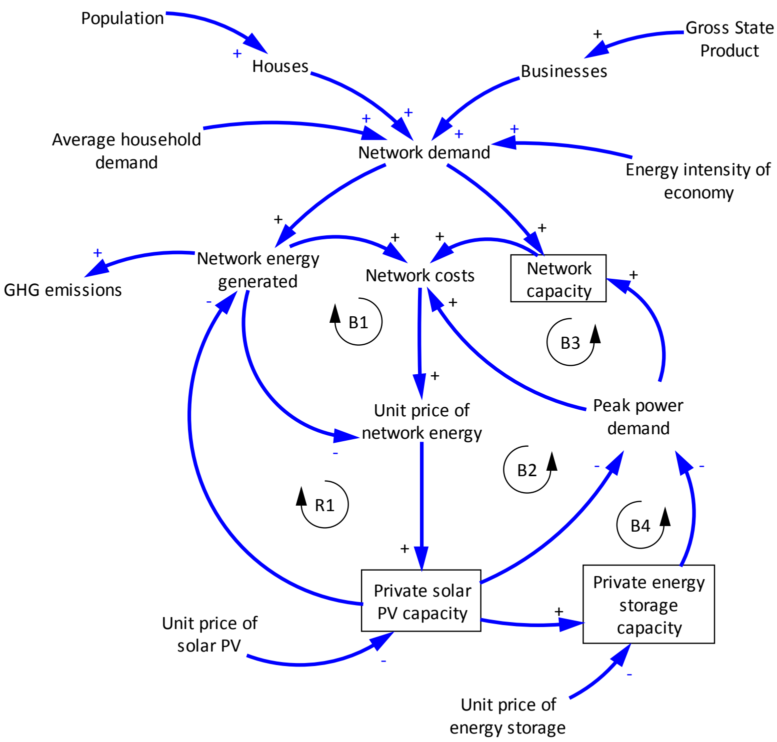

Figure 6 Causal loop diagram of model

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[7] Bloomberg New Energy Finance Summit 2012 (http://about.bnef.com/summit/content/uploads/sites/3/2013/11/BNEF_2012_03_19__University_Battery_Innovation.pdf)

The dynamic hypothesis is that the reducing price of solar PV systems (an exogenous variable in the model) will increase private solar capacity which in turn will reduce the quantum of energy generated on the network, pushing up unit prices and further incentivizing take-up of private solar PV[8] (Loop R1). This reinforcing loop is the essence of the so-called death spiral.

However, this is only part of the story. An increase in private solar capacity also reduces network generation costs by reducing both the total amount of energy generated and peak demand (Loops B1 and B2). Reducing peak demand directly reduces the cost of generation (peaking plants have higher operational costs), and also reduces the necessary network capacity, thus reducing capacity costs (Loop B3). Both factors will tend to offset otherwise increasing unit prices (balancing loops).

The addition of private energy storage does not change the quantity of energy generated, but does reduce peak network demand, thus creating a further balancing loop (Loop B4). This suggests that increasing private storage will somewhat offset the impacts of private solar generation on the network.

The behavior of the real system over time is determined by the relative strengths of the reinforcing and balancing loops. The results of most interest are:

- network costs;
- network unit prices;
- the overall economic costs of supplying electricity to the community; and
- greenhouse emissions

The model uses Version 6.3 of the Vensim[9] Professional software. A fuller explanation of the model structure, together with its documentation, is included in the supplemental information.

Electricity Demand

The model determines the electricity demand arising from:

- residential houses; and
- commercial and industrial facilities.

The existing residential demand and commercial demand profiles have been determined from historical half hourly reports of total network load, and presentations of the IMO WA on residential and commercial loads. The annual residential demand has been derived from the reported network loads, modified to include the demand met by private solar).

[8] Of course financial benefit is not the only driver behind the take-up of solar PV, including individual concern about global warming. Although these are difficult to characterise and have been neglected in this model, they will clearly only add to the momentum for growth.

[9] http://vensim.com/

	GWh
Reported 2012-13 residential load	5,035
Energy produced by 336 kW private solar	540
Estimated total residential demand	5,575
Reported 2012-14 commercial load	12,914
Estimated total residential and commercial demand	18,489

Hourly demands for a typical day of each month of the year are inputs to the model. The profiles for a typical January and June day are depicted in Figure 7 below. As these are typical days they do not reflect the absolute annual peak demand (around 3,700 MW in 2012/13).

The recent demand history for residential electricity indicates that the average usage per residence has not changed over the last five years if the growth in solar energy is taken into account[10]. Accordingly the electricity demand per dwelling is a constant in the model.

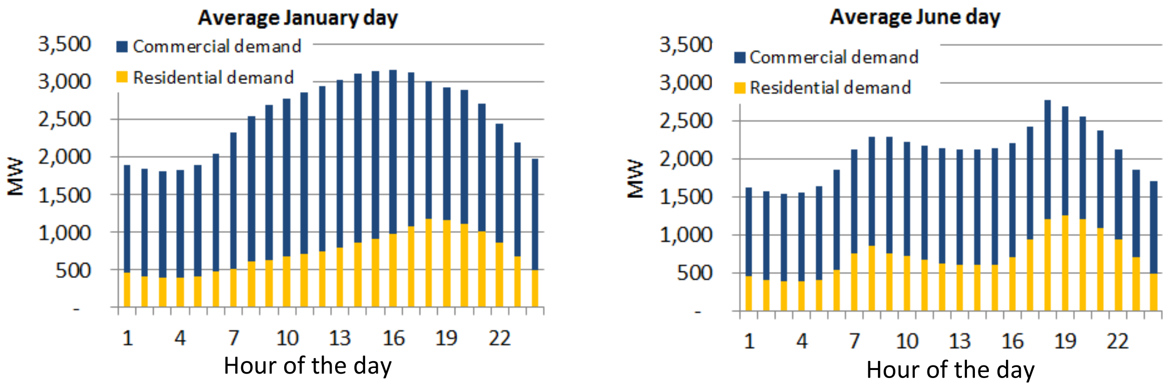

Figure 7 Electricity demand

The IMO base case forecast assumes population to grow at 2.1% per annum. The model assumes that the number of houses will grow at this rate as a default but can be readily varied through a slider.

The commercial and industrial demand is calculated in the model as the product of the state's Gross State Product (GSP) and the energy intensity (i.e. MWh per year per dollar of GSP). The recent data shows that energy intensity has been dropping by approximately 1% per annum and this is the default assumption in the model (again this can be readily varied). GSP is forecast by the Treasury to grow at 3% per annum and this is the default figure used in the model. It is assumed that the number of businesses grow by this amount. Again, these values can be readily varied through sliders.

Residential solar

The model calculates the contribution of household scale solar energy generation. It incorporates the following elements:

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[10] There is no research shedding light on the reasons why the recent regulatory changes requiring improvements in thermal efficiency of housing has not reduced demand. The most credible theory is that benefits arising from these measures have been offset by larger houses per person and demand from additional consumer appliances.

- Solar energy without storage; and
- Solar energy with storage.

Solar without storage

The existing number of residences with solar systems (15.5%) and the average size of their solar array (2.4 kW) have been taken from the IMO data. The impact of a 2.4 kW array on network loads is shown in the figures below for typical January and June days.

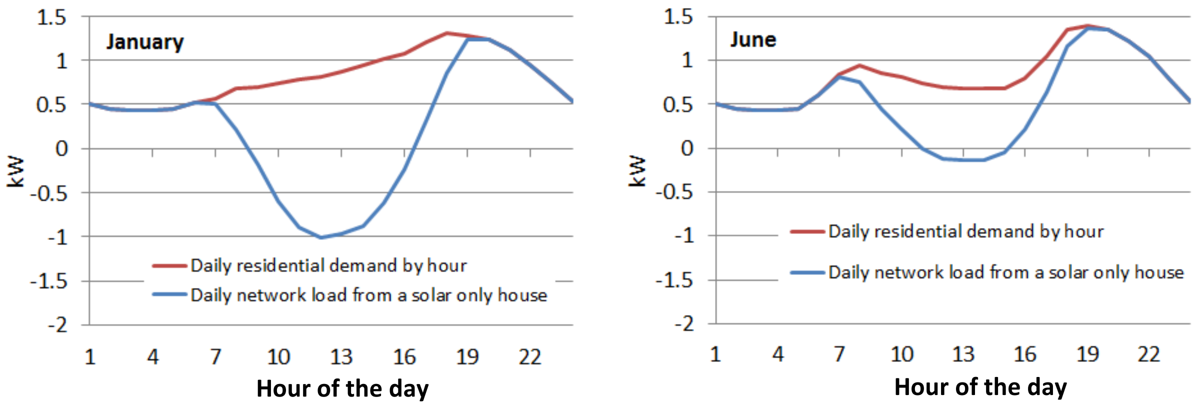

Figure 8 Impact of solar PV on network loads

It can be seen that solar has only a minor impact on reducing residential peak loads as these occur in the evenings. While significant energy is exported to the network in summer, exports are limited in the winter. Larger solar arrays maintain the shapes identified above, but the troughs in network load become larger.

