

NEM Wholesale Market ModellingProductivity Commission

12 December 2025



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Introduction



Report objective:

Aurora Energy Research (Aurora) has been engaged by the Productivity Commission (the Client) to conduct high-level analysis and power market modelling for the National Electricity Market (NEM).

Aurora has modelled multiple scenarios, to assess how key assumptions impact the NEM's energy transition, including wholesale electricity prices and power sector emissions.

It is also important to note that while wholesale electricity prices play a key role in the total cost to consumers, other factors such as network costs and government subsidies also impact the final price. Aurora's report has only considered wholesale market impacts in our analysis and in this report.

Wholesale modelling methodology:

Aurora's NEM power market model (AER-ES AUS) forecasts wholesale prices based on the fundamentals of supply and demand in the market. As an equilibrium model, it does not produce the very high peaks in wholesale prices (>\$1,000/MWh) that periodically arise in the NEM. To capture the impact of these very high price peaks, the modelling follows a two-step process:

- Firstly, Aurora's AER-ES AUS model is run to produce a forecast of **fundamental price volatility** over the modelling horizon.
- Secondly, AER-ES AUS is re-run and enabled to produce extreme price events (above \$1,000/MWh or below -\$100/MWh) using statistical methods and drawing on historical levels of peak price volatility. This produces a price forecast including extreme price volatility.

All price forecasts produced by Aurora are prepared inclusive of this approach to peak price volatility.

Market scenario:

Aurora has prepared market projections using our in-house power market model AER-ES AUS. Modelling has been conducted across 3 scenarios, as described below.

- Scenario 1 "Base Case", which is largely aligned with 2024 AEMO ISP Step Change scenario assumptions, where state renewable energy targets are assumed to be met.
- Scenario 2, which is aligned against Scenario 1 with the exception of Victoria's offshore wind targets. All other renewable energy targets are still met.
- Scenario 3, which considers a NEM-wide renewable energy target in place of state targets, but achieving the same renewable share of generation as Scenarios 1 and 2 throughout the modelling period. No offshore wind is assumed.

Report outputs:

This report shows outputs at a yearly granularity. The accompanying databook includes price outputs at yearly granularity. Technology capacity and generation outputs are in yearly only.

All prices in this report are shown in real \$2023 values.

All years in this report are in financial years, beginning 1st July and ending 30th June.

Source: Aurora Energy Research

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Scenario 1, the "Base Case," ensures that states meet their renewable and generation $A \cup R \supseteq R A$ targets, aligning closely with the 2024 AEMO ISP Step Change scenario

The Base Case is largely aligned with the 2024 AEMO Step Change Optimal Development Pathway (ODP), forcing the achievement of state targets - this includes Victoria's legislated offshore wind energy targets of 9GW by 2040, the meeting of NSW's Electricity Infrastructure Roadmap and Tasmania's TRET.

		Scenario 1 (Base Case) assumptions			
Federal schemes		 CIS: no requirement to meet full target by 2030. Retention of the LRET in its current form until 2030. No green certificate value post-2030. 			
Policy	State schemes	 NSW: EIR¹ met; 12GW renewable generation, and at least 2GW long-duration storage by 2030. QLD: No requirement to meet QRET. VIC: Pre-2022 VRET assumed to be met. VRET1 and VRET2 auction capacities included, 9GW offshore wind by 2041. Updated VRET met (65% by 2030, 95% by 2035). Victorian Energy Storage Target met. TAS: TRET² met. 			
	Underlying demand	AEMO 2024 ISP Step Change scenario underlying demand.			
Demand	Rooftop solar, behind-the-meter batteries & EVs	 AEMO 2024 ISP Step Change scenario rooftop solar, BTM batteries and EV uptake. 			
Commodity prices	Gas prices	 Aurora in-house global commodity price modelling - LNG netback prices, refer to Forecast Modelling Inputs. 			
Commodity prices Coal prices		 Aurora in-house global commodity price modelling – coal export price for uncontracted, non-mine-linked coal plants, refer to Forecast Modelling Inputs. 			
	Coal closures	• AEMO's latest (Jan 2025) announced closure timeline with the exception of Callide B (closing at end of FY2026), Millmerran and Callide C (both closing at end of FY2049), Stanwell (closing at end of FY2032), Kogan Creek (closing at end of FY2035), Tarong and Tarong North (both closing at end of FY2033), Loy Yang A & B (both closing at the end of FY2034); refer to Forecast Modelling Inputs. Closure dates may differ from AEMO due to modelled plant economics suggesting earlier retirement or new policy/announcements that are not yet reflected in AEMO's timeline.			
Supply	CAPEX	As per AEMO 2024 ISP Step Change scenario.			
	WACC	 For Solar and Wind assume merchant WACC of 9.5%. For BESS and Gas assume merchant WACC of 11.5%. 			
	New Hydro	 Kidston from 2025, Snowy 2.0 included from December 2028 and Borumba from September 2031 (Pioneer-Burdekin not included). 			
	Inter-regional	AEMO 2024 ISP Step Change Optimal Development Path: EnergyConnect, QNI & VNI upgrades, QNI Connect, VNI-West and Marinus Link Stage 1 and 2,			
Network augmentation	Intra-regional	 AEMO 2024 ISP Step Change Optimal Development Path, including Central-West Orana, New England and Western Renewables Link + Queensland Energy and Jobs Plan SuperGrid, Gladstone Grid Reinforcement, Mid-North South Australia REZ Expansion, Sydney Ring North & South Upgrades 			
Marginal Loss Factors	Endogeneity	 Asset specific MLFs incorporated into short-run marginal costs and therefore bidding behaviour. MLFs modelled endogenously by Renewable Energy Zone (REZ) ensuring capacity buildout and DWA prices reflect the premium required to bring on new investment. Current grid limits and robustness of MLFs factored into model build decisions. 			
		 Purpose-built uplift function - capturing the deltas between price and the short-run marginal cost of the system, based on historical behaviour. Incorporates time-of-day/week, scarcity margin, technology, bidding behaviour etc. 			
Weather Year		Modelled using 2016 weather year			

¹⁾ Electricity Infrastructure Roadmap. Total program includes 12GW renewables, 2GW long duration storage by 2030 2) 16TWh renewable generation by 2030, 21TWh renewable generation by 2040.

Source: Aurora Energy Research

Alternate Scenarios 2 and 3 have been designed to test the impact of removing offshore wind and replacing state targets with a NEM-wide renewable energy target



Model input sensitivities are varied across scenarios and compared against the Base Case to test the impact on National Electricity Market (NEM) capacity and generation mix, wholesale electricity market prices, power sector operating expenditure, capital expenditure and emissions.

As per Scenario 1	unless otherwise stated	Scenario 2 – Base Case without offshore wind	Scenario 3 – NEM-wide Targets
Policy	Federal schemes		A NEM-wide renewable energy target objective equivalent to the achieved renewable penetration in Scenarios 1 is assumed to be met in 2030, 2035 and 2040.
	State schemes		No requirement to meet state targets.
	Underlying demand		
Demand	Rooftop solar, behind-the- meter batteries & EVs		
Commodity	Gas prices		
Commodity prices	Coal prices		
	Coal closures		
Supply	CAPEX		
	WACC		
	Offshore wind	No requirement to build offshore wind in line with Victoria's targets.	No requirement to build offshore wind in line with Victoria's targets.
Network augmentation	Inter-regional		
Network augmentation	Intra-regional		
Marginal Loss Factors	Endogeneity		
Bidding behaviour	Scarcity pricing / Uplift		
Weather Year			

Source: Aurora Energy Research 6

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I. Wholesale market modelling overview

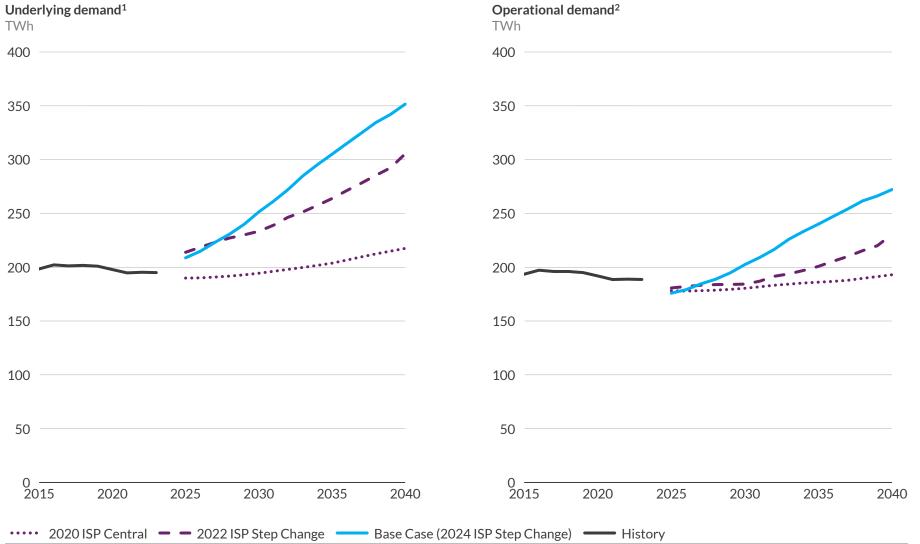
II. Forecast Modelling Inputs

II.1. Scenario 1 - Base Case Assumptions

III. Forecast Modelling – Scenarios

IV. Appendix

The Base Case adopts the AEMO 2024 ISP Step Change demand scenario trajectory



Comparison of demand forecasts

- AEMO has significantly revised its demand forecast upwards since the 2020 ISP.
- AEMO's 2024 ISP Step Change scenario underlying demand forecasts ~430TWh by 2050 to achieve economy-wide net zero and carbon budgets.
- The Step Change scenario's demand outlook is driven by electric vehicle uptake, hydrogen production and electrification of industry to achieve net-zero ambitions.

