

# National Bulletin

Bulletin 10 | 2019

## President's article

**Author: Jeff Allen, National President of the Electric Energy Society of Australia**

**Date: 20 October 2019**

As a member of the Energy Advisory Panel of Engineers Australia, I have been involved in reviewing an "Energy Policy Position Statement" that Engineers Australia is preparing. The overall approach for this position statement is that "Engineers Australia recommends that governments at all levels focus energy policy reform on three overarching issues -

- managing the energy transition,
- extracting value from energy and
- building long term resilience".

If we consider the first point of "managing the energy transition," over the last 10 to 20 years we have seen

- The rise of coal seam gas technology that has made Australia the largest LNG exporter in the world. This has had a major impact on local gas prices and in addition there has also been an issue with availability of sufficient gas supplies in certain areas around Australia
- Growing concern regarding the ongoing use of coal as a fuel source (both here and for export) due to its impact on greenhouse gas emissions. Hence the major power stations that are coming to the end of their economic life will not be replaced with coal fired stations – thus creating a "baseload generation issue."
- The highest rates of rooftop solar photovoltaic panel uptake in the world. Rooftop solar penetration has reached the point where a choice needs to be made between distribution networks spending many millions of dollars on new major substations and "poles and wires" to cope – or start delivering the "grid of the future" so consumers aren't landed with unnecessary future costs.
- Increasing development of large "solar farms" – often in remote areas and thus often requiring investment in upgrading the sub-transmission network to allow their connection.
- A growing interest in producing hydrogen that can be used as a fuel source (for electricity production as well as transport)
- Debate about the possible use of Nuclear power in Australia

We know that the costs of "renewable technologies" have been reducing and are reaching commercial price points that are competitive with highly mature conventional technologies – and hence we expect to see ongoing expansion in this area.

Thus - some of the key areas of change that I see occurring over the next ten years are

- The falling costs of both large and small-scale renewables and other distributed energy resources are driving their rapid deployment. Government subsidies are assisting this growth.
- Distributed energy resources are seen to be changing the role of a distribution network operator (DNO) to that of a distribution system operator (DSO).



**Jeff Allen**  
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## Affiliations



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- The changes in the mix of electricity generation require new methods for managing system frequency and stability.
  - The move to a DSO role requires the use of active network management solutions involving smart metering, energy market oriented control and monitoring of distribution networks (down to the customer level), distributed generation, microgrids, energy storage and customer installations – that is - a very complex “grid of the future” with two way flows of energy.
  - In addition, the dynamic behaviour of the transmission and distribution systems, specifically two-way flows of energy, provides new challenges for effective transmission and distribution network planning and operation.
  - Customer choices are also more directly driving investment trends by increasingly valuing services that use energy, such as home heating, cooling, water heating, electric vehicles and pool pumps, among many others.

Storage technologies are seen to be a key opportunity, not only for the transition to a new energy mix but also for reduction in greenhouse gas emissions. Major energy storage solutions currently range from conventional pumped-storage plants to advanced battery-based systems.

There is a view that Pumped-Storage power plants have somewhat limited potential in Australia due our water constraints, which means we have to find alternative storage technologies that will accommodate large volumes of electricity. Battery storage solutions have made huge advances in recent years with a number of utility-scale batteries connecting to the grid.

The drawback with all of the above is that they offer storage periods measured only in minutes or hours. Researchers are therefore focusing on solutions that will convert electricity into forms of energy that lend themselves to long-term storage, such as hydrogen, as well as chemicals such as ammonia and methanol.

Hydrogen storage therefore is seen to be a key enabling technology for the advancement of hydrogen and fuel cell technologies in applications including stationary power, portable power, and transportation. The concept supporting all this is that Hydrogen is an improved storage medium compared to batteries. Thus, excess Wind and Solar power can be used to create Hydrogen. This hydrogen then can then be stored and converted back into electrical power in gas turbines as required. Thanks to this so-called reconversion process, energy is available whenever it is needed for a number of uses in the generation area, the transport area (using fuel cells) and manufacturing/industrial and agricultural areas. In addition, there are major export opportunities.

The overall response to “managing the energy transition” has to date (in my view) been reactive and piecemeal. A more forward looking and proactive approach to the integration of these new technologies into the electric energy “market” is required to provide the planning foresight necessary to transition efficiently to the energy system of the future.

# Contents

|   |         |
|---|---------|
| AEMO provides vision of our future energy generation mix      | Page 4  |
| AEMC proposes major overhaul of rules for connecting ...      | Page 6  |
| Hydrogen -hype or happening?                                  | Page 7  |
| Home battery storage standard upsets industry players         | Page 8  |
| Power supply to the Daintree still in the too hard basket ... | Page 9  |
| The age of the Syncons  | Page 10 |
| International Articles  | Page 17 |
| History   | Page 32 |
| Humour Corner   | Page 33 |
| Cired Paper   | Page 34 |
| Updates on Working Groups                                     | Page 34 |
| Competitions  | Page 36 |
| Announcements   | Page 36 |
| What's on at EESA   | Page 37 |
| Thank You   | Page 41 |

Disclaimer: The views and opinions expressed in the articles in this bulletin are those of the author and do not necessarily reflect the official policy or position of the Electric Energy Society of Australia (EESA).

## AUSTRALIAN ARTICLES

### AEMO provides vision of our future energy generation mix

**Author:** Terry Miller

**Date:** October 2019

**Source:** AEMO

AEMO's stated aim of its 2020 Integrated System Plan (ISP) is to provide an actionable road map for navigating Australia's secure and reliable energy future. Its objectives are to maximise value to energy customers, leverage existing technologies and emerging innovations, and to inform and engage policy makers, investors, customers, researchers and other energy stakeholders.

On 10 October AEMO presented the outcomes of its preliminary modelling at a stakeholder workshop. This modelling followed recent feedback from a range of stakeholders.

Following further stakeholder feedback from the October workshop, AEMO proposes to publish a draft IPA on 12 December. This will be followed by a further round of consultations culminating in the publication of the final ISP in June 2020.

The full 77-page presentation to the workshop can be viewed from the AEMO link above and is recommended reading.

There are a number of interesting graphs and charts included in the presentation.

One of interest is the projected generation mix for 2040, which is reproduced below.

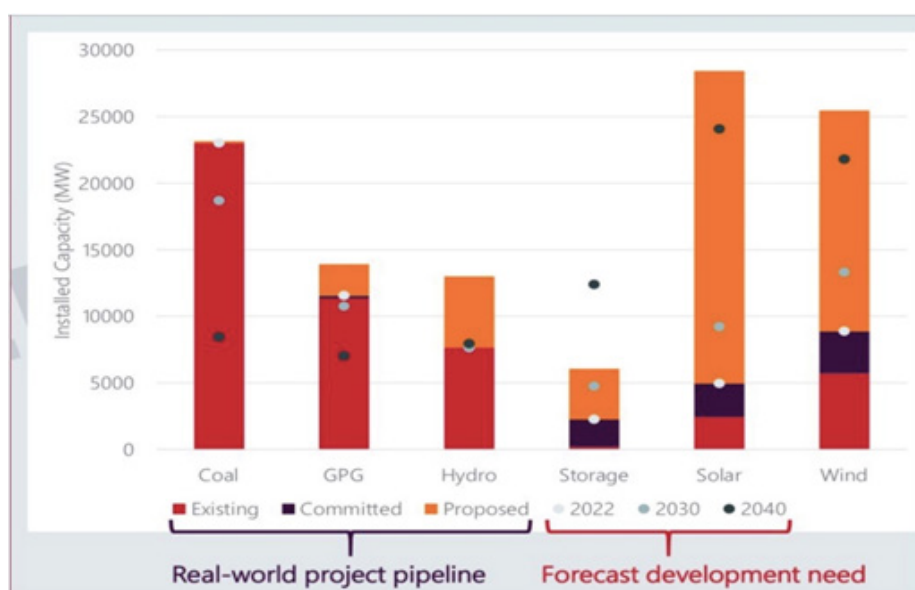
This highlights the advantage of further solar stations in western NSW and the need for transmission links to capture their output. The article is worth reading:

This shows the forecast decline in coal fired capacity from existing, with no new projects proposed and a number of retirements announced, and a substantial increase in solar and wind capacity from projects already committed or proposed.

Most significant is the forecast need for substantial storage capacity that is currently not proposed, let alone committed.

AEMO predicts that changing load patterns will impact the need for traditional baseload, mid-merit and peaking generation.

The outcome of this prediction is clearly revealed in the 24 hour forecast demand curves for February 2020 and February 2040 shown below. (I assume these are for NSW although it is not specifically mentioned in the presentation. In any case they are typical of what is predicted to apply generally across the nation.). Note the substantial increase in "behind the meter" generation from rooftop solar PV and, in particular wind.



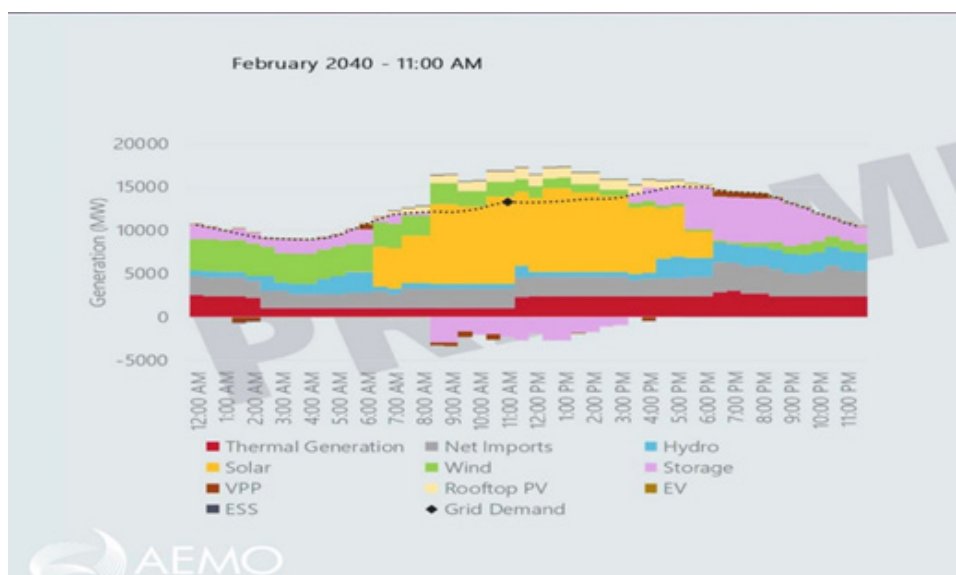
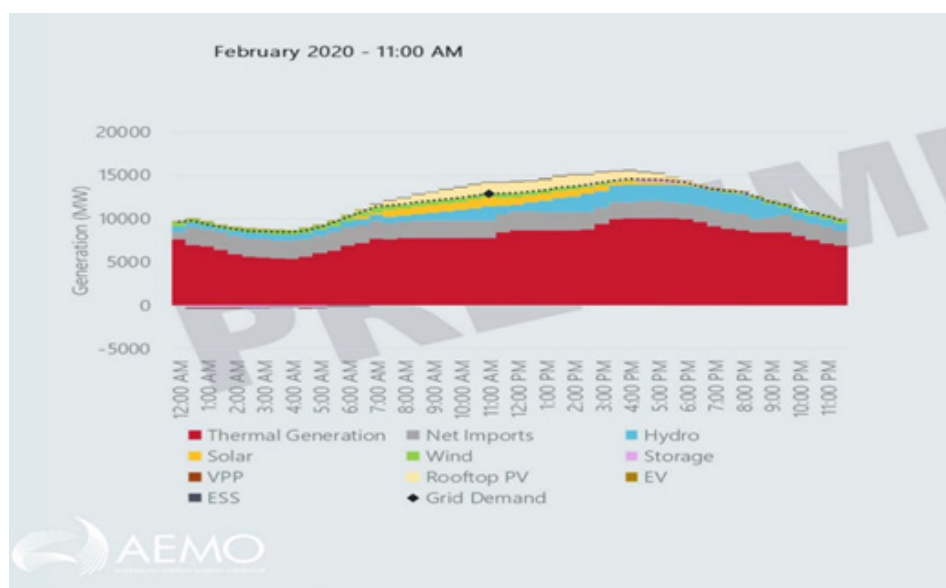
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## AEMC proposes major overhaul of rules for connecting generation and storage to the grid.

**Author:** Terry Miller

**Date:** October 2019

**Source:** [Australian Energy Market Commission](#)

The AEMC has released proposals to overhaul wholesale pricing and transmission access to lower the costs and risks of connecting new generation and battery storage into the grid.

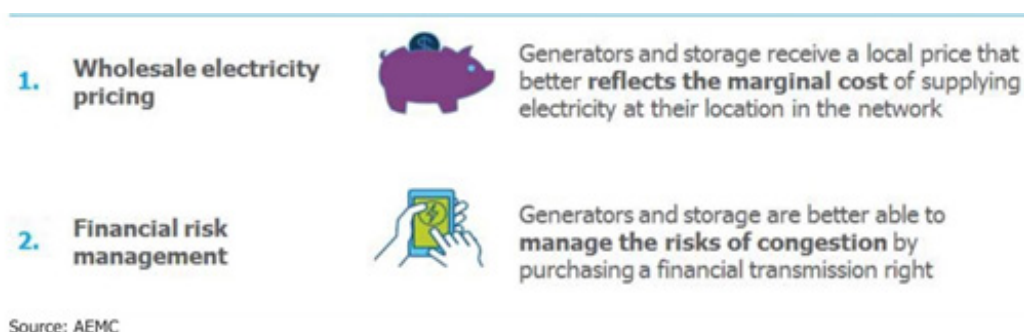
The COGATI (coordination of generation and transmission investment) blueprint redesigns the market to make sure that new generation and storage are connecting to the power system in the right place and at the right time to meet future needs.

AEMC Chairman John Pierce said the increasing growth of dispersed renewable generation and storage across the national electricity market means comprehensive market reform is needed to effectively integrate these new resources. The reforms are also needed to stop lower-cost generators being cut off congested networks.

The AEMC has released two discussion papers, which can be accessed from the link at the top of this article. These are:

- Coordination of generation and transmission infrastructure proposed access reform model, and
- Renewable energy zones.

