Technical Assessment Report

Review of the LCOE Parameters for Renewables & Black Coal in GenCost 2024-25

Executive Summary

A technical assessment of the capacity factor assumptions used in GenCost 2024-25 to calculate the levelised cost of electricity (LCOE) for onshore wind, large-scale solar PV and black coal is presented.

It is recommended that GenCost 2024-25 should present average values for the LCOE parameters in addition to the high and low values, because the average value is a useful parameter that can be used to estimate the probable cost over the lifetime of the generator. Note that the average value is not necessarily midway between the high and low value of LCOE, due to the non-linear interaction of the various LCOE parameters.

Additionally, a simple method of including output degradation in the LCOE calculation is also described, and it is recommended that output degradation be incorporated in GenCost 2024-25, because output degradation has a significant impact on the LCOE over the lifetime of the generator.

Tables 1 and 2 show the recommended values for capacity factor and output degradation and it is recommended that they be used in GenCost 2024-25.

Type of Generation	High Capacity Factor	Average Capacity Factor	Low Capacity Factor
Onshore Wind	42.8%	29.8%	19.6%
Large-Scale Solar PV	29%	23%	19%
Black Coal	89%	71%	53%

Table 1: Recommended Capacity Factors for Onshore Wind, Large-Scale Solar PV & Black Coal

Type of Generation	High Output Degradation p.a.	Average Output Degradation p.a.	Low Output Degradation p.a.
Onshore Wind	0.818%	0.570%	0.374%
Large-Scale Solar PV	1.5%	1.0%	0.5%
Black Coal	0.258%	0.195%	0.132%

Table 2: Recommended Output Degradation for Onshore Wind, Large-Scale Solar PV & Black Coal

The changes to the LCOE due to the amendments for capacity factor and output degradation presented in Tables 1 and 2 are depicted in Figure 1 (these are derived from the parameters presented in Table 5.1 of this assessment).

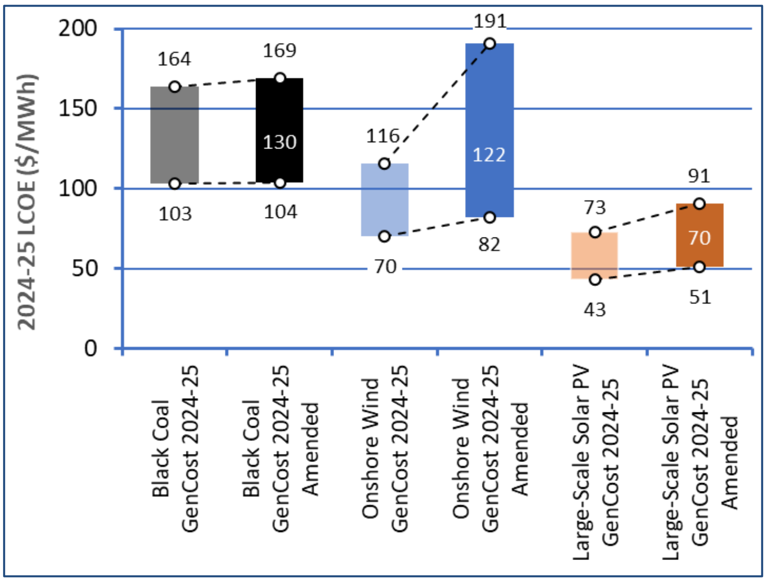

Figure 1: Changes to LCOE due to Amendments to Capacity Factor & Output Degradation

The following observations regarding the change in LCOE are also evident from Figure 1:

a. The cost of black coal increases slightly (by approximately 1-3%).
b. The minimum cost of onshore wind increases by 17% from $70 to $82/MWh. However, the maximum cost increases from $116 to $191/MWh, i.e., an increase of 65%.
c. The minimum cost of solar PV increases by 19% from $43 to $51/MWh. However, the maximum cost increases from $73 to $91/MWh, i.e., an increase of 25%.

In summary, (even after the inclusion of output degradation) large-scale solar PV remains the lowest cost generator, with a mean cost of $70/MWh, compared with $122/MWh for onshore wind and $130/MWh for black coal.

However, it is apparent that, when output degradation is considered, there is a substantial overlap between the cost of onshore wind and that of black coal, and the following values are highlighted:

a. The minimum cost of black coal of $104/MWh exceeds the $82/MWh minimum cost of onshore wind by 27%.
b. The average cost of black coal of $130/MWh exceeds the $122/MWh average cost of onshore wind by 7%.
c. The maximum cost of onshore wind of $191/MWh exceeds the $169/MWh maximum cost of black coal by 13%.

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Rev	Description	Date	Prepared by
00	Initial issue.	09-Feb-2025	A McFarlane

1 Review in Context

1.1 Background

The series of GenCost reports have been produced by CSIRO since 2018 and these reports have been used to formulate the Australian government's policy for electricity generation. In particular the GenCost reports state that variable renewables have the lowest cost range of any new-build technology for electricity generation.

1.2 Purpose of the Assessment

The purpose of this assessment is to evaluate the capacity factor assumptions used in GenCost 2024-25 to calculate the levelised cost of electricity (LCOE) for the following generation technologies:

a. Onshore wind.
b. Large-scale solar PV.
c. Black coal.

Additionally, a simple method of including output degradation in the LCOE calculation is proposed, since output degradation has a significant impact on the LCOE over the lifetime of the generator.

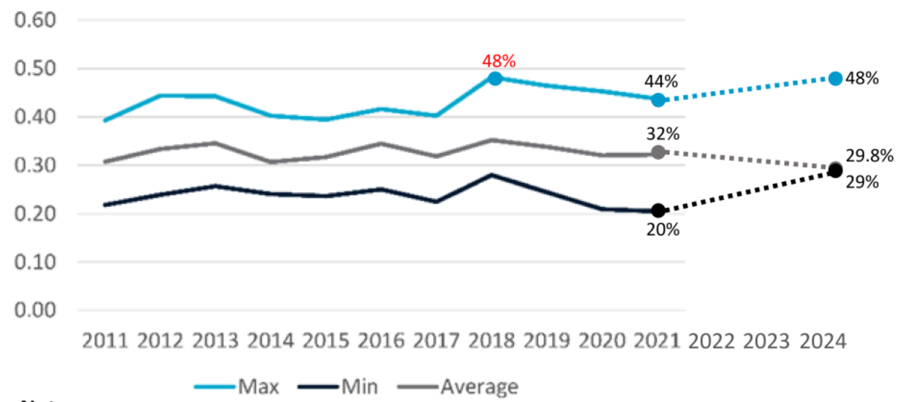
2 Capacity Factors for Onshore Wind

2.1 Introduction

The capacity factors for onshore wind presented in Apx Table B.9 of GenCost 2024-25 are as follows:

a. High capacity factor = 48%.
b. Low capacity factor = 29%.

Additionally, Figure 2.1 (adapted from GenCost 2022-23 Apx Figure D.1) shows that the maximum, minimum and average capacity factors for onshore wind in 2021 are 44%, 20% and 32%, respectively.



Notes:
1. Maximum, minimum and average capacity factors for 2021 are from GenCost 2022-23.
2. Maximum and minimum capacity factors for 2024 are from GenCost 2024-25.
3. Average capacity factor for 2024 is derived from Lang (2025).

Figure 2.1: Capacity Factors for Onshore Wind (adapted from GenCost 2022-23 Apx Figure D.1)

A cursory examination of Figure 2.1 indicates that the range in capacity factors of 20% to 32% to 44% in GenCost 2022-23 conforms with normal engineering practice. However, the low capacity factor of 29% in GenCost 2024-24 appears to be too close to the average.

The applicability of these capacity factors is discussed below.

