

Next Gen Planning Solution

Case For Investment
November 2022



Contents

Executive summary	2
1. Investment Summary	4
2. Project Proposal	10
3. Options Considered	15
4. Detailed description and costs of preferred option	23
5. Recommendations and Next Steps	23
Bibliography	24

Executive summary

Endeavour Energy will require a Next Generation Planning Solution (NGPS) to ensure our planning processes are fit for purpose in the changing requirements brought on by the energy transition.

The key drivers for the proposed investment are

1. the projected continued growth in DER and multi directional energy flow within Endeavour Energy's network, which will require more extensive network visibility, forecasting capabilities, and data processing.
2. the opportunities to meet the challenge by implementing new technologies to resolve network needs, evolve with industry best practice for next generation planning and facilitate our role as a distribution system operator, in line with existing industry roadmaps; and
3. the alignment of the proposed NGPS functionality with Endeavour Energy's existing business strategies.

Endeavour Energy are currently lacking a centralised planning system which can investigate the challenges facing the network beyond the current, heuristic-based approaches. These heuristics are all conservative approaches, which when applied to these problems, results in sub-optimal outcomes such as excessive Capex to cover the risks associated with uncertainty or excessive curtailment of DER. The latter is currently only detected when customers complain.

In addition, our current methodology sometimes results in the replacement of transformers or augmentation of the network sooner than necessary given the uncertainties in the forecasts. Improving the accuracy of load forecasting and the effects on the networks via simulations, will reduce the likelihood that work is performed that could have been deferred. A NGPS uses load and DER forecast together with network simulations to prevent such outcomes from occurring.

We expect that moving to a modern model-based load forecasting methodology (as part of the Next Generation Planning Solution), using year-round data will improve the accuracy of our LV transformer (distribution substation transformers) load forecasting, reducing the number of customers affected by unplanned outages due to transformer overloads during summer heatwave conditions. We have not sought to quantify this benefit in this business case in specific Value of Customer Reliability (VCR) terms, as it is already captured in other CFIs for network investments for Augex and DER Integration but recognise that this NGPS will serve to better plan for such potential incidents in a proactive and efficient way.

This proposed NGPS development will leverage initial learnings from a range of recent trials that explored some of the emerging issues. These have been undertaken in environments that were highly controlled with respect to both data and risk perspective. As DER growth presents more complex planning needs, and as the data processing requirements for effective planning increases, it is important to develop a more mature and holistic planning framework suitable for incorporation into Endeavour Energy's BAU planning procedures.

This CFI recommends investment in an \$9 Million (\$FY24) Next-Gen Planning Solution, a non-recurring ICT asset to meet a lost opportunity risk of \$15.85 Million over the RCP is needed on the basis that the preferred solution represents the highest value (economic benefit), and that a project value of \$9 Million be approved for consideration in 2024-2025 Investment plan. The opportunity risk is 1% of the full Augex, Repex and Resilience anticipated for the RCP24-29 and 10% of the full DER Investment amount for RCP24-29, which will be unoptimized in the absence of this proposed planning tool.

1. Investment Summary

The summary below sets out the key aspects to consider in recommending this investment, including:

- drivers for undertaking the investment,
- investment timing, estimated costs and expected benefits; and
- options considered.

If no action is taken, Endeavour Energy will face several risks relating to the safe and effective integration of DER with the network, will fail to meet customer expectations in developing capability required to integrate growing DERs and would lead to increasing loss of opportunity for the wider community (reliability risks).

Two options were evaluated in this business case:

Option 1 – The counterfactual (continue with existing DAPR and underlying models and tools that support its production).

Option 2 – A Next Gen Planning Solution which enables a range of customer energy choices, including accurate dynamic export for all customers.

The NGPS goes beyond the 'business as usual' expectations of our customers and aims to 'enable' our customers evolving energy choices. The proposed system is focused on using technology to cost effectively unlock the market value of constrained generation connected to our networks by maximising the utilisation of existing network in the light of seasonal peaks and providing them with power needs "just in advance" of their requirements.

1.1 Recommendation

This CFI recommends investment in an \$9 Million Next-Gen Planning Solution (NGPS). This non-network, ICT asset will address a lost opportunity risk of \$15.8 Million need or opportunity (prior to 2026) on the basis that the preferred solution represents the highest value (economic benefit), and that a project value of \$9 Million be approved for consideration in FY24-F25 Portfolio Investment Plan.

This is a proactive project to address the needs for Endeavour Energy to upgrade planning procedures, aligning with emerging industry best practice by incorporating features such as:

- More advanced DER Forecasting that allows for distribution network specific and locational (improve on down-casting AEMO) e.g., integrate physical, demographic, or tariff responses that will affect demand and DER uptake (including decarbonisation and broader electrification plans such as electrification of transport, heating and changing profile of use)
- Spatial connection of the network and model two-way energy flows for time-series data across our network elements.
- Hosting capacity analysis for existing network elements both for current and future states, in line with strengthening the analysis presented in the DER Integration Strategy
- Modelling of different investments that can resolve constraints (including NNOs)
- Account for distribution impacts of current and future embedded generation and storage.
- Expanded network planning scenarios – i.e., analysis of prospective components
- Greenfield Area forecasts and alternative network design impacts
- Advanced Minimum Demand forecasting
- Look at reliability (SAIDI and SAIFI and costs to serve) to inform better decision making

This type of advanced planning is being pursued by Western Power's Grid Transformation Engine (GT. Eng) to address the same issues now facing Endeavour Energy and other DNSPs.

1.2 Key Drivers

The key drivers for the proposed investment are (1) the projected continued growth in DER within Endeavour Energy's network, which will require more extensive network visibility, forecasting capabilities, and data processing; coupled with (2) opportunities to meet this challenge by implementing evolving industry best practice for advanced planning, in line with existing industry roadmaps. An additional consideration is (3) ensuring that the measures implemented are informed by and integrated with Endeavour Energy's existing business strategies and practices.

(A) Continuing customer DER adoption will lead to new planning capability requirements. As laid out in the Future Grid Strategy, continuing customer adoption of DER will increasingly introduce new factors for planning that are not well represented in existing planning methodology. Projections for Endeavour Energy's territory, based on AEMO's 2022 draft ISP, indicate that:

- Solar PV Systems on our network will increase from 220,000 in 2022 to 450,000 in 2030
- Residential BESS systems will increase from 12,000 in 2022 to 140,000 in 2030
- Electric Vehicles will increase from 2,000 in 2022 to 250,000 in 2030

The significant growth in behind-the-meter generation, together with changing load dynamics from electric vehicles, the "*electrification of everything*" and storage operation will require a range of new planning capabilities, such as more granular forecasting capability (at the distribution feeder and distribution substations level); detailed scenario modelling, time-series forecasting for renewable energy, behind-the-meter batteries, and EVs; efficient mining of telemetry data (such as from smart meters); and more.

(B) Emerging industry-recognized advanced planning practices provide an opportunity to meet these needs. A second, and closely related, driver is the opportunity to implement emerging industry best practices for advanced network planning into Endeavour Energy's planning workflow. CSIRO and ENA's 2017 Electricity Network Transformation Roadmap¹ outlined a series of milestones that provide markers of progress over the coming decade toward a more resilient 2027 future state. Milestone 2 stated that, by 2019, a basic set of Advanced Network Optimisation functions are performed where networks with very high distributed energy resources levels progressively implement:

- advanced network planning tools;
- distributed grid intelligence; and
- control and advanced network operation techniques.

This milestone introduces more sophisticated techniques for the utilisation of distributed energy resources. It is used as part of a coordinated and automated process for network management, for example, assisting in managing voltage excursions, responding to loading unbalance in real time or managing short term constraints, perhaps as part of an automated and intelligent control scheme to achieve integrated system operation.

