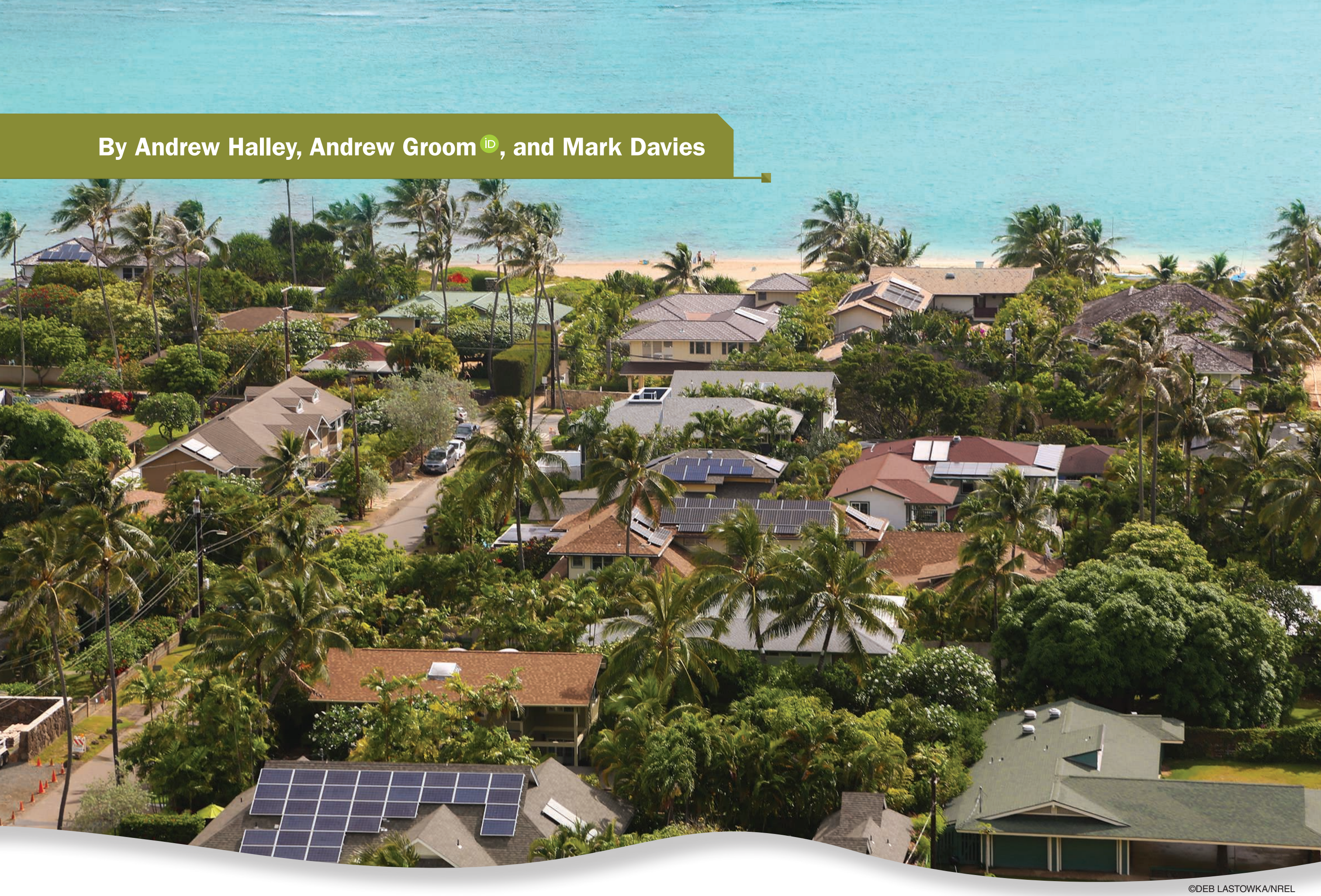

By Andrew Halley, Andrew Groom, and Mark Davies

Renewable Energy on the Apple Isle

Managing a high penetration of inverter-based energy resources in Tasmania.

TASMANIA IS THE ISLAND STATE OF AUSTRALIA, LOCATED approximately 42° south of the equator off the southern mainland coast. Although Tasmania has abundant hydrogeneration capacity, it has recently achieved an instantaneous penetration of inverter-based resources (IBRs), exceeding 90%, in a system with a typical demand of around 1,200 MW.

Sustained operation above 70% IBR penetration is now occurring regularly, comprising imports over the Basslink high-voltage direct current (HVdc) interconnector, which links Tasmania to the mainland, and on-island wind generation. While the installation of photovoltaics (PV) has lagged behind the world-leading take-up seen in other Australian states, the contribution of PV is now also becoming material. In combination, the installed capacity of wind, PV, and HVdc is already sufficient to meet Tasmania's average

Digital Object Identifier 10.1109/MELE.2022.3187906
Date of current version: 2 September 2022

2325-5897/22©2022IEEE

electricity demand, creating a new operating paradigm for the existing hydro fleet.

To manage power system security, several new strategies have been introduced. This has required coherency between the need for "pure" technical solutions and the commercial realities of operating within Australia's National Electricity Market (NEM). For example, the market dispatch process in Tasmania is now supported by new contracting arrangements to guarantee minimum levels of both system strength and synchronous inertia across the network, irrespective of energy market dispatch outcomes. Technical innovation has also been at the forefront, with a number of novel solutions implemented to enhance network frequency and voltage control in the presence of increased variable generation.

The installed capacity of wind, PV, and HVdc is already sufficient to meet Tasmania's average electricity demand, creating a new operating paradigm for the existing hydro fleet.

While challenges exist within the present system, more change will be needed to support the ongoing energy transition occurring across Australia. Significant new wind generation is already being actively progressed, with national planning investigations suggesting economically justified new developments exceeding 2 GW in Tasmania. While positioning Tasmania to become a significant contributor to Australia's emission-reduction targets, managing such high levels of geographically concentrated IBR is currently a daunting proposition, but one that the state is keen to understand and eventually realize.

This article provides an overview of the Tasmanian power system, describes its key attributes, and discusses a number of the solutions that have already been implemented to allow its operation with very high levels of IBR penetration. It is not surprising that some have described Tasmania as "the largest power system laboratory in the world."

An Overview of the Tasmanian Power System

Tasmania is a large island located approximately 260 km off the southeast corner of the Australian mainland (Figure 1). With an area of 68,400 square km, it is about 80% the size of Ireland. Tasmania has a cool temperate climate with relatively high annual rainfall in the western and central regions of between 1,500 and 3,000 mm. Known as the *Apple Isle*, given its historic and still-significant apple industry, Tasmania sits approximately 42° south of the equator, sitting directly in the path of the strong prevailing westerly winds known as the *Roaring Forties*. As a result, Tasmania has high-quality wind resources, with capacity factors in excess of 40% being typical for many areas of the state.

