Dynamic Operating Envelopes

Regulatory Business Case (RBC) 2024-29

Contents

1. Summary

This business case has been prepared to support the 2024-29 Regulatory Proposal. The business case demonstrates that Power and Water has undertaken appropriate analysis of the need and identified a full suite of credible options that will resolve the need, to ensure that Power and Water continues to meet the National Electricity Objectives and manage the network prudently and efficiently.

The project/program identified in this business case will undergo further assessment and scrutiny through Power and Waters normal governance processes prior to implementation.

This business case addresses the local network constraints which impose limits on the hosting capacity for distributed energy resources (DER) connected to the distribution network and threaten system security.

1.1 Business need

The Northern Territory (NT) is experiencing the second highest per capita uptake of rooftop solar PV systems ('rooftop solar') in Australia. By 2030, the Darwin-Katherine Electricity System Plan projects installation of up to 140MW of new small-scale solar, a 200% increase on current levels, accounting for up to 22% of total yearly generation for Darwin-Katherine Interconnected System ('DKIS') customers. The trends are likely to be similar for the Alice Springs and Tennant Creek networks.

The projected increase in the penetration of rooftop solar across the regulated networks and flat to moderate demand growth projections has led to the Utilities Commission to forecast steadily reducing system minimum demand.

The need for the project arises from our analysis of the network's ability to accommodate a forecast increase in the uptake of rooftop solar and forecast steadily reducing system minimum demand. Minimum demand conditions more typically occur overnight, but now regularly occur during the daytime. The analysis has been informed by an assessment of our network hosting capacity and impending problem of minimum demand events,[1] the binding constraint in the 2024-29 period.

The increased solar export is currently leading to localised excessive voltage rises and an increasing risk to system security at times of minimum demand. Similar issues have been experienced by other network utilities in Australia.

Addressing the root cause of localised voltage excursions will also address the system security risk.

A 'minimum demand event' describes any period of time when demand falls below the threshold necessary to maintain power system stability in the situation where a system disturbance happens at the same time (e.g. generator trip, fault on the power system). The consequence of a minimum demand event and a concurrent system disturbance is a system black event.

[1] A 'minimum demand event' describes any period of time when demand falls below the threshold necessary to maintain power system stability in the situation where a system disturbance happens at the same time (eg generator trip, fault of the power system). According to NTESMO, a gas generator trips roughly once every six days.

Absent any other form of intervention to prevent or mitigate the increasing frequency of minimum demand events and the risk of system blacks from occurring, NTESMO would rely on Power and Water to shed net generating parts of the network, resulting in widespread involuntary outages and undermining reliability. Power and Water has little visibility of the LV network, making it difficult to identify these regions. Its approach to shedding is therefore necessarily crude, effected by disconnecting parts of the LV network at the feeder level, which causes involuntary outages for all customers within the feeder area, regardless of whether they are net generators.

Power and Water does not have sufficient understanding of the performance[2] of the low voltage network with rooftop solar, battery storage, and electric vehicles. This limits Power and Water's ability to quantify the capacity of the LV network locally and in aggregate to 'host' solar export. Lack of LV network visibility also reduces the means of determining the best remedies to network performance issues and hinders an assessment of how voltage limitations may impact the network in the future.

Without a more sophisticated response to integrating DER[3] into the Power and Water networks, the likely responses to minimum demand conditions will be limited to:

- Tightening the static export limits on residential and commercial and industrial ('C&I') connections, thereby curtailing solar export year-round, not just during minimum demand events; and
- Augmenting the network to meet increasing peak demand resulting from evening EV charging.

Power and Water observe that other DNSPs are responding to the same issues as those being faced by Power and Water. In developing this business case and the underlying cost-benefit model, Power and Water has engaged with SAPN and other DNSPs, consultants, and vendors who are familiar with the technical, stakeholder, and commercial aspects of development of responses to the minimum demand challenge.

After extensive conversations with our People Panel and at two Future Network Forums, it is clear that our stakeholders expect Power and Water to be an active leader in facilitating renewables in the energy system, and to make prudent investments where there are clear benefits. We have taken this feedback into account in identifying and assessing options to address the existing and forecast minimum demand impacts.

This business case considers adoption of more flexible and dynamic management of export from solar PV systems through the use of dynamic operating envelopes (DOEs) that enable access increased number of connections and a larger capacity of solar PV installations. The prevailing advantage of DOEs is that they allow for maximum use of low cost renewable energy. They also provide the capability for our network to better manage electric vehicle charging in the future, which is consistent with our strategic priority to better utilise the network and electricity system.

[2] Such as voltage levels, which must be maintained within prescribed limits but are affected by rooftop solar output

[3] Distributed energy resources (DER) is the name given to renewable energy units or systems that are commonly located at houses or businesses to provide them with power. Another name for DER is "behind the meter" because the electricity is generated or managed 'behind' the electricity meter in the home or business. Common examples of DER include rooftop solar PV units, battery storage, thermal energy storage, electric vehicles and chargers, smart meters, and home energy management technologies. (Arena)

1.2 Options analysis

The following options have been considered for addressing the impacts of minimum demand.

Table 1 Summary of credible options

Option No.	Option name	Description	Recommended
1	Strict export limits	(Base Case) — revise the residential static export limit on residential rooftop solar installations from 5kW to 2.3kW from 2028 to curtail solar export year-round.	No
2	Comprehensive DOEs	Invest in dynamic operating envelope ('DOE') capability and offer dynamic solar export limits to all customers with distributed energy resources from 2028.	Yes
3	Targeted DOEs	Invest in dynamic operating envelop capability and offer dynamic solar export limits to commercial and industrial ('C&I') customers with distributed energy resources from 2028.	No
4	Other non-network and network options	Invest in infrastructure to offset the contributors to minimum demand.	No

1.3 Recommendation

Option 2 is the recommended option at a total estimated cost of $92.7 million (real 2021/22), with $17.9 million (real 2021/22) to be incurred in the 2024-29 regulatory period. Option 2 yields the highest return and represents the most efficient and prudent investment option.

The premise of Options 2 and 3 is that the dynamic solar export limits afforded by applying DOEs will reduce the frequency and extent of curtailment of solar export from rooftop solar compared to the Base Case. Options 2 and 3 are based on estimating the capacity of a network feeder to host the export of rooftop solar installed on that feeder. The hosting capacity would be updated regularly (e.g. every 5 minutes).

Understanding the hosting capacity will assist with achieving the NT Government's objective of achieving 50% of generation from renewable sources by 2030, reduce the payback period for new/upgraded rooftop solar installations, reduce the risk to system security from minimum demand events, and will inform future investment decisions to expand that network hosting capacity.

In the table below, we show the forecast capex and opex included for the 2024-29 regulatory period.

Table 2 Forecast annual capital and operational expenditure ($m, real FY22)

Item	FY25	FY26	FY27	FY28	FY29	Total
Capex	0.550	0.685	4.709	2.489	2.782	11.216
Opex	0.600	0.600	1.720	1.815	1.958	6.693
Total	1.150	1.285	6.429	4.305	4.740	17.909

Over the study period, the benefits of the preferred investment option are expected to exceed $124.9 million (real 2021/22), resulting in a net present value ('NPV') of $32.1 million and a benefit to cost ratio of 1.35. The quantified sources of benefits of the preferred option compared to the Base Case are:

- Avoided solar export curtailment of residential rooftop solar;
- Avoided or deferred network augmentation expenditure;
- Reduced cost of electric vehicle charging; and
- Avoided greenhouse gas emissions.

The cost-benefit analysis only includes the benefits associated with reduced curtailment of rooftop solar export from residential premises. The benefit of reduced solar export curtailment of C&I solar installations has not been estimated as yet. The benefit from the C&I sector is expected to be significant and Power and Water is working on estimating the value – it will be included in a subsequent version of this business case.

Therefore whilst the full benefit of the preferred Option 2 has not yet been captured, the full benefit would be delivered at the estimated cost of $92.7 million (i.e. at no extra cost for the C&I sector).

The benefits estimation approach does not include quantification of the value of improved information that results from improved low voltage ('LV') network visibility.[4] LV network visibility will (i) help with efficient and safe network operation despite the increased complexity introduced by DER, and (ii) help with

A lesson from other utilities facing the same minimum demand challenge as Power and Water is that it takes several years to develop an alternative to imposing static limits to curtail solar export. Other DNSPs are having success both technically and economically by developing the capability to allow customers with rooftop solar to elect to receive flexible (or dynamic) solar export limits.

orchestrating the utilisation of DER for the benefit of customers.

[4] Mainly voltage, current, power flows, power factor, solar export, demand at premises

2. Identified need

This section provides the background and context to this business case, identifies the issues that are posing increasing risks to Power and Water and its customers, describes the current management program, highlights challenges and emerging issues, and provides a risk assessment of the inherent risk if no investment is undertaken.

2.1 Background

2.1.1 A global shift to renewables

Around the world, environmental and economic pressures are resulting in the phase out of fossil fuel generation and increased investment in new forms of renewable generation – such as wind, solar PV, hydro and others. In the NT, the penetration of renewable energy resources, particularly large scale solar PV, has occurred at very high rates and will continue to increase to align with the NT Government policy to have 50 per cent of electricity supplied by renewables by 2030.

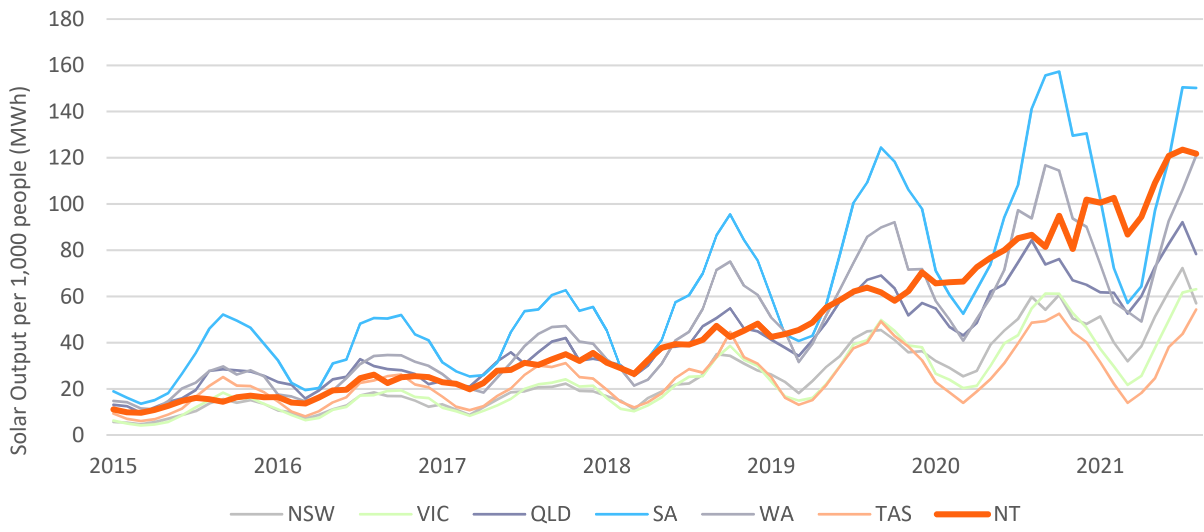
2.1.2 Our customers are becoming more involved as generators

Until recently, all electricity was generated at large scale power plants. Over the last decade, we have seen more of our customers produce solar PV and use our network to export their power to other customers.

In aggregate, rooftop solar PV is already one of the largest generators in the NT with its capacity being around 78 MW in the DKIS alone. Figure 1 presents the population-adjusted PV output for the NT and other Australian states, and as of 2021 clearly shows the rate of increase in the NT's solar PV output (which is under-pinned by increasing solar PV installations). The installed capacity represents around 17% of the total generation capacity, or 9% of total energy generated. This is consistent with other states in the NEM, where rooftop solar PV installations represent around 16% of the total generation capacity. About 25 per cent of households in the NT have a rooftop solar PV system, which is a higher proportion than in the Tasmania and Victoria, and uptake is rapidly growing.

Across Australia and in the Northern Territory customers are leading the transition to a decarbonised electricity system. Second only to South Australia, the NT is experiencing the highest per capita uptake of rooftop solar PV. We have seen a 1,200 fold increase in solar PV over the last 10 years.

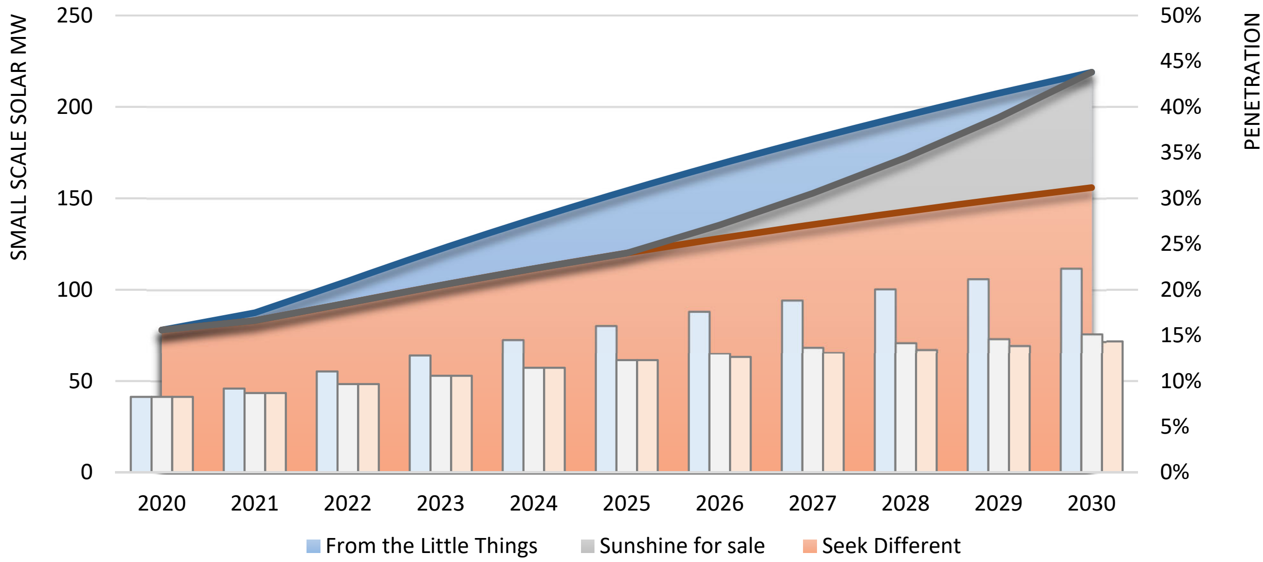
Figure 1: Population Adjusted PV Output by Jurisdiction



Source: APVI postcode data, Engevity analysis

Most homes in the Territory will have rooftop solar PV over the next ten years. At times, solar PV may power everything – including EVs, home batteries, air-conditioners and hot water systems. The Darwin-Katherine Electricity System Plan has forecasted small scale solar uptake for our biggest regulated network over three possible future scenarios, shown in Figure 2. By 2030, the DKESP projects up to 140MW of new small scale solar, a 200% increase on current levels, accounting for up to 22% of total yearly generation for DKIS customers. We expect these trends to be similar for our Alice Springs and Tennant Creek networks.

Figure 2: Forecast uptake of small scale solar - DKIS

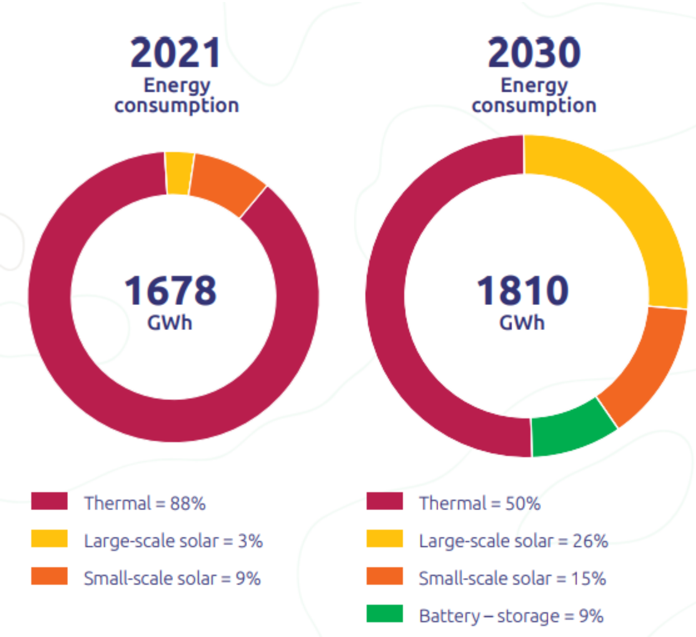


2.1.3 Large projected increase in solar power installations in the NT

The changing energy generation mix is challenging how electricity flows through our networks. Power and Water is responsible for developing its network in a way that facilitates the Government's renewable energy target. Our customers are also increasingly pushing for cleaner forms of energy, including their high uptake of DER.