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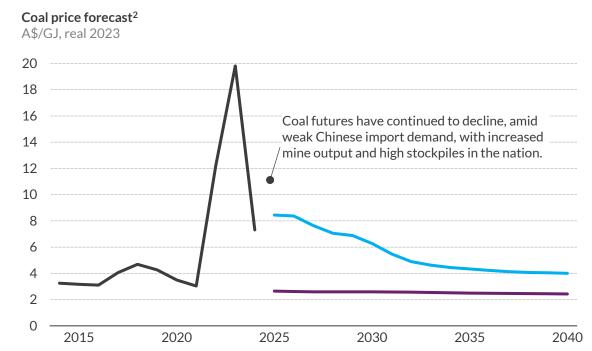
¹⁾ Underlying demand includes commercial and residential demand and EV demand; 2) Operational demand is underlying demand net of rooftop solar and BTM battery generation

Aurora expects gas prices to rise once the Federal Government's commodity price cap expires, though this could be impacted by further policy developments





- Aurora's domestic gas price forecast represents prices at Wallumbilla and is based on the netback price to Aurora's JKM (Japanese LNG) price.
- The Federal Government's cap of \$12/GJ on new gas contracts expired in July 2025. Aurora has not included an extension to the gas cap in our forecasts, although we note that the new Gas Price Code sets \$12/GJ as a "reasonable" gas price, which is not a strict market cap, and can be reviewed by the ACCC in future.

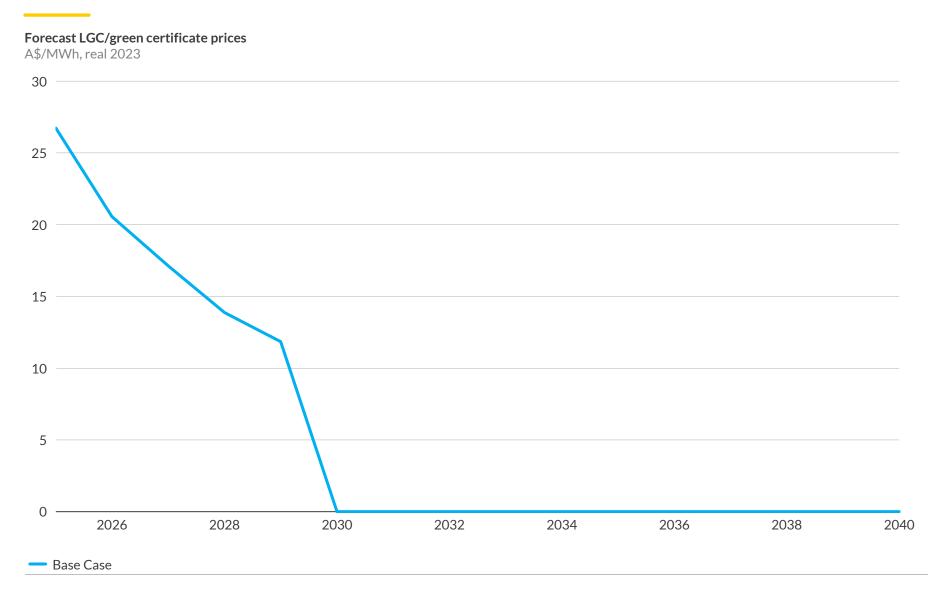


- Aurora's Newcastle coal price forecast is linked to Aurora's forecast for the global export value of coal. Plant-specific coal prices are used in combination with the export price to best reflect contract positions and mine-linked behaviour.
- The 4% decline observed in coal prices reflect Newcastle coal futures, which are down due to weak import demand from China, reflecting increased mine output and high stockpiles in the nation.



¹⁾ The LNG netback price averaged ~\$44/GJ between January 2022 to September 2022. 2) Australian thermal coal prices averaged ~\$21/GJ between July to January 2022. 3) 2024 ISP average QLD gas price 4) 2024 ISP average NSW coal price

Forecast LGC prices follow the futures curve to 2030, however no value is attributed to green certificates after this date





Forecast green certificate value

- In Aurora's modelling, the LGC price inputs are based on current futures prices.
- The Core Case adopts Aurora's methodology in the near term to 2030 but does not assume any post 2030 green certificate value in the absence of a legislated REGO certificate design.

The Base Case coal closure schedule largely aligns with expected closure dates closures, while privately-owned assets are closed no later than their announced date



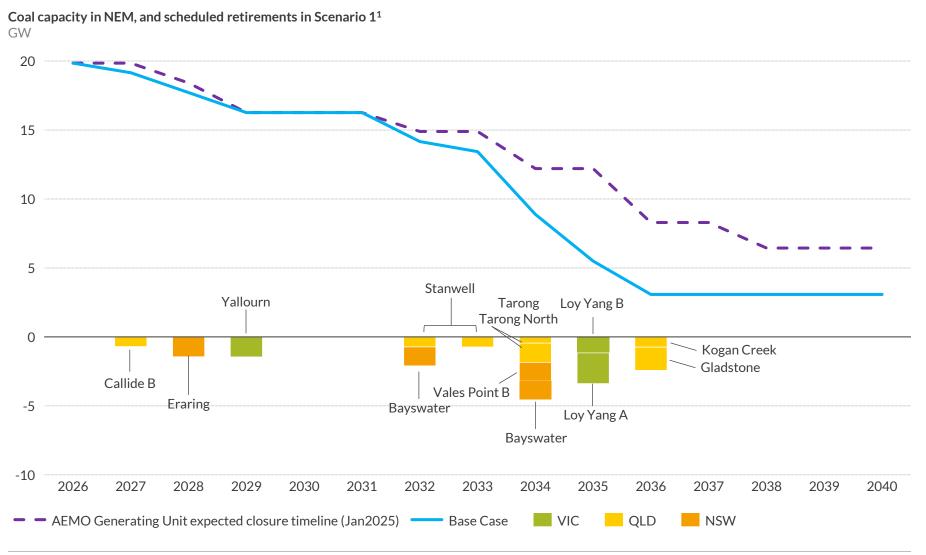
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Coal Plants	State	Capacity MW	Base Case closure timeline ¹	AEMO's expected closure timeline ²	AEMO's 2024 ISP Step Change closure timeline ³	Queensland Energy Roadmap
Bayswater	NSW	2740	2034	2034	2032	
Eraring ⁴	NSW	2880	2028	2028	2026	[*] Note: QLD Energy Roadmap leaves the retirement decisions for Callide C,
Liddell	NSW	1800	2024	2024	2024	Gladstone, and Millmerran up to the owners. Gladstone's owners have announced a retirement date as early as FY2030.
Vales Point B	NSW	1320	2034	2034	2029	
Mt Piper	NSW	1380	2041	2041	2038	451 12000.
Callide B	QLD	700	2027	2029	2028	2032
Callide C	QLD	840	20505	-	2034	2050*
Gladstone	QLD	1680	2036	2036	2032	2030*
Kogan Creek	QLD	744	20366	2043	2035	2043
Millmerran	QLD	852	2050	2052	2035	2052*
Stanwell	QLD	1460	20336	2047	2033	2044-2047
Tarong	QLD	1400	20346	2038	2034	2037-2038
Tarong North	QLD	450	20346	2038	2034	2038
Loy Yang A	VIC	2225	2035	2036	2034	
Loy Yang B	VIC	1140	2035	2048	2032	
Yallourn	VIC	1450	2029	2029	2029	

Variation to AEMO's expected closure timings

¹⁾ All years listed are the first financial year without generating capacity. 2) Timeline extracted from AEMO's *Generating unit expected closure year* – *January* 2025 3) Refers to year when final unit is decommissioned 4) The announcement on the extension of Eraring's operation to August 2027 has not been reflected in AEMO's ISP modelling, but AEMO's expected closure timeline has been updated.5) Assuming a ~50year life span in lieu of announced closure dates 6) Based on the QEJP timeline Sources: Aurora Energy Research, AEMO

The Base Case coal closure timeline largely follows the AEMO Generating Unit Expected Closure Year timeline with a few exceptions



Coal closure timings - Base Case vs AEMO

- AEMO's latest (Jan 2025) announced closure timeline with the exception of Callide B (closing at end of FY2026), Millmerran and Callide C (both closing at end of FY2049), Stanwell (closing at end of FY2032), Kogan Creek (closing at end of FY2035), Tarong and Tarong North (both closing at end of FY2033), Loy Yang A & B (both closing at end of FY2034).
- Closure dates may differ from AEMO due to modelled plant economics suggesting earlier retirement or new policy/announcements that are not yet reflected in AFMO's timeline.

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¹⁾ Line chart represents end-of-financial-year capacity

Interconnector assumptions in the Base Case are consistent with AEMO's 2024 ISP Optimal Development Path



nterconnector assumptions $\forall \forall \forall$			Interconnectors	Capacity, MW, Forward/reverse	Timing in Base Case
			1 QNI	460/10782	
NT			2 VNI	1420/1595 ³	
	OLD		3 Heywood	500/6004	
	QLD	ting	4 Terranora	50/180 ⁵	
		Existing	5 Basslink	594/4786	
	(E) (1) (4) ~~		6 Murraylink	200/2207	
SA			7 VNI SIPS	-/250	
3)	A		Total Existing	4022/3038	
	NSW				
	6 C 2 B		A EnergyConnect	800/800	2028
	B (C) (Z) (D)		B EnergyConnect	100/100	2028
Fairting	3 VIC	peg	C VNI West	1935/1670	2030 ²
Existing 2020s	(5)	Proposed	D Marinus Link (Stage 1) ¹	750/750	2031
2030s	DGF	P	E QNI Connect	1260/1700	2034
2000	TAS		F Marinus Link (Stage 2)	750/750	2038
			Total Proposed	5430/5655	

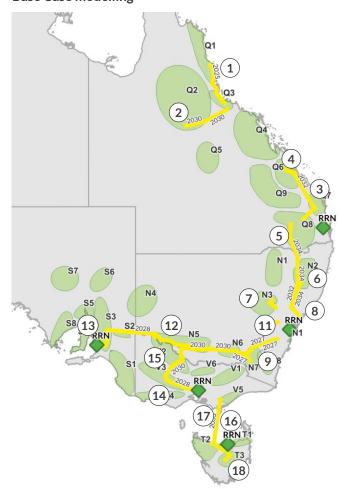
Base Case interconnector assumptions

 The Base Case assumptions around interconnector augmentations are aligned with AEMO's 2024 ISP Optimal Development Path (ODP).