The model calculates the payback period for a household arising from:

- avoided electricity imports from the network at the residential tariff; plus
- electricity exports to the network at the residential feed-in tariff (renewable buyback scheme); and
- the installed cost of solar energy.

Both the size of the solar array and the fraction of houses with solar energy grow towards a maximum fraction as a function of the payback period (Figure 9). The default value for the maximum fraction of houses with solar is 60%, and maximum solar array is 7.2kW (3 times the present average). At the commencement of the simulation period the payback period for residential solar is around 7 years and the model assumes that this will incentivise some 10% of remaining homes to purchase solar (spread over an adjustment time of 6.5 years). This percentage increases as the payback period decreases until it reaches 1 year, at which point all remaining houses would be incentivised to install solar PV.

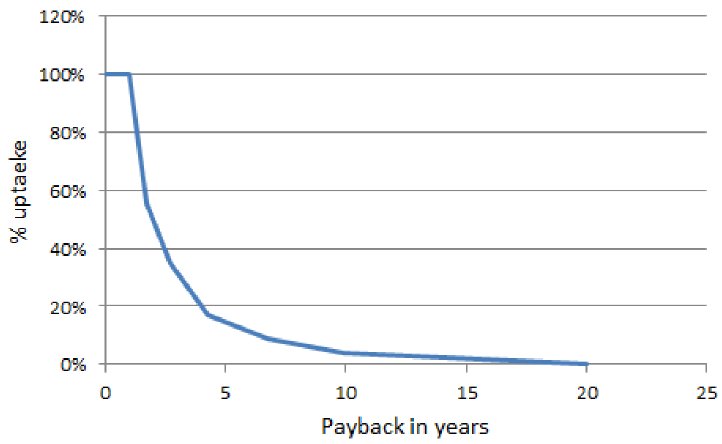

Figure 9 Uptake of solar PV

Avoided electricity imports are calculated in the model on an hourly basis in accordance with the profiles exemplified in Figure 8. Savings are determined as the product of the total avoided energy and the applicable network tariff. The existing residential time of use tariff (SM1) is used by the model to calculate normal hourly, monthly and annual charges. The model assumes that tariffs change over time pro-rata to changing unit costs of network energy.

Electricity exports are merely the difference between the annual household solar generation and the avoided imports. The value of exports is derived from the existing solar feed in tariff ($0.0713 / kWh).

The unit cost of solar PV is modelled as a stock with an initial value reflecting present unit costs ($2,200 /kW). This is the approximate installed cost of systems in Australia presently, excluding the benefit of the small scale technology certificates (STCs) which are presently worth approximately $690 / kW in the SWIS area. As there is currently uncertainty about the continuation of the STC scheme, the model neglects that benefit. The model assumes that the unit cost transitions to a final unit cost ($1000 /kW) in accordance with Figure 10. The curve is based on a review of published forecast costs including extrapolation of Figure 4 and the U.S. Sunshot Target of $0.06 / kWh[11]. Both the final unit cost and adjustment time can be easily varied in the model.

[11] http://energy.gov/eere/sunshot/sunshot-initiative

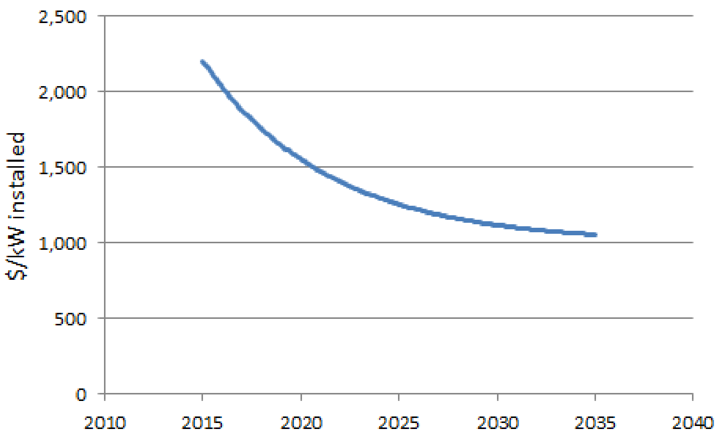

Figure 10 Solar PV cost curve

The quantity of residential solar electricity generated (in MW) is determined by the residential solar capacity (total number of houses x fraction of solar houses x the average residential array in kW) and the amount of solar energy generated annually per unit of capacity[12].

Solar with storage

The optimum storage capacity is 0 for solar arrays which are not sufficiently large to completely offset demand during the hours of generation (summer conditions determine this threshold which is about 1.1 kW for residential systems). For solar arrays above this capacity, there is increasing benefit in storing more energy to avoid network imports. However, there is an upper limit (about 10 kWh of storage for residential systems), above which there is excessive storage capacity for the amount of generation. This upper limit has been determined by selecting a storage capacity which discharges to (approximately) 0 on summer days[13]. Based on the hourly model of solar PV and household demand in Perth, the approximate optimum storage capacity for a given solar capacity was determined for both household and business systems[14] (Figure 11). The difference between households and businesses in respect of the minimum value is due to the difference in demand patterns.

[12] Taken as an average of 4.4 kWh/ kW in Perth (Clean Energy Council 2011).
[13] This is an approximation – most battery storage systems are recommended to only discharge regularly to around 30% of capacity.
[14] The approach to selecting optimum storage is described in the Model Explanation in the Supplemental Information.

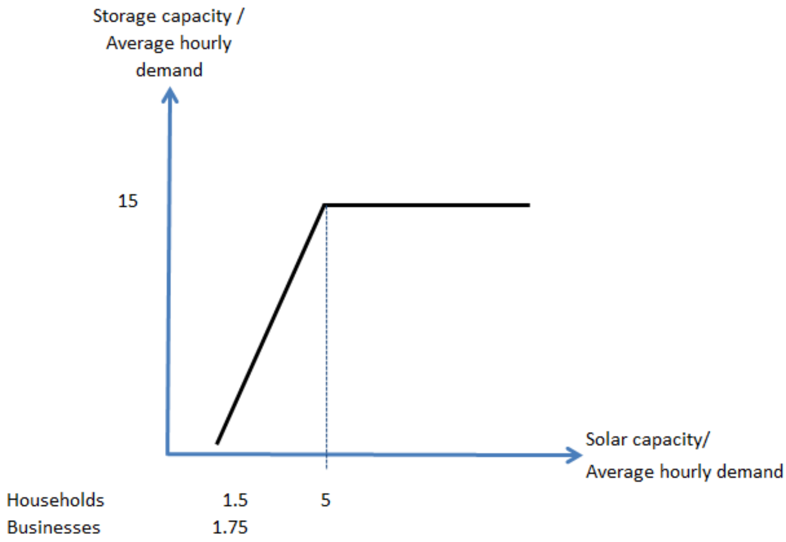

Figure 11 Optimum storage capacity

By adopting this approach to setting storage capacity, the model avoids multiple combinations of solar capacity and storage capacity. Solar capacity in the model is normalised as a fraction of average hourly demand.

The model calculates the additional benefit to the householder from adding storage to their solar array. It is assumed that storage operates simply on the basis that:

- solar generation in excess of demand is stored (up to the limit of the storage capacity);
- the storage discharges to meet demand that cannot be met by solar generation; and
- remaining demand is met by the SWIS network.