(C) The required capability is closely aligned with Endeavour Energy's existing Strategic Initiatives. Thirdly, this next generation planning capability becomes part of the physical manifestation of Endeavour Energy's already-defined ambitions and strategies, representing a line of sight between these and what the planning solution delivers.

It serves to align technology with improved, data-centric processes to enable engineers to be more effective within the planning realm of Endeavour Energy. As seen within Figure 1 People & Culture and Growth

¹ 3 CSIRO and Energy Networks Australia 2017, Electricity Network Transformation Roadmap, Final Report, pp. 58-59 – available at: http://www.energynetworks.com.au/sites/default/files/entr_final_report_web.pdf

through Innovation are the two most pertinent strategic initiatives addressed within the ambitions of the NGPS, and which are in turn, supported by at least four strategic enablers, as highlighted in red. In addition, under the Performance Strategic initiative the NGP will also provide the following:

- a. Improve processes to better align with customer expectations (including having consumers input through the regulation reference groups by way of co-designing the NGPS features, more importantly to streamline the provision of dynamic operating envelopes (DOEs) to customers for when they want to upgrade their rooftop solar PV or install a system for the first time.
- b. Identify and invest in network resilience (the ability to identify areas which have a high cost to serve which presents an opportunity to introduce stand-alone power systems with their inherent ability to island. This ability provides a more resilient grid to those consumers),
- c. Embed Future Grid Innovation initiatives into BAU (Innovation solutions require testing and a trial stage and then when successful, need to be integrated into the BAU activities, a planning solution is the natural system to test those broader business impacts)
- d. Be the system to incorporate new technology solutions and platforms into asset management processes (the same premise as in point c.)



Figure 1 Most pertinent Strategic Initiatives met supported by all three Strategic enablers

- 2) It incorporates the ability to investigate rapid changes in data inputs (faster EV and behind the meter battery adoption rates driven by net-zero acceleration) and also the evolving technology landscape (V2G charging, data-centres (DC) participating in FCAS markets, block-chain energy intensities, etc) which require higher levels of automation for the purposes of running many “what if scenarios” with a much greater velocity than those traditionally allowed for by the annual planning cycles which support the Distribution Annual Planning Report (DAPR). Additionally, planning annually without reliance on pseudo real-time data sets would make participation as a DSO in 5-minute settlements (5MS) next to impossible.
- 3) Accurate and viable planning outcomes mitigates the risks that Endeavour Energy are exposed to by not having such a system, i.e., not being able to consider all the relevant options in a comprehensive way. Gold-plating the network or not having adequate capacity “just in advance”,

will result in discontented consumers. Planning for local area microgrids² may present a substitute to connection with all that these may offer in the future such as: peer-to-peer energy trading with their neighbours, etc.

1.3 Options Considered

The system considered proposed in Option 2 is a hypothetical enterprise-based system which meets Endeavour Energy's requirements. Due to the specificity of each DNSPs incumbent systems, geography and data access, there is no commercial off the shelf (COTs) system which performs this function, there is thus also no solution alternatives applicable to form a broader set of options than those proposed below.

Option 1: the counterfactual, use the existing DAPR with its supporting tools and processes

The most significant option to consider is what the current approach may present in terms of excessive Capex spending and also the potential undue constraints being imposed on customers' future energy choices (this could be reliability impacts or DER curtailment impacts).

If the demand at zone substations is only measured twice during the peak season of the year (once in summer and once in winter), this practice will ensure that the zone transformer capacity is adequate in the near term but gives no indication of issues that occur downstream from that point in the network, such as on the distribution transformer and LV feeder circuits. Further to that point, the forecast driving the MV/HV augmentation is subject to heuristics such as the Load Realisation Factor (LRF) which is a factor which reduces the total connection requested demand to account for the slower build-up of new spot-loads before these reaching their ultimate value (the amount that was originally applied for by the connection applicant). If a judgement error is made with this factor, a reliability issue may develop, especially when aggregating many smaller connections onto a particular zone substation. Given that 70% of Augex expenditure (see *Figure 2* for the forecast methodology), in the current planning methodology, is driven by this type of additive forecast, this could result in either reliability or investments made too early and "not in advance" of being required.

² For example, the islandable Bawley Point and Kioloa Community Microgrid currently being implemented as a trial on the southern most tip of our network, but also other non-island able but high embedded generation microgrids that could be more efficiently designed (e.g. "thing grid") if considered at the outset for meeting greenfield development.

Relationship between various input forecasts and need for augex investment

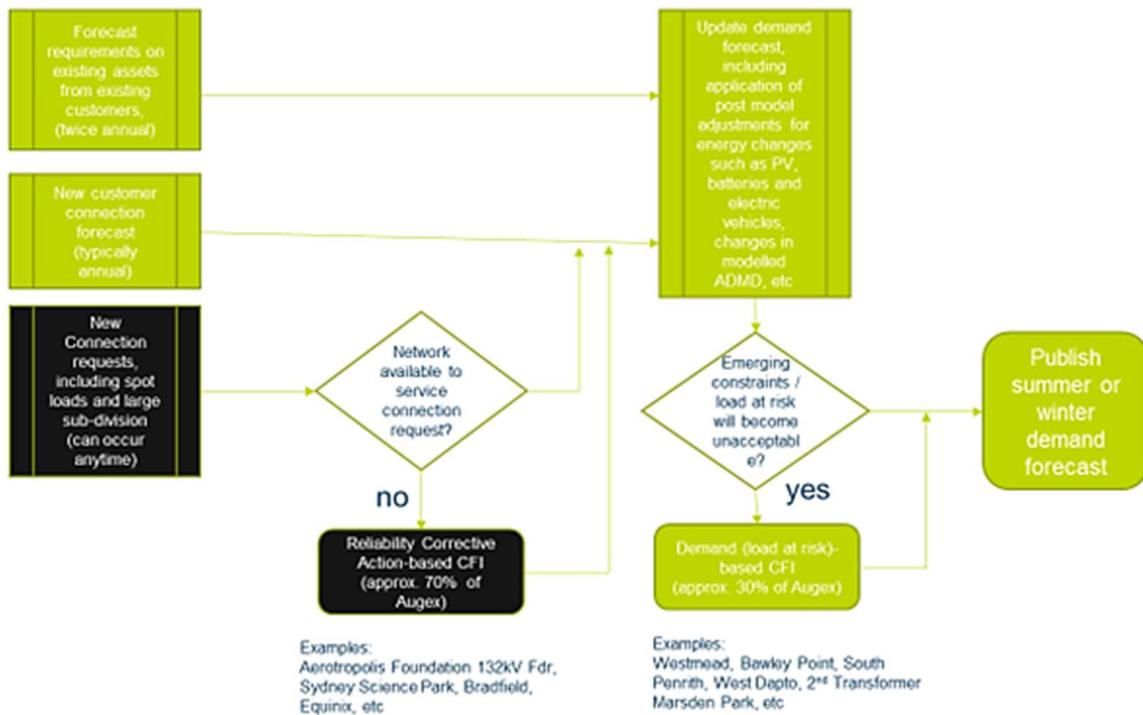


Figure 2 Relationship between various input forecasts driving Augex investments

There may be LV issues resulting in capacity issues or excessive voltages, which when combined with inverter settings results in curtailed exports from DER, which will go undetected in the current planning process. If the planning process modelled the time-series flows beyond the Zone Transformer the temporal and spatial nature of issues would be better understood and better addressed. The models developed in 2022 that underly the DER Integration strategy have gone some way in addressing these issues but remain limited in capability and are not an automated solution. This is because the opportunity to unlock further value requires an enterprise system taking additional factors into considerations such as: actual LV flows (rather than an average from 10,000 smart meter records), integration with the high voltage network models and more comprehensive scenario and sensitivity analysis etc.

