The Queensland Energy and Jobs Plan – electricity market and economic modelling outcomes

Department of Energy and Public Works

23 September 2022

EY

Building a better working world

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Ernst & Young was engaged on the instructions of Department of Energy and Public Works (the Department) to deliver a report describing modelling outcomes of the Queensland Government's Queensland Energy Plan on the electricity sector and the Queensland economy.

The key inputs, assumptions, methodology, scenarios and qualifications made in preparing the modelling are set out in EY's report dated 23 September 2022 ("**Report**"). You should read the Report in its entirety including any disclaimers and attachments. A reference to the Report includes any part of the Report. No further work has been undertaken by EY since the date of the Report to update it.

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Readers are advised that the information provided is based on many detailed assumptions. These assumptions were selected by the Department after consultation with other stakeholders. The modelled scenarios represent several possible future options for the development and operation of the National Electricity Market, and it must be acknowledged that many alternative futures exist. Alternative futures beyond those presented have not been evaluated as part of this Report.

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1. Executive summary

1.1 Introduction

The Queensland Government has set a 50% renewable energy target by 2030 and a 30% economy wide emissions reduction target by 2030. The Queensland Government has developed a Queensland Energy and Jobs Plan (the Energy Plan), which outlines a pathway to transform the Queensland electricity system to achieve these targets, including (but not limited to):

- Setting targets and governance mechanisms for the Queensland energy system
- Investment in new generation, transmission network and storage in the electricity sector
- Providing confidence to capital markets that Queensland has a plan to decarbonise.

The Department engaged EY to conduct modelling and analysis to quantify the outcomes of the Energy Plan for the electricity sector and the Queensland economy. The modelling projects the possible industry and economic growth opportunities resulting from the transformation. This Report compares the forecast outcomes in two scenarios: a preferred pathway (Energy Plan) and a counterfactual (Uncoordinated Outlook).

EY's outcomes presented in this Report are the product of two workstreams:

- Electricity market modelling conducted using EY's 2-4-C model
- Economic outcomes modelling conducted using EY's whole of economy model.

1.2 Energy Plan potential benefits

Table 1 summarises the key potential benefits of the Energy Plan as quantified in EY's modelling for this Report.

Table 1: Summary of potential policy benefits based on EY's modelling outcomes[1]

Policy objective	Summary of potential benefits
Electricity sector model outcomes	
Low electricity prices	Annual retail bills for a typical household are projected to be up to $112 lower in 2030 and up to $77 lower on average from 2025 to 2040
Electricity emissions reductions	A forecast 56% reduction in emissions reductions by 2030 compared to 2005 levels, and 96% reduction by 2040 (compared to 34% and 71%, respectively in the counterfactual)
Renewable energy uptake	Renewable energy generation forecast to grow to 61% of Queensland electricity demand by 2030, exceeding the 50% Queensland Renewable Energy Target (QRET) (compared to 46% in 2030 in the counterfactual, not meeting the target)
Whole of economy model outcomes	
Total investment	Additional $23.2b in total estimated investment across the Queensland economy
Gross State Product (GSP) ($b NPV)	Under the Energy Plan scenario, up to an additional $25.7b in GSP across the Queensland economy compared to the Uncoordinated Outlook

Table 2 presents the potential policy benefits with a focus on three selected years from the modelling.

[1] The summary is based on the detailed modelling which is in turn based on scenarios and assumptions used in undertaking the analysis. The scenarios and assumptions used are outlined in the later sections of this Report.

Table 2: Summary of potential policy benefits in three selected fiscal years based on EY's modelling outcomes of the Energy Plan Scenario relative to the Uncoordinated Outlook Scenario

Policy objective	2029-30	2031-32	2039-40
Reduced electricity bills for households	-$112	-$150	-$190
Reduced electricity bills for small business	-$1,115	-$1,495	-$1,904
Reduced electricity emissions for Queensland generators compared to 2005 levels (Uncoordinated Outlook Scenario in brackets)	-50% (-34%)	-60% (-33%)	-96% (-71%)
Renewable energy generation as percentage of Queensland electricity demand (Uncoordinated Outlook Scenario in brackets)	61% (46%)	68% (47%)	94% (75%)
GSP	+$2.9b	+$4.7b	+$3.9b

1.3 Scenarios and key assumptions

Two scenarios have been modelled over a 17-year horizon from 2023-24 to 2039-40. The narratives behind the two modelled scenarios are follows:

- **Uncoordinated Outlook**: in this scenario it is assumed that the Queensland Government does not make early investments in the electricity sector and there is no clear plan for the energy transformation available in the public domain. Investment in generation and storage occurs in response to electricity market signals only and policies already in place to promote renewables in other states.
- **Energy Plan**: this represents an outlook where there is a robust vision and infrastructure blueprint for the transformation of the Queensland energy sector including key decisions relating to publicly-owned assets as well as proactive investment in wind and solar generation, pumped hydro storage and the transmission network.

Both scenarios use the Integrated System Plan (ISP) Step Change demand outlook, which includes projected uptakes in distributed energy resources (DER) including rooftop PV. Table 3 summarises the differences in assumptions between the scenarios. All assumptions for the Energy Plan were provided by the Department, except the transmission network augmentations, which were developed in consultation with Powerlink.

Table 3: The differences in assumptions between the scenarios as selected by the Department

Assumption	Uncoordinated Outlook	Energy Plan
QRET	No explicit targeting of the QRET	QRET to be met – 50% renewable generation as a percentage of consumption by 2030
Coal-fired generation retirement schedule	Announced retirement dates	Queensland coal-fired generation withdrawals across units from 2026-27 as advised by the Department based on the Infrastructure Blueprint[2]
Transmission network augmentations	As per the 2022 ISP optimal development path	Additional augmentations in Queensland to support new capacity. This does not include CopperString[3] due the complexity of adding another region to the model.

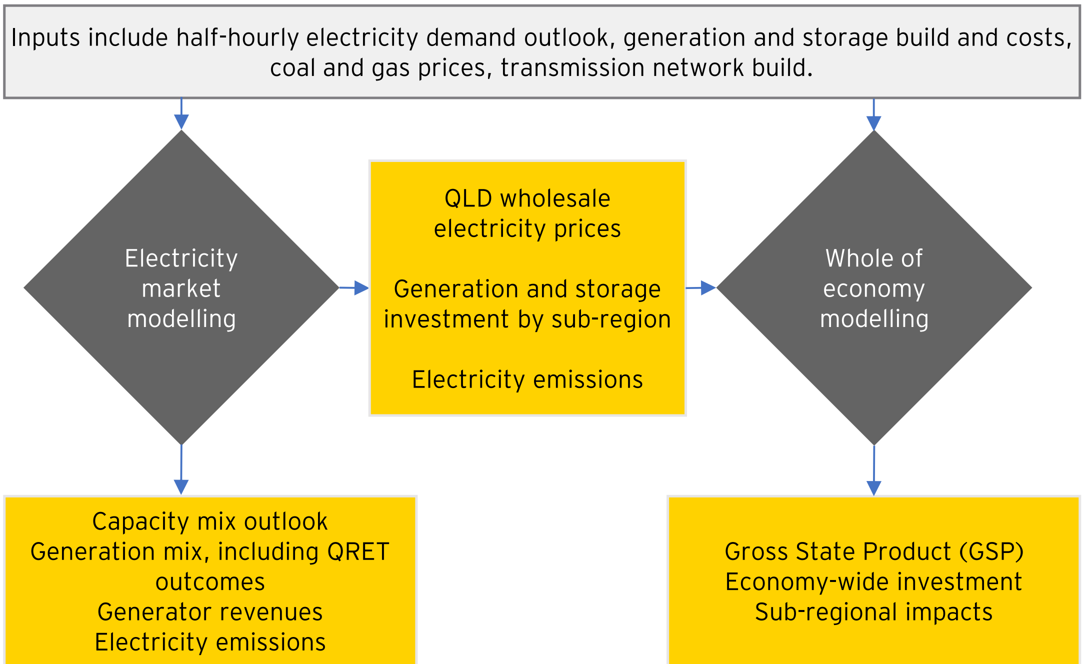
[2] The Infrastructure Blueprint is a technical document prepared by the Queensland Government outlining the investment pathway for major infrastructure in Queensland's electricity system under the Energy Plan.
[3] https://www.statedevelopment.qld.gov.au/coordinator-general/assessments-and-approvals/coordinated-projects/projects-discontinued-or-on-hold/copperstring-project

Assumption	Uncoordinated Outlook	Energy Plan
Pumped hydro	Committed projects only	Borumba (2 gigawatt (GW), 24 hour) in 2029-30 Proxy 5 GW North Queensland Pumped Hydro[4] made up of: ▶ North Queensland (3 GW, 24 hour) in 2032-33 ▶ Additional pumped hydro storage (2 GW) (modelled as 8-hour batteries[5], 1 GW in 2031 and 1 GW in 2033)
Renewable and firming capacity	Market-driven capacity only	Early investment in renewable and storage capacity backed by the Queensland Government or private industry
Weighted-average cost of capital (WACC) for new generation and storage in Queensland (pre tax, real)	5.5%[6]	4.8% A lower WACC was selected by the Department informed by independent analysis. It is based on anticipated lower risk due to increased policy certainty and reflects broad benefits to the market anticipated as a result of publishing the Queensland Energy Plan and Infrastructure Blueprint and the actions contained within

1.4 Overview of modelling approach

Figure 1 illustrates an overview of the electricity market modelling and whole of economy modelling workstreams and how they interact.

Figure 1: Overview of the two workstreams



[4] At the time of modelling, the North Queensland Pumped Hydro project was not in the public domain.
[5] Assuming 8-hour batteries is a modelling simplification agreed with the Department and this is intended to represent pumped hydro with 24 hours of storage.
[6] AEMO, 30 June2022, *2022 Inputs, assumptions and scenarios workbook*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/inputs-assumptions-and-scenarios-workbook.xlsx

The market modelling is conducted using EY's in-house 2-4-C market dispatch model. This model has been applied with half-hourly time-sequential modelling over the modelled horizon to forecast the generation and wholesale electricity prices across the National Electricity Market (NEM) in each scenario. By modelling generator bidding and transmission constraints, 2-4-C can forecast wholesale electricity prices and market revenues of individual generators.

As indicated in the diagram, the Queensland wholesale electricity prices, generation and storage investment by sub-region and electricity emissions outcomes from 2-4-C are used as inputs into the whole of economy modelling.

To model the economic outcomes of the Energy Plan relative to the Uncoordinated Outlook, EY's computable general equilibrium (CGE) model, EYGEM, has been used. EYGEM captures the economic outcomes of changes to electricity prices and other variables on the Queensland economy, divided up into nine sub-regions. A full description of the model and its application can be found in Appendix B.

1.5 Electricity sector modelling outcomes

Figure 2 illustrates the forecast large-scale capacity mix in the Queensland Energy Plan Scenario for the NEM-connected area of Queensland in 2023-24 and the final year of the modelled horizon, 2039-40. The figure highlights significant change, with no coal-fired capacity remaining online in Queensland by 2039-40 and total capacity more than doubling and transitioning to mostly wind, solar PV and storage.

Figure 2: Forecast annual mix of NEM-connected large-scale capacity in Queensland in the Energy Plan Scenario

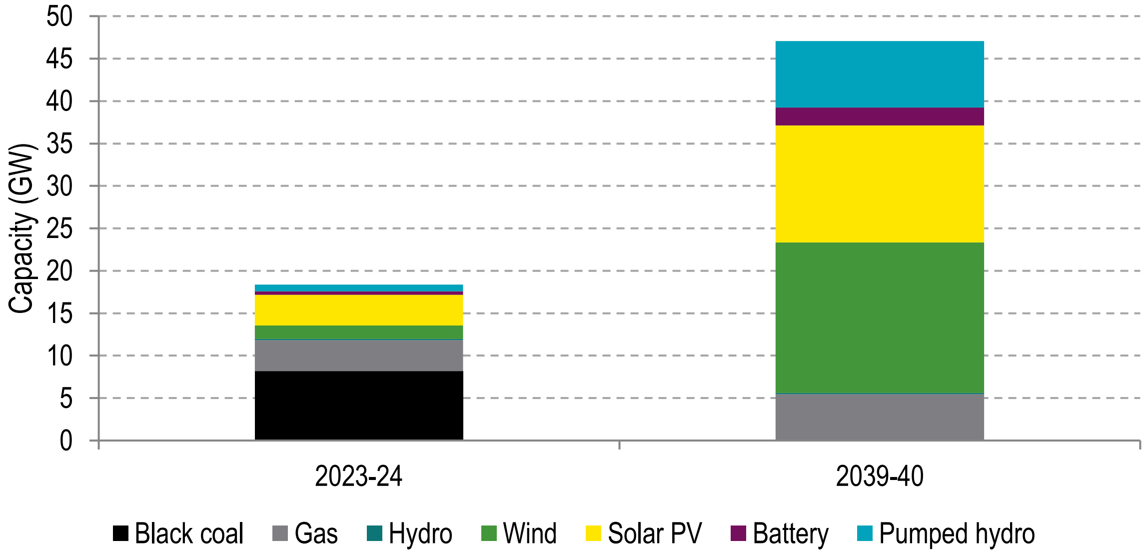


Figure 3 compares the forecast large-scale generation mix in Queensland, highlighting that the total generation has increased by approximately 25%, which is driven by a forecast increase in electricity demand in the ISP Step Change scenario, net storage load and reduced imports of electricity from the interconnectors. The storage generation is not shown as it also has load and acts to shift the renewable generation from the time of supply to the time of consumption.

Figure 3: Forecast annual mix of NEM-connected large-scale generation in Queensland in the Energy Plan Scenario

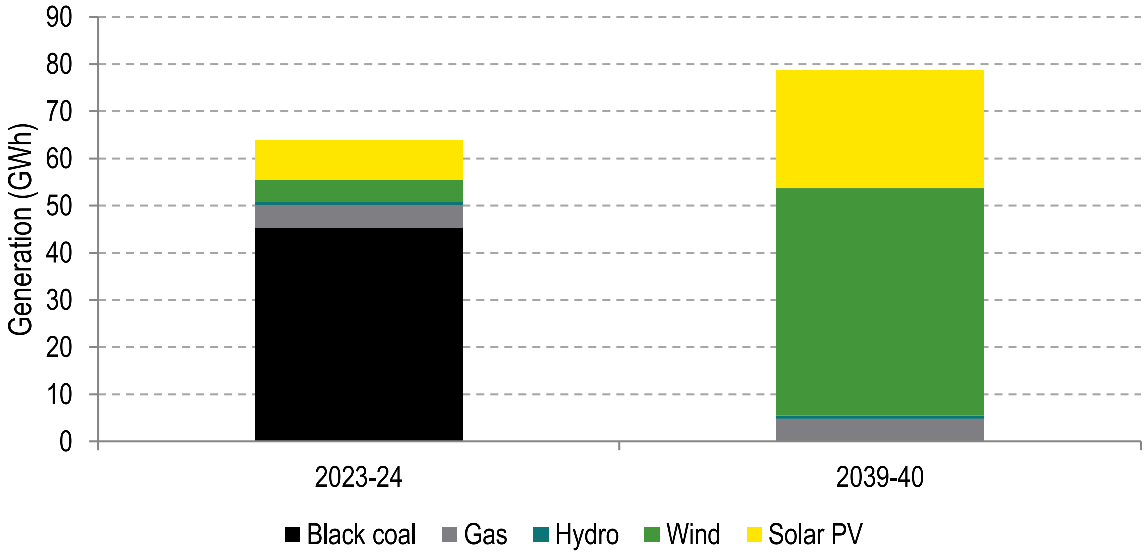


Figure 4 shows the forecast year-to-year changes in the Queensland large-scale capacity in the Energy Plan Scenario. The chart demonstrates a steady development of wind and solar capacity, with more development in years where more coal-fired generation retires and pumped hydro projects are installed. The precise timing of projects built under the Energy Plan may differ to this scenario.

Figure 4: Forecast year-to-year changes in Queensland large-scale capacity, Energy Plan Scenario

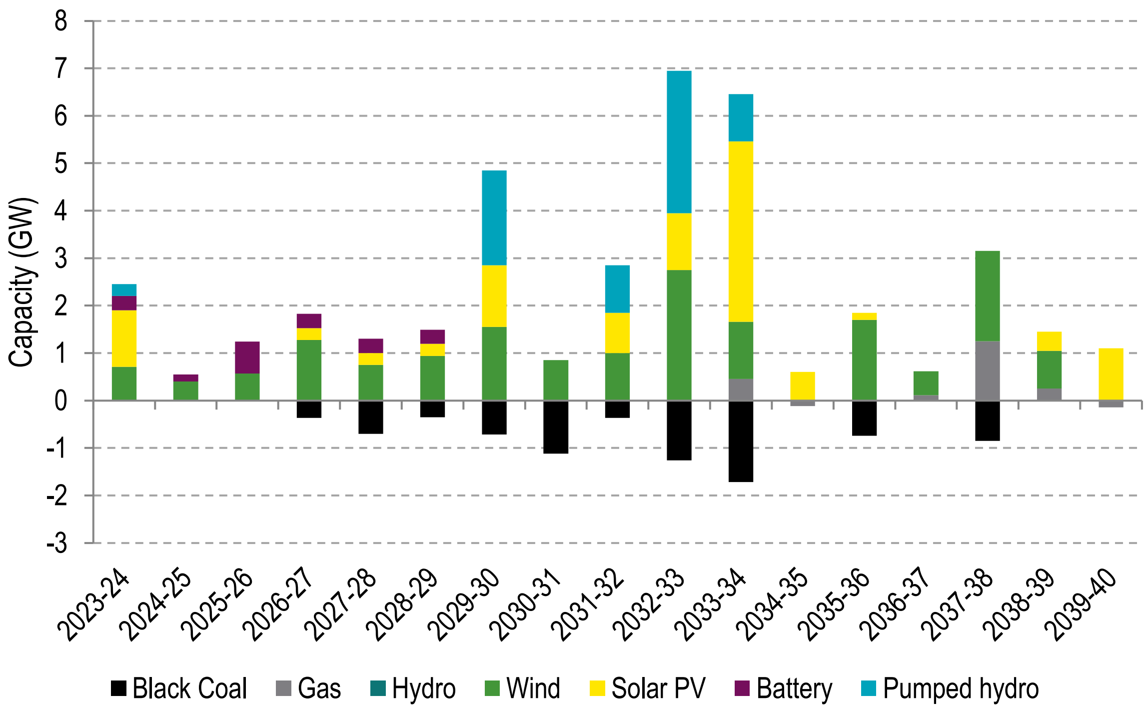


Figure 5 shows the annual difference in the capacity mix between the Energy Plan and Uncoordinated Outlook scenarios, highlighting how much wind, solar and storage development is brought forward in the Energy Plan Scenario along with withdrawal of coal-fired capacity.