¹⁾ Funding of the project has been recently renegotiated between the Commonwealth and state governments for only Stage 1 of the project 2) The NSW-QLD export capacity is dependent on the status of Kogan Creek and other large Queensland generators; 3) The nominal capacity of this interconnector is highly dependent on the output of Murray generators (NSW to VIC) and Lower/Upper Tumut (VIC to NSW). There is also an additional 250MW of capacity from NSW to VIC due to the capability of the new Neoen SIPS battery, as stated in The Victorian Big Battery: Fact sheet; 4) Forward direction is VIC to SA; 5) Forward direction is QLD to NSW; 6) Forward direction is TAS to VIC; 7) Forward direction is VIC to SA Sources: Aurora Energy Research, AEMO

The Base Case is aligned with the 2024 ISP ODP on all Committed, Anticipated and Actionable projects

Committed, Anticipated and Actionable projects included in the Base Case modelling



	Committed, Anticipated and Actionable Projects ¹	Assumed commissioning date
1	Far North Queensland REZ	2025
2	QEJP Stage 4 - Copperstring 2032	2030
3	QEJP Stage 2 - SuperGrid South	2032
4	Gladstone Grid Reinforcement	2031
5	QNI Connect	2035
6	New England REZ Network Infrastructure Project Stages 1,2,3	2029, 2035
7	Central-West Orana REZ Network infrastructure Project	2029
8	Sydney Ring North	2029
9	HumeLink	2030
10	Hunter-Central Coast REZ Network Infrastructure Project ²	2031
11	Sydney Ring South	2030
12	Project EnergyConnect	2028
13	Mid North South Australia REZ Expansion – Option 1	2030
14	Western Renewables Link	2028
15	VNI West	2030
16	Project Marinus– Stage 1	2031
17	Project Marinus – Stage 2	2038
18	Waddamana to Palmerston transfer capability upgrade	2030



Base Case 2024 ISP implementation

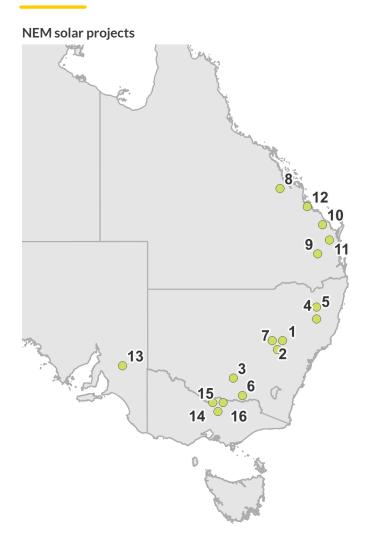
 The Base Case implements the Optimal Development Path Step Change timings for all Committed, Anticipated and Actionable projects.

Source: AEMO 14

¹⁾ All network augmentations listed as Committed, Anticipated or Actionable in the 2024 ISP. 2) Hunter-Central Coast REZ NIP consists of a new switching station and no new lines, so is not displayed on the map.

Near-term solar projects included in Base Case [1/2]





	Project Name	State	Capacity [MW] ¹	Expected Commissioning Date	Status ²
1	Stubbo Solar Farm	NSW	400	2025	Committed
2	Wellington North Solar Farm	NSW	330	2025	Commissioning
3	Yanco Solar Farm	NSW	60	2025	Publicly announced
4	New England Solar Farm Stage 2	NSW	320	2026	Construction
5	Tilbuster Solar Farm	NSW	152	2026	Committed
6	Culcairn Solar Farm	NSW	350	2027	Committed
7	Maryvale Solar Farm	NSW	172	2027	LTESA4
8	Ganymirra Solar Power Station	NSW	60	2027	CIS
9	Goulburn River Solar Farm	NSW	450	2029	CIS
10	Sandy Creek Solar Farm	NSW	700	2030	CIS
11	Broadsound Solar Farm	QLD	368	2025	Committed
12	Kingaroy Solar Farm	QLD	40	2025	Commissioning
13	Bundaberg Solar Farm	QLD	78	2026	Committed
14	Munna Creek Solar Farm	QLD	154	2026	Committed
15	Aldoga Solar Farm	QLD	380	2027	Construction
16	Hopeland Solar Farm	QLD	250	2027	CIS
17	Ganymirra Solar Power Station	QLD	150	2028	CIS
18	Majors Creek Solar Power Station	QLD	150	2028	CIS

¹⁾ Capacity is measured in AC capacity; 2) Per AEMO's October 2024 Generation Information page, along with project announcements before 12 December. Where a PPA has been agreed for a portion of a future plant or a project has received state backing via a land agreement (SLA), Aurora has included this capacity in the Central scenario, but not the full project. This is shown as either *PPA Agreed* or *SLA*Sources: Aurora Energy Research, AEMO

Near-term solar projects included in Base Case [1/2]



	Project Name	State	Capacity [MW] ¹	Expected Commissioning Date	Status ²
1	Stubbo Solar Farm	NSW	400	2025	Committed
2	Wellington North Solar Farm	NSW	330	2025	Commissioning
3	Yanco Solar Farm	NSW	60	2025	Publicly announced
4	New England Solar Farm Stage 2	NSW	320	2026	Construction
5	Tilbuster Solar Farm	NSW	152	2026	Committed
6	Culcairn Solar Farm	NSW	350	2027	Committed
7	Maryvale Solar Farm	NSW	172	2027	LTESA4
8	Glanmire Solar Farm	NSW	60	2027	CIS Tender 1
9	Goulburn River Solar Farm	NSW	450	2029	CIS Tender 1
10	Sandy Creek Solar Farm	NSW	700	2030	CIS Tender 1
11	Broadsound Solar Farm	QLD	368	2025	Committed
12	Kingaroy Solar Farm	QLD	40	2025	Commissioning
13	Bundaberg Solar Farm	QLD	78	2026	Committed
14	Munna Creek Solar Farm	QLD	154	2026	Committed
15	Aldoga Solar Farm	QLD	380	2027	Construction
16	Hopeland Solar Farm	QLD	250	2027	CIS Tender 1
17	Ganymirra Solar Power Station	QLD	150	2028	CIS Tender 1
18	Majors Creek Solar Power Station	QLD	150	2028	CIS Tender 1

¹⁾ Capacity is measured in AC capacity; 2) Per AEMO's October 2024 Generation Information page, along with project announcements before 12 December. Where a PPA has been agreed for a portion of a future plant or a project has received state backing via a land agreement (SLA), Aurora has included this capacity in the Central scenario, but not the full project. This is shown as either PPA Agreed or SLA

Sources: Aurora Energy Research, AEMO

Near-term solar projects included in the Base Case [2/2]



	Project Name	State	Capacity [MW] ¹	Expected Commissioning Date	Status ²
19	Solar River Solar Farm	SA	230	2026	CIS funding
20	Girgarre Solar Farm	VIC	76	2025	Committed
21	Wunghnu Solar Farm	VIC	75	2025	Construction
22	Derby Solar Farm	VIC	95	2025	Anticipated
23	Fulham Solar Farm	VIC	80	2025	Publicly announced
24	Kiamal Solar Farm – Stage 2	VIC	150	2025	Publicly announced
25	Fraser Solar Farm	VIC	77	2025	Anticipated
26	Horsham Solar Farm	VIC	119	2025	Anticipated
27	Mokoan Solar Farm	VIC	46	2025	CIS Tender 1
28	West Mokoan Solar Farm (Hybrid)	VIC	300	2026	CIS Tender 1
29	Goorambat East Solar Farm	VIC	250	2027	Committed
30	Campbells Forest Solar Farm	VIC	205	2027	CIS Tender 1
31	Barwon Solar Farm	VIC	250	2028	CIS Tender 1
32	Barnawartha Solar Farm	VIC	64	2028	CIS Tender 1
33	Elaine Solar Farm	VIC	125	2030	CIS Tender 1

¹⁾ Capacity is measured in AC capacity; 2) Per AEMO's October 2024 Generation Information page, along with project announcements before 12 December. Where a PPA has been agreed for a portion of a future plant or a project has received state backing via a land agreement (SLA), Aurora has included this capacity in the Central scenario, but not the full project. This is shown as either PPA Agreed or SLA Sources: Aurora Energy Research, AEMO

Near-term wind projects included in the Base Case



	Project Name	State	Capacity [MW] ¹	Expected Commissioning Date	Status ²
1	Rye Park Wind Farm	NSW	384	2025	Commissioning
2	Coppabella Wind Farm	NSW	270	2027	LTESA1
3	Uungula Wind Farm	NSW	400	2027	Construction
4	Thunderbolt Wind Farm	NSW	230	2027	CIS Tender 1
5	Junction River Wind Farm	NSW	585	2028	CIS Tender 1
6	Spicers Creek Wind Farm	NSW	700	2030	CIS Tender 1
7	Valley of the Winds	NSW	936	2031	CIS Tender 1
8	Clarke Creek Wind Farm	QLD	450	2025	Committed
9	Macintyre Wind Farm	QLD	923	2025	Committed
10	Wambo Wind Farm Stage 1	QLD	500	2025	Committed
11	Forest Wind Farm	QLD	600	2026	Committed
12	Boulder Creek Wind Farm	QLD	228	2027	Committed
13	Lotus Creek Wind Farm	QLD	285	2028	Committed
14	Palmer Wind Farm	SA	274	2028	CIS Tender 1
15	Goyder North Renewable Energy Facility	SA	300	2030	CIS Tender 1
16	Golden Plains Wind Farm Stage 1	VIC	756	2026	Construction
17	Golden Plains Wind Farm Stage 2	VIC	574	2028	Construction
18	Kentbruck Green Power Hub	VIC	600	2029	CIS Tender 1

¹⁾ Capacity is measured in AC capacity; 2) Per AEMO's October 2024 Generation Information page, along with project announcements before 12 December. Where a PPA has been agreed for a portion of a future plant or a project has received state backing via a land agreement (SLA), Aurora has included this capacity in the Central scenario, but not the full project. This is shown as either *PPA Agreed* or *SLA*Sources: Aurora Energy Research, AEMO

Future battery assets included in the Base Case [1/2]