The figure below shows the expected change in generation mix between 2021 and 2030 necessary to achieve the NT Government's 50% Renewable Energy Target by 2030. Under the scenario shown, by 2030, 50% of underlying energy will be met by renewables, consisting of 15% small-scale solar and 26% large-scale solar, with 9% from utilising battery storage.[5]

Figure 3: Projected change in generation mix in the Darwin-Katherine system by 2030



Source: Darwin-Katherine Electricity System Plan, Figure 6

2.1.4 Integrating DER requires a new approach to energy flows

Increasing renewables and DER exports are currently impacting the performance of our network. This is creating consequential costs, and the need for new investment to maintain customer reliability and quality of supply and facilitate even higher solar PV penetration.

The uptake of solar PV has fundamentally changed the way our distribution network is being used. Our customers now expect us to actively facilitate a more open, dynamic mix of generation, consumption and storage as their energy and lifestyle technologies evolve.

[5] The remaining 50% of electricity generation will come from more efficient and agile thermal energy, including a new plant that is compatible and ready for a hydrogen future.

Two-way electricity flow means that we are now managing different peak 'usages' of our network – with peak exports (solar feed-in to the grid) during the middle of the day, while the traditional evening peak imports (consumption) remains.

In the absence of new approaches, higher renewables and DER penetration creates risks of:

1. Overloading of existing assets, particularly at times of peak solar PV export;
2. Exceeding quality of supply (voltage) tolerances – risking damage to customer and network equipment, causing customers' inverters to disconnect or curtail, increasing transient variations and flicker;
3. Reduced resilience of the network to faults, whereby relatively small network perturbations could place the stability of large portions of the network at risk; and
4. Challenges to the management of power system security as minimum operational demand levels decrease and shift to daylight hours.

In addition, a rule change in August 2021 made by the Australian Energy Market Commission (AEMC) has put new obligations on Power and Water to provide export services to our customers, increasing the need to invest in enabling two-way flows. New requirements include that we are not able to offer a static zero export limit to a small customer who seeks to connect DER to the network (with some exceptions), and we must offer a 'basic export level' under each proposed export tariff to allow our customer to export to the grid without charge (among other things). This means we must be more proactive in managing network constraints – which underlies the importance of Power and Water's Future Network Strategy – that reflects a whole of system response.

2.2 Challenges, Risks and issues

2.2.1 Managing the challenges of a transitioning power system

The transition from a small number of centrally located, fossil fuel generators to a wider mix of large scale solar, rooftop PV and batteries means our power grid needs to be operated differently. Renewable technologies generate electricity differently and they are located where the renewable resource is high, which may not be where the current network is set up to manage large energy flows.

Power and Water has identified several key challenges arising from the forecast connection of renewable generation that may compromise reliability and security of electricity supply in the short to medium term.

Power and Water must evolve its network to support the uptake of large- and small scale renewables, while navigating these technical challenges to ensure energy supply to customers remains secure and reliable throughout the energy transition. In particular, Power and Water will need to strengthen its existing network infrastructure, invest in new infrastructure and capabilities, and explore better ways to manage the voltages across its networks.

Over the next five years, each of the key technical challenges driving this business case are explored.

2.2.2 Minimum demand conditions

Whilst traditionally, power systems have been primarily designed to cope with maximum demand, the transition to renewable generation and more efficient energy use has led to issues with safely and securely operating the electricity network and the power system at times of minimum demand.

Causes of minimum demand conditions

Minimum demand conditions more typically occur overnight, but now regularly occur during the daytime due to factors including:

- The increase in distributed energy resources (DER), particularly rooftop photovoltaic (PV), referred to above, reducing the requirement for supply from large generators;
- Lower economic growth and higher efficiency equipment, resulting in lower levels of demand; and
- Retirement of old generating plant, shifting the mix of generation from large-scale synchronous power generation to non-synchronous renewable generation (such as large-scale and small-scale solar).

'Minimum demand events' occur when the demand falls below thresholds which may lead, in the worst-case, to system blackouts, and more typically, local supply power quality issues. Minimum demand events usually occur with a coincidence of the following:

- Mild weather (in spring/autumn), which leads to relatively low or no demand for heating and cooling via air conditioners; and
- Sunny days on the weekend in the dry seasons which are characterised by:
  - relatively high solar PV output (on sunny days), which leads to less system demand from premises with PV and net generation from PVs into the system,
  - lower commercial demand for power.

Several other factors can contribute to change in minimum demand over time, namely changes in:

- Population size;
- The composition of customer types (e.g. industrial, business and residential);
- The profile of underlying demand of each customer type; and
- The removal of 'step' or 'block' loads (e.g. through relocation or closure).

The adoption of rooftop solar and, to a lesser extent, electric vehicles (EVs) are expected to account for most of the change in minimum demand over the regulatory period and beyond. Increasing penetration of rooftop solar will decrease the proportion of underlying demand met by synchronous generators via the grid. An increase in the adoption of EVs will alter the profile of underlying demand, particularly for residential customers, and will depend on the charging profile adopted by these customers.

Minimum demand forecasts

Minimum demand in the Darwin-Katherine network is forecast to fall below the existing 67MW threshold in 2025-26 and continue to decline to 13MW by 2030-31.[6] Figure 4 below shows the minimum demand forecast for the Darwin-Katherine system, which shows the expected decline below the 67MW threshold from FY23.

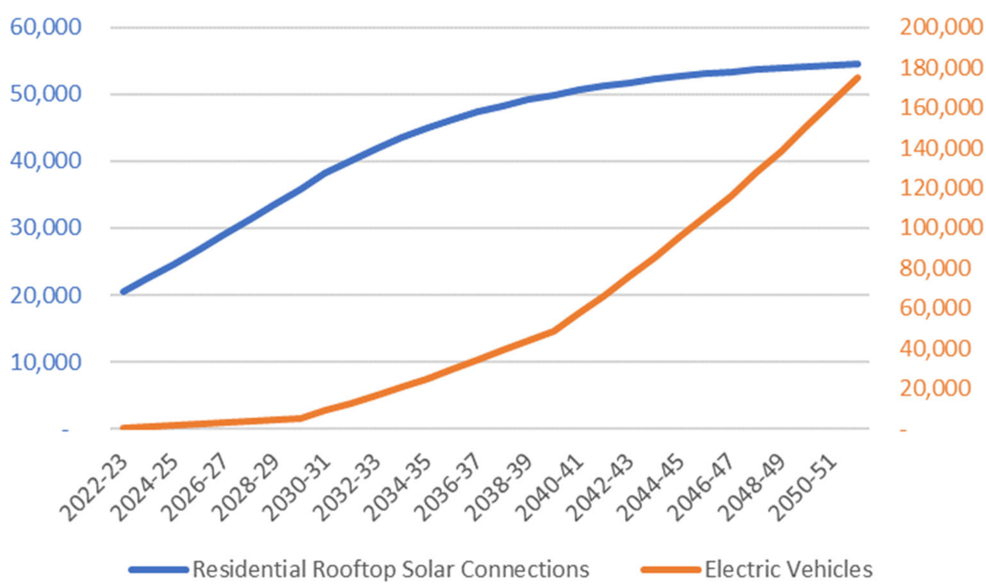
[6] Energeia's PWC System Forecast Draft Results, page 22.This study result is similar to the Utility Commission's 2021 NT Electricity Outlook Report forecast of '*below 20 MW at the end of the outlook period*', which is FY31 (page 7)

Figure 4: Historical and forecast minimum demand in the Darwin-Katherine system, Darwin node

Source: 2021 NT Electricity Outlook report, Utilities Commission

Minimum demand is likely to continue to deteriorate until the mid-2040s, reflecting the continued penetration of rooftop solar, albeit at a decreasing rate. From the mid-2040s minimum demand is likely to increase marginally, as the uptake of EVs counteracts slowing rooftop solar growth, as shown in Figure 5.

Figure 5: Projected quantity of residential rooftop solar installations and EVs in the NT



Source: DOE Business Case Model 111122

2.2.3 Minimum demand and the impact on localised power quality

Planning criteria

Power and Water's planning decisions are based on the requirements of the Network Technical Code and Network Planning Criteria ('the Network Technical Code'). Further, Power and Water has a regulatory obligation to adhere to good electricity industry practice when providing network access services and in planning, operating, maintaining, developing and extending the electricity network.

The Network Technical Code sets out network performance criteria including frequency, quality of supply, stability, load shedding, reliability, steady state criteria, and safety and environmental criteria. It also sets out power system security requirements.

Breaches of voltage criteria at minimum load

The NT networks were designed for one-way energy flows from substations to consumers. Until recently these networks have been able to accommodate the exports of electricity generated from rooftop solar.

The limit to the quantity of solar exports the low voltage network can accommodate at any given time and location under existing grid operating conditions, without adversely impacting safety, power quality, reliability, or other operational criteria, and without requiring significant infrastructure upgrades is referred to as the 'hosting capacity' of the network. As solar exports reach the hosting capacity limit, it can cause both localised excessively high voltage levels at times of minimum demand and thermal overloads[7] of network assets at times of peak demand (e.g. due to reverse power flow), requiring corrective action.

Excessive voltages arise when DER generating units export to the grid during periods of low demand and the capacity of the system to regulate the voltage is limited.[8] Rooftop solar systems are generally designed and configured to reduce output or disconnect from the grid (i.e. trip) when the upper network voltage limit is reached to ensure the LV network operates within its technical capability.

Assessment of hosting capacity is extremely limited but over voltages are prevalent

Power and Water has a poor level of visibility of its LV network through a small stock of advanced metering infrastructure and network monitoring devices to identify excessive solar export before it becomes an issue for the network. This means that Power and Water is only identifying constraints to hosting capacity on an ad hoc basis.

However, comparison of the prevalence of rooftop solar in the NT with the penetration in Australian states such as South Australia indicates that there is a current and increasing level of voltage non-compliance in

[7] Thermal issues arise where equipment is not able to carry any more power because the equipment has reached its upper temperature limit. Continually operating network equipment beyond its thermal limit will lead to overheating, reducing its working life or leading to equipment failure. To mitigate this risk, Power and Water usually choose LV fuses and set circuit breakers so that supply is interrupted when temperature limits are exceeded.

[8] Network responses to over-voltages is via transformer tap changing, switching in shunt reactors, switching off shunt capacitors, changing voltage set points, and deploying dynamic devices such as STATCOMS, SVCs, and synchronous condensers; generators, including batteries, can help control over voltages by absorbing reactive power

Power and Water's networks. Failure to act soon will lead to widespread issues, including reputational damage for Power and Water and the NT Government.

Excessive solar export is identified as the root cause of power quality issues when investigating customer complaints about such things as their solar inverter switching off, burnt out appliances, or voltage flicker.

In October 2022, Power and Water identified high voltages on the network in the Katherine region and in Alice Springs when conducting routine power flow analysis as part of the rooftop solar connection process. The high voltages are caused by excessive solar export on these feeders in the middle of the day (i.e. a minimum load period).

2.2.4 Minimum demand and the impact on system security

System Strength

System strength is the measure of a power system's ability to maintain voltage stability following faults or disturbances and it is critical to a secure power system. Historically, system strength has been supplied by synchronous generators, such as coal-fired, gas-fired, and hydro.[9] In the NT, gas-fired synchronous generators have an inherent rapid response, absorbs reactive power up to their operating limit to help reduce system voltages. To avoid absorbing too much reactive power (i.e. beyond the reactive power absorption limit, which varies from generator to generator), synchronous generators will trip. During times of minimum demand, few synchronous generators are on line, so the collective react ive absorption capability is correspondingly low. An unplanned trip of a single generator may lead to cascading failure of the remaining synchronous generators and system black.

Solar generation does not provide the same inherent essential system services support as the gas generators. As solar generation displaces gas generation the supply of system strength has reduced. Currently there are insufficient tools to control small-scale solar to maintain the demand-supply balance and protect the security of the power system.

NTESMO actively manages the dispatch of energy from centralised generators to maintain precise supply and demand balance. A minimum number of these centralised units must be online, at or above minimum generation levels, to supply essential system security services, including system strength, inertia/frequency control, voltage control/reactive power management, and ramping management.

To support the minimum generation levels of the units that provide the services required for the secure operation of the grid, NTESMO estimates that a minimum of approximately 67 MW of net operational demand is required in the Darwin Katherine system at any given time. Below this level, there is risk of insufficient system strength to cope with the impacts of a major system disturbance. According to NTESMO, a gas generator trips roughly once every six days. If tripping occurred during a period in which operational demand is below this 'minimum demand threshold', a system black event would likely occur.

Following the installation of TGEN's proposed security battery energy storage system ('security BESS') in 2024, the minimum demand threshold is predicted to fall to 50MW.

[9] Similarly, the inertial response of synchronous generators provide a 'frequency control service'.

Minimum demand events can lead to involuntary curtailment of rooftop solar exports

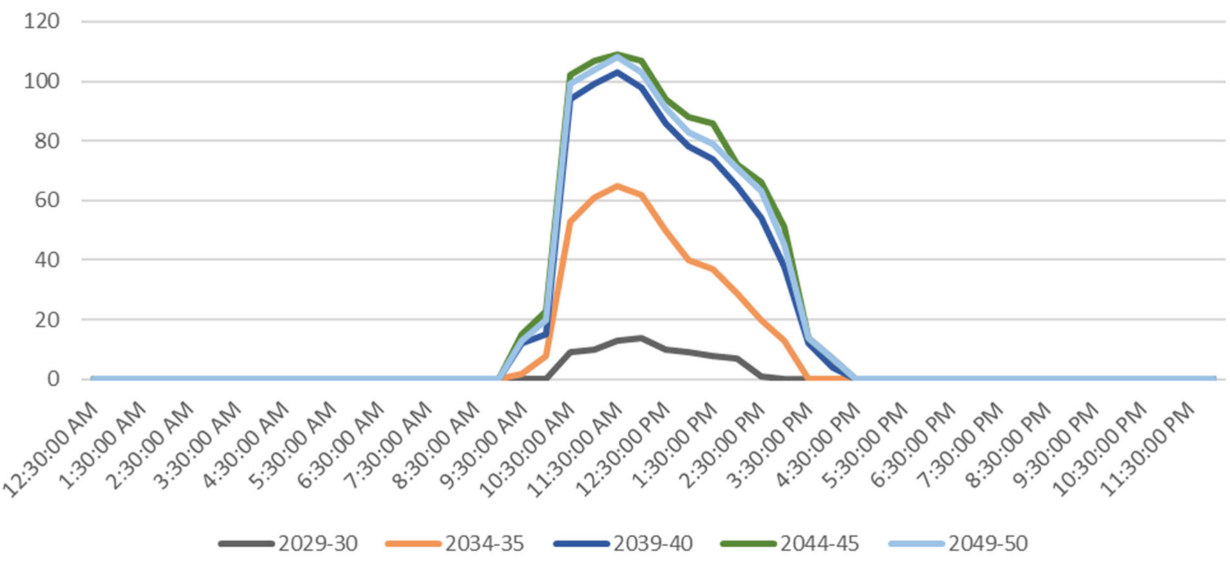
In the absence of effective interventions, the projected increase in the penetration of rooftop solar across the regulated networks combined with the modest projected demand growth will increase the frequency of events where minimum demand is below the threshold necessary to maintain adequate system strength.

These are referred to in this business case as minimum demand events.