Figure 5: Forecast annual Queensland capacity mix difference (GW), Energy Plan Scenario minus Uncoordinated Outlook Scenario

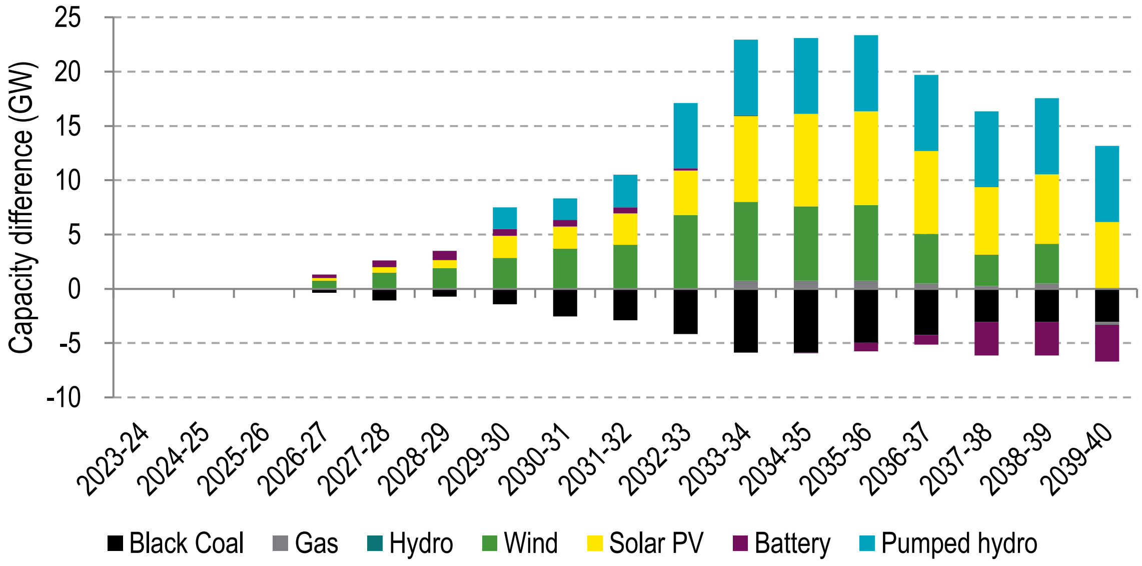


Figure 6 compares the annual electricity emissions from Queensland NEM-connected coal and gas-fired generators in the two scenarios. The reduced emissions in the Energy Plan Scenario are primarily driven by the assumed earlier withdrawal of Queensland coal-fired capacity.

Figure 6: Forecast annual Queensland emissions comparison, both scenarios

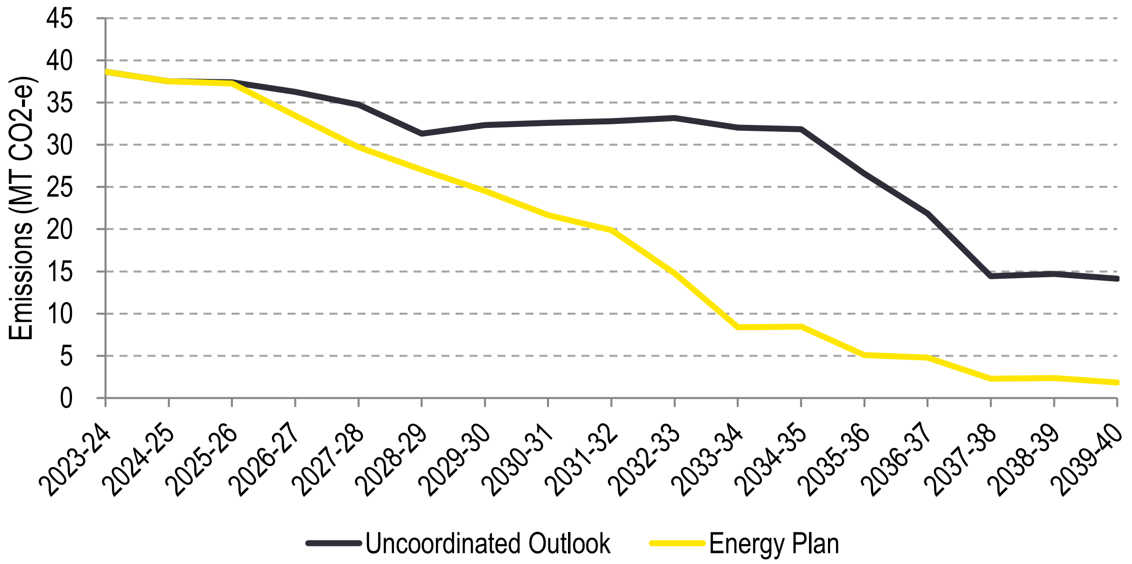


Figure 7 compares the forecast renewable generation in Queensland as a percentage of Queensland electricity consumption in the two scenarios and to the QRET target. The Energy Plan meets this target two years early, while the target is not met in the Uncoordinated Outlook Scenario and only meets 50% by 2033-34.

Figure 7: QRET comparison, both scenarios

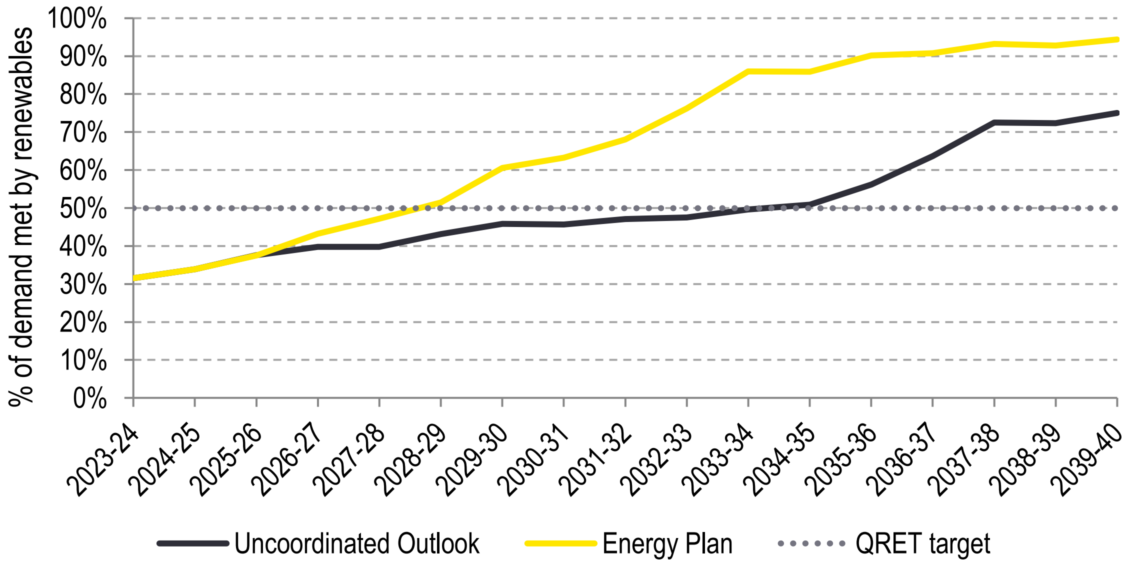
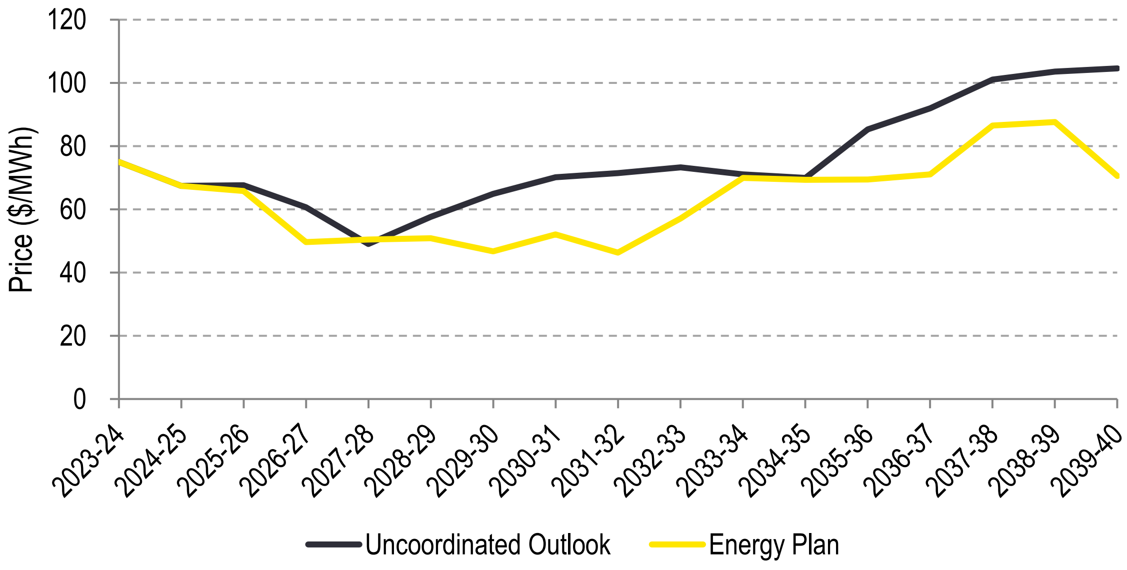


Figure 8 compares the forecast annual average wholesale electricity prices in the two scenarios. The Energy Plan Scenario is forecast to have approximately equal or lower average electricity prices in every year compared to the Uncoordinated Outlook Scenario, and these savings would be expected to be passed through to the wholesale electricity component of Queensland retail electricity bills.

Figure 8: Forecast annual average Queensland wholesale electricity prices, both scenarios



The lower average wholesale electricity price outcomes in the Energy Plan Scenario are forecast despite the earlier withdrawal of coal-fired generation. This is due to assumed investments in electricity infrastructure in the Energy Plan Scenario, namely large pumped hydro projects, transmission network projects and more wind and solar capacity commissioned proactively.

The Department's assumption of proactive investment under the Energy Plan Scenario compared to the Uncoordinated Outlook Scenario is based on a range of factors including potential additional revenue streams (e.g., corporate and GOC offtake agreements), long-term signal for investment created by the Energy Plan's announced coal-fired capacity withdrawal schedule, deep storage in the market from the Government's investment in pumped hydro supporting more renewables, potential reduced risks and costs for developers through Queensland's renewable energy zone framework, impacts of national policy like the Safeguard Mechanism, Rewiring the Nation or National Electricity Market reform including energy security services, capacity market benefits, and other potential market reforms resulting from the Energy Security Board's post 2025 reforms. Queensland's GOCs are also expected to deliver substantial investment, accessing competitive debt through Queensland Treasury Corporation and funding from the Queensland Renewable Energy and Hydrogen Jobs Fund to bring forward new projects. These factors are expected to have an impact on asset funding and revenue but are challenging to capture within the market modelling. Accordingly, considerations around publicly-owned asset funding and revenue in the whole of economy modelling for gross state product and income are excluded.

Further considerations

Under the Energy Plan Scenario Queensland's electricity market prices are less dependent on fuel prices, particularly coal prices, due to there being less coal-fired generation in operation. The market is therefore more resilient to future price shocks resulting from global instability, such as the most recent outcomes in the energy sector during winter 2022, which were driven in part by global factors like overseas conflict.

By 2040, the Queensland network and capacity mix are very different in the two scenarios. In the Energy Plan Scenario there is no Queensland coal-fired capacity remaining online and there are further opportunities for wind and solar investment. For these reasons, it is expected that wholesale market prices would continue to be steady in the Energy Plan Scenario beyond 2040.

In contrast, in the Uncoordinated Outlook Scenario further Queensland coal-fired generation withdrawals are anticipated in the 2040s but without the network investments made under the Energy Plan, the options for new renewable generation and associated storage capacity are limited. If this continued, wholesale prices would be expected to continue to be higher than the Energy Plan Scenario until investment in new storage and transmission is made to unlock opportunities for new renewable generators.

The Uncoordinated Outlook Scenario also carries higher risk of higher energy prices associated with unforeseen events such as coal-fired capacity outages as assets age and fuel cost uncertainty remains.

Furthermore, cumulative electricity emissions are significantly higher in the Uncoordinated Outlook Scenario compared to the Energy Plan Scenario, meaning that other sectors of the economy would need to do more to meet emissions targets.

1.6 Whole of economy modelling outcomes

The Queensland Energy Plan drives significant capital investment in new renewable generation, storage and transmission. As the Energy Plan is delivered and operationalised with Queensland's electricity system, it is expected to generate a range of short and longer run economic benefits.

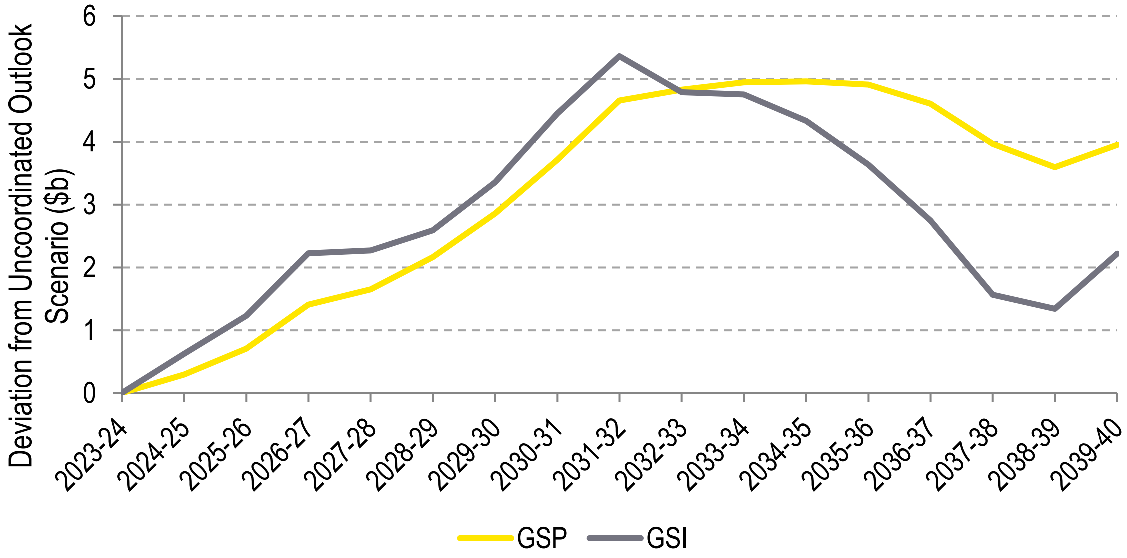
There are three major channels through which the Energy Plan stands to lift Queensland's economic performance:

- **A reduction in electricity prices**, which lowers the cost base for businesses and consumers.
- **A decrease in the cost of carbon emissions** as a result of having a low-emissions electricity grid, and a subsequent decrease in the level of emissions required to be offset.

- **A green premium on Queensland production** making Queensland a more attractive place to invest[7].

Economic modelling, using EY's in-house CGE model, was undertaken to assess the economic outcomes of the Energy Plan Scenario in comparison to the Uncoordinated Outlook Scenario over the modelled horizon to 2039-40. Under the Energy Plan Scenario, economic output in Queensland is projected to be $25.7b higher than the Uncoordinated Outlook Scenario in Net Present Values (NPV) terms. Reflecting the size of the capital installation, there is a significant boost in the first decade of the Energy Plan, coinciding with the peak of construction activity. Figure 9 shows the annual outcomes for GSP and GSI relative to the Uncoordinated Outlook Scenario.

Figure 9: Forecast annual outcomes of the Energy Plan Scenario on GSP and GSI compared to the Uncoordinated Outlook Scenario



Over the longer term, the major economic outcomes are expected to accrue through higher levels of induced investment, which could increase by over $25b in aggregate terms, and gains via improving Queensland's attractiveness as a green producer.

Table 4 summarises the overall results of whole of economy modelling for the Energy Plan Scenario compared to the Uncoordinated Outlook Scenario.

Table 4: Overall forecast outcomes of the Energy Plan Scenario in the whole of economy modelling, relative to the Uncoordinated Outlook Scenario

Economic variable	Value
Gross State Product (GSP) ($b NPV)	+25.7
Gross State Income (GSI) ($b NPV)	+25.1
Total investment ($b NPV[8])	+23.2
Household income ($ NPV per household)	+10,380

An important economic benefit of the Energy Plan is its potential to lower electricity prices for Queensland households and boost incomes through uplifting broader economic activity. The

[7] The assumptions on green premia have been provided by Queensland Treasury.
[8] All NPV values are calculated using a 7% discount rate and are discounted back to 2022-23.

modelling indicates that each Queensland household's income could be on average $1,140 higher per year than in the Uncoordinated Outlook Scenario.

The Energy Plan involves significant investment in regional Queensland and is projected to lift economic activity across the state. The whole of economy modelling indicates that approximately 51% of increased economic output will occur in regional Queensland, with significant gains for Central Queensland, Mackay and Whitsundays, Darling Downs and Townsville.

In a separate report, "A Plan for Greener Growth: The economic impact of Queensland's Energy Plan", EY has estimated direct and indirect jobs resulting from the infrastructure pipeline under the Energy Plan and potential green uplift opportunities.

2. Introduction

The Department engaged EY to conduct independent modelling and analysis to forecast the outcomes of the Energy Plan on the electricity sector and the Queensland economy. This Report describes the main results and analysis of the modelling as well as the methodologies, key assumptions and data sources used in EY's modelling.