	Project Name	Region	Nameplate Capacity [MW/MWh]	Expected Commissioning Date ¹	Status
1	Eraring Big Battery stage 1	NSW	460/1073	2026	Commissioning
2	Limondale	NSW	50/400	2026	LTESA1 recipient
3	New England	NSW	150/150	2026	Construction
4	Smithfield	NSW	65/130	2026	LTESA2 recipient
5	Maryvale	NSW	186/372	2026	Publicly announced
6	Orana	NSW	415/1660	2027	LTESA2 recipient
7	Williamsdale	NSW	250/500	2027	Construction
8	Eraring Big Battery stage 2	NSW	240/1030	2027	Publicly announced
9	Liddell	NSW	500/1000	2027	LTESA2 recipient ²
10	Richmond Valley	NSW	275/2200	2027	LTESA3 recipient
11	Stoney Creek	NSW	125/1000	2027	LTESA4 recipient
12	Glanmire	NSW	60/104	2027	CIS Tender 1 recipient
13	Goulburn River	NSW	49/392	2028	LTESA3 recipient
14	Silver City Energy Storage Project	NSW	200/1600	2028	LTESA3 recipient ²
15	Griffith	NSW	100/800	2028	LTESA4 recipient
16	Junction River	NSW	200/800	2028	CIS Tender 1 recipient
17	Greenbank	QLD	200/400	2025	Construction
18	Tarong	QLD	300/600	2025	Committed
19	Western Downs	QLD	200/540	2025	Committed
20	Brendale	QLD	205/410	2026	Commissioning
21	Swanbank	QLD	250/500	2026	Commissioning
22	Ulinda	QLD	155/300	2026	Commissioning
23	Supernode	QLD	250/500	2026	Committed
24	Broadsound	QLD	180/360	2026	Construction
25	Ganymirra	QLD	150/600	2028	CIS Tender 1 recipient
26	Majors Creek	QLD	150/600	2028	CIS Tender 1 recipient

¹⁾ Expected commissioning date based on AEMO's October 2024 Generation Information database; 2) Project has also been granted funding from ARENA; 3) only inclusive of batteries above or equal to 45 MW.

Future battery assets included in the Base Case [2/2]



	Project Name	Region	Nameplate Capacity [MW/MWh]	Expected Commissioning Date ¹	Status
27	Koorangie	VIC	185/370	2025	Construction
28	Rangebank	VIC	200/400	2025	Committed
29	Melbourne Renewable Energy Hub	VIC	600/1600	2026	Construction
30	Mortlake	VIC	300/600	2026	Construction
31	West Mokoan	VIC	300/560	2026	CIS Tender 1 winner
32	Springvale Energy Hub	VIC	115/230	2027	CIS SA-VIC winner
33	La Trobe Valley	VIC	100/200	2027	Committed
34	Wooreen Energy Storage System	VIC	350/1400	2028	CIS SA-VIC winner
35	Barwon	VIC	250/500	2028	CIS Tender 1 winner
36	Barnawartha Energy Storage System	VIC	64/148	2028	CIS Tender 1 winner
37	Elaine	VIC	125/250	2030	CIS Tender 1 winner
38	Blyth	SA	200/400	2025	Construction
39	Templers	SA	111/290	2026	Construction
40	Clements Gap	SA	60/143	2026	CIS SA-VIC winner
41	Hallett	SA	50/200	2026	CIS SA-VIC winner
42	Mannum	SA	100/200	2026	Publicly Announced
43	Solar River	SA	170/653	2026	CIS SA-VIC winner
44	Bungama	SA	200/400	2026	Publicly Announced
45	Limestone Coast West	SA	250/1000	2027	CIS SA-VIC winner

¹⁾ Expected commissioning date based on AEMO's October 2024 Generation Information database; 2) Project has also been granted funding from ARENA; 3) only inclusive of batteries above or equal to 45 MW.

2,000

1,500

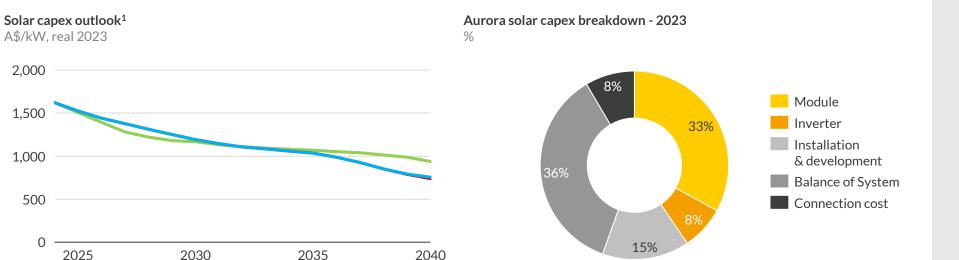
1,000

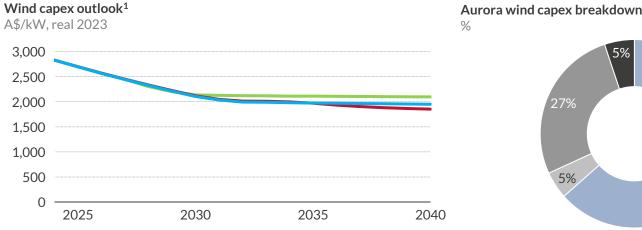
500

2025

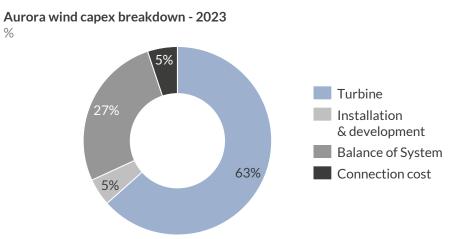
Utility-scale solar PV and Wind capex forecast and cost breakdown







— Base Case [CSIRO Gen Cost 2024 (NZE post 2050)] — CSIRO Gen Cost 2024 (Current Policies) — CSIRO Gen Cost 2024 (NZE by 2050)



Solar and wind capex forecast have been buoyed in the short term by supply chain issues. Longer term trends are driven by:

Solar

- Future cost reductions are expected to be achieved through the increase in module efficiency, which is likely to reach 30% by 2050
- This impacts CAPEX and OPEX through:
 - Less land area required
 - Fewer modules to install
 - Less weight to transport

Wind

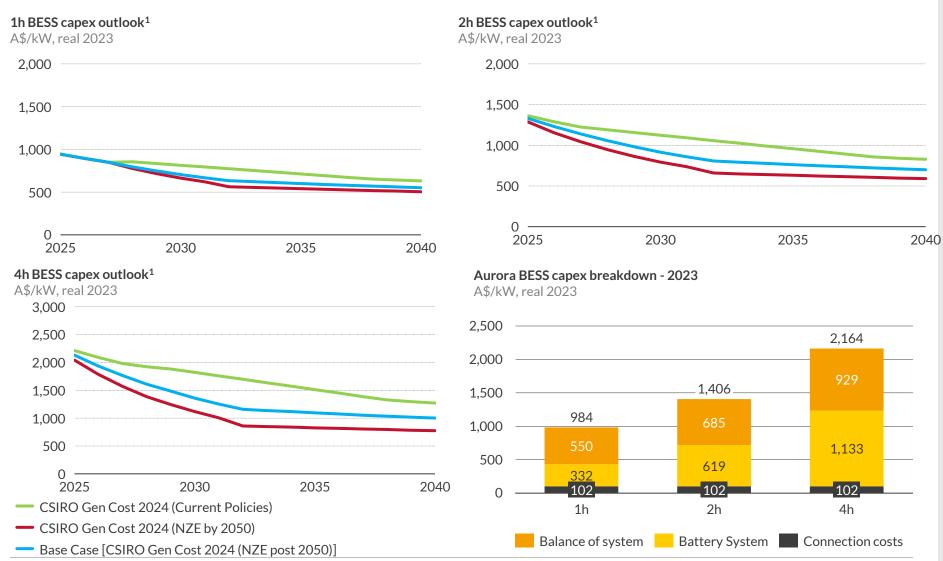
- Cost reductions are achieved from:
 - CAPEX: improved rotor design, standardisation and reduced project contingencies
 - Fixed OPEX: improvements from holistic approach to asset management and improved component manufacturing

1) Capex forecast charts excludes connection costs

21 Source: CSIRO, AEMO, Aurora Energy Research

BESS capex forecast and cost breakdown





Battery storage capex forecast

- The Base Case adopts CSIRO's Gen Cost 2024 NZE post-2050 capex scenario, also used in AEMO's 2024 ISP Step Change scenario.
- Battery costs are forecast to fall as the supply chains improve and technology learning rates reduce manufacturing costs.

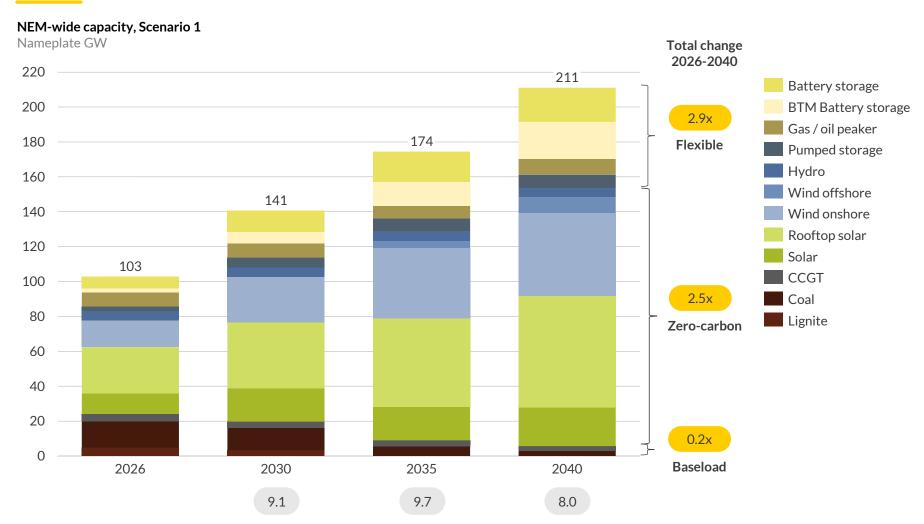
1) Capex forecast charts exclude connection costs

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The NEM is expected to become increasingly dominated by renewable and flexible technologies under the Base Case



Total 5-year CapEx for new-build utility-scale solar, wind and battery, real \$A2023 bn¹

AUR 😂 RA

Scenario 1 capacity expansion

- Renewable capacity grows throughout the forecast, with solar (utility & rooftop) and wind (onshore & offshore) attributing to around 67% of all capacity in the NEM by 2040.
- Coal capacity retirements accelerate from the late 2020s as costs increase with end-of-life issues and greater required ramping.
- Increased buildout of battery and storage assets stem from the rise in uptake of rooftop and utility solar, as the energy can be utilised during periods of peak demand.
- CapEx for new-build renewable and storage assets reduce in the long-term due to slower renewable buildout as state targets are met, along with cheaper technology prices.

