INDEPENDENT EXPERT ADVISORY PANEL FOR ENERGY TRANSITION

Hills of Gold Wind Farm Proposal

Advice on energy production cost impacts under turbine configuration scenarios

Date 14 June 2024

Report No: IEAPET 2024-01

EXECUTIVE SUMMARY

Engie Australia and NZ has proposed a 64 turbine wind farm project called Hills of Gold, located 8km south-east of Nundle NSW. After an assessment, the Department of Planning, Housing and Infrastructure (the Department) recommended a reduction to 47 turbines to avoid a range of anticipated environmental and social impacts.

Engie has advised that if this reduction is adopted, the project would be non-viable and has provided an economic assessment in support of its advice. It has, however, accepted a reduction of two turbines based on their environmental impacts.

The Department has recently established an independent expert panel for energy transition (the Panel). The Department has asked it for advice on the levelised cost of energy (LCOE), return on investment (ROI) and project viability implications for Hills of Gold with a reduced number of turbines.

The Panel has compared the economic performance of four turbine scenarios – 62 as now proposed by Engie, 47 as recommended by the Department and two illustrative intermediates. The analysis considers only the costs and benefits experienced by the Proponent, as wider social, economic and environmental impacts (positive and negative) do not affect the project's economic performance and the viability questions that the Panel has been asked to consider.

The Panel created a spreadsheet model as an organising framework for systematically reviewing cost and energy production assumptions, and their resulting implications. The Panel has also referenced external industry benchmarks and drawn on members' knowledge of prevailing industry conditions. The model outputs are as follows.

	LCOE ($/MWh)	ROI[a] (% per annum)	NPV ($million)
Scenario 62	112	7.3	27
Scenario 47	126	5.8	-97
Scenario 55	119	6.5	-45
Scenario 50	118	6.6	-36

[a] Internal rate of return was used as the measure of ROI

While each investor will make decisions based on their circumstances and assessments, the Panel advises on project viability as follows:

Scenario 62 - viable. The Proponent seeks approval for it and the LCOE is under the benchmark cost of $114/MWh accepted by the Panel.

Scenario 47 – not viable. NPV is significantly less than zero, mainly because fixed costs are spread across fewer turbines.

Scenario 55 – marginal. Based on the model this scenario is non-viable. However, viability might be possible if one or more of the following occurs: the project would deliver strategic benefits for Proponent; costs could be reduced through optimisation and tendering; wholesale power prices are expected to increase; costs of capital fall; or green energy policy settings change favourably.

Scenario 50 – not recommended. Removing the lowest performing turbines makes only a slight difference to LCOE. If the lowest performing turbines are considered acceptable on other grounds, then the decision to include or remove them should be left with the Proponent.

Other Advice

Allowing for optimisation - One provision that would be favourable for this (and all wind farm projects) is for approval conditions to maximise allowable scope for post approval optimisation without requiring further formal assessments, especially if approved turbine numbers are fewer than assumed in the proposed configuration.

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1.0 INTRODUCTION AND SCOPE OF WORK

The NSW Department of Planning, Housing and Infrastructure (the Department) has established the Independent Expert Advisory Panel for Energy Transition (the Panel). The Panel's purpose is to provide access to world's best scientific advice when assessing energy projects under the *Environmental Planning and Assessment Act*. More background on the Panel can be viewed at https://www.planning.nsw.gov.au/policy-and-legislation/renewable-energy/independent-expert-advisory-Panel-energy-transition.

The Department has asked the Panel to provide advice to assist in the preparation of its assessment of a development application received from Engie Australia and New Zealand (referred to as the Proponent in this report). The application is for a wind farm project known as Hills of Gold, located 8km SE of Nundle. The Department's assessment is being provided to the NSW Independent Planning Commission (the Commission), which will determine the application.

In its initial assessment, the Department advised the Commission that 17 of the proposed 64 turbines should not be approved. The Proponent subsequently attended meetings with and made a submission to the Commission and advised (among other matters) that removal of these turbines would make the project 'commercially unviable[1]'. The Proponent has subsequently provided a revised economic analysis supporting this view[2].

The Commission asked the Department to respond to the additional information provided by the Proponent. As part of preparing its response, the Department has requested advice from the Panel on the levelised cost of energy (LCOE), return on investment (ROI) and project viability implications of reducing the project's impacts by approving a reduced number of turbines.

In preparing its report, additional questions were posed by the Department. As part of responding the Panel asked for further information from and met with the Proponent seeking clarification or further information.

This document constitutes the Panel's advice on all these questions.

[1] Letter from the Proponent to the Commission dated 12 February 2024
[2] HOG – Project Economics Report attached to letter from Proponent to the Commission dated 12 February 2024.

2.0 METHOD OF OPERATION

A Panel of four expert members was convened by the Panel's chairperson to prepare the advice. All members confirmed that they were unaware of any potential for a perceived or actual conflict of interest in connection with the Hills of Gold project.

The Panel members were Simon Smith (Chair), Rick Baker, Nic Candotti, and Clint Purkiss. Their combined professional expertise covers economic, commercial, and financial analysis and the design and delivery of renewable energy infrastructure. Their individual professional expertise is as displayed on the Department's website (see https://www.planning.nsw.gov.au/policy-and-legislation/renewable-energy/independent-expert-advisory-Panel-energy-transition).

The Panel convened on multiple occasions by videoconference during the preparation of its advice and was administratively supported by Secretariat staff provided by the Department. Each member was appointed to lead and/or assist in one or more sections of the report and all members reviewed and contributed to the finalisation of the whole document.

The Panel was briefed by the Department's energy projects assessment staff but conducted its work independently. Where additional information was sought, it was requested and provided through the chair and the Secretariat.

The Panel prepared this advice between the 4th of April and the 14th of June 2024.

A number of documents were provided through the Department to support the Panel in preparing this advice, and some of these referenced other documents that were of use. All of these documents are listed below. Other documents cited in the advice are referenced in footnotes.

- IPC and Proponent Meeting Transcript from 15 January 2024
- Hills of Gold Wind Farm Pty Ltd Submission to IPC dated 12 February 2024
- Request from the Commission to DPHI for response to Proponent's submission on 16 February 2024
- Hills of Gold letter from Dept to Proponent requesting further information on 22 February 2024
- Letter from Proponent to Dept responding to request for additional information dated 27 March (including Appendix 1 – Project Economics)
- GenCost: Annual insights into the cost of future electricity generation in Australia - CSIRO:
- GenCost 2022-23 (Final Report), July 2023
- GenCost 2023-24 (Consultation Draft Report), December 2023

3.0 BACKGROUND CONSIDERATIONS

State significant projects typically undergo a multi-stage assessment process which involves a technical and consultative consideration of a project's potential social, economic and environmental impacts. The Proponent for the Hills of Gold Wind Farm (the Project) is in the final stage of this assessment process, having commenced in 2018 with a proposal for up to 97 6MW wind turbines. The Project is proposed to connect to the National Electricity Market (NEM) in NSW at 330kV (330,000 volts) via a connection to the existing Liddell to Tamworth transmission line owned by Transgrid.

3.1. DEVELOPMENT ASSESSMENT TIMELINE

An Environmental Impact Statement (EIS) was placed on public exhibition in late 2020 and early 2021. This process sought to engage with and seek the opinions of the community. 1,185 people registering their interest - 400 within 5km and 785 across the broader community. The Proponent receiving a variety of supportive and objecting submissions that resulted in eight key issues being raised requiring response from the Proponent.

The Proponent's response saw the number of wind turbines being reduced from 97 to 70 to address proximity to landowners and/or biodiversity constraints identified during the phase leading up to the EIS report. Engagement with the NSW Government's Biodiversity Conservation Directorate (BCD) saw 23 turbines being relocated in an effort to reduce collision risks for birdlife and bats. This process with the BCD saw a further 6 turbines removed resulting in a revised EIS submission in 2022 that that the Proponent considered were 64 better sited and lower impact wind turbines. Refer Diagram 1.