The planning also needs to value other metrics such as SAIDI, SAIFI improvements, the costs to serve (maintenance costs), reliability impacts etc when planning for network augmentations, this is currently not the case.

The Electricity Network Transformation Roadmap (ENTR)³ attempts to quantify the full extent of the problem and states that a ~\$1.6B investment required in augmentation (across the NEM) between 2021-26 to deal with PV and battery hosting capacity issues which are all assumed to be based on current planning methods.

³ <https://www.energynetworks.com.au/projects/electricity-network-transformation-roadmap/>

In *Figure 3* the challenges of attempting to get the timing correct for an investment, are shown, especially when only taking two data points per annum. In addition to the large range of forecasts showing different dates for when the load becomes at-risk, this forecast shows how DER-uptake and non-network options affect this forecast (period between 2006 and 2010)

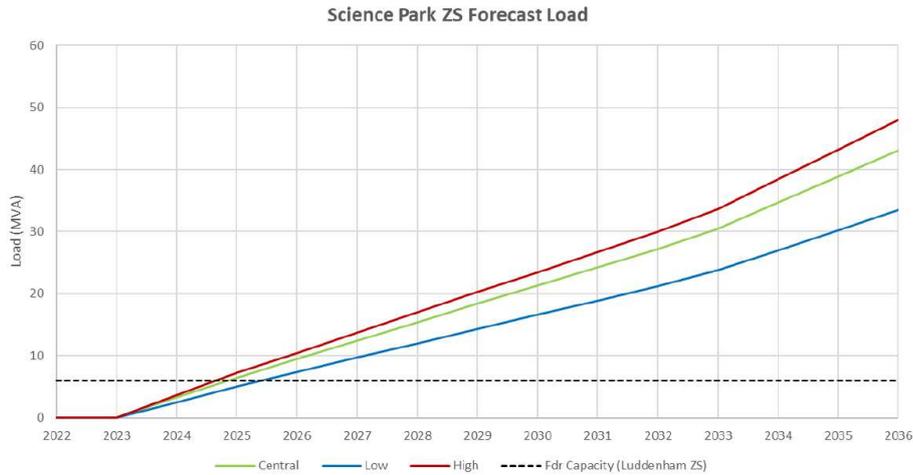
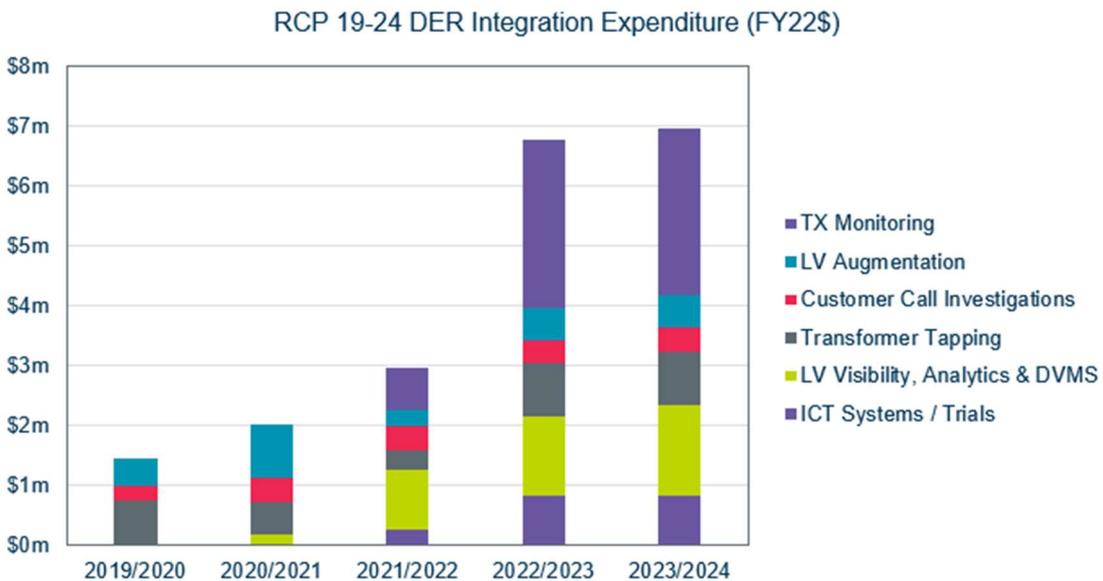


Figure 3 The variability of load over-time and different forecasting approaches (load at risk timing is anywhere between mid-2024 to mid-2025, in this example by using a single measurement per year)

Option 2: Based on the past work on low-voltage compliance (which was reactive in nature) this can rather be modelled and addressed proactively, within the expanded NGPS system

The alleviation of voltage violations is enabled by undertaking LV visibility and analytics, using some time-series data, and undertaking investigations from customer calls, changing taps on distribution transformers having fixed-tap and in some instances undertaking network investments. These expenditures are shown in the diagram below from a historic perspective. The NGPS will do this proactively rather than reactively thus preventing either lost opportunity to customers by them either being constrained with DER exports or them potentially being part of a LV trip from an unknown overload condition.



It is recognised by the AEMC, that new monitoring techniques and better modelling are important components of the future planning landscape, this observed within the following statement:

“Where it is cost effective, invest in new monitoring and modelling equipment to improve the visibility of loads and voltages on the part of the grid between a customer’s property and the local substation so distribution businesses can better understand current and future network constraints (underway)” [AEMC ENERFR 2019 infographic⁴]

2. Project Proposal

2.1 Identified Need or Opportunity

Endeavour Energy’s current planning process, based heavily on historical load measurements and embodied in the DAPR on a five-year cycle, is not fit for purpose to ensure efficient investment over the 2024-2029 regulatory period. As continued growth of DER and demand-side technologies impacts network operations and planning, and more data-intensive operations become increasingly important, Endeavour Energy will require expanded capability to integrate increasing data streams and efficiently work with a range of future planning scenarios.

Key functionality that is lacking in the current planning framework, but which will be required within five years, includes:

- More granular forecasting capability - extending to distribution feeders and distribution substations
- Forecast behind-the-meter ‘generation’ and incorporate this into load forecasting, currently this has been achieved through the DER-Integration Strategy, but will need significant enhancements for repeatability and improving the forecast layers.
- Incorporate weather forecasting into behind-the-meter generation forecasts, including understanding the upstream network impact of intra-day events such as cloud cover which can result in sudden power swings
- Efficiently interrogate and analyse telemetry data using AI
- Accurately estimate load curves and/or ADMDs for greenfield areas
- Need to evaluate carbon impacts, e.g., loss evaluations
- Incorporate a range of scenarios to inform planning (e.g., AEMO scenarios around climate change and technology uptake; also scenarios around development uptake e.g., for greenfield areas)
- Time series forecasts for network impact of rooftop PV, behind-the-meter batteries, and EVs - at the zone substation as well as feeder level.