Without another form of intervention to eliminate or at least mitigate the frequency and impact of minimum demand events, it is likely that NTESMO will more frequently instruct Power Services to temporarily disconnect sections of the network, tripping solar power export from rooftop solar systems to remove excess the generation.

The minimum demand is forecast to fall below the 50MW threshold for the first time in 2028-29. From 2029-30 onwards, minimum demand events are projected to become more frequent. Minimum demand events are projected to occur on more than 60 days of the year by 2034-35 and 100 days of the year by 2039-40 as seen in in Figure 6.

Figure 6: Projected frequency of minimum demand events in Darwin-Katherine, by half-hour internal, by year (1 x security BESS)



Source: DOE Business Case Model 111122

Lack of LV visibility and control means curtailing rooftop solar output is indiscriminate

Power and Water has started to identify localised power quality issues in areas of concentrated rooftop solar. The low visibility across the low voltage (LV) network prevents Power and Water from adequately quantifying the hosting capacity across the network and to make informed decisions about how to most effectively mitigate the localised power issues that result from increasing penetration of rooftop solar.

Absent any other form of intervention to prevent or mitigate the increasing frequency of minimum demand events and the risk of system blacks from occurring, Power and Water's future approach to shedding rooftop solar in response to NTESMO's directions may be crude, effected by disconnecting parts of the LV network at the feeder level, and causing involuntary outages for all customers within the feeder area, regardless of whether they are net solar generators or not. This may mean that not only customers with rooftop solar are left without supply (and with 'tripped' solar panels), so are all the other customers in the section(s) of the network that is disconnected. Absent other effective measures, this indiscriminate curtailment of customers is necessary to help avoid system instability and possible black-out in addition to the current static limits that are imposed on new connections.

2.2.5 Static export limits on rooftop solar

As a very coarse form of control over solar export to mitigate the sort of local power quality and system security issues described above, an export limit of 5kW is imposed on single phase solar installations.

This is referred to as a 'static export limit' as it applies at all times of the day and year, regardless of whether there is sufficient hosting capacity to allow greater solar export or whether the 5kW export limit collectively causes local or system issues.

In our counter-factual 'base' case, rooftop generation is curbed by imposing a lower static export limit for new connections and for customer who modify/upgrade their existing installation. In addition, voltage limitations will likely increase as solar penetration increases over time. Currently, with the limited LV visibility we are unable to assess how voltage limitations may impact the network in the future.

2.3 Experiences and responses in other states

Power and Water's existing and imminent issues with localised power quality and system security issues has been experienced by other utilities in Australia to a greater or lesser extent.

2.3.1 SAPN Example

South Australian Power Networks (SAPN) has for example embarked on a method of integrating rooftop solar with the grid that it refers to as Flexible Exports in response to the same local and system wide issues that Power and Water face. Solar penetration in SAPN's network is even higher than the NT's but the NT is following a similar trajectory. SAPN's initiative is based on offering 'flexible solar export limits' rather than a lower, fixed export limit of 1.5kW. SAPN states that:

> *'This means that more customers may benefit from investing in rooftop solar, with higher exports, less solar energy wasted, greater reliability of solar systems and a more stable electricity supply.'*[10]

2.3.2 Power and Water is learning from the experiences of others

In developing this business case and the underlying cost-benefit model, Power and Water has engaged with SAPN and other DNSPs, consultants, and vendors who are familiar with the technical, stakeholder, and commercial aspects of development of responses to the minimum demand challenge.

[10] https://www.sapowernetworks.com.au/future-energy/projects-and-trials/flexible-exports-for-solar-pv-trial/

2.3.3 Relevant industry reviews

Where relevant we have drawn from industry reviews and reports relevant to our issues.

A report by the Distributed Energy Integration Program (DEIP)[11] working group, published by ARENA, focused on the management of export from solar PV systems through the use of dynamic operating envelopes (DOEs). The report summarised the benefits of moving towards application of DOEs as:

> *'DOEs will allow for more DER connections and larger capacities through more efficient utilisation of the existing electricity system infrastructure. This will benefit all customers, not simply DER customers. By using DOEs, distribution network operators can support greater access to customer generated renewable energy without the costs of major network upgrades, while maintaining current reliability, security, safety and quality of supply.'*[12]

The report recognised the issues currently faced by DNSPs in managing the impacts of increasing penetration of solar PV on electricity networks, including those considered in this business case. The report concluded that the current regulatory framework supports DOE implementation where there is an identified network need and further that adopting DOEs represent an efficient approach to addressing this need.[13]

Also, that DOEs, based on its assessment of current practice and trends have broad application:[14]

> *'DOEs are expected to be implemented by DNSPs in the near term in such circumstances as:*

- *On existing networks to accommodate expected growth in new connecting embedded generators,*
- *On constrained parts of the distribution network providing an alternative to network augmentation and/or customers facing reduced static export limits,*
- *Across whole network areas to address DER related network contingency and minimum system load directions issued by AEMO,*
- *To manage the potential network impacts of many orchestrated devices, such as where a particular aggregator has significant levels of DER under management,*
- *An innovative product offering for customers to provide them with greater access and flexibility in their use of the network.'*

2.4 Interim measures and related projects

2.4.1 Operational measures

Operational measures have been implemented to minimise the identified issues, including:

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[11] The Distributed Energy Integration Program (DEIP) is a collaboration of government agencies, market bodies, industry associations and consumer associations aimed at maximising the value of customers' distributed energy resources (DER) for all energy users. DEIP is not an organisation, it is a forum where organisations come together to share insights and develop priorities.

[12] https://arena.gov.au/assets/2022/03/dynamic-operating-envelope-working-group-outcomes-report.pdf, page 18

[13] https://arena.gov.au/assets/2022/03/dynamic-operating-envelope-working-group-outcomes-report.pdf, page 43

[14] https://arena.gov.au/assets/2022/03/dynamic-operating-envelope-working-group-outcomes-report.pdf, page 43

- Switching out zone substation and distribution capacitor banks – this is an effective step with switching undertaken manually if a minimum demand event window is expected.
- Proactively engaging embedded and large-scale customers to enable VOLT VAR settings on their invertor equipment to help reduce voltages – this approach limits PV output to help mitigate voltage rise; however, based on customer feedback and response, Power and Water's objective is to not constrain-off solar production.
- Proactively engaging large customers to shift demand patterns during the day to help reduce voltages – again this has been met with limited success due to the strong preference of customers to operate as they want to unless compensation is offered; this is discussed as one of the options in section 3.

These operational measures have been actioned in the short term as contingency solutions and have been taken into account in the technical analysis.

Another initiative that was explored is opening one of the two OS-LG 66kV transmission lines to reduce line charging (i.e. generation of VARs) during daytime minimum demand conditions. However, an unplanned outage of the second OS-LG 66kV transmission line would cause a system blackout. This approach will only be used as a last resort as the Alice Springs system has limited supply redundancy, particularly when RGPS closes.

2.4.2 Proposed investment in improved distribution system visibility and control

As more and more customers adopt solar PV, other DER, and EVs, export from residential customers' PV systems will eventually need to be restricted, despite investments in traditional network solutions in the short-medium term. Therefore, in parallel with the investment in traditional network solutions to manage immediate issues from minimum demand events and other DER-related challenges, a longer term initiative is to dramatically improve Power and Water's very limited visibility of the low voltage networks and to invest in removing constraints on DER output. This is considered in section 3.

2.4.3 Proposed investment from Darwin-Katherine System Plan

The NT Government via TGEN has proposed investment in new 'high specification security batteries' to provide the equivalent inertia service of a large thermal generator. The battery investment would reduce the demand threshold required to securely operate thermal generators and provide these security services. The Darwin-Katherine System Plan 2022 concludes that: [15]

> *'3 [three] high spec security batteries hold the key to providing sufficient system security services by 2030... batteries can provide necessary frequency services and potentially play a role in supporting system strength. Importantly, these batteries provide the system with more headroom to meet minimum demand days.'*

Construction of the first high spec 35MVA security BESS is already underway. It is expected to be operational by 2024 and reduce the minimum demand threshold from 67MW to 50MW.

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[15] Darwin-Katherine System Plan 2022, page 46

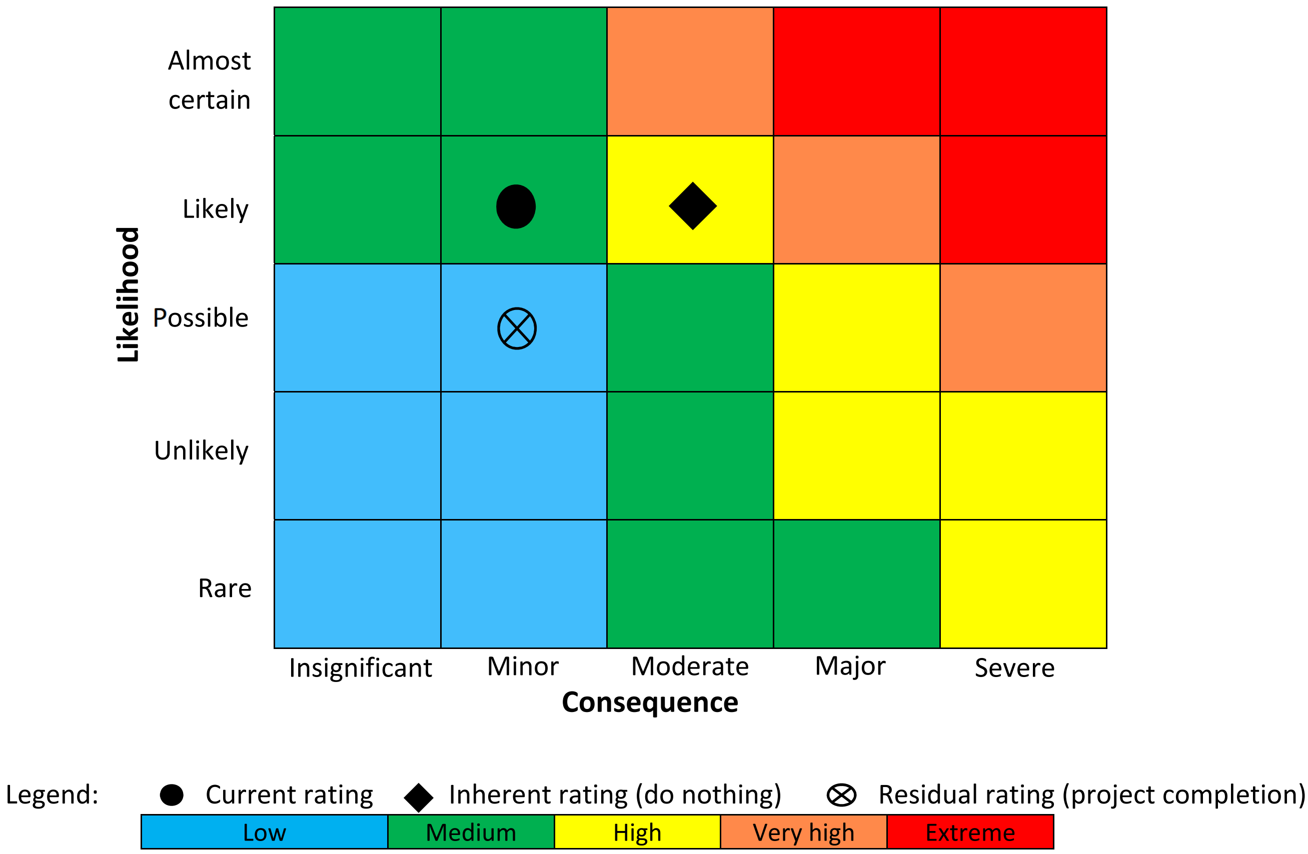
Whilst the NTG/TGEN's plan is to install a second security BESS by 2026 (or sooner) and third security BESS by 2030, this is by no means guaranteed.

2.5 Risk assessment

The figure below shows the current risk rating, inherent rating in 2029 (if there is no remedial action(s)), and the residual (post-treatment) risk rating associated with minimum demand events:

- **Current Rating** is 'Medium' – whilst Power and Water has limited visibility of its LV network, the level of rooftop solar penetration and the current minimum demand threshold (i.e. below which system security is threatened) point to inherent risks to voltage compliance and system security. It is likely that excess voltages are a problem now, but with only relatively minor local impacts.
- **Inherent rating** is 'High' - without any intervention over the duration of the next RCP, including by reducing static export limits, it is likely that both the frequency and impact of solar curtailment through load shedding and or otherwise inefficient network investment, will increase to the point where the impact is moderate.
- **Residual rating** is 'Low' if the proposed proactive steps to provide customers with the choice to adopt flexible solar export limits is delivered. It would reduce the frequency and impact of solar curtailment because curtailment would be temporary, not all year-round.

Figure 7: Risk assessment through to the end of the next RCP



2.6 Summary

To enable the connection of increasing penetration of rooftop solar and to maintain power system quality and stability, investment in a solution to manage the hosting capacity of the network is needed. Absent these measures, both localised power quality and system stability is likely to be negatively affected.

The need for improved LV network visibility to quantify hosting capacity is important given the scale of generation in aggregate and the value of DER. However, Power and Water has:

- Limited data to assist quantify the impact of the increasing level of DER on hosting capacity, local area constraints and power quality; and
- Limited control over rooftop solar output to alleviate local power quality issues caused by excessive solar export.

Power and Water does not have sufficient understanding of the performance of the LV network with rooftop solar, battery storage, and electric vehicles. This limits Power and Water's ability to quantify the capacity of the LV network locally and in aggregate to 'host' solar export. Lack of LV network visibility reduces the means of determining the best remedies to network performance issues.

Without a more sophisticated response to integrating DER into the Power and Water networks, the likely responses to minimum demand conditions will be limited to:

- Tightening the static export limits for residential connections from 5KW to a much lower level over time, thereby curtailing solar export year-round, not just during minimum demand events;
- Augmenting the network to meet increasing peak demand resulting from evening EV charging.

Reducing static export limits (year round) is a 'blunt instrument' that would not support the NT Government's 50% renewables target and would not align with customer expectations for (largely) unconstrained access to the network to export solar power from their rooftop solar installations.

The prevailing advantage of the proposed DOE solution (discussed in the following section) is that it allows for maximum use of low cost renewable energy. DOEs also provide the capability for our network to better manage electric vehicle charging in the future, which is consistent with our strategic priority to better utilise the network and electricity system.

3. Options analysis

This section describes the various options that were analysed to address the increasing risk to identify the recommended option. The options are analysed based on ability to address the identified needs, prudency and efficiency, commercial and technical feasibility, deliverability, net benefit, and an optimal balance between long term asset risk and short-term asset performance.

Our methodology has been guided by the AER's DER integration guidance note ('Note'). The Note requires networks to develop a DER integration strategy and to follow the procedure for evaluating projects. The Note is complemented by the AER's Customer Export Curtailment Value note (CECV) which provides a methodology for quantifying the value of constrained solar exports and which we have also adopted.

3.1 Comparison of credible options

The credible options are designed to address the need to increase hosting capacity or reduce the minimum demand threshold and will address both local excess voltages and mitigate the risk to system security.

The following options have been identified:

- Option 1 - Lower static export limit (Base case). This option is based on reducing the residential static export limit on residential rooftop solar installations from 5kW to 2.3kW from 2028 to curtail solar export year-round.
- Option 2 - Comprehensive DOEs. This option is based on Investing in dynamic operating envelope ('DOE') capability and offering dynamic solar export limits to all customers with distributed energy resources.
- Option 3 - Targeted DOEs. This option is based on investing in dynamic operating envelop capability and offer dynamic solar export limits only to C&I customers with distributed energy resources.
- Option 4 - Other solutions. This option is based on investing in alternative network and non-network solutions to offset the contributors to minimum demand.

A comparison of the identified credible options against the evaluation criteria is shown in the table below. Discussion of each option is provided below.