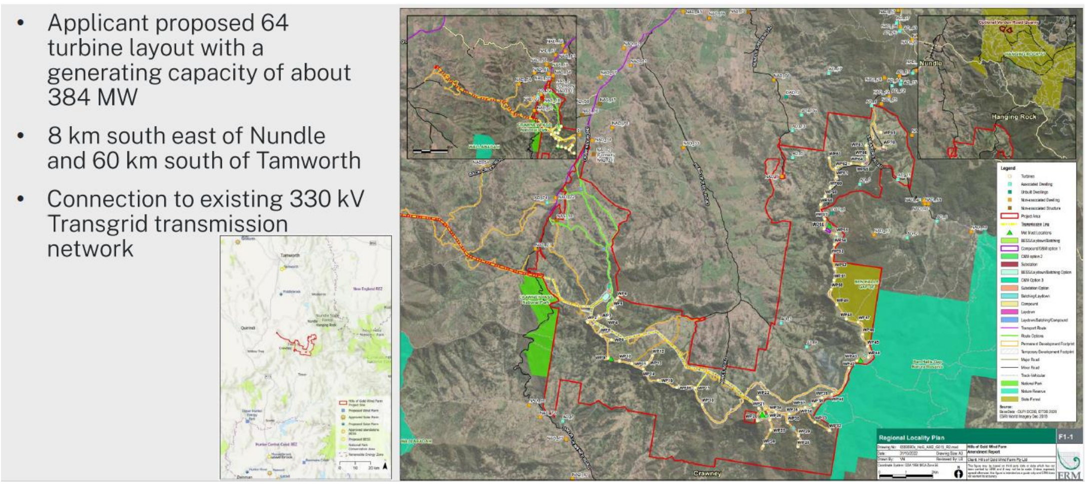
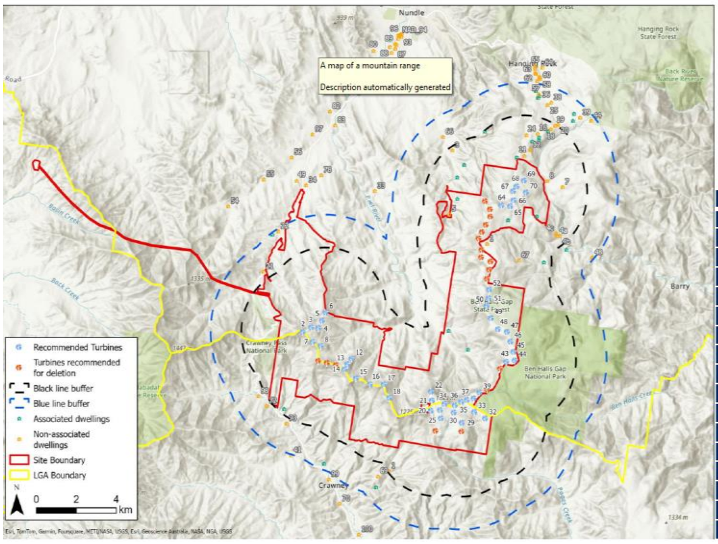


Diagram 1 – Revised Proposed Number of Wind Turbines (EIS 2022) of the Proponent at the Development Location

<u>December 2023</u>

On 12 December 2023, the Department provided an Assessment Report recommending a further reduction of 17 wind turbines from the Project for reasons of visual (and noise) impacts and some biodiversity values. Refer to Diagram 2.



Proposed deletions for multiple reasons:

- Visual to a number of receivers
- Noise criteria cannot be met
- Biodiversity impacts

Turbine	Comment
T9*	Visual - NAD 72, NAD 98, NAD 33
T10*	Visual - NAD 72, NAD 98, NAD 33
T11*	Visual - NAD 72, NAD 98, NAD 33
T24	Visual - NAD69 and biodiversity – *accepted by Engie*
T28	Biodiversity
T42	Biodiversity – *accepted by Engie*
T53*	Visual - DAD 01, NAD 33 and noise
T54*	Visual - DAD 01, NAD 33 and noise
T55	Visual - DAD 01, NAD 33 and noise
T56	Visual - DAD 01, NAD 33 and noise
T57	Visual - DAD 01, NAD 33 and noise and ice throw
T58	Visual - DAD 01, NAD 33 and noise
T59	Visual - DAD 01, NAD 05 and noise
T60	Visual - DAD 01, NAD 05 and noise
T61*	Visual -NAD 67, NAD 33, NAD 05, DAD 01 and noise
T62*	Visual -NAD 67, NAD 33, NAD 05, DAD 01
T63*	Visual -NAD 33, NAD 05, DAD 01

Diagram 2 – Recommendation by the Department and basis for wind turbine removals

The Department's Report was forwarded to the NSW Independent Planning Commission, which is the body that will determine the outcome of the Project application.

January 2024

The Commission held a number of meetings with the Proponent, the Department, and local councils. It also held public meetings with community members on the 1st and 2nd of February 2024. The Proponent spoke in support of its project and sought the reinstatement of 15 of the 17 wind turbines (being turbines 53-63, 9-11 and 28) that the Department had recommended for removal.

February 2024

The Proponent provided a formal submission to the Commission as a follow up to the various meetings. It addressed a range of key issues that apply to the consideration of the reasons for removing turbines. The Proponent advised that in its view if 15 turbines are removed from the Project, then it will be commercially unviable.

The Proponent stated that '*It is important to note that the series of refinements that occurred between 2018 and 2022 were not in the interest of improving the economic viability of the Project, but to improve, where reasonable and feasible, any biodiversity and/or visual impact outcomes.*'

The Proponent flagged that a high proportion of the wind turbines recommended for removal were high energy producing turbines, specifically turbines 53-63 with an anticipated yield of 22% more energy per annum that the remaining wind turbines.

The Proponent said that a 62-turbine wind farm would contribute 372 MW of generation capacity towards the State's energy transition goals. The recommended reduction in turbines would result in a 10.6% increase in the levelised cost of energy that would result in a 'constructive refusal' of the Project (because at this higher cost the project would not be competitive in the electricity market). Scale was stated as being critical for wind farm projects due to the high cost of the fixed price infrastructure required, most notably the assets required to connect the wind farm to the power grid and the higher cost associated with building infrastructure in difficult terrain where wind resource are commonly found (on ridgelines and escarpments).

During February 2024 the Commission asked the Department to comment on this information. As part of preparing its response the Department requested additional information from the Proponent. The Proponent provided an information package with the detailed economic analysis to the Department in March.

<u>April 2024</u>

To assist with reviewing the range of information provided by the Proponent, the Department sought independent expert advice. The Department had recently convened a Panel to provide independent expert assessment advice, called the Independent Expert Advisory Panel for Energy Transition (the Panel) to help with decision-making for the anticipated large number of renewable energy projects in the State's renewable energy zones - wind, solar, transmission. The Panel is modelled on another panel established some years earlier to provide expert advice on mining projects.

The Panel has been provided the relevant information and asked to provide its advice on the levelised cost of energy (LCOE), return on investment and project viability implications. The Department will consider this advice as it formulates its response to the Commission. The Department will also share the Panel's advice with the Commission.

The Department is considering a wider range of issues than the Panel, including visual, noise and biodiversity impacts and the application of legal precedents. The Panel has been asked to focus on the economic and commercial implications of reducing the number of turbines.

3.2. KEY CONCEPTS USED IN THE PANEL'S ECONOMIC ANALYSIS

Obtaining development consent is one important factor for wind farm proponents. They must also consider a wide range of other factors before making final decisions to construct their planned assets. Their decisions are made within the context of a competing range of projects within a region that are all looking to do the same thing, that is, to generate power at a price low enough to attract customers while high enough to realise an adequate return on the costs of building and maintaining their assets over their projected span of operation.

The Panel has used a number of well-established analytical concepts in preparing its advice.

3.2.1. Levelised Cost of Energy

The Levelised Cost of Energy (LCOE) is a high-level metric that compares the competitiveness of different energy sources and technologies, including wind farm projects. It represents the average minimum price at which the electricity generated by the asset is required to be sold to offset the total costs of production over its lifetime. These include the costs of development, construction, grid connection, operation, and maintenance. It also includes a return on invested capital judged sufficient to attract the required funding.

The LCOE equals the net present value (NPV) of total costs over the lifetime of the project divided by the NPV of the electrical energy expected to be produced. In calculating these NPVs, future values are 'discounted' to reflect the fact that a dollar today is worth more than a dollar in future years.

The LCOE is generally expressed as cost per megawatt-hour ($/MWh). It is widely used for high level planning for future energy supply, enabling comparison between different technologies and projects.

Energy on Australia's east coast is bought and sold every day (traded) in the National Electricity Market (NEM or market). Generators can also enter long term agreements to sell their production at agreed prices through power purchase agreements (PPAs). Additionally, they may obtain revenue from the sale of large-scale generation certificates (LGCs) for renewable energy (either directly or indirectly). Whatever the sales arrangements, a wind farm Proponent will not proceed to build their project unless satisfied that future electricity prices and green incentives will be high enough to generate sufficient revenue to cover their project's unique costs and earn a return on their investment. The lower a project's LCOE, the more likely it is to proceed. In the case of Hills of Gold, the Proponent has said that reducing the number of turbines as recommended will increase the project's LCOE to an extent that the project could not proceed.

3.2.2. Estimating the cost components of LCOE

There are two main types of cost used in LCOE analysis - capital and operational. Both types have fixed or variable elements.

Fixed Capital and Operational Costs: Fixed costs are part of the essential costs of the whole project. They do not change significantly if the number of wind turbines is reduced or increased. They include electrical cables traversing and connecting the wind farm to the grid, internal access tracks, transport route upgrades, development and ongoing operational management of the project. They also include the costs of agreements with utilities (for access to the power grid), landowners and the community to be paid over the life of the Project.