Without these capabilities, Endeavour Energy will be exposed to, or may expose customers to, the risk of inefficient network investment, through

- Higher than necessary augmentation costs due to reactive, rushed-procurement upgrades – resulting from inadequate proactive planning to accommodate foreseeable, but unforeseen, network demands related to e.g., growing PV export or growing load from EVs;
- Planned premature investment in augmentation,
- Underutilizing existing (or already-planned) capacity, e.g. by failing to appropriately incentivize load shifting through tariff design, behavioural demand response, and controlled load mechanisms

⁴ AEMC, Designing the Grid of the Future Infographic, Electricity network economic regulatory framework review: final report, 26 September 2019

- The **Green** text is what is in existence, **Blue** text is what is required for the NGP

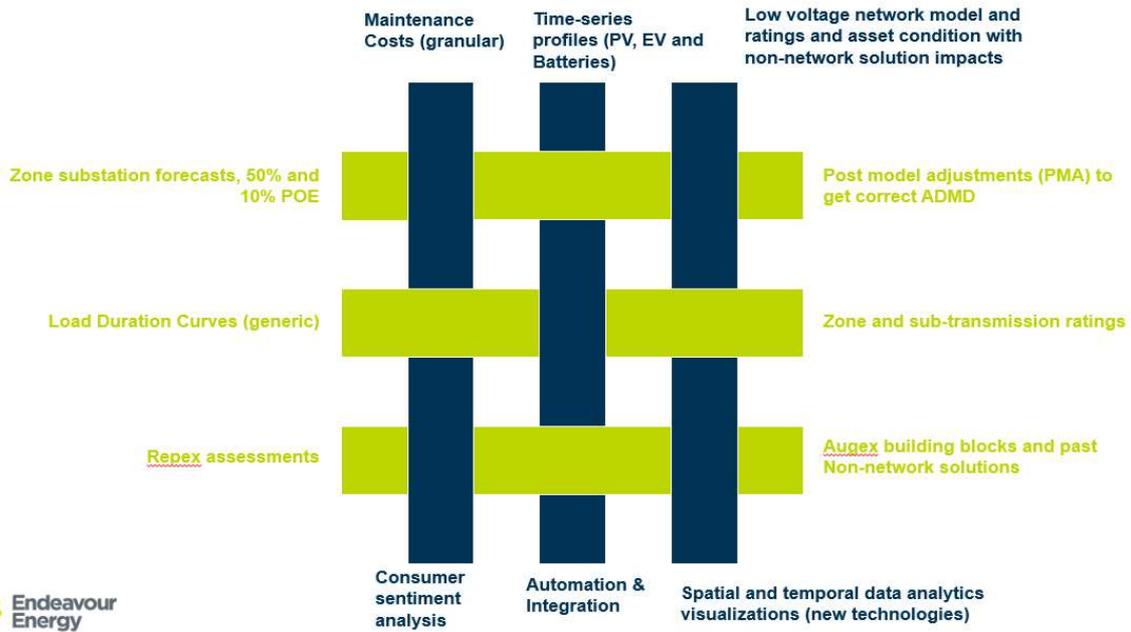


Figure 4 Gap-analysis from current DAPR to a future fit-for-purpose Next-Gen Planning (NGPS) system

The Endeavour Energy Growth servicing strategy also requires a system to identify areas where network utilisation and capacity limitations may be improved (at all levels of the network) this both for load and also considering DER uptake on capacity limitations. The NGPS will be required to provide that functionality, without which deferrals of Augmentation of ~\$50Million as seen within this next regulatory period will be missed as the analysis to find these options is becoming more challenging in the future. It is explicitly stated within the Growth servicing plan that “Non-Network optioneering are now standard BAU with further investment in NTMP. All CFIs consider non-network options and select the commercially and technically credible option.”

The required functionality described here extends beyond the scope of Endeavour Energy’s already-initiated tool development within the New Technology Master Plan program (or “NTMP 1.0”). The NTMP 1.0 has a focus on technoeconomic pre-feasibility comparison of network and non-network solutions to identified network needs, but has a limitation in its depending on existing systems to identify those needs as well as ability to understand local DER resources that could be available. In contrast, planning over the next 5-10 years will also need to consider both (1) emerging DSO functions; and (2) an awareness of NNO resources and their availability (including VPPs, V2G, evaluating and published DOEs, and more).

While Endeavour Energy’s current planning approach has served the network and its customers well, the additional planning requirements described above will soon exceed its capabilities. In the current planning approach, the current annual load measurements from the ADMS Historian system are taken as the starting point to forecast each Zone substation’s load growth over a five-year planning horizon.

The amount of load at risk for that year in MW is compared to a generic load duration curve to determine the unserved energy (USE) in MWh that will result if proactive action is not taken for the increased load at that substation. These are reported in the Distribution Annual Planning Report (DAPR)⁵. This aggregated

⁵ Distribution Annual Planning Report -

https://dapr.endeavourenergy.com.au/endeavour_data/Endeavour%20Energy%202020%20DAPR.pdf

forecast incorporates a number of dependencies, including adoption trends for PV, EVs, and demand management, as well as energy efficiency standards. The DAPR provides the market with an understanding of the various investment programs and projects being undertaken by Endeavour Energy to fulfil its obligation as a licensed DNSP in the National Electricity Market.

However, because the assessments provided DAPR extend only to the zone substation level, and do not incorporate time series projections for increasingly important DER factors such as PV and EVs, the existing planning process will become increasingly suboptimal over the next planning period. The proposed NGPS is designed provide the required capability.

Location	FDR Name	Actual Summer 20/21	Forecast Summer 21/22	Forecast Summer 22/23	Forecast Summer 23/24	Actual Winter 2021	Forecast Winter 2022	Forecast Winter 2023	Forecast Winter 2024	Reduction Required (MVA)	Potential Solution
Abbotsbury	AB1246	264.1	10.00%	14.80%	19.70%	-	0%	0%	0%	0.9	Load Transfer
Abbotsbury	AB1289	248.4	3.50%	8.00%	12.60%	-	0%	0%	0%	0.58	Monitor
Albion Park	APH2	249.5	4.00%	8.40%	13.10%	230.2	0%	0%	4%	0.6	Monitor
Ambarvale	T876	242.6	1.10%	5.40%	10.00%	-	0%	0%	0%	0.46	Load Transfer
Anzac Village	AZ1205	244.9	2.00%	6.40%	11.00%	-	0%	0%	0%	0.5	Monitor
Anzac Village	AZ1227	254.2	5.90%	10.50%	15.20%	-	0%	0%	0%	0.7	Monitor
Anzac Village	AZ1253	269.8	12.40%	17.30%	22.30%	-	0%	0%	0%	1.02	Load Transfer
Amdell Park	46774	243	1.20%	5.60%	10.10%	-	0%	0%	0%	0.46	Monitor
Baulkham Hills	35304	247.7	3.20%	7.60%	12.30%	-	0%	0%	0%	0.56	Monitor
Bella Vista	49357	255.2	6.30%	10.90%	15.70%	-	0%	0%	0%	0.72	Monitor
Bella Vista	49362	256.6	6.90%	11.50%	16.30%	-	0%	0%	0%	0.75	Monitor

Figure 5 Zone substation feeders over-loaded within next 2-4 years

2.2 Related Projects

There are many trials that have been conducted within Endeavour Energy to answer questions relating to specific challenges which have arisen within Endeavour Energy’s network in the recent past. These are part of a concerted process within Endeavour Energy to minimise risks with reduced-impact trials, thereafter, to operationalise those trials which are most fruitful and then lastly to refine those business-as-usual (BAU) initiatives using tried-and-tested continuous improvement activities. This process is captured in the following diagram (see Figure 6).