The model determines the fraction of energy imported on an hourly, daily and annual basis with the selected combination of solar array and storage.

Larger scale solar arrays will generate more electricity than can be optimally stored so there is also a component of generation that is exported (allowing for storage losses).

The additional benefit of storage is therefore determined by:

- savings from the additional avoided network imports (at the normal tariff); plus
- the benefit of exports (at the feed in tariff).

The incentive to add storage is again determined by a payback period calculated from the benefits noted above and the unit cost of solar storage. The latter has been determined from the technical press and assumes the present storage costs of approximately $1,000 / kWh will drop to around $200 / kWh (Figure 12). These values may be considered conservative given the curve set out in Figure 5.

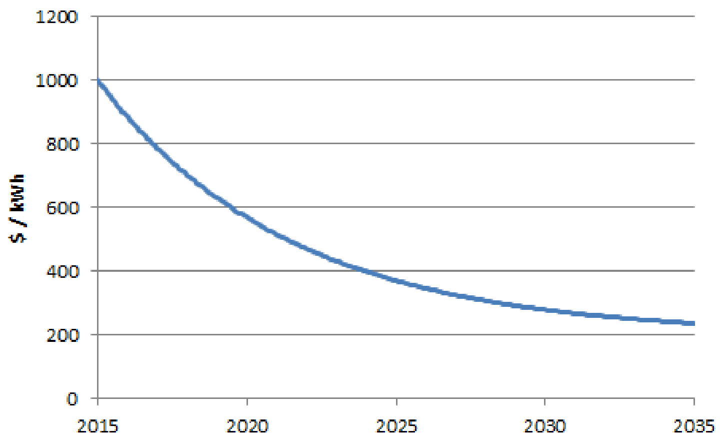

Figure 12 Storage cost curve

The fraction of houses with storage trends towards the number of houses with solar energy in accordance with the same algorithm assumed for solar arrays. The fraction is assumed to be zero at the commencement of the simulation.

At any given time therefore the model predicts:

- the average residential solar array;
- the number of houses with solar arrays; and
- the number of houses with an optimal storage system

The combination of these impacts on the network at each time step is used to calculate the network load on an hourly basis for each month of the year from:

- A house without solar;
- A house with solar but no storage; and
- A house with solar and optimum storage.

The net impact is merely the product of these values and the number of houses in each category.

Commercial Solar

The model structure for the commercial solar is identical to the residential model in all respects, except for the initial conditions. The model assumes that at the outset there is no commercial solar or storage.

There is no available information on the potential for uptake of solar PV in the commercial sector. As this sector incorporates a spectrum of activities spanning small service businesses in rented and shared accommodation and large industrial facilities with large roof space, the opportunities will vary widely. In this study the maximum fraction of solar businesses defaults to 50% in the model but this is variable. Because the electrical demands of the business sector are much greater than the residential sector and the available space (on average) for solar PV is larger, the model sets a much larger array size for the maximum average array – 150kW. However, unit costs for both solar and storage are assumed to be the same for residential and commercial systems.

It is important to note that paybacks for business PVs are marginally shorter than for residential customers because the commercial peak is earlier in the day and is therefore served more effectively by solar generation, meaning that more of the generated energy goes to import avoidance (at the normal tariff) rather than export (at the lower REBS tariff).

The functions controlling take-up of both solar and storage are the same as for the residential sector, as is the payback function. Payback again is determined by the savings and benefits arising from avoided electricity imports and exports. In this case, the business tariff R1 is read into the model and is used in this calculation. The model simplistically assumes that tariffs change over time pro-rata to changing unit costs of network energy.

Utility Network

The network generation capacity is used to calculate the recurrent generation costs and spot price arising from the Short Term Energy Market (STEM). The initial capacities of each type of generation are based on the existing capacity credits allocated by the IMO, and other information.

Coal	1,777 MW
Gas combined cycle (Gas CC)	715 MW
Gas combustion turbines (Gas CT)	2,609 MW
Diesel	210 MW
Wind	169 MW
Total	5,480 MW

Information on the capital and operating (including fuel) costs and other characteristics of each type of generation has been derived from the Australian Energy Technology Assessment (AETA) by the Australian government's Bureau of Resources and Energy Economics (BREE 2012).

The model assumes there are no additions to the existing generation capacity (including wind). As the network is presently over capacity the model allows for retirements to each type of thermal generation. The default condition is for coal retirements at 20 MW / year throughout the simulation period, commencing in 2016.

The network loads arising from residential and business premises are aggregated and, these figures together with the generation capacity, are used to determine the hourly spot price on the network. Under the present arrangements only a small proportion of energy is purchased via the STEM. The vast majority is traded bilaterally by generators and retailers. As information on these trades is not publicly available the model assumes all generation is dispatched via a spot price mechanism. Accordingly, the spot prices in the model are not directly comparable to the actual STEM prices on the SWIS.

The spot price mechanism applies only to the thermal network, assuming that both private solar and network wind generation "must-run".

Average bid prices for each type of thermal generation are assumed to approximate the fuel and variable operating costs prices associated with each type of generation (set out in the AETA report), together with a 10% markup. This yields the following average bid prices:

Coal	$35.10 / MWh
Gas CC	$98.22 / MWh
Gas CT	$143.15 / MWh

The model assumes that each generation type will bid these figures ± 20% depending on demand. This model structure derives an hourly spot price on the assumption that the lowest cost available generation is deployed. A ceiling price of $200 is assumed.

Wind generation in the model is derived from random function that assumes a capacity factor of 0.38 on average is achieved (a figure normally assumed for the SWIS).

The model also calculates the hourly and monthly costs of generation, assuming that each type of generation costs its average bid price per hour to operate. These calculations derive a unit cost ($/MWh) for the generation component of system costs.

System Costs

The model calculates the total SWIS costs. The monthly fixed cost of generation is added to the generation component described above. The fixed costs are again derived from the AETA report. Guidance for the calculation has been derived from the IMO report outlining the calculation for the reserve capacity credit cost per MW (which assumes that gas combustion turbines will determine this figure).

The annual fixed cost of generation has been taken to be the annualised cost of capital and fixed operations and maintenance costs amortised over 30 years using the weighted average cost of capital of 7.01%. The capital costs per MW[15] are derived from the AETA report for each type of generation.

The monthly costs of transmission, distribution and retail (TDR) are added to the generation costs to give a total system cost figure per month. The costs for these items have been calculated on the basis of the existing reported costs for the SWIS[16]. The following includes the cost of government subsidy to calculate an approximate overall unit cost.

Capacity	5,685	MW
Energy	18,133,609	MWh

	$/MWh	$m pa	$/MW
Generation costs	127.69	2,315	
Transmission & distribution	105.67	1,916	337,064
Other costs	61.64	1,118	196,621
Assume total unit cost	295.00	5,349	

The model assumes the cost of transmission and distribution is $337,000 per MW pa if the capacity of the system remains the same or grows. If capacity falls below the initial value the

[15] A markup of 50% has been applied to the capital costs set out in the AETA to allow for legal, financing and other costs associated with purchase of the asset.

[16] http://www.westernpower.com.au/aboutus/save_electricity/The_price_of_power_.html

costs are assumed to remain at their current figure on the basis that this infrastructure will continue to be in place and cost approximately the same to operate.

Other system costs are assumed to vary in accordance with capacity, i.e. at the rate of $197,000 / MW pa.

The total system unit cost is simply the addition of the generation and transmission, distribution costs and other costs (including retail) divided by the quantity of network electricity generated. The average system unit cost is simply the average of the previous year's monthly values. The model assumes that changes to tariffs are pro-rata to unit cost increases and applied as a multiplier to the existing household and business hourly tariff regime (one year in arrears).

The model includes the cost of the REBS as a system cost, although the REBS tariff is assumed to remain constant at the current rate.

The present network is heavily dominated by fossil fuel generation. At the time of writing, a carbon price has been removed in Australia and hence no cost has been accrued in this study to account for greenhouse gas emissions. Given the global impetus for pricing carbon, it is unlikely that this situation will persist for the duration of the simulation period.

All costs in the model are un-escalated and therefore quoted in 2014$.

Greenhouse Gas Emissions

The greenhouse emissions arising from the thermal network are also calculated. The emission intensities of each type of generator have been taken from the AETA report and the Account Factors from the National Greenhouse and Energy Reporting scheme[17].