Variable Capital and Operational Costs: Variable costs apply to each wind turbine individually and reflect differences in the location, ground conditions and ease of installation for each. If a turbine is removed from the project, the variable costs for that turbine are removed from the project's overall costs. In the industry, 'constructability' is used as a shorthand for these variable costs. Key components are foundation and hardstand (civil earthworks, concrete and steel which can vary dramatically due to ground conditions and location), biodiversity (provision for compensatory habitat where construction will cause losses), the supply and installation of the wind turbine (craneage to erect the turbines and the supply and delivery of the wind turbines themselves) and turbine maintenance.

3.2.3. Capacity Factor

Every wind turbine has a rated maximum energy production. This is the amount of energy it would generate when operating under optimal conditions for its design. However, at each location wind changes direction and speed moment to moment and over the seasons and years. Hence, over a year, energy production is always less that maximum rated capacity multiplied by 24 hours per day and 365 days per year. This gap between actual and theoretical potential is known as the 'capacity factor'. It is a theoretical measure based on many factors (assumptions) and calculated as a ratio of the wind turbine's anticipated actual output compared to its maximum theoretical potential over 1 year.

The typical range of capacity factors is in the order of 20% to 40% and is influenced by the quality of wind resource at any given location but also in selecting the most appropriate wind turbine for the intended site's wind conditions.

Other factors being equal, a project comprising turbines with high capacity factors will have a lower LCOE than another with lower capacity factors. This is because high capacity wind turbines produce more electricity. In practice, projects have a mix of higher and lower capacity factors, reflecting the favourability of the individual turbine sites. They also have high and low costs for each turbine, reflecting variations in site conditions and access.

3.2.4. Cost and Capacity Factors combined

There is an interplay between capacity factors, fixed and variable costs that is important to understand for the Hills of Gold project.

The smaller the number of turbines, the larger share of fixed costs each must 'carry' if the overall project is to achieve a competitive LCOE. On the other hand, if an individual turbine has very high construction costs and/or a very low capacity factor, it could increase the project's overall LCOE. The model prepared by the Panel enables the net impacts of these outcomes to be compared in each scenario.

3.2.5. Return on Investment (ROI)

Return on investment (ROI) and internal rate of return (IRR) are sometimes treated as different concepts and sometimes not. Investors typically use IRR to calculate the return on investment of prospective investments and so it has been used in the modelling for this report as the measure of ROI.

IRR is the annual rate of growth that an investment is expected to generate. For example, if $100 is invested in a one year bank term deposit and, with interest, it is worth $105 at the end of the year, its IRR would be 5%.

IRR can be compared across potential projects to see which is expected to generate the highest return. In this document IRR presents the economics of projects from the investor's perspective and does not include costs or benefits accruing to others or the public at large.

3.2.6.Net Present Value (NPV)

From an investor's perspective, the net present value of a project is the difference between the sum of expected cash inflows and cash outflows of a wind farm project over its expected operational life (30 years for Hills of Gold). These include a benchmark return on investment suitable for wind farm projects under the current economic and regulatory settings. A discount rate is applied to cashflows after year 1, to reflect the opportunity cost of capital. This is because a dollar spent or received this year is worth more (from the perspective of today's decision-maker) than a dollar in future years.

The NPVs in the document provide a measure of the overall economic value added (or reduced) by a wind farm project viewed from the investor's perspective.

In the absence of confounding factors, a positive NPV indicates that a wind farm project is likely to be economically viable. A negative NPV would indicate that the wind farm project will not progress to financial close and construction.

The NPVs generated in this analysis do not include public benefits or disbenefits. Disbenefits could include the impacts of noise or on views of the landscape, while benefits could include avoided greenhouse gas emissions. These wider matters are being considered by the Department and the Commission.

3.2.7.Project Viability

The Panel has interpreted 'project viability' to be the measure of whether a rational Proponent would, on economic grounds, proceed to fund and construct the project in the light of the decision on the allowable number of turbines.

In this context, a decision to proceed with a project is not reducible to any single metric. Every rational investor will have a range of investment criteria and they must adopt views on many future variables that are hard or impossible to predict with certainty. These are discussed in more detail below.

However, the Panel has noted that the Proponent has accepted the recommended removal of two turbines to reduce environmental impact and nevertheless continues to seek approval for the project. The Panel has therefore adopted the 62 turbine version of the project as viable based on the suite of criteria and assumptions that will be used by the Proponent.

The analysis that follows therefore seeks to determine whether the removal of turbines would result in economic outcomes for the Proponent that would be sufficiently less favourable to reasonably cause the project to be become non-viable.

4.0 EVALUATION APPROACH

A spreadsheet model was built based on the data supplied by the Proponent. This provided an organising framework for analysis and discussion between Panel members. Each category of data input was reviewed using industry benchmarks and expert knowledge. Outputs were then compared with conclusions provided by the Proponent and with Panel members' knowledge of prevailing market conditions and practises. All significant differences were used to guide further testing and review. Model outputs were then used in developing the Panel's advice, following further testing and discussion.

4.1. LIMITATIONS AND BASIS OF ASSESSMENT

As part of developing its project over multiple years, the Proponent has engaged specialists to deeply investigate and advise on each project component. The Panel has not sought or been provided with access to the detailed outcomes of their work. The specialist organisations have specific skills and capabilities and have been engaged to undertake project and site-specific analysis and design. The Proponent has used this detailed information to build up the design and economic model for its project.

The Panel has taken the results of this work as provided by the Proponent as the starting point for our analysis. We have taken a view about the likely level of maturity and currency of the information given the stage and duration of project development and design and we have tested the data against external benchmarks and our combined knowledge of market conditions and industry practice in order to derive a suite of assumptions and estimates that can be used for analysis.

The financial models usually developed for large wind farm projects are complex. They incorporate a very wide range of parameters that go beyond what is needed or useful for the Panel's task. Hence, the Panel constructed a simplified economic model for the purposes of systematically testing assumptions and performing comparative analysis. The model provided a systematic framework for testing assumptions and inputs and identifying anomalies when compared to industry benchmarks and standards. It also allowed evaluation of the sensitivity and importance of alternative input values. The model provided a sound basis for the Panel's deliberations and developing its conclusions.

4.2. MODEL OPERATION

To help it provide the requested advice, the Panel developed a simple economic model of the costs and benefits of the project from the investor's perspective. This involved the following steps:

1. Constructing the model using the data on project costs, energy production, benchmark LCOE, discount rate etc provided by the Proponent in late March
2. Extending the model to cover two additional turbine configuration scenarios beyond the two covered by the Proponent (see section 4.3)
3. Replacing any cost and other inputs provided by the Proponent with inputs that the Panel judged to be more appropriate and factoring in assumptions not fully specified by the Proponent (for example, that the wind farm's

construction would occur over two years, with energy production commencing at the start of year 3)

4. Revisions to the model were made in mid-May following the receipt of additional information from the Proponent (including on marginal loss factors[3] and approach to provisioning for periodic major and unplanned maintenance).

The main outputs of the model are:

- Levelised cost of energy (LCOE)
- Return on investment (ROI) measured as the internal rate of return generated by the investment
- Net present value (NPV)

4.3. WIND TURBINE CONFIGURATION SCENARIOS

The economic information provided by the Proponent covers two possible turbine configuration scenarios (scenarios 62 and 47 below). Other configurations are also possible, and it is important that in seeking to find the option that best balances the social, environmental and economic trade-offs that they are considered. Accordingly, the Panel (in consultation with the Department) identified two further configurations to help illuminate decision-making. The four scenarios considered by the Panel are:

Scenario 62: The 62 turbine layout sought by the Proponent (they previously sought 64 turbines but have agreed with the Department to two being removed).

Scenario 47: The 47 turbine layout recommended for approval by DPHI, with 15 turbines removed due to issues relating mainly to visual amenity, noise and biodiversity.

Scenario 55: A modified layout that reinstates 8 of the 15 turbines that the DPHI recommended for removal (turbines reinstated: WP9, 10, 11, 53, 54, 61, 62 and 63). DPHI proposed this scenario with the Panel to help it further assess potential revised recommendations.

Scenario 50: This is the same as scenario 55, but with the five turbines with the worst cost and energy production combinations removed (turbines removed: WP 5, 11, 12, 16, 18). Removing each of these turbines marginally lowers the LCOE. Removing any of the other turbines increases LCOE. The purpose of this scenario is to explore whether, if Scenario 55 was approved, the Proponents might be able to improve on the economics of the project by choosing not to proceed with some turbines.

Appendix 1 shows which turbines are included for each scenario.

[3] Marginal loss factors are applied to electricity generators to represent the financial impacts of losses in electrical energy experiences during transmission between source and use. They vary across the State and over time, reflecting proximity to available transmission capacity and demand.

4.4. PROJECT DEVELOPMENT COST INPUTS

The Panel used a range of methods to review the Proponent's indication of costs. First, the Proponent's estimates of all up generating costs were compared to published sources.