2.2 Discussion of Capacity Factors for Onshore Wind

2.2.1 High Capacity Factor

At first consideration, the high capacity factor of 48% for onshore wind used in GenCost 2024-25 would not appear to be unreasonable when compared with the value of 44% from Figure 2.1, because new wind turbines would be expected have a higher capacity factor than earlier turbines. Additionally, Note 30 of GenCost 2024-25 states that, *"The capacity factor range…is based on a formula which uses the ten-year average capacity factors. For the high range, we use the high range of historically achieved capacity factors."* Additionally, clause D4.15 states, *"Given these are new build, it is appropriate to be less conservative on the high range assumption. Again, the approach is the same for coal and renewables."*

Notwithstanding the above, Hughes (2012) does note that the capacity factor of newer (larger) turbines is less than that of older (smaller) turbines in the UK and Denmark. Furthermore, Lang (2025) presents weekly capacity factors for onshore wind in the NEM of 26.2% (latest 52 weeks) and 29.8% (latest 331 weeks), and the capacity factor data from Lang (2025) is summarised in Figures 2.2 and 2.3 below. (Note that capacity factor degradation rate of 0.570% p.a. in Figure 2.2 is obtained from the linear trendline of the capacity factor data).

A cursory inspection of Figure 2.2 would appear to suggest that the high capacity factor of 48% presented in GenCost 2024-25 would not seem to be unreasonable because there are five data points that are higher than 48%. However, the value of 48% is not based on any rational engineering analysis, it is based on *"the highest achieved over a ten year period"*, which appears to be the value for 2018 as shown in red in Figure 2.1.

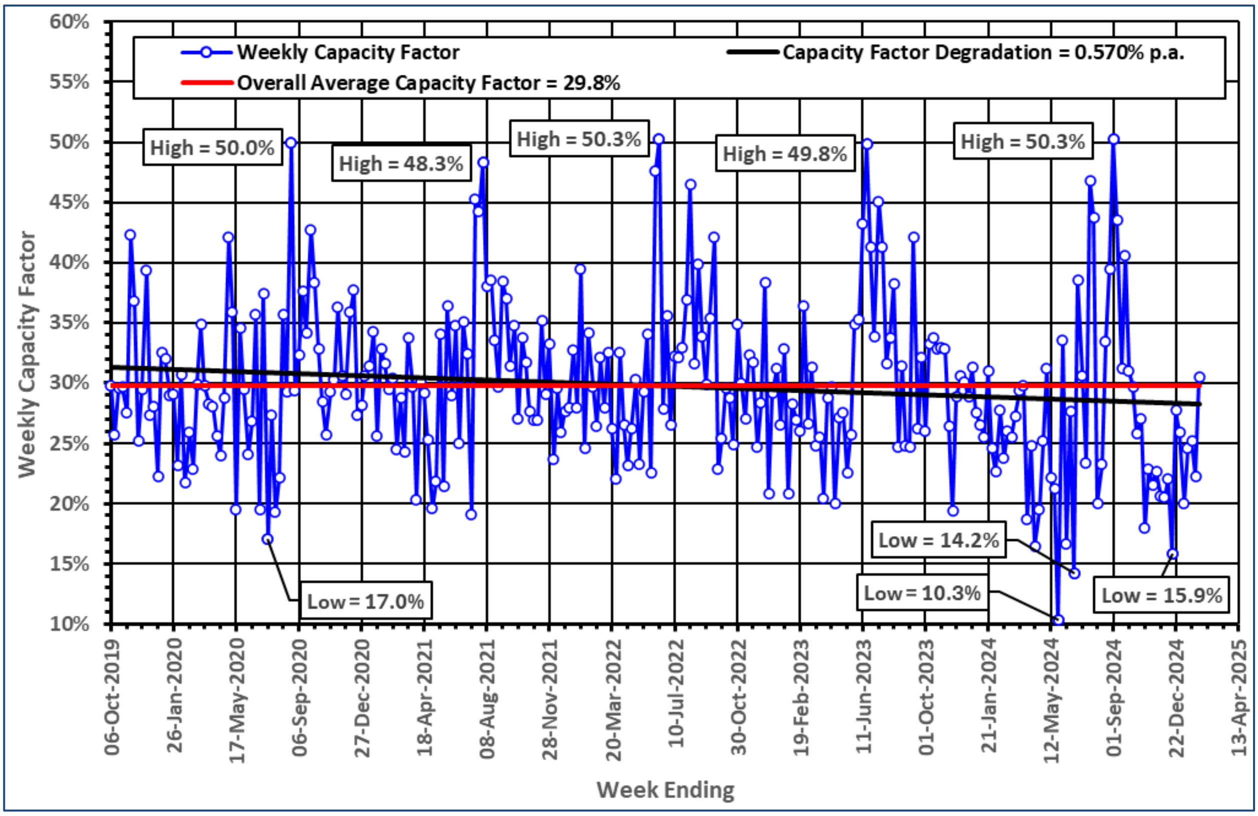


Figure 2.2: Weekly Wind Capacity Factor Data (after Lang, 2025)

However, a more rational approach would be to use the 95th percentile for the maximum value, e.g., as presented in IRENA (2023). It should also be noted that 95th and 5th percentile values are used extensively in engineering analyses. Indeed, GenCost 2022-23 presents 95th and 5th percentiles for high and low values of capacity factor in Apx Figure D.2, when considering global trends for renewables.

Furthermore, it is it is evident from Figure 2.3 that the 95th and 5th percentile of capacity factors are 42.8% and 19.6%, respectively. Moreover, out of the 279 data points presented in Figure 2.3, 14 are greater than 42.8% and 14 are less than or equal to 19.6%. Additionally, the 95th percentile of capacity factor of 42.8% is near to the 44% value presented in GenCost 2022-23 (see Figure 2.1).

Consequently, is recommended that the 95th percentile value of 42.8% be used for the high capacity factor value in the levelised cost of electricity (LCOE) calculations in GenCost 2024-25.

2.2.2 Average & Low Capacity Factors

The low capacity factor of 29% appears to be untenable because it is too close to the average value of 29.8% presented in Figure 2.2.

However, GenCost 2024-25 explains that minimum value is determined by assuming that [emphasis added], "*…the **low range value is 10% below the average** on the basis that if a project cannot achieve a capacity factor [of] **at least that level it is unlikely to proceed** as a new investment."*

The above GenCost 2024-25 statement appears to be erroneous, because capital investment is almost always based on the average rate of return on capital invested over the lifetime of a project. Consequently, investors would normally base their decision on the full range of engineering data – not an arbitrary minimum value that is set at *"10% below the average"*.

Additionally, the use of a low capacity factor value that is 10% below the average is contrary to normal engineering practice, which would typically use the 5th percentile for the low value. For example, IRENA (2023) uses 5th percentiles for low values of capacity factor. Furthermore, GenCost 2022-23 presents 95th and 5th percentiles for high and low values capacity factor in Apx Figure D.2 (when considering global trends for renewables).