The Report is structured as follows:

- Section 3 provides an overview of the modelling and scope of work. This includes the scenario narratives and the assumptions that underpin them.
- Section 4 explores the outcomes of the electricity sector modelling as well as going into greater detail into the market modelling methodology.
- Section 5 describes the whole of economy modelling outcomes, including the outcomes for the Queensland economy and analysis by sub-region.
- Appendix A provides a detailed description of EY's market dispatch modelling software suite, 2-4-C® and the Scenario assumptions.
- Appendix B describes the CGE model, EYGEM, used to complete the economic modelling and the assumptions used in the whole of economy modelling.
- Appendix C provides a list of definitions and acronyms used in this Report.

We note that the Department has selected the scenario assumptions and themes. It should be noted that there is a significant range of alternative assumptions that, in isolation or in aggregate, could transpire to produce outcomes that will differ from those that have been modelled. These possible alternative futures have not been considered in this engagement.

2.1 Conventions used in this document

All prices in this Report refer to real June 2022 dollars unless otherwise labelled. NPVs presented in the whole of economy modelling are calculated using a 7% discount rate and are discounted to 2022-23, as selected by the Department. All annual values (e.g., 2022-23) refer to the fiscal year (1 July – 30 June) unless otherwise labelled.

3. Modelling and scope overview

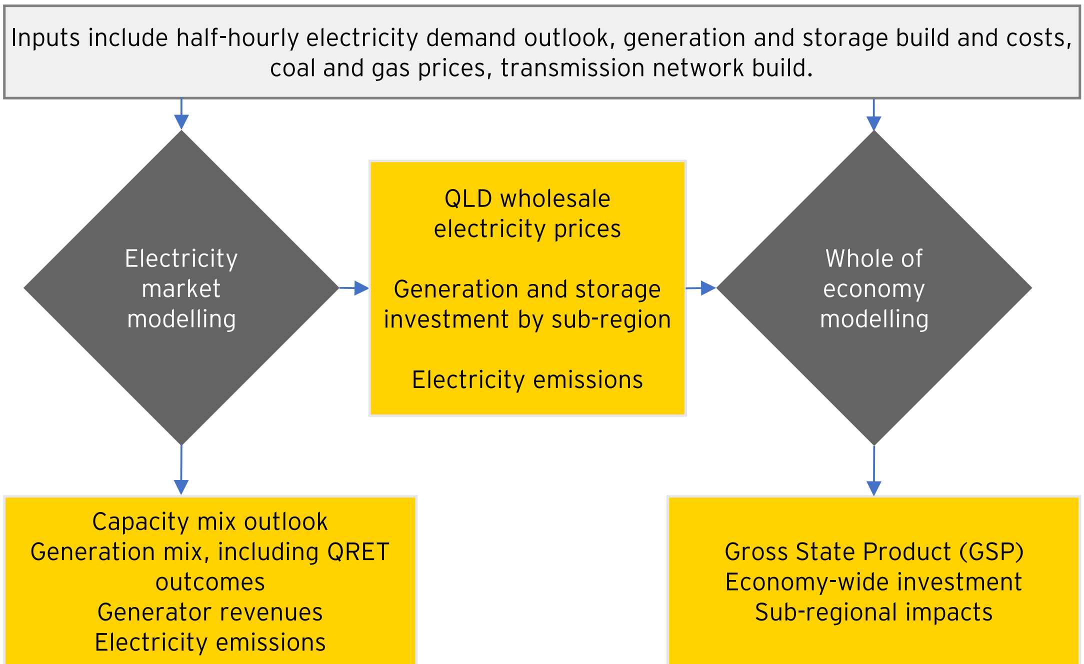
The Department engaged EY to conduct independent modelling and analysis to forecast the outcomes of the Energy Plan on the electricity sector and the Queensland economy. The modelling compares the outcomes of two scenarios: the Energy Plan and the Uncoordinated Outlook.

EY's outcomes presented in this Report are the product of two workstreams:

- Electricity market modelling conducted using EY's 2-4-C model
- Detailed economic analysis conducted using EY's whole of economy model.

Figure 10 illustrates an overview of the electricity market modelling and whole of economy modelling workstreams and how they interact.

Figure 10: Overview of the two workstreams



The market modelling is conducted using EY's in-house 2-4-C market dispatch model. This model has been applied with half-hourly time-sequential modelling over the modelled horizon to forecast the generation and wholesale electricity prices across the NEM in each scenario. By modelling generator bidding and transmission constraints, 2-4-C can forecast wholesale electricity prices and market revenues of individual generators.

As indicated in Figure 10, the Queensland wholesale electricity prices, generation and storage investment by sub-region and electricity emissions outcomes from 2-4-C are used as inputs into the whole of economy modelling.

To model the economic outcomes of the Energy Plan relative to the Uncoordinated Outlook, EY's computable general equilibrium (CGE) model, EYGEM, has been used. EYGEM captures the economic outcomes from changes to electricity prices and other variables on the Queensland economy, divided up into nine sub-regions. A full description of the model and its application can be found in Appendix C.

The scope of each workstream is explained in greater detail in Appendix A and Appendix B.

3.1 Scenario narratives

The narratives behind the two modelled scenarios are follows:

- **Uncoordinated Outlook**: in this scenario the Queensland Government does not make early investments in the electricity sector and there is no clear plan for the energy transformation available in the public domain. Investment in generation and storage occurs in response to electricity market signals only and policies already in place to promote renewables in other states.
- **Energy Plan**: this represents an outlook where there is a robust vision and infrastructure blueprint for the transformation of the Queensland electricity sector including key decisions relating to publicly-owned assets as well as proactive investment in wind and solar generation, pumped hydro storage and the transmission network.

3.2 Overview of scenario assumptions

Each scenario is modelled over a 17-year horizon from 2023-24 to 2039-40. EY has consulted with the Department Energy and Public Works, Queensland Treasury, Queensland Treasury Corporation (QTC), and Powerlink Queensland to define the input assumptions for the two modelled scenarios. Both scenarios use the 2022 ISP Step Change scenario input assumptions[9] and outcomes[10] for:

- Electricity demand outlook, including electric vehicles, distributed energy resources such as rooftop PV and batteries, electrification and hydrogen load
- State-based policy drivers, such as the New South Wales Electricity Infrastructure Roadmap (NSW Roadmap) and Victorian Renewable Energy Target (VRET)
- Future capital costs and fuel prices for generation and storage technologies
- The network development across the NEM based on the 2022 ISP optimal development path
- Renewable energy zone (REZ) capacity factors and build limits for wind and solar technologies.

Both scenarios assume a coordinated uptake of DER consistent with the Step Change outlook in the 2022 ISP. It is noted that this coordination is dependent on further actions by Government to ensure DER is effectively integrated into the network. If DER is not effectively integrated this may result in increased need for large-scale generation and storage along with potentially sub-optimal outcomes for consumers. This potential impact of this has not been modelled in the Uncoordinated Outlook Scenario.

Two key assumptions common to both scenarios that differ from the 2022 ISP Step Change scenario, as selected by the Department, are:

- No explicit emissions constraint is applied across the NEM. Instead, emissions reductions are achieved as a result of assumed state-based renewable policies.
- Coal and gas prices are increased throughout the modelled horizon to reflect the current market conditions and a continuation of the present drivers for high fuel prices including global trade uncertainty and fuel scarcity.

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[9] AEMO, 30 June 2022, *2022 Inputs, assumptions and scenarios workbook*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/inputs-assumptions-and-scenarios-workbook.xlsx

[10] AEMO, 30 June 2022, *2022 Integrated System Plan*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf

Table 5 summarises the differences in assumptions between the scenarios. All assumptions for the Energy Plan were provided by the Department and the transmission network augmentations were developed in consultation with Powerlink.

Table 5: The differences in assumptions between the scenarios as selected by the Department

Assumption	Uncoordinated Outlook	Energy Plan
QRET	No explicit targeting of the QRET	QRET to be met – 50% renewable generation as a percentage of consumption by 2030
Coal-fired generation retirement schedule	Announced retirement dates	Queensland coal-fired generation withdrawals across units from 2026-27 as advised by the Department based on the Infrastructure Blueprint[11]
Transmission network augmentations	As per 2022 ISP optimal development path	Additional augmentations in Queensland to support new capacity. This does not include CopperString[12] due the complexity of adding another region to the model.
Pumped hydro	Committed projects only	Borumba (2 GW, 24 hour) in 2029-30 Proxy 5 GW North Queensland Pumped Hydro[13] made up of: ▶ North Queensland (3 GW, 24 hour) in 2032-33 ▶ Additional pumped hydro storage (2 GW), (modelled as 8-hour batteries[14], 1 GW in 2031 and 1 GW in 2033)
Renewable and firming capacity	Market-driven capacity only	Early investment in renewable and storage capacity backed by the Queensland Government or private industry.
WACC	5.5%[15]	4.8% A lower WACC was selected by the Department informed by independent analysis. It is based on increased policy certainty and reflects broad benefits to the market anticipated as a result of publishing the Queensland Energy Plan and Infrastructure Blueprint and the actions contained within

Under the Queensland Energy Plan and Infrastructure Blueprint the Queensland Government has outlined a staged approach to coal-fired generation withdrawal ensuring system security and reliability is maintained. The schedule for withdrawals included in this modelling reflects when units are no longer generating but may not represent retirement or decommissioning dates. Figure 11 shows the assumed coal-fired generation withdrawal schedules for Queensland in each scenario.

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[11] The Infrastructure Blueprint is a technical document prepared by the Queensland Government outlining the investment pathway for major infrastructure in Queensland's electricity system under the Energy Plan.

[12] https://www.statedevelopment.qld.gov.au/coordinator-general/assessments-and-approvals/coordinated-projects/projects-discontinued-or-on-hold/copperstring-project

[13] At the time of modelling, the North Queensland Pumped Hydro project was not in the public domain.

[14] Assuming 8-hour batteries is a modelling simplification agreed with the Department and this is intended to represent pumped hydro with 24 hours of storage.

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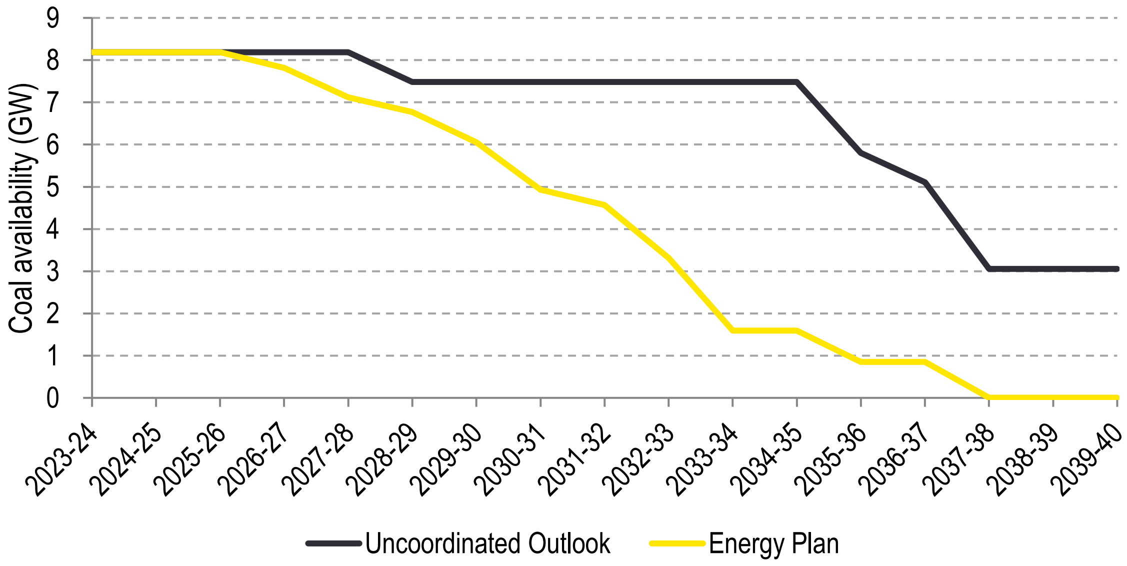
Figure 11: Queensland coal-fired generation availability, both scenarios



The Uncoordinated Outlook Scenario reflects announced retirement dates as per Australian Energy Market Operator (AEMO) Generating Unit Expected Closure Year May 2022[16] with the exception of an additional withdrawal of around 800 MW of coal-fired capacity that is assumed by the Department to withdraw on a commercial basis in 2037-38. The modelling also allows for earlier economic withdrawal where required.

The Energy Plan Scenario presents a faster withdrawal schedule as provided by the Department based on the Infrastructure Blueprint. By 2035-36, there is zero regular reliance on Queensland publicly-owned coal-fired generators, and the single privately-owned coal-fired generator remaining withdraws in 2037-38[17].

The Energy Plan Scenario includes assumed new transmission network links along with the two specific assumed pumped hydro projects and their locations, as selected by the Department. The new transmission links connect renewable and pumped hydro projects to the grid, connecting from the southern Queensland load centre north to the Gladstone load centre, the North Queensland Pumped Hydro project, Townsville and west to Hughenden. The Department has selected not to include the proposed CopperString transmission project in the modelling, primarily due to the complexity it would add as it could entail adding a new region to the National Electricity Market.

Note that no new capacity is assumed to be installed in the North QLD Clean Energy Hub REZ[18] in the Uncoordinated Outlook Scenario due to no high-voltage transmission link being installed to connect those potential projects to the grid.

The lower WACC in the Energy Plan Scenario was provided by the Department informed by independent analysis on the assumption that the coordinated approach to renewable development in Queensland provides greater investment certainty. A reduced WACC is representative of the broad benefits to the market anticipated as a result of publishing the Queensland Energy Plan and Infrastructure Blueprint and the actions contained within. This includes greater certainty on the outlook for publicly-owned assets, lower costs and improved coordination through development of

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[16] AEMO, May 2022. *Generating unit expected closure year – May 2022*. Available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[17] This is on the basis that the energy system at this time can support a zero-coal system. This is also an assumed outcome as provided by the Department and does not represent decisions made by a private company about their assets.

[18] https://www.aemo.com.au/aemo/apps/visualisations/map.html

Queensland REZs, and proactive investment into long-duration storage and transmission infrastructure by Government. In this scenario, the lower WACC is applied to the investment of new generation and storage in Queensland only. As generation and storage investment in the Energy Plan Scenario is assumed to occur proactively due to the long-term signal for investment provided by the policy, the lower WACC in Queensland in not a key driver of wholesale market capacity outlook under the Energy Plan Scenario and wholesale market outcomes. The value assumed does influence the estimated investment costs based on the wholesale market modelling outcomes, but these are not incorporated in the whole of economy modelling regardless (see Section 4.2.6).

4. Electricity sector modelling

This section presents the outcomes of the electricity sector modelling for the Energy Plan Scenario and the Uncoordinated Outlook Scenario.

4.1 Modelling approach

EY has used its proprietary time-sequential market dispatch model 2-4-C for the results presented in this Report. We model the whole of the NEM. In Queensland, the Mt Isa electricity grid and other off-grid electricity is not explicitly modelled for the outcomes in this Report.

The 2-4-C dispatch engine is equivalent to the NEM Dispatch Engine (NEMDE) used by the AEMO to operate the market in real time. This study is modelled at a half-hourly, time-sequential resolution over the modelled horizon. The model includes explicit representation of each generating unit and the capabilities of the electricity transmission network. 2-4-C incorporates strategic bidding profiles for each generator, as well as comprehensive network constraint equations for current and future networks states, both of which are essential to forecast wholesale electricity prices and generator wholesale market revenue expectations. In addition, in this study 2-4-C incorporates three historical weather years for the modelled locational wind and solar generation profiles, which is key to capture sufficient variability from wind and solar generation in the capacity development plan and the relationship between demand and wind and solar availability.

Subject to the assumptions for each scenario including assumed build limits by REZ (see Appendix A.2.2), a capacity mix based on market revenues is forecast. The primary metric used in forecasting the capacity mix is the return on investment for each new individual generator, expressed as the net profit or loss in each modelled year[19] as a percentage of the annualised capital cost. New candidate generator types are solar PV, wind, batteries, open cycle gas turbines (OCGTs) and combined cycle gas turbines (CCGTs). The final outcomes in each scenario achieve a return on investment for each new generator within +/-20%.

New generation and storage are installed on an economic basis from 2025-26 in the Uncoordinated Outlook Scenario. Under the Energy Plan Scenario, the Department anticipates greater renewable investment is brought online through proactive development of REZs, investment in storage, withdrawal of coal-fired generation and direct investment by the private sector and publicly-owned energy corporations.

Existing power stations could also be retired earlier than their announced retirement dates based on their forecast market revenue less assumed operating costs, but this did not occur in the two scenarios.

A more detailed description of the market modelling approach is given in Appendix A.