The Proponent's current build cost projection to deliver the Project with 62 turbines in 2025-2026 is estimated to be approximately 2,630 $/kW. These costs were then recalculated against the Department's recommended configuration with 47 turbines and is estimated to be approximately 2,790 $/kW.

These values are both higher than the $2,564 $/kW estimated build cost for wind projects in 2025-26 provided in the CSIRO's GenCost Report and referenced by AEMO[4].

At this consolidated level, the Panel considers that the build cost estimate provided by the Proponent is reasonable. While the Panel notes that earlier reports from AEMO provided an estimate 35% lower for projects constructed in 2021-22, panel members have also observed that significant increases in build costs have and are occurring.

The equipment supply market is being driven by strong global demand for the services and products needed to build wind farms. Similar projects are experiencing both price increases and tougher commercial conditions from the suppliers of wind turbines, towers, cables and substation components. This view is consistent with the GenCost 2023-2024 consultation draft [5] which indicates a further increase of 8% in onshore wind technology costs.

Projects in development face cost pressures due to the increasing complexity and duration of the processes prior to financial close (environmental monitoring, project design, development assessment, grid connection, landholder negotiation etc). Those moving into construction experience further cost pressures due to the limited number and high demands on turbine suppliers in the Australian market (<5) and civil/electrical companies qualified and available to undertake the work. Cable manufacturers are increasingly short in available manufacturing slots, requiring early slot reservations, sometimes years in advance of projects reaching financial close.

Most projects smaller than 250MW are struggling to get adequate 'attention' from the market leading turbine suppliers. Without scale a project must be sufficiently simple for suppliers and installers to construct to get sharper pricing and space in the manufacturing queue. The Hills of Gold site is complex and a substantial reduction in turbine numbers will reduce scale.

4.4.1. Review of individual costs elements

At this stage of project development, most costs and revenue assumptions are estimates informed by turbine site assessments and market intelligence. As a project moves towards financial close, these data become more precise and provide greater

[4] *AEMO Draft ISP 2024 Inputs and Assumptions, Build Cost.*
[5] https://www.csiro.au/en/research/technology-space/energy/energy-data-modelling/gencost

certainty. The Proponent has advised that if a viable development approval is obtained, a further $7m must be spent on further detailed assessments to reach readiness for to consideration of an investment commitment. This is due to:

- further work to optimise the design aiming to improve energy generation potential
- deeper engagement with potential tenderers (for construction and supply), the transmission network operator, and energy customers which can reduce conservative contingencies in cost planning and improve revenue expectations.

Taking this into account, the Panel has reviewed the input data that has been provided by the Proponent and compared them against the available industry benchmarks and Panel members' knowledge of comparable projects to form a view on reasonableness. Where the Proponent's data appeared consistent with the references, the Panel used them in its model. Where not, the model was used to test whether the differences would be significant in the overall outcomes, and with adjustments made where thought necessary.

As a summary, the following Table 1 provides an overview of the parameters considered and the Panel's approach in each case.

Parameter	**Proponent's Value or Range**	**Used in Panel Model**	**Comment**
Wind Turbine S&I[6]	$10.963m / WTG[7]	Yes	Accepted cost estimate
Foundation & Hardstand	$699k to $3.483m /WTG	Yes	Accepted the three level cost estimate approach
Biodiversity	$0m to $1.22m per WTG depending on location	Yes	Accepted Credit Cost Estimate (2023) generated using the BCD[8] methodology and BCT[9] pricing
Fixed CAPEX	$201.151m	Yes	Accepted cost estimates WP[10] 2-25 $2.863m/WTG

[6] Supply and Install (S&I)
[7] Wind Turbine Generator (WTG)
[8] BCD is the Biodiversity Conservation Directorate which is a part of the NSW Department of Climate Change, Energy, the Environment and Water
[9] BCT is the NSW Biodiversity Conservation Trust, established under NSW statute
[10] WP is the labelling used by the Proponent to identify individual turbine sites eg WP2 refers to turbine number 2 in the Proponent's site plans

			WP26-70 $2.422m/WTG Project Owner[11] $673k/WTG
Fixed OPEX	$16.988m p.a.	Yes	Accepted cost estimate. Includes provision for grid connection fees
Variable OPEX	$121k p.a. /WTG	Yes, with sensitivity analysis	While likely to be an underestimate due to the increasing need for maintenance as the turbines age, this would not be expected to have a material effect on the relativities between scenarios. Sensitivity analysis using higher costs (five-yearly major maintenance costs @ $535k/WTG) was done to test this.
Discount Rate	7% real	Yes	AEMO has reviewed, Panel accepted
Proportion of CAPEX 1st year	not specified	Adjusted	Panel assumed 60% year 1 and 40% in year 2
Capacity Factor	18.4% to 40.7% /WTG	Yes	Wind speeds vary 5.72 to 8.38 m/s across the Project area. Accepted individual turbine capacity factors
Lifetime	30 years	Yes	Acceptable for 6MW WTGs

Table 1 – Evaluation Parameters Summary

<u>Constructability</u>

The Proponent’s analysis shows that the highest variability in the capex per turbine relates to foundation and hardstand costs and the biodiversity cost.

The Proponent has established three categories of sites, each with a different scale of earthworks, concrete and cost. This is accepted as a plausible approach to account for anticipated cut volumes (benching) at each turbine location. This approach and the basis of cost derived from a tender process is considered reasonable.

It is noted that this is a development stage project, and as such, it does not yet have development approval (with associated conditions) to enable contractors pricing works to do so with a firm baseline. The conditions of the development approval are

[11] Project owner costs have been interpreted as the costs associated with owning and operating the asset e.g. establishment of a control room or integration in owner’s systems, staffing onsite and scope outside of the O&M contract i.e. the expenses borne by the Proponent for the development and management of a project of this scale.

vital to enable firming of contract prices, scope and the identification of risks and any site constraints.

The Panel has not reviewed the extent of any tendering process and hence would caveat that pricing received by the Proponent at this stage would be budget-based and hence, may be able to be improved upon during detailed design. However, we do not consider that such improvements would be material in the scheme of the analysis and as such the added cost of $1.5m for volumes between 12,001 to 40,000 cubic meters and circa +$3.0m for volumes greater than 40,000 cubic meters have been considered a valid assumption.

The approach proposed by the Proponent in relation to fixed costs, where they have been evenly distributed across turbine locations, seems reasonable. The Proponent has made a minor exception for electrical reticulation allocated to the turbines situated on the Project's western ridgeline (WP2 to WP25).

The Project notably has a transport access corridor restriction, with access from the SW end of the site the only available route for movement of large plant or equipment. This means that, in effect, the project should be considered to be linear, with largely even apportionment of fixed CAPEX and OPEX across all turbines. This is because haul roads and interconnection cables must pass all of the proposed sites from the SW to the northern most tip of the site. Removing wind turbines from anywhere except the north end would not materially reduce these costs.

Access Tracks and Electrical Balance of Plant

Cost estimates for access tracks and electrical reticulation are on a per-kilometre basis which is a typical approach to quantifying and establishing the basis of costing. Actual derived routes to turbines would likely be required to be optimised based on the terrain, however, the materiality would likely not, as an unders and overs consideration, be material to overall cost in the Panel's opinion.

The complex terrain of this project could generate higher than normal capital requirements later in the project life, to manage roads and sediment run off that would otherwise impact on adjoining sensitive and non-related landowners. The Panel is not able to quantify these costs but notes that they represent a downside risk that will be taken into account by the Proponent when assessing viability.

Biodiversity

Biodiversity costs were established as an output from the Biodiversity Conservation Trust (BCT) credit cost estimate prepared for the Project in January 2023. These costs were reported as encompassing both flora and fauna credits and been allocated for each location based on the specific amount and type of vegetation required to be cleared for the relevant turbine.

The Panel believes it is fair to use the credit costs calculated from the BCT's estimator as an estimate for costs likely to be incurred. It is possible that lower prices could be obtained by direct dealings following finalisation of turbine footprints but there is no data available to the Panel to indicate the magnitude of any possible savings. The costs are expressed for each turbine site, with a range between zero and $1.2m (average $189k for scenario 62).

Grid Connection Cost

The grid connection cost will be borne by the Proponent based on the scale of required new infrastructure (substations and transmission lines), complexity of project site and interface/ complexity at the point of connection. Grid connections at the 330kV level represent a significant investment. Proponents need to address their project's relationship to other connected parties and the impacts of their connection considering the technology being connected and its inter-relationship with the wider high voltage network.

Generator's Performance Standards (GPS) will be negotiated with TransGrid and AEMO for new connection applications. These will outline the technical requirements that must be met at the point of connection. The Proponent's response showing how the GPS will be met enables network modelling to determine the extent of any required system support (i.e. for any system strength remediation scheme) and other considerations for physical plant and equipment. All these costs form part of the Project's fixed costs, with the amounts subject to detailed analysis following planning approval.