Hydropower in Tasmania dates back to the 1880s, with several small power stations installed on the west coast to support early mining operations. Since then, hydro has grown to be the dominant generation source in Tasmania. The current installed capacity of 2,295 MW is operated by the government-owned Hydro Tasmania.

Large-scale wind development in Tasmania commenced with the first stage of Woolnorth Wind Farm (65 MW), commissioned in 2002. Following completion of two new wind farms in 2020, installed wind capacity is now 568 MW, with the majority being operated by independent generators. Distributed energy resources, mainly in the form of rooftop photovoltaic installations, have grown steadily, with the photovoltaic capacity reaching 241 MW as of February 2022.

In addition to these renewable energy resources, Tasmania has 386 MW of gas-fired generation. Because of gas prices and the dynamics of the energy market, they are seen as increasingly unlikely to see regular service going forward, unless required to manage periods of low water storage.

The average system demand in Tasmania is around 1,200 MW. Tasmania is a winter-peaking system, driven by heating requirements, which for the last 10 years have been relatively consistent at around 1,700 MW. Minimum load periods currently occur overnight during summer and fall in the range of 900–950 MW. With an increasing contribution from PV during daylight hours, there is a strong likelihood that Tasmania will see the minimum net demand shift to the early afternoon, as already observed in other Australian states. The annual energy consumption in Tasmania was about 10.9 TWh in 2021, with around 50% of this energy consumed by four large industrial customers.

Tasmania is electrically connected to the mainland and the NEM via the Basslink HVdc interconnector. The bidirectional, monopole link was commissioned in 2006, operates at 400 kV dc, and is rated at ±500 MW. After losses, Basslink can deliver approximately 480 MW at the Tasmanian converter station when importing from the mainland.

As Basslink represents the largest single contingency for the Tasmanian region (by some margin), its operation is supported by a system protection scheme that rapidly trips either generation or load if the HVdc power flow is unexpectedly disrupted. The scheme operating time can be as low as 200 ms depending on the nature of the event, and it has been designed to manage both frequency and voltage stability for both import and export power flow conditions. Further information on this scheme is provided later in the article.

Tasmania's existing IBR capacity of approximately 1,289 MW (HVdc import plus wind plus PV) is now sufficient to satisfy the island's average load demand without the need for any synchronous generation when wind and sun are available.

The Changing Generation Mix Across the NEM and Tasmania

Unlike many other smaller islanded power systems grappling with the rapid growth of variable renewables, Tasmania has the added challenge of being part of the Australian

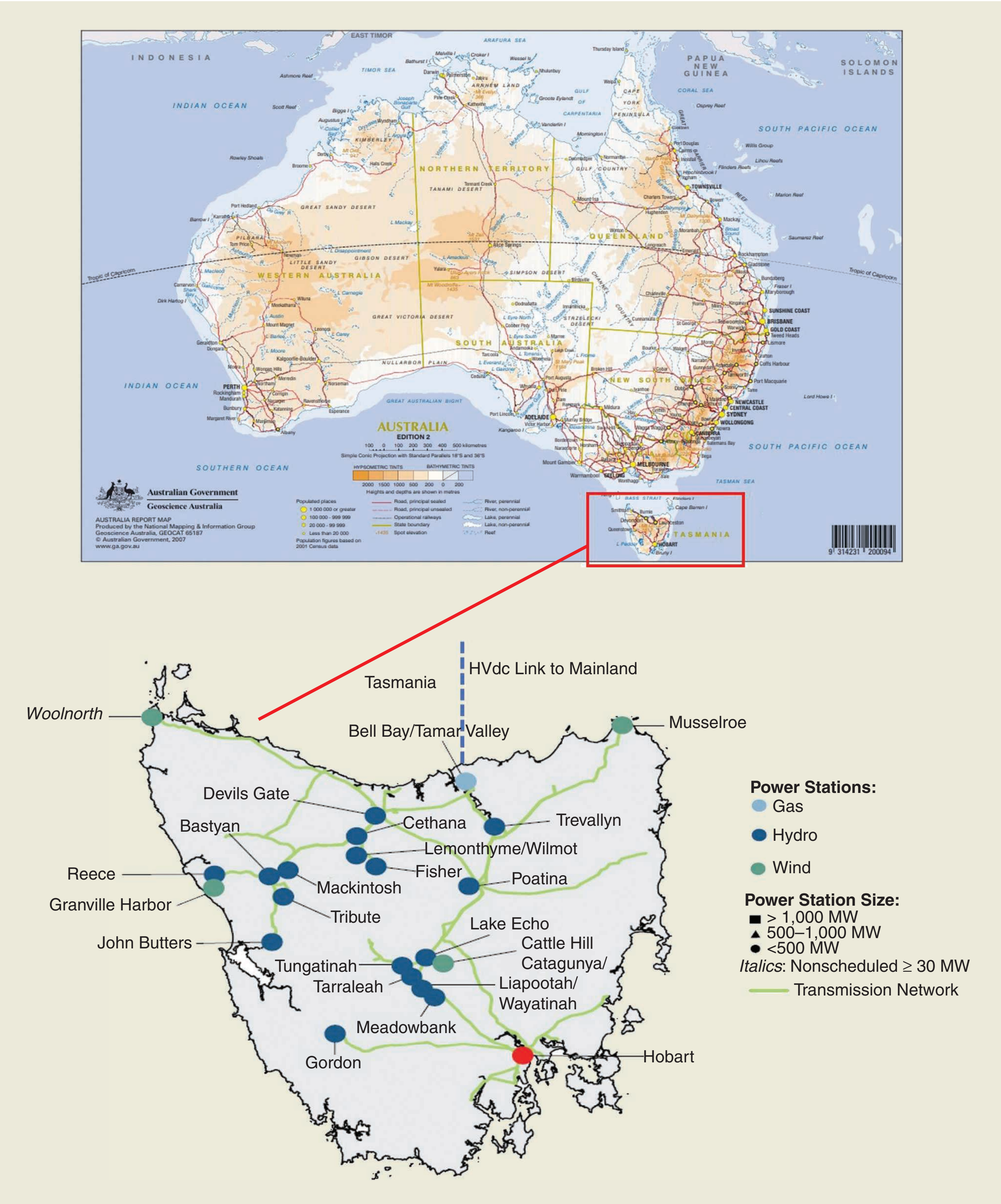

Figure 1. Tasmania—the island state of Australia.

NEM and therefore being directly impacted by a much broader set of changes that are playing out across Australia's eastern seaboard.

The Growth of Wind and Solar

As reported by the Australian Energy Regulator (AER) in its 2021 State of the Energy Market report, a little more than 10.4 GW of new transmission-connected wind, solar, and battery capacity was added to the NEM between July 2017 and March 2021 in a system with an overall demand ranging from 15 to 35 GW. These figures do not include any parallel growth of distributed energy resources, which have also been substantial. As shown in Figure 2, investment in new transmission-connected solar, wind, and batteries has followed the withdrawal of approximately 3.8 GW of black and brown coal generation. Forecasts for the NEM are dominated by similar trends going forward, i.e., the ongoing retirement of aging thermal generation, with energy replacement underpinned by variable renewables of significantly greater capacity.