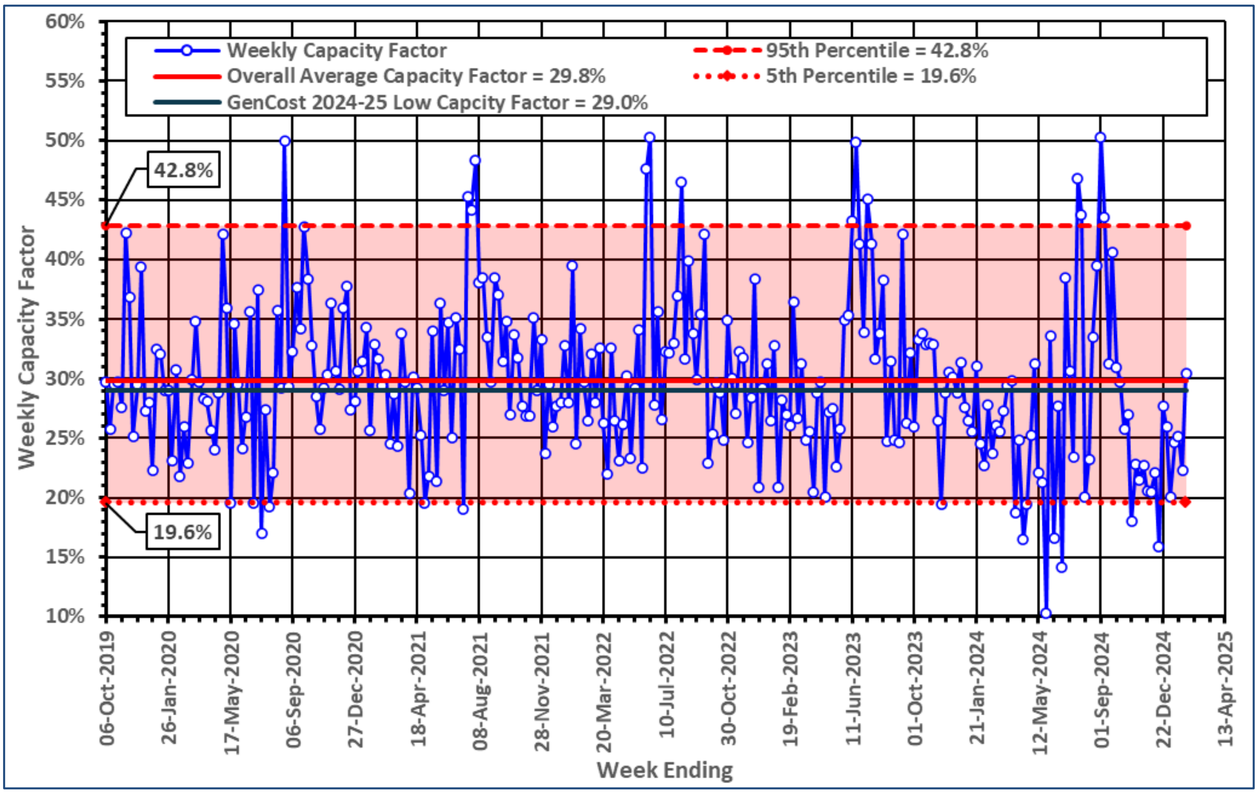


Figure 2.3: Weekly Wind Capacity Factor Data with 5th and 95th Percentiles (after Lang, 2025)

Moreover, detailed analysis of the data presented in Figure 2.3 indicates that nearly half of the capacity factor values are below 29% (133 of the 279 data points, or 47.7%, to be exact), which confirms that the low capacity factor should be significantly less than 29%.

As corroboration that the low capacity factor should be substantially less than 29%, Figure 2.4 compares weekly power generated with the nameplate capacity for onshore wind, from which the following is evident:

a. From 06-Oct-2019 to 09-Feb-2020 average power generated was 2010 MW compared with a nameplate capacity of 6702 MW. That is, the capacity factor for the 18-week period was 30.0%.
b. From 11-Dec-2022 to 24-Dec-2023 average power generated was 3140 MW compared with a nameplate capacity of 10277 MW. That is, the capacity factor for the 54-week period was 30.6%.
c. From 24-Dec-2023 to 06-Oct-2024 average power generated was 3240 MW compared with a nameplate capacity of 11409 MW. That is, the capacity factor for the 41-week period was 28.4%.
d. From 06-Oct-2024 to 02-Feb-2025 average power generated was 3161 MW compared with a nameplate capacity of 13460 MW. That is, the capacity factor for the 17-week period was 23.5%.
e. From items (a) and (d) above, nameplate capacity has increased by 101%, from 6702 MW to 13460 MW. However, the average power generated has only increased by 57%, from 2010 MW to 3161 MW. Therefore, it is evident that adding new wind turbines has not increased the power generation efficiency of the wind fleet.
f. On the 26-May-2024, the low power generated was 1179 MW, which is only 10.3% of the nameplate capacity of 11409 MW (see also Figure 2.2).

The low capacity factor of 23.5% in item (d) above indicates that adding newer wind turbines are not increasing the capacity factor of the wind fleet – to the contrary, the capacity factor has been dropping. Additionally, as stated earlier, Hughes (2012) notes that the capacity factor of newer (larger) turbines is less than that of older (smaller) turbines in the UK and Denmark.

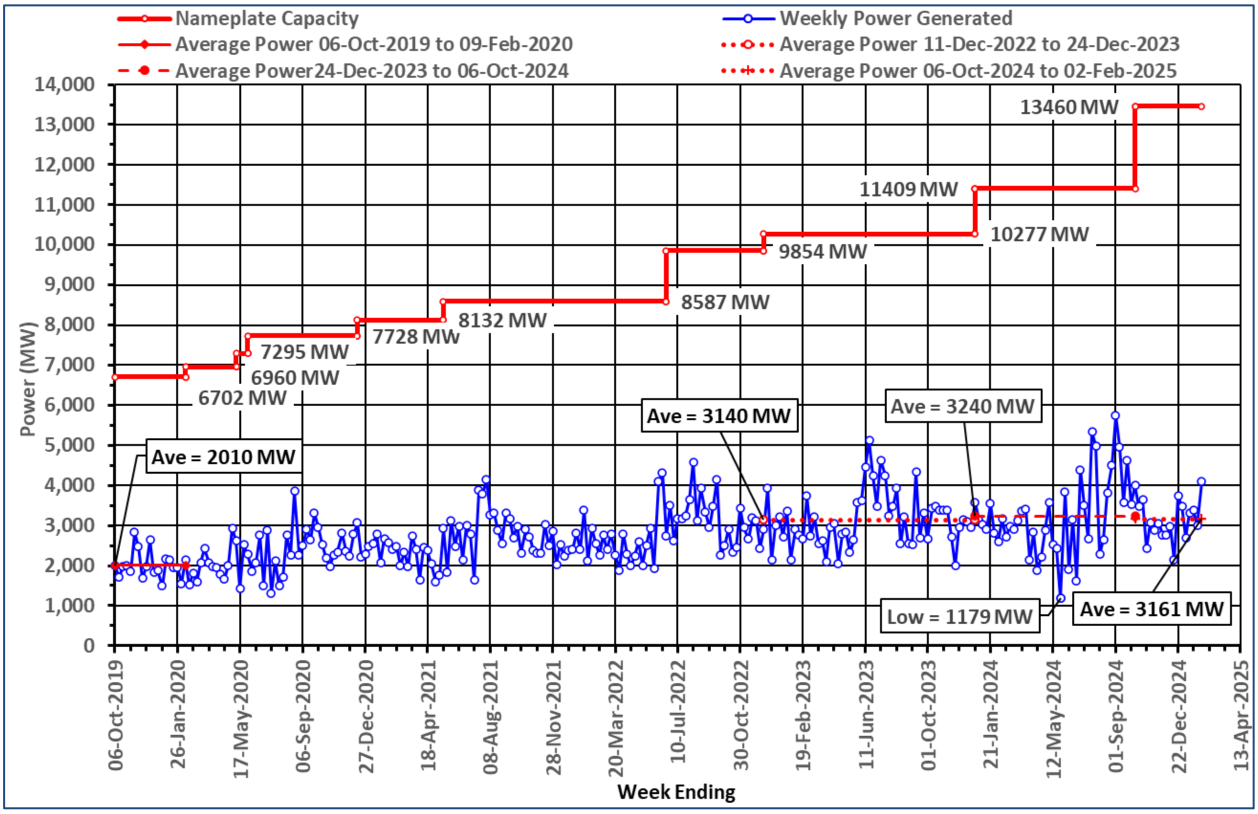


Figure 2.4: Weekly Wind Power Generated compared with Nameplate Capacity (after Lang, 2025)

Furthermore, Figure 2.5 compares the nameplate capacity with the capacity factor for the 112-week period from 11-Dec-2022 to 02-Feb-2025, and the capacity factors over this period are summarised as follows:

a. 30.6% for the period from 11-Dec-2022 to 24-Dec-2023.
b. 28.4% for the period from 23-Dec-2023 to 06-Oct-2024.
c. 23.5% for the period from 06-Oct-2024 to 02-Feb-2025.