The proposed reforms are aimed at creating better investment signals for generators to locate in more cost-effective places, and make it possible for them to use the transmission network more efficiently:



The announcement also includes reforms focused on make renewable energy zones happen faster across the market. The AEMC aims to introduce locational investment signals to the market which would encourage generator and investors who want to build large-scale renewable power stations and storage. Other new tools would deliver assured access to the grid. If the level of generator commitment supports the renewable energy zone, networks would work out the best way of delivering the capacity and the investment would continue to form part of its regulatory asset base.

Under the reforms proposed, generators and storage will receive a local price that better reflects the marginal cost of supplying electricity at their location in the network. In addition, the generators and storage will be better able to manage the risks of network congestion by purchasing a financial transmission right. (The issue of allocating capacity rights to competing generators (and consumers) in existing transmission and distribution networks has been a vexed one to date.)

The proposed model shares considerable similarities with common electricity market designs elsewhere, particularly in the US and New Zealand. The underlying rationale for the market designs elsewhere are the same – to provide appropriate, location specific price signals for generation and transmission network service providers, and the tools to allow them to manage risks.

However the AEMC's proposal reflects the unique features of the Australian NEM, including that it is a relatively long, stringy power system, as well as it having a formal wholesale spot market which sits alongside the contract market.

Under the current market framework, all market participants (generation and load) either receive or pay a single regional reference price regardless of where they are located in a region.

The AEMC proposed changes will see generators and storage receiving a “local price” that more accurately represents the marginal cost of supplying electricity at their location, taking into account both congestion and losses.

These changes should improve incentives for scheduled and semi-scheduled generators and storage to operate efficiently. These parties should have greater certainty over their revenue and should be better protected from changes due to congestion and loss factors. In turn, this should lead to a reduction in the number of generators bidding “unavailable”. This increased generation will be available to meet demand and so increase the security and reliability of the network.

The introduction of dynamic regional pricing is aimed at eliminating “race to the floor” bidding by generators when the system is congested, where generator bid to the floor price in order to maximise the chance they should be dispatched. They do this because they are unlikely to influence the price they actually receive, and are instead trying to maximise their dispatch through the congested system. This may be particularly important for generators who are contracted, who need to match the volume they physically deliver to the market with their contractual positions to avoid having to buy on the volatile spot market to cover their contracted commitments. This is currently contributing to higher electricity costs for consumers, because the generators actually dispatched are not necessarily the lowest cost combination.

Better locational operational and investment decisions should, in turn, result in a more efficient transmission network over the longer term, ultimately lowering costs for consumers.

Finally the AEMC considers that dynamic regional pricing improves the efficiency of dispatch by more accurately measuring the effects of losses and constraints within the system. Introducing dynamic loss factors will help to ensure the lowest cost combination of generation is dispatched at any given time.

The second aspect of the reforms aims to improve the financial risk management options for generators, storage, retailers and other market participants.

The AEMC proposes to enable scheduled market participants exposed to their local price to better manage the risks of congestion and transmission losses by being able to purchase financial transmission rights. These will hedge against the price differentials that arise under dynamic regional pricing due to congestion and losses.

## Hydrogen -hype or happening?

**Author:** Terry Miller

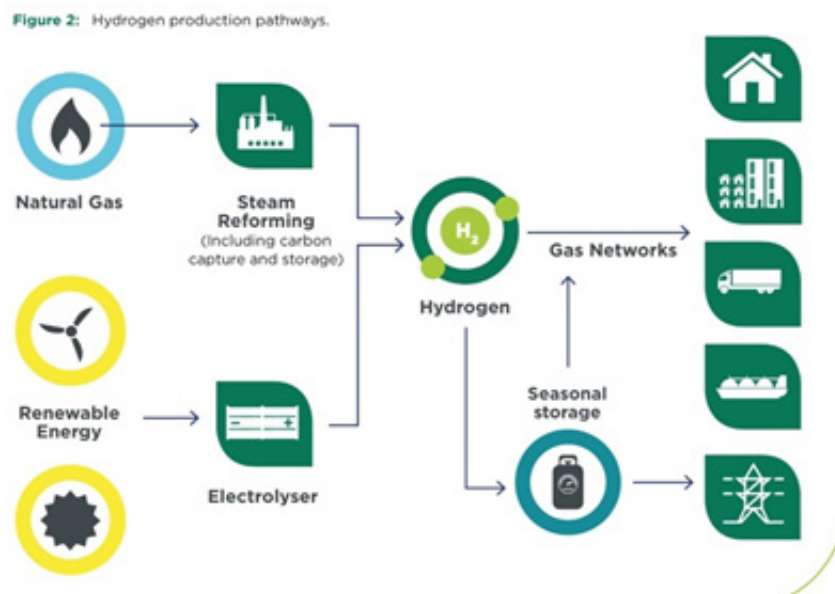
**Date:** October 2019

**Source:** [Energy Networks Australia](#)

This month Energy Networks Australia (ENA) and the Australian Pipelines and Gas Association (AGPA) released their report “Hydrogen Innovation: Delivering on the Vision, the latest chapter of their Gas Vision 2050 which was launched two years ago. The picture below summarises the report very succinctly:



While the report is focused on the use of hydrogen in gas networks and the “decarbonization” of reticulated gas, it highlights the increased focus on hydrogen as a flexible energy source that can be created either by electrolysis from (in particular) renewable electric energy or by “steam reforming” from natural gas, and then stored:



Electrolysers can act as flexible demand that can be paired with intermittent wind and solar to take advantage of excess renewable generation, providing value both to renewable generation as well as hydrogen production and use sectors. As the renewable generation sector expands, the opportunity for large scale renewable hydrogen production grows with it.

Renewable hydrogen is already being produced in Canberra and Perth and by mid 2020 two more projects (in Adelaide and Western Sydney) will come online. Across these projects more than 2 MW of hydrogen production capacity will be installed. Supporting research and development can produce new technologies to lower the cost of hydrogen capacity and accelerate the transition to hydrogen. It is expected that the cost of hydrogen will be compatible with natural gas within the next five to ten years.

The implications for electricity generation and storage are immense.

The initiatives detailed in the Report are being undertaken in advance of the Australian Government's National Hydrogen Strategy that will position Australia to leverage its competitive advantage in hydrogen production to grow both domestic and export markets.

## Home battery storage standard upsets industry players

**Author:** Terry Miller

**Date:** October 2019

**Source:** [One Step Off The Grid](#)

The much awaited revised version of AS/NZS 5139:2019 “Electrical Installations- Safety of battery systems for use with power conversion equipment” has not alleviated the concerns of the nascent Australian home energy storage sector, which claims it is bracing for a “massive brake” on new installations due to restrictive provisions related to potential fire hazards.

An earlier draft of the standard, that threatened to effectively ban the installation of lithium-ion batteries inside Australian homes and garages altogether, was scrapped in late 2017 after a major industry backlash.

Some industry members now claim that despite the promise of closer industry consultation, the revised and now final version of the Standard is not much better.

The new Standard permits batteries in “non habitable” rooms such as laundries and garages, but only in compliance with rules relating to



positioning and fire proofing. These include the use of compressed fibre cement sheeting on any walls connected to habitable rooms and a restriction on installing batteries close to any doors, windows, ceilings, stairs or un-associated electric appliances.

Well established companies like Tesla and Sonnen, who have installed hundreds of thousands of home batteries in the US and Europe (none of which have spontaneously combusted to date), find the new provisions confounding.

Sonnen Australia's James Sturch, who represented the battery maker in the Standards Australia process, claims that home batter storage is going to be really hard, complicated and expensive and will put a massive brake on the entire industry, adding about \$1000 minimum to the installation cost of most systems.

The industry complains that there will be a lot of systems, particularly (ironically) the larger ones like the Tesla Powerwall 2 and Sonnen Batteries that are already enclosed in their own fire proof containers, that will be almost impossible to install at all inside the majority of Australian homes or garages.

Battery makers also argue that the rule could have the opposite of the desired effect, by encouraging customers to see all storage systems as the same, regardless of the efforts the manufacturer may have gone to make their product safe. The standard's lack of discrimination between different products means customers will focus on price over a safety and technical specifications.

Standards Australia has argued that any standard is better than no standard when it comes to consumer safety, and that amendments can and will be made, and that it is expected that the will be future refinement of the new standard as the industry evolves.

The Smart Energy Council said it welcomed the new standard as a necessary step to protect consumers, but would be seeking changes to some of its provisions to bring it in line with its own "Best Practice" guide. It has indicated that it will be seeking an early and fast -tracked amendment process to remedy what it sees as a flawed section.

## Power supply to the Daintree still in the too hard basket - a case study in the challenges of electricity supply to remote communities

**Author: Terry Miller**

**Date: October 2019**



Earlier this year I holidayed in Far North Queensland. A highlight was a visit to the World Heritage Listed Daintree region, a long narrow coastal strip bounded by a steep, heavily forested mountain range to the west and the ocean to the east, and extending from the Daintree river in the South to Cape Tribulation in the North. A narrow winding road with steep, heavily forested sides provides the only access to the region, which consists of a string of small communities. The main commercial activities rely on tourism. The electricity demand is approximately 6 MW for a permanent population of approximately 130, swollen by 400 000 tourist visitors each year. Virtually all development is alongside the 50 km long road. It is a unique area.

Apart from pure geographical constraints, environmental concerns for the sensitive Daintree rainforest have prevented grid reticulation to the area to date.

Residents and businesses rely largely on diesel generators, themselves an environmental concern. Individual solar and wind installations are usually impracticable due to the high, dense tree canopy that covers a large proportion of the area. Larger scale solar farms in some of the rare cleared area are feasible, but would then require backup generation or storage and local grid reticulation.

I became aware from the local press that the provision of grid supply to the Daintree has been a political issue and an engineering challenge for decades, with commercial businesses wanting a solution other than costly diesel, and environmentalists fearful of the impact of grid supply while at the same time not happy with diesel generators. The area has been excluded from Ergon Energy's supply territory and successive state governments have been unable to find an equitable, reliable, economic and environmentally solution to the challenge.

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The Australian Renewable Energy Agency (ARENA) commissioned a study [Powering Daintree](#), published in 2018 (as best I can gather, as it is undated). The report examined five scenario options for supplying the whole Daintree community.

These were:

1. A single electrical (underground) microgrid with synchronous generators and a stage pathway for high renewable uptake. (This was the preferred option).
2. Three separate electrical microgrids
3. Gas microgrid with high renewable uptake using power to gas and biomethane
4. Microgrid supply to Cape Tribulation only (the largest centre in the region)
5. Upgrade of individual Remote Area Power Supply options.

A subsequent report by KPMG, [Daintree Electricity Supply Study](#), was commissioned by the Queensland Government and published in September of this year. It examined similar options and concluded that a single microgrid would supply a reliable and secure energy network but would present numerous technical and commercial risks and is likely to be financially unviable without significant upfront and ongoing Government support.

The report also concluded that Standalone Power Systems (SPS) -ie the status quo -better preserve the existing natural and cultural heritage values of the Daintree, but there are limited short term solutions to materially improve on existing arrangements. Reactions from politicians and local residents to these two reports have been varied. It would appear that the engineering, environmental and political issues will not be resolved in the foreseeable future.

If you get a chance to visit the Daintree, take the opportunity to examine and reflect on the challenges facing engineers and governments in trying to solve the many problems in providing an economic, reliable and environmentally friendly electricity supply to the region. And enjoy the beautiful scenery as well.

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## The age of the Syncons

**Author:** Verity Watson

**Date:** 26 September 2019

**Source:** [Energy Insider](#)

**South Australia now generates more than half its electricity from renewable sources. Less reliance on synchronous generators, such as coal or gas-fired generation, means less stability in the power system.**

In October 2017, the Australian Energy Market Operator (AEMO) declared a shortfall in system strength in South Australia and specified that system strength services were required on an ongoing basis to keep the grid stable. In November 2018, AEMO also issued the same direction to a generator in Victoria and the following month, declared an inertia shortfall in SA. The latter led to the planned deployment of high-inertia synchronous condensers by ElectraNet.

The Australian Energy Regulator has approved a \$166 million investment by ElectraNet for the four synchronous condensers, which will act as shock absorbers to fluctuations in energy supply. Installing these synchronous condensers on the transmission network has been identified as the most efficient and least-cost solution in the short to medium-term to stabilise the grid.

### What is system strength?

*System strength is important as it relates to the ability of the power system to withstand changes in supply or demand while maintaining stable voltage levels.*

*When system strength is low, generators may not be able to remain connected to the grid, control of the power system voltage level becomes more difficult and protection systems (which control and maintain the safe operation of the network) may not operate correctly. This can result in supply interruptions to customers.*

*System strength is typically provided by synchronous generation such as coal or gas-fired generation or pumped hydro.*

### What are synchronous condensers?

*Synchronous condensers are an old technology, commonly used as far back as the 1950s to stabilise power systems.*

*They are large machines which spin freely and can absorb or produce reactive (Alternating Current – AC) power in order to stabilise and*

strengthen a power system.

Synchronous condensers help when there are changes in load as they increase network inertia. The kinetic energy stored in a synchronous condenser contributes to the total inertia of the power system and is beneficial from a frequency control perspective.

## What is inertia?

Inertia in the energy system refers to the continuous momentum of energy typically provided by the large spinning turbines of synchronous generators like large coal-or gas-fired power stations. This type of generation helps withstand changes in generation output and load levels to keep the system stable. The retirement of synchronous power plants and more renewable generation coming into the energy system means there is less inertia available, so flexibility or stability must be found elsewhere in the system to back it up.

A secure power system needs adequate levels of system strength and inertia. When there is not enough of these services, there is an increased risk of system instability and supply interruptions.

AEMO declared minimum requirements which ElectraNet must address to support the electricity system. New renewable generators also must ensure the impact of their connection does no harm to the power system.

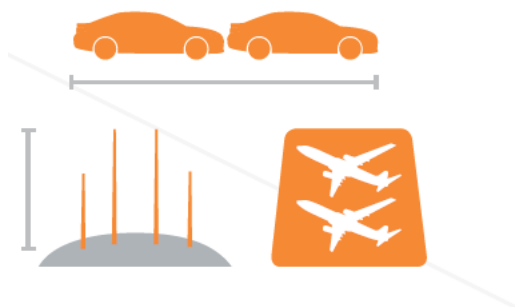
ElectraNet's synchronous condensers will strengthen the SA power system and ensure there is adequate system strength and inertia. While the \$166 million project cost will be recovered from customers over a 40-year period, it will be offset by avoided costs of AEMO market directions estimated at about 34m\$pa[3]. The new synchronous condensers will result in an estimated net saving of \$3 to \$5 a year on a typical residential customer bill.