These figures combined with the monthly generation regime determine the emission intensity of the network as a whole, which is presently 0.76 TCO_2-e / MWh.

Solar Costs

The model calculates the incremental solar and storage investment costs from the inflows to the stocks of houses and businesses and multiplies those flows by the fraction of premises that have solar or storage at that time step, and the unit cost of solar and storage. This identifies the total private investment in solar and storage at each time step.

Public and Private Expenditures

The solar and storage investments are added to the recurrent network generation costs to give an indication of the total private and network expenditures throughout the simulation period. The calculation neglects the operations and maintenance costs associated with private solar and storage systems.

This calculation also neglects the investment in both private solar and the existing thermal network generation prior to the simulation period.

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[17] http://www.environment.gov.au/climate-change/greenhouse-gas-measurement/publications/national-greenhouse-accounts-factors-july-2014

Model Results

Scenarios Considered

The model has been used to investigate a number of scenarios related to the possible growth of private solar PV and storage and the impacts of this growth on the SWIS network. For comparison purposes a Base Case is included which assumes:

- Economic growth of 3% pa;
- Population growth (represented by housing growth) of 2.1% pa;
- The penetration of private residential solar remains at the present value of 15.5%;
- The average size of arrays remain at 2.4MW;
- There is no residential storage; and
- There is no business solar PV or storage.
- The recent reductions in energy intensity (approximately 1% pa) continue; and
- The network thermal capacity is reduced by 20MW pa from 2016.

The model calculates demand and generation hourly (assuming a typical hourly pattern for each day of each month) and runs for 20 years starting in 2015.

The purpose of the model is to explore the underlying dynamics of the SWIS over the medium term. It does not seek to precisely simulate the short term dynamics such as the backlog of works like pole replacements and undergrounding works. It assumes that the essential nature of the existing system (including transmission and distribution costs) is sufficiently representative to explore systemic changes over the 20 year time horizon of the model.

Results - Solar Growth without Storage

This case examines the implications of residential and business solar growth without storage, i.e.:

- growth in residential solar PV penetration continues; and
- growth in business solar PV penetration commences in 2015.

Under the model assumptions, payback periods continue to fall as system sizes grow and unit costs reduce. This results in rapid growth in both the residential and business sectors. By 2035 around 50% of houses and 40% of businesses have solar PV (Figure 13).

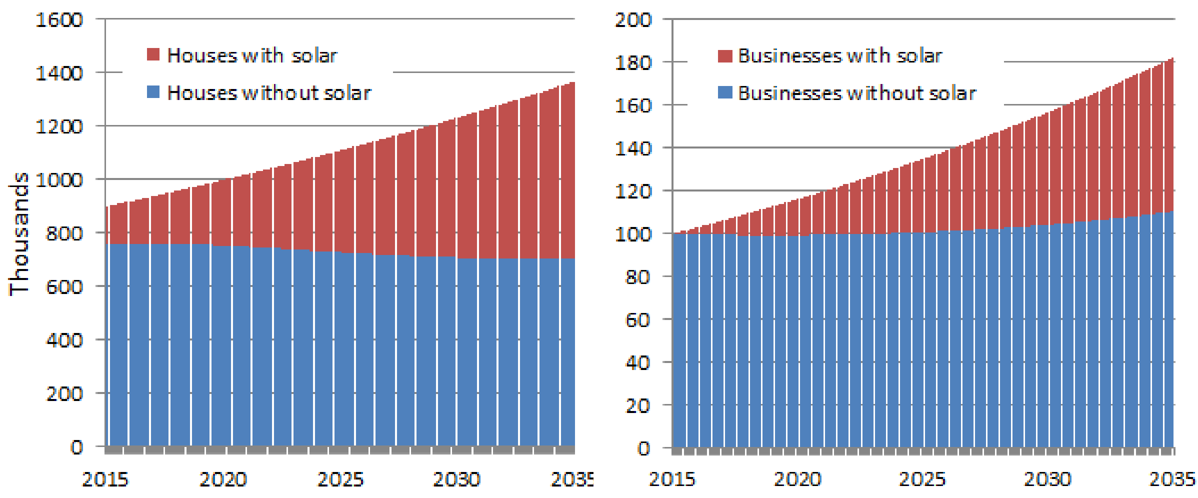

Figure 13 Growth in solar PV penetration

Reducing payback periods also lead to larger installed systems with average array sizes increasing to around 4.5 kW for residential systems and 90 kW for business systems. The total capacity growth is depicted in Figure 14.

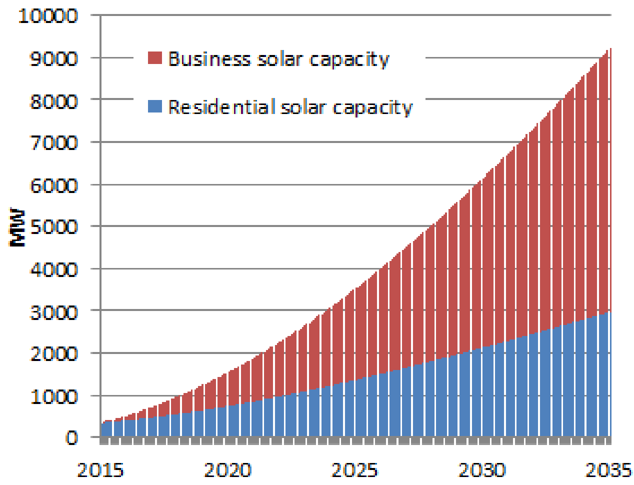

Figure 14 Growth in solar PV capacity

There are significant implications for the SWIS if this scale of growth in private solar PV occurs. By 2025, average hourly loads on the network are significantly reduced from the Base Case (Figure 15) and this divergence grows thereafter.

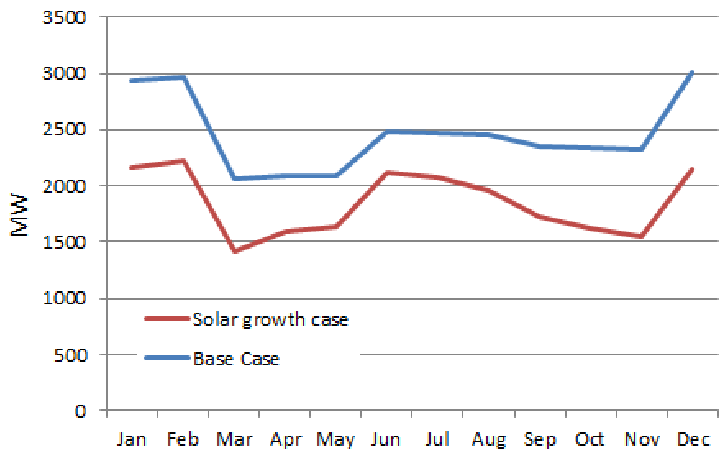

Figure 15 Average hourly network loads (2025)

However, maximum loads are only marginally reduced by daytime solar generation. Accordingly, the maximum hourly loads by 2025 show only a minor reduction in comparison to the Base Case (Figure 16).

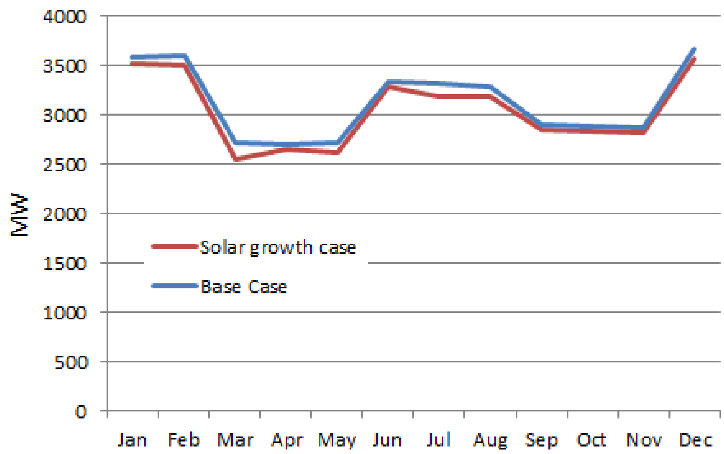

Figure 16 Maximum hourly network loads (2025)

This means that the capacity of the network is required to be maintained at the levels of the Base Case, with consequent capacity based costs.

