ASTRI
Australian Solar Thermal Research Institute

AUSTELA
Australian Solar Thermal Energy Association

ASTRI and AUSTELA response to consultation on GenCost 2024-25 Draft Report

11th February 2025

Dear GenCost team,

The Australian Solar Thermal Research Institute and the Australian Solar Thermal Energy Association welcome the opportunity to provide feedback on the GenCost 2024-25 Draft Report. We are available to discuss our feedback at your convenience.

Key points

- The latest report shows the value and potential of solar thermal given its 'costs are low' (page xi). However, to properly reflect the value of the technology we recommend the following changes and considerations:
    - One of the ongoing challenges that still needs to be addressed and is acknowledged in the report (p.31) is that solar thermal, uniquely amongst renewables technologies, can both generate and provide storage for electricity. As outlined in previous engagements with the GenCost team, we feel this should be better reflected in the report to show the value of solar thermal to Australia's energy mix more clearly.
    - The categorisation challenge also arises in solar thermal being placed in the 'flexible load, low emission' category alongside nuclear and fossil fuel technologies. Solar thermal is zero emission and is truly flexible unlike nuclear.
    - GenCost emphasizes again that wind and PV with the inclusion of integration costs are the lowest LCOE of new build systems, however in comparing this to solar thermal which is reported as next lowest, we feel this is a misrepresentation. In an optimized mix, solar thermal would not be competing with wind and pv plus integration, it would rather be part of the mix that provides the integration role.
    - The CapEx figures for solar thermal used in the report should be re-checked. There appears to be inconsistency with Aurecon's report, confusion over whether learning offsets inflation and possible double counting of land and development costs. Calibration of costs to ''Vic low'' for consistency with other technologies as input to the IASR needs checking. There remains the issues of the reporting of only a single configuration by Aurecon and which configuration that is.
    - CST provides firm, dispatchable power with long-duration storage, making it a critical technology for balancing intermittent renewables like solar PV and wind. Unlike batteries and PHES, solar thermal contributes inertia, frequency control, and other ancillary grid services, reducing the need for additional infrastructure investments. GenCost should consider these additional grid benefits when evaluating CST's economic and technical value.

Elaborating on these and other points

Transmission costs for CST

- In the executive summary (p. xii) and on page 66 it is suggested transmission costs could add $14/Mwh to the cost of solar thermal. This deserves a more nuanced discussion. For optimal deployment, solar thermal plants are likely to be in or close to inland REZs and as such share much of the transmission upgrades needed for large scale PV. By complementing PV generation, solar thermal will leverage and optimise transmission assets at greater capacity and higher efficiency. Thus solar thermal would work to lower the overall impact of transmission extensions on the transition to net zero.

NOAK vs FOAK

- Page 27 states that ''the cost estimates in GenCost are mostly on a NOAK basis''. This seems unnecessarily imprecise. It would expected that they are and should be completely not mostly on an NOAK basis. An additional line would be valuable noting that for long term system planning and policy development it is the NOAK costs that should be used. The warning on FOAK is correct and pertinent.

Risk of inflation double counting

- At the bottom of page 27 it is noted that Aurecon costs are based on a July 2024 estimate. This is a little confusing as the previous GenCost used a basis of hypothetical systems costed as at contracting in December 2023. When data is then presented in tables labelled by year without clearly specifying if it is financial vs calendar there is a danger of misinterpretation / double counting for inflation.

Storage technology costs

- In 3.4 on storage technology costs, the final paragraph discusses CST as a combined storage and generation technology, which is a valid and very welcome inclusion. We would however argue as we have done in the past that it is straight forward to also include it in the graphs in figure 3.3 and 3.4 by simply counting the capital cost of the thermal storage and the power block only but not the mirror field. This then makes it directly comparable with the other technologies for which the capital cost of the energy collection (i.e. wind and PV) are not included.

Proportion of solar thermal vs. PV

- In 5.2 global generation mix. The caption to figure 5.1 notes that the category solar includes solar thermal and solar photovoltaics. It would helpful to identify exactly how much is solar thermal, either as a category in the graph and/or in the text.