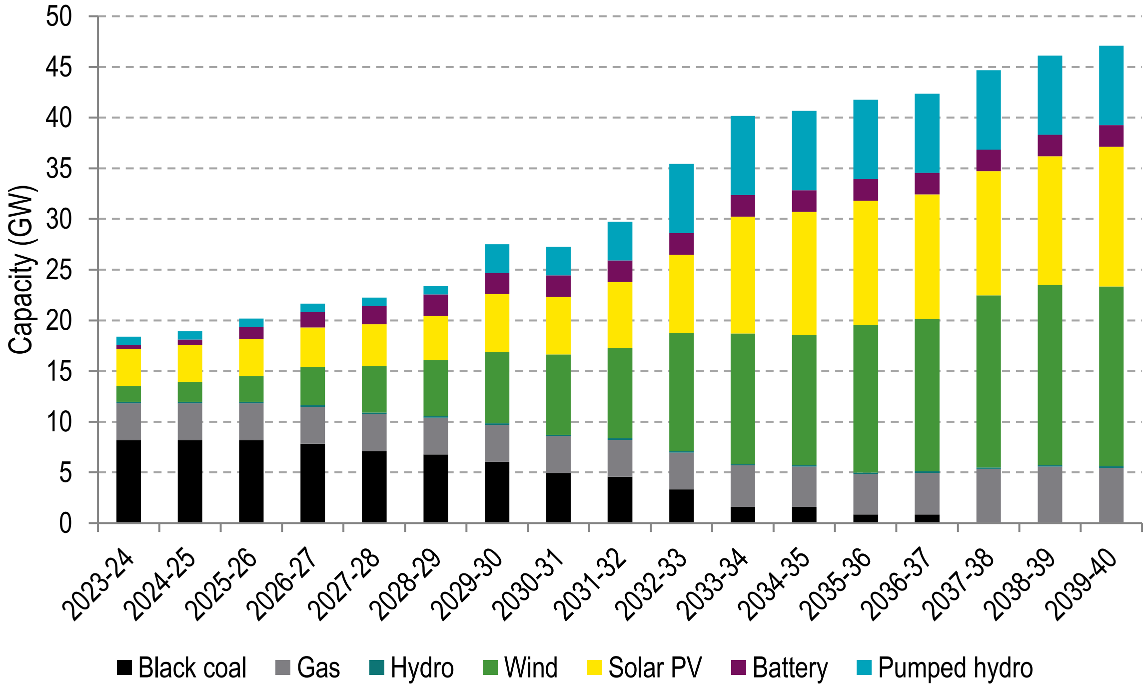
4.2 Modelling outcomes

4.2.1 Capacity mix

Figure 12 shows the forecast capacity mix outlook for Queensland in the Energy Plan Scenario and Figure 13 shows the annual changes in capacity.

[19] The net profit or loss is calculated as the modelled electricity market revenue less annualised capital costs and operating costs including fuel and operations and maintenance.

Figure 12: Forecast Queensland large-scale capacity mix, Energy Plan Scenario[20]



The chart above shows a steady transformation with wind, solar and storage capacity replacing Queensland coal-fired capacity from 2026-27. In addition to the large-scale capacity shown in the chart, there is also an assumed uptake of rooftop PV, small non-scheduled solar PV (PVNSG) and behind-the-meter battery capacity that is part of the ISP Step Change scenario. In the Step Change scenario rooftop PV capacity in Queensland is assumed to increase from 6 GW in 2023-24 to 13 GW in 2039-40, and behind-the-meter storage capacity is assumed to increase from 0.5 GW to 8.8 GW over the same period.

[20] In the Energy Plan Scenario 2 GW of 8-hour battery capacity installed in 2031-32 and 2033-34 is modelled to represent additional pumped hydro capacity. It is shown in this chart as pumped hydro capacity. The additional North Pumped Hydro was not in the public domain at the time of modelling.

Figure 13: Forecast year-to-year changes in Queensland large-scale capacity, Energy Plan Scenario

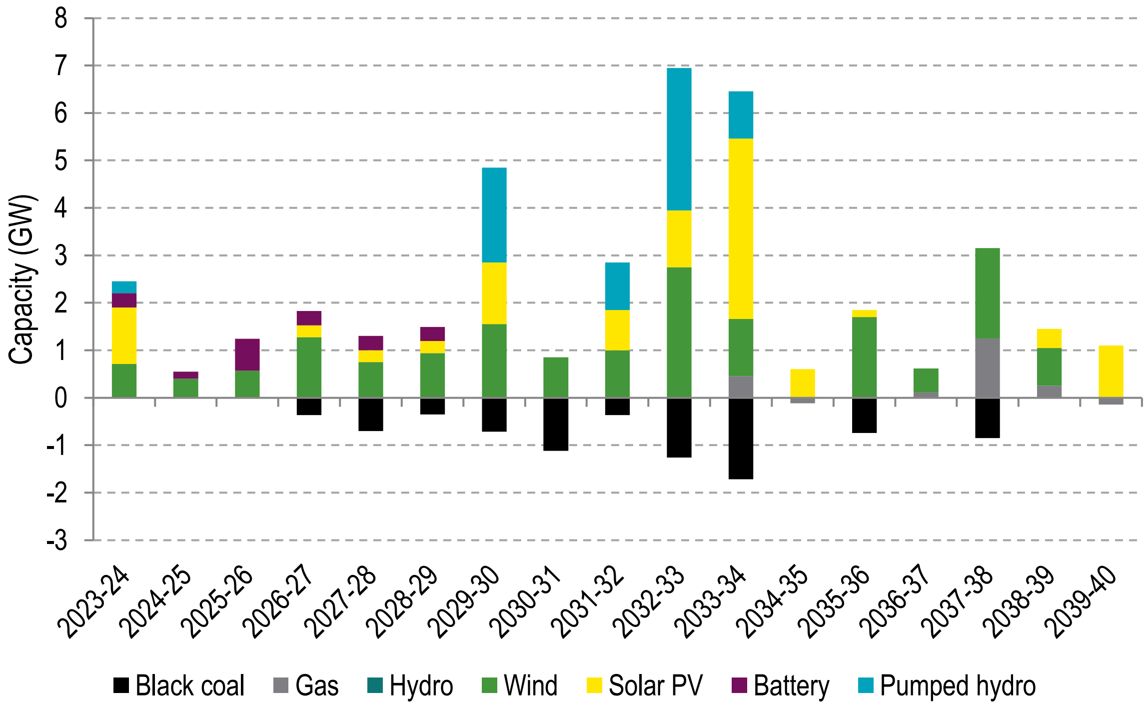


Figure 13 shows the year-to-year change in Queensland new large-scale capacity and illustrates:

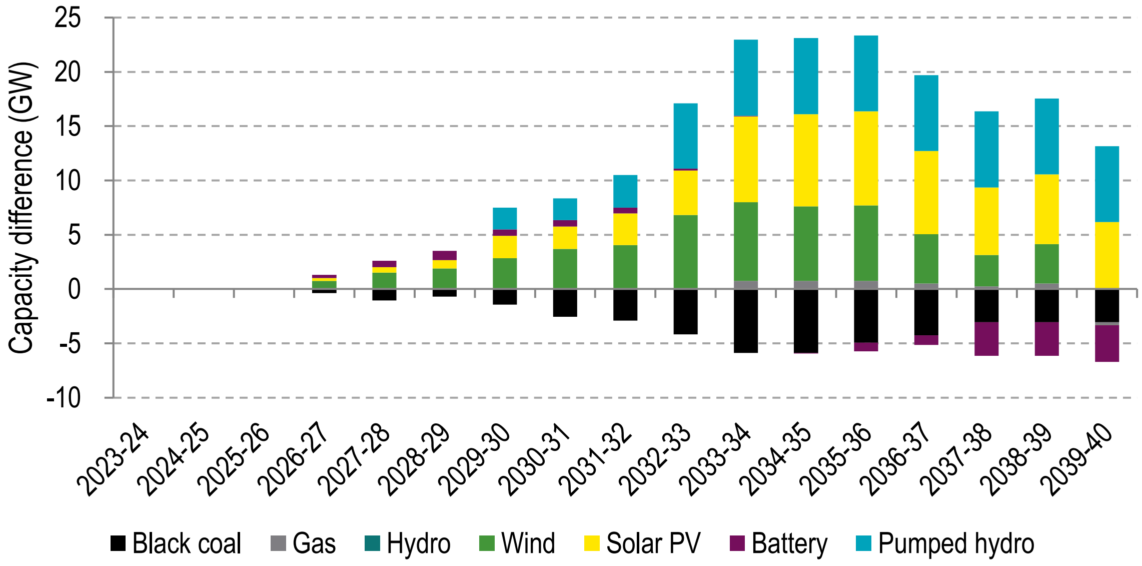
- Committed capacity built up to 2026-27, as selected by the Department (this is the same across both scenarios)
- Additional renewable and battery storage capacity anticipated to be backed by publicly-owned corporations or private industrial decarbonisation targets[21] and to moderate the annual build rate under the Department's assumption of a coordinated transformation
- The assumed new pumped hydro capacity built as part of the Energy Plan, as selected by the Department.

In line with the Department's assumption of a coordinated transformation and steady build, the combined build of new wind and solar capacity was limited to 5 GW per year, which binds in 2033-34. However, it is anticipated that renewable energy will be built in advance of this build limit being reached, and this has been included in the Energy Plan Scenario with 4 GW built in the previous year, 2032-33. The build rate in other years generally varies between 1-2 GW/year, except with 3 GW built in 2029-30. As capacity is developed across the NEM and network augmentations unlock new REZs for generation development, industry may be able to achieve higher build rates over time.

Figure 14 shows the difference in forecast capacity mix in Queensland between the Energy Plan Scenario and the Uncoordinated Outlook Scenario in each year.

[21] For example: Rio Tinto, 8 June 2022. *Rio Tinto calls for proposals for large-scale wind and solar power in Queensland* [media release]. Available at: https://www.riotinto.com/news/releases/2022/Rio-Tinto-calls-for-proposals-for-large-scale-wind-and-solar-power-in-Queensland

Figure 14: Forecast difference the annual Queensland capacity mix, Energy Plan Scenario minus Uncoordinated Outlook Scenario



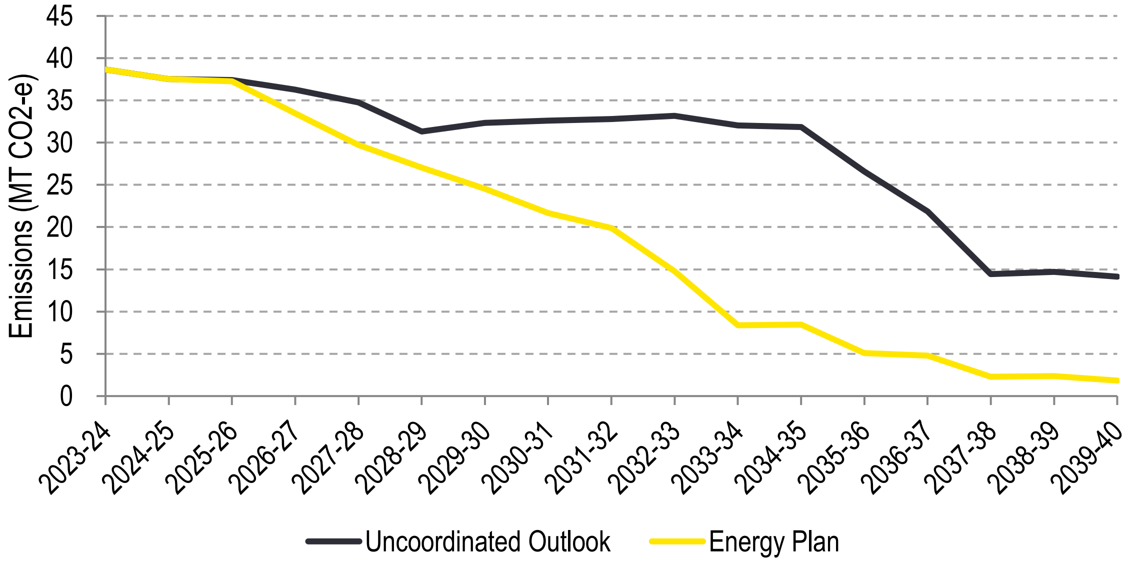
The Energy Plan Scenario is assumed to develop wind, solar and batteries in excess of the Uncoordinated Outlook Scenario from 2026-27 as coal-fired generation is assumed to begin withdrawing from the market ahead of assumed withdrawal timings in the Uncoordinated Outlook Scenario. Under the Energy Plan Scenario this is estimated to result in around 15 GW more variable renewable energy being developed by the mid-2030s, and around 7 GW of pumped hydro storage. The chart shows that more firming capacity provided by pumped hydro storage (or potentially large-scale battery storage) in the Energy Plan Scenario is required as Queensland coal-fired generation withdraws. This storage is used to shift the energy from wind and solar from time-of-generation to time-of-consumption.

4.2.2 Electricity emissions

The Energy Plan Scenario is forecast to have materially lower emissions from Queensland generators than the Uncoordinated Outlook Scenario. Figure 15 presents the annual emissions from Queensland generators forecast in both scenarios. The combustion and fugitive emissions are estimated from the dispatched energy of fossil fuelled generators in the half-hourly modelling based on AEMO's 2022 assumptions of the emissions intensity of each individual power station[22].

[22] AEMO, 30 June 2022, *2022 Inputs, assumptions and scenarios workbook*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/inputs-assumptions-and-scenarios-workbook.xlsx

Figure 15: Forecast annual Queensland generation emissions (Mt CO_2-e), both scenarios



Under the Energy Plan Scenario, emissions from the NEM-connected Queensland electricity sector are anticipated to fall by 56% on 2005 levels from 49 Mt in 2005[23], to 22 Mt in 2030-31 and by 96% on 2005 levels by 2039-40, down to 2 Mt.

The figures show that the Energy Plan Scenario is forecast to have a quicker rate of emissions reduction and hence lower cumulative emissions from Queensland generators. This is due to the Energy Plan Scenario having a more rapid assumed withdrawal of the State's coal-fired power stations, and replacement by new renewable capacity.

In the Uncoordinated Outlook Scenario, there is limited reduction in annual emissions forecast until the mid-2030s when Queensland coal-fired generators are assumed to start to withdraw based on their current announced end-of-lifetime closure dates.

4.2.3 QRET

Only the Energy Plan Scenario is forecast to meet the QRET of 50% of Queensland demand met by renewable generation by 2030. Figure 16 shows the projected proportion of Queensland demand met by renewables in both scenarios.

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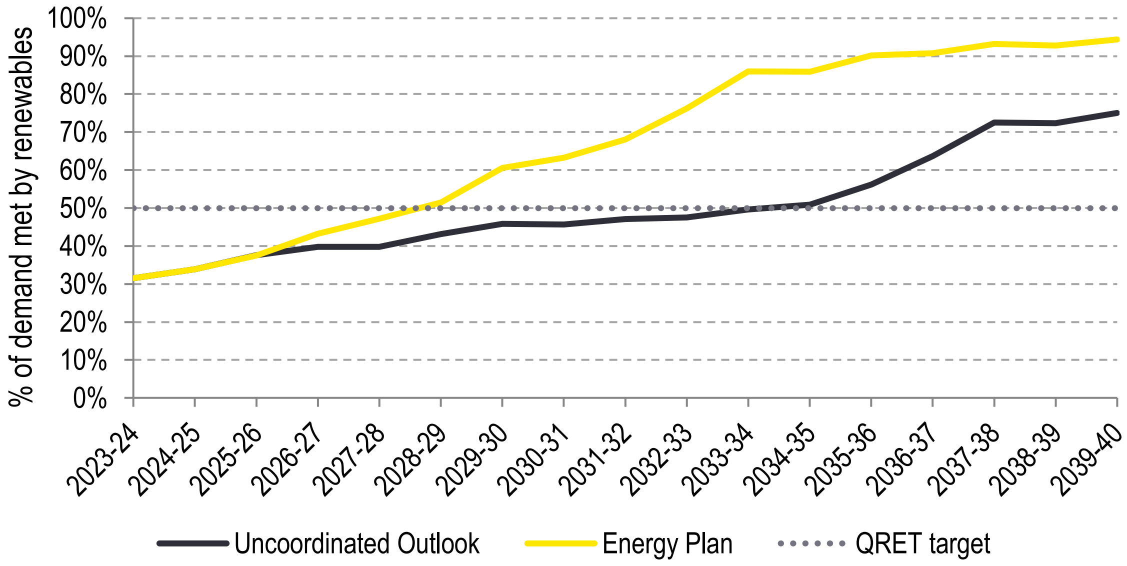
[23] Department of Industry, Science, Energy and Resources, October 2021, *Australia's emissions projections 2021*, Available at:https://www.industry.gov.au/sites/default/files/October%202021/document/australias_emissions_projections_2021_0.pdf

Figure 16: QRET comparison, both scenarios



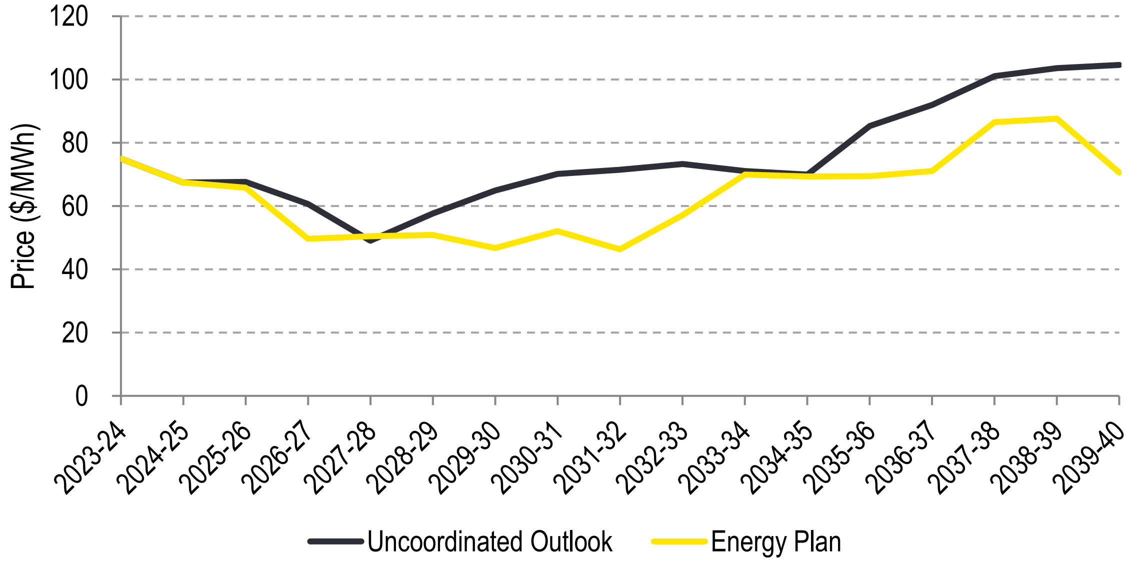
In the Energy Plan Scenario, the QRET target is forecast to be met 2 years early, by 2028-29, primarily driven by committed projects and the assumed early development of renewable capacity through both industrial decarbonisation ambitions and government direct investment. By 2030-31 the Energy Plan Scenario reaches 63% renewable energy, around 75% in 2032-33 and this increases to around 90% in 2035-36.