However, the most significant implication of this scale of solar generation is on minimum network loads, i.e. when solar generation is at its maximum during the middle of the day in general and in the summer in particular. By March 2030 available solar exports exceed the total electricity demand in the middle of the day and accordingly, network loads fall to zero (Figure 17).

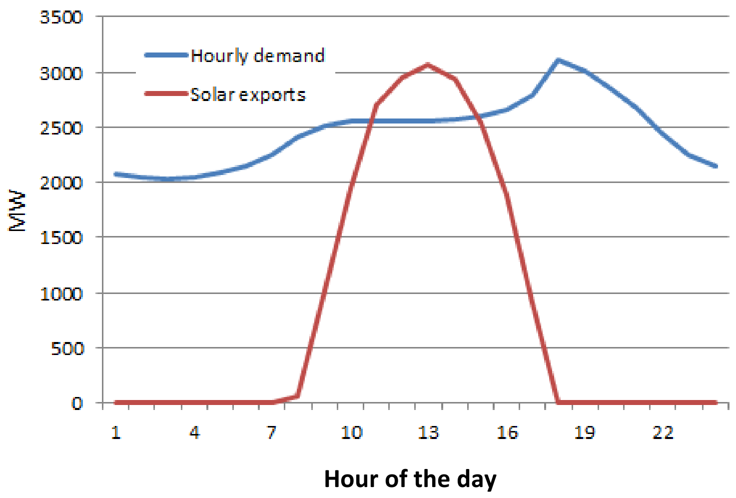

Figure 17 Solar exports (March 2030)

The lead up to this circumstance is shown in the following figure which depicts the so-called "duck curve" (Figure 18). This encapsulates the problem for networks of accommodating highly varying daytime solar generation.

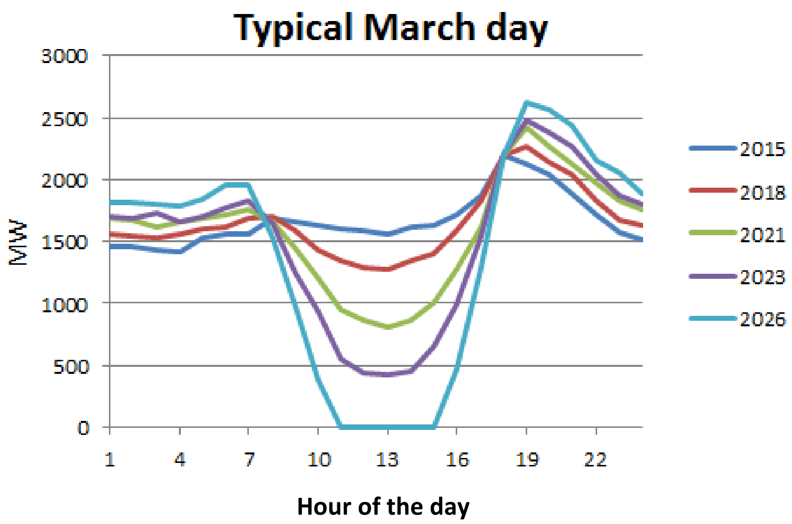

Figure 18 Duck curve

This suggests that there could be an intermittent over-generation problem by 2020 when minimum network loads fall below the normal operating capacity of baseload coal generation, which is intended to run consistently and cannot be readily cycled down and up in a matter of hours. Steep ramping of generation is required in the hours of declining solar generation. A similar situation has been identified by the California Independent System Operator[18].

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[18] http://www.caiso.com/documents/flexibleresourceshelprenewables_fastfacts.pdf

Results - Solar Growth with Storage

This case examines the implications of residential and business solar growth with storage, i.e.:

- growth in residential solar PV penetration continues;
- growth in business solar PV penetration commences in 2015; and
- both are accompanied by growth in private storage.

Storage payback periods in the model are dependent on storage costs, savings and REBS income which are all a function of solar array size. Accordingly, it takes some time for paybacks to drop to the level where take-up would be financially attractive. However, after around 2020 paybacks have dropped to the 10-15 year range.

Penetration thereafter increases steadily in both residential and business facilities (Figure 19). By 2035, there is some 13,000 MWh of storage capacity and 405,000 houses and 45,000 businesses possess storage (Figure 20). However, this is still only about 1.5 hours of storage at the nameplate solar capacity.

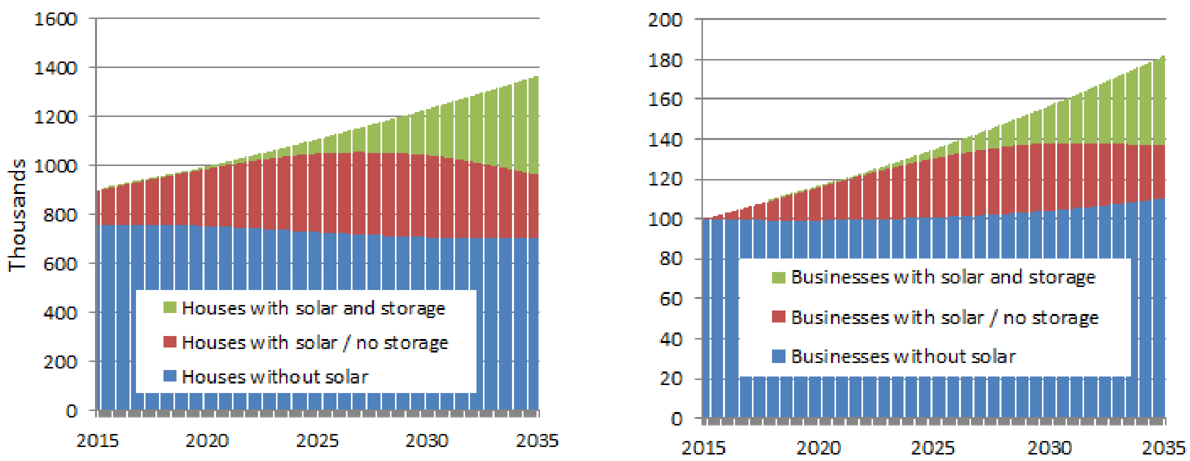


Figure 19 Energy Storage Growth

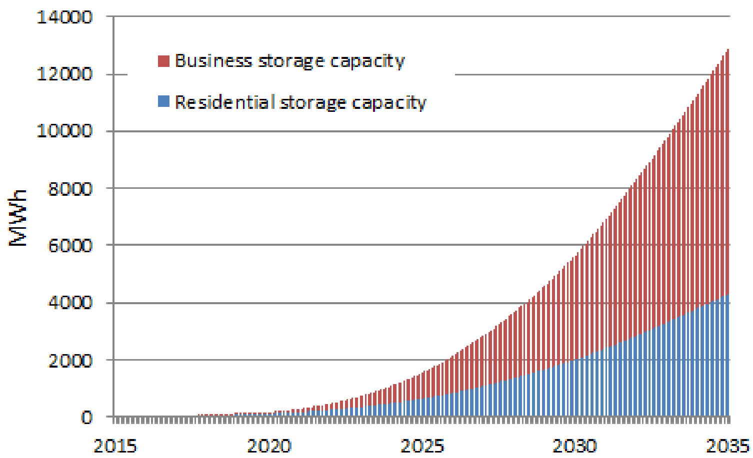


Figure 20 Storage Capacity

By observation (Figure 20) the storage case has little impact on the network for the first half of the simulation period. The duck curve up to 2025 is similar to that for the solar only case. It is only thereafter that the influences of storage are felt. By 2034 storage has reduced maximum network loads significantly from the solar only case (Figure 21).