Aanalysis of the data presented in Figures 2.5 shows that from 11-Dec-2022 to 02-Feb-2025, the average capacity factor is 28.5%. This is less than the overall average of 29.8% for the entire data set, which confirms that the capacity factor is decreasing – not increasing, despite the significant addition on newer (and larger) wind turbines.

Consequently, it is apparent that the lower capacity factor phenomenon for newer wind turbines also exists in Australia, as well as in the UK and Denmark as presented in Hughes (2012).

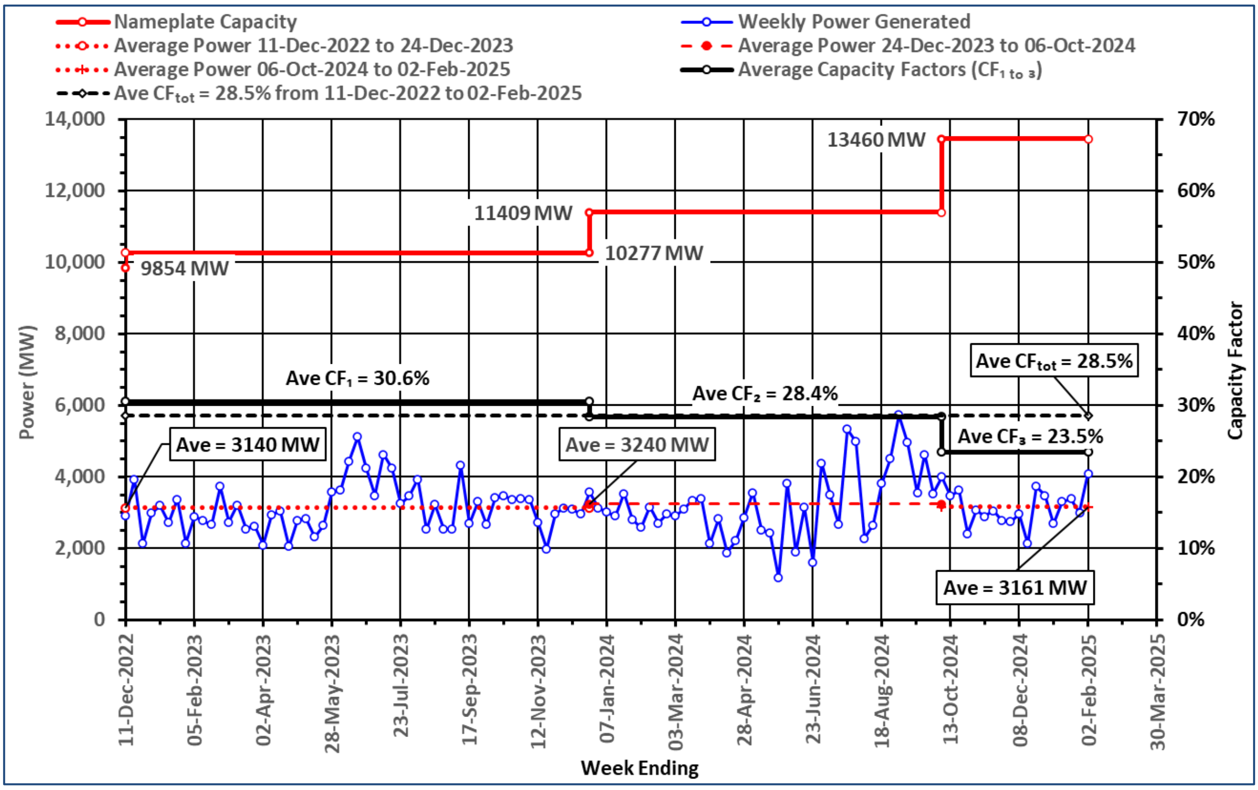


Figure 2.5: Nameplate Capacity compared with Capacity Factor (after Lang, 2025)

From the foregoing, it is evident that there are many instances where the capacity factor is below 19.6%, namely, 14 of the 279 data points, or 5% (as shown in Figure 2.3). Consequently, it is proposed that GenCost 2024-25 should use the 5th percentile as the low capacity factor, in accordance with normal engineering practice. It is also proposed that GenCost 2024-25 should present average values of capacity factor.

Therefore, it is recommended that the following capacity factors should be used (see Figure 2.3 for the data):

a. Average capacity factor = 29.8%.
b. Low capacity factor = 19.6% (i.e., the 5th percentile).

2.2.3 Conclusions & Recommendations from Capacity Factors for Onshore Wind

It is proposed that GenCost 2024-25 should present average values of capacity factors in addition to the maximum and minimum values based on the 95th and 5th percentile values. This would enable a realistic appraisal of the financial viability of a project, and it would be in accordance with normal engineering practice. It is also proposed that the following values be used for the capacity factors for onshore wind:

a. The high capacity factor of 48% presented in GenCost 2024-25, at first consideration, would not seem to be unreasonable because there are five data points that are higher than 48%. However, the value of 48% is not based on any rational engineering analysis. Therefore, it would be prudent to adopt the adopt the 95th percentile value of 42.8% value presented in Figure 2.3, which is close to the 44% value Apx Figure D.1 of in GenCost 2022-23.
Furthermore, Figures 2.4 and 2.5 indicate that high capacity factors are not currently being achieved for onshore wind power generation that would mean that more conservatism should be used, which would invalidate the statement in GenCost 2024-25 clause D4.15 which states that, *"Given these are new build, it is appropriate to be less conservative on the high range assumption."*
b. An overall average capacity factor of 29.8% for the whole Lang (2025) dataset is reasonable (see Figures 2.2 and 2.3). However, it is noted that the average capacity factor CF_{tot} = 28.5% for the 112-

week period from 11-Dec-2022 to 02-Feb-2025 (see Figure 2.5), which is less than the overall average for the whole data set, despite the significant addition on newer (and larger) wind turbines.

c. The low capacity factor of 29% is untenable because it is too near to the overall average value 29.8%, and it is not consistent with normal engineering practice (which usually uses the 5th percentile for low values).

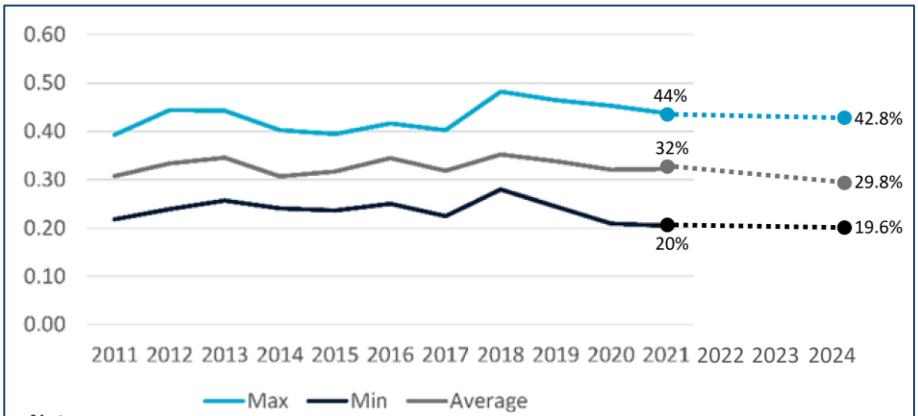
GenCost 2024-25 stating that minimum value is determined by assuming that [emphasis added], "*…the* ***low range value is 10% below the average*** *on the basis that if a project cannot achieve a capacity factor [of]* ***at least that level it is unlikely to proceed*** *as a new investment"* is probably erroneous, because capital investment is usually based on the average return on capital invested over the lifetime of a project.

Therefore, it is recommended that the 29% value be replaced by the 19.6% value presented in Figure 2.3 above, which is close to the value of 20% presented in Apx Figure D.1 of GenCost 2022-23 (see Figure 2.1).