In addition to the capital costs directly incurred during construction, ongoing connection charges are typically payable by the Proponent in the form of a monthly annuity (to TransGrid in this instance) and are spread across the life of the asset. The fees vary significantly based on capacity of the project, extent of new network-owned infrastructure required and complexity – accounting for ancillary equipment, such as harmonic filters, capacity banks and the like.

The Proponent has provisioned $10m per annum for grid connection costs. It is unlikely that at this stage of project development that the details of the grid connection requirements and the value of future monthly connection payments are known with precision. These would typically be finalised after the number and type of turbines is settled at the completion of network impact modelling, specifications and tendering. Nevertheless, the Panel finds that the costs indicated in the Proponent's submission for this category of cost are not unreasonable for its purpose, reflecting the level of uncertainty to be expected at this stage of development.

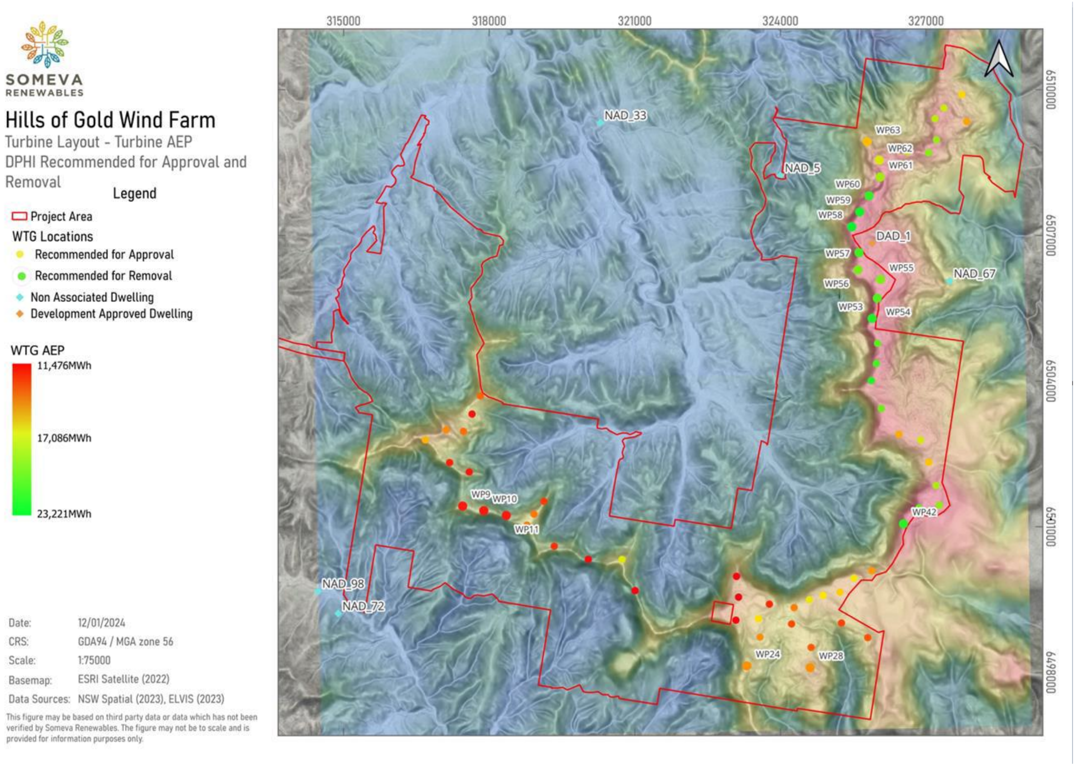
4.5. PROJECT ENERGY GENERATION MODEL INPUTS

The Proponent has provided energy generation data for a 62 turbine and 47 turbine configurations for the Hills of Gold Wind Farm. The energy generation data includes summary information on the estimated capacity factors and Net Annual Energy Production (AEP) for both layouts and is deemed adequate data for the purpose of the LCOE relativity assessment.

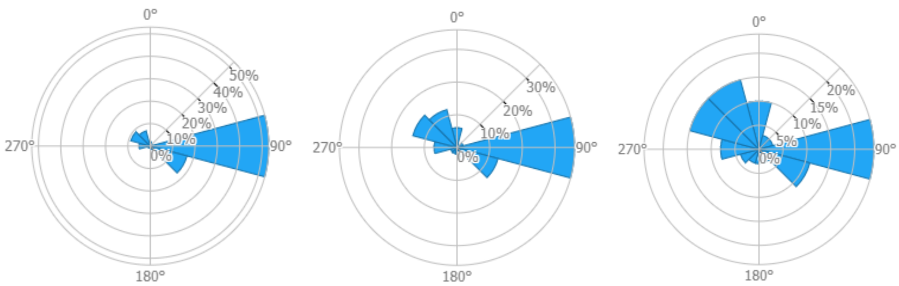
The data underpinning the Proponent's estimate of LCOE impact from layout changes is a simple deletion of turbines exercise, removing the direct CAPEX and energy production associated with the removed turbine(s), whilst the fixed costs are retained and allocated across fewer turbines and a lesser total generation profile.

This is considered reasonable as an approach to assessing LCOE relativity, fit for the purpose for this exercise.

The Hills of Gold Wind Farm is depicted below, illustrating the highest Net AEP performing turbines and those recommended for approval/removal.



The profile at Hills of Gold is dominated by easterly winds. The turbines located on the north-south axis of the project with open exposure to the east will generate the most energy. High level wind information extracted from the Global Wind Atlas is presented below[12].



The directional power/speed and frequency illustrates the relative importance of turbines with a clear aspects due east at the Hills of Gold site. Turbines 53-63 are examples of this configuration, being high performing turbines that significantly contribute to improve the LCOE. Conversely turbines located along East-West ridges

[12] https://globalwindatlas.info/en

such as turbines 9,10,11 or 16 and 18 are lower performing turbines. This accords with the data provided by the Proponent.

The Proponent's resource information and generation data are consistent with macro level wind information cited above and are considered to be suitable data points for assessment at this development stage.

Removing or re-positioning turbines can have a minor impact on nearby downwind units. It is not possible to quantify these impacts without undertaking revised energy assessments, greater engineering/design analysis and further engagement with the equipment suppliers. The quantum of impact is very site and turbine specific therefore no attempt has been made to quantify the impact to energy generation at this stage.

The ridgeline and its transport constraints means that the configuration of the Hills of Gold Wind Farm is linear. As a result the relative contribution from the highest performing turbines is higher than on less topographic sites that have a uniform aspect to the prevailing wind directions and no noticeable acceleration features.

In summary the energy related data is fit for purpose. A cautious approach should be taken to trying to improve granularity given the limited sophistication of the model and the immaturity of the project relative to financial close.

4.6. OTHER MODEL INPUTS

The LCOE model is based upon the project development costs summarised in section 4.4 and the Energy Generation assumptions in Section 4.5. The following additional input assumptions are noted to provide further information about the approach adopted by the Panel.

4.6.1. Construction Duration and Spending profile

The profile of major costs during the construction phase, typically known as an 'S-Curve' is important for modelling. The S-Curve models the cashflow or deployed capital once construction has commenced. This is a major part of the negotiation for all construction contracts – DPC[13], S&I, BoP and the connection agreements.

The 'S-Curve' has a significant influence on overall IRR/ROI. The longer capital is deployed (equity or debt) without cashflow (from generation) the larger the drag on the economics.

The Proponent has not indicated its intended Capex profile. Based on its experience with other projects, the Panel has assumed that construction would occur across a two year period, with 60% of expenditure in year 1 and 40% in year 2. This also allows for the ability of some suppliers to require up front payments from project developers in order to guarantee delivery to match construction schedules. It is recognised that

[13] DPC is design, procurement and construction. S&I is supply and installation of turbines and BoP is balance of plant required (i.e. infrastructure and facilities other than wind turbines and their enabling elements).

final completion may take longer than 24 months in practice. Extended delays would tend to increase LCOE.

4.6.2.Marginal loss factor

Marginal loss factors (MLFs) represent incremental power lost in the transmission network from incremental generation. Under current arrangements for the NEM, generators receive payments for electricity based on the electricity they supply multiplied by an MLF determined by AEMO. This means that to assess the economics of a wind farm project it is necessary to apply an appropriate MLF to the net annual energy production.

The Proponent reports that they expect an MLF for Hills of Gold of 0.92, based on site-specific studies by expert consultants. MLFs vary across location and across time. as the mix and location of generators, grid capacity and demand change. Recent examples from other sites range between 0.8 to greater than 1.0. The Proponent has advised that its proposed value is derived from a credible industry consultant. The Panel accepts this figure on this basis.

4.6.3. Discount Rate

The Proponent uses a discount rate of 7% in calculating the present value of future costs and benefits, and point out that this is the discount rate used by AEMO in its ISP cost benefit analysis frameworks.