Solar thermal costs

- 5.3.8 solar thermal costs. The text refers to a system with 16 hours storage whereas the caption to figure 5-10 refers to 14 hours. The increase for the 2024 value compared to the 2023-24 value is not clearly explained. There is clearly some inflationary impacts but countering this to some extent should be the underlying cost reduction trend consistent with CSIRO's modelled trajectories. There has been continued deployment in the last 12 months but it is not possible to get an accurate empirical number for learning cost reduction in that period, so it is rational to rely on the underlying modelled trend rather than assume it is zero. As further discussed below, Aurecon's report is confusing on this point.

Variable renewables integration costs

- Discussion on page 63. The modelling the GenCost team has done, assesses how much transmission, storage and synchronous generator addition is needed to support VRE. This is a sensible approach, but it would be worth discussing that this is a ‘’proxy” mix of technology to determine the integration cost. To the extent that new flexible dispatchable generators, such as CST, are added to the system in parallel, these will equally naturally provide the integration capabilities. CST in particular would contribute to the needed storage and also offset the need for synchronous condensers.

Variable with integration is cheapest

- In the LCOE comparison ‘’VRE with integration costs” is presented as the cheapest approach to new build generation that maintains system reliability. This is of course true, however, we suggest the discussion should be nuanced a little more. The point is made on page 64 that ‘’if we exclude high emission… the next most competitive technologies are solar thermal, gas with ccs…etc”. We would suggest this is not quite the right interpretation. At face value it is true, but actually solar thermal in particular, is not going to compete with VRE with integration. Instead, it is a potential low cost part of the essential “integration” capability needed for the VRE.

Flexible technologies

- We suggest the GenCost team should give some thought to the use of the label ‘’flexible load” it might be better to refer to this category as ‘’dispatchable”. The term flexible is more commonly used to describe the speed with which a dispatchable generator is able to respond. I.e. a gas turbine is traditionally regarded as being ‘’flexible” whereas a coal plant is much less flexible. A nuclear plant is arguably the least flexible of all in this category. CST plants are built with steam turbines designed for faster response times, they are thus nearly as flexible as gas and certainly much more flexible than traditional coal or nuclear plants.
- In the low emissions dispatchable / flexible category those technologies that are more flexible make a greater contribution to firming VRE. All are synchronous generators and so add to system strength and their presence would minimise the need for adding costly synchronous condensers.

Peaking technologies vs dispatchable

- It would be worth briefly noting that the roles of peaking technologies and the more flexible dispatchable systems such as CST can be interchangeable. Peaking technologies are simply those that are flexible but have a low capital cost / high fuel cost characteristic. Thus the market uses them only as needed. To the extent that a zero emissions flexible dispatchable generator like CST were in the system it would displace the role of gas peaking plants whilst still being operated at relatively high-capacity factor given its zero fuel cost.

Queries/ inconsistencies

- Tables B1, 2,3 all have an entry for solar thermal (16hours) of \$6769/kW for 2024. This is higher than Aurecon’s costings that quote \$6104/kW. See discussion below.
- The economic life of a CST plant is listed as 25 years (along with many other techs like on shore wind). That’s fair, but why is PV 30 years? Also Aurecon suggest 30 years for CST.
- We continue to argue that for modelling inputs such as AEMO’s ISP, multiple configurations of storage and solar field size should be used as multiple durations of battery and PHES storage are used. Use of a single configuration is second guessing the results of such models and if wide of the mark, will lead to predictions of no up-take.

Aurecon report

For consistency and completeness, we have also reviewed Aurecon's costings report which feeds into GenCost. Our feedback is below.

4.6 Solar Thermal

- The overview and commentary on recent trends is well written.
- On cost estimation there is some confusion. The Fichtner study from 2023 is cited as the best source for a CST cost for Australia which it clearly is.
- The table for Fichtner's reference cost model for NSW medium cost region is reproduced:

Table 4-19 Summary of Fichtner cost model as at October 2023

System	Value	Specific Cost	Total Cost (AUDm)
Power block net capacity (MWe)	140	2,028,795	284
Thermal energy storage (MWth)	4667	35,880	167
Solar field (MWth)	720	644,320	464
EPC Cost			**915**

- However this is described as "*the most likely deployment*". That is a misinterpretation, although it is reflective of a plant configured for night time only, it is basically just the cost model linked to a somewhat arbitrary reference system.