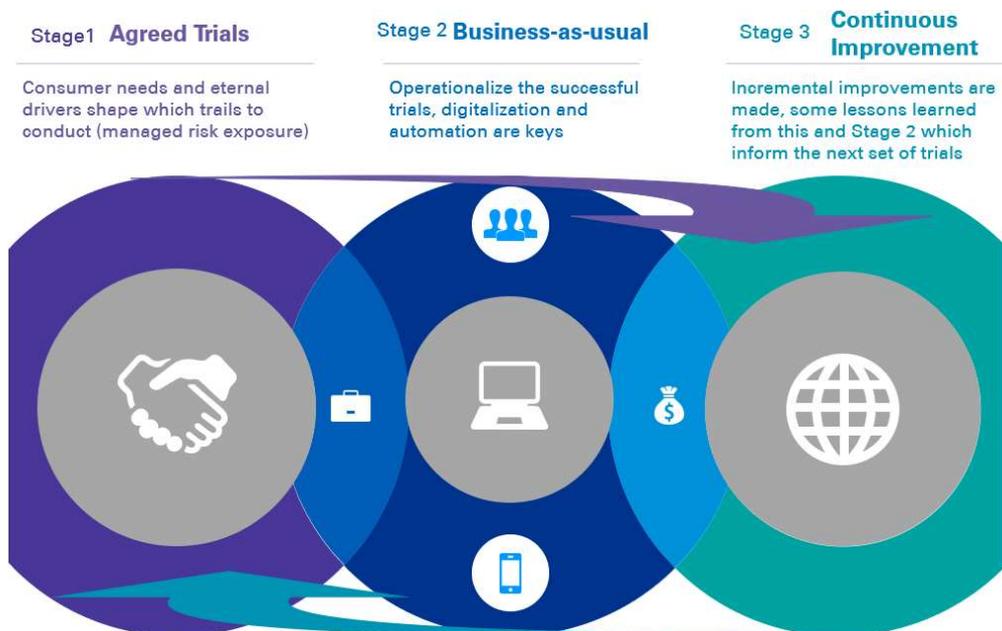


Figure 6 The Grid Transformation paradigm being followed by Endeavour Energy

These trials do not in themselves deliver comprehensive NGPS capability, but they explore many of the issues, technologies, and solutions for which an uplifted, faster velocity, planning process must evolve to accommodate – i.e., through having an NGPS. The NTMP, as a successful trial, has led to the need for the NGPS and the more comprehensive functionality that it may offer.

2.3 Assumptions

The main assumption is that the trials and the initiatives undertaken to date (see Figure 8) both within Endeavour Energy and within the broader Distribution Industry throughout Australia, need to be further built upon in developing the Next-Gen Planning Solution (NGPS). The current initiatives are captured within the following diagram which are not BAU solutions and not Enterprise grade solutions.

The work done by Western Power on their Grid Transformation Engine (GT-Eng) is an assumed external reference point for Endeavour Energy. This implies taking the costings of that system as a starting point, but also the relevant features thereof to inform the NGPS. This GT-Eng system has been reported as delivering considerable savings for Western Power since its inception in 2019. The architecture thereof is shown below, see Figure 7):

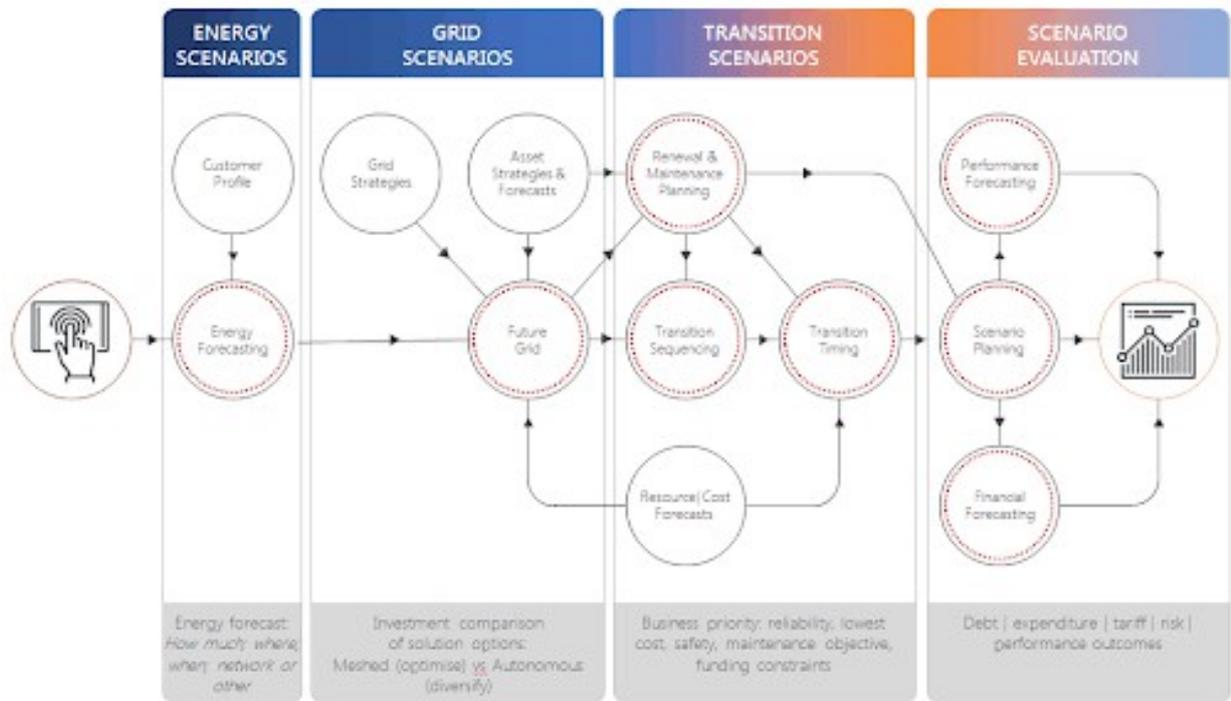


Figure 7 Solution architecture of the Western Power GT-Eng solution

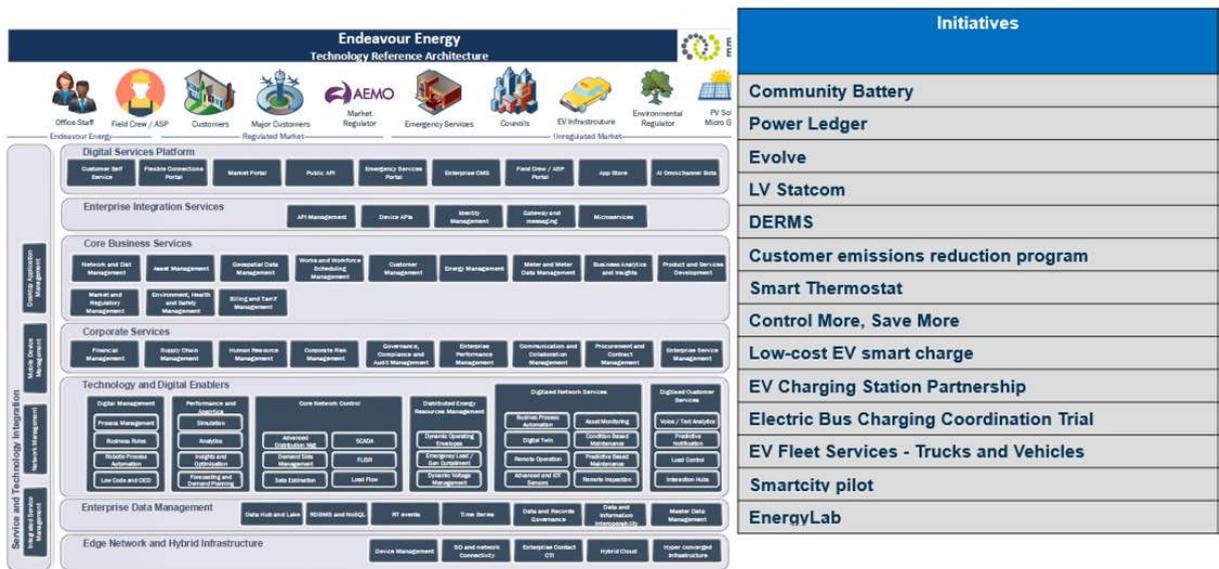


Figure 8 Building on work performed already undertaken within Endeavour Energy (Technology reference architecture on the left and the Future Network initiatives on the right)

3. Options Considered

3.1 Summary of Options

The options comparison table below sets out the credible options that were considered, together with a counterfactual option: “no proactive intervention” to assist the overall comparison. These include all substantially differing commercially and technically credible options, including non-network solutions. Credible options (or a group of options) are those that meet the following criteria:

- addresses the identified need
- is (or are) commercially and technically feasible
- can be implemented in sufficient time to meet the identified need

For all options a review period of 10 years has been used discount rate of 3.26% in accordance with Finance’s February 2021 paper.