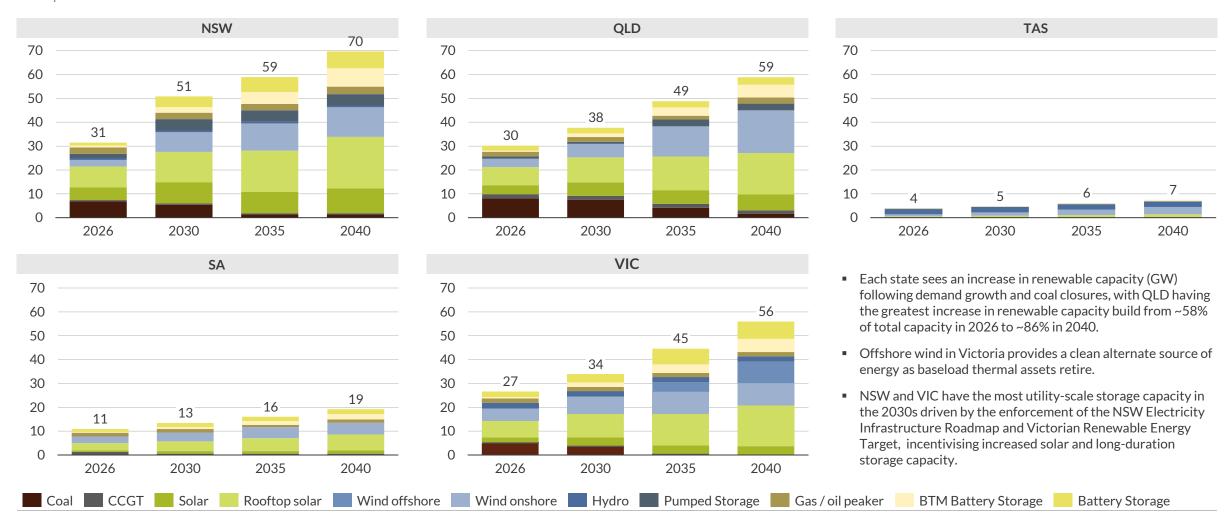
¹⁾ Each CapEx figure is inclusive of the preceding 5-year period i.e. FY26-30 CapEx provided in FY30, calculated using 2023 AEMO IASR CapEx assumptions – see Forecast Modelling Inputs for details

All mainland states see a rise in solar, wind and flexible capacity, while baseload thermal capacity declines

AUR 😂 RA

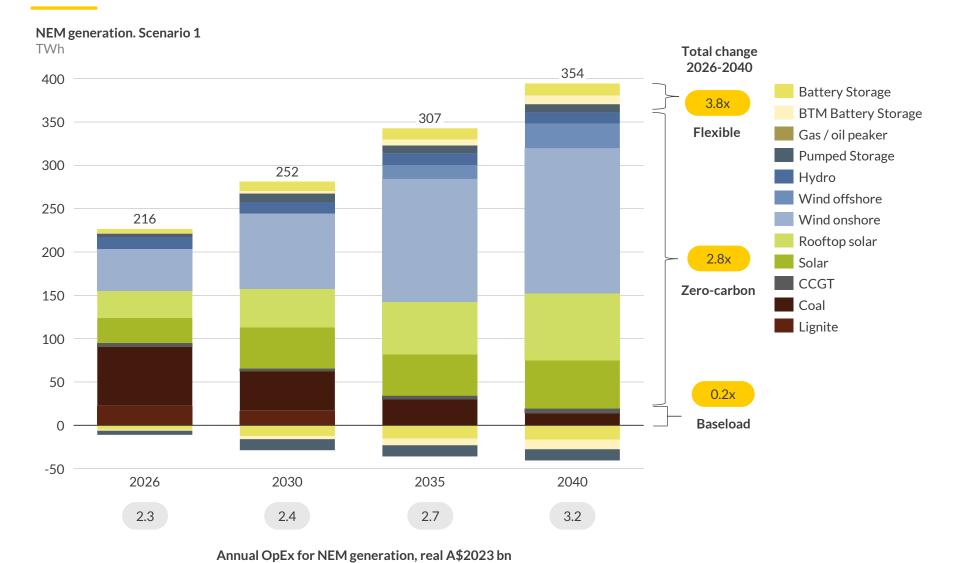
Capacity by state, Scenario 1

Nameplate GW



Source: Aurora Energy Research

Bulk energy is forecast to be increasingly provided by renewables under the Scenario 1 Base Case





Scenario 1 generation outlook

- Generation from renewable resources makes up an increasing portion of the production as assets are rapidly deployed to meet state-based renewable energy targets. By FY30, renewable generation is expected to increase by ~60% from 2026 levels.
- The 2030s see rapid exit of coal across the NEM. This incentivises further buildout of renewables and flexible technologies such as battery storage, increasingly the make up of the generation mix.
- OpEx costs increase in the NEM as more peaking and storage assets are introduced to cover supply gaps with increased renewable penetration.
- The resulting combination of high-cost gas and low-cost renewables creates higher price spreads, driving increases in storage generation.

Source: Aurora Energy Research

State generation mix follows a similar trend to each state's respective capacity build-out forecast



Generation mix and emissions by state

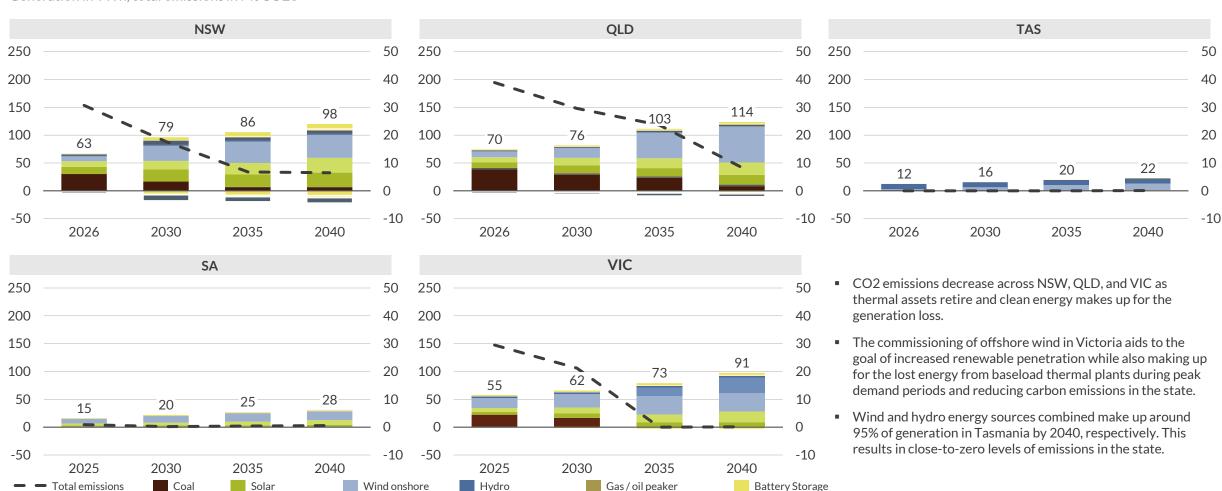
Lignite

CCGT

Rooftop solar

Wind offshore

Generation in TWh, total emissions in Mt CO2e



Source: Aurora Energy Research

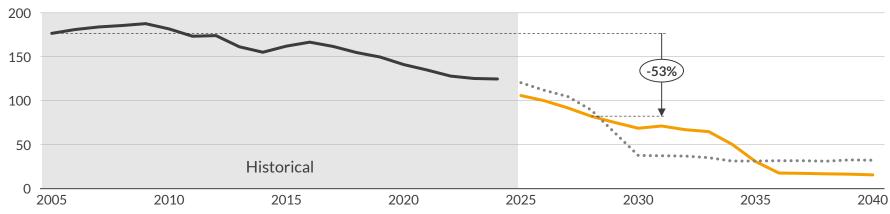
BTM Battery Storage

Pumped Storage

In the Base Case, by 2030 total NEM emissions will represent a reduction of 61% relative to 2005 levels under existing frameworks

Total NEM power sector emissions

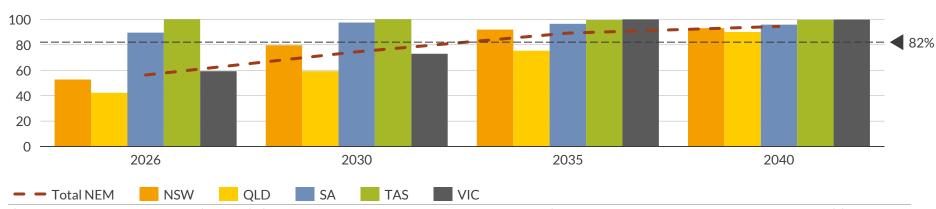




Total renewable penetration by state

─ Base Case • DCCEEW¹ ─ historic

% of total generation²



¹⁾ Australia's emissions projections 2025 (DCCEEW); 2) Renewables penetration as a % of generation is calculated as (hydro + rooftop solar + solar + wind onshore + wind offshore)/(peaking + hydro + rooftop solar + solar + wind onshore + wind offshore + lignite + coal + CCGT)

AUR 😂 RA

Emissions

 Current coal closure timings will result in emissions halving by 2028 (relative to 2005) in the base case.