## Do no harm

During the planning phase for new connections, grid studies are undertaken to ensure new renewable connections do no harm to the grid. These requirements can be achieved by the generators installing synchronous condensers or in renewable energy zones sharing the costs of a more cost-effective larger synchronous condenser across a number of generators. The Australian Energy Market Commission rule change on the transparency of new generator connections will be helpful to allow generators to consider more cost-effective connection to the grid.

## Fun facts

The synchronous condensers to be installed in South Australia (see map at Figure 1) are almost as tall as the AFL goal posts or the length of two Toyota Corollas parked end to end. They are also heavy, weighing more than two Boeing 737 planes!



## Where are they being installed?

The first two synchronous condensers will be installed at Davenport by mid-2020 and the second two at Robertstown by early 2021.



**Figure 1: Installation locations of ElectraNet synchronous condensers (Source – ElectraNet Information Sheet, Installation Sheet, Aug 2019)**

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### Are synchronous condensers the future for a renewable grid?

As more renewables such as solar and wind generators connect to the grid, traditional synchronous coal and gas-fired generators operate less often or may even become uneconomic.

Synchronous machines have provided system strength for free in the past, but these services are becoming less available in sufficient quantities. Hydro-electric schemes or pumped hydro can also provide system strength services depending on the technology deployed. However, in a dry state like SA, there is not the water resource or mountainous terrain required to support them – like there is for Snowy or Hydro Tasmania.

Recent Australian National University research has indicated that the growth in renewables is four to five times faster per capita in Australia than the European Union, Japan, USA or China and ten times faster than the world average<sup>[5]</sup>.

Conventional synchronous plants respond naturally to changes in frequency with an immediate response. Synthetic inertia could also be provided to emulate the behaviour of synchronised spinning machines. It's all about the response timing and the ability to operate in sub-seconds. Inverter settings of grid-connected renewables can be reprogrammed to emulate the behaviour of synchronised spinning machines. Synthetic inertia could also be provided by battery energy storage systems and other technologies, subject to the speed of the response to grid disturbances.

As Australia transitions to increasing amounts of renewable generation, over time there will new technologies that can support the power system. But for now, expect the age of synchronous condensers to continue to enable the transition to a lower emissions grid.

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## Lord Howe Island renewable energy project

**Author:** Terry Miller

**Date:** October 2019

**Source:** [Australian Renewable Energy Agency](#)

ARENA has announced the Lord Howe Island Hybrid Renewable Project, which will add more than 1.2MW of solar generating capacity and over 3.2MW of battery storage to the current diesel power generation system on the island.

Lord Howe Island currently relies totally on diesel fuel for its electricity supplies. This is transported to the island by a small freight ship, which comes to the island every two or three weeks.

The project initially aimed to install 1MW of combined solar and wind powered generation, with no battery storage.

The Lord Howe Island Group is inscribed on the UNESCO World Heritage List in recognition of its outstanding biodiversity, uniqueness and international importance, and is an iconic tourist destination.





## DNSPS to provide stand-alone power systems

Author: Anne-Marie Mina

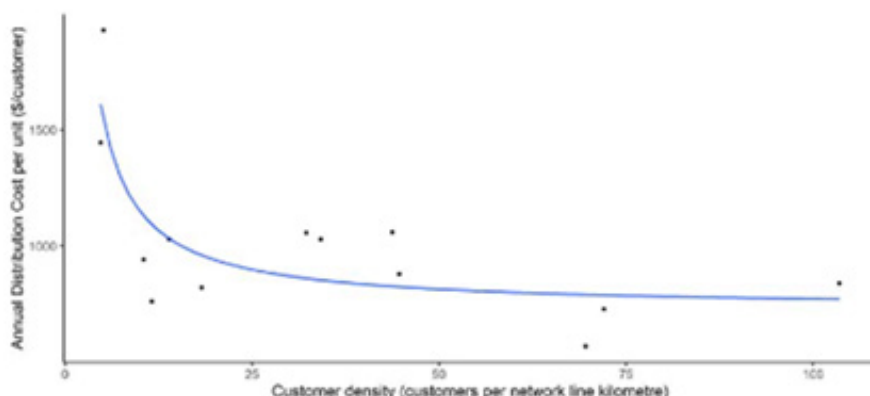
Date: 24 September 2019

Source: [Energy Storage Alliance](#)

On 30th May 2019 the Australian Energy Market Commission (AEMC) released its final report on the "Review of the Regulatory Frameworks for Stand-Alone Power Systems – Priority 1". The report sets out the recommendations from the Commission for regulatory change which allows Distributed Network Service Providers (DNSPs) to create their own Stand-Alone Power Systems (SAPS)...and the implications for this are huge. (Editor's note: The AEMC is currently developing the required regulatory and rule changes to implement these recommendations.)

The National Electricity Market (NEM) consists of approximately 40,000 kilometres of transmission lines and 850,000 kilometres of distribution lines. The NEM serves approximately 9.7 million customers and there was \$17 Billion traded on the NEM in financial year 17/18. The NEM represents the largest amount of electrical infrastructure per capita of any electrical grid in the world and is one of the world's longest continuous end-to-end interconnected power systems running 5,000km from Port Lincoln to Port Douglas. In short, the NEM is big.

In order to support the NEM, there exists a cross subsidy whereby the cost to service remote electricity customers is socialised and therefore inflates the cost borne by the rest of connected electricity users. Remote customers can cost DNSPs five times as much as an urban customer to serve.

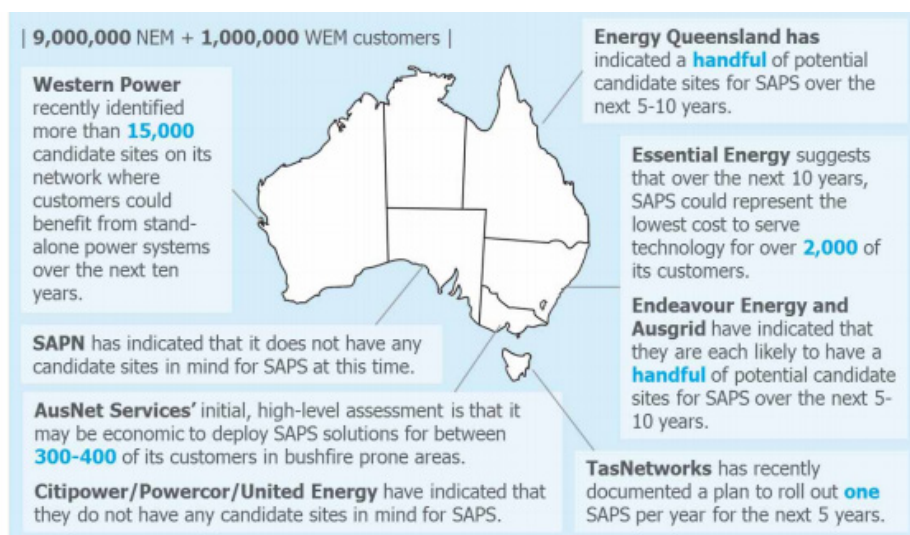


An example of how this plays out: South Western WA (not part of the NEM but overseen by the AEMC) has over 50% of its High Voltage infrastructure dedicated to just 3% of its customers. And this is not atypical of Australian networks.

The report suggests that remote customers would receive higher quality service at a lower cost if the DNSP which currently serves them creates a Stand-Alone Power System to do so. The flow on would be lower costs for DNSPs, better service for remote customers and cheaper electricity distribution for all customers. The report attempts to capture the opportunities for SAPS across all Australian networks as per the below figure.

Figure 1:

<https://www.aemc.gov.au/sites/default/files/2019-05/SAPS%20Priority%201%20Final%20Report%20-%20FOR%20PUBLICATION.pdf>



Source: AEMC

Though the report was light on opportunity details, suggesting that there were a “handful” of opportunities, networks have been quoted (via <https://reneweconomy.com.au/off-the-grid-aemc-paves-way-for-stand-alone-systems-to-replace-poles-and-wires-44240/>) giving big savings estimates:

- Western Power argued it would save \$400 million/year when they lobbied for a similar rule change in 2016
- Essential Energy in NSW said it identified savings of more than \$220 million due to this potential rule change
- Energy Queensland said that the savings could be in the order of \$600 million.

Therefore, NEM wide, the savings could be in the billions of dollars.

The report lays out the models of supply in order to address the structure of how a DNSP led SAPS system would look. It sets out four models of supply:

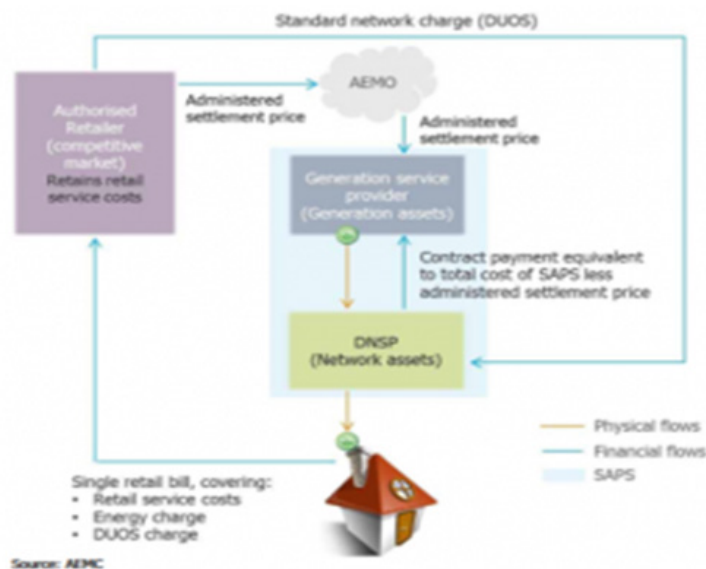
1. Standard NEM Supply: This is the traditional NEM setup with centralised generation, transmission, distribution and end-users on the demand side.
2. Embedded Network: This network structure was defined by a number of rule changes made over the past few years (see Power of Choice Review) and allows private networks and retailers to connect behind a parent meter which ultimately interfaces with the NEM (think shopping malls with many tenants where the shopping mall owns its own electricity infrastructure and on-sells energy to its tenants)
3. Individual Power Systems: These are the traditional SAPS which exist independent from the grid (think homes and villages which are off-grid and not governed by NEM rules)
4. Microgrid (defined as “isolated from the interconnected grid”): These are Stand Alone Power Systems which contain their own generation, distribution and loads and, as the report suggests, will be governed by the National Electricity Law (NEL), the National Energy Retail Law (NERL), the National Electricity Rules (NER) and the National Energy Retail Rules (NERR) after the rule change is complete.

The report gives recommendations for the creation of microgrids in five areas:

1. Planning and Engagement:
  1. DNSPs existing network planning and investment framework is deemed as satisfactory including the Regulatory Investment Test for Distribution (RIT-D)
  2. DNSPs will be required to report on SAPS opportunities, implementations and projects considered and will need to keep metrics on customer transitions and total SAPS implemented
  3. DNSPs will NOT be required to obtain explicit consent from customers in order to transition them to off-grid supply.
  4. DNSPs must develop a SAPS customer engagement strategy and must issue formal, public notice to affected parties.
  5. AEMO suggests that customer consent will at least be implicit as they will need to be engaged to ascertain land requirements, load profiles, planned load growth and other technical requirements.
2. New Connections and Reconnection
  1. New customers seeking SAPS will enter a competitive market where DNSPs and 3rd parties will provide SAPS at cost-reflective prices (not required to subsidize service as with existing customers)
  2. Customers should NOT have a specific, additional right of reconnection to the interconnected grid (AEMC views the SAPS as the DNSPs grid)
3. Service Classification
  1. SAPS will comprise two components, each providing a separate service:
    1. A Stand-Alone Distribution System
    2. A Generating System
  2. DNSPs will be allowed to operate the distribution system but must procure generation from a 3rd party or subsidiary via the AER's ring-fencing guideline.
4. Consumer Protections and Reliability
  1. The existing energy-specific consumer protection framework is fit for purpose with regard to SAPS, including the National Electricity Customer Framework and jurisdictional consumer protections.
  2. AEMC recommends that jurisdictional governments update their legislative frameworks.
  3. The NERL will apply energy-specific consumer protections to SAPS customers.