AEMO's 2023 Inputs, Assumptions and Scenarios report provides commentary on the 7% real discount rate. AEMO states that:

> *Following stakeholder feedback on the Draft 2023 IASR, AEMO engaged OEA [Oxford Economics Australia] to survey developers in the NEM regarding their cost of capital to gather additional input, including evidence on the suitability of Synergies proposed discount rates. OEA found that there is anecdotal and empirical evidence that suggest that the central discount rate proposed by Synergies [7% real] is reasonable and similar to those faced by developers in the NEM.*[14]

The Panel has accepted the 7% real discount rate as appropriate on this basis and has used it in the model.

4.6.4.Levelised Cost of Energy 'Benchmark'

The Proponent compares the LCOEs for Hills of Gold with an LCOE of $110/MWh for a generic NSW wind site modelled using inputs and assumptions from AEMO's Draft 2024 Integrated System Plan (ISP) and other sources. They state that: '… this comparison is relevant because the LCOE of that generic NSW wind site is deemed by AEMO to achieve a level of return on which it can be assumed that a market

[14] AEMO, 2023 Inputs, Assumptions and Scenarios Report, p. 123

participant would reasonably execute the project'. In other words, they use an LCOE as a benchmark for assessing the financial viability of NSW wind farms.

The $110 figure is not reported by AEMO, but rather is calculated by the Proponent based on AEMO parameters, including a build cost for a generic NSW wind farm of $2,564/kW and a capacity factor of 32%. The Proponent also uses other data in calculating the benchmark LCOE, for example, using their own assumptions for opex and a marginal loss factor of 0.89, which they report is the average MLF for NSW wind farms according to Aurora Energy Research.

The merit of using AEMO's ISP in estimating a benchmark LCOE relates to the purpose of the ISP, which is to outline 'the lowest-cost pathway of essential generation, storage and transmission infrastructure to meet consumers' energy needs for secure, reliable and affordable energy, and to achieve net zero emissions targets'[15]. The ISP identifies that NSW wind farms are an important component of that lowest-cost pathway and in the Panel's view the maximum LCOE for those wind farms is, conceptually, a valid benchmark to use for assessing viability - the assumption being that wholesale electricity prices (possibly supplemented by green incentives) will attain levels that will make them financially viable for investors.

The Panel has examined the derivation of the $110 figure and found it to be reasonable, with the exception that there is no allowance for the time needed to build the wind farm and the associated delay before revenue is obtained from the sale of electricity. Making allowances for this, the 'benchmark' LCOE would increase to $114. (As discussed later, this time-scale issue also affects the Proponent's calculations of LCOEs for Hills of Gold).

More broadly, the Panel's view is that while this is approach of calculating a benchmark is reasonable, it is only capable of providing an approximate guide to what is likely to be viable. This is mainly because of the assumptions that need to be made in moving from the build costs and other parameters reported by AEMO to an LCOE. While the Proponent appears to have generally taken a realistic approach to making these assumptions, there is some scope for making different assumptions, which would lead to a somewhat different LCOE.

In discussions on an earlier version of this report, the Department asked the Panel to calculate an LCOE based purely on the average inputs from the draft ISP and to consider whether this might provide a more reliable benchmark to use in the analysis. The Panel found that this was not a straightforward matter as there were choices to be made on which values to average. With this caveat in mind, the Panel calculated an LCOE of $97, which is considerably lower than the $114 benchmark.

In the Panel's view the $114 benchmark derived from the Proponents method is generally more reliable than the one derived from ISP averages. While there are some uncertainties, it appears that the Proponent drew on data from sources other than the ISP to achieve greater reliability and consistency with the HOG project, rather than to achieve a particular result. Appendix B provides details on the comparison and the

[15] AEMO 2024 Draft Integrated System Plan, p. 3

reasons for these conclusions. The Appendix also provides information on the Panel's responses to some other questions put to it by the Department.

Another source of evidence that the Panel looked at in assessing the $114 benchmark was power purchasing agreement (PPA) prices. The AER has noted that long term PPAs are often relied on by wind farm developers to secure project finance. PPAs offer a long-term guarantee of price that is typically lower than anticipated weighted spot prices for the agreement period. Securing a PPA can be used by developers to obtain release of project finance, because they provide comfort to financiers that the project will earn sufficient revenue to pay interest or dividends. Prevailing PPA offers implicitly express energy market buyers' considered views of long-term prices. They therefore play an important role in benchmarking wind farm viability.

While PPA values are usually commercial-in-confidence, the Panel's understanding of the necessary 'going rate' for new PPAs for wind in NSW is around $85-90, which is 20 to 25% below the $114 benchmark. Based on this perspective, a Proponent with an LCOE of $114 would require an energy sales strategy that would realise prices and revenue significantly above prevailing PPA rates, and/or revenues from ancillary sources to proceed with their project. The wide range of reasons that influence project viability are discussed further below.

The Panel took into account the exclusions in the AER assumptions, the recent and current upward movements in construction costs, the relative slowness of wind projects moving to financial close in Australia and the gap between current PPAs and the $114 value. The Panel also took into account the uncertainty regarding future carbon emission related prices or incentives that might apply post the 2030 expiry of the Renewable Energy Target scheme. In the light of these considerations, the $114 benchmark has been adopted by the Panel as an indicator of the maximum level of cost that would indicate financial viability, and has incorporated it into its model by using it as the electricity price when estimating ROI and NPV.

The Panel acknowledges that the $114 benchmark is an approximate figure. Based on the analysis of draft ISP averages and PPA prices discussed above, it is more likely that the 'true' benchmark is lower than $114 rather than higher. This judgement has been important in the Panel's findings on viability because if a benchmark well above $114 was plausible there would be greater scope for the removal of turbines not to threaten the viability of the Hills of Gold wind farm.

5.0 MODEL OUTPUTS AND THEIR IMPLICATIONS

5.1. MODEL RESULTS

The table below shows the model outputs for each of the scenarios.

	LCOE ($/MWh)	ROI[a] (% per annum)	NPV ($million)
Scenario 62	112	7.3	27
Scenario 47	126	5.8	-97
Scenario 55	119	6.5	-45
Scenario 50	118	6.6	-36

[a] Internal rate of return was used as the measure of ROI

The LCOEs for Scenarios 62 and 47 are somewhat higher than those reported by the Proponent (which are $108 and $122 respectively). This is because the Proponent produced what they call 'simple LCOEs', which do not account for the time to build a wind farm and the associated delay before revenue is received from the sale of electricity. In contrast, the Panel's model allows for a two-year construction period, with the sale of electricity commencing at the start of the third year. While the two sets of LCOEs are somewhat different, the relativities between the scenarios are very similar. For example, using the Proponent's figures, the LCOE for Scenario 47 is 12.7% higher than Scenario 62, while using the Panel's figures, it is 12.4% higher.

The 62-turbine layout is the preferred layout for the Proponent. From an energy generation perspective, the 47-turbine layout removes:

- 6 of the 12 lowest LCOE turbines
- 8 of the 18 highest performing turbines (Net AEP[16])
- 5 of the 13 lowest CAPEX turbines

The differences in the modelling results for these two scenarios are about 80% due to Scenario 47 sharing the fixed costs across a smaller number of wind turbines and 20% due to Scenario 47 having lower average energy production per turbine. The Panel is aware that this may oversimplify the reasons for difference. For example, the model does not account for the diurnal performance of the turbines, which might enable energy sales in more or less favourable price intervals that would generate additional revenues for HOG.

Scenario 55 has superior results than Scenario 47 primarily because it shares fixed costs across a greater number of turbines. While some of the turbines reinstated for Scenario 55 are relatively high energy producers, some are low producers, so on

[16] AEP is annual energy production

average the two scenarios produce about the same quantity of energy per turbine (Scenario 55 is very slightly higher).

The idea behind Scenario 50 is not that consideration should be given to approving these 50 turbines, but rather whether if (for example) Scenario 55 was approved, the Proponent might be able to improve on the economics of the project by choosing not to proceed with some turbines. The results indicate that there may be some scope for this, but any advantage gained would likely be small. It may also be the case that there are considerations that are not accurately reflected in the model that could lead the Proponent to build all 55 turbines if approved. The Panel notes that turbine WP16 stands out, having a particularly poor cost and energy production combination.

The Panel conducted sensitivity analysis for average power price assumptions of $126 and $103 (these being +/- $10 compared to the $114 benchmark discussed in section 4.6.3. At $103 all scenarios have a negative NPV. At $126, scenario 47 still has a slightly negative NPV, while the other scenarios are positive. Given the discussion in the section 4.6.4, a $103 average power price is more plausible than one of $126.

5.2. IMPLICATIONS OF THE RESULTS

The Panel's advice is that the model results can be used as one input in arriving at decisions that best deliver the objectives of the planning legislation, provided the uncertainties and limitations of them are properly taken into account.