The NEM features a 5-min security-constrained dispatch process run by the Australian Energy Market Operator (AEMO). This supports network operations by allowing continuous adjustment of generation output and incorporates management of network limits via dispatch constraints.

The increase in variable generation across the eastern seaboard has dramatically altered spot market outcomes at different times of the day, with negative prices, and price volatility becoming a regular feature. A typical example of afternoon spot market conditions is shown in Figure 3, with the states of South Australia and Victoria operating with negative spot prices, which sometimes persist for extended periods, particularly during times of high output from rooftop PV.

Tasmania's Opportunity Through HVdc Interconnection

The outcome of such market conditions is that Tasmania will import during periods of low mainland prices and export when prices rise, typically driven by either high demand and/or low generation output from wind and solar on the mainland. Energy trading is made possible through the Basslink HVdc interconnector and the flexibility offered by Tasmanian hydrogeneration. Most hydro power stations can be readily started when needed or alternatively shut down when cheaper energy options exist. While complicating factors including the risk of spill and managing the water needs of downstream users (including maintaining minimum flows for environmental reasons), the flexibility of hydro is complementary to other Tasmanian renewables that are inherently more variable in nature.

Power flow on the Basslink interconnector is driven purely by energy market conditions. Basslink has a very high utilization, averaging around 66% in 2021. Multiple flow reversals per day are common as are periods of extended operation at full-rated power transfer (in either direction). However, the net annual energy transfer across Basslink is now around zero, with Tasmania recently becoming "energy neutral" in terms of annual energy inflows (from rainfall and wind) versus on-island energy demands.

A Double-Edged Sword

The flexible nature of Tasmania's hydrogeneration fleet, coupled with access to an increasingly volatile electricity

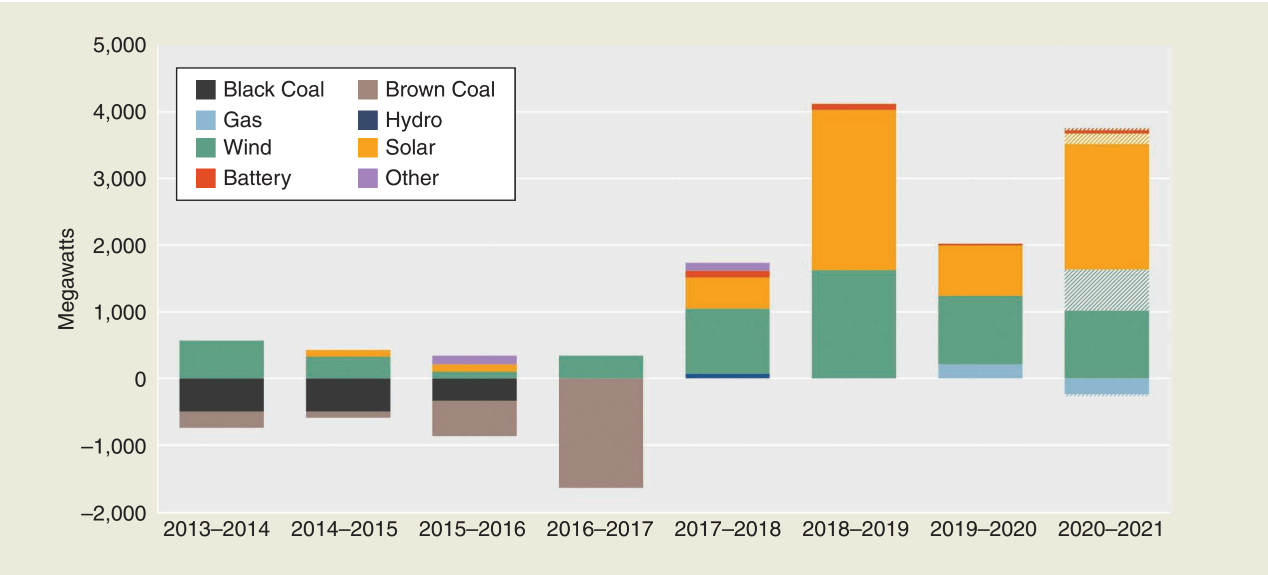

Figure 2. New-generation investment and plant withdrawals across the NEM. Capacity includes scheduled and semischeduled generation but not nonscheduled or rooftop photovoltaic capacity. 2020–2021 data are at 31 March 2021. Investment and closures expected between 1 April and 30 June 2021 are shown as shaded components. AEMO: Australian Energy Market Operator. [Sources: AER; AEMO (data).]

market, creates both opportunities and challenges. While Tasmania can rapidly respond to the energy needs of the mainland, ready access to low-cost mainland energy sources can at times eliminate the need for any synchronous generation in Tasmania.

With the commissioning of the Wild Cattle Hill (148 MW) and Granville Harbour (112 MW) Wind Farms in 2020, the installed capacity of wind generation increased to 568 MW. On 16 January 2021, a combination of low spot prices on the mainland (refer to Figure 3), coupled with excellent wind conditions in Tasmania, resulted in our record instantaneous system nonsynchronous penetration (SNSP) ratio of 91.6%. [The SNSP is the ratio of IBR supply (HVdc imports plus on-island wind generation) to demand drawn from the transmission system.] The peak SNSP of 91.6% was recorded on 16 January 2021 at 3:55 p.m. and comprised 390 MW of HVdc import and 525 MW of on-island wind generation supplying an operational demand of 997 MW. The balance of demand not supplied by wind and HVdc import was supplied by on-island hydrogeneration.

Importantly, high SNSP outcomes have been sustained for significant periods of time and are not "transient" in nature. On 16 January, operation above 80% SNSP was sustained continuously by high wind and HVdc import conditions for nearly 8 h, as shown in Figure 4.

For the calendar year 2021 (see Figure 5), the 95th percentile SNSP was 67.3%, meaning that 5% of all operating periods were above this value. The 99th percentile was 79.6%. While 1% of the time does not sound like much, it equates to three and one half days per year when Tasmanian customers are being supplied from at least 80% nonsynchronous generation. The average SNSP over the year was 23.8%.

System Security Challenges and Solutions So Far

The Tasmanian power system has long had unique performance challenges, particularly in relation to system frequency control. These challenges arise from the relatively large contingency sizes in Tasmania compared to the size of the system as well as the dominance of hydrogeneration, which can exhibit slow governor control action limited by hydraulic time constants. The situation is further exacerbated when system inertia is reduced by hydrogeneration coming offline due to energy market outcomes, as described previously. The ongoing integration of wind generation and the resulting high instantaneous penetration of IBRs have created several new challenges, some of which will be outlined in the following discussions.