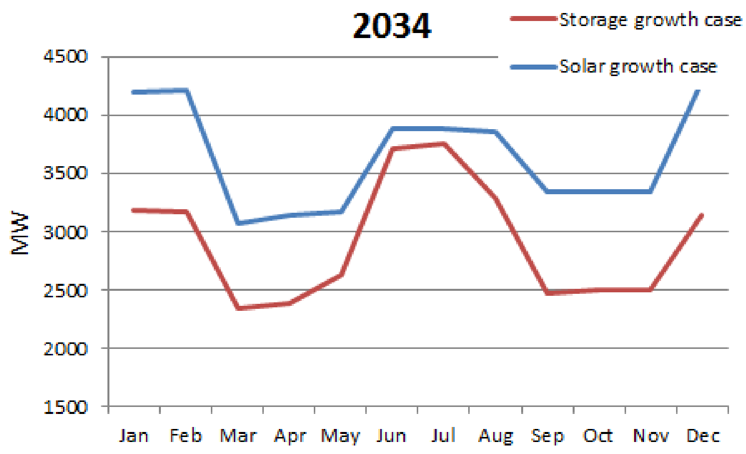


Figure 21 Maximum hourly network loads

The over generation problem is somewhat ameliorated in the storage case but minimum network loads will still fall to 0 under certain circumstances (Figure 22).

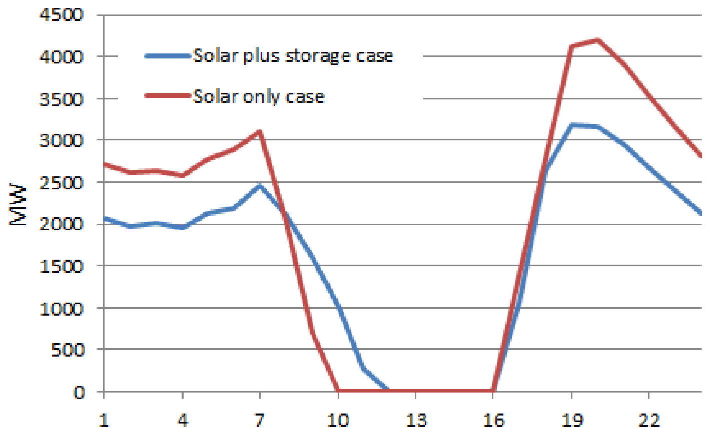
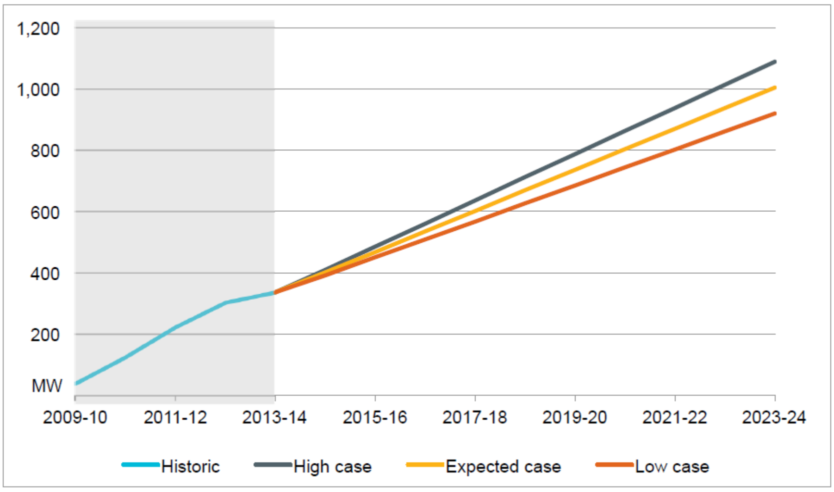


Figure 22 January day network loads (2034)

The Implications of the Model Results

Solar growth

In a recent report, the IMO forecast the growth of private solar to grow linearly for the coming decade to reach approximately 1,000 MW of nameplate capacity by 2024.



Source: IMO/NIEIR

Figure 23 IMO Solar penetration forecast

In contrast the model, which is based on an increasing take up as payback periods reduce, suggests that this figure could be as high as 3,000 MW by 2024 and 3 times that figure by 2035.

The IMO forecast is based on linear growth. Exponential growth is a more common phenomenon, and is usually observed in the time histories of innovative technologies, including solar PV take-up in Australia[19].

Although growth in the commercial sector has been slower than residential to date, as awareness grows and unit prices decline, this is potentially the largest contributor to growth by far. Payback periods are lower for commercial systems because there is a better match between solar generation and demand, and time-of-use tariffs are higher during peak periods.

Network loads

The most dramatic effect on the network of growth in solar penetration of this scale is seen in the impact on minimum loads on the network (Figure 24). This illustrates the impact of growing solar exports to the network during daytime periods in general and in summer in particular.

[19] http://apvi.org.au/wp-content/uploads/2014/07/PV-in-Australia-Report-2013.pdf

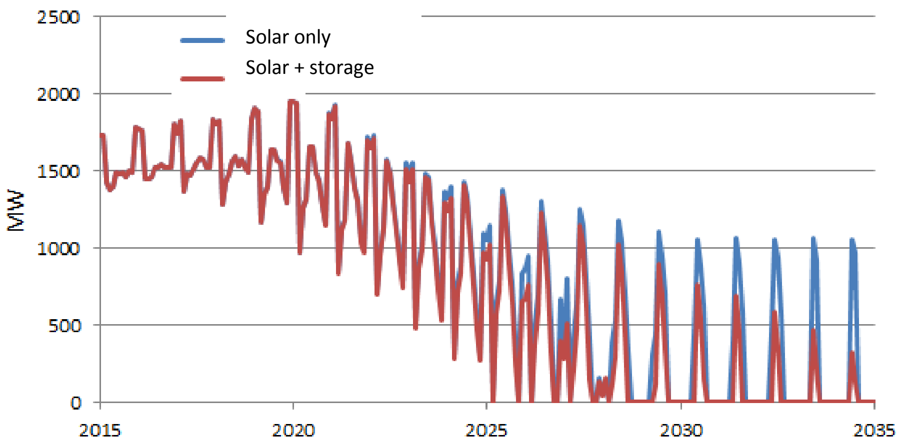


Figure 24 Minimum hourly network loads

The following figures (Figure 25 and Figure 26) show the percentage of hours in each month that network loads may reach over-generation and zero generation points.

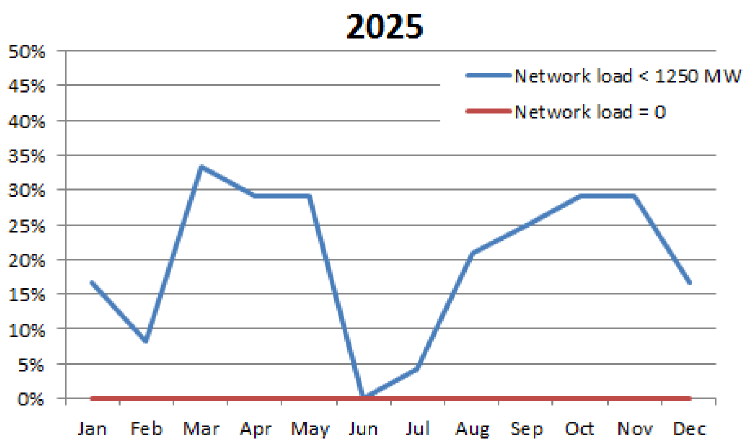


Figure 25 Over-generation risk by 2025

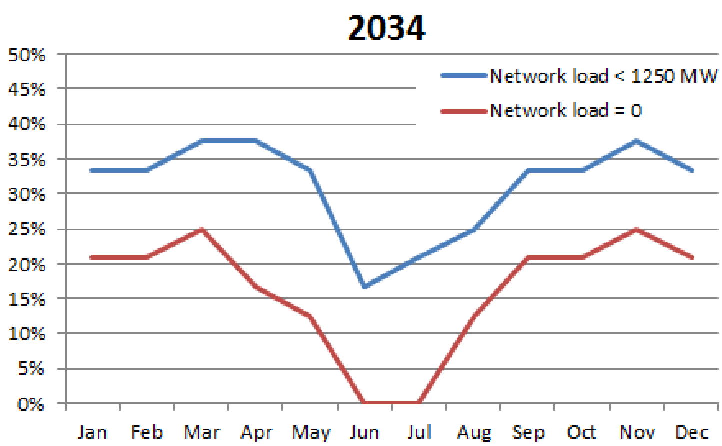


Figure 26 Over-generation risk by 2034

Over the longer term the "hollowing-out" of network load would likely require a different configuration of generation type on the network.