Table 3: Summary of options analysis outcomes

Criteria	Option 1	Option 2	Option 3	Option 4
Address investment need: Improve LV network visibility	✗	✓	✓	✗
Address investment need: reduce impact of minimum demand	✓	✓	✓	✓
NPV ($m, FY22)	0	+32.1	<Option 2	-79.5

BCR	n/a	1.35	<Option 2	0.68
Capex ($m, FY22)		92.7	74.7	251.0
Payback period	n/a	14 yrs	>Option 2	never
Customer Preferred	○	●	◑	○
Deliverability	●	◕	◕	◕
Technical Viability	●	◕	◕	●
Preferred	×	✓	×	×

● Fully addresses the issue ◕ Adequately addresses the issue ◑ Partially addresses the issue ○ Does not address the issue

n/a = not applicable; [1] this is the estimated incremental cost for developing DOEs in the Alice Springs system leveraging off the proposed DOE project for the Darwin-Katherine system

This section describes each of the credible options available to address the investment need and their costs and benefits, over a 30-year time horizon, in present value terms, relative to the Option 1 (the base case).

3.1.1 Option 1 – Lower Static Export Limits

Power and Water could mitigate minimum demand impacts by implementing stricter static export limits. Static export limits are a blunt tool for curtailing solar during minimum demand events. They are applicable year-round.

Power and Water presently allows residential customers on single phase connections to export up to 5kW.[16] A downward revision of this static export limit would increase the proportion of underlying demand met by the grid and increase minimum demand.

Lower static export limits would apply to new or modified connections. It is assumed that:

- 10% of customers with existing solar connections will seek to modify their connection each year, to replace or upsize their installed capacity; and
- In the absence of any alternative action, all existing customers would be subject to lower static export limits within 10 years (i.e. FY33).

The efficacy of static export limits on mitigating the minimum demand impacts depends on the rate of compliance to the limit. A significant proportion of inverters do not set exports at levels required by the

[16] The export limit of single-phase connections in 5kVA, and the export limit of three phase connections with installed capacity less than 30KW is 7kVA. See https://www.powerwater.com.au/customers/power/solar-power-systems/pv-class-requirements

Connection Agreement. Power and Water does not know what proportion of customers are non-compliant with static export limits. For the purposes of this analysis, it is assumed non-compliance is 30%.

In determining the maximum static export limit that would prevent minimum demand from falling below the 50MW operational threshold in the Central case, the assumptions set out in Table 4 were adopted.

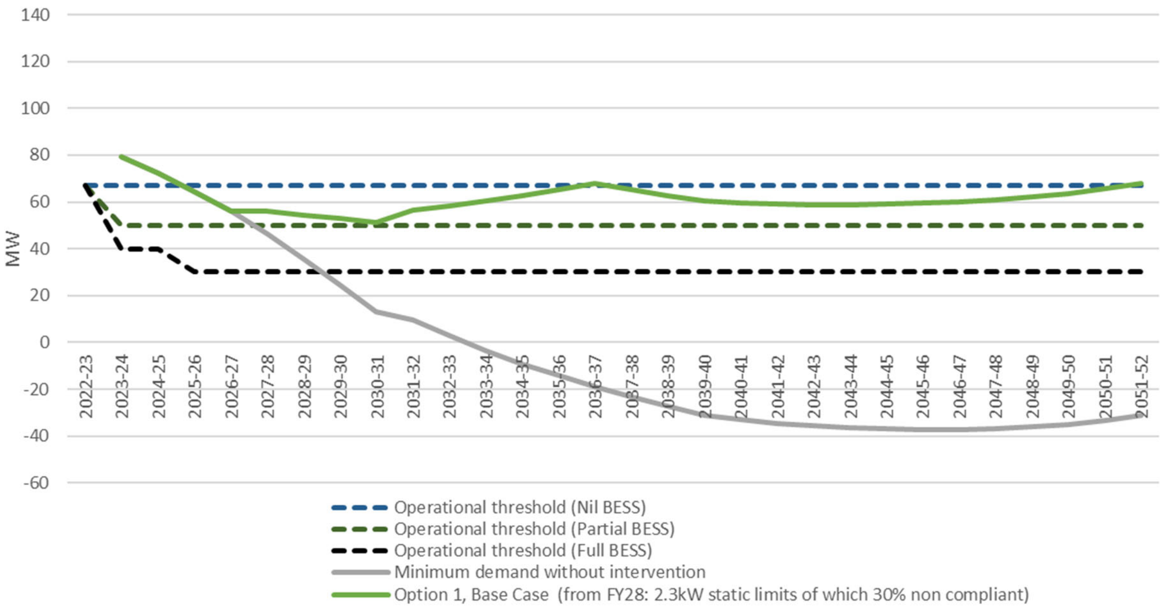
Table 4: Assumptions informing stricter static export limits for Option 1

Assumption	Independent variable	Value	Source
Average capacity of a residential rooftop solar installation	Constant	7.21 kW	Energeia
Average generation profile of residential rooftop solar installation	Time of day and month of year	Maximum of 68%	Darwin Katherine System Plan, Figure 21
Average daily underlying residential consumption profile	Time of day and season	0.63-1.56 kW	Energeia
Proportion of existing customers seeking to modify their connection	Constant	10% per year	Assumption informed by Power and Water
Proportion of customers non-compliant with a static export limit	Constant	30%	Assumption informed by Power and Water

On the basis of these assumptions, Power and Water could adopt a revised static export limit of 2.3kW for new and modified connections from 2029-30[17] and which could assist prevent minimum demand from falling below the 50MW operational threshold in the central scenario, as illustrated in the figure below.

[17] DOE Business Case Model 111122

Figure 8: Minimum demand (i) without intervention and (ii) under Option 1 – lower export limits



Source: DOE Business Case Model 111122

The implementation of this option requires few resources to implement. The major task would be the change to the Connection Agreement. The costs associated with this option have not been modelled in detail, as they are likely to be low. The costs to enforce compliance and/or increase the level of compliance with the revised export limit have not been estimated.

More importantly, this option is best characterised as the Base case, the reference point against which other investment options are assessed to quantify their costs and benefits.

To the extent that the other investment options result in cost savings, relative to the Base case, those savings will be represented as a benefit accruing due to the investment option.

This option is not consistent with the needs of our stakeholders who want Power and Water to be an active leader in facilitating renewables in the energy system, and to make prudent investments where there are clear benefits. This follows extensive conversations with our People Panel and two Future Network Forums.

In the absence of investment, we would need to constrain customers from exporting onto the network when facing local constraints.

This option is not recommended.

3.1.2 Option 2 – Comprehensive DOEs

This option proposes targeted curtailment of solar exports at specific times. Targeted curtailment would be made possible through an investment in DOEs, which vary the connection import and export limits from DERs to the electricity grid. This option is comprehensive because it makes dynamic export limits accessible to all customers with DER, regardless of the connection type or the size of installation.

DOEs are implemented at a feeder level. Engineering data from meters downstream of a given feeder are input into a state estimation model and operating constraints are overlaid to derive the dynamic import and export limits, thereby ensuring real-world network operating conditions meet but don't exceed those constraints.

Developing the state estimation necessary to roll out DOEs across all the feeders in the network takes time. There are around 280 feeders across the regulated network, state estimation of the feeders can occur at around 3-4 feeders per month, or 15% of feeders per year. As a result, some lead time for state estimation is required before DOEs are made available across most of the network.

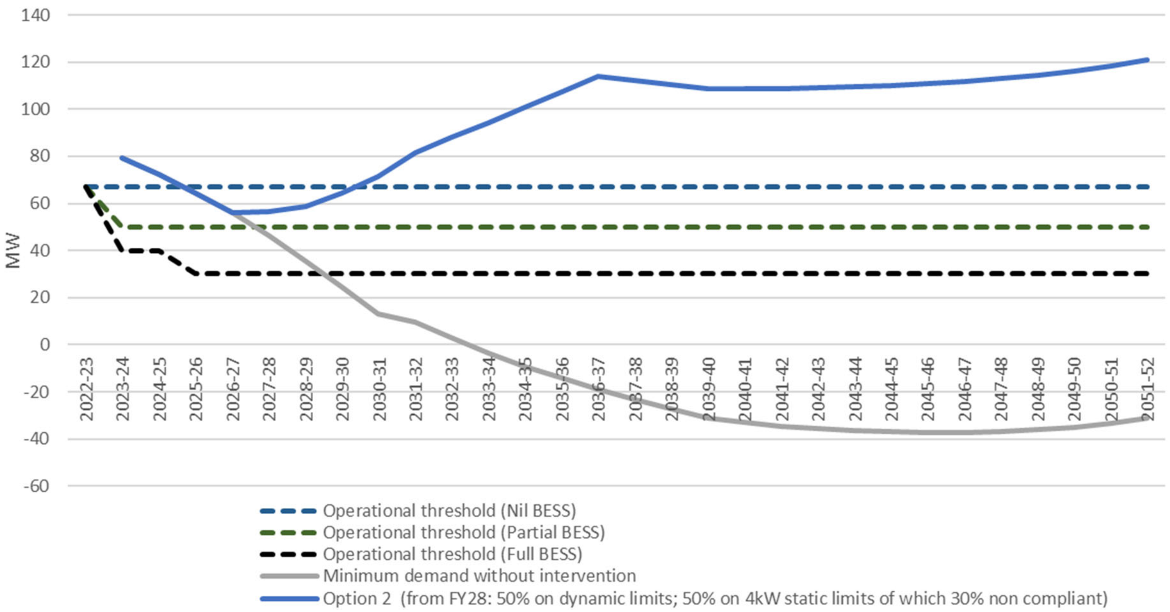
This option allows local area constraints to be managed and optimised with solar output and assists with preventing minimum demand events forecast from 2029-30. Option 2 makes DOEs available to customers in 2028-29. Investment in state estimation would begin four years earlier in 2024-25, to enable 60% of feeders with DOEs by 2028-29 and 100% of feeders by 2030-31.

Option 2 has a total estimated cost of $92 million (real 2021/22), with $17.9 million (real 2021/22) to be incurred in the 2024 – 29 regulatory period. Option 2 yields the highest return and represents the most efficient and prudent investment option.

Dynamic export limits, enabled by DOEs under Option 2, would be available on an opt-in basis to all connections with DER. To be conservative in the benefits calculations, it is assumed that only 50% of new or modifying connections choose dynamic export limits, with the other 50% adopting or retaining a static export limit.

The additional headroom offered by DOEs between minimum demand and the operational threshold, allows the static export limit under this option to be more generous, relative to the base case. The 50% of connections that select a static export limit under this option would be offered a 4kVA export limits. The combined effect, shown in the figure below, is avoidance of minimum demand events from 2029-30, despite assuming a 30% static export limit non-compliance rate.

Figure 9: Minimum demand without intervention and under Option 2



Source: DOE Business Case Model 111122

The benefit of Option 2 is expected to exceed $124.9 million, as shown in the table below. Six benefits streams resulting from Option 2, relative to the base case (Option 1) were identified:

- Avoided solar export curtailment from residential customers;
- Avoided solar export curtailment from C&I customers;
- Avoided or deferred network augmentation expenditure;
- Reduced cost of EV charging;
- Avoided greenhouse gas (GHG) emissions; and
- Improved LV network visibility.

Of these six benefit streams, four benefits have been quantified (refer to Table 5 and Appendix B).

The benefits associated with avoided solar export curtailment from C&I customers were not calculated because of the difficulty in estimating a typical export profile due to the heterogeneity of C&I customers. Any such benefit accruing from Option 3 (detailed in section 3.1.3) would also be realised in Option 2, therefore the net present value of Option 2 will always exceed that of Option 3.

The cost and benefits are summarised in Table 5. The NPV of Option 2 is expected to exceed $32.1 million.

The benefit from the C&I sector is expected to be significant at no extra cost. It would therefore significantly improve the Option 2 NPV and BCR. Power and Water is currently investigating means of quantifying the C&I sector benefit.

Table 5 Benefits and costs of Option 2 ($m, real 2022)

Benefits and Costs	Value
Benefit	
Avoided solar export curtailment from residential customers	86.9
Avoided solar export curtailment from C&I customers	unquantified
Avoided or deferred network augmentation expenditure	12.5
Decreased cost of EV charging	10.9
Avoided GHG emissions	14.6
Improved LV network visibility	unquantified
Total benefit	**>124.9**
Cost	
State estimation and constraints engine	49.8
Agent fees to communicate with inverters	10.9
Power and Water ICT capabilities	22.5
Supporting activities	9.5
Total Cost	**92.7**
Net Benefit	**>32.1**

3.1.3 Option 3 – Targeted DOEs

Option 3 also involves the roll-out of DOE capability across all network feeders. However, Option 3 is more targeted than Option 2 in that it limits the implementation of DOEs to C&I customers with DER only.

The cost components of Option 3 are similar to Option 2, in that it still requires the development of a state estimation model with ICT support to integrate it with other ICT systems. The agent fees for Option 3 would be lower than for Option 2, because fewer customers are required to receive the DOE information. It is assumed that the supporting activities for Option 3 are limited to:

- DER connection process, standards and policies; and
- Customer consultation initiatives— hosting of forums with customers to understand their expectations and preferences.

The cost of Option 3 is expected to be $74.7 million (real 2021/22) as shown in the table below.

Table 6 Costs of Option 3 ($m, real 2021/22)

Cost Category	Value
State estimation and constraints engine	49.8
Agent fees to communicate with inverters	9.6
Power and Water ICT Capabilities	13.9
Supporting activities	1.3
Total cost	**74.7**

The benefits associated with Option 3 are very difficult to measure due to heterogeneity of C&I customer export profiles. Regardless, it is possible to demonstrate that the net benefits of Option 2 exceed that of Option 3 because the marginal benefit of expanding the DOE capability to residential customers exceeds the marginal cost.

The cost structure of DOE investments makes a targeted DOE rollout less economically feasible relative to a comprehensive DOE rollout. More than two thirds of the costs of implementing DOEs are fixed, in that they do not vary with the number of customers utilising dynamic import or export limits. However, the benefits of the implementing DOEs are almost linear with the number of customers using dynamic limits. As a result, the most attractive DOE option is that which rolls DOE functionality out to the largest proportion of customers.

3.1.4 Option 4 – Other non-network and network solutions

Power and Water has considered other non-network solutions and network solutions as outlined in Table 7. As shown in the summary table, further work is required on some of these options, which would certainly need to be addressed through the RIT-D process (assuming the project reaches that milestone).

Each of the network engineered infrastructure solutions provide limited benefits by addressing some characteristics of the distribution system. However, despite these potential benefits, many of the infrastructure solutions and technologies lack an ability to cost effectively respond to the impacts of continued uptake of DER technologies.

As an example, in the Darwin region, the LV network voltage regulation settings were reduced in 2015/16 to a 10.7kV set point from 11.2kV. This had the benefit of increasing the solar hosting voltage capacity of the network, whilst remaining within the regulated preferred range (225V-244V) and not exceed the limits (216V-253V) as required by the Australian Standard.[18] However, this option was deemed unviable at the time in Alice Springs and Tennant Creek due to tap changing limitations. Currently the network is again experiencing voltage rise issues associated with excess solar, meaning a longer-term solution is necessary.

[18] AS 60038:2012 Standard Voltages

Table 7 Qualitative assessment of other non-network and network solutions

Network Solutions	Local network benefits	System benefits	Technical & commercial viability	Elaboration
Transformer upgrades or tap changes	✓	✕	In limited applications	Complimentary network BAU solutions to be considered on an as needed basis. Would help with local PQ issues but limited whole of system benefit and functionality.
Feeder reconfiguration & phase rebalancing	ü	✕	In limited applications	
LV regulators & statcoms	✓	✕	In limited applications	Statcoms are very expensive. LV regulators provide limited functionality.
Reduce operating voltage	Not applicable	Not applicable	Not applicable	This option has already been implemented to the extent possible
Non Network Solutions				
BESS	✕	To be determined	To be determined	The ability of the proposed security BESS to reduce the threshold for system security is yet to be proven. Using BESS to control local voltage rise at times of system low is unlikely to be cost effective at least for the foreseeable future.[19]
Synchronous Condenser	✕	ü	To be determined	Synchronous condensers are a proven technology and would provide system strength and inertia. However it/they would little benefit at the local network level

[19] Assuming an 8-hour redox flow battery with a 15-year asset life and 2 year investment lead times, the cost of the deploying batteries to solely manage the minimum demand issue exceeds $250 million. By contrast, the benefit associated with Option 4 of avoided solar export curtailment, is valued at just under $172 million and the net benefit would be -$79.5 million.

Backstop Mechanisms	To be determined	**To be determined**	**To be determined**	"Emergency Backstops"[20] would result in disconnection curtailment in return for some sort of payment.