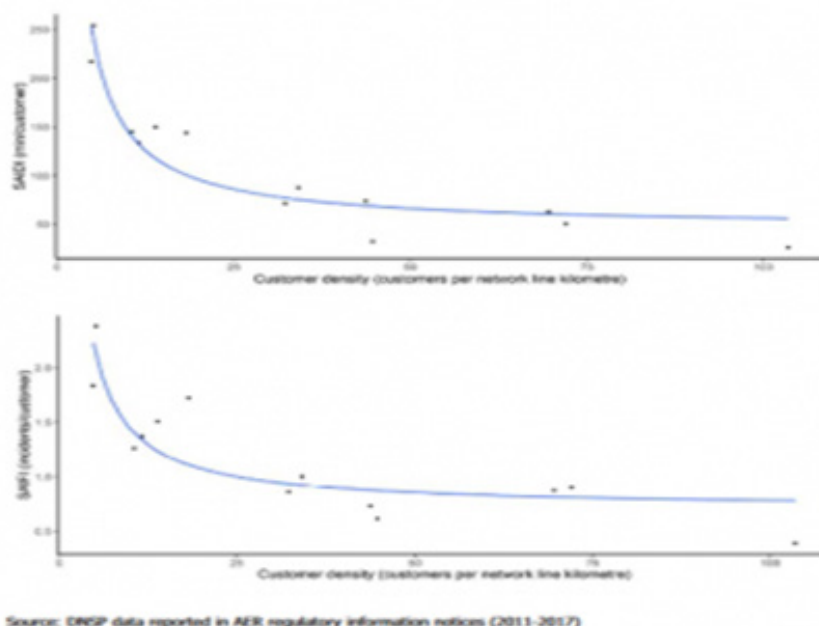
## 5. Service Delivery Model

1. AEMC suggests that the existing wholesale energy market arrangement (with regard to retail) is fit for purpose except, instead of 5 min settlements, retailers will be charged an administered settlement price for energy.
2. This way SAPS customers can retain their retailer if they so desire.
3. An administered settlement price simplifies the retail process and removes the risk of inappropriate price signaling or hedging to affect SAPS customers

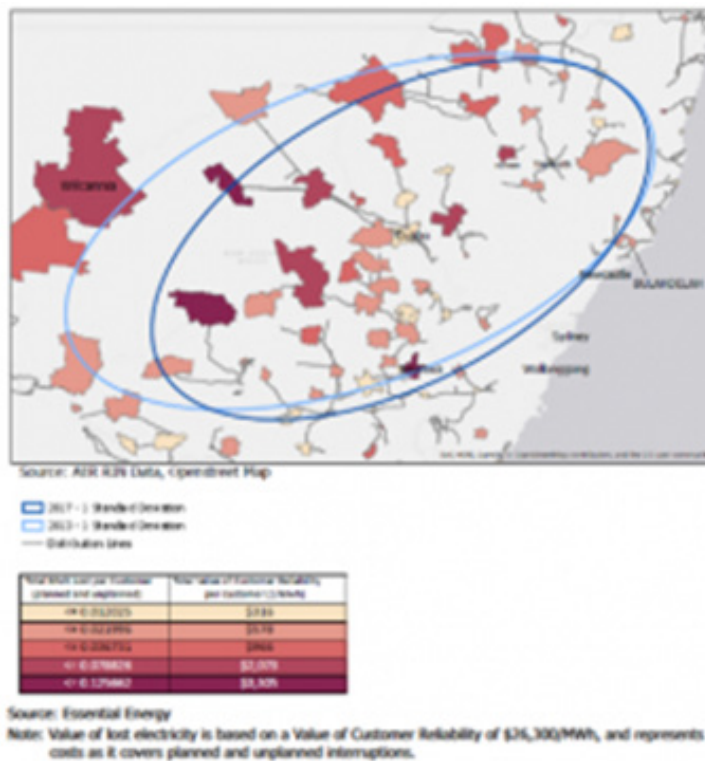


The settlement price mechanism might be the most contentious of the recommendations but it has been put forward as it invokes AEMO, keeping the NEM flavour of the SAPS recommendations. AEMC makes suggestions about the settlement term but says that will ultimately be determined when the rules are drafted. Long settlement periods may leave some opportunity on the table but it creates a simple consumer protection mechanism which is important in the first instance.

The report suggested that SAPS could reduce the duration and frequency of grid outages (System Average Interruption Duration Index or SAIDI and System Average Interruption Frequency Index or SAIFI respectively).



Interestingly, locations which have below average reliability but are more densely populated have a higher economic cost associated with interruptions, therefore the business case for SAPS may not be limited to the very remote. This may make SAPS more interesting than the “handful” of opportunities outlined by the networks initially, especially as solar and batteries continue to move down the cost curve.



The report provided an example of a case where a SAPS would make sense over the commonly used Single Wire Earth Return (SWER) lines. It said that basically any SWER line over 4km should be turned into a SAPS. Australia operates around 200,000km of SWER lines and many of them are likely to be longer than 4km node to load.

The timeline between this rule change recommendation and the actual rule change is likely to be in the order of 18 months. The implications of the rule change are yet to be seen but it seems like the opportunities that this rule change will present will be big.

GSES provide Stand-Alone Power Systems courses which provide a pathway to Clean Energy Council Accreditation. For more information on this article, see GSES at <https://www.gses.com.au/> and for details of the AEMC Draft Report, see (LINK) <https://www.aemc.gov.au/sites/default/files/2019-06/SAPS%20%20Draft%20report%2027%20June%202019.pdf>



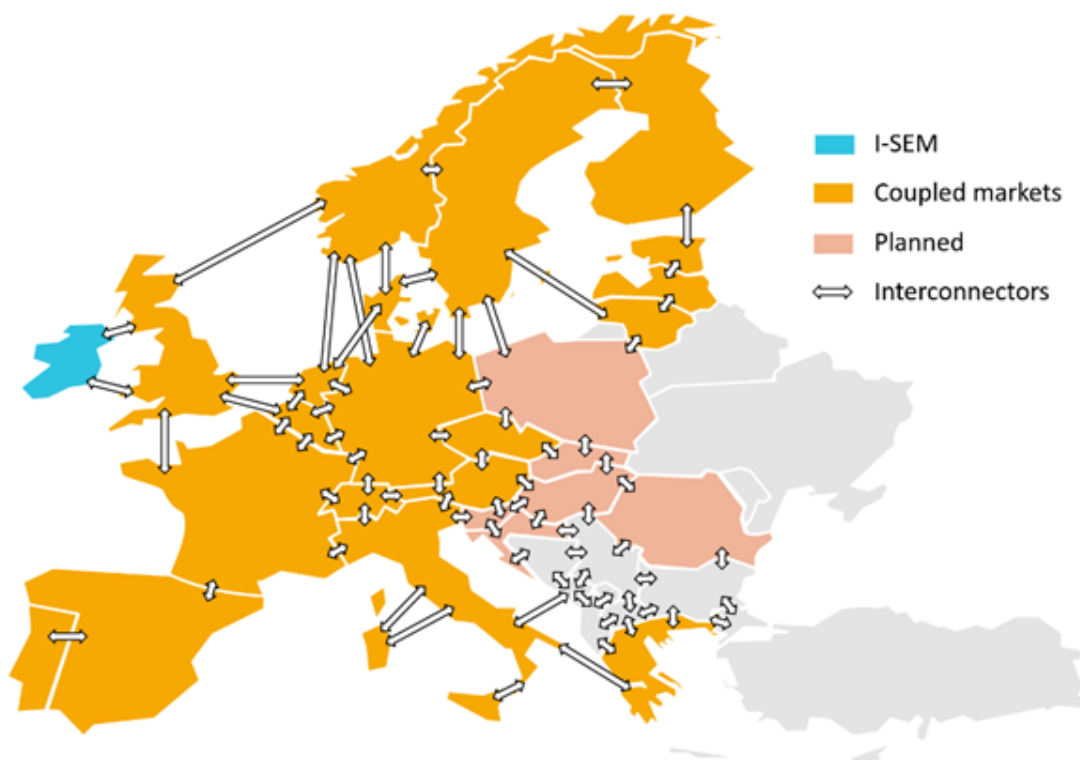
## INTERNATIONAL ARTICLES

### Ireland's new "integrated single electricity market" any lessons for the NEW?

Author: Peter Carruthers, Terry Grimwade and Brendan Ring

Date: 17 October 2019

Source: [Australian Energy Council](#)



The key drivers for change and the goals of the I-SEM project were:

- Compliance with, and efficient implementation of, the European Union target model obligations into Ireland[i];
- Improvements to current market operations, in particular the rational and more efficient use of the interconnector capacity with Great Britain, particularly with increasing wind generation in Ireland;
- Greater participation and opportunities for trading, hedging and arbitrage and,
- Improved security of supply, transparency and integration of the market with system operations.

#### Market Components

The I-SEM market design is comprised of a number of inter-related markets which are outlined below:

##### *Day-Ahead and Intraday Markets*

The Day-Ahead market is a pan-European trading market designed to facilitate greater integration of European markets and more efficiently allocate electricity flows across Europe. Ireland is required to integrate into this market. The Day-Ahead market operates every day and closes at midday, 12 hours ahead of the trading day commencement. Retailers, generators and demand-side participants submit bids and offers into a double-sided auction for supply and demand. In contrast to the NEM, retailers bid their customer load into

the auction process. Interconnector flows are scheduled based on the regional prices and interconnector capacities. Based on their cleared bids and offers in the Day-Ahead Market, generators and retailers will establish an aggregate net position to buy or sell a quantity of energy in each trading period for the day at the Day-Ahead market clearing price.

Financial transmission rights to hedge against inter-region price differentials caused by congestion are available, and typically procured by those participants wishing to hedge their cross-border exposures between Ireland and Great Britain. This is common, as a number of participants are active on both sides of the Irish Sea.

#### *Intraday Market*

After closure of the Day-Ahead Market, there are three intraday auctions and a facilitated continuous local market trading through which participants can trade up to an hour before each 30 minute real time trading period. The intraday markets collectively enable participants to adjust their position closer to real-time. This is most typically utilised when a participant does not establish their desired technical or commercial position in the day-ahead market, to respond to changes on the system (such as outages) and/or to respond to changes in supply (eg wind) or demand forecasts.

#### *Linking the Day-Ahead & Intraday Markets with the Balancing Market*

A participant's final aggregated traded position in the Day-Ahead and Intraday markets represents a financially binding commitment and is actually cleared and settled daily, independently of real time outcomes. The core concept of this is similar to the day-ahead scheduling arrangements in the WEM.

#### *Balancing Market*

This offers the participant the opportunity to set their position ahead of real-time, and therefore:

- Schedule plant accordingly – this is particularly important for demand-side participants.
- Limit financial exposure to on-the-day occurrences.
- Trade any residual or opportunistically around that position.

Participants are required to submit minute by minute physical notifications (PNs) based on their Day-Ahead and Intraday traded positions – initially after closure of the Day-Ahead Market but updated to reflect trading in the Intraday Market, or any change in their physical capabilities. Gate closure is fixed one hour prior to real time dispatch.

In real time, the system operator schedules and dispatches relative to participants' physical notifications.

As for the WEM balancing market, participants have the opportunity to offer bids and offers to adjust their physical notification. The system operator will accept these bids/offers from participants on a least-cost basis to support balancing energy or manage system constraints. A balancing market clearing price is established accordingly. The balancing market determines prices every 5 minute dispatch period, but an average of the 5 minute prices is used to calculate the 30 minute settlement price for each trading period.

A participant's actual real time deviations from its final aggregated ex-ante traded energy position are settled and cashed out for each 30 minute trading period at the balancing market clearing price.

#### *Capacity Market*

The pan-European target model does not include a capacity market. However, in Ireland, there was a pre-existing capacity payment mechanism and the regulators determined that an enhanced capacity market, or "capacity remuneration mechanism" (CRM), was required to reduce the cost of funding capacity.

In the long term, the intention is to conduct annual auctions four years ahead (called T-4 auctions). However, a number of single year auctions (T-1) will be run for a transitional period, with capacity being awarded for 1 year for existing capacity and for up to 10 years for new capacity.

The capacity auctions procure capacity on a "de-rated basis" that reflects the marginal contribution of a one more unit of that technology maintaining the annual reliability of the power system for the year that the capacity is procured for. For example, a gas-fired unit may get de-rated to 90 per cent of installed capacity, whereas a wind unit may get 10 per cent. There is a qualification process to determine the nature of each capacity market unit and all qualified capacity, other than intermittent and new resources, must bid into the auction.

The capacity market results in successful participants being awarded "reliability options". In return for a firm payment for their auction capacity, the capacity provider is required to return to wholesale customers (via the market operator) energy revenues (across all markets) earned above a regulatory set strike price (currently about €500/MWh) on their capacity obligations. The capacity obligations vary across time and may equal their auctioned capacity at peak times but will be lower at other times when demand is less.

Capacity providers can be left financially exposed if not running at the time the strike price applies, though the market does cap their exposure over time. These caps do mean that reliability options may not fully hedge wholesale customers above the price cap, with this cost socialised across consumers.

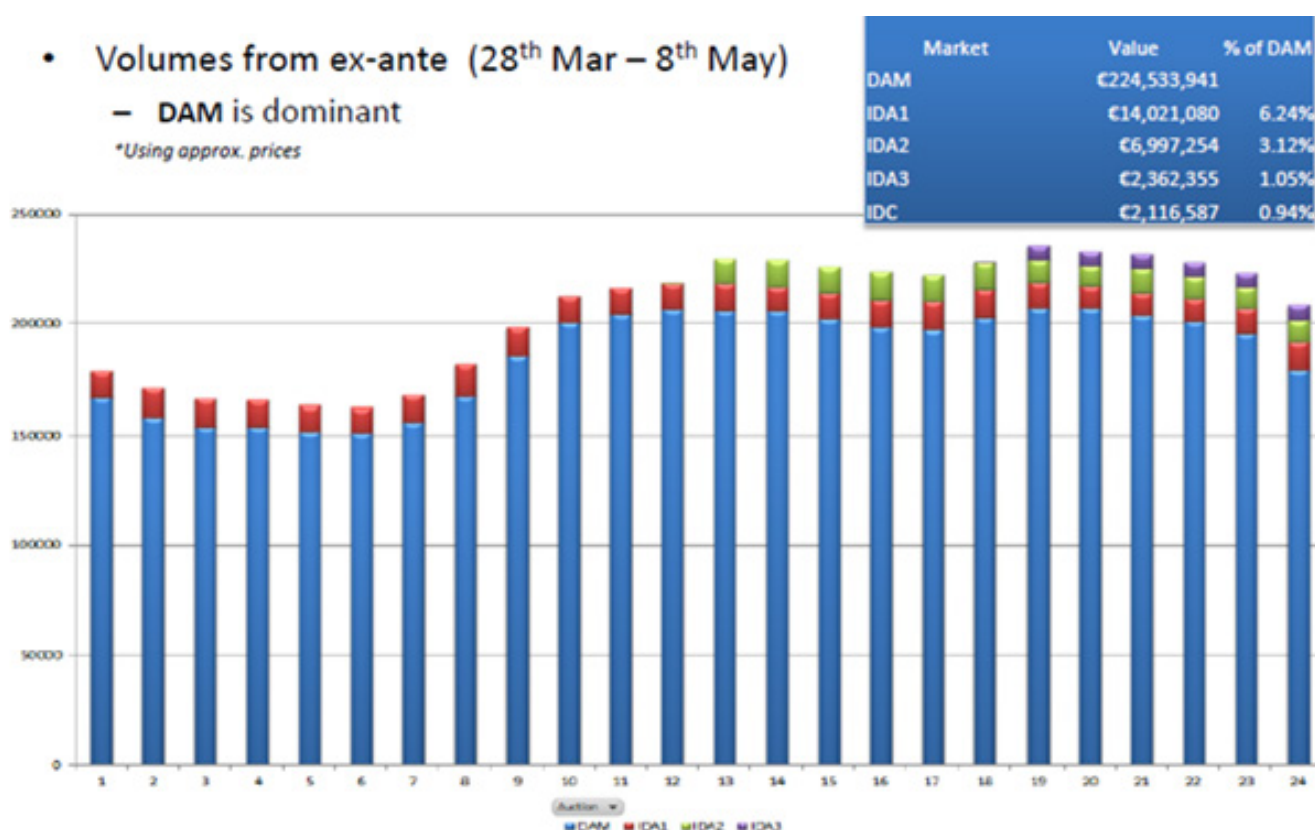
### I-SEM Performance to Date

The I-SEM arrangements went live in October 2018. So what are the early outcomes and issues that have emerged?