Private energy storage ameliorates the impacts of solar generation on the network as it reduces both the peak and average energy demands, thus lowering system costs.

With projected growth in storage lagging the growth in solar PV, storage only partially offsets the over-generation problem. By the end of the simulation period there is only around 1.5 hours of storage (at nameplate). This means that the amount of over-generation from solar will likely continue to increase, albeit to a lesser extent than without storage (Figure 27).

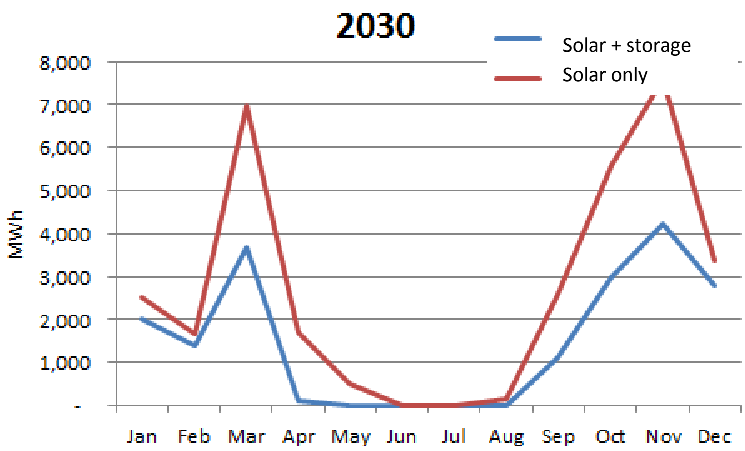


Figure 27 Typical day over-generation

Network Energy and System Costs

All of the cases considered result in lower annual energy required from the network than the Base Case. In the most likely case that business premises also adopt private solar and storage there would be a dramatic reduction in required energy, both in relative (45%) and absolute terms (15%) as identified in Figure 28.

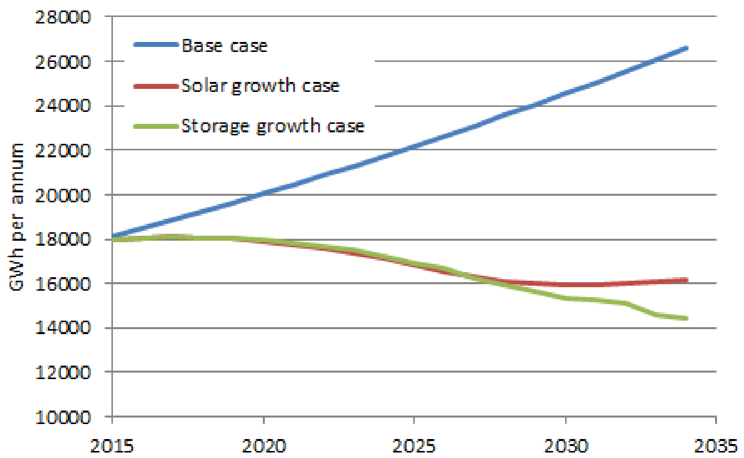


Figure 28 Annual network energy

A reduced energy demand translates to reduced system costs. Under the storage scenario (residential and business solar and storage), system costs would rise only slowly, and then potentially fall to near current costs (Figure 29). This is due partly to a reduction in the capacity of the network (assumed mainly related to coal generation), which induces savings in the cost of capacity credits. However, this neglects any ongoing debt obligations associated with this generation capacity which, while not a direct cost to the SWIS, is a cost to publicly owned entities and hence the taxpayer. The costs of writing off this debt are not included in this study.

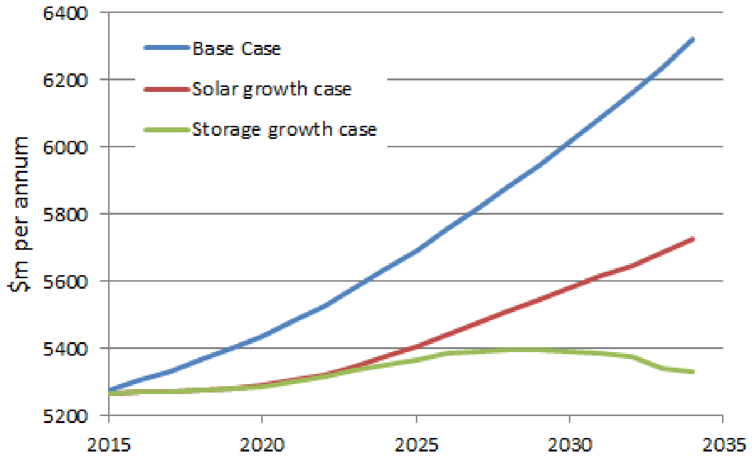


Figure 29 Annual system costs

If tariffs presently delivered $295 / MWh, the SWIS would recover all costs. The model suggests that unit costs will fall from this figure under the Base Case conditions. However, under the other cases it is likely that, although overall system costs will decrease, unit costs and therefore tariffs will increase substantially (Figure 30).

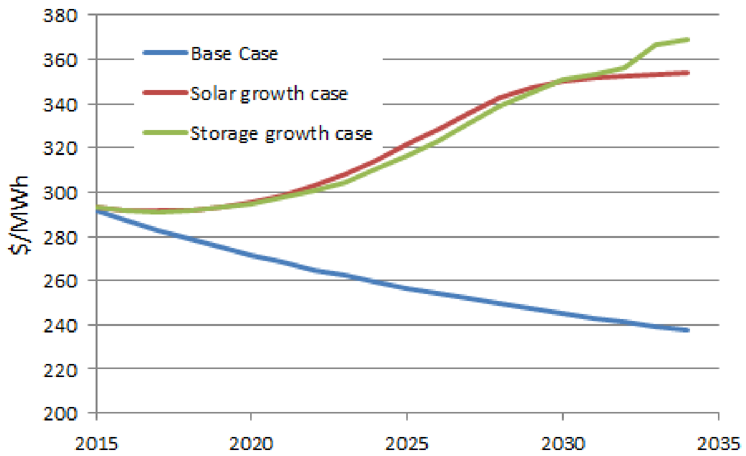


Figure 30 System unit costs

Although reduced system costs indicate that increased solar penetration will lead to an overall economic benefit, a rise in unit costs is still problematical. Individual consumers, who for one reason or other cannot reduce their network energy consumption sufficiently to offset tariff increases, will pay more for energy under this scenario. As this group will include those who are least able to absorb the additional cost, equity will become an important element of the policy response.

A Broader Perspective on Costs

Of course, the SWIS costs do not represent all the costs incurred as they do not take into account the private investments in solar PV and battery storage. The model tracks these costs and accrues them over time to enable a more complete cost comparison of the options (Figure 31).

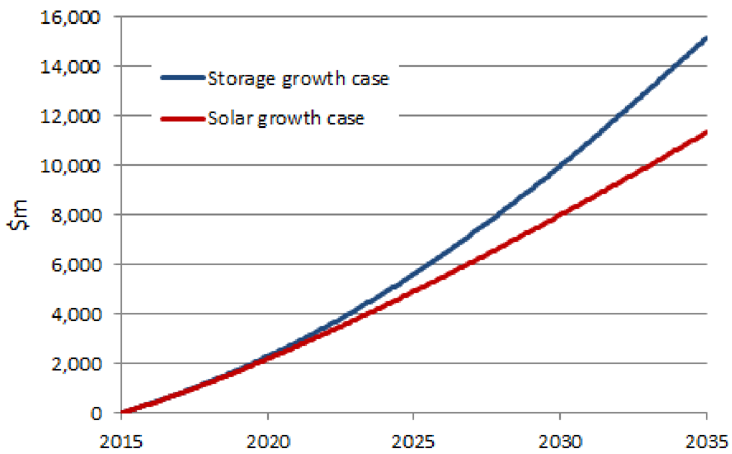


Figure 31 Private investment in solar / storage

A range between $11bn and $15bn is the most likely case for private investment in solar and storage. As the net annual savings for the SWIS accrue to around $7.6 bn, the 20 year accumulation of private and SWIS costs are only marginally higher than the Base Case (Figure 32).