In the Uncoordinated Outlook Scenario the QRET is not met. The 50% generation target is not achieved until 2033-34 and the renewable percentage does not reach above 60% until after 2035-36. This slower transformation occurs as wind and solar are forecast to only enter the market when commercially driven by a combination of factors including the assumed increase in electricity demand, increased exports to New South Wales upon the withdrawal of Bayswater Power Station in New South Wales in 2033-34 and assumed withdrawals of coal-fired capacity in Queensland in the late 2030s.

4.2.4 Wholesale electricity market prices

Wholesale electricity market prices in Queensland are forecast to be lower in the Energy Plan Scenario than the Uncoordinated Outlook Scenario, as illustrated in Figure 17.

Figure 17: Forecast Queensland time-weighted average wholesale electricity market price, both scenarios



Under the Energy Plan Scenario, wholesale prices are expected to be 15% lower than the Uncoordinated Outlook Scenario on average to 2039-40. This equates to an average difference of $15/megawatt hour (MWh) over the modelled horizon.

Annual changes in the forecast Queensland wholesale market price under the Energy Plan Scenario are driven by the following:

- Prices are forecast to be lower in the Energy Plan scenario between 2025-26 and 2029-30 due to the additional 6.5 GW of new wind and solar capacity, and 900 megawatts (MW) of battery capacity assumed to enter backed by industrial decarbonisation and government direct investment. This capacity is forecast to more than compensate for the assumed withdrawals of Queensland coal-fired capacity leading to lower prices on average.
- Between 2029-30 and 2033-34 more Queensland coal-fired generation is assumed to withdraw while Borumba Pumped Hydro, and North Queensland Pumped Hydro are assumed to be developed to provide firming capacity along with further new renewable capacity. This new renewable and storage capacity is forecast to continue to keep average wholesale electricity prices lower than in the Uncoordinated Outlook Scenario, despite forecast rises in the Energy Plan Scenario between 2031-32 and 2033-34 due to coal-fired generation withdrawals over this period (~3 GW). In 2033-34, the assumed 5 GW annual combined wind and solar build limit is forecast to bind, limiting commercial build of additional renewable generation in that year and raising forecast Energy Plan prices to meet Uncoordinated Outlook prices.
- From 2033-34 to 2036-37 the forecast average prices in the Energy Plan Scenario are stable and continue to remain below the Uncoordinated Outlook Scenario outcome. When the final publicly-owned coal-fired power station is assumed to exit the market in 2035-36, nearly 2 GW of wind and solar PV capacity is forecast to be commercially commissioned in the North QLD Clean Energy Hub REZ (i.e., with sufficient wholesale market revenue to achieve its assumed required rate of return on investment). New capacity first becomes available in this REZ in this year due to the assumed new transmission network connecting Hughenden to Ross.
- In 2037-38, the last Queensland coal-fired power station is assumed to withdraw from the market (0.9 GW of privately-owned coal-fired capacity) along with further assumed increases in electricity demand. 1.9 GW of wind and 1.3 GW of peaking gas capacity are

forecast to be the commercially driven new capacity along with an increase in average wholesale electricity prices to over $80/MWh.

- The average wholesale electricity prices are forecast to reduce back to approximately $70/MWh in 2039-40, largely driven by the assumed new transmission link from Hughenden to Halys, unlocking previously curtailed wind generation installed in the North QLD Clean Energy Hub. An additional 3.7 TWh of wind generation is able to be dispatched in 2039-40 from the North QLD Clean Energy Hub, which is the equivalent energy of approximately 1 GW of wind capacity at 40% capacity factor.

Annual changes in the forecast prices under the Uncoordinated Outlook Scenario are driven by the following:

- Prices decrease in the Uncoordinated Outlook Scenario to a low in 2027-28 due to the development of the NSW Roadmap without the withdrawal of Queensland coal-fired generators. Whilst the NSW Roadmap is assumed to be developed in both scenarios, the Uncoordinated Outlook benefits from lower priced electricity imports from New South Wales, as the capacity mix in Queensland remains constant, leading to a decline in annual average prices.
- Between 2028-29 and 2032-33 prices are forecast to gradually rise due to announced coal-fired generation withdrawals in Queensland and New South Wales without significant new capacity being developed based on market price signals. Over this period 1 GW of commercial wind is developed in Queensland and no large-scale solar PV is forecast to be commercially viable, compared with 6 GW of wind and 3 GW of solar in the Energy Plan Scenario.
- From 2034-35, the price increases with the assumed withdrawal of Gladstone Power Station, Swanbank E, Tarong and Tarong North Power Stations and an additional approximately 800 MW of coal-fired capacity.

Additionally, under the Energy Plan Scenario Queensland's electricity market prices are less dependent on fuel prices, particularly coal prices, due to there being less coal-fired generation in operation. The market is therefore more resilient to future price shocks resulting from global instability, such as the most recent outcomes in the energy sector during winter 2022, which were driven in part by global factors like overseas conflict.

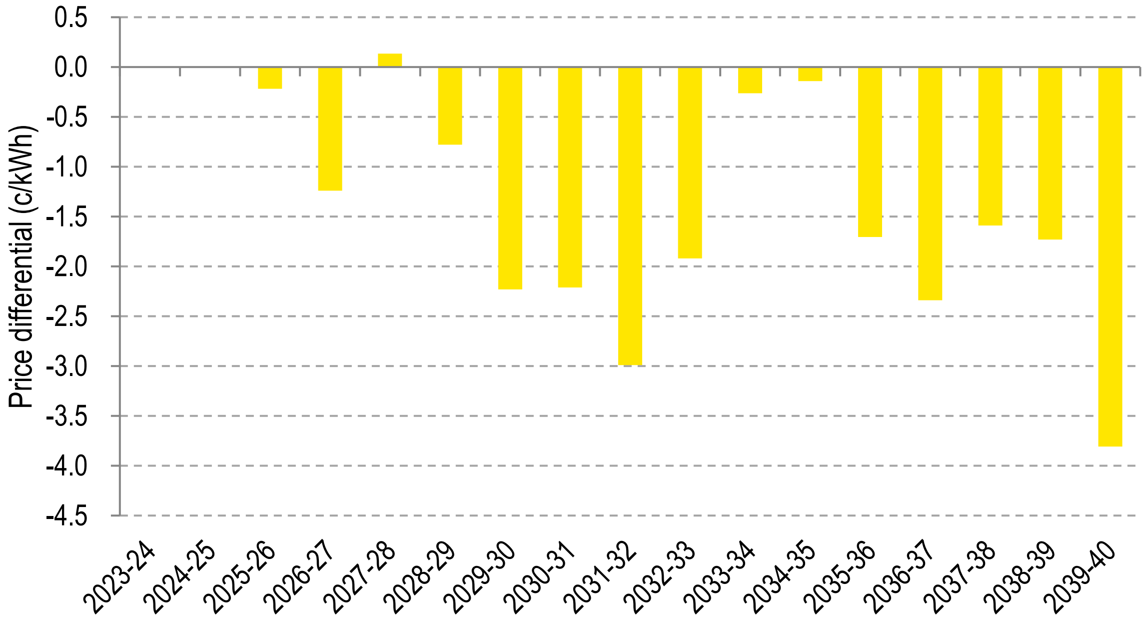
4.2.5 Outcomes for electricity retail prices

To estimate the outcome of the Energy Plan Scenario's reduced wholesale electricity market prices on Queensland retail electricity bills, EY adopted the following approach:

- An assumption that the entire differential in the wholesale market price between the Energy Plan and Uncoordinated Scenarios is passed through to electricity customers and that this is spread evenly amongst all types of customers.
- The differential in the annual demand-weighted average wholesale electricity price is used as this represents the average wholesale price for each kilowatt hour (kWh) of electricity consumed from the electricity grid.

Using this approach, Figure 18 shows the outcomes for the wholesale market component on Queensland retail electricity bills.

Figure 18: Outcome of the Energy Plan Scenario on the wholesale electricity component of Queensland retail bills, compared to the Uncoordinated Outlook Scenario



The year-to-year variations follow the year-to-year differences in the average wholesale electricity prices as described in Section 4.2.4. The forecast average reduction in the wholesale component of Queensland retail electricity bills due to the Energy Plan Scenario compared to the Uncoordinated Outlook Scenario is 1.4 c/kWh.

Table 6 presents these outcomes for a representative residential customer, who consumes around 5 MWh per annum[24], and a representative small business who consumes around 50 MWh[25].

Table 6: Annual outcomes of the Energy Plan Scenario on the wholesale electricity component of Queensland representative residential and small business retail bills, compared to the Uncoordinated Outlook Scenario, for selected modelled years

Year	Residential	Small business
2029-30	$112	$1,115
2031-32	$150	$1,495
2039-40	$190	$1,904

4.2.6 Investment costs

As summarised in Section 3.1, the Energy Plan involves key decisions relating to publicly-owned assets as well as proactive investment in wind and solar generation, pumped hydro storage and the transmission network. EY has estimated the investment costs required for the Energy Plan based on a combination of input assumptions and electricity market modelling outcomes. Table 7 summarises the approach taken for each of these components.

[24] Source: Table 9 in Frontier Economics' Residential energy consumption benchmarks for the Australian Energy Regulator. Available at: https://www.aer.gov.au/system/files/Residential%20energy%20consumption%20benchmarks%20-%209%20December%202020_0.pdf

[25] Source: Queensland Government, Business Queensland, Energy Supply and Pricing. Available at: https://www.business.qld.gov.au/_designs/content/guide-printing2?parent=53427&SQ_DESIGN_NAME=print_layout

Table 7: Approach to estimating the investment costs of the Energy Plan

Category	Approach	Source
New wind, solar and battery capacity funded by industry and government	Annualised capital costs[26] + operating costs – forecast wholesale market revenues - forecast wholesale market charging/pumping costs (storage only)	Input assumptions and market modelling outcomes
New pumped hydro capacity[27]		
New transmission links	Annualised capital costs[28]	Input assumptions as provided by Powerlink
Changes in net revenues for publicly-owned coal-fired generators	Difference between the two scenarios on: Forecast wholesale market revenues - operating costs	Input assumptions[29] and market modelling outcomes

In calculating the whole of economy outcomes, assumptions on investments costs have been agreed with the Department. Funding sources for these investment costs will vary depending on asset type, future policy decisions by Government and investment decisions by the private sector. In the Energy Plan scenario, the gradual withdrawal of coal-fired generation means that the revenues these generators could have made in the later years of the model (if profitable) are forgone. The electricity market model calculates these revenues to be an average of $0.7b per annum over the modelled period. Importantly, outcomes later in the model are subject to increased uncertainty. Impacts of the changes in the net revenues for the existing generators will vary depending on a range of factors such as portfolio financial performance, Government policy and market conditions. As such, it is assumed that forgone revenue does not flow through to the whole of economy modelling.

As agreed with the Department, under the Energy Plan Scenario, generation and storage investments listed in Table 7 are brought forward ahead of wholesale market price signals to reflect the anticipated early investment by the market and GOCs. This is a key driver of lower wholesale electricity price outcomes in the Energy Plan Scenario. It is assumed that the investment costs associated with earlier project deployment compared to forecast wholesale market energy revenues (estimated to be $0.6b per annum over the modelled period) are addressed by additional revenue streams along with greater certainty and therefore do not flow into the whole of economy modelling. This earlier investment is assumed to be driven by a number of key factors which are expected to have an impact on asset funding and revenue but are challenging to capture within the market modelling. Namely:

- Additional potential revenue streams for renewable and storage projects beyond the wholesale energy market alone (e.g., large industrial players directly investing into renewable energy, offtake arrangements with corporations seeking to decarbonise operations and contracts with energy GOCs for power purchase agreements),
- The strong signal for early investment provided by the certainty from announced coal-fired generation withdrawal and investment in government-backed large-scale long duration pumped hydro energy storage (like Borumba and the North Queensland Pumped Hydro) that provides firming to the Queensland system,

[26] Generation and storage capital costs are annualised using the assumed WACC selected by the Department, which is 4.8% pre tax, real in the Energy Plan Scenario.
[27] This comprises the full 7 GW, i.e., it includes the 2 GW modelled as 8-hour batteries are described in Table 5.
[28] Transmission capital costs are annualised using an assumed WACC of 4% pre tax, real, as selected by the Department. This is lower than for generation due to transmission being a regulated asset.
[29] The Department supplied specific operating costs in $/MWh for each publicly-owned Queensland coal generator.

- Efficiencies gained through the development of the Queensland renewable energy zones framework, including initiatives to streamline project development that could lower risks and costs for renewable investors,
- Increased investment driven by national policy (for example an expanded Safeguard Mechanism or investment through national bodies like the Clean Energy Finance Corporation and Rewiring the Nation),
- Potential regulatory reform for the National Electricity Market including energy security services, capacity market benefits, and other market reforms resulting from the Energy Security Board's post 2025 reforms,
- Queensland's GOCs accessing competitive debt through Queensland Treasury Corporation and funding from the Queensland Renewable Energy and Hydrogen Jobs Fund to bring forward new projects.

The Department also notes that transmission investment could access schemes like the Federal Government's Rewiring the Nation policy and therefore is excluded from the whole of economy modelling.

4.2.7 Considerations beyond 2040

By 2040, the transmission network and the capacity mix in Queensland is very different in the two scenarios. In the Energy Plan Scenario there is no Queensland coal-fired capacity remaining online and further emissions reductions can focus on converting the remaining gas capacity to other zero-emission fuels. There is also still room for further wind and solar PV investment, including in the North QLD Clean Energy Hub. For these reasons, it is expected that wholesale market prices would continue to be steady in the Energy Plan Scenario beyond 2040.

In contrast, in the Uncoordinated Outlook Scenario further Queensland coal-fired withdrawals are anticipated in the 2040s but with the Queensland transmission network still largely similar to today and without access to the North QLD Clean Energy Hub wind and solar resources, the options for new renewable generation and associated storage capacity are limited relative to the Energy Plan Scenario. If this continued, wholesale prices would be expected to continue to be higher than the Energy Plan Scenario.

Investment in new storage and transmission to unlock opportunities for new renewable generators would likely still need to occur in the longer term in the Uncoordinated Outlook Scenario as coal-fired generators reach end-of-life. This delays the costs of investment, but there is an associated delay in realising the benefits associated with these large projects. Furthermore, cumulative electricity sector emissions are significantly higher.

The Uncoordinated Outlook also carries higher risk of higher energy prices associated with unforeseen events such as coal-fired capacity outages as assets age and fuel cost uncertainty.

5. Whole of economy modelling

This chapter discusses the potential whole of economy outcomes of the Queensland Energy Plan, which factors in the scale, composition and electricity market effects of the new generation and network capacity investments.

5.1 Estimating the economic outcomes of the Queensland Energy Plan

Economic modelling has been undertaken using EY's General Equilibrium Model, EYGEM (see Appendix B). As with the electricity market modelling, the economic modelling compares the Energy Plan Scenario as the policy case to Uncoordinated Outlook Scenario as the counterfactual.

The key economic channels

The Queensland Energy Plan is a policy to drive significant investment in electricity infrastructure, building new renewable generation, storage and transmission. As a major capital build, the infrastructure program will drive activity in construction and other related sectors such as transport, accommodation and food services. Importantly, reflecting the regional profile of the investment, much of the stimulatory outcomes of the Energy Plan are expected to occur outside of South East Queensland.

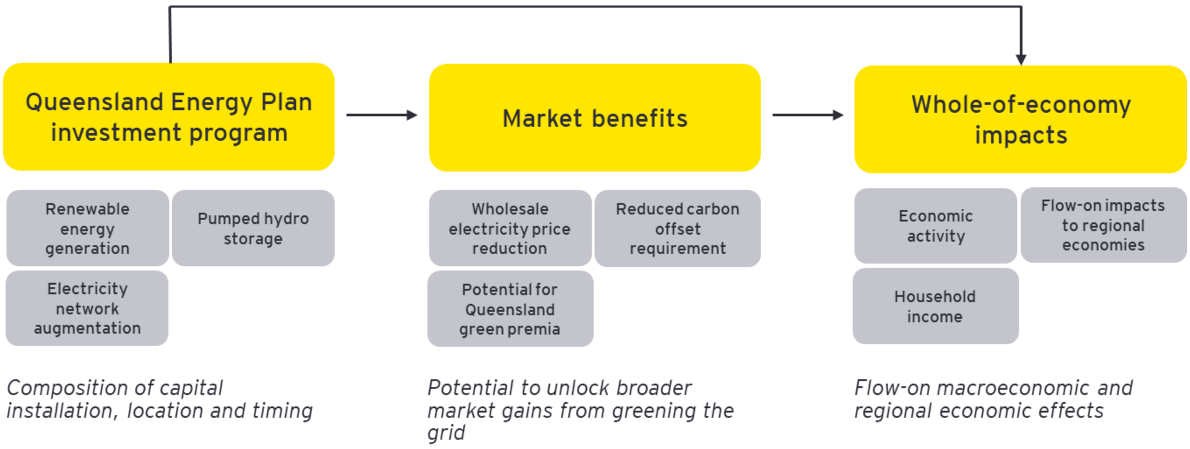
In addition to the direct infrastructure investment, the Energy Plan is also expected to have broader effects on the Queensland economy. These include the following key market benefits, which influence the economy in different ways:

- **A reduction in electricity prices,** which lowers the cost base for businesses and consumers.
- **A decrease in the cost of carbon emissions** as a result of a low-emissions electricity grid, and a subsequent decrease in the level of emissions required to be offset.
- **A green premium on Queensland production** making Queensland a more attractive place to invest.

These drivers were considered in assessing the overall economic outcomes of the Energy Plan[30]. A summary of the modelled flow-on impacts from the Energy Plan is shown in Figure 19.

[30] The modelling has not considered economic activity as a result of small-scale renewable energy investments like rooftop solar, batteries or electric vehicles. This is because both the Energy Plan and Uncoordinated Outlook scenarios assume the same AEMO ISP Step Change uptake of distributed energy resources (DER). Further policies from Government are likely required to improve coordination and integration of DER to realise their full potential. Increased uptake of these technologies, especially in highly populated regions like SEQ, are likely to result in increased economic activity associated with the installation and maintenance of these devices.