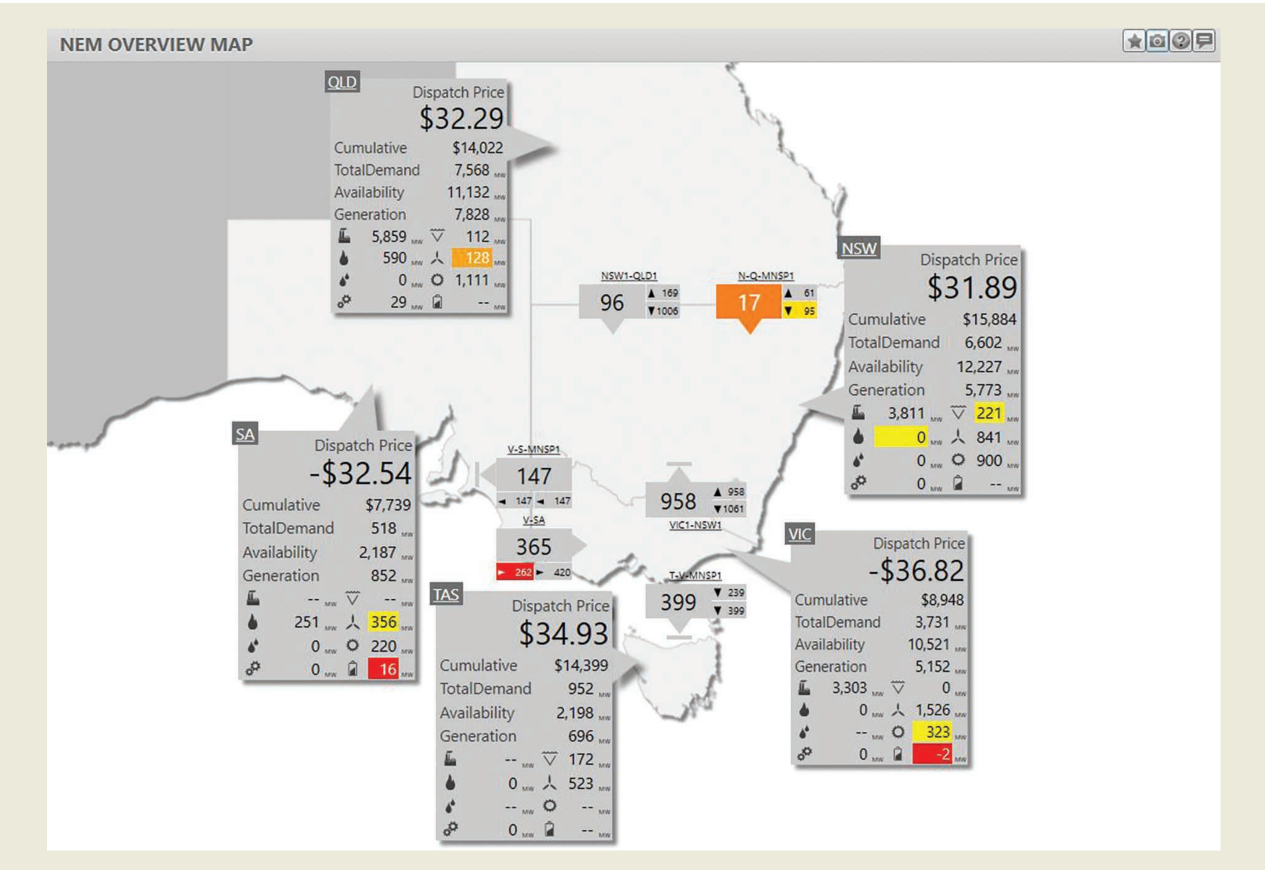

Figure 3. The NEM spot market at 3:55 p.m. on Saturday, 16 January 2021.

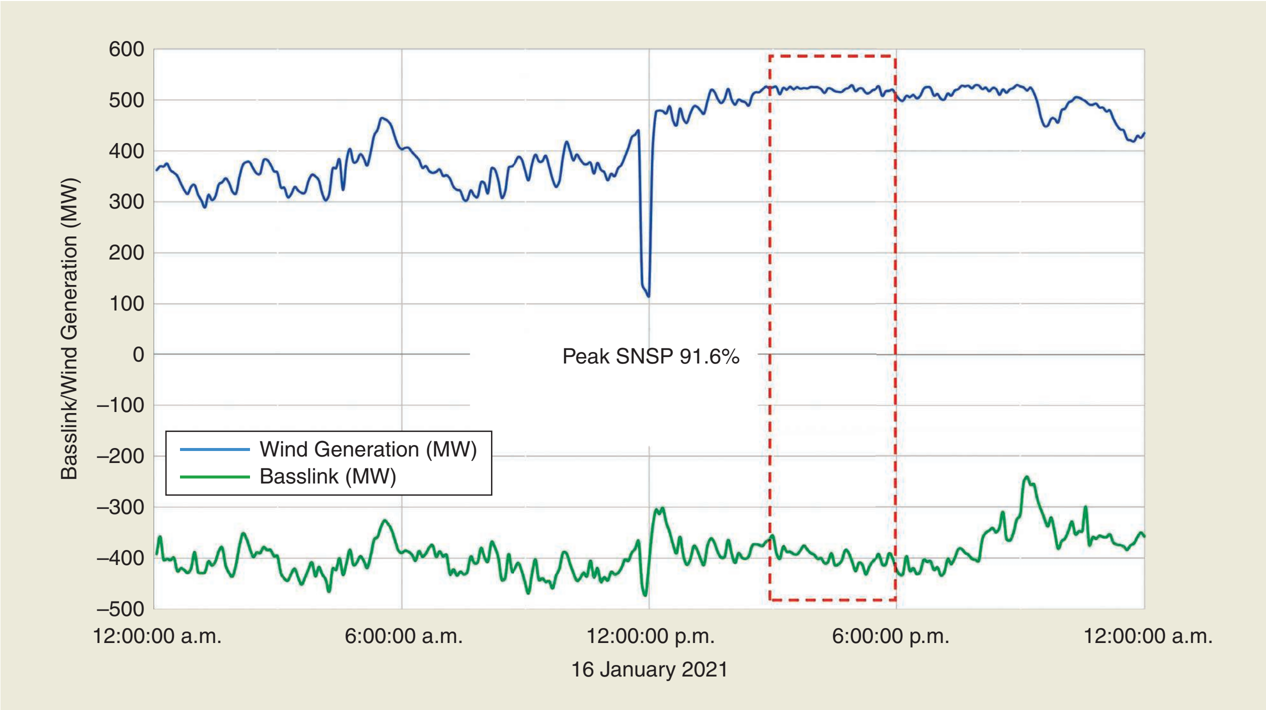

Figure 4. High SNSP operating conditions (and peak nonsynchronous generation) on Saturday, 16 January 2021 in Tasmania. Basslink import into Tasmania is negative in this figure.