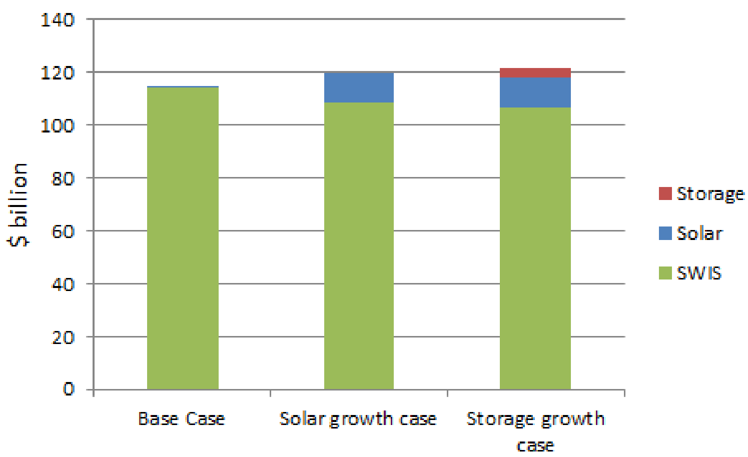


Figure 32 20 year public and private expenditures on energy

The Influence of Tariff Increases

Part of the death spiral metaphor is that increasing solar penetration will lead to higher tariffs which will only further improve the cost-benefit equation for consumers. By default, the model increases existing household and business tariffs pro-rata to system unit cost increases. However, the influence of increasing tariffs is easily tested by "switching off" tariff increases in the model. Doing so demonstrates that the tariff increases are not the main driver of reduced paybacks. The reducing unit cost of solar PV has much more influence than increasing tariffs (Figure 33).

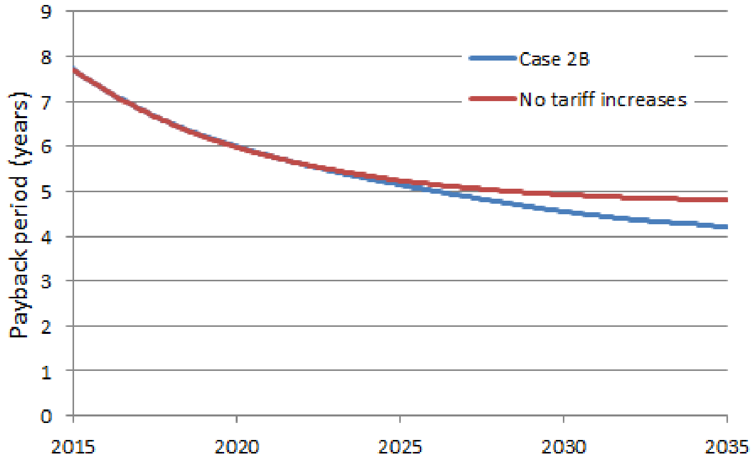


Figure 33 Influence of tariffs on payback periods

Greenhouse Gas Emissions

The Base Case indicates that greenhouse gas emissions could rise by around 20% by 2035. The most likely scenario, i.e. growth in private residential and business solar and storage would reverse this and deliver reductions of around 25% (Figure 34). However, even this contribution would be insufficient to represent a credible emission reduction target for south west Western Australia.

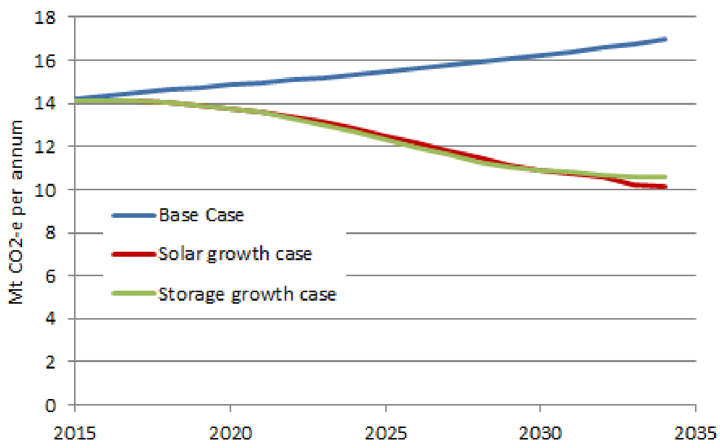


Figure 34 Greenhouse gas emissions

Policy Response

Transition Strategy

The current review of the Wholesale Electricity Market (WEM) does not address the dependence of the SWIS on fossil fuel generation, a situation that cannot continue irrespective of the current adverse political environment. Even if supply is not dampened through action on global warming, prices will inevitably and steadily rise forever after peak production in gas and coal later this century (Maggio and Cacciola 2012).

Electricity industry investments are made for decades and so it is essential that the future energy generation mix and network strategy is established now to ensure that new investments minimise the risk of stranded assets.

This study identifies that the growth of renewables in the form of private solar is inevitable and will have major implications for the network irrespective of any changes likely to arise from the WEM review. The energy system will change, and therefore the implications of this study should be considered in the context of this broader transition, for which a coherent long term energy strategy is required. The inevitable increase in the take up of private solar PV systems in WA homes and businesses will merely hasten a transformation of the electricity network during the coming decade that is needed anyway.

An Integrated Energy Policy

The growth of private solar PV is being driven by global forces which are leading to lower unit costs for solar PV panels and economies of scale are driving down balance of system costs. Although it may be affected in the short term by various factors, Western Australia cannot escape the reality of this momentous technological shift.

The days of the electricity industry being the sole provider of energy services to consumers are over. They are now competing with their customers and their response to this challenge will determine where the balance between network and private assets eventually lies. Policy must drive the most efficient economic outcome, not seek to "protect" the existing industry players. Lower emissions and lower total energy costs are positive outcomes for society and should be embraced, not resisted. While the fact that Synergy and Western Power are state owned enterprises obviously must influence policy, it should not cloud the fact that major change is inevitable. The future energy system must effectively and efficiently integrate private and network generation.

Network Storage

This study identifies that excess solar generation in daytime hours will create an over-generation problem on the network in the coming decade, initially in the mid-seasons and then in the summer. This will require either network baseload generation to be intermittently reduced and / or private solar generation to be "floated". The former is problematical from the operational perspective and the latter wastes energy that has no marginal cost. Although private storage will ameliorate this situation somewhat, the capacity of private storage will not be sufficient to eliminate it.

The only way to avoid the steep ramping evident in the "duck curve" is to introduce network storage into the SWIS. This could potentially occur at existing substation sites which dispatch and receive electricity from the private systems in homes and businesses[20]. The introduction of storage, if commenced soon enough and with appropriate policy settings (e.g. in respect of the REBS rate), could potentially "head off" the growth in private storage modelled in this study. Economies of scale would mean lower costs per MWh for network scale storage, and

[20] Although not covered in this study, storage at this scale could also facilitate decentralised micro-grids operating at the precinct / suburb scale.

if this was of sufficient scale to store all excess private solar generation, this could lead to the encouragement of private solar while dis-incentivising private storage.

Storage at this “downstream” scale would logically be complemented by larger scale storage “upstream” aimed at smoothing supply and demand from network generation. This would be part of a strategy to transition generation from fossil fuels to renewables, many of which are intermittent in nature, e.g. wind. Ontario is one jurisdiction that is planning for network storage for this purpose. The Independent Electricity System Operator (formerly the Ontario Power Authority) has procured approximately 35 MW of storage and is presently in a tender process to procure a further 15 MW. The United States is expected to add some 220 MW of energy storage to networks in 2015[21].

System dynamics has previously proven useful in simulating the role of centralized energy storage. Examples include the proposed strategic fuels (i.e., gasoline) reserve in California (Ford 2005) and the use of pumped hydro storage for wind integration in the Pacific Northwest (Llewellyn 2011).

Professor Andrew Ford (personal communication 2014) has developed an innovative approach to the system dynamics modelling of network systems with storage that combines a long-term model (30-year interval, monthly time step) with an operations model that simulates a typical week (hourly time step). Inputs for the operations model are selected to match the corresponding results for a particular month and year in the long-term model. The operational simulations are studied to obtain aggregate measures of performance of the storage facility, with results transferred to the long-term model.

It is proposed to extend the model described in this study by incorporating network scale storage in the SWIS in Western Australia.

[21] http://energystorage.org/news/esa-news/us-energy-storage-market-grow-250-2015-0

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