Figure 19: The economic drivers of the Energy Plan



The following sections describe the modelled outcomes of the Energy Plan and the potential macroeconomic benefits that could occur. As described in Section 4.2.6, the outcomes represent an upper bound to the benefits, given considerations around funding of investments and revenue changes of publicly-owned assets have not been considered in the whole of economy modelling.

5.2 Input assumptions

This section describes each of the economic drivers modelled and provides macroeconomic insights into the effect of the Energy Plan.

5.2.1 Electricity infrastructure investment

The decarbonisation of the Queensland electricity grid under the Energy Plan is underpinned by significant investment in renewable power sources, storage and electricity transmission network. The build program (described in Section 3.2) is expected to lead to increased economic activity through demand for construction services and materials.

The pattern of investment under the Queensland Energy Plan is regionally focused (see Figure 20), with new electricity infrastructure investment varying between $9.9b[31] in Darling Downs and $1.1b[28] in Outback Queensland.

[31] In 2022 NPV terms using a 7% discount rate.

Figure 20: Map of the sub-regions represented in the whole of economy modelling and electricity infrastructure investment under the Queensland Energy Plan

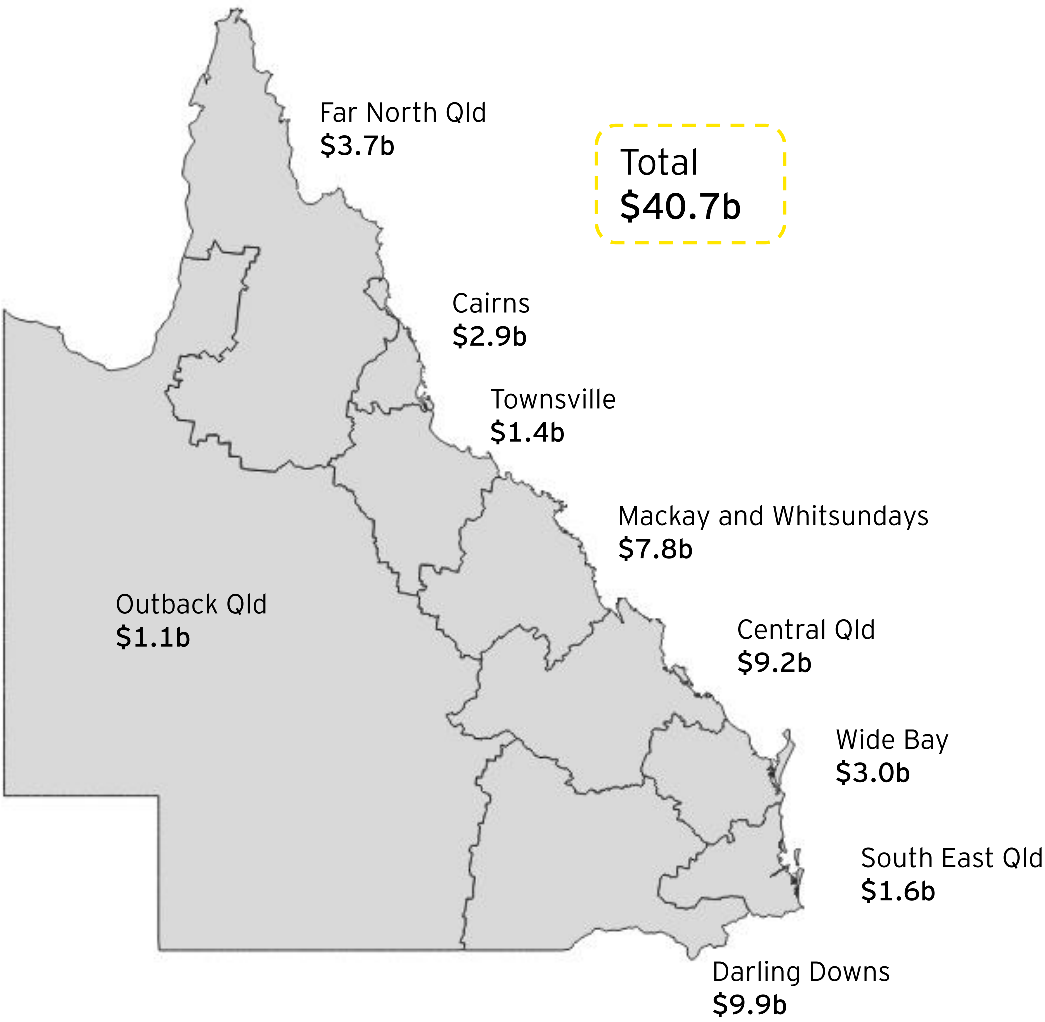
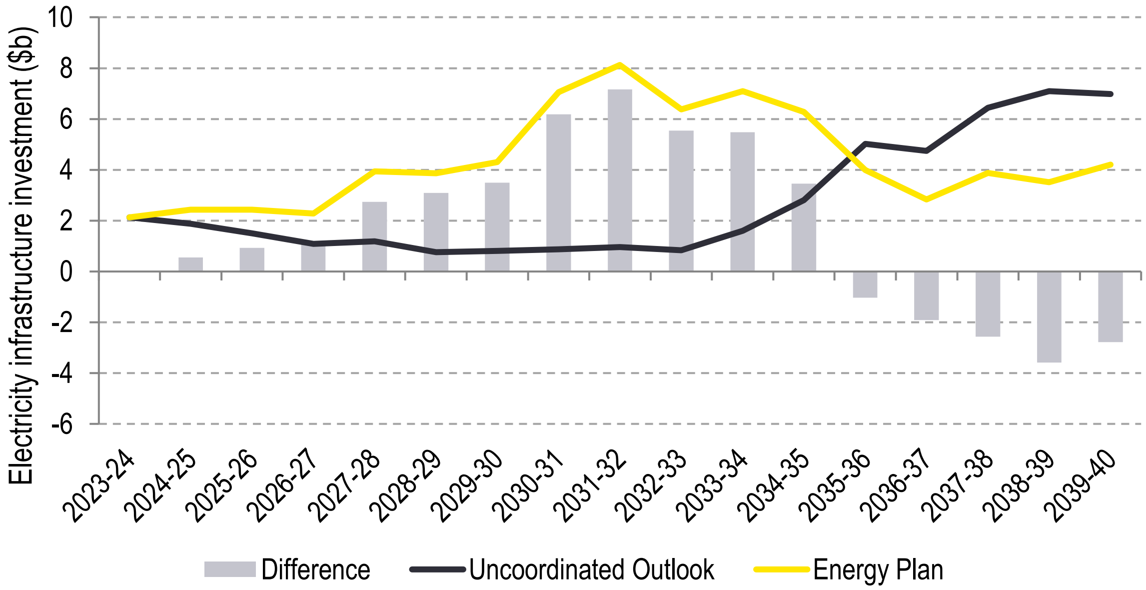


Figure 21 shows the annual electricity infrastructure investment in the Energy Plan and Uncoordinated Outlook scenarios, as applied in the whole of economy modelling[32]. The peaks in the investment program under the Energy Plan Scenario involve the development of significant pumped hydro projects and related renewable energy infrastructure. Under the Energy Plan Scenario overall investment in electricity infrastructure is $18.4b higher than in the Uncoordinated Outlook Scenario, in NPV terms. This figure is derived from a combination of the input assumptions provided by the Department for the two scenarios and the electricity market modelling outcomes for the generation and storage capacity mix in each scenario.

[32] The whole of economy modelling uses a 5-year lead time across all investments, with a simple average of the investment costs over the 5 years leading up to and including the year of commissioning for all investment.

Figure 21: Total capital investment in generation, storage and transmission comparing the Energy Plan and Uncoordinated Outlook Scenarios, as applied in the whole of economy modelling



The Energy Plan Scenario involves significant investment in renewables, storage and transmission infrastructure over the next decade, while the Uncoordinated Outlook Scenario sees minimal additional investment activity prior to 2034-35.

In the Uncoordinated Outlook Scenario, some Queensland coal-fired generators reach their assumed end of life after 2035-36 with associated investment in generation and battery storage expected to occur following this decommissioning. The 'front loading' of the investment in the Energy Plan Scenario boosts construction activity earlier, bringing forward the benefits of increased economic activity.

5.2.2 Reduced electricity prices

Electricity is a major cost for industry, especially heavy industry, and households. Excluding households, a small group of heavy industries in Queensland concentrated in the mining and metal refining sectors consume the majority of the electricity in the state. Large consumers of electricity are most exposed to fluctuations in price.

As discussed in Section 4.2.5 the Energy Plan Scenario results in lower electricity prices (see Figure 18). The reduction in price decreases the operating costs of almost all businesses, but particularly heavy industry such as aluminium production. This cost reduction improves competitiveness on a global and domestic level and can lead to an increase in production, exports and investment..

5.2.3 Carbon offset costs

The Queensland Energy Plan increases renewable electricity deployment and reduces emissions, relative to the Uncoordinated Outlook Scenario. The Energy Plan Scenario is forecast to have significantly reduced electricity emissions from 2026-27 compared to the Uncoordinated Outlook Scenario (see Figure 15).

The specifics of future carbon mitigation scheme design (and, in particular, any future carbon budgets for Queensland) are the subject of ongoing policy refinement at the national level, and the depth and maturity of international markets for carbon permit trading will continue to evolve over the modelled horizon to 2039-40.

Notwithstanding these uncertainties, a reduction in emissions at the Queensland state level is likely to either lead to an increased ability for Queensland to sell excess permits (should state emissions be lower than an allocated carbon budget) or a reduced requirement for Queensland to purchase offsetting permits (should state emissions be higher than an allocated carbon budget), resulting in a change in the financial flows associated with the sale and purchase of carbon permits. This relative increase in net financial flows to the state will likely drive an increase in Gross State Income (GSI)[33] and a flow on increase in GSP.

To calculate the potential value of these permit transfers, the adopted price path was designed to be consistent with the modelling recently undertaken by the Australian Government in the Australia's Long-Term Emission Reduction Plan report[34], which assumes international carbon permit prices at a fixed level of $40/t CO_2-e in real terms across the modelling horizon.

5.2.4 Green premia

Increasing focus on environmental concerns has in recent years led to the emergence of a "green premium", whereby capital markets are willing to accept a relative discount on yields in return for assurance that their investment has a reduced environmental (and, in particular, greenhouse gas) footprint. The decarbonisation of the electricity grid under the Energy Plan will mark Queensland as a green destination for investment, potentially yielding a green premium and increasing Queensland's attractiveness as a destination for investment.

To value the potential green premia and its impacts, assumptions were provided by Queensland Treasury, which in turn draws on recent Commonwealth modelling assuming a 100 basis point (BP)[35] premia for decarbonisation. As the electricity system contributes to approximately 30% of Queensland's emissions today, it is assumed that a maximum of 30 BP may be attributed to electricity sector emissions. Of these 30 BP it is assumed that only the incremental difference between the Energy Plan and Uncoordinated Outlook Scenario emissions may be considered when calculating the change in the green premia[36].

Finally, it is assumed that the change in premia may be forward-looking in nature and may occur before any actual reduction in emissions. Figure 22 shows the potential annual green premia assumed in the modelling, developed with the Department to reflect the trajectory of emissions reductions, taking into account the above considerations.

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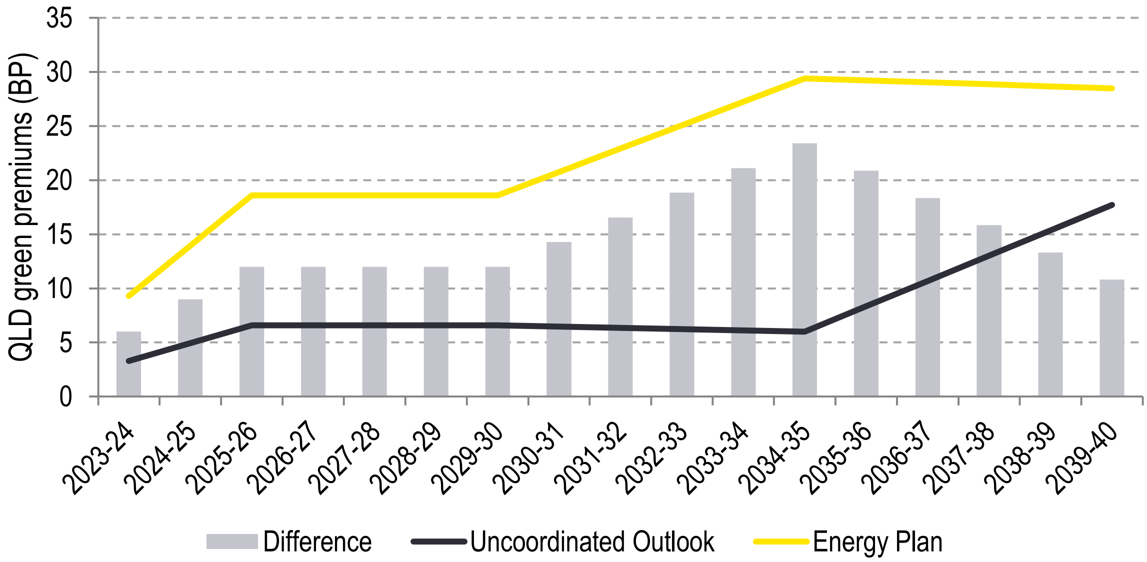
[33] While less commonly used, GSI is a superior measure of economic welfare when compared to production metrics such as GSP.

[34] Australian Government, 2021.

[35] 100 basis points is equal to 1%.

[36] An alternate interpretation for the shocks that have been applied would be the avoidance of a cost of capital penalty that would otherwise be applied to investment in the state. The modelling assumes that Queensland derives this benefit independent from the remainder of Australia.

Figure 22: Comparison of assumed green premia to Queensland in the two scenarios



The benefit of the green premia is largest in 2034-35, when the difference between emissions between the two scenarios is largest.

5.3 Outcomes for the Queensland economy

The key macroeconomic variables examined using EYGEM are as follows:

- **Gross State Product (GSP)** is the measure of total value of goods and services in the economy and is a key metric in tracking the overall progress of an economy and the effectiveness of policies. The model estimates the GSP as the sum of consumption, investment, government expenditure and net exports in real terms.
- **Gross State Income (GSI)** is used as a measure of the total income in an economy and is used to track the wealth generated by an economy both domestically and through overseas investment.
- **Household income** is the measure of the average income per household in Queensland.
- **Total investment** is also referred to as Gross Fixed Capital Formation in the system of national accounts, and comprises both changes in direct electricity infrastructure investment (as presented in Section 5.2.1) and changes in investment in other sectors of the economy induced by reduced electricity prices and green premia.

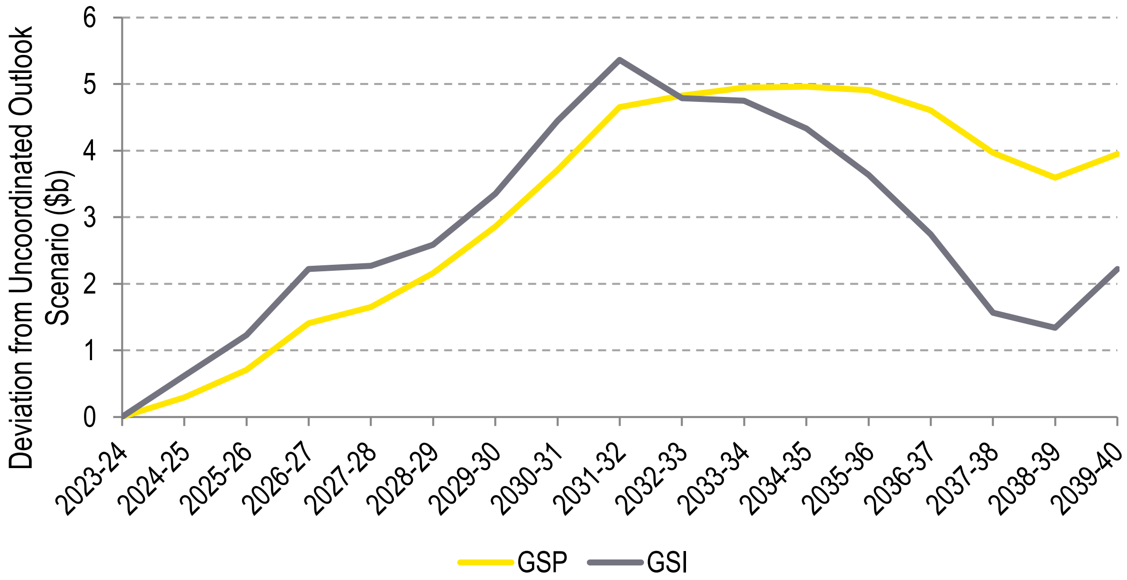
The following tables and graphs present results of the Energy Plan Scenario as compared to the Uncoordinated Outlook Scenario. Table 8 summarises the overall results of the whole of economy modelling.