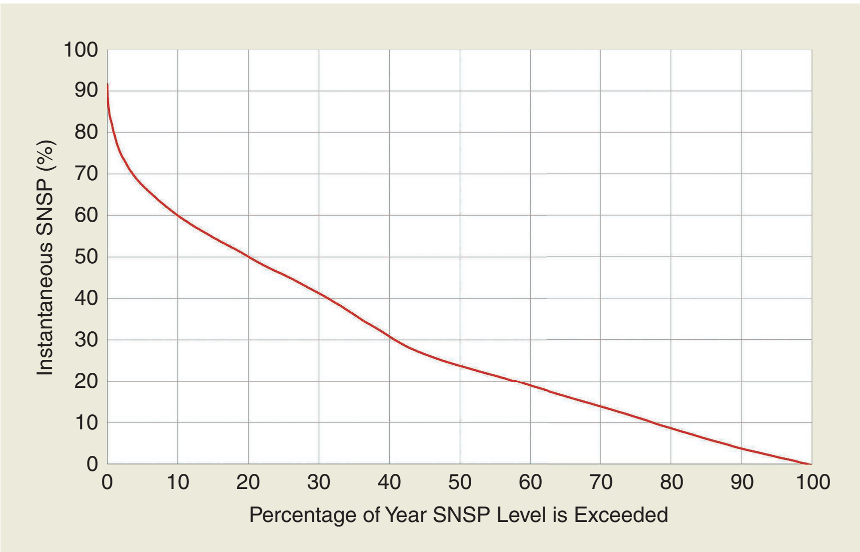

Figure 5. The distribution of Tasmanian SNSP for the calendar year 2021 [5-min supervisory control and data acquisition data (SCADA)].

Managing Loss of the HVdc Interconnector

A key operational challenge for the Tasmanian power system is loss of the Basslink HVdc interconnector. As Basslink is a monopole design, loss of power transfer is considered a credible contingency ($N-1$ planning criteria). With a ±500-MW rating, this particular event can represent more than half of the Tasmanian system and, if not rapidly corrected, would lead to an extreme rise or fall in system frequency, depending on the direction of the power transfer. Because of typical system inertia levels and the relatively slow governor response characteristics of hydrogeneration, this event is unmanageable without the use of a fast-acting control scheme, aptly called the *frequency-control system protection scheme* (FCSPS).

The FCSPS dynamically arms either contracted industrial load blocks (for loss of HVdc import into Tasmania) or generators (for loss of export) to compensate for the Basslink power transfer level. The arming of generators or loads is updated every 4 s based on real-time measurements of system conditions. Upon receipt of a loss-of-link signal from the HVdc converter station, the FCSPS acts to rapidly disconnect whatever load blocks or generators have been prearmed (within approximately 200 ms).

The design of the FCSPS has recently been updated with the introduction of wind farms into the generator arming list for tripping during HVdc export conditions. This ensures that synchronous generation remains online where possible to maximize system inertia after tripping of generation by the scheme. The FCSPS has proven to be very reliable and has correctly acted on all occasions following loss of Basslink, resulting in relatively minor frequency disturbances.

Management of Contingency Sizes

The largest single hydrogenerating units in Tasmania are 144 MW, with this contingency size historically determining frequency-control requirements for the system. This is a relatively large event to manage using "conventional" frequency-control techniques, i.e., non-SPS solutions, being more than 15% of the system under low-demand conditions. The largest single load contingency has also been maintained at approximately 120 MW for some time, resulting in slightly asymmetrical "raise" and "lower" frequency-control requirements, respectively.

The 144-MW maximum generator contingency size limit is now codified in the operating standards for the Tasmanian power system and sets an important "guard rail" when considering future frequency-control requirements. Larger generating systems are still able to connect; however, the standard requires that such installations mitigate their "additional" frequency-control requirements by installing a control scheme that intertrips one or more appropriately sized load blocks. In this way, the "effective" contingency size seen by the power system can be limited to no more than 144 MW. While the operating standards do not yet formally specify a maximum load contingency size, the issue is actively managed to prevent control of overfrequency events also becoming problematic in the future.

The underlying need for management of contingency sizes is related to the availability and cost of sufficient primary frequency-response reserves. In the NEM, frequency-response reserves are managed and procured through the 5-min security-constrained dispatch process. As wind and solar farms have historically not participated in these frequency-response reserve markets, there has been growing supply/demand pressures, which have increased their costs markedly in recent years. This issue is even more critical in Tasmania because of the following one discussed next.

Managing the Rate of Change of Frequency by Maintaining Adequate System Inertia

If absolute contingency size were the only consideration, frequency control would be somewhat more manageable. However, in a power system with a high concentration of IBRs within a geographically small footprint, the phenomenon of the fault ride-through (FRT) behavior of IBRs contributing to frequency disturbances becomes significant. This has been widely reported in other power systems, including those of Ireland and Spain, and it is a notable contributor to both the rate of change of frequency (ROCOF) and frequency nadir in Tasmania.

As an example, the event shown in Figure 6 occurred on 30 August 2020 when nonsynchronous penetration was approximately 70%, supplying a system demand of 970 MW. The failure of an overhead earth wire resulted in a deep two-phase-to-ground fault in southern Tasmania,