In summary, it is recommended that the following capacity factors be used in the GenCost 2024-25 LCOE calculations for onshore wind:

a. High capacity factor = 42.8% (i.e., the 95th percentile).
b. Average capacity factor = 29.8%.
c. Low capacity factor = 19.6% (i.e., the 5th percentile)

These recommended values are depicted in Figure 2.6.



Notes:
1. Maximum, minimum and average capacity factors for 2021 are from GenCost 2022-23.
2. Maximum and minimum capacity factors for 2024 are proposed by this report.
3. Average capacity factor for 2024 is derived from Lang (2025).

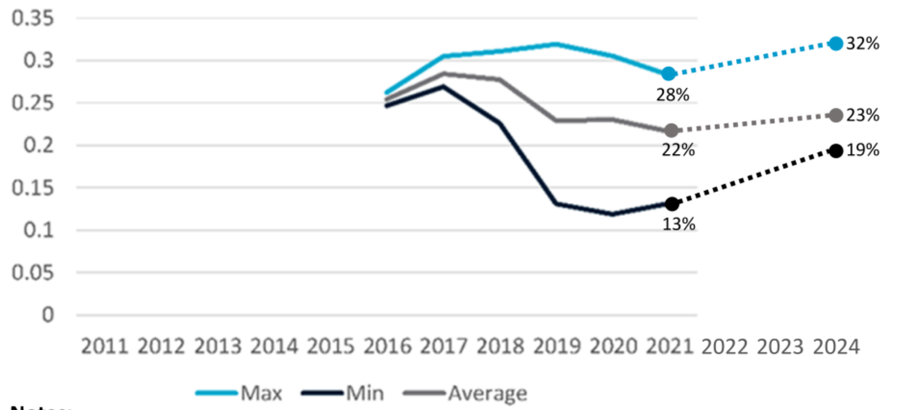
Figure 2.6: Recommended Capacity Factors for Onshore Wind (adapted from GenCost 2022-23 Apx Figure D.1)

3 Capacity Factors for Large-Scale Solar PV

3.1 Discussion of Capacity Factors for Large-Scale Solar PV

Table 4-10 of Aurecon (2024) states that effective annual capacity factor of large-scale solar PV is 29% (this value is based on a system installed in regional NSW).

However, GenCost 2024-25 Apx Table B.9 Data assumptions for LCOE calculations shows a high capacity factor of 32% and a low factor of 19% for large-scale solar PV. Furthermore, Figure 3.1 (adapted from GenCost 2022-23 Apx Figure D.1) shows that the maximum, minimum and average capacity factors for large-scale solar PV are 28%, 13% and 23%, respectively.



Notes:
1. Maximum, minimum and average capacity factors for 2021 are from GenCost 2022-23.
2. Maximum and minimum capacity factors for 2024 are from GenCost 2024-25.
3. Average capacity factor for 2024 is derived from Lee (2023).

Figure 3.1: Capacity Factors for Large-Scale Solar PV (adapted from GenCost 2022-23 Apx Figure D.2)

Additionally, Lee (2023) presents capacity factors shown in Figure 3.2 that are similar to the high and low values in Figure 3.1. Consequently, if we were to ignore the two low values in Figure 3.2, the resulting capacity factors would be 29%, 18% and 23% for the maximum, minimum and average, respectively. It would be better to use the 95th and 5th percentile values as was done for onshore wind, however, this author lacks the pertinent data. Therefore, it is proposed to use the Lee (2023) data.

The low capacity factors of 18% and 19% in Figure 3.2 are near to the low value of 19% used in GenCost 2024-25. Therefore, 19% should be used for the low capacity factor.

However, the high capacity factor of 32% in GenCost 2024-25 is 10% greater than the high value of 29% presented in Figure 3.2. Consequently, it is suggested that the high capacity factor of 29% from Figure 3.2 be used in GenCost 2024-25.

3.2 Conclusions & Recommendations from Capacity Factors for Large-Scale Solar PV

From the foregoing, it is recommended that the following capacity factors be used in the GenCost 2024-25 LCOE calculations for large-scale solar PV:

a. High capacity factor = 29%.
b. Average capacity factor = 23%.
c. Low capacity factor = 19%.

These recommended values are depicted in Figure 3.3

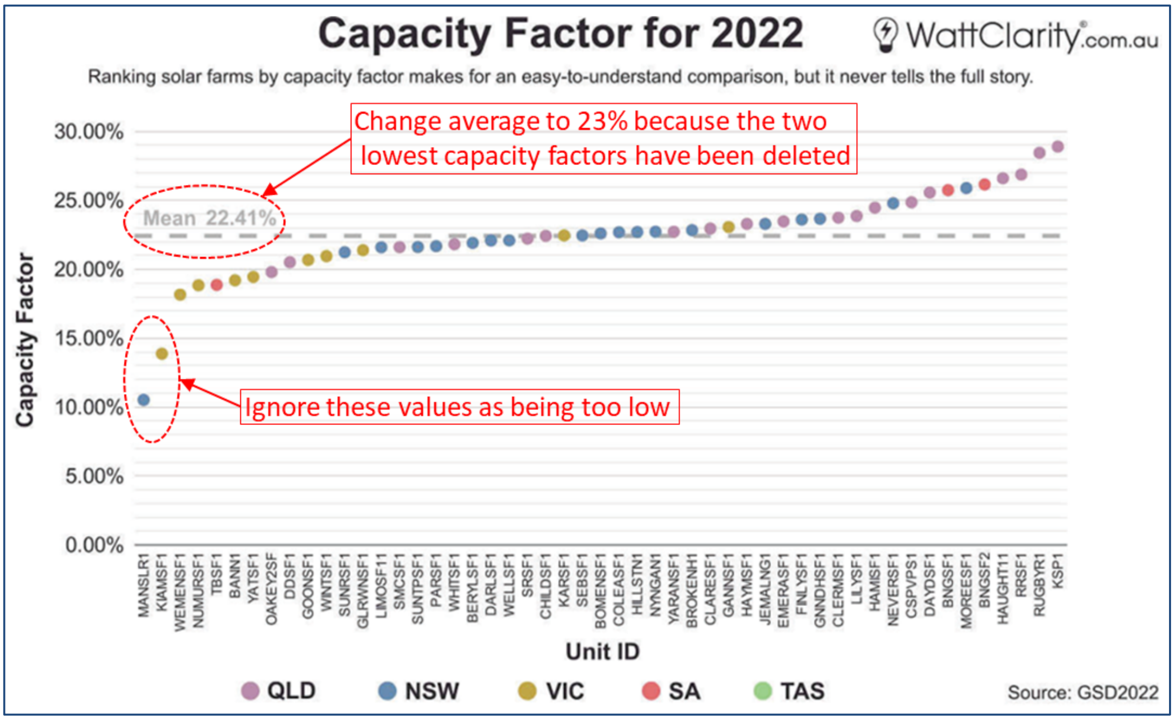


Figure 3.2: Capacity Factors for Large-Scale Solar PV (adapted from Lee, 2023)
Note: *Comments in red have been added to the original diagram.*

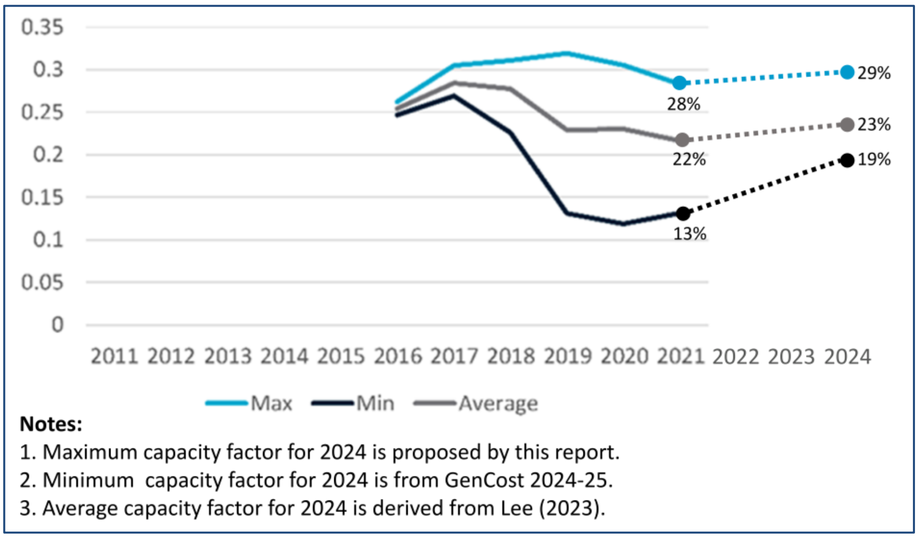


Figure 3.3: Recommended Capacity Factors for Large-Scale Solar PV (Adapted from GenCost 2022-23 Apx Figure D.2)

4 Capacity Factors for Black Coal

4.1 Summary

The capacity factors for black coal presented in Apx Table B.9 of GenCost 2024-25 are as follows:

c. High capacity factor = 89%.
d. Low capacity factor = 53%.