Renewable penetration

- Under existing policy approaches and taking into account delays in renewable buildout, we expect the NEM to achieve 70-80% renewables penetration by 2030.
- Renewable penetration is expected to reach the target of 82% by 2035 and continue to increase until the late 2030s, after which the renewable penetration remains stable at ~ 94%.

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Base Case without offshore wind

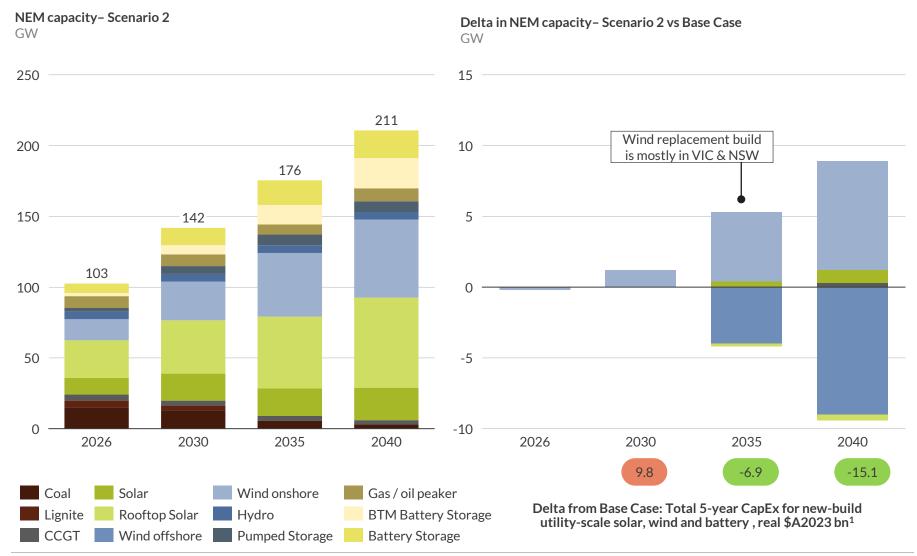


As per Scenario	1 unless otherwise stated	Scenario 1 Base Case assumptions	Scenario 2
	Federal schemes	 CIS: no requirement to meet full target by 2030. Retention of the LRET in its current form until 2030. No green certificate value post-2030. 	
Policy	State schemes	 NSW: EIR¹ met; 12GW renewable generation, and at least 2GW long-duration storage by 2030. QLD: No requirement to meet QRET. VIC: Pre-2022 VRET assumed to be met. VRET1 and VRET2 auction capacities included, 9GW offshore wind by 2041. Updated VRET met (65% by 2030, 95% by 2035). Victorian Energy Storage Target met. TAS: TRET² met. 	
	Underlying demand	AEMO 2024 ISP Step Change scenario underlying demand.	
Demand	Rooftop solar, behind-the- meter batteries & EVs	 AEMO 2024 ISP Step Change scenario rooftop solar, BTM batteries and EV uptake. 	
Commodity	Gas prices	 Aurora in-house global commodity price modelling - LNG netback prices, refer to Model Input Assumptions. 	
prices	Coal prices	 Aurora in-house global commodity price modelling – coal export price for uncontracted, non-mine-linked coal plants, refer to Model Input Assumptions. 	
	Coal closures	 AEMO's latest (Jan 2025) announced closure timeline with the exception of Callide B (closing at end of FY2026), Millmerran and Callide C (both closing at end of FY2049), Stanwell (closing at end of FY2032), Kogan Creek (closing at end of FY2035), Tarong and Tarong North (both closing at end of FY2033); refer to Model Input Assumptions. Closure dates may differ from AEMO due to modelled plant economics suggesting earlier retirement or new policy/announcements that are not yet reflected in AEMO's timeline. 	
	CAPEX	 As per AEMO 2024 ISP Step Change scenario. 	
Supply	WACC	 For Solar and Wind assume merchant WACC of 9.5%. For BESS and Gas assume merchant WACC of 11.5%. 	
	New Hydro	• Kidston from 2025, Snowy 2.0 included from December 2028 and Borumba from September 2031 (Pioneer-Burdekin not included).	
	Offshore Wind	■ 2GW of offshore wind in VIC by FY2033; 4GW of offshore wind in VIC by FY2035; 9GW of offshore wind in VIC by FY2040	No requirement to build offshore wind in line with Victoria's targets.
Network	Inter-regional	 AEMO 2024 ISP Step Change Optimal Development Path: EnergyConnect, QNI & VNI upgrades, QNI Connect, VNI-West and Marinus Link Stage 1 and 2. 	
augmentation	Intra-regional	 AEMO 2024 ISP Step Change Optimal Development Path, including Central-West Orana, New England and Western Renewables Link + Queensland Energy and Jobs Plan SuperGrid. 	
Marginal Loss Factors	Endogeneity	 Asset specific MLFs incorporated into short-run marginal costs and therefore bidding behaviour. MLFs modelled endogenously by Renewable Energy Zone (REZ) ensuring capacity buildout and DWA prices reflect the premium required to bring on new investment. Current grid limits and robustness of MLFs factored into model build decisions. 	
Bidding behaviour	Scarcity pricing / Uplift	 Purpose-built uplift function - capturing the deltas between price and the short-run marginal cost of the system, based on historical behaviour. Incorporates time-of-day/week, scarcity margin, technology, bidding behaviour etc. 	
Weather Year		Modelled using 2016 weather year	

¹⁾ Electricity Infrastructure Roadmap. Total program includes 12GW renewables, 2GW long duration storage by 2030 2) 16TWh renewable generation by 2030, 21TWh renewable generation by 2040.

Source: Aurora Energy Research

The buildout of onshore wind and solar primarily offsets the removal of offshore wind in Scenario 2



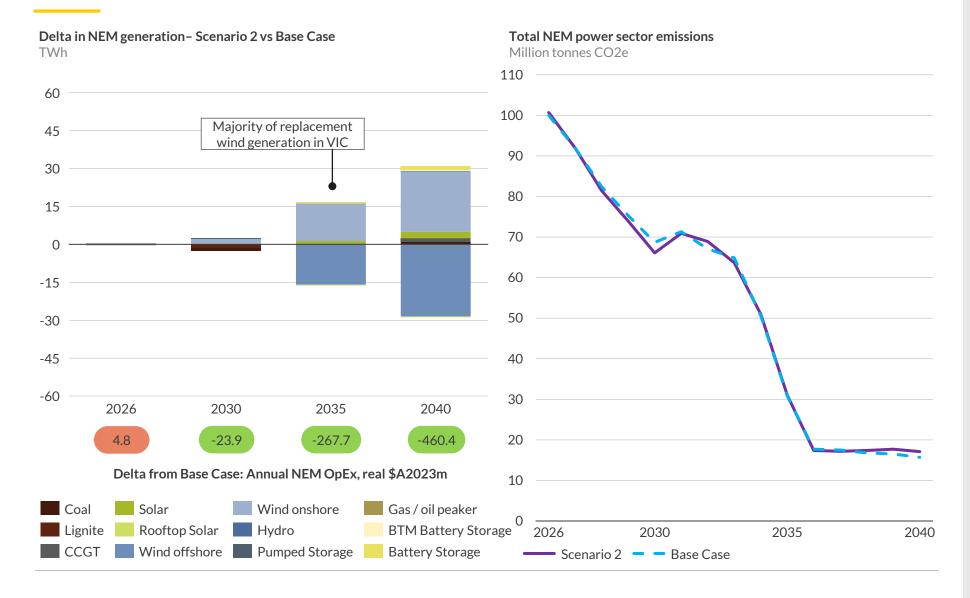
Scenario 2 vs Base Case

- Both Scenario 2 and the Base Case feature a similar capacity mix, as state and federal renewable targets remain in place to drive comparable development. The key exception is offshore wind, which is fully excluded in Scenario 2.
- Additional onshore wind and gas peaking assets are assumed to be built in Scenario 2 to offset the capacity void caused by excluding offshore wind.
- CapEx for new-build renewables is lower in Scenario 2 in the 2030s due to the lack of offshore wind, which has higher CapEx than onshore wind.

AUR 😂 RA

¹⁾ Each CapEx figure is inclusive of the preceding 5-year period i.e. FY26-30 CapEx provided in FY30, calculated using 2023 AEMO IASR CapEx assumptions – see Forecast Modelling Inputs for details

Without offshore wind, Scenario 2 sees more deployment in alternate renewables to replace with a comparable emissions profile





Scenario 2 vs Base Case

Generation mix and OpEx

- Onshore wind, batteries, and gas peaking assets see increased generation in Scenario 2 to offset the loss of generation from not including 9GW of offshore wind, which contributes to around 30TWh of generation, in this scenario.
- In Scenario 2, renewable energy penetration in the National Electricity Market (NEM) reaches approximately 80-85% by FY2035 – broadly comparable to the level projected in Scenario 1.
- Scenario 2 sees lower OpEx costs compared to the Base Case largely due to the lack of offshore wind fixed operational costs from the 2030s onwards.

Emissions

 Since both scenarios have a similar balance of renewable and nonrenewable generation, Scenario 2's emissions closely follow those of the Base Case.