The results reflect the Panel's best estimates of the costs and benefits to the Project's investors from their business of producing electricity for customers. As well as these 'private' costs and benefits, the project would result in other direct social, economic and environmental impacts that are to be considered by the Department and the Commission, including:

- noise and visual amenity impacts for some local residents and visitors to the area (negative)
- biodiversity impacts (although, given that NSW's Biodiversity Offsets Scheme aims to achieve a standard of 'no net loss'[17] these may be largely compensated for by biodiversity credits paid for by the Proponents and hence be considered neutral)
- contribution to lowering greenhouse gas emissions (positive).

On this last point, the NSW Treasury[18] specifies that in cost–benefit analyses, emission reductions should be assigned a value of $126 per tonne of CO2 in FY 2024, rising by 2.25% real thereafter. The Hills of Gold project is intended to displace energy currently generated by existing generators, including thermal coal plants that

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17 NSW Government Department of Environment and Heritage https://www2.environment.nsw.gov.au/topics/animals-and-plants/biodiversity-offsets-scheme/about-bos/biodiversity-offsetting

18 https://www.treasury.nsw.gov.au/sites/default/files/2023-03/20230302-technical-note-to-tpg23-08_carbon-value-to-use-for-cost-benefit-analysis.pdf

are scheduled to close in coming years. Wind farms will play a key role in delivering the State's emission reduction and energy transition goals.

While the Proponent may capture some revenue from its abatement contribution, $126 per tonne is considerably higher than the incentives that it may be able to access under government incentive arrangements that support renewable energy. Hence the Hills of Gold project (and other wind farms) would generate large economic benefits that accrue to the public at large rather than the operator. These benefits are not included in the analysis for the report, as the Panel has been asked to focus on the commercial dimensions that influence project viability.

The analysis in this report enables clear comparisons between scenarios. For example, leaving aside for a moment the issue of viability, it can be seen from the modelling outputs that Scenario 55 is better than Scenario 47 on the basis of private costs and benefits by about $52 million (in net present value terms). Scenario 55 is also better on greenhouse gas emissions, but it is worse on noise and visual amenity and possibly biodiversity. While it may not be feasible to put a value on all these differences in impacts, the $52 million difference does put a magnitude on the difference in private costs and benefits between the two scenarios.

It is also relevant to consider who incurs the relevant costs and benefits. In the first instance, the economic cost to the project of approving fewer than the 62 turbines would be borne by the Proponent. This is because its costs to produce each unit of energy would increase, while it would face an unchanged price – a single wind farm has no ability to pass on higher costs to the whole electricity market. However, over time decisions that increase costs for generating electricity can be expected to flow through to higher wholesale (and ultimately retail) electricity prices because sufficient new generation capacity must be built to meet electricity demand, while investors will only finance new facilities that are expected to generate positive returns ie prices would need to rise to cover the costs of available generation projects.

The main trade-off for decision-makers, therefore, is likely to be between regional visual amenity, noise and possibly biodiversity impacts on the one hand, and a potential precedent for upward pressure on electricity prices and slower progress towards government emission reduction targets on the other.

The Panel has been asked to provide advice on project viability. While the Commission might approve a smaller version of a wind farm because it is judged to be preferrable to a larger version, lack of commercial viability might mean it is not built. That is, the choice might effectively be between the larger version and no Hills of Gold wind farm at all.

The model results suggest that Scenario 62 is the only one that is commercially viable as it is the only one showing a positive net present value. However, the model is not a perfect representation of reality and there are a range of factors not captured by the model that could make other scenarios viable. The main factors are listed in the following section.

Favourable changes in such factors are much more likely to make Scenario 55 viable than for Scenario 47. That is, it would take a smaller positive change in the investment environment to push Scenario 55 into viability compared to what would be needed for Scenario 47.

6.0 ADVICE

We have been asked to advise on key financial metrics and the viability of the Hills of Gold project under a range of turbine scenarios. The Panel's advice on the metrics is in the table above in section 5.1.

There is no single financial metric that will invariably indicate that a project is 'viable' and would therefore proceed. On the other hand, some metrics outcomes will close down a project for as long as current external economic and regulatory environments prevail.

In the process of reaching financial close (ie the making of a commitment to invest in and proceed to construct a project) a project investor will:

- undertake detailed optimisation planning and market engagement to seek reductions in the final estimates of costs and to maximise production potential. For example, construction cost estimates will become more granular and precise, and turbine type and configurations may be optimised to maximise energy output. It is reasonable at this stage for the Proponent to have included conservative assumptions on costs and outputs.
- adopt a final view on future energy prices (both the 'black' price of energy produced and any associated 'green' products) and hence combined future revenues. Revenues are in turn influenced by the developer's energy contracting strategy. Investors must also take into account the prospect of changes in Commonwealth or State government policies or new market regulations from the array of energy regulatory bodies. These may benefit or disbenefit the project. Each investor will take different views on these critical factors
- assign individual weights to 'sunk' development costs already incurred
- compare the anticipated financial performance of their project with competing projects and alternative opportunities to deploy capital. Investors will be averse to investing in a project that is significantly higher cost than competitors', because high-cost projects' future values and returns will be impacted if future electricity prices prove lower than anticipated due to the entry of lower cost competitors
- bring their own investment criteria to bear, reflecting their risk appetite, cost of capital and (potentially) any ancillary corporate objectives or commitments. This means that different investors may reach different decisions to proceed (or not) with a project if financial metrics are tight. For example, energy retailers may invest to hedge retailing price exposure, replace retiring generation capacity or deliver specific low emission energy products for customers. Investment funds, on the other hand, may have narrower expectations of return, access to different costs of capital and longer time horizons, leading to different investment decisions.

Subject to the qualifications above, the Panel believes it is reasonable for the Department to rely on the following investment guardrails for HOG.

1. If estimated net present value[19] (NPV) is significantly below zero, it is unlikely that a project would be viable or would proceed under current economic and regulatory circumstances.
2. If return on investment (IRR) is significantly less than 7% (in the current and anticipated interest rate environment), it is unlikely that a project will attract the investment needed to proceed.
3. If levelised cost of energy (LCOE) is less than $114, a project that is in all other respects satisfactory should be considered viable and would be likely to proceed.

The Panel's advice on the four Hills of Gold scenarios is therefore as follows.

Scenario 62 - viable. The Proponent seeks approval for it and the LCOE is under the benchmark of $114/MWh adopted by the Panel.

Scenario 47 – not viable. The Panel advises that this scenario is very unlikely to be viable, as it has a large negative net present value. This arises mainly because the fixed project costs must be spread across a smaller number of wind turbines.

Scenario 55 – marginal. Based on the metrics of the analysis, this scenario is non-viable. However, viability might be possible if one or more of the following occurs: the project would deliver strategic benefits for the Proponent; costs could be reduced through optimisation and tendering; wholesale power prices were expected to increase; costs of capital fall; or green energy policy settings changed favourably.

Scenario 50 – not recommended. This scenario was developed to explore whether removal of the highest cost and least productive turbines included in Scenario 55 could reduce the overall LCOE. The model results suggest that there could be some very limited scope for this.

The Panel recommends, however, that if the lowest performing turbines are considered acceptable on other grounds, then the decision to include or remove them should be left with the Proponent, who will be best placed and motivated to achieve the maximum possible power generation capacity at lowest cost.

Other Advice

Allowing for optimisation - One provision that would be favourable for this (and all wind farm projects) is for approval conditions to maximise allowable scope for post approval optimisation without requiring further formal assessments, especially if approved turbine numbers are fewer than in the Proponent’s proposed configuration.

Turbulence from a turbine impacts on the performance of downwind turbines. Hence, the removal of some turbines may slightly increase yield from the remaining turbines or reduce capital costs if small adjustments can be made to

[19] Using net present value as defined above, ie referring only to costs and benefits for the Proponent

turbine placements within an approved project envelope or distance from approved locations.