A reasonable argument could be made that the high capacity factor of 89% is slightly low because Table 4-26 of Aurecon (2024) has an effective annual availability factor in the 89-93% range.

Furthermore, a sensible argument could also be made that the low capacity factor of 53% is too low. However, GenCost 2024-25 explains that the low capacity factor is derived by assuming it to be 10% below the historical average of 59% derived from GenCost 2022-23 (see Figure 4.1). It also explains that the low capacity factor is also determined by the, *"...effects of competition or other market constraints which limit generation."*

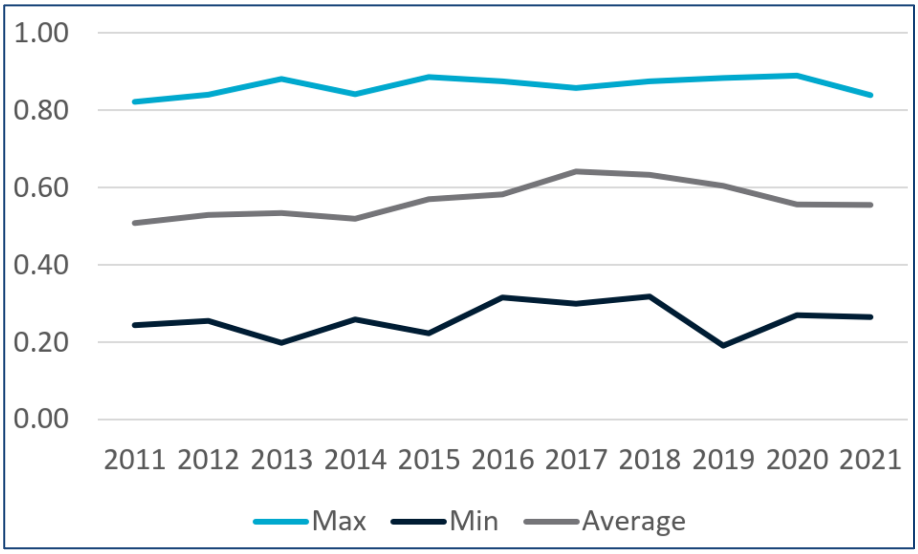


Figure 4.1: Capacity Factors for Black Coal (Source: GenCost 2022-23 Apx Figure D.3)

4.2 Discussion of Capacity Factors for Black Coal

Deriving the high and low capacity factors from historical data appears to be illogical, because new coal-fired plant would almost certainly be advanced ultra-supercritical power stations – not the previous technology of most of the existing fleet of coal-fired power stations.

Furthermore, using a minimum value that is *"10% below the average"* in GenCost 2024-25 does not conform with normal engineering practice. A more rational approach would be to use 95th and 5th percentile values, for the high and low values, respectively. These percentiles are used extensively in engineering analyses, indeed, 95th and 5th percentiles are presented in IRENA (2023) for renewable energy generators.

Notwithstanding the argument presented above, (and also not to change the original GenCost 2024-25 assumptions, which would complicate comparisons with onshore wind and large scale solar PV), it is recommended that the following GenCost 2024-25 high and low capacity factors be used in the LCOE calculations for black coal, (the average capacity factor is derived from the mean of the high and low values):

a. High capacity factor = 89%.
b. Average capacity factor = 71%.
c. Low capacity factor = 53%.

5 Output Degradation

5.1 Introduction

GenCost 2024-25 does not consider output degradation for the various forms electricity production – it only considers that initial output capacity of the generator by assuming that the generator will continuing operating at its initial capacity for its entire design life.

However, all forms of equipment suffer from a degradation thus reducing the efficiency and output. Therefore, the omission of output degradation is discussed in greater detail in this Section of the report.

Furthermore, regarding output degradation, Graham (2024), in personal correspondence, explains that [emphasis added], *"If we were **to accommodate** issues such as **degradation**, we would **need** to move to **cash flow analysis** which begins to lose transparency and would certainly **involve more than an Excel sheet** page. We accept that our process doesn't include degradation but we're happy with the trade-off in favour of higher transparency for now."*

Contrary to the above statement, it is suggested that output degradation can be accommodated very simply in a spreadsheet by using the final capacity factor and average capacity factor as presented in Equations (5.1) and (5.2) below:

$$final\_capacity\_factor = initial\_capacity\_factor \times (1 - degradation\_rate)^{design\_life} \quad (5.1)$$

$$average\_capacity\_factor = (capacity\_factor + final\_capacity\_factor)/2 \quad (5.2)$$

where:

initial_capacity_factor	= Capacity factor of the generator at the start of its of design life
degradation_rate	= Annual degradation rate of the generator
design_life	= Design life of the generator in years
final_capacity_factor	= Capacity factor at the end of the design life of the generator
average_capacity_factor	= Average capacity factor achieved over the generator's design life

Note that Equation (5.2) will slightly overestimate the average capacity factor when compared with calculating it by using more accurate methods. However, it is a simple arithmetical calculation and (for the low degradation rates of the generators discussed here) it is accurate to three significant figures, when compared with more accurate methods.

An example of the use of Equations (5.1) and (5.2) in a simple spreadsheet is presented later in this Section of the report.

5.2 Output Degradation in Onshore Wind

5.2.1 Discussion of Output Degradation in Onshore Wind

Table 4-1 of Aurecon (2024) presents a linear annual degradation of 0.1% p.a. for onshore wind. However, this value appears to be too low, as discussed below.

Staffell & Green (2014) state that modern wind turbines in the UK and Denmark exhibit an annual degradation in output of 1.6% ± 0.2%. This unrecoverable loss is attributed to gradual deterioration, such as fouling of the blades (which inhibits the aerodynamic performance) and a gradual reduction in component efficiencies (gearbox, bearings, and generator). Additionally, Staffell & Green (2014) state that these losses may not be recoverable by maintenance procedures, but only recoverable by component replacement. Furthermore, Hughes (2012) presents significantly worse degradation values than Staffell & Green (2014) for the UK, but similar values to Staffell & Green's (2014) UK values for Denmark.

Moreover, Staffell & Green (2014) state that [emphasis added], *"This level of degradation reduces a wind farm's output by 12% over a twenty year lifetime, increasing the levelised cost of electricity by*

*9%...This is **unlikely** to be large enough to **change the business case** for wind power, but nonetheless it **needs to be accounted for** to give an **accurate** picture of its **cost**."*

Notwithstanding the degradation rates presented by Staffell & Green (2014), inspection of the data for Australia in Lang (2025) presented in Figure 2.2 shows a considerably lower capacity factor degradation rate of 0.570% (this degradation rate is obtained from the linear trendline of the capacity factor data). It is not known why the degradation rate for Australia is significantly lower than that for the UK and Denmark. It may be that the Australian wind environment is more benign than that in Europe.