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Base case without offshore wind or state-level renewable energy targets

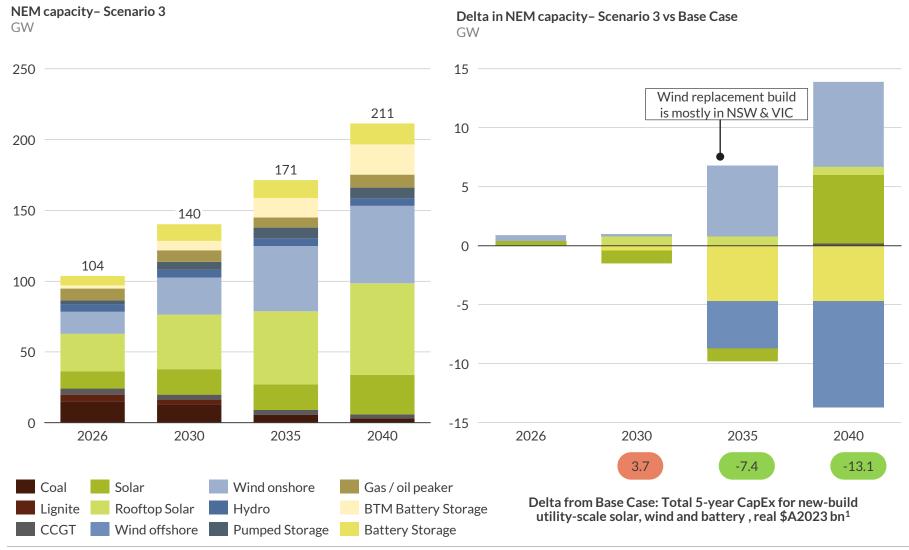


As per Scenario	1 unless otherwise stated	Scenario 1 Base Case assumptions	Scenario 3					
	Federal schemes	 CIS: no requirement to meet full target by 2030. Retention of the LRET in its current form until 2030. No green certificate value post-2030. 	 A NEM-wide renewable energy target equivalent to the achieved renewable penetration in Scenarios 1 is assumed to be met in 2030, 2035 and 2040. 					
Policy	State schemes	 NSW: EIR¹ met; 12GW renewable generation, and at least 2GW long-duration storage by 2030. QLD: No requirement to meet QRET. VIC: Pre-2022 VRET assumed to be met. VRET1 and VRET2 auction capacities included, 9GW offshore wind by 2041. Updated VRET met (65% by 2030, 95% by 2035). Victorian Energy Storage Target met. TAS: TRET² met. 	State targets not enforced					
	Underlying demand	 AEMO 2024 ISP Step Change scenario underlying demand. 						
Demand	Rooftop solar, behind-the- meter batteries & EVs	 AEMO 2024 ISP Step Change scenario rooftop solar, BTM batteries and EV uptake. 						
Commodity	Gas prices	 Aurora in-house global commodity price modelling - LNG netback prices, refer to Model Input Assumptions. 						
prices	Coal prices	 Aurora in-house global commodity price modelling – coal export price for uncontracted, non-mine-linked coal plants, refer to Model Input Assumptions. 						
	Coal closures	 AEMO's latest (Jan 2025) announced closure timeline with the exception of Callide B (closing at end of FY2026), Millmerran and Callide C (both closing at end of FY2049), Stanwell (closing at end of FY2032), Kogan Creek (closing at end of FY2035), Tarong and Tarong North (both closing at end of FY2033); refer to Model Input Assumptions. Closure dates may differ from AEMO due to modelled plant economics suggesting earlier retirement or new policy/announcements that are not yet reflected in AEMO's timeline. 						
Supply	CAPEX	 As per AEMO 2024 ISP Step Change scenario. 						
	WACC	 For Solar and Wind assume merchant WACC of 9.5%. For BESS and Gas assume merchant WACC of 11.5%. 						
	New Hydro	• Kidston from 2025, Snowy 2.0 included from December 2028 and Borumba from September 2031 (Pioneer-Burdekin not included).						
	Offshore Wind	■ 2GW of offshore wind in VIC by FY2033; 4GW of offshore wind in VIC by FY2035; 9GW of offshore wind in VIC by FY2040	 No requirement to build offshore wind in line with Victoria's targets. 					
Network	Inter-regional	 AEMO 2024 ISP Step Change Optimal Development Path: EnergyConnect, QNI & VNI upgrades, QNI Connect, VNI-West and Marinus Link Stage 1 and 2. 						
augmentation	Intra-regional	 AEMO 2024 ISP Step Change Optimal Development Path, including Central-West Orana, New England and Western Renewables Link + Queensland Energy and Jobs Plan SuperGrid. 						
Marginal Loss Factors	Endogeneity	 Asset specific MLFs incorporated into short-run marginal costs and therefore bidding behaviour. MLFs modelled endogenously by Renewable Energy Zone (REZ) ensuring capacity buildout and DWA prices reflect the premium required to bring on new investment. Current grid limits and robustness of MLFs factored into model build decisions. 						
Bidding behaviour	Scarcity pricing / Uplift	 Purpose-built uplift function - capturing the deltas between price and the short-run marginal cost of the system, based on historical behaviour. Incorporates time-of-day/week, scarcity margin, technology, bidding behaviour etc. 						
Weather Year		Modelled using 2016 weather year						

¹⁾ Electricity Infrastructure Roadmap. Total program includes 12GW renewables, 2GW long duration storage by 2030 2) 16TWh renewable generation by 2030, 21TWh renewable generation by 2040.

Source: Aurora Energy Research

With state targets removed, replacement onshore wind is introduced across the NEM to meet NEM-wide renewable targets



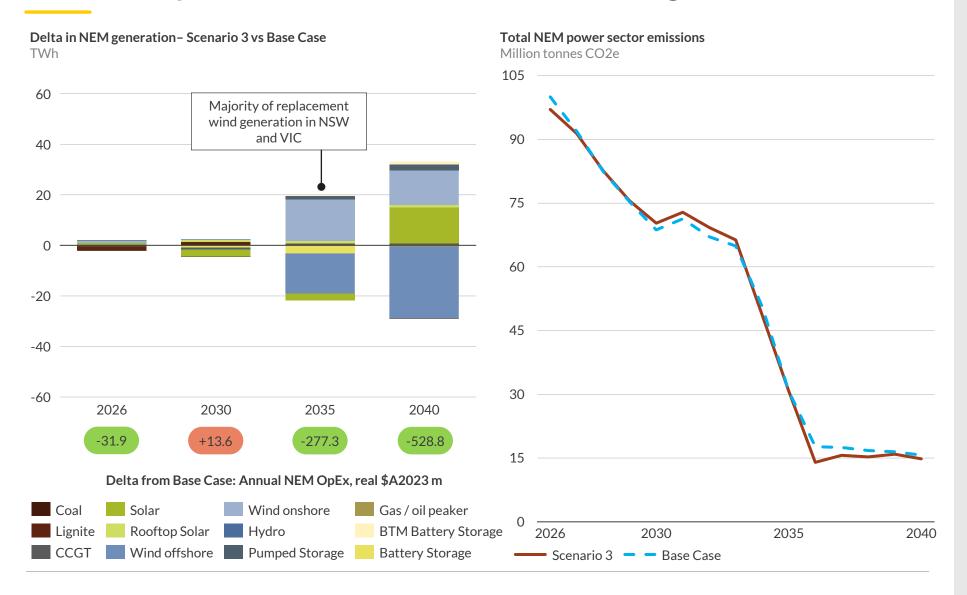
Scenario 3 vs Base Case

- Without state targets enforced, onshore wind buildout increases in the NEM from the mid-2030s to offset capacity loss from excluding offshore wind in Scenario 3.
- Additional renewables capacity is required to come online in the 2020s to achieve NEM-wide targets, resulting in increased CapEx relative to Base Case during the late 2020s.
- Total new-build utility-scale solar, wind and battery CapEx in Scenario 3 is ~4% lower than that of Scenario 2, where state renewable targets are enforced.

AUR 😂 RA

¹⁾ Each CapEx figure is inclusive of the preceding 5-year period i.e. FY26-30 CapEx provided in FY30, calculated using 2023 AEMO IASR CapEx assumptions – see Forecast Modelling Inputs for details

Emissions in Scenario 3 closely follow that of the Base Case due to a similar composition of thermal versus renewable generation sources





Scenario 3 vs Base Case

Generation mix and Opex

- With the forcing of NEM-wide renewable energy targets and removal of offshore wind in Scenario 3, onshore wind and solar is introduced to account for the capacity gap whilst achieving targets.
- At a federal level, we expect the NEM to achieve around 75% renewables penetration by 2030 under Scenario 3. The target of 82% renewables is forecast to be met by 2034, in line with the Base Case.
- OpEx deltas between Scenario 3 and the Base Case widen after the mid-2030s, when offshore wind begins commissioning in the Base Case. Because Scenario 3 relies more on lower-cost technologies such as onshore wind and excludes offshore wind entirely, it sees lower long-term OpEx.

Emissions

 Since both scenarios have a similar balance of renewable and nonrenewable generation, total NEM emissions in Scenario 3 tend to track that of the Base Case.

NEM CapEx and Opex comparison across all scenarios

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NEM forecast CapEx costs per scenario¹

A\$bn, real 2023

Financial Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Scenario 1	-	9.5	9.5	7	10.3	6.2	7.3	8.1	13.2	13.3	13	7	8	5.7	6.4
Scenario 2	-	15.8	12	7.9	10.4	2.6	4	9.3	12.3	13	11.3	5	3.7	2.3	2.7
Scenario 3	-	13.3	10.8	6.7	9.2	3.5	4.7	7.3	15	10.2	14.8	1.6	4.4	1.9	4.3

NEM forecast OpEx costs per scenario

A\$m, real 2023

Financial Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Scenario 1	2,319	2,343	2,343	2,371	2,417	2,567	2,727	2,848	2,893	2,742	2,787	2,893	2,997	3,086	3,154
Scenario 2	2,324	2,347	2,333	2,356	2,393	2,494	2,599	2,654	2,678	2,474	2,464	2,529	2,597	2,642	2,694
Scenario 3	2,288	2,332	2,343	2,364	2,430	2,511	2,610	2,667	2,649	2,464	2,429	2,507	2,553	2,601	2,625

CapEx costs in the NEM

- CapEx costs in the Base Case remain elevated in the 2030s driven by the forcing of offshore wind build to meet Victorian state targets.
- Costs in Scenario 3 are slightly lower in comparison to Scenario 2 due to the replacement of state targets with NEM-wide objectives.
- Total new-build CapEx over the forecast per scenario:
 - Base Case \$124.5bn
 - Scenario 2 \$112.3bn
 - Scenario 3 \$107.7bn

OpEx costs in the NEM

The Base Case sees the highest OpEx figures from the 2030s, when offshore wind begins commissioning in Victoria. Because Scenarios 2 and 3 rely more on lower-cost technologies such as onshore wind and does not force offshore wind to build, the forecast OpEx is lower than that of the Base Case.