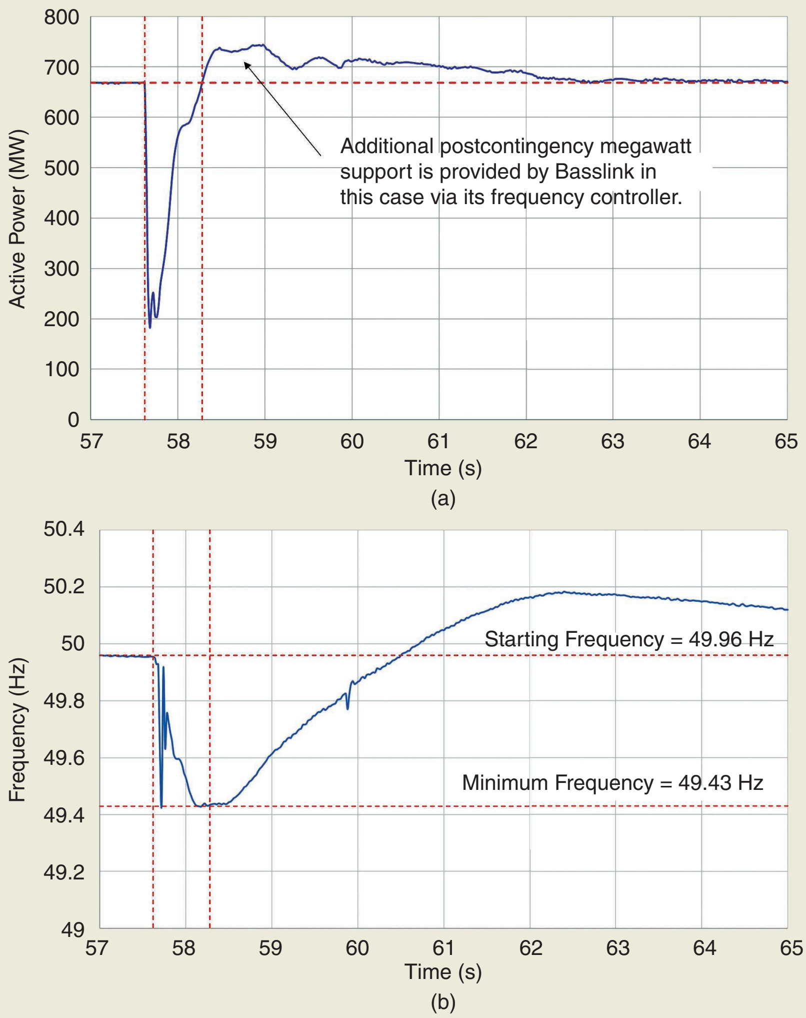

Figure 6. The impact of a deep two-phase-to-ground-transmission line fault on IBR operation and system frequency: PMU recordings. (a) HVdc plus transmission-connected wind generation (response to fault in southern Tasmania). (b) Tasmanian frequency (response to network fault in southern Tasmania). PMU: phasor monitoring unit.

which was sufficient to cause all operational wind farms and Basslink (which was importing at the time) to enter FRT mode. The peak transient power deficiency caused by these IBRs entering FRT was 480 MW, contributing to an energy deficit of 139 MW.s. The minimum frequency was recorded at 49.43 Hz with an average ROCOF measured over 500 ms of approximately 1 Hz/s.

While clearance of the fault did not directly disconnect any generation or load, more than 100 MW of industrial load did ultimately disconnect in response to the voltage disturbance. Given the large initial frequency dip that resulted from the transient power deficiency, despite this overall net loss of load, it is easy to appreciate the compounding effect that the loss of a large generating unit could have for such an event. The overshoot of active power shown in Figure 6 was due to the controls on Basslink automatically increasing power transfer into Tasmania in response to the frequency dip, after it recovered from the initial fault.

A secondary consideration is the potential impact of a larger contingency event involving the loss of multiple generating units. Whereas traditional under-frequency load-shedding schemes may have been capable of managing a particular set of events prior to the connection of significant IBRs, the risk of maloperation due to an increased ROCOF becomes real when FRT-induced energy deficits are included. At an excessive ROCOF, discrimination between load blocks may be lost, resulting in potential overtripping of load, excessive frequency rebound, and progressive loss of frequency control.

The approach to address this issue in Tasmania has two parts.

- The inertia is maintained above a set threshold at all times, effectively defining a minimum floor condition. The current Tasmanian inertia floor is 3,800 MW.s, corresponding to approximately a 4-s H time constant on a system demand of 950 MW. The requirement to maintain a minimum inertia level was codified in the National Electricity Rules in 2017 and fully operationalized by early 2020.
- The megawatt output of the IBRs is constrained through the 5-min central dispatch process as a function of system inertia, such that the peak ROCOF does not exceed 3 Hz/s averaged over 250 ms or exceed 1.1 Hz/s (averaged over the same time frame) as the frequency passes through 49 Hz (noting that the under-frequency load shedding commences at 48 Hz, and the frequency must be arrested above 47 Hz for all events).

The second criterion is linked to the design of the Tasmanian under-frequency load-shedding scheme as well as generator performance standards defined in the National Electricity Rules. The approach of defining two distinct ROCOF periods is broadly consistent with concepts published by the European Network of Transmission System Operators for Electricity in its guidance document on ROCOF withstand capability (January 2018).

With decreasing levels of synchronous generation dispatched in the market at times of high IBR output, minimum inertia levels are now actively managed by operating a number of suitably capable hydrogenerating units in synchronous condenser mode. This has required new commercial and operational arrangements to be developed, including payments to the generator for this service and real-time mechanisms to commit and withdraw the services to manage system security as required.

Maintaining Adequate System Strength

The system strength may be thought of as the “stiffness” of the voltage at any location on the power system. A high sensitivity of voltage magnitude and/or phase angle to changes in reactive and active power flows indicates a “weak” point in the network, usually associated with a high impedance connection back to controlled voltage sources in the “core grid.” With the rapid increase in IBR connections, however, entire areas of network can now at times be classified as weak. A three-phase fault level has been the usual proxy metric to characterize the available system strength, allowing relatively straightforward calculations to be undertaken as part of planning studies and during real-time operation.

The system strength is an important factor for secure operation of a power system. Minimum levels of system strength must be maintained to ensure stable operation of conventional “grid-following” IBRs, particularly following disturbances (including fault events). All IBRs in Tasmania are currently of the grid-following type, which rely on the presence of a suitably stable external voltage waveform against which to synchronize their internal control systems.

The mechanism to manage system strength in Tasmania to date has been to define four “fault-level nodes,” which represent critical points in the transmission network (Figure 7). Through extensive offline analysis, it has been possible to define minimum three-phase fault levels for the intact network, which enable correct operation of IBR equipment, including when it is subjected to key fault events. Network outage conditions are managed as a separate issue, with constraints imposed on IBRs where it becomes impractical to maintain the levels of system strength needed to support maximum power output.

As with inertia, new commercial and operational arrangements have been necessary to maintain minimum levels of system strength during real-time operation. The solution at the present time is largely the same as for inertia, i.e., managing commitment of hydro units in synchronous condenser mode, noting that the system strength is much more dependent on location, requiring available synchronous condensers to be allocated against each of the four system strength nodes.

Other Notable Solutions That Have Been Implemented

Several other innovations have been progressively introduced in recent years to better support the network as the energy transition continues. They include

- Implementation of a "synchronous condenser with fast raise" mode on two 115-MW Francis turbine units. The modifications were successfully designed and commissioned by Hydro Tasmania to enable the provision of frequency-control capability when initially operating as a synchronous condenser. Upon detection of an under-frequency event, the units are capable of automatically transferring back to generation mode within 1–2 s and then returning to synchronous condenser operation once the frequency is stabilized.
- Implementation of a "boost mode" into a number of hydro governor control systems. This involves introducing variable governor tuning, which is responsive to the rate of change of frequency and absolute frequency error. The temporary application of more aggressive tuning parameters during the initial part of a frequency disturbance has notably increased the primary frequency-response capability that can be safely delivered from a number of units.
- Implementation of an adaptive under-frequency load-shedding scheme. This scheme provides frequency-response reserves by tripping commercially contracted and prearmed load block(s) as the frequency falls. It adapts the number of blocks to be tripped as a function of both the measured ROCOF after a disturbance (calculated using a 100-ms filter) and real-time system inertia.
- Provision of continuous primary frequency control from a data center. The data center operator Firmus has recently commenced operations in Tasmania, offering cloud computing services. The business identified an opportunity to provide frequency-response reserves into the existing NEM reserve markets and included this capability as part of their design specification. The site controls are capable of varying the power demand in response to measured network frequency, delivering a proportional active power response, as shown in Figure 8. This primary frequency response is based only on local measurements and does not depend on communication with the system operator. The provision of a continuous rather than a switched response from such a load to a frequency event makes for simpler network integration and a better outcome for the load customer and system.
- Implementation of a wide-area voltage-control scheme. To improve network voltage regulation, especially during times of highly variable IBR output, a centralized voltage-control scheme has been installed, acting in a similar manner to traditional automatic generation control of active power. The scheme is split into two geographic control areas across the north and south of the state. It automatically adjusts the voltage set points of generators to maintain nominated target voltages in the 220-kV network, with an average time constant for control action of approximately 60 s. The scheme also manages the status of switched capacitor banks to maintain "headroom" on dynamically variable sources to improve transient response capabilities.