However, analysis of the recent data from 11-Dec-2022 to 02-Feb-2025 shows a higher degradation rate of 2.27% p.a. (see Figure 5.1). This higher degradation rate is counter-intuitive because it would be expected that the addition of newer wind turbines would lead to a reduction in the degradation rate.

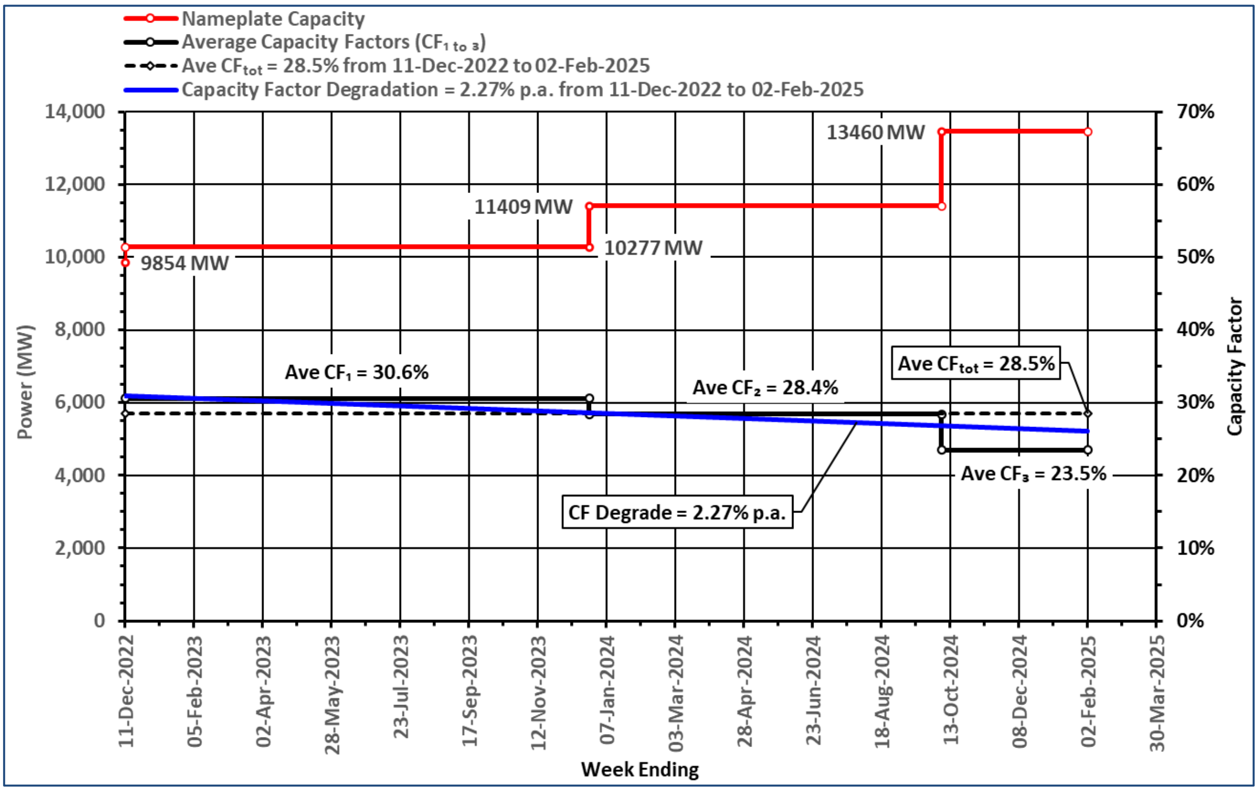


Figure 5.1: Nameplate Capacity compared with Capacity Factor (after Lang, 2025)

It is not known why the higher degradation rate exists after the addition of newer wind turbines, but this may be due to one or more of the following:

a. Newer wind farms being sited in less than ideal locations – the best wind sites having already been chosen by earlier projects.
b. Older wind turbines degrading at a significantly higher rate than the overall average, which would cancel out the (expected) better performance of newer turbines.
c. A reduction in wind speed, perhaps due to climate change.

Notwithstanding the higher degradation rate of 2.27% p.a. presented above, it is proposed that the 0.570% degradation rate shown in Figure 2.2 for the entire Lang (2025) data set be used as the average annual degradation rate in Australia – high and low degradation values are obtained from the 95th and 5th percentiles.

5.2.2 Conclusions & Recommendations from Output Degradation Onshore Wind

A degradation rate of 0.570% p.a. is not insignificant, and it would lead to the initial capacity factor of 29.8% in Figure 2.2 being reduced to 25.8% at the end of a 25-year design life. Consequently, it is concluded that this degradation rate should be included in the LCOE calculation for onshore wind.

Therefore, it is recommended that the following annual degradation rates be used in the GenCost 2024-25 LCOE calculations for onshore wind:

a. High degradation rate = 0.818% (i.e., the 95th percentile).
b. Average degradation rate = 0.570%
c. Low degradation rate = 0.374% (i.e., the 5th percentile).

5.3 Output Degradation in Large-Scale Solar PV

5.3.1 Discussion of Output Degradation in Large-Scale Solar PV

Table 4-10 of Aurecon (2024) presents an annual degradation of 0.4% p.a. for large-scale solar PV. Additionally, regarding the degradation rate of solar PV, AEC (2022) state that the *"Numbers vary from approximately 0.1 per cent to 1 per cent depending on the system. The Australian Energy Council has used 0.5 per cent as a constant degradation rate for all LCOE calculations."* However, these values appear to be too low when compared with the following literature.

Aboagye et al (2021), Daher et al (2023) and Sanchez et al (2021) present a wide range of degradation rates from large-scale solar PV. Their degradation values range from a low of 0.53% to a high of 1.67%, depending on the type of solar panel and the climate to which it is exposed. In particular, Dimish & Alrashidi (2020) found that the degradation rate for large-scale solar PV sites installed in Australia was in the range from 1.35% to 1.46% p.a.

Furthermore, Table 3 of Sanchez et al (2021) presents the following values for annual and total power degradation for different solar PV projects:

a. After 22 years in operation: Total degradation = 30.9%, with an annual degradation rate = 1.4%.
b. After 17 years in operation: Total degradation = 11.5%, with an annual degradation rate = 0.96%.
c. After 15 years in operation: Total degradation = 9.0%, with an annual degradation rate = 0.53%.

It is evident from the above, that the total power degradation of 30.9% is very significant for the high rate of 1.4% p.a. in item (a) above. Additionally, the total power degradation of 9.0% in item (c) for large-scale solar PV power output is not insignificant, even for the low degradation rate of 0.53% p.a.

5.3.2 Conclusions & Recommendations from Output Degradation Large-Scale Solar PV

It is concluded that the power degradation in large-scale solar PV power is significant, and from the foregoing, it would be reasonable to use a high degradation rate of 1.5% and a low degradation rate of 0.5%.

Therefore, it is recommended that the following annual degradation rates be used in the GenCost 2024-25 LCOE calculations for large-scale solar PV:

a. High degradation rate = 1.5%.
b. Average degradation rate = 1.0%.
c. Low degradation rate = 0.5%.

5.4 Output Degradation in Black Coal

5.4.1 Discussion of Output Degradation in Black Coal

Table 4-26 of Aurecon (2023) presents a zero annual degradation for advanced ultra-supercritical coal (AUSC). However, this value appears to be too low.

For example, Mott McDonald (2010) suggest a degradation in output from coal of 2.9% and Parson Brinckerhoff (2011) suggest a degradation of 5.5%, for an advanced super critical (ASC) coal plant with a design life of 45 years. These values equate to annual degradation rates of 0.132% and 0.258% and they will be used as the low and high degradations rates, respectively.

5.4.2 Conclusions & Recommendations from Output Degradation in Black Coal

From the foregoing, we can take the average degradation rate as the mean of the McDonald (2010) value of 0.132% and the Parson Brinckerhoff (2011) value of 0.258%, that is, the average degradation rate equals 0.195%.