¹⁾ Forecast CapEx for new-build utility-scale solar, wind and batteries

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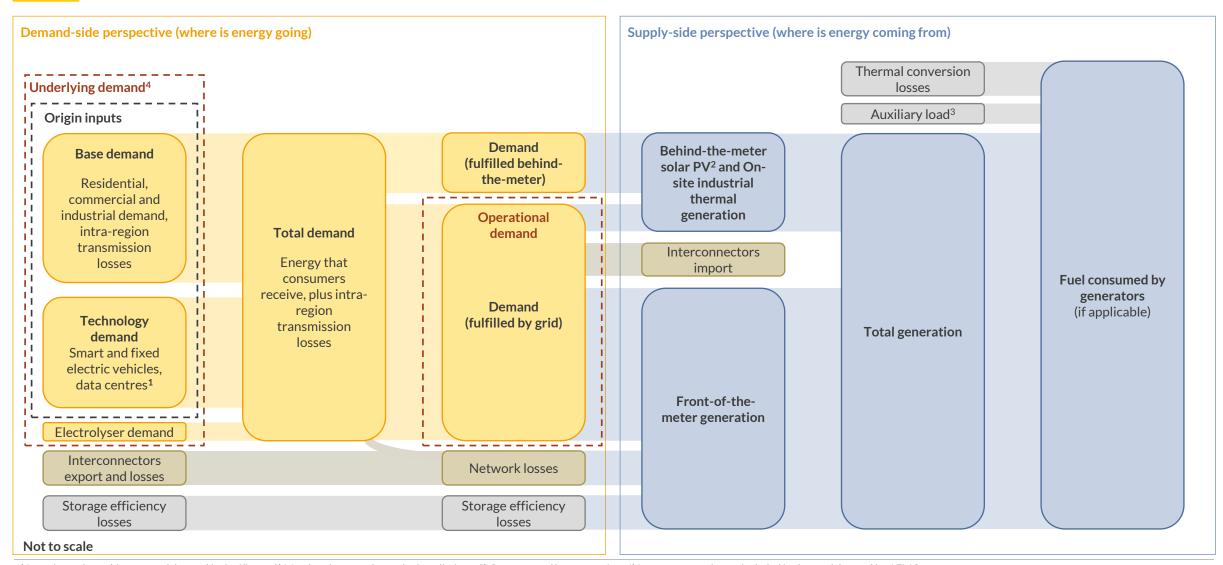


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Aurora's demand methodology considers flexible and inflexible demand components, imports, transmission losses, and BTM demand

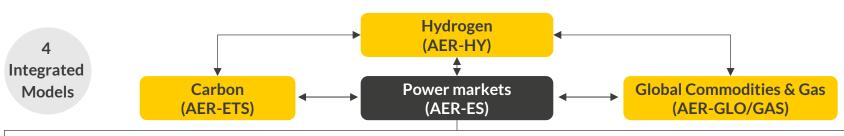




¹⁾ In regions where this source of demand is significant. 2) Mostly private rooftop solar installations. 3) Generator self-consumption. 4) Interconnector losses included in the total demand by AEMO

Source : AEMO 39

Unique, proprietary, in-house modelling capabilities underpin Aurora's superior analysis



INPUTS

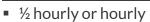
Policy

Technology









- Iterative modelling
- Dynamic dispatch of plant
- Endogenous Interconnector flows



Continuous iteration until an equilibrium is reached

Demand





Investment decisions module

- Capacity market modelling
- Capacity build / exit / mothballing
- IRR / NPV driven
- Detailed technology assessments

OUTPUTS



Capacity mix



Generation mix



Wholesale & imbalance prices



Capacity market prices



Profit / Loss and NPV



Electric vehicle charging



Advantages of Aurora approach

- Aurora have invested heavily in developing our dispatch models since 2013 and believe they are the most sophisticated available
- Our models have been rigorously tested and refined in a wide range of client contexts
- Flexible and nimble because we own the code
- Transparent results
- State-of-the-art Infrastructure
- Zero dependence on black-box thirdparty software (e.g., PLEXOS)
- Constantly up to date through subscription research
- Ability to model complex policy changes quickly

Source: Aurora Energy Research

¹⁾ Gas, coal, oil and carbon prices fundamentally modelled in-house with fully Integrated commodities and gas market model

Explanation of key concepts [1/2]



Key Terms	Description
TWA	■ The time-weighted average price is the simple average of all half hourly prices during a given period
	 Dispatch-weighted average price is the average of the regional reference node price achieved by an asset (or type of technology) where the average price is weighted by the asset's generation in a given period
DWA	 There are a number of different ways of defining the dispatch-weighted average prices. Aurora's forecast DWA prices are defined as follows: Pre-MLF and Post-Curtailment – This means that losses due to MLFs are not accounted for and assumes that assets economically curtail at 0\$/MWh to avoid negative prices Pre-MLF and Pre-Curtailment – This means that losses due to MLFs are not accounted for and assumes that assets still generate through negative price periods
	 Final asset revenues can then be calculated according to the following formula: [Post-curtailment final revenues] = [Pre-mlf, post-curtailment DWA]x[MLF]x[(1 - curtailment rate) x Pre-Curtailment Generation] [Pre-curtailment final revenues] = [Pre-mlf, pre-curtailment DWA]x[MLF]x[Pre-Curtailment Generation]
Price cannibalisation	 Price cannibalisation is the price impact of high levels of zero-marginal cost renewable generation on dispatch-weighted prices. When solar and wind output is high, it tends to bring down prices in those periods as lower cost technologies set the margin in the wholesale market ('merit order effect')
Inflation	 Aurora's forecast prices are published in real 2023 calendar year prices as at 30th June 2022. Aurora models all forecasts in real terms and provides the International Monetary Fund's future CPI expectation as a possible metric to use to convert our forecasts to nominal terms. However, CPI has not historically been strongly and consistently correlated with electricity prices and Aurora's subscribers typically apply a range of in-house views on future inflation rates
Financial years	 Aurora's forecasts are in financial years and follow the federal financial year (1 July to 30 June). Years refer to the end of the financial year, so e.g. FY 2026 refers to 30 June 2025 to 1 July 2026
Reference weather years	 Aurora's half-hourly renewable generation and demand traces are based on the FY2016 reference weather year. The alignment of each of these input traces to the same reference weather year is critical due to the impact that weather has on renewable generation and demand, and the knock-on impact on half-hourly wholesale prices

Explanation of key concepts [2/2]



Key Terms Description Large-scale generation certificates (LGCs) are created on a yearly basis based on the amount of power generated by an accredited and registered renewable energy power station. **LGCs** An LGC represents one megawatt hour (MWh) of net renewable energy generated. Registered LGCs can be sold or transferred to entities with liabilities under the Renewable Energy Target or other companies looking to voluntarily surrender LGCs • The levelised cost of electricity (LCOE) is the NPV of the unit-cost of electrical energy over the lifetime of a generating asset. It is effectively a simplified assessment of the cost LCOE competitiveness of an electricity-generating system that incorporates all costs over an asset's lifetime: initial investment, operations and maintenance, cost of fuel, cost of capital Marginal loss factors (MLFs) reflect the impact of electricity losses along the network and are applied to market settlements in the National Electricity Market (NEM), and so affect MLFs generator revenues. They represent electricity losses along the transmission network between a connection point and the regional reference node (RNN), which is used to represent the regional centre of the transmission network Non-volatile / Aurora's standard power market model only includes "fundamentals-based" volatility and therefore the half-hourly prices do not include extreme price events above approximately fundamental prices \$1,000/MWh (as these typically cannot be explained by generator SRMC / shadow pricing) • Revenues from +\$1,000/MWh price periods are a material factor in the investment case of flexible assets, such as batteries. To capture this market feature, Aurora has a fourth step to price formation (not to be confused with "uplift" which is the second step to price formation). This fourth step is a "post-model" process to add +\$1,000/MWh price periods in line "Typical volatility" with what has been seen historically over the last 3-5 years in each state (but excluding any major/minor system incidents from the calibration – hence the term "typical" volatility, as prices this approach does not try to recreate persistent, significant market events that may be driven by long-term network outages or coal plant explosions). This "post-model" processing involves using a stochastic (Markov Chain) approach where spiky prices are probabilistically added to half-hours according to spare capacity margin in that half-hour.

Glossary of key NEM and modelling terms [1/2]



Abbreviation	Explanation
A\$	 Australian Dollars (assumed to be real 2023 terms unless otherwise stated
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Stock Exchange
втм	■ Behind-the-Meter
Capex	Capital Expenditure
CIS	 Capacity Investment Scheme
СМ	Capacity Market
COAG	Council of Australian Governments
COD	 Commissioning Date
CCGT	Combined Cycle Gas Turbine
CfD	Contract for Difference
СНР	Combined Heat and Power
CO ₂	Carbon Dioxide

Abbreviation	Explanation
DLF	Distribution Loss Factor
DSP	Demand Side Participation
DWA	Dispatch Weighted Average
EIS	Emissions Intensity Scheme
ESB	■ Energy Security Board
ESOO	Electricity Statement of Opportunities
ETS	■ Emissions Trading Scheme
EVs	Electric Vehicles
FCAS	■ Frequency Controlled Ancillary Services
FOB	■ Free On Board
GJ	■ Gigajoule
GW	■ Gigawatt
kW	Kilowatt
LCOE	Levelised Cost of Energy
LGCs	Large-scale Generation Certificates
LRET	Large-scale Renewable Energy Target

Glossary of key NEM and modelling terms [2/2]



Abbreviation	Explanation
LNG	Liquefied Natural Gas
MLF	Marginal Loss Factor
Mt	 Mega tonne (one million metric tonnes)
MWh	Megawatt Hour
MW	 Megawatt
NEG	National Energy Guarantee
NEM	National Electricity Market
NSG	Non-Scheduled Generation
Opex	Operational Expenditure
PPA	 Power Purchasing Agreement
RES	Renewable Energy System(s)
REGO	 Renewable Energy Guarantee of Origin
RRN	Regional Reference Node
RRO	 Retailed Reliability Obligation
SRMC	Short-Run Marginal Cost
TWA	■ Time-weighted Average
TWh	■ Terawatt Hour
WACC	Weighted Average Cost of Capital

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