Risk of double counting land and development

It is noted correctly that "*Fichtner has included an additional allowance of 20% for indirect costs and 5% for owner costs including land cost, development cost, utility connections and additional owner's cost during construction and commissioning.*" It is then stated that "*We have provided a separate estimate for land and development costs below but have not reduced the estimate based on the Fichtner costs for clarity*".

- This suggestion of effectively double counting land and development costs appears unjustified.

Learning cost reductions

In considering changes from 2023 to 2024 costs it is stated that;

- *''The Fichtner cost modelling predicted a cost reduction between 2023 and 2024 of around 4% based on longer-term learning rate forecasts. However, as noted above there is limited data available from international projects to validate this cost reduction. Average OECD inflation over the last 12 months has been around 4-5% which offsets the expected reduction in costs so the Fichtner costs from October 2023 have been escalated by 4% to represent current values.''*
- This argument would suggest learning cost reductions are approximately cancelled by inflation and so the same dollar value should be used. This is at odds with the final line says costs have been escalated by 4%.

4.64 describing the selected hypothetical project, references and describes the system configuration for Longreach from ITP's discussion paper last year. However whilst table 4-20 captures most of that configuration correctly, it lists a solar field capacity of 720MWh whereas the system described in ITP's report with that capacity factor in Longreach, has a solar field capacity of 1,100MWth.

The cost estimate in table 4-22 is $6140/kW gross. Which is equivalent to $6540/kW net. This is the same as the Fichtner reference plant in NSW medium , unescelated. The lack of escelation is consistent with the learning balances inflation argument. Gencost and the Aemo IASR however take all baseline costs as referenced to Vic low, which is 0.941 x NSW medium. Land and development costs are still listed as extra.

Inconsistencies between Aurecon report and GenCost

Returning to solar thermal cost numbers in the draft GenCost report;

Table b9 of gencost assumptions for LCOE calculations has:

Apx Table B.9 Data assumptions for LCOE calculations

	Constant						Low assumption			High assumption		
	Economic life	Construction time	Efficiency	O&M fixed	O&M variable	CO_2 storage	Capital	Fuel	Capacity factor	Capital	Fuel	Capacity factor
2024	Years	Years		$/kW	$/MWh	$/MWh	$/kW	$/GJ		$/kW	$/GJ	

….

Solar thermal	25	1.8	100%	124.2	0.0	0.0	8278	0.0	71%	8179	0.0	57%

These numbers are exactly as suggested in ITP's report last year so there use is appropriate if the argument that learning approximately balances escelation is adopted. Note however that the economic life of 25 years is less that the 30year number quoted in Aurecon's report.

Tables B1 and B2 and b3 all have the same 2024 line;

x Table B.1 Current and projected generation technology capital costs under the *Current policies* scenario

	Black coal	Black coal with CCS	Brown coal	Gas combined cycle	Gas open cycle (small)	Gas open cycle (large)	Gas with CCS	Gas reciprocating	Hydrogen reciprocating	Biomass (small scale)	Biomass with CCS (large scale)	Large scale solar PV	Rooftop solar panels	Solar thermal (16hrs)	Wi
	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/k
2024	6037	12263	9321	2455	2426	1310	5802	1980	2071	8916	24366	1463	1336	6769	32

Thus reporting solar thermal as $6769/kW net. This does not appear to align with Aurecon's number and it is not clear what assumptions have been made. It is assumed that the table should be referenced to Vic low as it becomes the basic input for the AEMO IASR.

It is also unclear if the 2024 reference is calender year 2024 or FY. Last year GenCost costs were linked to December of the calender year

We look forward to working with the ISP development team during the course of 2025.

Kind Regards,

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