Consequently, it is recommended that following annual degradation rates be used in the GenCost 2024-25 LCOE calculations for advanced ultra-supercritical (AUSC) coal:

a. High degradation rate = 0.258%.
b. Average degradation rate = 0.195%.
c. Low degradation rate = 0.132%.

5.5 Overall Conclusions from Output Degradation

5.5.1 Degradation Rates for Various Generators & Impact on LCOE

The incorporation of output degradation in a single spreadsheet for various generators is presented in Table 5.1, which shows the original GenCost 2024-25 data (in black) and the amended data (in blue), which includes output degradation as described earlier in Equations (5.1) and (5.2).

Power Plant	Original GenCost 2024-25 Data						GenCost 2024-25 Data Amended								
	Black Coal		Onshore Wind		Large-Scale Solar PV		Black Coal			Onshore Wind			Large-Scale Solar PV		
LCOE Parameters	Low	High	Low	High	Low	High	Low	Average	High	Low	Average	High	Low	Average	High
Design Life (y)	30	30	25	25	30	30	30	30	30	25	25	25	30	30	30
Construction Time (y)	2.0	2.0	1.0	1.0	0.5	0.5	2.0	2.0	2.0	1.0	1.0	1.0	0.5	0.5	0.5
Efficiency	42%	42%	100%	100%	100%	100%	42%	42%	42%	100%	100%	100%	100%	100%	100%
Discount Rate	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%
O&M Fixed ($/kW)	64.9	64.9	28.0	28.0	12.0	12.0	64.9	64.9	64.9	28.0	28.0	28.0	12.0	12.0	12.0
O&M Variable ($/MWh)	4.7	4.7	0.0	0.0	0.0	0.0	4.7	4.7	4.7	0.0	0.0	0.0	0.0	0.0	0.0
Initial Capacity Factor	89%	53%	48%	29%	32%	19%	89%	71%	53%	42.9%	29.8%	19.6%	29%	23%	19%
Degradation Rate p.a.							0.132%	0.195%	0.258%	0.374%	0.570%	0.818%	0.50%	1.00%	1.50%
Final Capacity Factor							85.5%	67.0%	49.0%	39.1%	25.8%	16.0%	25.0%	17.0%	12.1%
Average Capacity Factor							87.3%	69.0%	51.0%	41.0%	27.8%	17.8%	27.0%	20.0%	15.5%
CAPEX															
Capital ($/kW)	6037	6037	3223	3223	1463	1463	6037	6037	6037	3223	3223	3223	1463	1463	1463
Fuel ($/GJ)	3.1	4.6	0.0	0.0	0.0	0.0	3.1	3.85	4.6	0.0	0.0	0.0	0.0	0.0	0.0
LCOE Contribution															
Capital ($/MWh)	63	106	63	105	39	66	64	81	110	74	110	171	46	62	80
Fuel ($/MWh)	27	39	0	0	0	0	27	33	39	0	0	0	0	0	0
O&M ($/MWh)	13	19	7	11	4	7	13	16	20	8	12	20	5	8	11
LCOE ($/MWh)	**103**	**164**	**70**	**116**	**43**	**73**	**104**	**130**	**169**	**82**	**122**	**191**	**51**	**70**	**91**

Table 5.1: Example of including Output Degradation in a Single Spreadsheet

It is apparent from Table 5.1 that output degradation is highest for large-scale solar PV. It is also evident that the output degradation for onshore wind is approximately three times that for black coal. This is probably due to the coal generators being housed in a controlled environment, whereas onshore wind is exposed to the vagaries of the weather.

The initial capacity factors in Table 5.1 are derived from those presented earlier in this assessment, and the changes to the LCOE due to the amendments for output degradation shown in Table 5.1 are depicted in Figure 5.2.

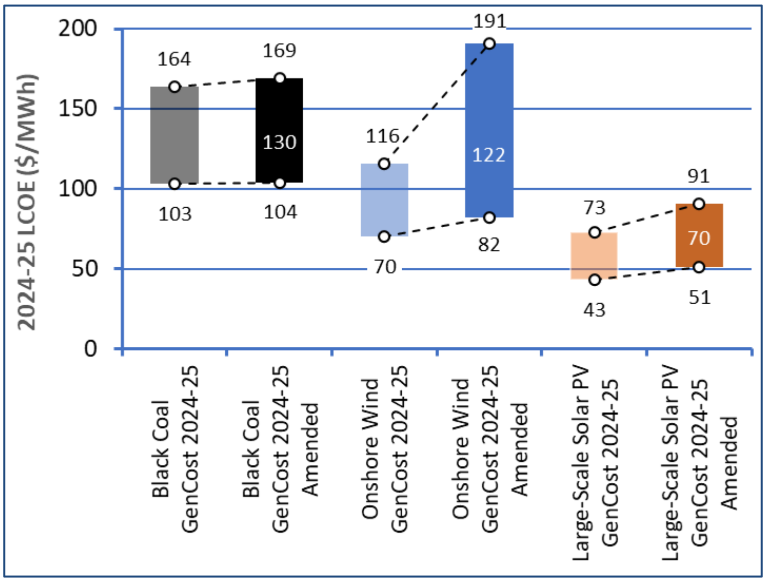


Figure 5.2: Changes to LCOE due to Amendments to Capacity Factor & Output Degradation

The following observations regarding the change in LCOE are evident from Table 5.1 and Figure 5.2:

a. The cost of black coal increases slightly (by approximately 1-3%).
b. The minimum cost of onshore wind increases by 17% from $70 to $82/MWh However, the maximum cost increases from $116 to $191/MWh, i.e., an increase of 64%.
c. The minimum cost of solar PV increases by 19% from $43 to $51/MWh However, the maximum cost increases from $73 to $91/MWh, i.e., an increase of 25%.

In summary, (even after the inclusion of output degradation) large-scale solar PV remains the lowest cost generator, with a mean cost of $70/MWh, compared with $122/MWh for onshore wind and $130/MWh for black coal, as shown in Figure 5.2.

However, it is apparent that (when output degradation is considered) there is a substantial overlap between the cost of onshore wind and that of black coal, and the following values are highlighted:

a. The minimum cost of black coal of $103/MWh exceeds the $82/MWh minimum cost of onshore wind by 27%.
b. The average cost of black coal of $130/MWh exceeds the average cost of onshore wind by 7%.
c. The maximum cost of onshore wind of $191/MWh exceeds the $169/MWh maximum cost of black coal by 13%.

6 Conclusions & Recommendations

A technical assessment of the assumptions of the capacity factors in used in GenCost 2024-25 to calculate the LCOE for onshore wind, large-scale solar PV and black coal is presented.

In addition to the high and low values for the LCOE parameters, it is recommended that GenCost 2024-25 should also present average values for the relevant parameters, because the average value is a useful parameter that can be used to estimate the probable cost over the lifetime of the generator. Note that the average value is not necessarily midway between the high and low value of LCOE, due to the non-linear interaction of the various LCOE parameters.

Additionally, a simple method of including output degradation in the LCOE calculation is presented, and it is recommended that output degradation be incorporated in GenCost 2024-25, since output degradation has a significant impact on the LCOE over the lifetime of the generator.

Tables 6.1 and 6.2 show the recommended values for capacity factor and output degradation and it is recommended that they be used in GenCost 2024-25.

Type of Generation	High Capacity Factor	Average Capacity Factor	Low Capacity Factor
Onshore Wind	42.8%	29.8%	19.6%
Large-Scale Solar PV	29%	23%	19%
Black Coal	89%	71%	53%

Table 6.1: Recommended Capacity Factors for Onshore Wind, Large-Scale Solar PV & Black Coal

Type of Generation	High Output Degradation p.a.	Average Output Degradation p.a.	Low Output Degradation p.a.
Onshore Wind	0.818%	0.570%	0.374%
Large-Scale Solar PV	1.5%	1.0%	0.5%
Black Coal	0.258%	0.195%	0.132%

Table 6.2: Recommended Output Degradation for Onshore Wind, Large-Scale Solar PV & Black Coal

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