Table 8: Overall forecast outcomes of the Energy Plan Scenario in the whole of economy modelling, relative to the Uncoordinated Outlook Scenario

Economic variable	Value
GSP ($b NPV)	+25.7
GSI ($b NPV)	+25.1
Total investment ($b NPV)	+23.2
Household income ($ NPV per household)	+10,380

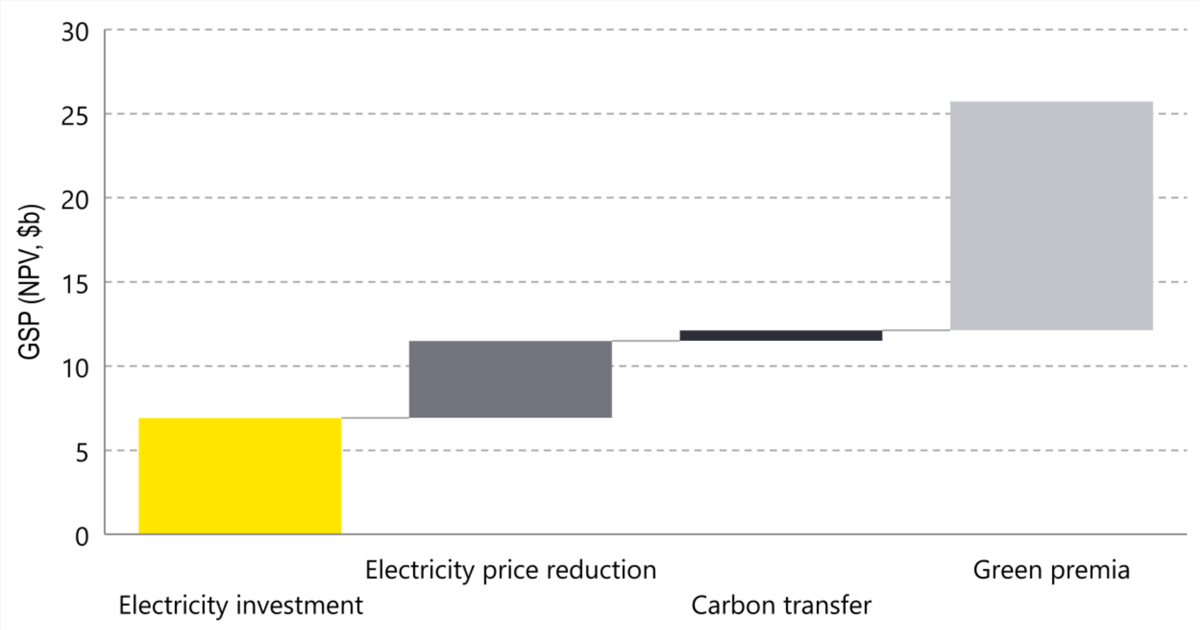
The forecast annual increase in GSP and GSI is presented in Figure 23. The economy sees a significant boost in the first decade of the modelled horizon, which coincides with the forecast increase in construction activity, increasing green premia and large carbon transfers. The peak difference in GSP is predicted to occur in 2034-35, at $5.0b higher than the Uncoordinated Outlook Scenario.

Figure 23: Annual outcomes of the Energy Plan Scenario on GSP and GSI compared to the Uncoordinated Outlook Scenario



The forecast increase in GSP can be broken down into the four key input mechanisms: electricity infrastructure investment, reduced electricity prices, carbon transfers and green premia. Figure 24 presents this breakdown over the modelled horizon in NPV terms. The charts shows the potential impact of the green premia is wide-reaching and could represent around 50% of the aggregate economic benefit of the Energy Plan. The electricity infrastructure investment and a reduction in electricity prices are also projected to drive large economic benefits to Queensland.

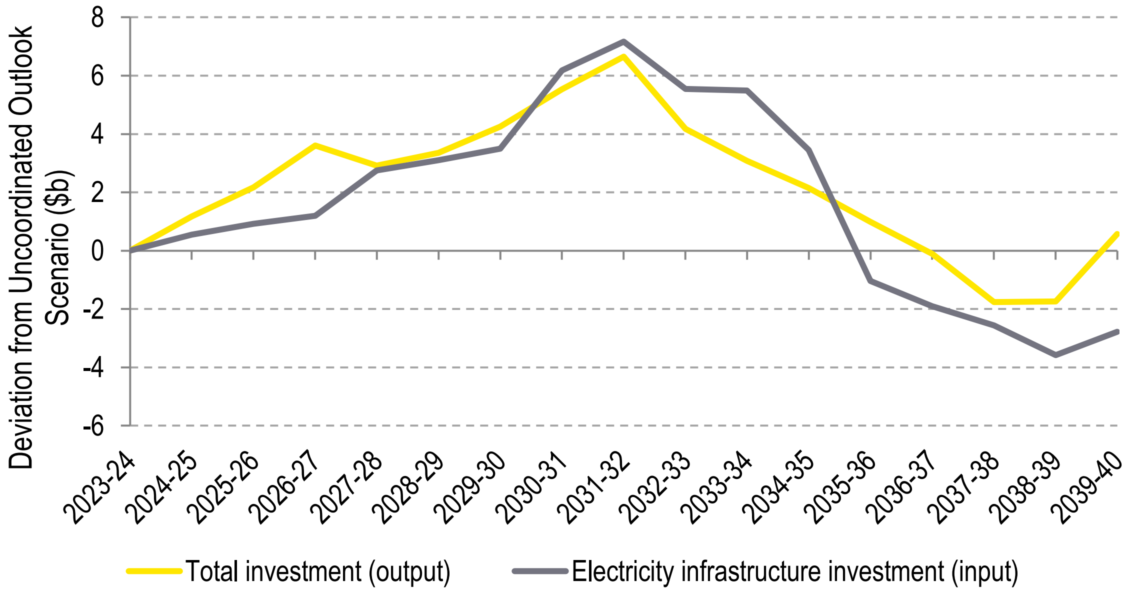
Figure 24: Breakdown of the GSP outcome into the four key mechanisms – Energy Plan Scenario relative to the Uncoordinated Outlook Scenario



As described earlier, EYGEM forecasts the outcomes of the Energy Plan Scenario on total investment across the Queensland economy, including the direct electricity infrastructure investment and other economy-wide investments. The forecast flow-on impacts to investment in other sectors reflect a number of factors, including the extent to which electricity investment drives complementary investment in industrial activities and the potential crowding out of other investments in a capacity constrained environment[37]. Figure 25 compares the forecast increase in the electricity infrastructure investment used as an input to EYGEM and the potential increase in economy-wide total investment forecast in the modelling outcomes (which includes electricity sector investment).

[37] Crowding out occurs in EYGEM when assumed constraints in labour and capital markets bind.

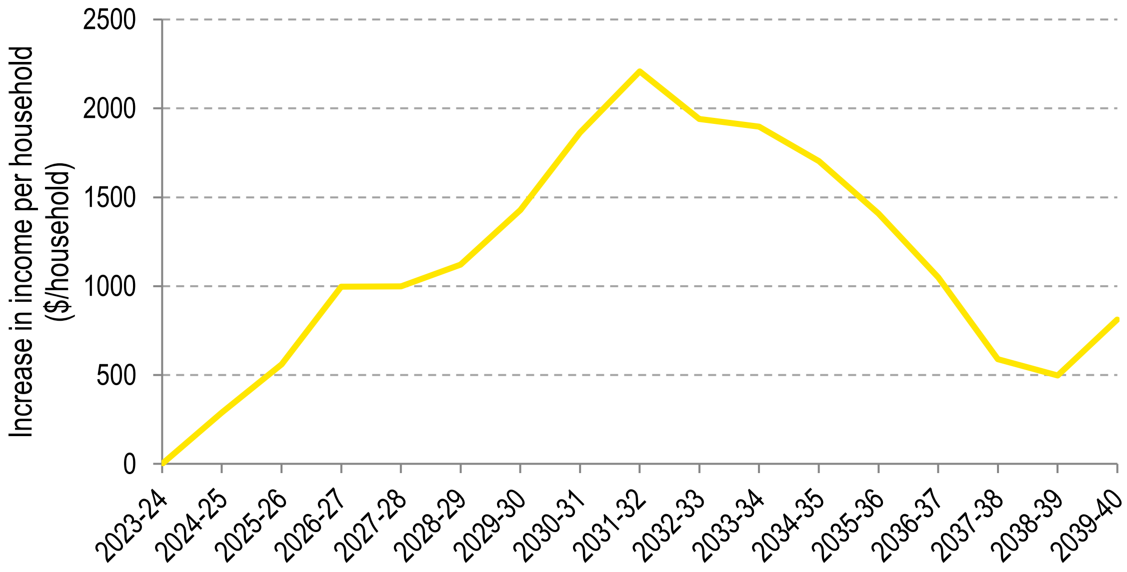
Figure 25: Forecast annual outcomes of the Energy Plan Scenario on total investment compared to Uncoordinated Outlook Scenario, compared with the input increase in electricity infrastructure investment



The total investment across the economy is forecast to occur earlier than the electricity infrastructure investment primarily due to the assumptions of earlier green premia as discussed in Section 5.2.4. The difference in economy-wide total investment in Queensland between scenarios peaks in 2031-32, driven by the spending in electricity infrastructure in the Energy Plan Scenario and the increased competitiveness of Queensland industries. The model forecasts a total increase in economy-wide investment of $23.2b in NPV terms across Queensland, compared to $18.6b in additional electricity infrastructure investment.

Along with reduced electricity prices for households, the Energy Plan's capacity to drive broad-based economic activity may potentially increase households' income. Figure 26 shows the potential annual increase in Queensland household income in the Energy Plan Scenario as forecast by EYGEM, which is on average $1,140 above the Uncoordinated Outlook Scenario each year over the modelled horizon. This peaks in 2031-32, which aligns with the peak in total investment.

Figure 26: Forecast annual outcomes of the Energy Plan Scenario on the income for Queensland households compared to the Uncoordinated Outlook Scenario



The increased household incomes are driven, in part, by improvements in the wage rate and greater employment opportunities. The Energy Plan Scenario also drives down costs for households, such as through reduced electricity prices.

5.4 Regional outcomes of the Energy Plan

The Energy Plan is a state-wide strategy that targets investment towards renewable generation, storage and transmission network upgrades into suitable regional locations. While this investment primarily occurs in regional Queensland, benefits flow throughout the state to both urban and regional centres. The benefits from reduced electricity prices and from carbon offsets and green premia apply more broadly across the state.

Figure 27 shows the modelled breakdown of the increase in the GSP in SEQ in the Energy Plan Scenario relative to the Uncoordinated Outlook Scenario. Figure 28 shows the same for regional Queensland.

Figure 27: Breakdown of the GSP outcome in SEQ by mechanism – Energy Plan Scenario relative to the Uncoordinated Outlook Scenario

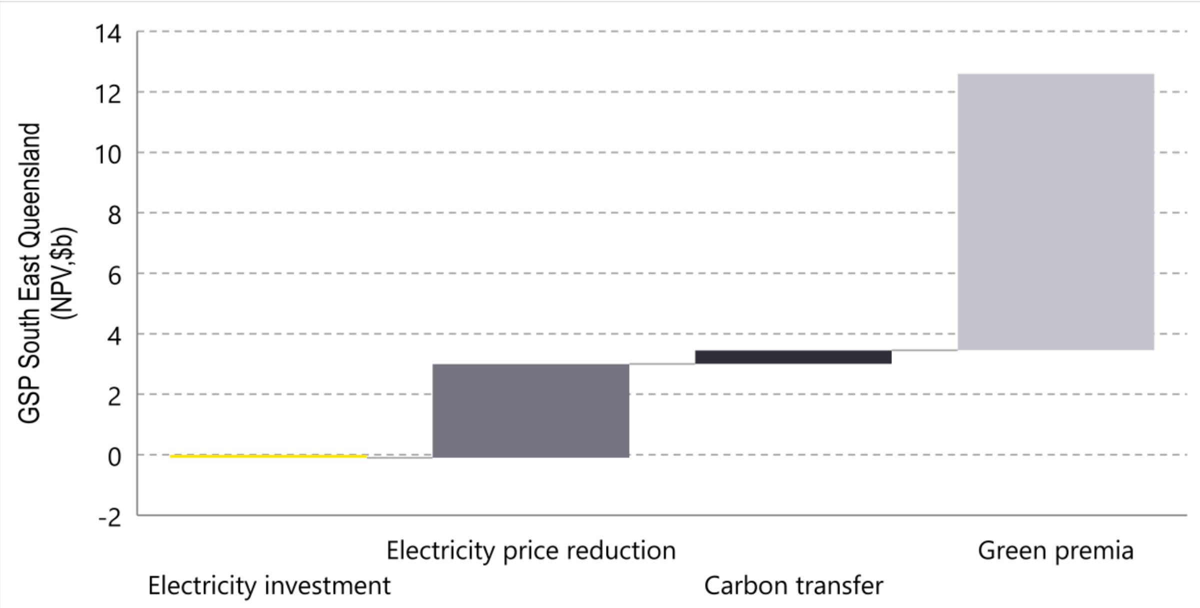
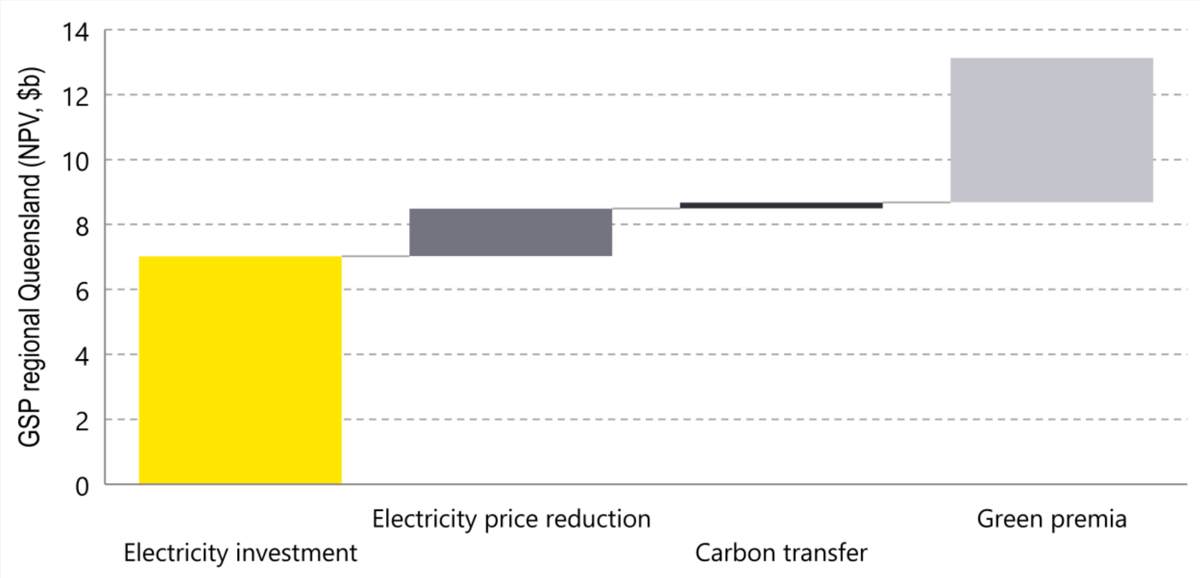


Figure 28: Breakdown of the GSP outcome in regional Queensland by mechanism – Energy Plan Scenario relative to the Uncoordinated Outlook Scenario



The infrastructure developed as part of the Energy Plan Scenario is predominantly occurring in regional areas of the state (for example, renewable energy projects, transmission and pumped hydro) and is targeted towards regions with strong renewable resources. As a result, there are different outcomes between regional Queensland and the metropolitan South East Queensland (SEQ)[38].

As regional Queensland is forecast to attract more electricity infrastructure investment, these regions attract most of the economic benefits of the construction activity in the modelling outcomes. The increased economic activity in regional Queensland draws employees and investment into those regions as people move for jobs and businesses invest in areas with increased activity. The outcomes depend on the type and location of the investment as well as the structure of the regional economies. Greater benefits flow for projects that involve greater domestic manufacture, such as pumped hydro, compared to solar and wind, which can be imported. This shift in economic activity, due to the infrastructure investment, is expected to contribute to 50% of the GSP increase in regional Queensland, compared to SEQ which changes little due to the investment.

While the investment in renewables predominantly occurs in the regional Queensland, the rest of the state is expected to benefit from the a decarbonised electricity market, including reduced electricity prices and the potential for green premium, which is modelled to lead to increased economic activity. This includes SEQ, which is the largest economy in the state.

Table 9 highlights the potential economic returns for each sub-region from the Energy Plan Scenario, compared to the Uncoordinated Outlook Scenario. The expected outcomes at the sub-regional level depend on the size and structure of the economy, its exposure to electricity prices and the amount of investment received. The spread of benefits among regions reflects the decentralised nature of the state.

Table 9: Summary of economic results by sub-region, showing increases in the Energy Plan Scenario compared to the Uncoordinated Outlook Scenario

Region	GSP ($b NPV)	GSI ($b NPV)
Central QLD	3.7	2.7

[38] Regional Queensland includes all sub-regions modelled excluding SEQ for the purpose of this Report.

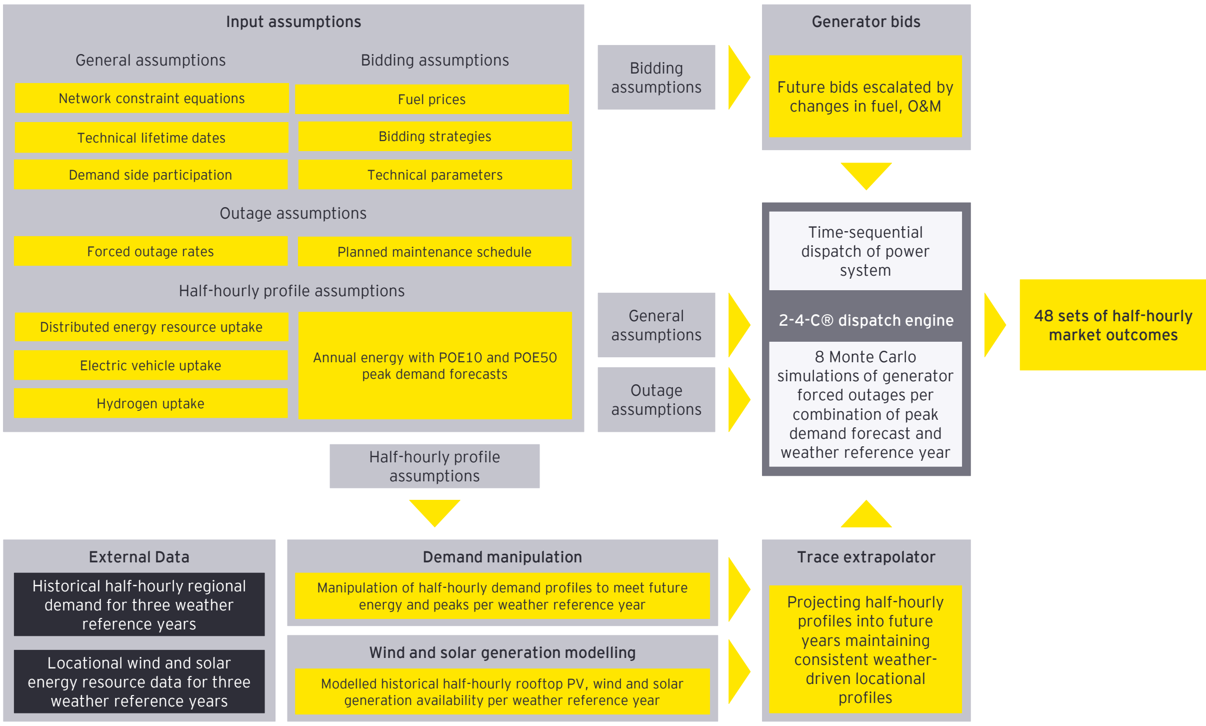
Region	GSP ($b NPV)	GSI ($b NPV)
Darling Downs	1.3	1.1
Far North QLD	1.0	1.0
Mackay and Whitsundays	3.1	2.5
Outback QLD	0.6	0.6
SEQ	12.6	13.9
Townsville	1.3	1.3
Wide bay	1.5	1.2
Cairns	0.7	0.8
Total	25.7	25.1

Appendix A Further details and assumptions on modelling the NEM with 2-4-C

A.1 Electricity market simulations

The market simulations are conducted using EY's market modelling suite of software 2-4-C, which consists of an energy market dispatch engine and several software tools that develop input data and analyse output data. The 2-4-C dispatch engine is equivalent to NEMDE used by the AEMO in operating the market in real time. The 2-4-C dispatch engine has been applied in this engagement with half-hourly time-sequential modelling over the 17-year modelled horizon, with explicit modelling of each generating unit and the capabilities of the electricity transmission network. Figure 29 provides an overview of the array of inputs used in a market simulation with 2-4-C.