Table 1: example option summary table

Option	Description	Solution Type	PV residual risk \$M ¹	PV Cost ² \$M	PV Benefits ³	NPV ⁴ \$M	Rank	Assessment Description
1	No change over current DAPR approach	Base case / counterfactual	15.8	-			2	Non-preferred as will lead to unacceptable risk or higher cost for customers if opportunity not captured
2	Create a fit-for-purpose Next-Gen Planning Solution (NGPS)	Network Planning solution		-9	15.8	5.65	1	Preferred

Notes:

1: The counterfactual risk of 1% of the Augex, Repex and Resilience and 10% of the DER Integration expenditure for when planning is not optimised in the absence of the NGPS, snapshot of proposal was taken based at time of October 2022.

2: PV of total costs, both Capex and Opex. See Appendix for further details.

3: PV of total quantified benefits, both risks mitigated, and any forecast decrease in Capex or Opex arising because of undertaking the investment (opportunities).

4: PV Benefits less PV Investment Costs

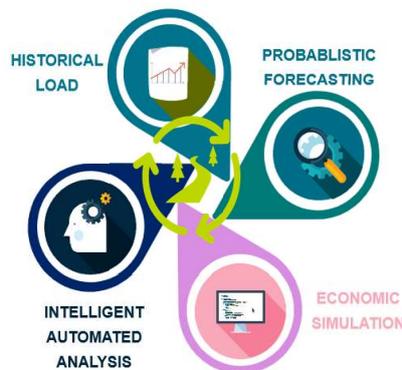
Consequence of ‘no proactive intervention’

The inability to make correct decisions, decisions with are obtained from automated, data-driven insights will be \$10 Million in opportunity cost (a risk), which is conservatively estimated at 1% of the combined Augex, Repex and Resilience expenditure in the 2024-2029 RCP. In addition, an improved planning processes will unlock an additional benefit of 10% of the current estimated DER Integration investment.

3.2 Option 2 Next-Gen Planning Solution

Scope

The key components required from an NGPS are shown below.



- **Leverage** the collected data to understand current load (Historian triggers) and network/market dynamics (consumer and behavioural changes of consumers) driven by choice and cost prioritisations from DER and by technology cost curves. Ingest AEMO ISP, DPIE & LGA data, Economist's forecasts, developer data (a better DARTS-DB) and make Augex (VCR) cases.
- **Accept** the future uncertainty and create a range of spatial and temporal forecasts (time-series databases) that analyse a broad range of possible future outcomes/trajectories. Clustering the problem on parts of the LV networks where the problems are similar.
- **Automate** the load-flow analysis (P,Q,V and losses, incl. CVO, VVO and OPF⁶) to calculate network deficiencies and intelligently match to network and non-network alternatives for each future trajectory. Enterprise tool for broader set of users. Provide study cases with phased scenarios (LF Analyser to compare outputs)
- **Perform** economic simulations to understand the best Capex and Opex strategy that delivers maximum impact NPV) and return on invested assets and simultaneously improving customer satisfaction index (sentiment).
- **Monitor**, Investigate, Alleviate, Enable and Optimise DER Integration investments
- **Take** account of broader factors such as SAIDI, SAIFI, cost to serve and do reliability/availability-based simulations based on active failure rates and mean-time-to-repair (MTTR) to inform the reliability aspects of network designs. This helps understanding the

Figure 9 Key components of an NGPS

⁶ CVO – Conservative Voltage Optimisation

VVO – Volt-Var Optimisations and

OPF – Optimal Power Flow

position of automatic network switches and how much load is at risk and is informed by built-in redundancies etc, the latter of which are inherent in the Common Information Model (CIM).

The NGPS will need to consider the following:

- Leveraging learnings from the international context (mostly notably from the USA) it has been shown that TNSPs and DNSPs need tightly integrated joint planning with a view to DER Integration for the functioning of an efficient market and that the DSO needs to manage the network constraints before the AEMO has charge of market forces related to DER:
- “Closer coordination implies that distribution and transmission systems will increasingly need to be planned and operated as an interactive, integrated whole, with power flows to and from distribution systems that shift as DERs respond to changing conditions in wholesale markets, and wholesale markets and operations respond to changes in loads and DERs in distribution systems. Moving toward this more interactive grid will require better integrating DERs into wholesale markets and operations as well as distribution system operations. However, regulatory frameworks and market rules to do so remain in the early stages.” (ESIG, 2022)

The architecture that has been devised to meet those needs and which is both flexible, scalable and uses as much of the existing systems and data within Endeavour Energy, by means of modern automation/orchestration workflows is as shown within Figure 10.

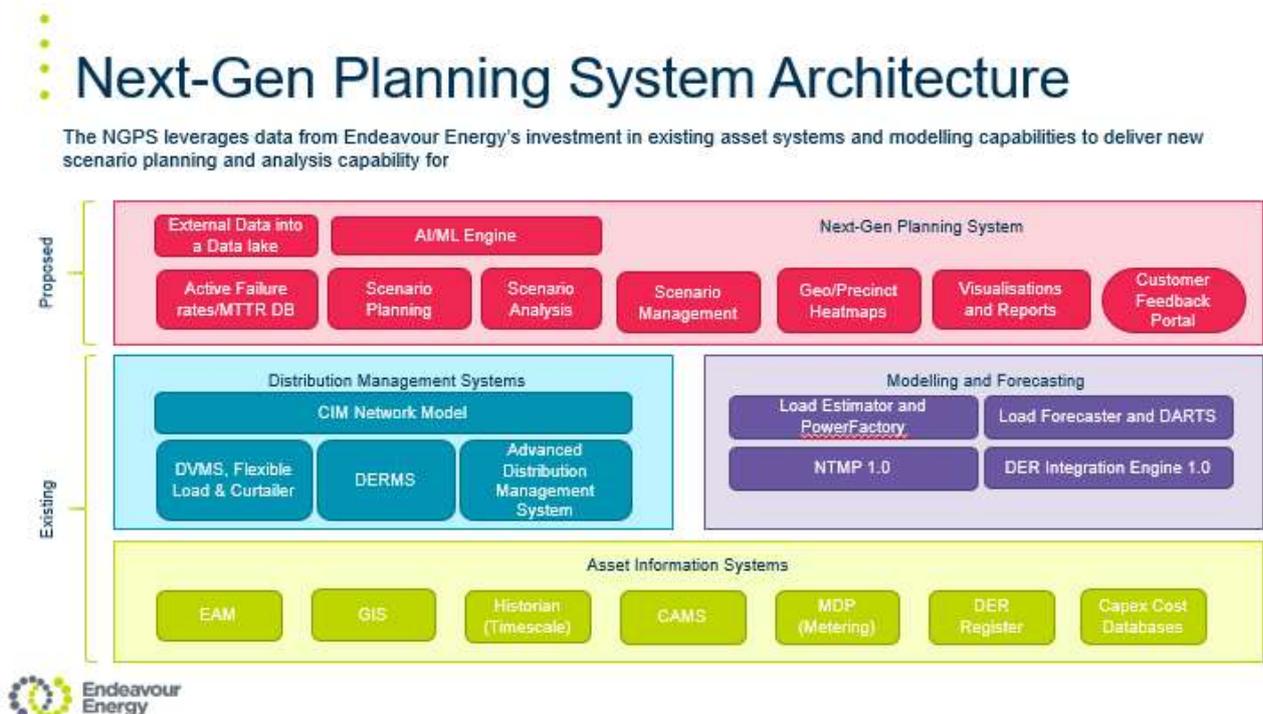


Figure 10 Architecture for the NGPS using existing systems and data and a CIM as a source of truth

Assumptions

The use of technology and automation has proven itself to be a major means to gain actionable insights and improve organisation efficiency.