#### Day-Ahead/Intraday Markets

The Day-Ahead/Intraday markets have performed reliably with healthy volumes of trading in the Day-Ahead Market, and a gradually increasing volume of trading in the intraday markets (see Figure 2).

**Figure 2: Traded Volumes in Day-Ahead and Intraday Markets**

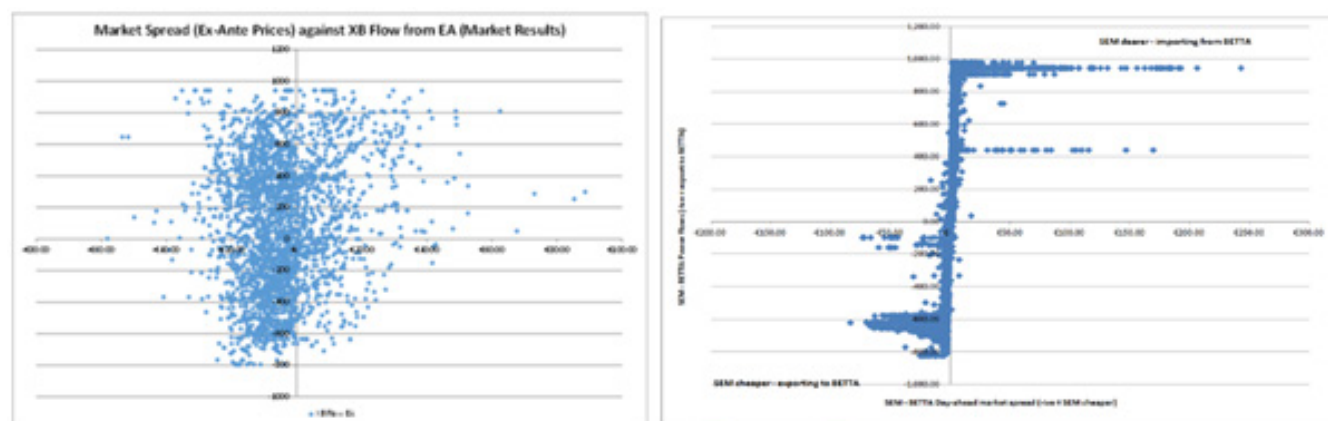


Retailers are securing around 95 per cent of their demand through the Day-Ahead market, leaving around 5 per cent of their load exposed to the balancing market.

Market prices have appeared to be rational, and explainable based on supply and demand conditions with intraday prices increasing nearer to real time. Prices have ranged from 0–€300/MWh, and averaged €72/MWh (around A\$116/MWh).

Importantly, the volumes of trading across the interconnectors with Great Britain are far more rational, based on price differences across the interconnectors, than prior to the I-SEM (see Figure 3).

**Figure 3: Interconnector Flows Before and After I-SEM Go-Live**



### Balancing Market

While a simple concept and capable of relatively simple implementation, in the case of I-SEM there were significant complexities introduced into the balancing market pricing mechanism. Many of these stem from a desire to set a single clearing price which is based purely on energy balancing actions, i.e. bids or offers that are called on purely to balance energy, rather than to deal with system constraints. For example, intra-regional congestion is managed as a system constraint. To some extent, such a separation is largely artificial but the I-SEM design went to some lengths to implement complex mechanisms that attempt to separate out and exclude from the pricing algorithm, bids and offers that are accepted for the purpose of managing constraints.

Participants have struggled to understand some of these complexities and IT vendors have struggled to deliver the required system functionality reliably.

Since market start, balancing market prices have ranged between -1000€/MWh (the price floor) and 5636.62 €/MWh for 5-minute periods, equating to -238€/MWh and 3773.69€/MWh for the 30-minute settlement prices.

While the volatility and range of prices has not, of itself, been a cause for concern, the price outcomes have at times been counter-intuitive. For example, the high price of 3773.69€/MWh was set by a constrained on peaking unit when, overall, the market was long.

The regulatory authorities have since implemented an urgent rule change to remove a number of the complex “system operator flags” in the pricing algorithm to address this and are pursuing further modifications to simplify the pricing algorithm and make it less volatile.

### Capacity Market

There have been two T-1 and one T-4 auctions to date. The first T-1 auction highlighted some issues and resulted in inadequate capacity being successful in the auction to manage a specific local constraint in the Dublin area. Judicious resetting of the desired price/capacity curve and resetting of constraint limits by the regulators successfully addressed this in the second T-1 auction, perhaps indicating the ability of regulatory intervention to manipulate the capacity market outcomes.

In the first T-4 auction, there was initially no capacity cleared based on the price/capacity curve. The total capacity procured was reduced from existing levels by covering constraints first and then only clearing any further capacity if this improved the net benefit.

On the strength of the first T-4 auction, the cost of capacity to consumers has been reduced. However, it is too early to assess whether this is sustainable.

Under the reliability options, some generators have also found themselves exposed to the strike price with no possibility of being scheduled, even though they were available – the regulators are now looking to address this.

Another limitation is that the capacity auction does not yet consider renewable targets, or the mix of capacities required to support those targets.

### Renewable Energy Penetration and Managing System Security

Ireland's renewable energy targets set substantial challenges for managing system security.



A system non-synchronous penetration (SNSP) limit has been set to limit zero inertia generation as a percentage of the total. An SNSP of 75 per cent would be required to support the renewable target for 2020. The initial SNSP was 50 per cent, it is now 65 per cent and a trial of 70 per cent is soon to commence.

Ireland's Secure, Sustainable Electricity System ("DS3") process procures a range of 14 ancillary services – including various reserves, frequency response and inertial response – through a mix of regulated tariffs and pay-as-bid procurement process which incentivise the development of capabilities to help support high levels of intermittent resources and resources that do not produce inertia (wind, solar, batteries, HVDC interconnectors).

### Conclusion

The I-SEM market design process was led by the Irish Regulatory Authorities and a highly consultative approach was taken. Development of the Rules and market implementation was led by the Market/System Operator, again with a highly consultative approach. Overall, this was an effective approach, although the cautionary note is the need to monitor complexity levels carefully. In particular, complexity in the balancing market caused implementation difficulties across the industry for perceived limited gains.

Whilst the challenges facing the Irish wholesale electricity market were by no means identical to the challenges facing the NEM, similarities do exist and certainly the solutions implemented offer the potential for a great learning opportunity for the Australia's NEM post-2025 design process.

## California's decision to shut off power to avoid wild fires backfires

**Author: Fereidon Sioshani, Ph D, President, Menio Energy Economics, California USA**  
**PG&E's Wild Fire Fiasco**

Following the devastating wild fires in 2017 and 2018, for which the **Pacific Gas & Electric Company** (PG&E) was found to be partially at fault, the utility's finances have taken a dive. Its liabilities from scores of lawsuits exceeds its assets by a wide margin, the standard accounting definition for being bankrupt. Of course, a company this big and this vital – it serves roughly half of California's population – cannot really be allowed to go bankrupt, can it? It is merely under "bankruptcy protection". But it certainly has no appetite for more lawsuits from more wild fires. Under new management and overseen by a court appointed bankruptcy judge, PG&E has assumed a low-risk exposure, down to basics posture, no surprise.

Its mission, to the extent that it has one, is to re-emerge from bankruptcy protection unscathed and with some resemblance of normalcy restored. Anticipating hot, dry and wind conditions in October – a perennial feature of California weather made worse in recent years by climate change – the utility had earlier warned that it would shut off power to customers in advance to avoid sparking new wild fires, or be blamed for them. The idea was to do this as a last resort, and selectively to minimize the loss of life and property. If the choice was between service or safety – read more lawsuits – PG&E would go for the latter.

As it turned out, hot, dry windy conditions were forecast for large portions of the state for 9-10 Oct and PG&E decided to shut power off to about 738,000 customers in Northern & Central California – affecting roughly 1 million residents and businesses. Fortunately, no major fires were reported and the company started restoring power to some 426,000 customers on the following day. In some cases, restoration may take a day or longer since the company has to inspect the condition of the wires before it can re-energize them.

No matter how noble or justified the motivations, the service disruption, poorly planned and hastily communicated, did not go well with the public, those who were disrupted as well as those who might have been disrupted including this editor.

The backlash was immediate and unanimous. PG&E screwed up badly managing to turn more customers, regulators and politicians into skeptics on its ability to run a business.

To be fair, **Southern California Edison Company** (SCE), the other big utility that essentially serves the rest of the state – setting aside a few smallish areas – also shut off power to some 13,000 customers while putting another 200,000 on alert. But these were isolated and did not cause the massive disruptions caused by PG&E.

The new president of **California Public Utilities Commission** (CPUC), **Marybel Batjer**, was typical in stating that PG&E's response "has been absolutely unacceptable" to communities, "to individual people, to the commerce of our state and the safety of our people." Others, especially customers literally stranded in the dark and not knowing when the power will be stored, had even harsher words.

California Gov. **Gavin Newsom** was blunt in blaming PG&E for the blackouts. He said, "This is not a climate change story as much as a story about greed and mismanagement over the course of decades. Neglect, a desire to advance not public safety but profits." Understandably, the newly elected governor wants to deflect any criticism of the incident on himself. He must have known that this was coming, did he not? And if not, why not?

The central question is if PG&E cannot operate its network safely and reliably, then why has it not done something about it already? Climate change is partly to blame for making the fire danger more prevalent and more deadly, but surely utilities in warmer and hashier climates manage to keep the lights on, don't they?

**Mindy Spatt**, speaking for **The Utility Reform Network (TURN)**, a customer advocacy group, said, "Every time you think PG&E can't do worse they do." Making matters worse, PG&E's website went down and the phone lines were flooded making it difficult for customers to get information on when the power may be restored.

Restoring power is not as simple as tuning on a switch, on average takes about 48 hours but can take longer, especial in the case of a major shut off like this. The only silver lining, if there is one, is that more customers may decide that they cannot rely on the local utility for reliable service, prompting them to invest in self-generation, battery storage and/or back-up emergency generation. That would drive more customers away from the incumbents.

Clearly, the fiasco is far from over as everyone in the chain of command – from Governor Newsom to PG&E's CEO **Bill Johnson** to commissioners at the CPUC are scrambling to decide how best to move forward. California is getting warmer and drier and the fire hazard is imminent and serious as was experienced during the recent events with major fatalities and massive loss of property. A better way must be found to balance the safety vs. service option.

## How Much Renewable Energy Can a Power Transmission System Accommodate? EPRI Journal

Source: EPRI Journal



A new EPRI tool can help utilities answer this question.

Transmission planning increasingly is driven by needs associated with grid-connected variable renewable energy resources. Transmission infrastructure, particularly in remote areas suitable for large wind and solar capacity, may nevertheless be limited with respect to the amount of new generation that can be accommodated without exceeding thermal or voltage limits.

EPRI's Transmission Hosting Capacity Tool builds on similar EPRI software for distribution systems. It enables utilities to screen various scenarios for generation, load, dispatch, and grid conditions and to gauge where and how new generation could impact the system's thermal and voltage performance. The tool can inform utility decisions on grid upgrades and optimal locations for renewables, although it's not intended to replace detailed system impact studies necessary for investment decisions.

In 2018, EPRI and Salt River Project (SRP) tested the tool on the utility's transmission system. They determined that it provides a useful "first cut" in assessing the maximum renewable generation that can be accommodated without system upgrades. By automating the analysis, the tool enabled substantial savings in work hours.

"EPRI's newly developed Transmission Hosting Capacity Tool has allowed SRP to easily understand how the development of solar photovoltaic resources will impact transmission system reliability," said Justin Lee, SRP manager of transmission system planning. "The work done by this team allowed SRP to demonstrate the tool in a real-world environment, showing how this new automatic assessment capability can benefit system planning."

EPRI plans to test the tool with other utilities to develop its application to larger systems.

### Key EPRI Technical Experts:

Vikas Singhvi, Deepak Ramasubramanian

For more information, contact [techexpert@eprijournal.com](mailto:techexpert@eprijournal.com).

## EPRI Tool Helps Utilities Assess 'Hosting Capacity' on Distribution Systems

**Author:** Chris Warren  
**Source:** EPRI Journal

New York investor-owned utilities are using EPRI's Distribution Resource Integration and Value Estimation (DRIVE) software to develop distribution system maps to indicate where it is less costly to interconnect distributed energy resources. "Now we can refer developers to for electric distribution planning at Central Hudson. "We have received feedback from developers who say they use the maps and find them beneficial."

It was crunch time for Central Hudson Gas & Electric. On March 9, 2017, the New York Public Service Commission required the Poughkeepsie-based power company (along with other investor-owned utilities in New York) to create publicly available maps showing the hosting capacity of all distribution system feeders operating at 12 kilovolts and above, with a deadline of October 1, 2017. The commission wanted to clearly identify for the public the locations that could more readily host distributed energy resources (DER) without adverse grid impacts. For Central Hudson, new stand-alone solar projects of 2–5 megawatts were considered most likely to have significant impacts.

Central Hudson and the other investor-owned utilities in New York joined with EPRI to develop the maps. Using EPRI's Distribution Resource Integration and Value Estimation (DRIVE) software, Central Hudson was able to calculate the hosting capacity of its approximately 230 distribution feeders operating at 12 kilovolts and above and completed the maps before the deadline. Released in 2016, DRIVE analyzes a distribution system's hosting capacity at specific locations on individual feeders and provides detailed information on DER's potential grid impacts, particularly related to grid reliability and power quality.

"Because New York's investor-owned utilities all use different power flow modeling tools, it would have been difficult to develop a standardized methodology to compute the hosting capacity," said Stephanie Genesee, associate engineer for electric distribution planning at Central Hudson. "We were pleased with the tool and grateful that EPRI was able to help us."