Power and Water is already investing in complimentary technologies such as state estimation trials in Alice Springs, progressively rolling out smart meter infrastructure (which will lead to better LV visibility).

Whilst some of the solutions covered in Option 4 may be viable in some circumstances, it is unlikely that any of them will be superior to the DOE path in managing both the local voltage rise issue and the system security risk posed by the forecast minimum demand trend. It is unlikely that any of the solutions in Option 4 will yield a superior NPV/BCR to Option 2 after including the contribution from the C&I sector.

Based on the available information, including the experiences and progress in other states, Option 2 is preferred. This means investing in DOE capability and offering all customers with rooftop solar (including C&I customers) the choice of opting-in to receive higher export capability compared to the base case.

3.2 Non-credible options

Our analysis also identified a number of options found to be non-credible. These options are described below and were not taken through to detail analysis for the reasons provided.

3.2.1 Price incentives – does not address the need

Price incentive options are also available to incentivise customers to increase consumption during periods of minimum demand to prevent minimum demand events. However, on their own, price incentives lack the firmness required to prevent minimum demand events because there is little guarantee that customers will be responsive to altered price signals.

Price incentives are not a credible option for addressing the investment need on their own, however, they can complement credible options. It is assumed across all base case and investment scenarios that tariff reform and incentives will contribute to an increase the proportion of customers that charge their EVs on managed charging profiles, shifting the EV Load from the evening to the middle of the day.

[20] Solar Flexibility Partnerships is an example of an initiatives to test a simple 'emergency backstop' for willing solar participants on the regulated network before upgrading to the full DOE solution once the technology is made available. Solar Flexibility Partnerships also intends to trial demand side management of loads for willing participants; for example enabling control and ramping of HV Air-conditioning plant during emergency conditions.

4. Recommendation

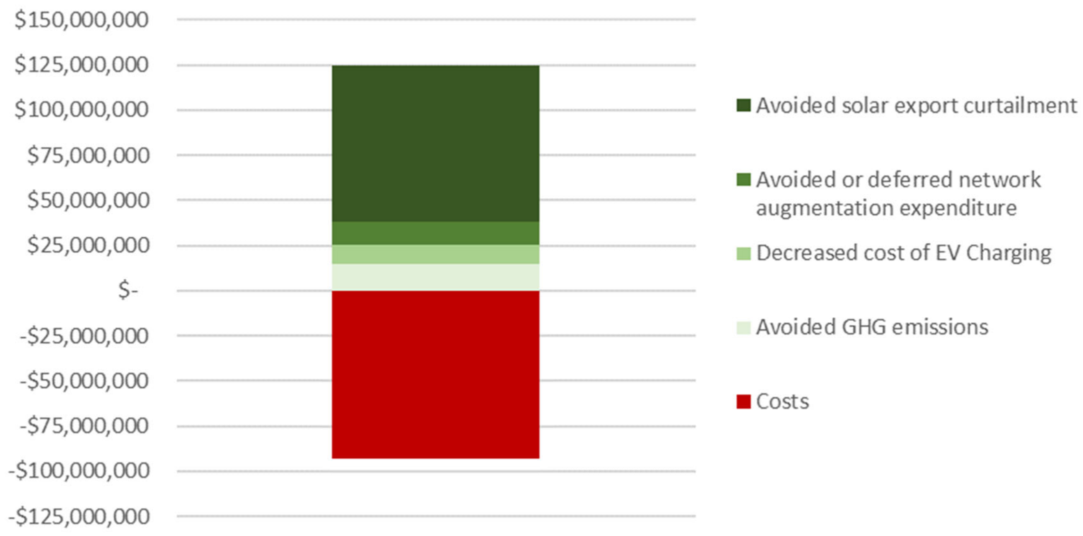
Option 2 is the recommended option at a total estimated cost of $92.7 million (real 2021/22), with $17.9 million (real 2021/22) to be incurred in the 2024 – 29 regulatory period, as shown in Table 2. Option 2 yields the highest return and represents the most efficient and prudent investment option.

The option proposes to invest in DOE capability and offer dynamic limits to customers with DER from 2028 as the prudent and efficient solution to address the identified needs. The analysis demonstrates a clear benefit to reducing the level of curtailment (i.e. the value of avoided curtailment). When presented with Options 1, 2 and 3 in the Future Power Networks forum, customers expressed a preference for this option as a means of proactively facilitating additional renewable energy on the network.

Benefits and costs are expressed relative to Option 1, the Base case, in present value terms using a real discount rate of 2.69%.[21]

The costs of the program are expected to extend beyond the regulatory period. Over a 30-year horizon, the total costs of the program are expected to reach $92.7 million, comprised of $38.6 million in capital expenditure and $54.1 million in operating expenditure. More details on the costs are provided in Appendix A. The benefits of the program over the same period are expected to exceed $124.9 million (Figure 10), resulting in a NPV of $32.1 million and a BCR of 1.35. This benefit does not include the substantial, but currently unquantified, benefit from applying DOE to the C&I sector (at no additional cost). More details on the benefits are provided in Appendix B. The factors and assumptions considered as part of the sensitivity analysis are provided in Appendix C.

Figure 10: Comparison of costs and benefits of the preferred option



Source: DOE Business Case Model 111122

[21] Real WACC approved by the AER for the Transgrid regulatory proposal.

The proposed program is consistent with the National Electricity Rules Capital Expenditure Objectives as the expenditure is required to maintain the quality, reliability, and security of supply of standard control services and maintain the safety of the distribution system.

4.1 Strategic alignment

Power and Water's strategic direction is to meet the changing needs of the business, and our customers, and is aligned with the market and future economic conditions of the Northern Territory projected out to 2030.

This proposal aligns with the Policies, Strategies and Plans that contributes to the D2021/260606 'PWC Strategic Direction' as indicated in the table below.

Table 8: Strategic alignment

	Strategic direction focus area	Strategic direction priority
1	Living within our means	Cost Prudency
2	Sustainable solutions for the future	Sustainable Energy and Water Services

4.2 Dependent projects

There are no known projects or other network issues that are dependent on the resolution of this network issue.

The objective of the Dynamic Operating Envelope (DOE) initiative in the Future Network Strategy is to achieve control of Behind the Meter inverters across all regulated networks. This initiative will take learnings from the Alice Springs Future Grid project that will conclude at the end of this financial year. Learnings from this project will be developed and implemented across the network through the Future Networks Strategy.

This business case takes into consideration focus areas in the DK Electricity System Plan and estimates that the whole of network DOE solution will be required at the end of the 2027-2028 financial year. This project will require a number of years to implement including the creation of a whole of network real-time LV visibility tool, the development of the DOE technology, stakeholder engagement, connection contracts and integration with Power and Water's ICT systems.

To facilitate the development of DOE immediately after the conclusion of the Alice Springs Future Grid project Power and Water has created the Solar Flexibility Partnerships program. This program ensures that whole of network DOE learning and development commences in this financial year. The Solar Flexibility Partnership intends to test a simple 'emergency backstop' for willing solar participants on the regulated network before upgrading to the full DOE solution once the technology is made available. Solar Flexibility Partnerships also intends to trial demand side management of loads for willing participants; for example enabling control and ramping of HV Air-conditioning plant during emergency conditions.

4.3 Deliverability

Power and Water faces unique challenges in delivering the preferred option relating to the nature and scale of work, skills mix available to it, market size and capability in the NT, and the interaction with similar demands by other Australian and international networks. Each of these issues are dealt with in the sections below to demonstrate the considerations that Power and Water has taken to ensure that the preferred option can be delivered in a prudent, efficient, and timely manner that appropriately manages reliability, performance and transition risks to NT electricity customers.

4.3.1 Nature of Work

The nature of the work involved in the preferred option is similar to current future grid projects delivered by Power and Water, including the Alice Springs Future Grid Project.

The Alice Springs Future Grid Project focusses on addressing barriers to higher renewable energy penetration in the local electricity network and involved modelling, household battery and tariff trials, cloud forecasting techniques, dynamic export limits for rooftop solar. The program relies on community engagement to educate customers.

As demonstrated in the Alice Springs Future Grid Project, the nature of the preferred option is within the proven deliverability capabilities of Power and Water.

4.3.2 Scale of Work

The scale of the work involved in the preferred option is comparable to the value of work delivered in previous and current technology and communications projects such as the Solar Energy Transformation Program (SETuP).

SETuP involved the deployment of high penetration renewable energy systems to 25 remote communities and encompassed a total project value of $59 million from 2014 to 2022, Australia’s largest off-grid solar program in remote communities.

As demonstrated in SETuP, the scale of the preferred option is within the proven deliverability capabilities of Power and Water.

In the next regulatory period, the scale of works will be initially targeted and expanded over the period with costs peaking in 2030-31. The preferred option will initially target enabling DOEs across feeders that are likely to yield the greatest net benefit. All feeders are expected to be DOE enabled by 2030-31. It will also focus on new DER connections or modified DER assets, as has been shown to be effective in other Australian networks.

4.3.3 Skills Mix

The skills mix required to deliver the preferred option differs from the traditional network augmentation and asset replacement programs that Power and Water has focussed on in the past. However, it is reasonably aligned with Power and Water’ record of enabling new energy technology, information systems and communications upgrades in a geographically diverse network, with low customer numbers and a comparatively high level of sensitivity to increases in electricity prices.

The skills required to implement the preferred option are aligned more towards the ICT, comms, metering and system control capabilities that Power and Water has maintained in the past.

It is reasonable to expect that Power and Water will be able to access the skills needed to deliver the preferred option. The remainder of the section describes the skillsets required, initial resourcing plan based on procurement approach and availability, and optionality to respond to tightening labour markets for the necessary skills over the 2024-29 period.

4.4 Customer considerations

As required by the AER's Better Resets Handbook, in developing this program Power and Water has taken into consideration feedback from its customers.

Feedback received through customer consultation undertaken at the time of writing this business case, has demonstrated strong support amongst the community for appropriate expenditure to enable sustainable development of the network to ensure access to DER, and continued reliability and safety of supply.

For example, participants at the Future Power Networks forum expressed a preference for the recommended option as a means of proactively facilitating additional renewable energy on the network.

4.5 Expenditure profile

Table 10 shows a summary of the expenditure requirements for the 2024-29 Regulatory Period.

Table 9: Annual capital and operational expenditure ($m, real FY22)

Item	FY25	FY26	FY27	FY28	FY29	Total
Capex	0.550	0.685	4.709	2.489	2.782	11.216
Opex	0.600	0.600	1.720	1.815	1.958	6.693
Total	**1.150**	**1.285**	**6.429**	**4.305**	**4.740**	**17.909**

4.6 High-level scope

The high level scope of work includes four key components:

- The state estimation and constraints engine use engineering data from meters and constraint functions to derive DOEs at a feeder level.
- To implement the flexible export limits, a third-party trader observes the limit and communicates it to consumer devices, requiring third party agent fees
- Internal ICT resources will be required to provide a significant amount of new enabling services and modify existing services.
- A range of supporting activities are required to realise the benefits of the DOE investment, including hosting of forums with customers to understand their expectations and preferences.

Table 10: Summary of high-level scope

Item	Need	Value
State estimation and constraints engine	• While minimum demand is worsening with increased PV penetration, AEMC requires PWC to offer export services. • Maintaining of static export limits at existing levels (i.e. 5KVA for residential homes) will increase frequency of load/generation shedding events over time. Therefore DOE is an optimal solution.	• Critical to delivery of DOEs. • DOE calculation will expand customer import/exports and increase utilisation of distribution network. • Avoids imposition of zero static export limits for new customers (reference case against which benefits are quantified). • Facilitates increased solar exports, offsetting centralised generation. • Facilitates the shifting of EV charging load from peak times to the middle of the day, when solar generation is lower cost and abundant • Enables increased load during periods of minimum demand, decreasing the frequency of generation shedding events, and improving system reliability.
Agent fees to communicate DOEs to inverters	• Communications link between DOE engine and inverter is needed to implement DOE solution.	• Critical to delivery of DOEs.
Internal ICT capabilities for DOEs	• ICT capabilities are needed to support DOE solution.	• Critical to delivery of DOEs.
Supporting activities	• Greater visibility of rooftop solar output in LV system which impacts load profiles (e.g. minimum demand events). • PWC needs to understand the location, type and characteristics of CER assets. The current database does not adequately capture CER assets in the network. • With EV uptake to occur across Australia and NT, standards for public	• Increases utilisation of network hosting capacity by informing state estimation and allocation of DOEs. Increases resilience by forecasting supply/demand fluctuations. • Greater visibility of CER assets in LV network for future application of DOEs and demand management. • Enables EV load to integrate with DOEs communications.

	charging, smart charging and interoperability are needed to be adopted in NT to integrate with PWC systems and network. • Unmitigated EV load is expected to multiply peak demand and require significant network augmentation, driving up costs. • NT specific CER connection requirements need to be updated to allow for DOE implementation. • It is estimated that the majority of inverters on PWC's network are non-compliant inverters, likely from installation. These inverters don't behave as anticipated and may not respond to DOEs. • Installers are a key stakeholder on uptake of CER and rollout of DOEs. Need to establish more buy-in, support and capacity building among installers. • Understanding customer insights and uptake of CER is critical to rollout of DOEs.	• DOEs to EVs will provide PWC with a tool to manage EV charging load and support EV integration into the grid. Value: Enables DOE implementation to CER devices including PV inverters. • Value: Inverter compliance is a critical enabler of effective implementation of DOEs. • Value: Installer buy-in for DOEs is a critical enabler for DOE mass uptake. This activity will build relationships between PWC and the key middleman for DOE implementation. • Value: Understanding the value proposition of DOEs for customers, customer response experience (e.g. communications, preferences, etc) is critical to the mass uptake of DOEs over time.

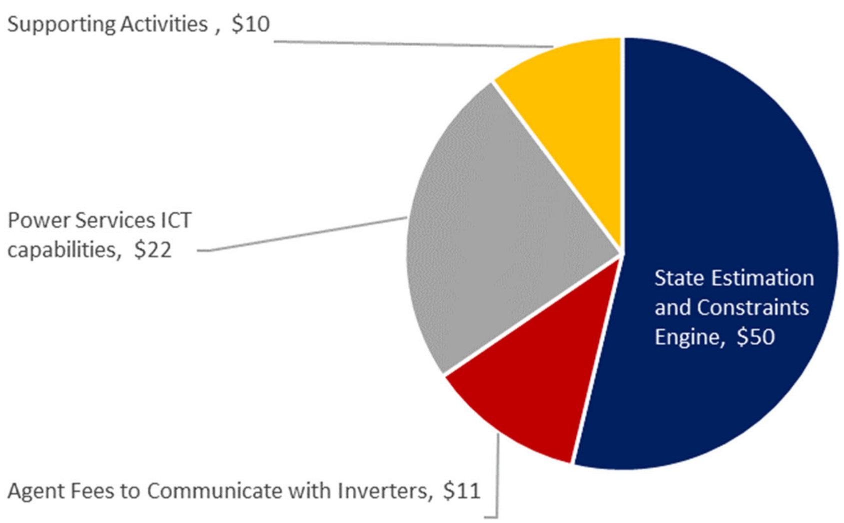
The approach to estimating the cost for each of these components is described in Appendix A.

Appendix A. Cost of the preferred option

A.1 Overview

The costs of the preferred option are estimated at $92.7 million (real 2021/22). Over half of the costs are attributable to the development of the state estimation and constraints engine which calculates the DOEs for each feeder Figure 11. The nature and method of the proposed costs are discussed in the remainder of this section.

Figure 11: Composition of costs attributable to the preferred option ($ million)



Source: DOE Business Case Model 111122

A.2 State Estimation and Constraints Engine

The state estimation and constraints engine use engineering data from meters and constraint functions to derive DOEs at a feeder level. The costs of developing this modelling capability include:

- Hardware costs to provide computing power;
- Licencing costs to a third-party provider to develop and maintain the state estimation model;
- Ongoing ICT support for the state estimation model within Power and Water; and
- Remote reading of meters downstream of a given feeder to provide input data into the state estimation model.