A significant body of work precedes this work in the broader industry as represented by the directions captured within the CSIRO and ENA Roadmap⁷ around the theme of Advanced Network Optimisation functions and in particular the need for advanced network planning tools.

Cost

The cost is based on the learning from the various trials previously undertaken within Endeavour Energy which serves to address issues from the last couple of years, such systems are as per the following:

- Timescale as deployed by Langdale (Langdale Consultants Pty. Ltd, 2022)
- Grid sight (Gridsight.ai, 2022) and their Load Estimator in particular
- Future Grid (Future Grid,, 2022)
- NTMP (2022)
- Bawley Point Microgrid Modelling (2021)
- The work done by Wester Power in creating the Grid Transformation engine (GT-Eng) (Western Power Corporation, 2022)

The costs from all these sources are estimated at \$9 Million in 2022 terms given that the hardware, software and 5-year support for the platform is estimated at a cost of \$12M for Western Power. That system was the first of its kind and hence had a higher cost than a system such as the NGPS which will leverage the lessons learnt from that implementation. The cost of a COTS module that only looks at hosting capacities (by employing a Next-Gen System Automation with Volt-VAR optimisations) costs about \$1 Million upfront and then \$0.5 Million a year thereafter in technical support and system upgrade costs—representing a platform for hosting capacities and DOEs only, within a 5MS of about \$3.5M over five years (ETAP, 2022). To be clear there does not exist one COTS package that includes all the functionality that Endeavour Energy requires, it would need to be developed from a number of different systems with suitable integration by Endeavour Energy.

While a DER marketplace application, ARENA Project Edge is also considered as a data reference point because of the underlying needs to solve similar issues but in a real time operational context - which is estimated to cost \$29 Million across all project partners. (ARENA Project “EDGE”, 2022)

Benefits

As the DAPR is only run once a year with a focus only on ZSS and medium voltage feeders, the estimated lost opportunity for better market participation of DER, application of capital to alleviate constraints through a better planning process is estimated 1% of the combined Augex, Repex and Resilience expenditure over the 2024-2029 RCP, and thus representing a \$10 million benefit. In addition, a better DER Integration planning process will result in 10% of the in capital expenditure for RCP24-29 being saved due to the limitations within the current planning systems.

This system needs to become more enterprise focused and thus become more related to the following architecture (courtesy (ENZEN, 2019)) or that of one of the most tried and tested platforms of that kind worldwide, referring to: (ETAP, 2022). This assertion comes from a peer review assessment where ETAP is ranked the highest electrical model-driven planning and operating system see (Automation Professionals Forum, 2020). Figure 12 shows that Next Generation Planning requires the ability to simulate the impacts of control set-point changes for better DER Integration in the context of DSOs in advance of negotiating with VPPs to connect to the network to orchestrate DER.

⁷ CSIRO and Energy Networks Australia 2017, Electricity Network Transformation Roadmap, Final Report, pp. 58-59 – available at: http://www.energynetworks.com.au/sites/default/files/entr_final_report_web.pdf

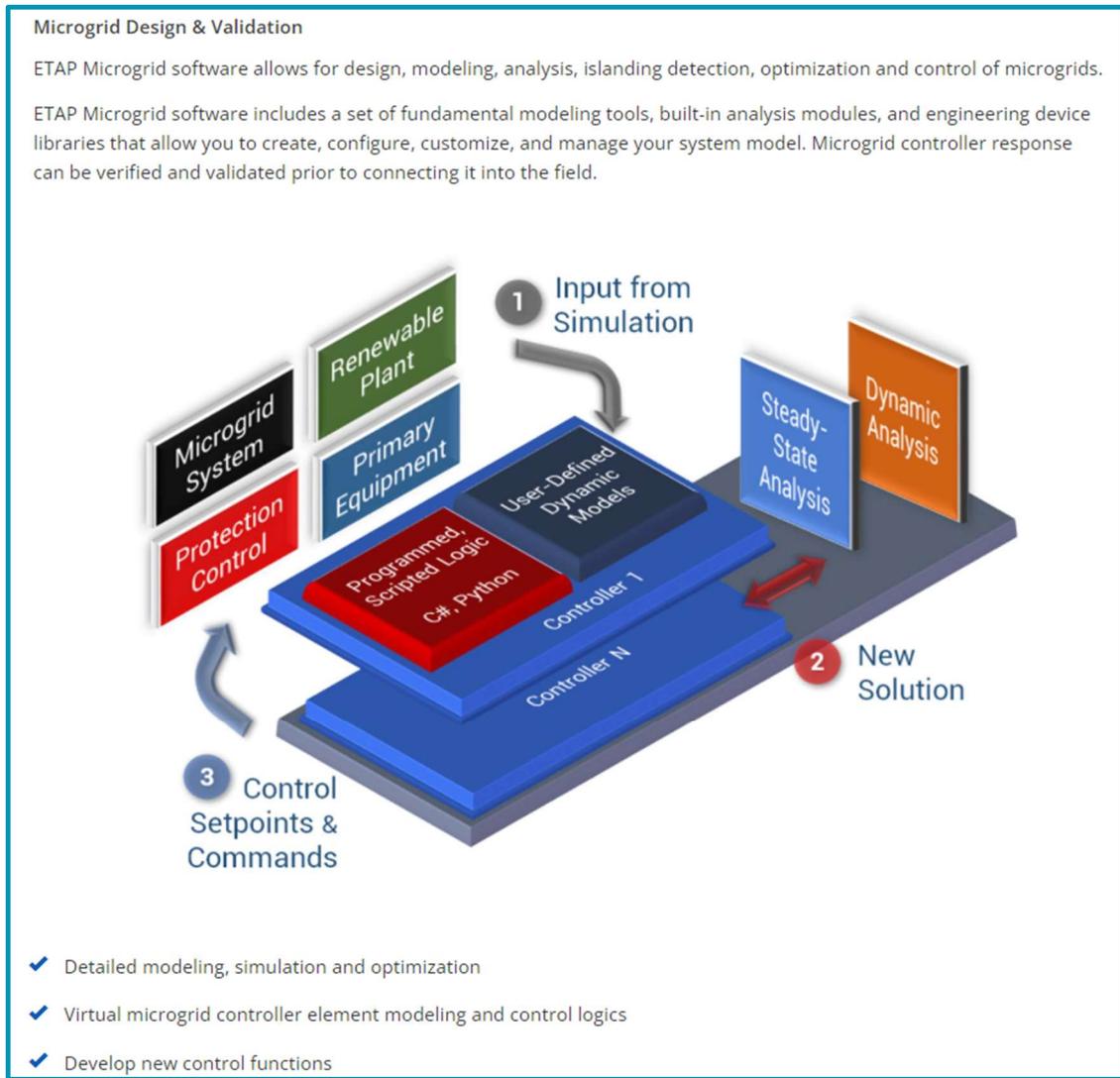


Figure 12 ETAP Planning system for DER/DSOs

To be clear, it is specific requirement of the AER that all Augex and Repex investment be as prudent and as efficient as possible. The purpose of the proposed NGPS is to ensure that, that objective is achieved, on the basis that the current DAPR is no longer able to do so.

NPV

The NPV is calculated at: \$8.8 Million with the investment in Year 0 of the RCP and benefits being realised as 20% in Year 1, 30% in Year 2 and 50% in Year 3.