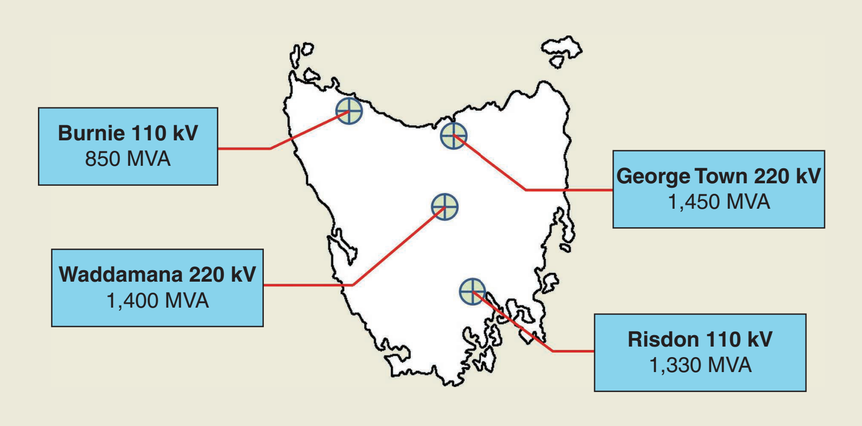

Figure 7. Fault-level nodes in Tasmania.

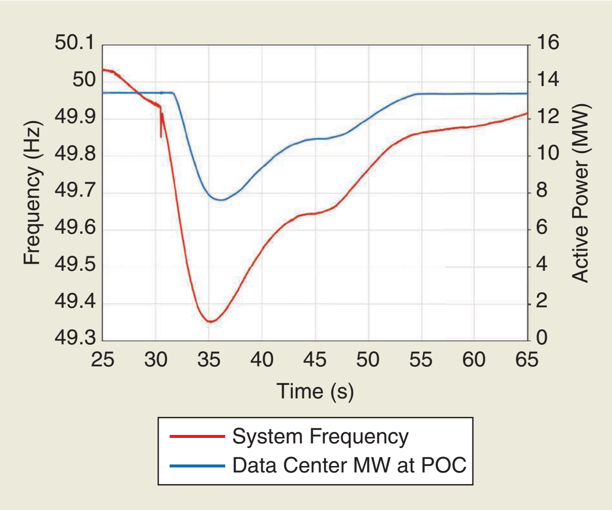

Figure 8. The frequency-control capability delivered from a cloud computing data center located in Tasmania (the response of the Firmus data center to an under-frequency event). POC: point of connection.

Simulations and Real-Time Security Tools Currently in Use

Simulation Platforms and Models

As the owner and operator of the Tasmanian transmission and distribution network, Tasmanian Networks Pty Ltd

(TasNetworks) is responsible for defining the "technical envelope" of the power system. It also works to identify future system security issues that may require either new solutions or modifications to existing processes.

TasNetworks has historically used the software package PSS/E as the primary modeling tool for simulating the dynamic performance of the Tasmanian power system. There has been a long-standing focus on accurate modeling of all synchronous generation, particularly governor control systems, with widespread use of custom-written, site-specific simulation models. This includes detailed modeling of "waterways" to include explicit features, such as the use of common penstocks and distribution manifolds in multimachine stations. Numerous custom excitation system models have also been developed and validated over time.

These models are used for determining system operating limits (the technical envelope) as well as for network planning, generator and interconnector integration studies, and operational analysis. The performances of the customized PSS/E dynamic models have been regularly benchmarked against actual system disturbances, with the models having proven effective at predicting the frequency-control response and stability characteristics of hydrogeneration with suitable accuracy.

In more recent times, the same level of rigor has been applied to transmission-connected wind generation, including the response of reactive power and/or voltage regulation capabilities implemented within park-level control schemes. While the limitations of root-mean-square simulation platforms to replicate all phenomena associated with IBRs are well known, TasNetworks considers that tools like PSS/E will continue to play an important part in planning and operating the power system.

The first "system-level" experience with electromagnetic transient (EMT) modeling occurred as part of planning studies for the Basslink HVdc interconnector, which was commissioned in 2006. With the ongoing growth of IBRs and corresponding reduction of online synchronous generation, accurately predicting the dynamic performance of the system under conditions of low system strength has become an increasing concern and has driven significant efforts to develop and validate EMT models.

This has included detailed reviews of vendor-supplied, site-specific representations of installed plants, where the provision of such models has been required during the connection process. TasNetworks now maintains a complete EMT model in PSCAD software format for the entire Tasmanian power system with specific models available to represent

- the entire 220-kV and 110-kV transmission network, including step-down transformers to lower voltage levels
- all hydro power stations including alternators, excitation systems, power system stabilizers, and governors
- all wind farms, including turbine-level control and protection elements as well as park-level control schemes
- the Basslink HVdc interconnector.

At present, an EMT simulation of 10 s running at 20-μs time steps takes approximately 15 min to complete on a dedicated 20-core computer. TasNetworks is using EMT studies to investigate transient phenomena that are beyond the bandwidth of PSS/E to properly replicate or require a full three-wire representation of the network to be valid, including

- IBR interaction analysis (subsynchronous control interactions)
- FRT behavior, especially for unbalanced fault conditions
- control of reactive current injections from IBR during and immediately following fault clearance (for balanced and asymmetrical faults)
- commutation stability of HVdc
- transformer and transmission line energization studies at low fault levels
- response of IBR protection systems during network faults and the ability of such protection to grade with the characteristics of the network following different types of disturbances, e.g., ROCOF and voltage angle shifts, allowable temporary over voltages, delayed voltage recovery, and temporary waveform distortion.

In 2018, in preparation for increased HVdc interconnection via the proposed Marinus Link, TasNetworks extended its EMT analysis capabilities by purchasing a real-time digital simulator (RTDS) (Figure 9). The RTDS system model now includes the complete transmission network (116 lines), all major generators (63), and all substation loads (55). A major challenge in commissioning the RTDS was to ensure the same accurate performance as existing user and vendor-supplied models available in the PSS/E and PSCAD software packages.