The development of the state estimation and constraints engine will be done on a per feeder basis, at a rate of around 3-4 feeders per month. Investment in the state estimation and constraints engine begins in 2024-25, in preparation of DOE implementation in 2027-28, by which time 60% of the NT feeders will be DOE enabled.

A.3 Agent Fees to Communicate with Inverters

To implement the flexible export limits, a third-party trader observes the limit and communicates it to consumer devices. Only a small proportion of these agent fees are fixed, namely the set-up fee and annual servicing and maintenance fees. To be conservative, it is assumed that these set up costs are incurred in 2026-27, a year before DOEs are implemented. The remainder of the agent fees are a function of the number of connections with dynamic export limits, which will only start in the year of implementation 2027-28.

A.4 ICT Capabilities

Internal ICT resources will be required to provide a significant amount of new enabling services and modify existing services. These services would include data storage, integration, interoperability, cyber security, application delivery, infrastructure and networking, high availability systems, disaster recovery mechanisms, logging, monitoring, load balancing, and environments including those for software and hardware testing.

The cost of these capabilities has been developed from estimates of the number of full-time equivalent (FTE) staff required, their unit cost, and the number of years in which there are required. It is assumed that these resources are not required until 2026-27, the year prior to the DOE implementation.

A.5 Supporting Activities

A range of supporting activities are required to realise the benefits of the DOE investment including:

- Solar forecasting— the development of geospatial solar forecasting capability to track LV supply/demand, informing the network state estimation and allocation of DOEs and increasing the utilisation of network hosting capacity for DER.
- DER register—improvement of the non-public DER register database to itemise DER assets in the network, including rooftop solar, EVs, and home batteries to increase LV network visibility through increased understanding of the location, type and characteristics of DER assets.
- EV Standards—implemented pro-actively to achieve high standards on smart charging and interoperability.
- Pilot DOEs to EV—development and testing of the capabilities and outcomes to facilitate DOEs to EV loads to shift EV charging.
- DER connection process, standards and policies.
- DER compliance program—updating of DER connection requirements to develop NT specific DER technical standards for connections.
- Installer consultation initiatives—hosting of forums with installers to understand their expectations and preferences.
- Customer consultation initiatives— hosting of forums with customers to understand their expectations and preferences.
- Open Network data hub—development and distribution of a read-only LV network map which outline network voltage and capacity constraints and opportunities.

- Self-service portal—development of an online portal for customers and other stakeholders such as installers to review strategic communications, which may include outages, connection agreements and import/export parameters.

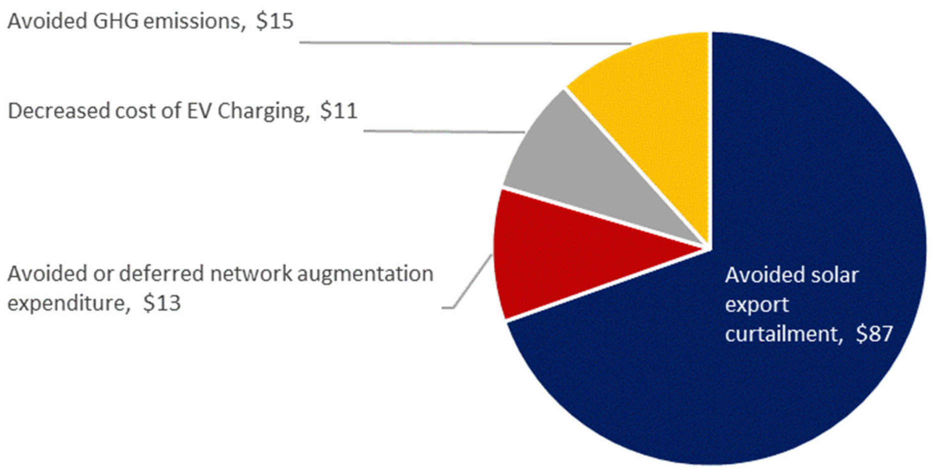
The cost of these capabilities has been developed from estimates of the number of full-time equivalent (FTE) staff required, their unit cost, and the number of years in which there are required. It is assumed that these resources are not required until 2026-27, the year prior to the DOE implementation.

Appendix B. Benefits of the preferred option

B.1 Overview

The preferred investment is projected to result in at least $128.9 million in gross benefits (real 2021/22). Nearly three quarters of the quantified benefit is attributable to avoided solar export curtailment, or increased solar exports, relative to the base case (Figure 12). The nature and method of these quantified and additional unquantified benefits are discussed in the remainder of this section.

Figure 12: Composition of benefits accruing from the preferred investment ($ million)

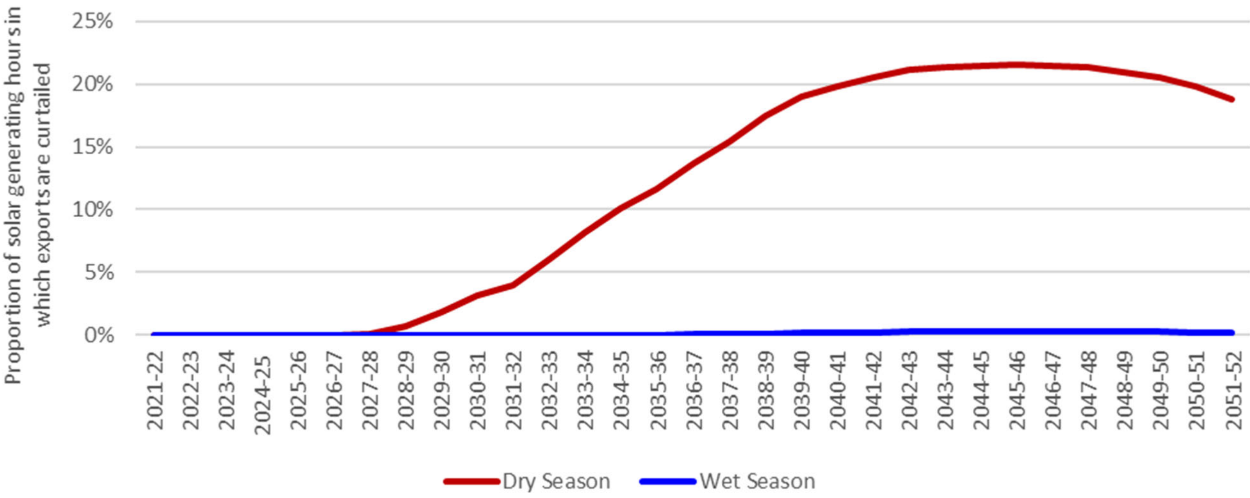


Source: DOE Business Case Model 111122

B.2 Avoided solar export curtailment from residential customers

The preferred investment facilitates the targeted curtailment of solar during periods on minimum demand, and so facilitate increase solar exports for the remainder of the year, relative to the base case. Figure 13 illustrates how often solar exports are projected to be curtailed under dynamic limits, in both the wet and dry season.

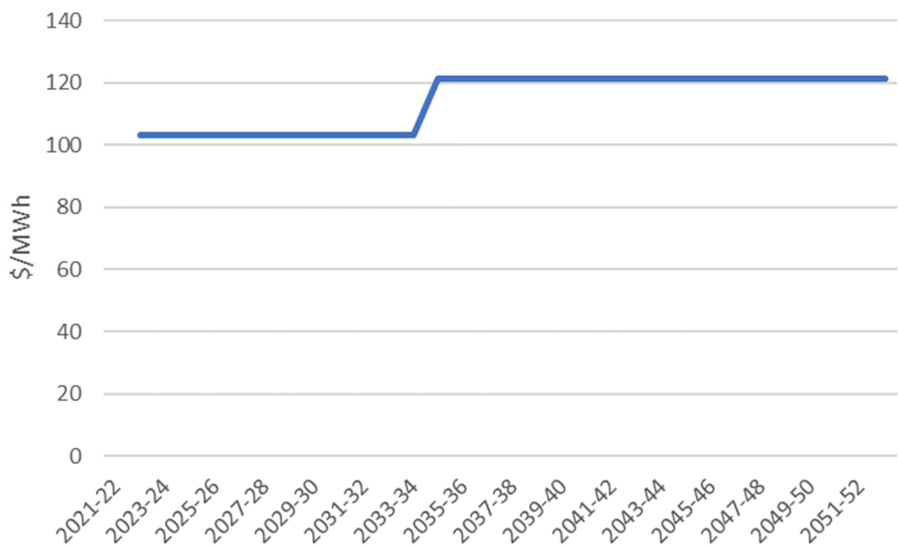
Figure 13: Frequency of solar export curtailment with dynamic export limits



Source: DOE Business Case Model 111122

The value of the additional exports facilitated by the preferred investment is calculated by multiplying the additional exports, or the alleviation profile, by the Customer Export Curtailment Value (CECV). In the NT gas is the marginal fuel source, and a unit increase in solar exports results in a unit decrease in gas-fired generation, at a savings of between $98 and $115/MWh, plus avoided transmission and distribution losses of 5.6% (refer to Figure 14). A sensitivity of the returns to the preferred investment for a range of gas price scenarios is set out in section C.4.

Figure 14: NT CECV ($/MWh)



Source: DOE Business Case Model 111122

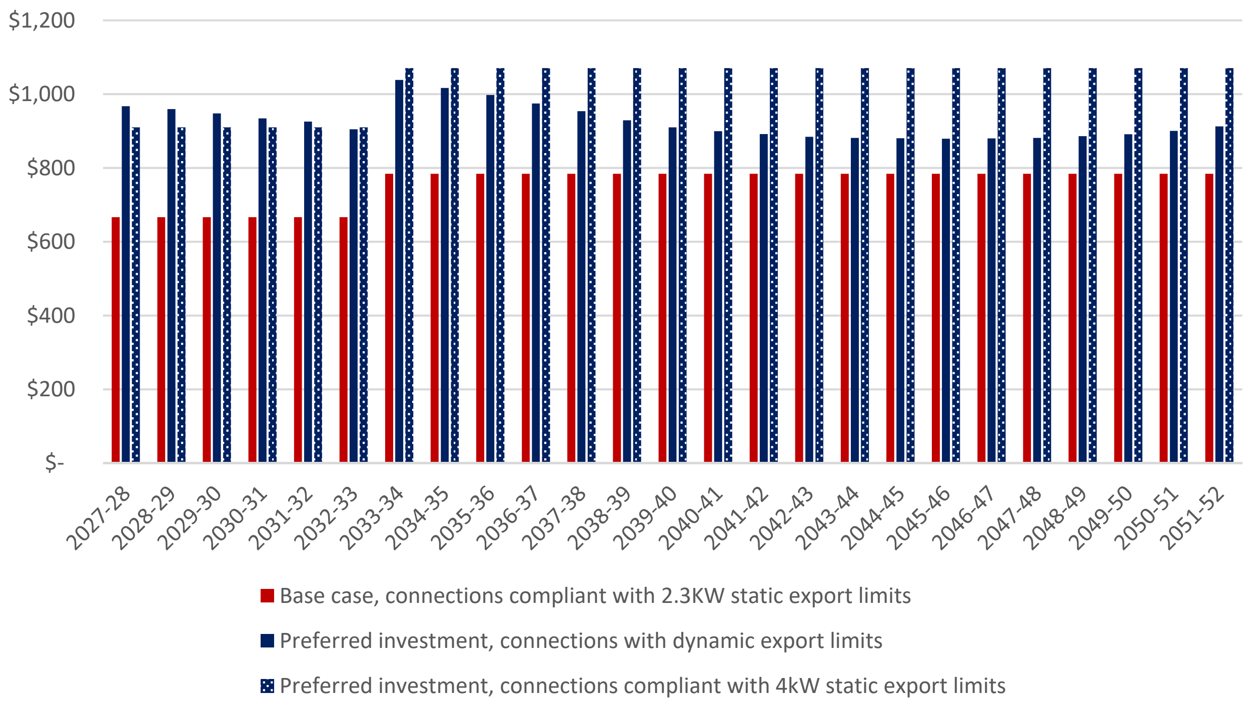
The alleviation profile created by the preferred investment is based on a typical residential connection and scaled by up by the projected number residential connections on static and dynamic export limits. It does not include C&I customers, and so represents a lower bound of the benefits associated with avoided solar export curtailment.

If the preferred investment proceeds, solar exports from a typical residential connection with a 7.21KW solar installation are projected to be valued between $910 and $1,114 per year, depending on whether that customer opts for a dynamic or static export limit. By contrast, more stringent static export limits imposed under the base case would limit the value of that same typical residential customer to between $667 to $784 per year (see Figure 15).

Aggregated across all projected new and modifying connections[22] over the 30-year horizon, the value of avoided solar export curtailment due to the preferred option is expected to exceed $86.9 million.

[22] 10 percent of existing connections with rooftop solar are assumed to modify their systems each year.

Figure 15: Annual value of solar exports, per residential connection, with and without the preferred investment



Source: DOE Business Case Model 111122

B.3 Avoided solar export curtailment from C&I customers

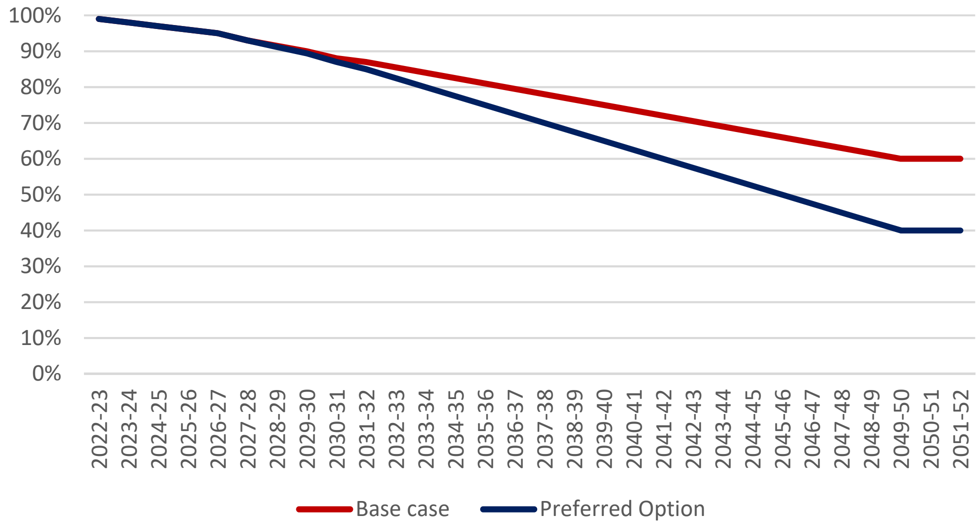
DOEs also facilitate additional solar exports from C&I customers, but it is difficult to quantify these additional exports because there is not a representative C&I customer, the export profile of which can be scaled by the total number of C&I customers in the network. The capacity of the solar installations of C&I customers varies wildly, as does their consumption profile.

These benefits have not yet been quantified, and so the total benefits quoted for the preferred option 2 are highly conservative.

B.4 Avoided or deferred network augmentation expenditure

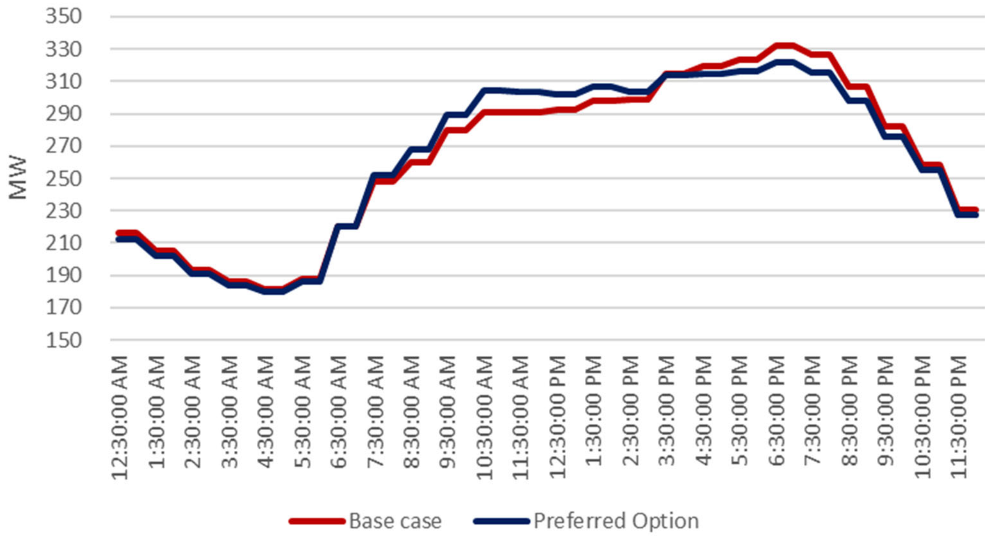
While the impetus for a preferred option is to prevent minimum demand events through export management, the technical capabilities of DOEs can also help manage the integration of EVs by signalling the additional capacity that may be available at certain times of the day for low-cost EV charging, and times when charging would contribute to grid congestion. DOEs are expected to encourage the proportion of customers with EVs to move from unmanaged to managed charging profiles as shown in the figure below, which will shift EV loads from the evening peak to the mid-day (Figure 17).