APPENDIX A: LIST OF TURBINES INCLUDED IN EACH SCENARIO

Turbine	Variable capex ($million)	Annual energy production (net MWh)	Scenario 62	Scenario 47	Scenario 55	Scenario 50
WP2	14.8	16,500	yes	Yes	yes	yes
WP3	13.2	14,600	yes	Yes	yes	yes
WP4	13.3	13,100	yes	Yes	yes	yes
WP5	14.4	11,100	yes	Yes	yes	no
WP6	15.7	14,000	yes	Yes	yes	yes
WP7	11.8	12,400	yes	Yes	yes	yes
WP8	11.7	12,661	yes	Yes	yes	yes
WP9	14.6	12,895	yes	No	yes	yes
WP10	13.3	12,648	yes	No	yes	yes
WP11	13.3	11,000	yes	No	yes	no
WP12	14.6	11,900	yes	Yes	yes	no
WP13	11.7	14,037	yes	Yes	yes	yes
WP14	11.7	13,000	yes	Yes	yes	yes
WP15	13.7	12,000	yes	Yes	yes	yes
WP16	14.9	10,000	yes	Yes	yes	no
WP17	15.0	13,000	yes	Yes	yes	yes
WP18	13.4	10,300	yes	Yes	yes	no
WP20	13.3	15,007	yes	Yes	yes	yes
WP21	11.9	15,366	yes	Yes	yes	yes
WP22	13.7	15,581	yes	Yes	yes	yes
WP25	13.7	14,244	yes	Yes	yes	yes
WP26	11.8	17,400	yes	Yes	yes	yes
WP28	13.3	17,400	yes	No	no	no
WP29	14.0	15,000	yes	Yes	yes	yes
WP30	11.9	14,400	yes	Yes	yes	yes
WP32	12.0	16,400	yes	Yes	yes	yes
WP33	15.3	15,400	yes	Yes	yes	yes
WP34	13.7	14,206	yes	Yes	yes	yes
WP35	13.4	15,900	yes	Yes	yes	yes
WP36	11.7	17,800	yes	Yes	yes	yes
WP37	13.2	17,800	yes	Yes	yes	yes
WP38	11.7	19,300	yes	Yes	yes	yes
WP39	11.7	19,400	yes	Yes	yes	yes
WP40	14.5	19,100	yes	Yes	yes	yes
WP43	12.0	20,600	yes	Yes	yes	yes
WP44	11.7	21,000	yes	Yes	yes	yes
WP45	13.6	20,700	yes	Yes	yes	yes
WP46	13.2	18,700	yes	Yes	yes	yes
WP47	11.7	19,100	yes	Yes	yes	yes
WP48	11.8	19,600	yes	Yes	yes	yes
WP49	11.7	21,400	yes	Yes	yes	yes
WP50	13.5	21,300	yes	Yes	yes	yes

WP51	13.2	21,400	yes	Yes	yes	yes
WP52	13.2	22,000	yes	Yes	yes	yes
WP53	11.7	22,100	yes	No	yes	yes
WP54	11.7	21,400	yes	No	yes	yes
WP55	11.7	19,900	yes	No	no	no
WP56	11.7	20,400	yes	No	no	no
WP57	13.3	20,500	yes	No	no	no
WP58	13.3	21,400	yes	No	no	no
WP59	14.5	21,000	yes	No	no	no
WP60	14.5	20,400	yes	No	no	no
WP61	14.7	19,200	yes	No	yes	yes
WP62	11.7	18,200	yes	No	yes	yes
WP63	13.3	17,600	yes	No	yes	yes
WP64	13.5	19,100	yes	Yes	yes	yes
WP65	11.7	20,600	yes	Yes	yes	yes
WP66	13.2	21,200	yes	Yes	yes	yes
WP67	11.7	21,400	yes	Yes	yes	yes
WP68	13.2	19,100	yes	Yes	yes	yes
WP69	13.2	19,000	yes	Yes	yes	yes
WP70	11.8	17,400	yes	Yes	yes	yes

APPENDIX B: PANEL RESPONSES TO FURTHER QUESTIONS FROM THE DEPARTMENT

After reviewing an earlier version of this report, the Department of Planning, Housing and Infrastructure asked the Panel to respond to a series of questions and do some further analysis. Where relevant the findings from that work have been incorporated into the main body of this report. The purpose of this appendix is to provide further information on the Panel's responses to questions that may be of wider interest for decision-makers.

Comparison of the $114 LCOE benchmark with an LCOE based entirely on draft ISP averages

In discussions on an earlier version of this report, the Department asked the Panel to calculate an LCOE based purely on the average inputs from the draft ISP and to consider whether this might provide a more reliable benchmark to use in the analysis than the benchmark (of $114) derived using the Proponent's inputs. The Panel found that this was not a straightforward matter as there were choices to be made on which values to average. With this caveat in mind, the Panel calculated an LCOE of $97, which is considerably lower than the $114 benchmark.

The table below shows the principal sources of differences between the different LCOE values.

Parameter	Benchmark LCOE based on Proponent's inputs	LCOE using workbook averages selected by the Panel	Contribution to LCOE difference*	Comment
Capacity factor	32.1%	33.3%	-$4.10	The Panel used the average of 'Wind High' and 'Wind Medium' for REZ regions. This is a case where different averages could be chosen.
Marginal loss factor	0.8866	0.9287	-$5.20	The NSW Average MLF in the Workbook is based on an average of only 3 data points for NSW (2 in or near the Hunter Valley and one near Wagga Wagga) which is unsatisfactory. The Proponent's MLF is taken from Aurora forecast reports (average of all NSW REZ MLFs), which seems more appropriate.
Build cost	$2,564/kW	$2,644/kW	+$2.70	The Panel used the Workbook's 'NSW medium'. Different

				averages could be chosen.
Additional capex for pre-development	$26.4 million	None	-$2.30	The Proponent's addition appears to relate to 'fixed owners capex' for pre-development studies and third-party engagement. CSIRO acknowledges that it may not comprehensively cover pre-development costs, so this may justify adding some additional capex.
Connection costs	$10 million per year (total NPV of $124 million)	$53.5 million capex	-$5.80	The Panel used AEMO projections for 2025/26 averaged across NSW REZs. The Proponent have assumed connection costs equal to its estimate for HOG.
Operating costs	$14.5 million per year (excluding the connection cost annuity)	$11.1 million per year	-$3.50	The Panel used AEMO's 'NSW medium'. The Proponent assumes operating costs would be the same as its estimate for HOG. This may be justified to achieve greater consistency (as it seems likely that operating costs for HOG would be similar to the average NSW wind farm).
Total LCOE	$114.2	$96.9	-$17.3 (-11.9%)	

* The individual differences do not sum to the total difference due to interactions between different parameters

While there are uncertainties, in the Panel's view the benchmark based on the Proponent's inputs are likely to be more realistic for comparing to Hills of Gold with respect to MLFs, additional capex for pre-development and operating costs for the reasons given in the table. For other parameters there is greater uncertainty. For example, while Hills of Gold could well have a somewhat higher connection cost than the average the NSW wind farm, the ISP value seems very low when compared to connection costs for other NSW wind farms that the Panel is aware of.

Does Hills of Gold have high costs compared to other wind farm projects?

The Panel offers the following comments of on the inherent costs of Hills of Gold wind farm proposed compared to other sites:

- Conceptually, the lowest cost sites would have simple terrain for constructability, be located close to major transmission lines with available capacity, and have very strong wind resources. They would also be on already cleared land and be removed from houses and population centres. Many of the 'easiest' ie most favourable sites in NSW have already been developed. Hence the pipeline of remaining sites all have less than ideal conditions in one or more respects
- Specifically for Hills of Gold (HOG):
    - Terrain is slightly more complex than for most of the already completed wind projects but likely to be more representative of the next generation of windfarms proposed to be located on or in the foothills of the Great Dividing Range
    - Some individual proposed turbines are on cleared land, but some others require vegetation clearing that generates significant biodiversity offset costs. There may be other sites with a higher percentage of cleared land that do not incur such costs. The Panel has noted above that the HOG biodiversity offset costs range from zero (for cleared land) to \$1.2m per turbine (average \$189k).
    - The overall wind resource is probably slightly better than average, but this relies on the turbine hub heights and proximity to topographic acceleration features (hills) to make it "windier" than (for example) a flat site in the south of the State ie flatter sites might have lower constructability costs, but the trade-off is that they are likely to have lesser wind resources.
    - Grid connection costs appear higher for HOG than the advised costs of connections for projects to be located in the New England Renewable Energy Zone. Prima facie this is a reasonable expectation, as the promise of a REZ is that connection costs can be shared between projects. However, the Panel has noted that the actual costs of REZ development can increase significantly, so caution is required if making a general conclusion. An example is the cost increase of the Central West REZ that was reported to have been modelled initially at \$400m - \$800m but following detailed design is now has an estimated to cost of \$3.2 billion[21].
    - Combined fixed and variable operating cost estimates from the workbook are about 23% lower than the HOG provisions. However, the Panel does not see any reason why HOG opex would be inherently higher than competing sites, and expects that the differences arise from market intelligence of the latest prices and/or different scope and estimation methods.

[21] /https://climateenergyfinance.org/wp-content/uploads/2023/07/FINAL_NSW-Electricity-Plan-to-2030_CEF_TimBuckley_18Jul2023-1.pdf p53

If Hills of Gold costs are overestimates how would this affect the viability of scenarios?

The Panel has looked at whether project scenario viability would be changed significantly if costs were overestimated. To answer this, the Panel used its model to investigate the impact on ROI and NPV if the lower costs derived above from the workbook were applicable for HOG.

For consistency, electricity prices were also assumed to reflect the lower LCOE estimates. This follows from the AEMO investment and market framework, where it is assumed that over time electricity prices will adjust to reflect the LCOE of the least cost new entrants that are required to meet electricity demand.

The directional impact of these changed assumptions was clear. Entering lower benchmark and cost assumptions into the model reduced the ROI and NPV of all scenarios, including producing negative NPVs for all four scenarios.

The Panel therefore concluded that a systematic (but plausible) overstatement of costs would not result in different advice on scenario viability.