Since then, Central Hudson has used DRIVE to update the maps annually. This year, they will include information on smaller areas on feeders known as nodes. In fact, all New York investor-owned utilities are using DRIVE to develop distribution system maps to indicate where it should be less costly to interconnect DER.

"Using DRIVE to compute hosting capacity is straightforward, and I can quickly train new engineers to use the tool," said Genesee. "We also took the time to learn how the tool processes the data to better understand its functioning."

The maps make business more efficient for New York's solar developers as well. In the past, the utility was unable to provide applicants with insights on feeder hosting capacity without performing a detailed impact study. "Now we can refer developers to the map, which may indicate that one feeder has the potential to handle six megawatts while another may be able to handle only one megawatt. This gives developers guidance on which locations may be better suited to proceed with an interconnection project," said Genesee. "We have received feedback from developers who say they use the maps and find them beneficial."



New York's investor-owned utilities are using EPRI's DRIVE tool to develop distribution system maps to indicate where it should be less costly to interconnect solar. Photo courtesy of U.S. Department of Energy.

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## Faster Interconnection, Integration with Other Utility Tools

**Source: EPRI Journal**

Historically, solar installers and developers across the United States seeking to build new systems have had to submit applications to the utility for extensive reviews.

"It's a time-consuming and expensive process," said EPRI Technical Leader Matthew Rylander.

DRIVE is helping to change this by enabling utilities to quickly provide an approximation of whether new DER interconnections would result in distribution grid problems. This capability is particularly important as more regulators seek to streamline DER integration. New York's Reforming the Energy Vision initiative aims to integrate DER into distribution planning and operations and includes a requirement that utilities identify where DER can best be accommodated. Regulators in Minnesota and California are pursuing similar efforts.

Through a feature called Connect, DRIVE helps utilities speed interconnection screening by linking to the utility websites that developers use to submit applications. The application data—including details on the size and type of DER—feed into DRIVE, which quickly determines if hosting capacity is available at the proposed location. "It will come back and indicate whether there is hosting capacity and how much," said EPRI Senior Project Manager Lindsey Rogers. "If there's no capacity, a utility engineer steps in and does a manual analysis to determine what upgrades are feasible, then contacts the developer who submitted the application."

DRIVE can integrate data from other utility planning tools—such as power flow and generation of existing DER—to estimate potential voltage and thermal impacts of different sizes and types of additional DER at specific locations. "DRIVE was developed to work with different tools," said Rylander. "Utilities have different distribution analysis software, and we wanted to create something that could work well on its own and with those tools."

The tool can calculate hosting capacity feeder by feeder as well as location by location within a feeder—for current and future grid configurations. Utilities can use this capability to identify distribution system locations where DER can be interconnected without significant additional cost for infrastructure upgrades. This is valuable market information that can inform the planning of developers, regulators, and policymakers. Distribution planners can use DRIVE's location-specific hosting capacity data along with load and DER deployment forecasts to assess necessary grid infrastructure upgrades.

"DRIVE enables users to input various parameters such as whether energy resources are solar or wind, how rapid are output fluctuations, and what additional fault current will come out of the system," said Rogers. "Based on these analyses, the tool can inform users on impacts from various resources."

While today DRIVE is used primarily to assess hosting capacity and DER's grid impacts, EPRI plans to incorporate features to help planners estimate the grid benefits and values of siting and integrating new DER.

**Key EPRI Technical Experts:**

Matthew Rylander, Lindsey Rogers

For more information, contact [techexpert@eprijournal.com](mailto:techexpert@eprijournal.com).

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## Swappable Flying Batteries Keep Drones Aloft Almost Forever

**Author: Evan Ackerman**

**Date: 26 September 2019**

**Source: [IEEE Spectrum](#)**

*Mid-air docking of flying batteries can massively extend the flight time of a drone*

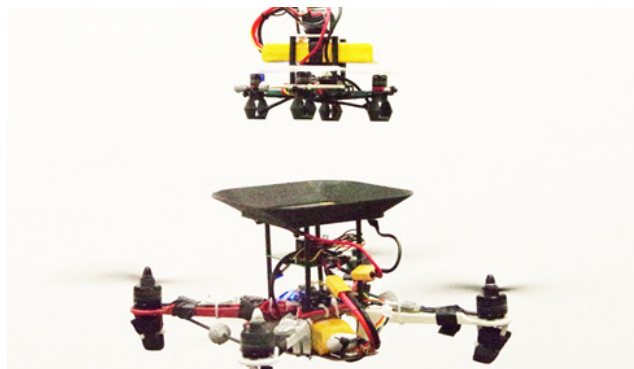


Photo: UC Berkeley



Each flying battery can power the main quadrotor for about 6 minutes, and then it flies off and a new flying battery takes its place.

Battery power is a limiting factor for robots everywhere, but it's particularly problematic for drones, which have to make an awkward tradeoff between the amount of battery they carry, the amount of other more useful stuff they carry, and how long they can spend in the air. Consumer drones seem to have settled around about a third of their overall mass in battery, resulting in flight times of 20 to 25 minutes at best, before you have to bring the drone back for a battery swap. And if whatever the drone was supposed to be doing depended on it staying in the air, then you're pretty much out of luck.

When much larger aircraft have this problem, and in particular military aircraft which sometimes need to stay on-station for long periods of time, the solution is mid-air refueling—why send an aircraft all the way back to its fuel source when you can instead bring the fuel source to the aircraft? It's easier to do this with liquid fuel than it is with batteries, of course, but researchers at UC Berkeley have come up with a clever solution: You just give the batteries wings. Or, in this case, rotors.



video on [www.youtube.com](http://www.youtube.com), or enable JavaScript if it is disabled in your browser.

The big quadrotor, which weighs 820 grams, is carrying its own 2.2 Ah lithium-polymer battery that by itself gives it a flight time of about 12 minutes. Each little quadrotor weighs 320 g, including its own 0.8 Ah battery plus a 1.5 Ah battery as cargo. The little ones can't keep themselves aloft for all that long, but that's okay, because as flying batteries their only job is to go from ground to the big quadrotor and back again.

How the flying batteries work

As each flying battery approaches the main quadrotor, the smaller quadrotor takes a position about 30 centimeter above a passive docking tray mounted on top of the bigger drone. It then slowly descends to about 3 cm above, waits for its alignment to be just right, and then drops, landing on the tray which helps align its legs with electrical contacts. As soon as a connection is made, the main quadrotor is able to power itself completely from the smaller drone's battery payload. Each flying battery can power the main quadrotor for about 5 minutes, and then it flies off and a new flying battery takes its place. If everything goes well, the main quadrotor only uses its primary battery during the undocking and docking phases, and in testing, this boosted its flight time from 12 minutes to nearly an hour.

All of this happens in a motion-capture environment, which is a big constraint, and getting this precision(ish) docking maneuver to work outside, or when the primary drone is moving, is something that the researchers would like to figure out. There are potential applications in situations where continuous monitoring by a drone is important—you could argue that switching off two identical drones might be a simpler way of achieving that, but it also requires two (presumably fancy) drones as opposed to just one plus a bunch of relatively simple and inexpensive flying batteries.

"Flying Batteries: In-flight Battery Switching to Increase Multirotor Flight Time," by Karan P. Jain and Mark W. Mueller from the [High Performance Robotics Lab](#) at UC Berkeley, [is available on arXiv](#).

## PG&E admits fault in sparking large 2019 wildfires, judge demands 'precise details' for 3

Author: [Robert Walton](#)

Date: 3 October 2019

Source: [Utility Dive](#)

### Dive Brief:

- Pacific Gas & Electric (PG&E) told the U.S. District Court for the Northern District of California this week that its system may have "contributed" to nine wildfires of 10 acres or larger in 2019, including two attributed to vegetation and one to equipment.
- Judge William Alsup in an Oct. 2 order directed the bankrupt utility to provide "precise details" regarding the three related to vegetation and equipment by next Wednesday. Alsup is charged with overseeing PG&E's probation related to the deadly San Bruno, California, gas pipeline explosion in 2010.
- The number of fires sparked by PG&E's system this year marks a significant year-over-year decline, according to Bloomberg. The utility's system sparked 19 fires across a similar 2018 timeline.

### Dive Insight:

PG&E is preparing for California's high wind season, including a system inspection and ramping up its proactive power shutoffs. The utility's work to reduce fire risk appears to be paying off, but Alsup is demanding answers about the fires caused by previous problem areas.

PG&E said five of the six fires Alsup did not ask for more details on were caused by third parties — three cases involved animals on their lines and two were related to cars crashing into their poles — while the cause of the final blaze is unknown.

The utility says its "analysis of these events is ongoing," with the data current as of mid-September.

"PG&E is continuing to work aggressively to further strengthen its programs and infrastructure to maximize safety and mitigate the potential wildfire risk," the utility told Alsup in a Tuesday filing, adding it "has implemented several additional measures designed to address the risk of wildfires as a result of an increased likelihood that parts of its service territory will experience drier, higher-speed winds in the coming months."

PG&E is working through an Enhanced Vegetation Management (EVM) program and as of Sept. 21 had completed identified work on approximately 760 line miles.

"PG&E's ability to complete inspection and clearance of the 2,455 line miles forecasted for 2019 is dependent on its ability to significantly increase the number of qualified personnel engaged in the EVM effort," the utility told the court.

PG&E is hiring additional personnel but also said its ability to complete the 2019 line miles target to be cleared "will depend on various factors including vegetation density, topography, access and environmental considerations. ... Moreover, until PG&E inspects the lines, the number of trees that require trimming or removal, which is unknown, could impact the rate at which lines can be cleared."

The utility is making speedier progress on its Wildfire Safety Inspection Program, which includes accelerated inspections of certain transmission, distribution and substation assets. PG&E told the court its program is "substantially complete with these enhanced inspections" and expects to complete inspections of the remaining few assets "as expeditiously as possible."

The utility's proactive power shutoffs are also coming into play more frequently.

"PG&E expects to de-energize more in 2019 than it did last year," the utility said. In June, PG&E conducted one PSPS event in two locations; in September, the utility shut off power in Public Safety Power Shutoff events on two days.

[https://www.renewableenergyworld.com/2019/09/20/how-to-extend-the-lifetime-of-wind-turbines/?cmpid=&utm\\_source=enl&utm\\_medium=email&utm\\_campaign=wind\\_energy\\_news&utm\\_content=2019-09-25&eid=288971227&bid=2527728](https://www.renewableenergyworld.com/2019/09/20/how-to-extend-the-lifetime-of-wind-turbines/?cmpid=&utm_source=enl&utm_medium=email&utm_campaign=wind_energy_news&utm_content=2019-09-25&eid=288971227&bid=2527728)

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## How to extend the lifetime of wind turbines

**Authors:** Christian Schumacher and Florian Weber

**Date:** 20 September 2019

**Source:** [Renewable Energy World](#)

*Although wind turbines generally are designed for a service life of 20 years, many can continue to operate past their original design life. In fact, the lifetime of a wind turbine can often be extended by minor and low-cost repairs. This article describes the methods and results of a safety evaluation of wind turbines.*

As wind farms age, their operators face significant business decisions. Decommissioning, repowering or continued operation are the main options to be considered. Two of the key factors affecting these decisions are determining the physical condition and theoretically admissible lifetime of a turbine. Physical condition can be evaluated through on-site inspections. The theoretically admissible lifetime is usually determined by means of a comparison of site-specific and design loads.

A work group created by the German Wind Energy Association has defined the basic principles of the lifetime extension assessment of a wind turbine, in order to ensure sustainable use of wind energy. This work group – formed by manufacturers, technical experts, operators, legal experts and representatives from the authorities – was assigned the task of specifying the technical requirements necessary for ensuring the safe operation of a wind turbine after the end of the design lifetime.

### Principles of a lifetime extension assessment

To evaluate the current condition of a turbine, the lifetime extension assessment is usually performed during the last year of validity of the operating permit. If divestment of the turbine is being considered, or in the case of medium-term budget planning, it may be preferable to carry out the analysis at an earlier stage. Preliminary results are normally arrived at without a physical inspection and indicate whether continued operation is feasible and when specific components are likely to need replacing. These findings may be incorporated into a lifetime extension assessment at a later point in time.

The assessment to determine whether a wind turbine may operate beyond its design life consists of two parts, conducted in parallel. Experts in the analytical and practical evaluation provide each other mutual assistance during the entire process. After the analytical evaluation and on-site inspection, a status report is drawn up specifying the requirements needed for lifetime extension. For instance, repairs or precautionary replacements of the bolted connections of the rotor blade are often necessary, as these are usually the first elements to reach their design load limits. Thus, an accurate financial estimate of the potential costs involved in a lifetime extension can be generated. The results of the assessment provide valuable input for weighing opportunities and efforts for continued operation and are important in assisting wind farm operators in their decision-making process.

### Structural stability of a turbine

One critical factor in the safety evaluation process is establishing the structural stability of a wind turbine. The tests required to verify structural stability are mainly focused on the load-bearing components, from the rotor blades to the foundation, as well as the safety devices, braking systems and turbine control systems. The actual loads to which a turbine has been exposed during its operational lifetime need to be calculated and compared with loads resulting from design conditions. This information is obtained from computer simulations that reflect design conditions after type testing, as well as environmental operating conditions. Furthermore, an on-site inspection of the turbine is performed.

Environmental operating conditions include site-specific wind conditions. Data documenting average wind speeds, turbulence intensities and extreme wind events for the previous 20 years need to be quantifiable in order to calculate loads for the period of operation. This calculation is based on operating data and data from the anemometer on the nacelle. Should this data not be known for the entire period, other data sets (i.e. reanalysis data) are used to perform long-term extrapolation. In the case of a wind farm with a variety of capacity additions, turbulence is calculated individually for each turbine as well as for each of the windfarm layouts during the design lifetime.

### Environmental conditions and required documents

In the analytical assessment, the potential duration of continued operation is calculated based on turbine technical documentation, as well as the environmental operating data. Wind farm operators are responsible for arranging the assessment on time and for presenting the relevant documents. Required documentation includes information relating to turbine construction and commissioning; the operating permit of the turbine; repair, inspection and maintenance reports; operating and yield data; and wiring and hydraulic diagrams. In addition, a technical report is required documenting the conditions of the rotor blades, carried out within the last year of operation.