Figure 16: Proportion of customers on unmanaged EV charging profiles



Source: DOE Business Case Model 111122

Figure 17: Maximum operational demand in Darwin-Katherine in 2049-50



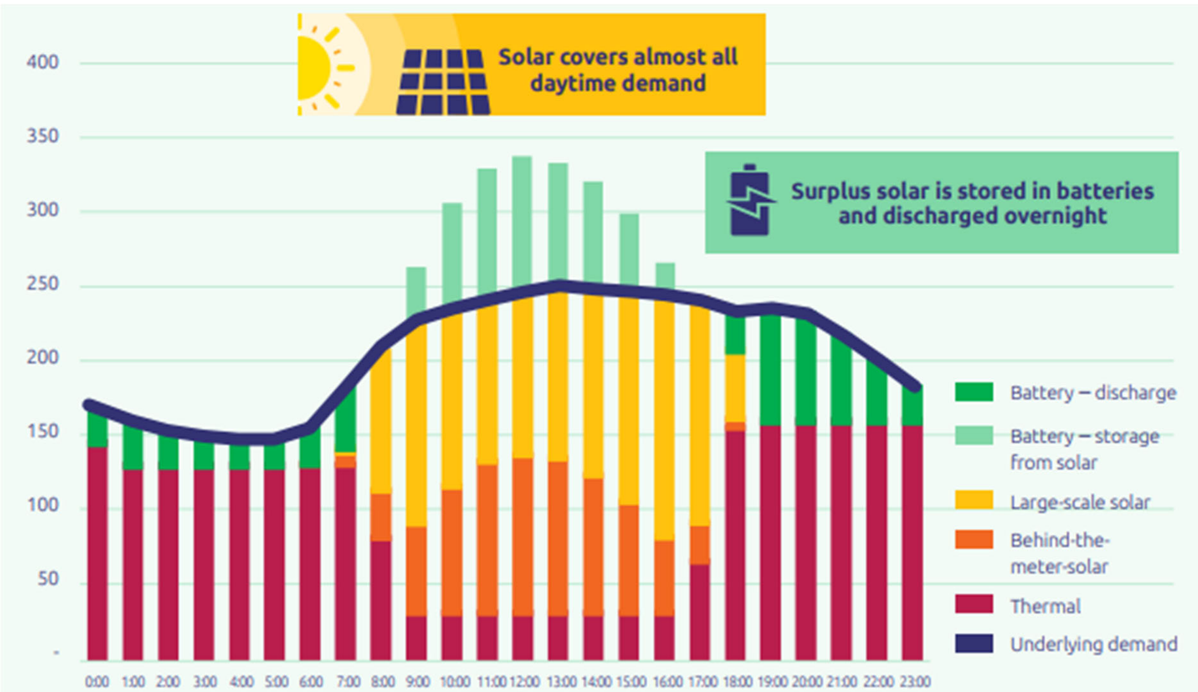
Source: DOE Business Case Model 111122

Reducing the evening peak will reduce the expected future cost of augmenting the network—decreasing network charges for all electricity customers. The preferred option is projected to reduce peak demand by 1.8MW by 2039-40, increasing to 10.2MW by 2049-50, yielding a cost savings of $12.5 million.[23]

B.5 Decreased cost of EV charging

The change in the EV charging profile resulting from the combination of the preferred option and a favourable pricing signal via tariff restructure is also expected to reduce the cost of generation required to meet the EV load. EVs that are charged in the middle of the day (Figure 18), when the majority of load is expected to be met by solar generation, will be charged at a zero marginal cost. It will result in a reduction in utilisation of gas generation and batteries in the evening, producing a cost savings associated with reduced gas fuel use and reduce battery investment. The total cost savings associated with the new generation profile is around $10.9 million.[24]

Figure 18: Generation profile on a typical day in 2030



Source: Darwin Katherine System Plan, page 16

[23] Power Services estimate that the long run marginal cost of augmentation expenditure in the low voltage network is $256/kVA/year.

[24] The gas fuel cost is estimated to be $98/MWh until 2032-33, increasing to $115/MWh for the remainder of the period. The levelized cost of battery storage is assumed to decrease from $200/MWh in 2022-23 to $100/MWh in 2051-52.

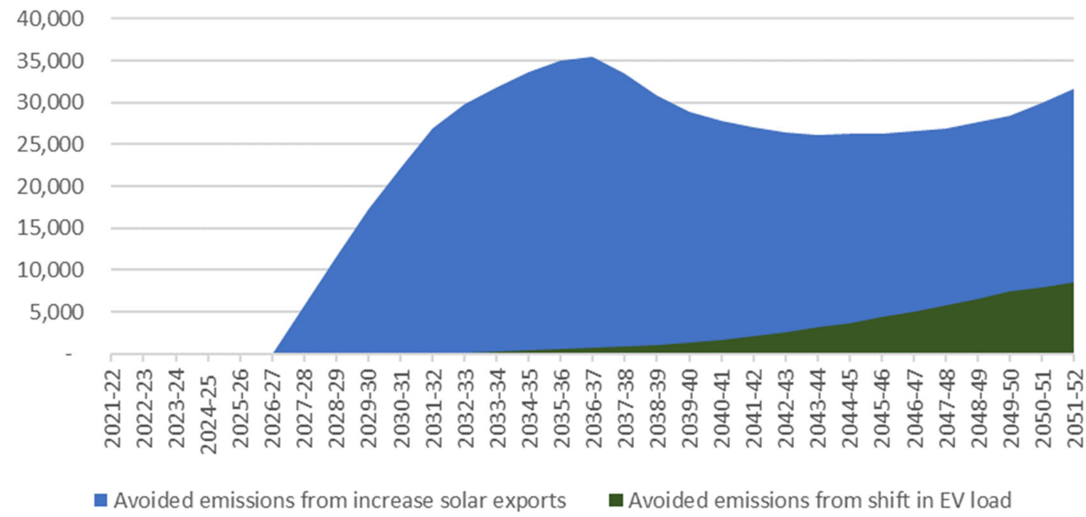
B.6 Avoided GHG emissions

The additional solar exports and the shift in the EV charging profile resulting from the preferred option and discussed in sections B.2 and B.4, respectively, reduce the emissions intensity of electricity generation in the NT.

According to emissions data published by National Greenhouse and Energy Reporting Scheme, each MWh of electricity generated from NT gas turbines produces 0.61 tonnes of carbon dioxide equivalent (t CO_2e). An increase in solar exports and shift of EV load to the middle of the day reduces the generation required from NT's gas turbines.

The preferred option is projected to mitigate over 1 million t CO_2e over 30 years (Figure 19). Assuming a constant carbon price of $30/t CO_2e, the present value of the abated emissions is expected to exceed $14.6 million.

Figure 19: GHG emissions abated under the preferred option (t CO_2e)



Source: DOE Business Case Model 111122

B.7 Improved LV network visibility

Power and Water presently has very poor visibility regarding how its customers consume, generate and export electricity on its LV network. In the last couple of months, it has discovered examples of constrained hosting capacity. However, its poor visibility over the LV network prohibits it from quantifying the remaining network hosting capacity or optimising the use of that capacity.

The preferred option greatly improves network visibility, providing real-time data on electricity direction, voltage, and frequency. The new data will inform future business cases for DER integration investments that increase network capacity, or better utilise remaining capacity.

Appendix C. Sensitivity Analysis

The purpose of this section is to illustrate how the return on the investment of the preferred option varies with alternative assumptions to those adopted for the central case.

C.1 NT Government Investment in BESS

This business case reflects the uncertainty in the minimum demand threshold with three operational threshold assumptions (refer to Figure 20):

1. Minimum demand threshold remains at 67MW ('Base case'/'Nil BESS') - NTG/TGEN does not deliver first security BESS
2. Minimum demand threshold of 50MW from 2024 ('Central case'/'Partial BESS') – NTG/TGEN installs a 35MVA security BESS by 2024
3. Minimum demand threshold of 30MW from 2026 ('Full BESS')– NTG installs a second 35MVA security BESS by 2026.

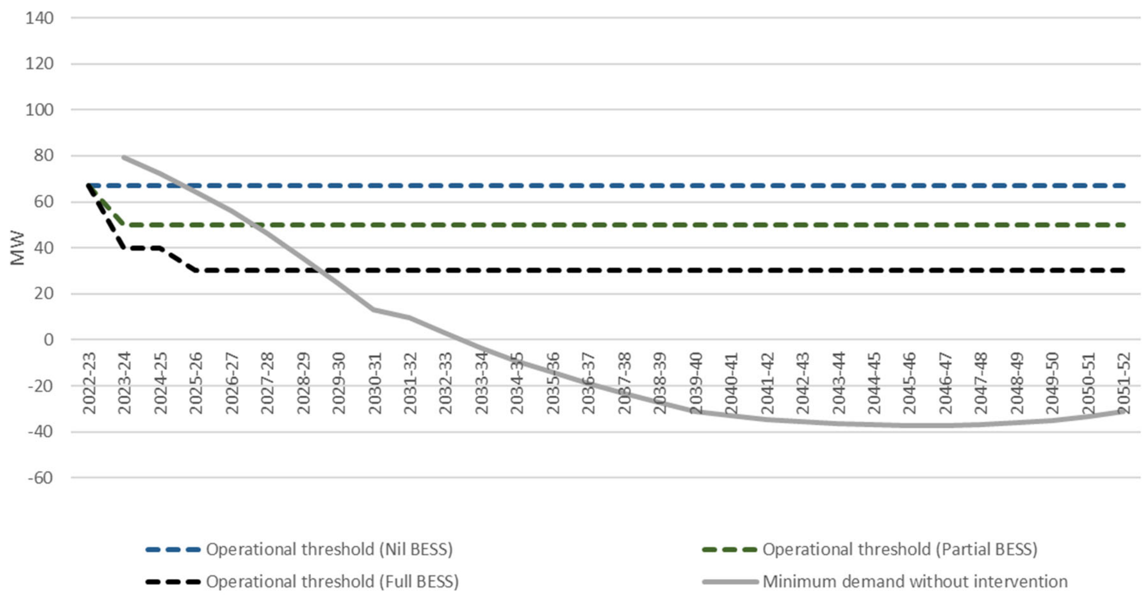
The assumptions regarding the NT Government's investment in BESS alters the parameters of the base case. As more battery capacity is installed, Power and Water can rely less on static export limits to mitigate minimum demand events. The alternative base case parameters and the effect on the NPV of the preferred option are set out in Table 12.

Table 11 Sensitivity of results to NT Government Investment in BESS

Parameter or Result	Nil BESS	Partial BESS (Central case)	Full BESS
Base case			
Revised static export limit	2.0kW	2.3kW	2.5kW
Date of revised static export limit implemented	2026	2028	2030
Preferred Option (Option 2)			
Date dynamic limits implemented	2026	2028	2030
NPV of Preferred Option	>$41.2 million	>$32.1 million	>$35.4 million

Source: DOE Business Case Model 111122

Figure 20: Projected minimum demand in Darwin-Katherine

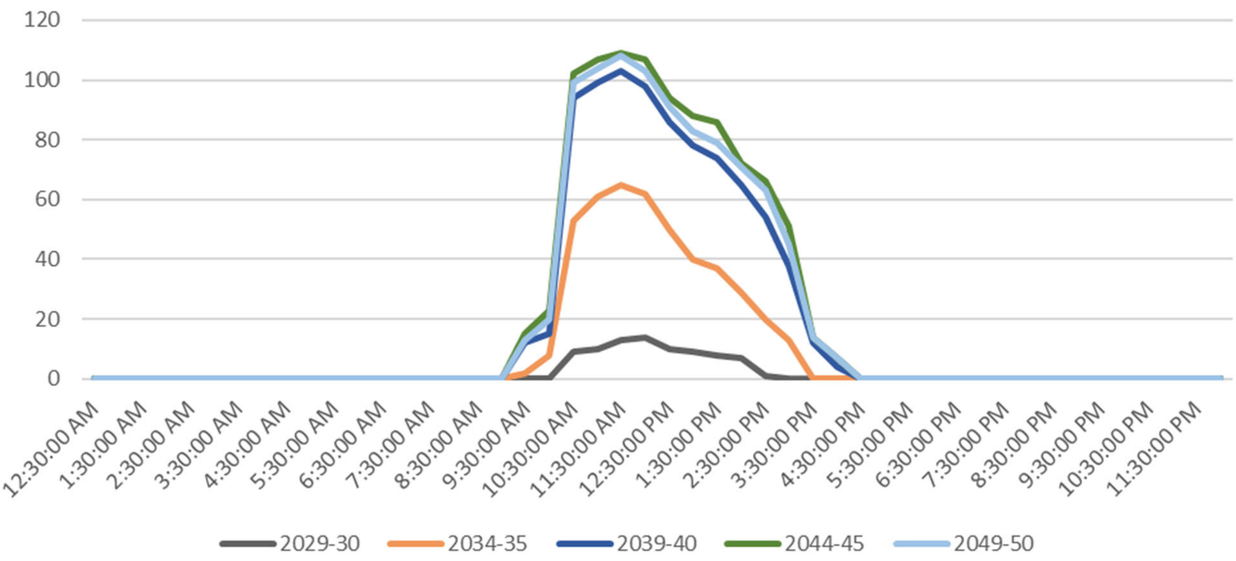


Source: DOE Business Case Model 111122

Under the central case, there remains a need to prevent the minimum demand from falling below the 50MW threshold and maintain system strength. In the absence of any investment or intervention, the minimum demand is forecast to fall below the 50kW threshold for the first time in 2028-29.

From 2029-30 onwards, minimum demand events are projected to become more frequent. Minimum demand events are projected to occur on more than 60 days of the year by 2034-35 and 100 days of the year by 2039-40 as shown in Figure 21.

Figure 21: Projected frequency of minimum demand events in Darwin-Katherine, by half-hour internal, by year



Source: DOE Business Case Model 111122

Absent any other form of intervention to prevent or mitigate the increasing frequency of minimum demand events, NTESMO would rely on Power and Water to shed net generating parts of the network, resulting in widespread involuntary outages and undermining reliability.

It is assumed that the continuation of current practices (i.e. 'do nothing' or 'business-as-usual'), which lead to minimum demand events and widespread involuntary outages across the network is not a credible option and should not form the Base case. Instead, the Base case is defined as the least cost option, one in which the static export limit is reduced to assist avoid future minimum demand events (see section 3.1.1).

If the NT Government successfully delivers the intended BESS investments as set out in the Darwin-Katherine Electricity System Plan, Power and Water need only impose a static export limit of 2.5kW for single phase residential connections from 2030 under the base case to maintain system strength.

Similarly, DOEs implemented under the preferred option could be postponed until 2030, saving nearly $4.5 million in deferred investment costs, relative to the central case. However, if the NT Government does not successfully deliver any of its intended BESS investments, Power and Water would need to impose a stricter static export limit of 2.0kW for single phase residential connections by 2026 under the base case to maintain system strength. The DOEs implemented under the preferred investment option would also be brought forward to 2026, increasing the net benefits of the preferred option to more than $41.2 million, relative to the base case.

C.2 Static Export Limit Compliance Rates

Power and Water is aware of high rates of non-compliance to static export limits, whereby customers export more than the limit stated in the connection agreement. The exact rate of non-compliance is unknown, but the rate of 30% assumed in the central case is thought to be conservative.