To faithfully replicate the hundreds of user-built governor and excitation models, a conversion tool was developed that automated the creation of RTDS models from existing PSS/E library files. In doing so, a single, proven source of truth was retained for virtually all synchronous plants. Some preexisting wind farm models did not have complete block diagrams available to allow direct conversion and are therefore represented in the RTDS by "tuned" generic models. Negotiating access to vendor-supplied, site-specific models for use in the RTDS is a challenge yet to be fully resolved.

The RTDS has been a useful addition to TasNetworks simulation capabilities and is used for studying the same EMT phenomena as outlined previously as well as for more rapid prototyping of control and protection system designs. As the installed capacity of IBRs continues to increase, TasNetworks has intentions to undertake hardware-in-the-loop testing of transmission line protection relays to ensure that impedance-based elements, including backup distance protection, continue to operate as expected when a different mix of fault current sources is in play.

Real-Time Analysis and Monitoring Capabilities

With an increasing level of IBRs in the network, TasNetworks has been progressively installing phasor monitoring units (PMUs) at strategic locations to improve system visibility, both for real-time and historical analysis. There are currently 55 units in service, providing coverage across the main 220-kV network, key 110-kV subtransmission corridors, all wind farms, the HVdc interconnector, and a number of key load customers. Existing protection relays also provide waveform-level data to support incident investigations.

As part of future proofing the network, TasNetworks has implemented a policy that all new IBR connections, either generation or load, will have a PMU and power quality meter installed at their point of connection. Real-time PMU data have been used to assist with wind farm commissioning activities and network switching operations, and archived data have been used for postcontingency analysis, generator compliance assessment, and model validation exercises.

PMU data are currently used in the control room to provide additional situational awareness for system operators (i.e., confirmation of fault type and severity, improvements in pinpointing fault location, and monitoring of frequency stability and observed ROCOF). Further enhancements to this capability are planned, with real-time oscillation monitoring and alarming the next significant addition.

TasNetworks has also developed a number of analysis tools within its energy-management system to help manage real-time network security, especially at times of high IBR penetration. Real-time fault levels are calculated using a network model embedded in the energy-management system as a proxy for the available system strength. Three-phase fault levels are calculated for key nodes across the system, for both the network in its current state as well as for postcontingency operating conditions, e.g., after the simulated loss of a transmission line.

If the intact network or postcontingency fault levels fall below nominated thresholds, as may occur when synchronous generators are taken offline, alarms are raised, alerting the operators to commit contracted services (as described earlier). In this way, the system strength is actively managed, albeit using an imperfect metric to represent the core technical issue (the existence of an adequate number of voltage sources providing a "grid-forming" capability). This concept will need to be reviewed if grid-forming IBRs, such as battery energy storage systems, are introduced into the network in the future.

As with the system strength, synchronous inertia is also calculated in real time and maintained above threshold values for intact and postcontingency operating conditions. TasNetworks continues to use the online status of synchronous generation as the method to determine system inertia, noting that approximately 40% of the load in Tasmania comprises industrial rectifier or arc furnace loads. This atypical composition results in a significantly reduced inertia contribution from the customer side, with TasNetworks demonstrating through postcontingency analysis that synchronous generators provide the majority of available inertia required to manage the ROCOF. Any inertia provided by load is treated as a safety margin. Inertia contributions from grid-forming converter technology may be considered in the future; however, the Tasmanian power system does not yet include any such capability.

Future Outlook

Looking forward, a big question is whether the Tasmanian power system can be run at 100% IBR penetration, meaning that instantaneous operational demand is fully satisfied from energy sources that are nonsynchronous. Can it be done? We believe that it can, with the right technology mix. Fundamentally, if the three components that define a sinusoidal waveform can be adequately controlled—magnitude, frequency, and phase angle—then it really shouldn't matter from where the active power is sourced.

Part of our future planning involves looking at these concepts and determining the "nonnegotiable"

Figure 9. TasNetworks RTDS laboratory—NovaCor two rack (20-core) system.

must-haves to maintain a secure and reliable power system. While the energy transition being experienced in Australia almost demands novel thinking, taking a live and functioning power system into these realms requires a proper understanding of the underlying physics, which will ultimately determine success or failure.

And in the future it won't just be during times of Basslink import. With the excellent wind resources on offer in Tasmania, the AEMO's Integrated System Plan predicts an installed wind capacity of approximately 3,000 MW by early to mid-2030. This aligns with a state government energy policy of doubling Tasmania's renewable energy production by 2040, which equates to 21,000 GWh of renewable electricity per year above the current baseline of 10,500 GWh. Even with a proposed increase in HVdc interconnection to the mainland (Project Marinus), involving the staged installation of two new voltage source converter monopoles of ±750 MW each, there will be the potential for significant instantaneous IBR penetration even during export conditions.

An alternative future could involve not only increased HVdc interconnection but also the development of new on-island load demand. There are three distinct load types that have the potential to be developed at a scale of many hundreds of megawatts.

- hydrogen, underpinned by a state government initiative to promote green hydrogen development opportunities in Tasmania
- pumped hydro as part of Hydro Tasmania's Battery of the Nation project. Tasmania does not currently have any purpose-built pumped hydro power stations, despite a significant asset base of both hydrogeneration and standalone pumping stations across the state
- The ongoing development of data centers.

While each load type brings with it certain opportunities to support the parallel development of large-scale wind assets, e.g., the provision of continuous frequency-control capabilities and/or flexible load demand capable of "following" the output of variable renewable generation, hydrogen and data centers in particular present their own challenges, given that they are also inverter-interfaced technologies.

Early investigations by TasNetworks suggest that FRT capability, rate of active power recovery (immediately post fault), protection performance, and power quality all will be issues requiring careful attention. We believe that the system strength will continue to be a significant issue in ways potentially not yet fully understood, even if load growth occurs in parallel with new wind generation.

Conclusions

The Tasmanian power system has evolved over time, from an islanded power system dominated by hydrogeneration to one that is interconnected and has now achieved more than 90% instantaneous penetration of IBRs. Notwithstanding the existing synchronous machine capabilities available to help support this result, this is considered a likely record for a gigawatt-scale power system.

It has been achieved with a strong focus on system modeling, particularly regarding system frequency control under low-inertia conditions and stable operation of IBRs under conditions of low system strength. In parallel with developing an understanding of the required technical solutions, the development of new commercial arrangements has been necessary to ensure that minimum levels of these system security services can be maintained irrespective of energy market outcomes.

The availability of multiple hydro machines capable of operating as either generators or synchronous condensers has allowed for more historically proven and well-understood solutions to be adopted thus far. While it has not yet been necessary to incorporate more novel inverter-based solutions (such as grid-forming controls) to achieve high IBR penetration levels, it is likely that the ongoing development of both wind resources as well as the introduction of new load types will continue to emphasize the need for adequate levels of system strength and inertia.

In the future, locational considerations, in parallel with any practical limitations associated with relying even more heavily on hydrogeneration assets, may require that additional security services be sourced from complementary technologies currently in the process of being proven at scale.

For Further Reading

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