Net-Present Value (NGPS)

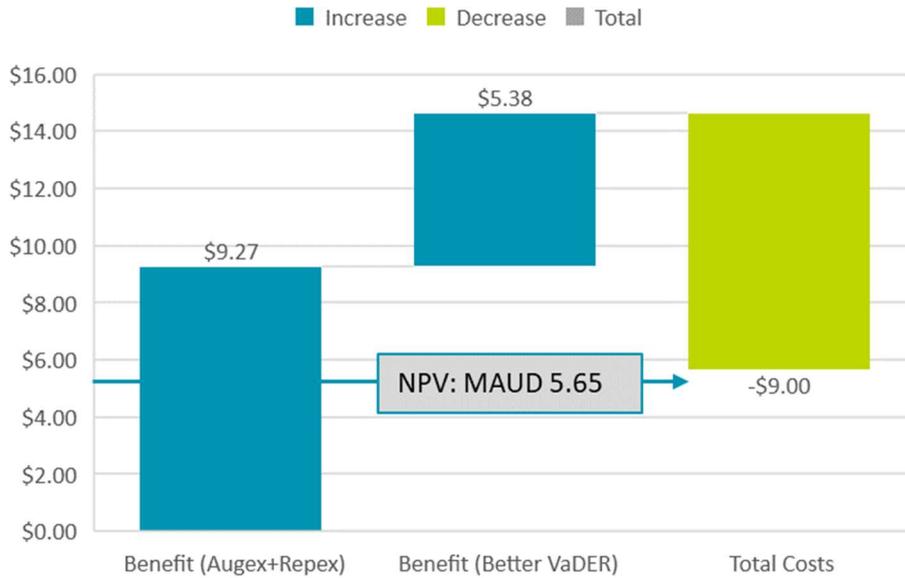


Figure 13 Net-present value calculation.

Summary

The counterfactual (Option 1) results in lost opportunity costs, excessive curtailment, and higher load at risk and hence the NGPS is the preferred option (Option2).

3.3 Sensitivity and Scenario Analysis

A sensitivity analysis was conducted on the key factors affecting the NPV including: Cost of the solution, Discount rate, % of energy not optimised by not having a Next-Gen Planning Solution (one from Augex, Repex and Resilience savings and one from DER Integration savings). The results are shown in the table below (see Table 1) where the variation is between -20% and +20% of the actual value for each of these parameters used within the analysis. The discount rate varies by two values: 2.2% and 4.3% from the base case value of 3.26% to be consistent with other CFIs

Table 1 Sensitivity Analysis of the key parameters

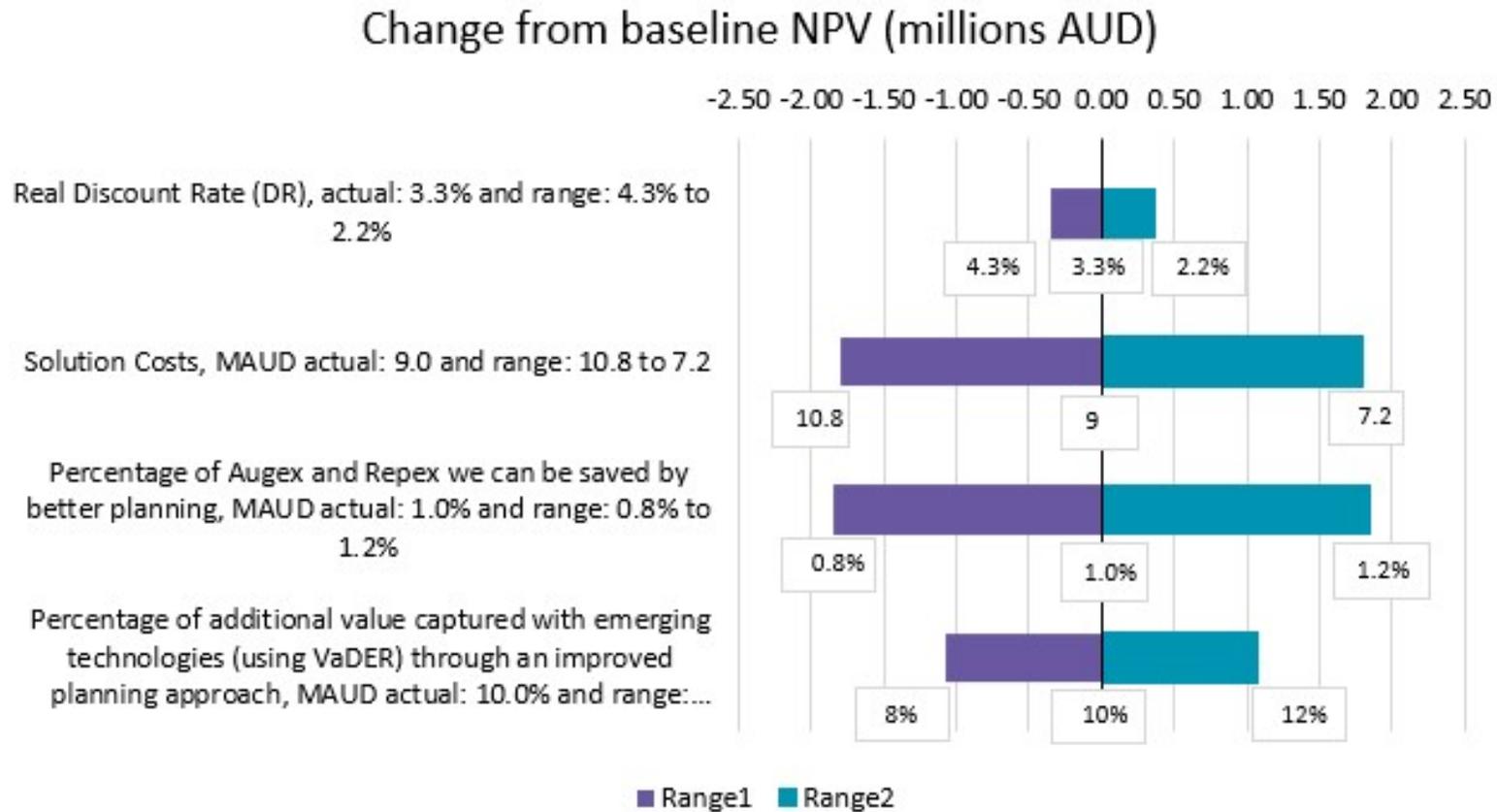


Figure 14 Sensitivity analysis

The sensitivity analysis shows that the NPV value is most sensitive to the benefits accruing from the % of Augex, Repex and Resilience expenditure saved), The other two numbers are 80% and 120% thereof respectively. The NPV is less dependent on the solutions costs or the discount rate.

3.4 Proposed Investment Timing

The intention is to use the point solutions which focus mostly on DER Enablement prior to the start of RCP24-29, as this addresses the bulk of the issues that have historically emerged in the network. The NGPS is focussed on addressing more of the issues in a proactive way, which will inevitably emerge during the RCP. Thus, it may take about three years to fully realise benefits from the NGPS which is implemented in the first year of the regulator control period. From that time 20% in benefits will be realised in year 1 after implementation, 30% in year 2 and then the balance of 50% in benefits will be realised in year 3.

It is expected that detailed scoping exercise will be undertaken in FY23 to plan the best pathway to implementation and a more detailed assessment of the benefits.

4. Detailed description and costs of preferred option

The ICT solution at Western Power cost a total of \$12 Million in manhours, software, compute & memory server hardware and ICT costs. This was the first of its kind and hence many lessons have been learned since then as well as there is more competitive tension in the market, so the cost for the NGPS is estimated at \$9 Million.

The costs from all these sources (Enzen and ETAP, etc) is estimated at \$9 Million in \$FY24 terms given that the hardware, software and 5-year support for the platform is estimated at a cost of \$12M for Western Power. The cost of a commercial- off-the-shelf (COTS) module that only looks at hosting capacities (by employing a Next-Gen System Automation with Volt-VAR optimisations) costs about \$1 Million upfront and then \$0.5 Million a year thereafter in technical support and system upgrade costs– representing a platform for hosting capacities and DOEs within a 5MS of about \$3.5M over five years (ETAP, 2022).

5. Recommendations and Next Steps

The next steps that will occur following CFI approval - to proceed to copperleaf optimisation stage, and further scoping as required to determine detailed design and costing.

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