The non-compliance rate informs the parameters of the base case, as higher rates of non-compliance require stricter static export limits to prevent minimum demand events. Table 13 sets out how the Base case parameters and returns to the preferred option vary with assumed non-compliance.

Table 12 Sensitivity of results to static export limit compliance rates

Parameter or Result	High Compliance	Central case	Low Compliance
Rate of non-compliance	20%	30%	40%
Base case static export limit	2.6kW	2.3kW	1.9kW
NPV of Preferred Option	>$11.5 million	>$32.1million	>$54.3 million

Source: DOE Business Case Model 111122

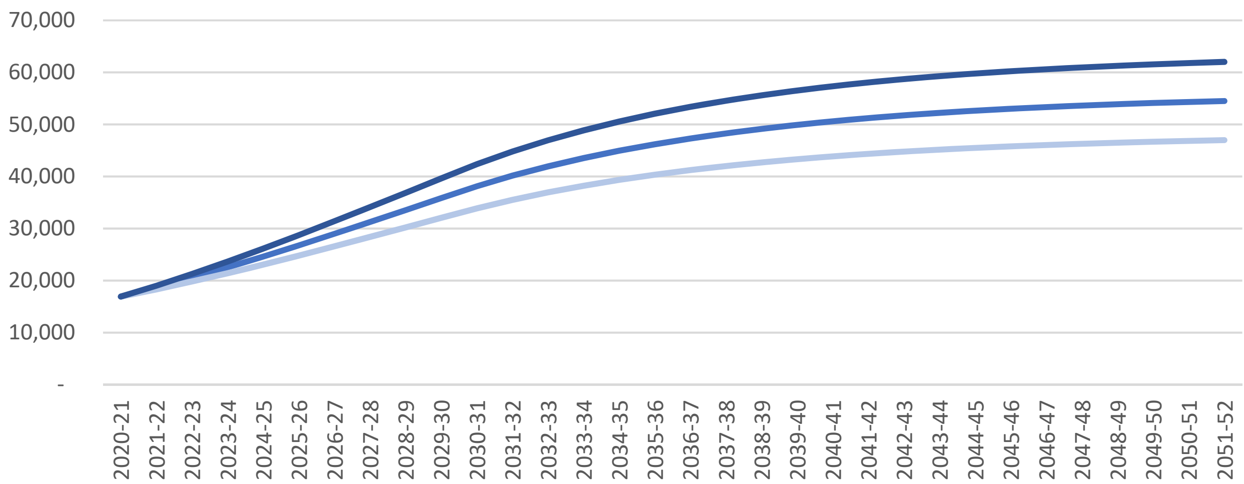
C.3 Penetration of Rooftop Solar

Power and Water expects rooftop solar connections to double from 19,600 in 2021-22 to over 40,000 by 2030-31. The continued uptake of rooftop solar was extrapolated to 2051-52 based on projections for other jurisdictions developed by Green Energy Markets.[25]

Recognising the uncertainty of long-term rooftop solar uptake projections, the investment returns of the preferred option are tested with alternative projections post 2034. A low solar case assumes growth in connections with rooftop solar is 20% lower than the central case, the high solar case assumes growth is 20% higher than the central case (Figure 22). The returns remain positive for both the low and high solar scenarios (Table 14).

[25] Green Energy Markets, June 2021, Final 2021 Projections for distributed energy resources – solar PV and stationary energy battery systems, Report for AEMO, < https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/green-energy-markets-der-forecast-report.pdf?la=en>

Figure 22: Residential connections with rooftop solar



Source: DOE Business Case Model 111122

Table 13 Sensitivity of results to rooftop solar growth

Parameter or Result	Low Solar	Central case	High Solar
NPV of Preferred Option	>$45.3 million	>$32.1 million	>$5.7 million

Source: DOE Business Case Model 111122

The net benefit of the preferred option increases under a low solar scenario because Power and Water curtails solar using DOEs less frequently than presently anticipated. By contrast, under a high solar scenario, Power and Water would rely on DOEs more frequently to curtail minimum demand events.

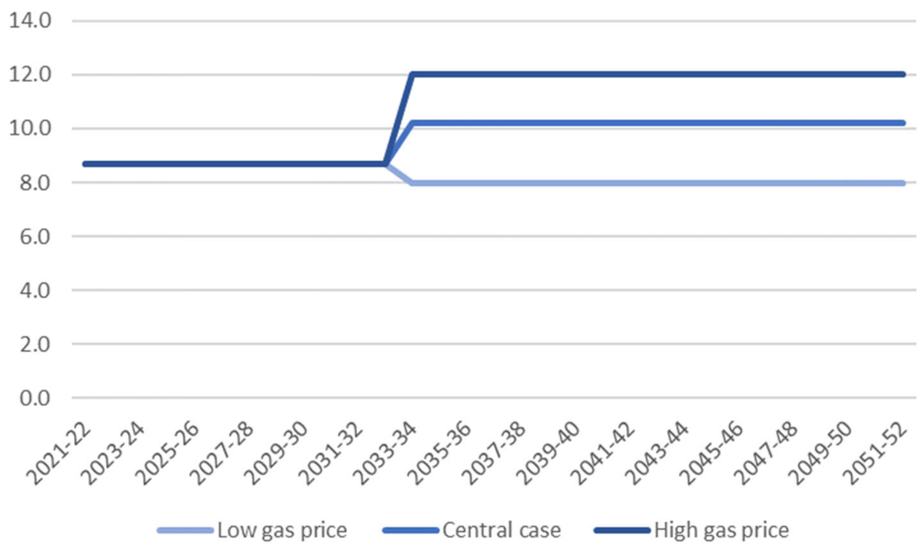
These results are counterintuitive and not particularly insightful, because it assumes that the minimum demand projections are independent of the solar uptake. In reality, solar uptake has significant implications for minimum demand and alternative solar uptake scenarios should yield alternative minimum demand projections and revisions to the Base case and investment options. These alternative minimum demand scenarios and the associated revised options were not developed for the sensitivity analysis.

C.4 Gas Price Post 2034

NT gas prices are expected to remain flat in real terms as prices are assumed to be fixed under a long-term contract with the NT government. It is assumed that these fixed prices are passed on to generators and retailers at cost. Prices are projected to inflate materially upon maturity of this contract in 2034 due to competition with oil-price linked eastern Australia source gas, given the two regions have become connected via the Northern Gas Pipeline from December 2018 (Figure 23). [26]

The investment returns of the preferred option are tested with alternative gas price projections post 2034. The returns remain positive for both the low and high gas price scenarios (Table 15).

Figure 23: Gas price sensitivity scenarios



Source: DOE Business Case Model 111122

Table 14 Sensitivity of results to NT Gas Price

Parameter or Result	Low Gas Price	Central case	High Gas Price
Gas Price	$8/GJ post 2034	$10.2/GJ post 2034	$12/GJ post 2034
NPV of Preferred Option	>$15.3 million	>$32.1 million	>$45.7 million

Source: DOE Business Case Model 111122

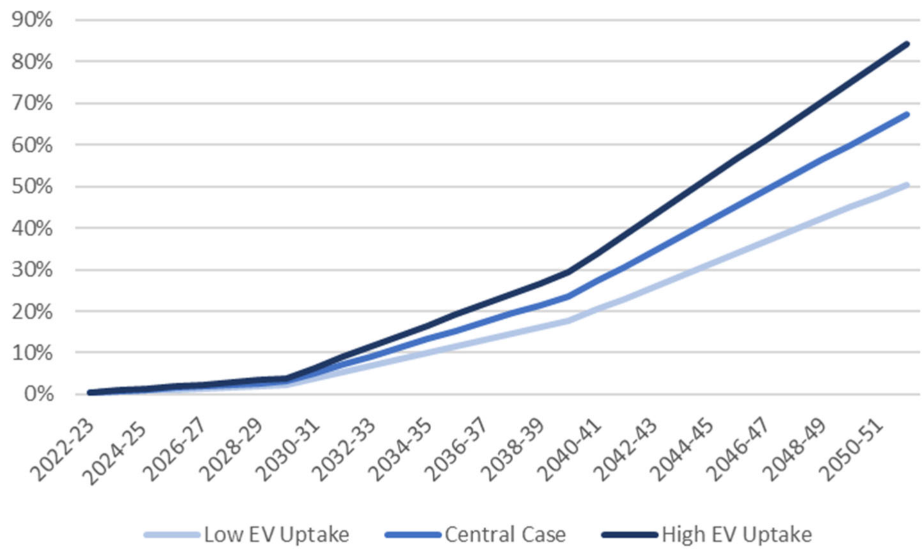
[26] Core Energy and Resources, Delivered Wholesale Gas Price Outlook 2019-2040 Residential & Commercial and Gas Generation Segments, <https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/CORE_Delivered-Wholesale-Gas-Price-Outlook_16-January-2019.pdf>

A higher gas price increases the customer export curtailment value (CECV), which is the opportunity cost of curtailing solar exports. The preferred option facilitates increased solar exports, relative to the Base case, and so an increase the gas price makes those additional solar exports more valuable.

C.5 EV Uptake

The central case assumes that the EV uptake in the NT reaches 60% of vehicles will be electric by 2050. Low and high EV uptake scenarios were developed, assuming a path to EV uptake of 45% and 75% by 2050, respectively as shown in Figure 24.

Figure 24: EV Uptake Sensitivity Scenarios



Source: DOE Business Case Model 111122

The return on the preferred option remains positive across all EV scenarios (Table 16). Higher projected EV uptake increases the benefits accruing to the preferred option, as the DOEs can increase the amount of deferred or avoided network augmentation expenditure and shift a larger load from the evening to the middle of the day.

Table 15 Sensitivity of results to the EV uptake

Parameter or Result	Low EV Uptake	Central case	High EV Uptake
EV uptake by 2050	45%	60%	75%
NPV of Preferred Option	>$27.5 million	>$32.1 million	>$36.6 million

Source: DOE Business Case Model 111122

C.6 Carbon Price

Around 12% of the quantified benefits accruing from the preferred option are the result of reductions in GHG emissions. The central case assumed a carbon price of $30/t$CO_2$e. Table 17 illustrates that the returns to the preferred option remain positive for a range of carbon prices, including a nil carbon price.

Table 16 Sensitivity of results to the carbon price

Parameter or Result	Nil Carbon Price	Central case	High Carbon Price
Carbon Price	$0/t$CO_2$e	$30/t$CO_2$e	$60/t$CO_2$e
NPV of Preferred Option	>$17.6 million	>$32.1 million	>$46.7 million

Source: DOE Business Case Model 111122

C.7 Other related investments

Power and Water considered that for the purpose of this analysis, the impact of the 30MVAr of reactors to be installed at Hudson Creek and Katherine do not materially impact the conclusions. This assumption will be reviewed as part of updates to the assumptions and modelling.

Appendix E. Delivery considerations

E.1 Strategy for Procuring Skills Required for the Preferred Option

Table 17 Strategy for Procuring Skills Required for the Preferred Option

Skillset	Description	Initial Resourcing Plan	Deliverability Risk	Risk Management Approach
Commercial professionals	Facilitate the DOE solution program within Power and Water' operations. This includes: > Strategy development > Project planning and delivery > Program management and reporting > Business process mapping	Use internal Power and Water resourcing to gain and retain knowledge in PWC.	Shifts in labour market demand lead to key personnel moving to alternative employment at more attractive remuneration/ employment conditions.	Monitor and review key staff incentives, retention measures and satisfaction. > Monitor and review resourcing in internal Power and Water areas to ensure that the implementation is having positive, rather than negative effects on the workload and work practices of critical staff. > Recognise teams and individuals who may be working above capacity for extended periods of time and offer respite via rescoping delivery plans where necessary.
Engineering professionals	Design and build the DOE solution software and hardware. This includes: > Visibility and forecasting of network state estimation > Constraints engine > Operating envelope calculation	Mixed resourcing model > Use contractors as specialist skillset > Use internal Power and Water and ICT resourcing to gain and retain knowledge.	> Necessary contract price increases for contractors and Power and Water to retain the personnel needed to deliver. > Shifts in labour market demand lead to key personnel moving to alternative employment at more attractive remuneration/	

			employment conditions.	> Manage and disseminate DOE knowledge widely in the business to minimise key person risk. > If resource constraints are anticipated, pre-emptively bring forward critical enabling scope while resources are available.
ICT developers	Deliver the core DOE ICT systems architecture and solutions. This includes: > Application delivery, testing and support. > Time series database set up and 24/7 support > 24/7 support systems including PI stack, constraints engine, etc > DOE Integration layer/ middleware setup and maintenance > NTESMO Requirements set up and maintenance > Customer experience and interface development > Building system integration and interoperability > Ensuring cyber security and other standards/protocols are met	Mixed resourcing model > Use contractors as specialist skillset > Use internal Power and Water ICT resourcing to gain and retain knowledge	> Necessary contract price increases for contractors and PWC to retain the personnel needed to deliver. > Shifts in labour market demand lead to key personnel moving to alternative employment at more attractive remuneration/ employment conditions.	
Network operations, control and SCADA technicians/engineers (OT)	Enable field data and central network operations integrating DOEs	Internal resourcing to gain and retain knowledge in	Shifts in labour market demand lead to key personnel moving	

	into normal operating procedures.	Power Services and System Control.	to alternative employment at more attractive remuneration/ employment conditions.	
Stakeholder engagement and consultation	Stakeholder engagement with customers, installers, OEMs, aggregators, Power and Water internal teams. Tasks may include communication channels, managing stakeholder reference groups.	Mixed resourcing model > Use contractors as specialist stakeholder engagement skillset > Use internal Power and Water corporate affairs resourcing to gain and retain knowledge	> Necessary contract price increases for contractors and Power and Water to retain the personnel needed to deliver. > Shifts in labour market demand lead to key personnel moving to alternative employment at more attractive remuneration/ employment conditions.	

E.2 Labour Market Factors

The labour market in the NT is constrained due to its relatively small and remote population. This limits the scale of the available labour and specialised resources available to Power and Water (when compared to other Australian networks).

The cost of contracting within the NT is higher than in other parts of Australia as service providers need to relocate specialist staff from other parts of Australia to deliver NT based projects. Power and Water offsets this through the longer-term retention of internal staff who have familial, historical or community links to the NT and a desire to remain local.

We recognise that there are three main skills risks to deliverability over the next period for the DOE program:

1. Internal resourcing capability
2. Skills available to the NT market to supplement Power and Water resources
3. Competition from similarly focussed interstate and international network transition strategies

Each are discussed in turn.

E.3 Capability of Power and Water workforce

Power and Water’ internal capability is maintained at a level that ensures that we can meet of service obligations to Territorians, maintain safety and affordability for households and businesses and transition the energy system to meet the Territory and Federal government.

The program has been scoped to be resourced with a hybrid mix of internal and contracted resources to accelerate delivery timeframes. This enables greater flexibility to respond to the foreseeable labour market tightening and resource constraints so that NT customers can be assured of realising benefits from the DOE initiatives in the upcoming RCP.

Power and Water’ internal workforce consists of over 800 FTE, including staff spread across the skills relevant to the DOE program. This enables components of the preferred option to be delivered internally with minimal deliverability risk.

E.4 NT Market Capacity

The local NT market for electrical, IT and communications contractors that can deliver the scope of the preferred option is small. The scale issues in the local NT market are exacerbated by the fact that Power and Water operates the smallest network by customer numbers that is regulated by the AER and does not operate under common ownership and/or management arrangements that are enjoyed by other Australian electricity networks.

This means that resourcing will almost certainly be reliant on contracting arrangements with specialised resources from interstate. Throughout the COVID-19 border restrictions, Power and Water was able to effectively leverage interstate resources with business practices and technologies that will continue to be used with contractor teams into the future. As a result, the scale of the local NT market is less of a concern than in prior periods.

E.5 Competition with Interstate and International Markets

As DOEs are implemented across Australian, particularly the National Electricity Market (NEM), there will be increased competition for specialist resources from around Australia. However, it is likely that there will also be increased supply of personnel experienced in the design and delivery of DOEs.

Power and Water is currently working with several specialists and technical experts involved in the design and delivery of DOEs across the NEM and anticipates that these relationships will continue and scale up as required.

Contact

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