It is not unusual for technical documentation to be incomplete. Missing certificates and technical documents can be obtained from the manufacturer. This includes documentation from the construction and commissioning phases. However, if a turbine manufacturer is no longer available, comparisons with other turbines and assessments based on previous experience may be used to bridge the knowledge gaps.

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## Physical inspection of a turbine

The physical condition of a turbine is assessed through an on-site inspection during the practical part of the lifetime extension evaluation. Prior to the on-site testing and inspection of the turbine, the information and data already available are analyzed. Technical documentation and reports, as well as weather and performance data, are examined so that the turbine can be checked for specific weaknesses and defects.

The objective of the physical assessment is to document any damage or unusual wear and tear to the turbine's components and equipment. Load-bearing and safety-relevant components are examined in detail. Maintenance records are checked, and the turbine condition is compared with the technical documentation. In particular, inspectors search for signs of corrosion, visible cracks and suspicious noises in the gearbox or other gear and bearing assemblies. Also, a detailed investigation is carried out for weaknesses or flaws associated with a particular type of wind turbine, such as known shortcomings in the quality management during specific production periods or certain components or design flaws that lead to premature defects.

The conditions of the main elements of the turbine – i.e. the rotor blade, the supporting structure and the foundation – are carefully evaluated. The immediate shutdown of a turbine is recommended in the event of significant damage that would compromise the safety of continued operation. In most cases, however, the damage discovered is relatively minor and caused by corrosion, weathering and material fatigue. For instance, rotor blades or cables frequently need maintenance. Close attention is also paid to any changes in the surrounding environment of a wind farm. Expansions in neighboring sites must be taken into account in turbulence calculations.

## Analytical evaluation

In the analytical part of the lifetime extension assessment, operating loads are compared with design loads. The results of the physical inspection are considered in these calculations. Fatigue loads are simulated using software-based models that take into account site-specific wind conditions as well as design conditions. All load-bearing components contributing to the structural stability of the turbine are examined: the tower and foundation, screws and bolts, load-bearing parts of the drive train, the hub, the shaft, the rotor blades, braking systems and the safety functions. This report specifies the remaining time until design loads are reached. Based on the calculations, a statement is prepared highlighting immediate measures required for continued operation, as well as measures that become necessary at defined points in time, like exchange of parts or individual inspection strategies.

## Results

As long as wind farms are operated within their design lifetime and the design conditions are not exceeded, a defined safety level against the occurrence of damages caused by material fatigue is maintained. TÜV SÜD's experience shows that many turbines still can be operated beyond their design lives while not crossing this safety level. In many cases, wind conditions at the site result in lower loads than originally planned. Thus, the supporting structure of the turbine is often free from significant damage and the necessary repairs are generally minor and cost-effective. A lifetime extension assessment determines whether continued operation is possible and assists managers and operators when planning for the future of their assets.

The results of a lifetime extension assessment can also be used to plan maintenance shutdowns and to forecast the costs that are likely to be incurred during the remaining lifetime of a turbine. This assessment is also recommended when applying for extension of insurance policies and is generally required by service providers after the end of the design life of the turbine.

*Christian Schumacher and Florian Weber are with TÜV SÜD Industrie Service GmbH.*

## Design service life

*The assumed loads a manufacturer factors into turbine design are based on a defined service life for the wind turbine. All operational, safety and construction relevant components and load-bearing parts of the turbine are designed, built and dimensioned to withstand foreseeable loads and stresses caused by wind, weather and operation for the length of this period. This design service life is usually 20 or 25 years, provided the specified maintenance is completed, regular inspections and testing are performed, and faults are immediately rectified.*

*The design service life and period of lifetime extension are used as a basis for calculating the total service life. Registrations undertaken within the terms of the German Renewable Energy Sources Act (EEG) showed that at the end of 2016/start of 2017, more than 1,200 wind turbines in Germany had been in operation for over 20 years, i.e. their lifetime had been extended.*

*Germany's first wind turbines to be placed into operation will no longer receive EEG subsidies from the end of 2020. Thus, market prices will have a major impact on turbine operators' decision-making process over the viability of lifetime extension. Between 2019 and 2024, the decision to decommission, repower or continue to operate will apply to about 1,500 to 2,000 turbines every year, decreasing to about 1,000 turbines per year from 2024. It is likely that repowering will not always be possible, particularly given the mandatory distance required between a turbine and the nearest residential area. In such cases, options for lifetime extension will be particularly attractive.*

## Surge in mixed turbine wind farms tests capacity of service

**Author:** Ed Pearcey

**Date:** 25 September 2019

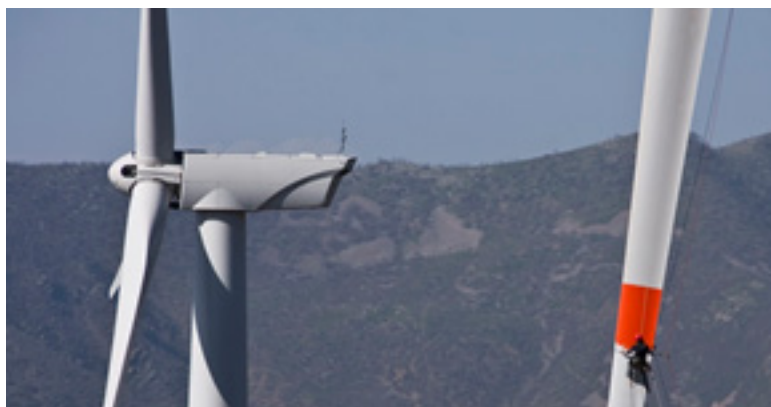
**Source:** [New Energy Update](#)

Wind operators are increasingly turning to multiple turbine configurations to boost siting and revenue opportunities, raising new challenges in component sourcing and maintenance training, industry experts told New Energy Update.

Price pressure and dwindling site options are spurring many wind developers to install multiple turbine capacities at sites to maximize returns.

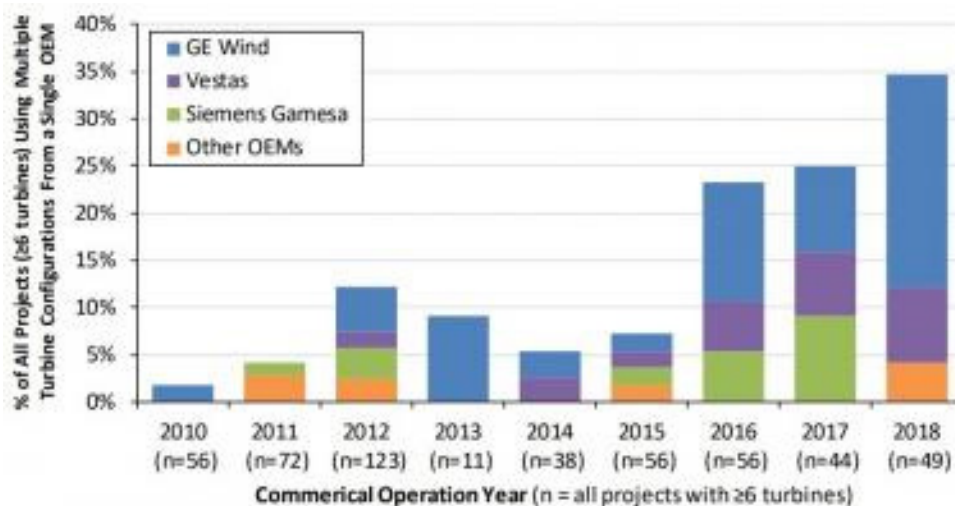
The percentage of U.S. wind power projects incorporating multiple turbine capacities from a single supplier hiked from 25% in 2017 to 35% in 2018, according to the Department of Energy's (DOE) recent Wind Technologies Market Report.

Most of these turbines "differed by all three of the major characteristics: hub height, rotor diameter, and capacity rating," DOE said.



Mixed turbine wind farms require broader maintenance skills and equipment bases. (Image credit: Ozturk)

### US wind projects installing multiple turbine capacities



Source: DOE's 2018 Wind Technologies market report (August 2019).

Larger, higher efficiency turbines can cut costs but raise fresh permitting and transport challenges.

Multiple turbine capacities can open up new turbine opportunities and allow operators to optimize specific site conditions. They also increase project complexity, testing installation and operations and maintenance (O&M) capabilities.

"From installation and O&M perspectives, having different turbine types in the same park usually only has disadvantages," Till Junge, Vice President, Product Strategy & Sales Support, Nordex Group, told New Energy Update. "Simply because it increases the variety of components within the facility."

### Extra revenue

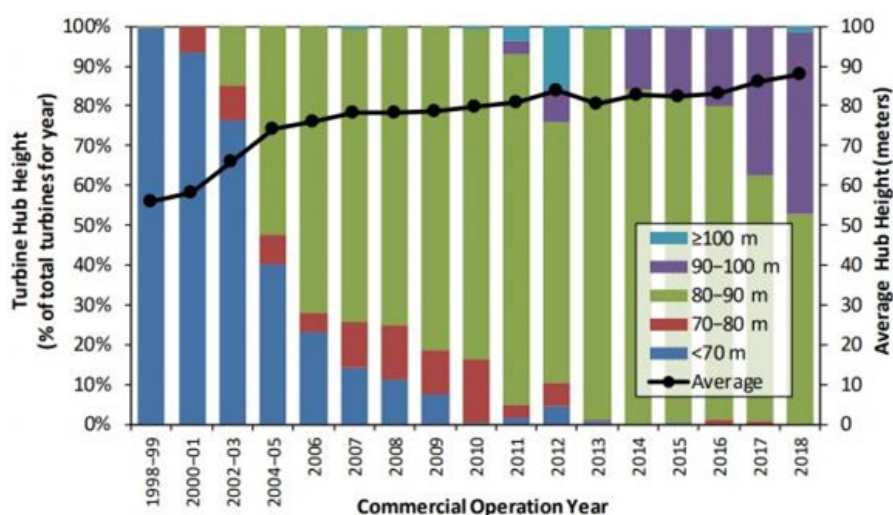
Turbine capacities have grown rapidly in recent years but many sites do not permit the installation of the latest large-scale models.

"You could be near housing developments or next to flight paths," Michael Taylor, Senior Analyst, International Renewable Energy Agency told New Energy Update.



"Smaller turbines within certain parts of the windfarm could be appropriate, and can be a good way to maximize the wind available," he said.

#### US average turbine height by installation year



Source: DOE's 2018 Wind Technologies market report (August 2019).

Multiple turbine capacities can allow operators to optimize output across "micro-wind climates" within a particular site, Taylor said.

"This may be in terms of maximizing electricity generation or ensuring a more even generation profile," he said.

Nordex multiple turbine configuration deals include the supply of 104 turbines of capacity 4.5 MW turbines and 10 turbines of 3.9 MW to E.ON and Credit Suisse's Nysater wind project in Sweden.

Using a mixture of tower heights, the 4.5 MW turbines will be operated between 4.0 MW and 4.5 MW and the 3.9 MW models will be operated between 3.1 MW and 3.9 MW, Nordex said in December 2018.

"This optimization potential and ability to customize the turbine configuration, provides a huge advantage with large-scale projects like Nysater, where typically the wind conditions and complex topography vary greatly across the site," it said.

In another recent deal, Vestas received an order for V150-4.2 MW and V110-2.0 MW turbines for a 242 MW wind project in the US. Vestas would look to create a "tailor-made" site layout which would optimize the site's wind resources, the company said.

In the U.S., qualification rules for the federal Production Tax Credit (or PTC) have accelerated demand for multiple turbine configurations. PTC incentives fall by 20% per year and "safe harbor" rules require developers to incur 5% of total project costs to qualify.

"In many cases, it's the dominant reason," Ryan Wiser, Senior Scientist and Group Leader of the Electricity Markets and Policy Group, Lawrence Berkeley National Laboratory, told New Energy Update.

"Developers purchase safe harbor turbines, then purchase more modern turbines later to fill out a project site. That's another reason to develop mixed sites," he said.

#### Wake control

Advances in data analytics and turbine operations are providing new tools to optimize total site output.

New wake control solutions are coming to market which allow operators to steer low-energy wind away from downstream units, increasing site output.

Earlier this year, technology group Emerson and A.I. data optimization specialist Vayu launched a commercial wind turbine control solution to reduce wake losses and increase site revenues.

Wake control strategies can increase output by as much as 10% at some sites, Jim Kiles, CEO of Vayu, told New Energy Update in June.

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Sites with low wind velocity, changeable wind direction and high temperatures could see the greatest revenue gains, he said.

#### **Service scope**

The installation of assorted turbine capacities raises a range of construction and maintenance challenges.

Different sized blades may require different types of transportation along different routes, impacting construction efficiency, Taylor said.

Multiple turbine configurations also require more complex inventory management and equipment sourcing and greater training requirements.

"Overall, using different turbine capacities within a single plant will probably push up operation and maintenance (O&M) costs," he said.

The growing trend of multiple configurations comes as O&M suppliers look to increase their share of the growing O&M market.

For example, Vestas agreed a 25-year service agreement as part of its recent 242 MW multi-configuration deal in the US.

"Using the same O&M provider (such as Vestas) can help minimize those extra costs," Taylor said. "But a lot depends on how good your supplier is, and what it's prepared to offer you."

#### **Growth driver**

Corporate demand for renewable energy is on the rise but wind developers face growing competition from falling solar and storage costs. Multiple turbine configurations will help wind developers maximize project pipelines in the coming years.

By opting for a mixed capacity array, operators can find an optimal solution for the specific project need, Karin Ohlenforst, Director of Market Intelligence, Global Wind Energy Council, said.

"The idea of mixed turbines on sites that are maybe not the prime locations is definitely an opportunity for growth within a mature market such as Europe, where lots of the most usable sites are already taken," Ohlenforst said.

## HISTORY

### Cost of Transmitted Energy

**Author:** Tony Patterson

**Date:** October 2019

**Paper:** Cost of Transmitted Energy

**Author:** G. W. Stewart

**Date:** This paper was presented to our conference in 1947

There is a real and ongoing cost to transmit electrical energy over power lines, whether they be Transmission or Distribution. Do we calculate these costs and take them into account when designing these lines?

Lines are often designed on conductor rating (temperature), sag clearance, fault rating, voltage reduction, etc. The associated volt loss can be compensated for by increasing the sending voltage or transformers / regulators with the ability to regulate the voltage over a substantial range. The bottom line is the voltage that we deliver to the customers terminals.

There is no direct cost for the kWh lost as heat in the delivery process.

The focus on energy and its efficient use is becoming more acute, mainly based on its source of generation and associated environmental impacts. There is now probably good argument for the increasing distributed renewable generation in our networks, as it reduces transport distance, but it does create other technical issues. However, remote large-scale renewable generation also has significant losses of this renewable energy, because of the distance from its load. The proposed transmission of renewable energy between states over long distances is also plagued by the energy loss issue.

Do we worry about energy loss or simply ignore it? Surely the bottom line is the voltage at the customers terminals!

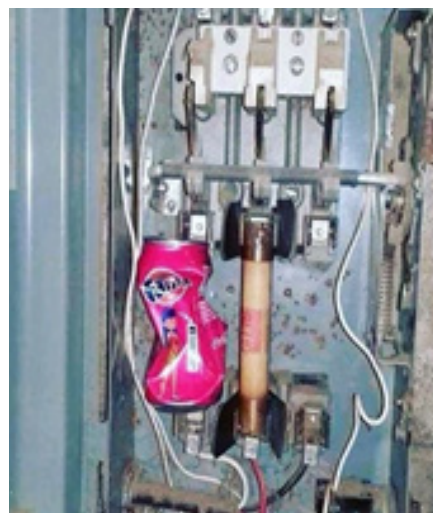
This issue was just as relevant in 1947 as it is today. Read about their approach to the problem in the attached conference paper.

[Download Paper](#)

## HUMOUR CORNER

Curated by Terry Miller

### HUMOUR BREAK: ENGINEERS NIGHTMARES ARE MADE OF THIS!



## CIREP PAPER

# THE REPRESENTATIVE CHARGING PATTERN FOR EVS BASED ON THE ACTUAL EVS CHARGING DATA FOR DISTRIBUTION SYSTEM PLANNING

Paper 135 from the Madrid CIREP Workshop held on 3-6 June 2019.

### Abstract

As the interests in eco-friendly energy has increased, the interests in Electric Vehicles (EVs) are increasing as well. Moreover, due to the government's economic support for EVs, the penetration level of it has rapidly increased. This sharp increase, however, induces various problems in distribution systems, such as voltage/frequency variations, peak demand increase, demand control, etc. To minimise these possible problems, much research has been conducted. Most of the research has assumed important factors, such as numbers and charging patterns of EVs. It inevitably results in errors in the research. In this paper, therefore, we use actual EVs charging data from KEPCO, and an analysis and deductions from it were conducted. The simulations were carried out for three aspects (season, region, purpose).

[Download Paper](#)

## UPDATES ON WORKING GROUPS

### CIGRE AUSTRALIA

#### CIGRE AUSTRALIA NEXT GENERATION NETWORK (NGN)

CIGRE Next Generation Network (NGN) is a division of CIGRE Australia that aims to develop the next generation of power engineering professionals.

CIGRE NGN membership is available (**and FREE**) to any of the following:

1. Individual members of CIGRE (Member II) who are aged 35 or under ([you can join CIGRE as an Individual Member](#)); or
2. Employees of [Collective members](#) who are aged 35 or under; or
3. Full time tertiary students (proof of full-time study required)

[To register for membership, please contact our Committee team by clicking here](#) and including the following details

1. Your name
2. Confirmation that you meet one of the three eligibility criteria above

You will then be provided with a registration link and:

1. The registration **must be completed within 72 hours**
2. The registrations details should **utilise your organisations email address** (this is how we verify your membership)
3. Further details will be provided with the registration link

CIGRE NGN is the first step for young engineers (up to 35 years old) to directly interact with one of the largest and most prestigious international power industry bodies. CIGRE was established to develop and distribute technical knowledge and experience in the field of generation, transmission and distribution of high voltage electricity. It does this by providing an interactive forum that brings together key players, research workers, producers, manufacturers, system operators, traders, and regulatory bodies.

Originally founded in France in 1921, CIGRE has expanded worldwide with representatives from more than ninety countries. The NGN provides the next generation of engineers with the opportunity to learn from industry experts, network with other like-minded young



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professionals and contribute to CIGRE papers, conferences and workshops. The CIGRE Australia NGN exists to help young engineers tap into CIGRE's wealth of expertise, from across the industry and around the world.

Our initiatives include:

- Web-based video of CIGRE seminar presentations
- Q&A with some of our industry's leading experts
- Access to CIGRE publications and articles

CIGRE NGN is where all parts of the power industry meet, share and develop ideas.

Expand your horizons by meeting other power engineers across the industry and across the world!

Advance your career by networking with researchers, producers, manufacturers, system operators, traders, and regulatory bodies nationally and internationally. By becoming a member of CIGRE Australia's NGN, you will be informed about CIGRE events, and opportunities. Dedicated NGN events, including site visits and networking-functions are also planned. Membership is free to any engineer aged <35yo who is an individual member of CIGRE Australia or an employee of a corporate member.

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## CIRE

### CIRE 2019 PROCEEDINGS NOW AVAILABLE ONLINE IN OPEN ACCESS!

The papers presented at **CIRE 2019** are now available online in **open access** through the new **CIRE Repository platform** where you can easily search, download and cite the proceedings.

Do not hesitate to have a look!

#### NEXT 3 EVENTS

- **4-5 June 2020** : CIRE workshop in Berlin : How to Implement Flexibility in the Distribution System?
- **26-27 October 2020** : CIRE workshop in Shanghai : Digital power distribution for fast growing large smart cities
- **21-24 June 2021** : CIRE conference in Geneva

[Find CIRE 2019 papers](#)

## COMPETITIONS

### The 2019 EESA National Virtual University Student Poster Competition



All poster submissions are now up on [Facebook](#) and [LinkedIn](#). Each post incorporates the hashtag #eesa\_postercomp\_2019

Go online and VOTE for your favourite poster. [Facebook](#) | [LinkedIn](#)

## ANNOUNCEMENTS

### A New National Council for 2020

Nominations for members of the 2020 National Council closed on 31 October 2019.

Three eligible nominations were received for three vacant positions, which means that no election vote is required.

The three successful candidates are:

Jeff Allen (NSW/ACT Chapter)  
Natalie Hutchinson (VIC Chapter)  
Tom Bammann (SA/NT Chapter)

Congratulations to Jeff, Natalie and Tom!

## UPCOMING EVENTS

### Insulation Co-ordination for Transmission & Distribution Equipment

Thursday 7 November 2019

QLD

[VIEW EVENT](#)



**Overview:**

EESA is pleased to present Colin Lee, a long-time electricity industry professional, who will present on the topic of **Insulation Coordination**.

Colin will go through the insulation coordination principles outlined in the various standards and how to apply it using worked examples to select the insulation requirements for transmission and distribution equipment.

**Time:**

Registration from 3pm  
Event from 3.30pm until 5pm

**Venue:**

Energy Queensland | WEBEX Available  
Level 1, 26 Reddacliff Street  
Newstead QLD

**Cost:**

EESA/EA members: \$0  
Non-members: \$30

### 2019 EESA National Virtual University Student Poster Competition

[VIEW EVENT](#)



**Overview:**

The Electric Energy Society of Australia (EESA) is hosting a virtual poster competition for undergraduate and postgraduate students. The goal of this competition is to introduce students to the power engineering industry by sharing their research with EESA members and the wider industry.

Go online and VOTE for your favourite poster. [Facebook](#) | [Linkedin](#)

### Could the Electricity Network withstand an Earthquake?

Wednesday 13 November 2019

NSW

[VIEW EVENT](#)



**Overview:**

During 2010 and 2011, Christchurch and the surrounding area experienced three major earthquake events; a magnitude 7.2 earthquake with its epicentre some 45 km west of the city followed by what were technically, magnitude 6.2 aftershocks, but located much closer to the urban area and thus resulting in much greater damage to the city.

**Time:**

5:30pm for 6pm start (AEDT)

**Venue:**

Engineers Australia Newcastle  
WEB AVAILABLE  
Suite 3, Tonella Commercial Centre - 125  
Bull Street, Newcastle West NSW

**Cost:**

EESA members \$0  
Non-members: \$30

## UPCOMING EVENTS

### Industrial HV Applications of Renewable Energy + VIC Chapter AGM

Thursday 14 November 2019

VIC

[VIEW EVENT](#)



**Overview:**

Rooftop solar, micro-grids, and alternative HV energy generation is resulting in a decentralised NEG, as the traditional customer becomes the generator. Explore how industrial HV applications of renewable energy alter the energy generation landscape.

This presentation will be followed by the EESA VIC 2019 AGM.

**Time:**

6pm - 7:30pm

**Venue:**

Engineers Australia  
Level 31, 600 Bourke Street  
Melbourne VIC 3000

**Cost:**

EESA members: \$0  
Non-members: \$30

### Modular Switch Buildings – Lessons from Practical Rollouts and Value Engineering

Monday 18 November 2019

WEB

[VIEW EVENT](#)



**Overview:**

The following content will be covered by the presentation:

- Brick Built Vs Modular Switch Building constructions – drivers for change
- Outline of modular concepts
- Additional design/construction considerations
- Lessons learned from earlier modular constructions
- Benefits realised to date

**Time:**

11am - 12pm AEDT

**Venue:**

Online webinar

**Cost:**

Entry is free and refreshments are available.

### EECON 2019

November 26th - 27th, 2019

AUS

[VIEW EVENT](#)



**Overview:**

The Electric Energy Society of Australia (EESA) takes great pleasure in inviting you to EECON 2019 at the International Convention Centre in Sydney on 26th and 27th of November 2019.

The theme of EECON 2019 - our annual national conference - is "Engineering leadership providing sustainable, customer-centric electric energy solutions through the interactive grid".

**Time:**

8am, 26 Nov - 3:30pm, 27 Nov

**Venue:**

International Convention Centre Sydney  
Level 4, Convention Centre, 14 Darling Drive  
Sydney NSW

**Cost:**

Standard fee: \$1050



# How to Implement Flexibility in the Distribution System?

**4 – 5 JUNE 2020 | ESTREL CONGRESS CENTRE | BERLIN | GERMANY**

## Submit your work to the CIRED 2020 Workshop

**Present, discuss and share new ideas and new developments in the realm of flexibility. The CIRED 2020 Workshop will showcase the rapidly developing innovations within this area from planning through to policy and will be the go-to forum for over 400 international experts.**

### TECHNICAL SCOPE

#### THEME 1

##### **Integrating new flexibility tools and principles for planning**

- Integrated energy system planning
- Enhanced asset management and risk assessment, e.g. traditional investment vs. flexibility
- Integration of local and distributed storage, new loads and load patterns
- Regulatory aspects of new tools and principles, including aggregated storage
- Cross sector and industry tools for decision making

#### THEME 2

##### **Opportunities and challenges with operation using flexibility**

- Workforce management
- Autonomous network operation and artificial intelligence to operate power systems
- Operational risk management
- Emergency operation
- Case studies, pilot projects and first experience

#### THEME 3

##### **Flexibility platforms and the role of future DSOs**

- Business models and regulatory frameworks
- The role of future DSOs
- Market/Interaction platforms
- DSO/TSO interaction
- Active customers – prosumers and citizens energy communities
- Energy policies

Accepted papers at CIRED Workshop 2020 will be published in IET Inspec, IEEE Xplore, EI Compendex and Open Access CIRED Journal.

[www.cired2020berlin.org](http://www.cired2020berlin.org)





## WHY CIRED?

CIRED is your chance to meet and share ideas with the global electricity distribution community. CIRED is attended by DNOs, utilities, product and service developers and researchers from both industry and academia.

### Publication Opportunities at CIRED

All presented papers at the CIRED 2020 Workshop will be published in the conference proceedings and submitted for indexing on:

**IET Inspec**

**Compendex**

**IEEE Xplore®**  
Digital Library

**OPEN**

Sponsor:

**ENEDIS**  
L'ELECTRICITE EN RESEAU

Media Partner:

**E&T**

### Key Dates to Note:

Abstract deadline

**25 November 2019**

Notification of acceptance

**24 January 2020**

Full papers deadline

**16 March 2020**



**CIRED 2020 Workshop**  
**4 – 5 June 2020**



## THANK YOU



The Electric Energy Society of Australia (EESA) is a non profit Technical Society of Engineers Australia, established to advance interest in the field of Electric Energy. The key objective of EESA is to provide a continuous professional development program to its members.

The successful functioning of EESA is owed to the support of EESA members and especially those who volunteer their time, effort, skills and expertise for the society. We thank our members and volunteers for their contribution.

### Keeping up with EESA events

To see an up-to-date list of EESA events, check under **EVENTS** on the EESA website or [CLICK HERE](#)

### Missed an event?

Recordings and papers are available under **RESOURCES** on the EESA website or [CLICK HERE](#)



We thank our corporate members for their support.

## Gold Members



### Essential Energy

At Essential Energy we look after the poles and wires that deliver electricity to 95 per cent of regional, rural and remote NSW and parts of southern Qld.



### Horizon Power

Horizon Power is a State Government-owned, commercially-focused corporation that provides safe and reliable power to about 100,000 residents and 10,000 businesses across Western Australia.



### AMSC Australia

AMSC generates the ideas, technologies and solutions that meet the world's demand for smarter, cleaner, better energy.



### Western Power

Western Power's vision is to deliver on the changing energy needs of Western Australians, powered by community trust and the passion of our people.

## Silver Members



### Evoenergy

Evoenergy is owned equally by Icon Water Limited and Jemena Ltd via subsidiary companies. Evoenergy owns and operates the ACT electricity network, and owns the gas networks in the ACT, Queanbeyan, Jerrabomberra, Bungendore and Nowra.



### nVent

We are a \$2.1 billion, high-performance electrical company with a dedicated team of 9,000 people and trusted brands. Known for innovation, quality and reliability, our products connect and protect, consistently delivering value to industrial, commercial, residential, energy and infrastructure customers.



### APD Engineering

APD Engineering have been providing Specialist Electrical Engineering Design and Consultancy Services to Power Utilities, Local Government Authorities, Land Developers, Mining, Construction and other industries for nearly 20 years.



### Wilson Transformer Company

Wilson Transformer Company is a leading specialist in the delivery of transformer solutions. In a changing world, organisations are increasingly turning to our specialist skills to meet their technical, safety and environmental challenges.

## Bronze Members



