Figure 29: Key input data flows in EY's 2-4-C electricity market model



As with NEMDE, 2-4-C bases dispatch decisions on the market rules, considering generator strategic bidding patterns and availabilities to meet regional demand. The model considers full and partial forced outages and planned outages for each generator, half-hourly renewable energy generation availability by individual power station as well as inter- and intra-regional transmission capabilities and constraints. This results in typical levels of price volatility at 30-minute time intervals captured in the modelling outcomes.

A.2 Forward-looking half-hourly modelling

EY's approach to forward-looking half-hourly modelling is to base all the inter-temporal and inter-spatial patterns in electricity demand, wind and solar energy on the weather resources and consumption behaviour in one or more historical years (reference years).

For this assessment, each future year is modelled with 48 individual iterations that make up one simulation. The 48 iterations are comprised of:

- Six different half-hourly demand profiles, comprising:

    - Three reference years of half-hourly underlying consumption patterns plus solar rooftop PV and small non-scheduled solar PV (PVNSG) profiles, and
    - Two seasonal peak demand projections, representing 50% POE and 10% POE years.
- Eight Monte Carlo simulations, or iterations, of different generator forced outage profiles, based on the forced outage probabilities for each generator, as sourced from AEMO's 2021 IASR[39].
- Each reference year also uses different wind and large-scale solar generation availability profiles based on the historical weather data. Three reference years are used to capture a wide range of weather patterns and their impacts on electricity demand and locational wind and solar generation. In general, the more reference years modelled, the more different types of weather patterns can be captured.

The 48 iterations used in the modelling are summarised in Table 10 below.

Table 10: Summary of individual half-hourly iterations made on each future year

Variable	Description	Number
Peak demand outlooks	50% POE 10% POE	2
Reference year	2016-17 2017-18 2018-19	3
Monte Carlo iterations	Different generator forced outage profiles	8
Total iterations per simulation		48

Annual average outcomes for each simulated year of half-hourly results are a weighted average of 0.7 on the 50% POE iterations and 0.3 on the 10% POE iterations, based on assumptions about the distribution of demand conditions, random of unplanned outages and reference years.

A.2.1 Half-hourly locational renewable generation modelling

EY models future half-hourly generation availability for forecast uptake of individual wind and large-scale solar PV power stations, based on historical wind and solar resource data and achieving the available capacity factor assumptions for existing generators as well as by technology and REZ for new entrant generators using the 2021 IASR[39].

A.2.2 Generation and storage candidate capacity in Queensland

Table 11 lists the assumed total capacity limits for solar PV and wind by Queensland REZ. For each candidate wind, solar PV and battery capacity option by REZ, up to three separate connection points are considered in the modelling. This allows for the modelling analysis to have some diversity in the wind and solar profiles modelled as well as explore the impact of network curtailment for different grid connection locations.

[39] AEMO, 10 December 2021, *2021 Inputs and Assumptions workbook*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

Table 11: Technology new build limits by REZ in Queensland[40]

REZ	New capacity limit (MW)		
	Wind (high)	Wind (medium)	Solar PV
Far North QLD	570	1,710	1,100
North QLD Clean Energy Hub	4,700	13,900	8,000
Northern QLD	-	-	3,400
Isaac	1,000	2,800	6,900
Barcaldine	1,000	2,900	8,000
Fitzroy	900	2,600	7,533
Wide Bay	300	800	2,200
Darling Downs	1,400	4,200	6,992
Banana	900	2,500	6,100

These build limits apply to new candidate capacity over and above the existing and committed capacity assumed in the scenarios. The high and medium wind headings in Table 11 refer to the resource quality of wind generation in the REZ. With a higher relative resource quality, wind (high) generation candidates achieve a higher capacity factor, and therefore a lower levelised cost of energy than wind (medium) generation candidates for the same REZ. Thus, wind (high) is preferred first in the modelling (up to their resource limits).

Where candidate long duration (8 hours) battery capacity is considered for a REZ, the potential capacity is assumed to be unlimited.

A.3 Generator planned maintenance and reliability

Planned maintenance is allocated such that the availability adjusted peak demand is minimised throughout the year. By allocating the largest units first, they are going to be on maintenance during the lowest demand periods. The ultimate date chosen is the date which has the lowest demand period throughout the maintenance duration, not necessarily the lowest demand day.

As described in Section A.1, EY conducts several Monte Carlo iterations in a market simulation to capture the impact of forced (unplanned) generator outages. Each Monte Carlo iteration assigns random outages to each generating unit, based on assumed outage statistics.

2-4-C applies forced outage rate statistics for different generator types, or each individual generation facility depending on the data sets available. These parameters are applied to randomly schedule forced outages for the relevant units in each Monte Carlo iteration. The relevant units are typically thermal units such as coal, gas and hydro. Outages for wind and solar PV units are built into the half-hourly availability profiles for these units.

A.4 Bidding

For this project, EY has constructed bidding profiles for each individual generator based upon recent historical data published by AEMO. This strategy yields results that accurately model a generator's market behaviour for most of the time, implicitly capturing their bidding behaviour with respect to portfolio and contracting positions. Some of the units have different bidding profiles

[40] AEMO, 10 December 2021, *2021 Inputs and Assumptions workbook*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

applied to different time slices, such as evenings, daytimes and early mornings if their historical bidding behaviour was determined to be better captured in that way.

In any single trading interval, each generating unit is modelled with a bid offering their capacity at up to 10 price-quantity pairs, as in the actual market. For example, a coal-fired unit will bid a certain proportion of its load at or near the market floor price (-$1,000/MWh) to reflect its self-commitment intention, and incremental proportions of its capacity at positive prices to reflect their running costs and higher priced bids potentially up to the market price cap to recover fixed costs and be exposed to opportunistic pricing events in the market.

All new wind and solar projects installed in the model bid at their operating costs, which are assumed to be zero as per the 2021 IASR[41]. Some existing wind and solar projects bid negative prices to reflect historical bidding behaviour which is expected to continue assuming that this reflects their individual contracting positions.

Whilst this approach produces a useful benchmark and provides probable volatility in pricing outcomes, its limitations are that it does not consider potential changes in portfolios over time and how the portfolios would respond with different bidding strategies to major changes in the competitive dynamics of the market over the 17-year modelled horizon.

A.5 Storage modelling

Battery and pumped hydro storage operation requires forward planning to ensure charging/pumping and generation captures the day-to-day opportunities for arbitrage revenue. In 2-4-C, EY adopts a different forward-planning methodology for short-duration (12 hours or shorter) and long-duration storage (greater than 12 hours). This is because long-duration storage requires forward planning over a week or longer to take advantage of its full flexibility. For example, it can charge/pump during periods of high wind and solar generation and save this to generate continuously for half a day or longer when there is low renewable generation available for an extended period and associated high prices. Long-duration storage is a key part of a low-emissions future market to manage high volumes of wind and solar generation. On the other hand, due to having less than half of day or storage, short-duration storage will tend to perform a full charge and full discharge every day, so it generally does not need longer than two days ahead of forward planning.

The two methodologies are summarised in the following sub-sections.

Long-duration storage methodology

EY's long-duration storage planning methodology is applied to individual long-duration storage projects with storage capacities of greater than 12 hours, which for this Report comprises the Snowy 2.0, Borumba and North Queensland pumped hydro projects. The methodology creates a generation and load plan ahead of simulating each year. This plan is primarily created using a linear program, which takes into an estimate of the half-hourly prices that would occur in each half-hour if the long-duration storage project's full capacity of generation or pumping was applied and these price estimates are used for the generation and pumping plan outcomes, respectively. The linear program also takes into account the capacity, reservoir size and round-trip efficiency of each long-duration storage project.

Short-duration storage methodology

EY's short-duration storage planning methodology is applied daily throughout each simulated year. It is based on developing an imperfect forecast of the wholesale market prices for the next two days and planning an optimal charging and discharging profile over those two days to maximise

[41] AEMO, 10 December 2021, *2021 Inputs and Assumptions workbook*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

wholesale market price arbitrage. The strategies developed take into account the parameters of each specific battery including the present state of charge, available storage capacity and the round-trip efficiency.

The imperfect price forecast is based on residual demand, which is equal to operational demand minus the available large-scale wind and solar generation and other low bidding generation or loads, such as the plan developed for long-duration storage projects. The strategy develops a relationship between residual demand and prices over the previously simulated four days, and then uses this relationship to forecast the price for the next two days to feed into the battery charge and discharge decisions. The optimal battery charge and discharge profiles determined by the strategy take into account the impact the battery's charging and discharging may have on the price, effectively considering that the battery's charge or discharge would change the residual demand.

A.6 Network constraints

The network constraint equations used in the modelling for this Report have been created for all transmission lines and transformers in the NEM. We incorporate into the simulations N-0 and N-1 thermal constraint equations for current and assumed future network states as well as selected stability constraint equations. All existing and new generators connection points are mapped to constraint equation terms.

A.6.1 Network augmentations

The new network links and their timing in the Energy Plan Scenario in relation to the pumped hydro projects and REZs was developed with the Department and Powerlink Queensland. Table 12 provides a list of all the assumed new augmentations across the NEM in the modelling and the differences between the two scenarios.

Table 12: Assumed network augmentation details and timing for the two modelled scenarios

<table>
<tr><th>Name</th><th>Uncoordinated Outlook</th><th>Energy Plan</th></tr>
<tr><td>Project EnergyConnect</td><td colspan="2" rowspan="4">1/07/2025</td></tr>
<tr><td>Central West Orana REZ</td></tr>
<tr><td>South-West NSW stability improvement</td></tr>
<tr><td>Western Victoria</td></tr>
<tr><td>Humelink</td><td colspan="2">1/07/2027</td></tr>
<tr><td>Early CQ reinforcement (Calvale - Calliope 275 kV double circuit line
Third Calliope River 275/132 kV 487 MVA transformer)</td><td>-</td><td>1/07/2027</td></tr>
<tr><td>Reinforcing Sydney Newcastle and Wollongong Supply 500 kV-North and South paths</td><td colspan="2" rowspan="4">1/07/2029</td></tr>
<tr><td>New England REZ</td></tr>
<tr><td>Marinus link Stage 1</td></tr>
<tr><td>Gladstone Grid Reinforcement</td></tr>
<tr><td>New network for Borumba pumped hydro
(Halys-Borumba-Woolooga 500 kV double circuit line
5 x 275/500 kV 1500 MVA transformers at Halys
2 x 275/500 kV 1500 MVA transformers at Woolooga)</td><td>-</td><td>1/07/2029</td></tr>
<tr><td>MarinusLink Stage 2</td><td colspan="2">1/07/2031</td></tr>
<tr><td>SQ-CQ augmentations
(Woolooga-Larcom Creek 500 kV double circuit line
- 2 x 275/500 kV 1500 MVA transformers at Larcom Creek)</td><td>-</td><td>1/07/2031</td></tr>
</table>

Name	Uncoordinated Outlook	Energy Plan
CQ-NQ augmentations to connect new generation and storage in North Queensland (Larcom Creek-Nebo-Pioneer-Ross 500 kV double circuit line - 2 x 275/500 kV 1500 MVA transformers at Nebo - 2 x 275/500 kV 1500 MVA transformers at Ross)	-	1/07/2032
VNI West	1/07/2035	
Connecting the North QLD Clean Energy Hub REZ to the coastal lines (Ross-Hughenden 500 kV double circuit line)	-	1/07/2035
QNI Connect Stage 1 & 2	1/07/2035	-
Connecting the North QLD Clean Energy Hub REZ directly to SQ (Hughenden-Halys 500 kV double circuit line)	-	1/07/2039

A.7 Modelling and assumption limitations

It should be noted that there is a significant range of alternative assumptions that, in isolation or in aggregate, could transpire to produce outcomes that will differ from those that have been modelled. These possible alternative futures have not been considered in this Report.

Along with uncertainty in the assumptions, all models and modelling approaches have limitations in representing the real world, and these need to be understood to assist in interpreting the results and in obtaining the full value from the modelling. Table 13 lists some of the key limitations that relate to the purpose of the modelling in this Report and describes the implications of each.

Table 13: List of key modelling limitations and their implications for the outcomes

Limitation	Implications
The modelled generator bids are based on strategic behaviours observed in recent years. Keeping these strategies constant throughout the modelled horizon may be unreasonable.	Generators may change their bidding behaviour significantly due to changes in the competitive dynamics of electricity supply, as well as broader market structural reforms, which is not captured in the modelling approach. Bidding behaviour is a significant uncertainty and driver of the wholesale market price outcomes. Alternative bidding behaviours can also change generation dispatch and ultimately the commercially-driven capacity mix outcomes of a modelled scenario.
Marginal loss factors (MLFs) are assumed as inputs only and holding these constant throughout the modelled horizon may be unreasonable.	MLFs were recalculated for 2035-36 based on preliminary modelling outcomes. If MLFs were recalculated for each future year in the baseline cases, they may provide different commercial signals for new entrant capacity at particular locations and potentially lead to different results for the scenarios.
Only wholesale market revenues are considered for new entrant generators and storage	Modelling the ancillary services markets, such as FCAS was out of scope for this engagement and could be material for existing thermal generators and storage in the short term. EY considers that FCAS revenue is unlikely to be significant following Snowy 2.0's commissioning (and possibly even earlier) due to the market likely being highly oversupplied from the storage capacity installed. Similarly, there is presently a material value for LGCs for renewable generators in the short term, but this is expected to diminish quickly over the next few years and if that occurred, it is considered to be immaterial to the outcomes in this Report. However, there is the potential for future additional voluntary demand for LGCs, which may give LGCs a non-material value, which would potentially lead to different modelling outcomes. Other potential future revenue sources are also not considered, such as from the supply of inertia, which pumped hydro can provide along with thermal capacity.
The transmission network is only modelled in a 'system normal' state, with all transmission lines in service.	Along with generator outages, transmission outages are a regular part of the actual market. Whilst it is a typical approach to only model system normal conditions for the network, transmission outages in the actual market put upward pressure on wholesale market prices and increase the risk of unserved energy (USE).

Limitation	Implications
Unit commitment constraints – ramp rates/start times/start costs	Generator ramp rates are included and adhered to in this modelling, however in 30-minute time intervals they are not frequently a binding limit on dispatch. The modelling applied in this study does not apply specific unit commitment type constraints. Most thermal generation facilities offer their minimum stable load quantities at the market floor price at all times when they are available, with the exception of a few combined-cycle gas-fired generators.
Pumped hydro and battery storage operation strategies	EY's methodology for developing generation and load profiles for long duration storage and shorter duration storage is described in Section A.5. Many alternative strategies exist, which could change the outcomes for the individual storage projects as well as on the electricity market as a whole.

Appendix B Whole of economy modelling

B.1 Whole of economy modelling assumptions

The whole of economy takes various assumptions to inform the model inputs. Table 14 details the source of each assumption.

Table 14: Whole of economy model input assumptions

Assumption	Source
Electricity price	The electricity price is an output of the electricity market modelling.
Electricity infrastructure investment	The electricity infrastructure investment expenditure is a combination of the inputs and outputs of the electricity market modelling.
Carbon transfers	The carbon transfers take the carbon price assumed by the Commonwealth Government's report *Australia's Long-Term Emission Reduction Plan*[42], at $40 a tonne in real terms and the electricity emissions reductions that are an output of the electricity market modelling.
Green premia	The green premia assumptions are provided by analysis undertaken by the Queensland Treasury and are based on the Commonwealth Government's report *Australia's Long-Term Emission Reduction Plan*.

B.2 The EYGEM model

Economic impact analysis measures the net impact of changes on an economy. It is used to measure the net change in response to a given event (e.g., such as the loss of an activity, or increased expenditure in a particular sector). The key economic metrics are expressed in terms of changes to gross domestic product and other macro-economic indicators.

The EYGEM model is a large scale, dynamic, multi-region, multi-commodity CGE model of the world economy. The EYGEM model enjoys significant flexibility both at the regional and sectoral level, including the capability to individually identify sub-regions of Australia, including (but not limited to) at the SA4 or the LGA level as separate economic regions. This capability to identify subnational regions is also readily extended to other international regions.

EYGEM draws on the global CGE modelling framework developed by the Global Trade Analysis Project (GTAP) based at Purdue University in the United States. Their model is described in Hertel (1997), with its antecedent being the Industry Commission's Salter model (Jomini et al 1991). The GTAP model was greatly enhanced by the Australian Bureau of Agriculture and Resource Economics (ABARE) to incorporate dynamic capabilities. The MEGABARE model (ABARE 1996) and its successor, the Global Trade and Environment Model (Pant 2002), were the fruits of ABARE's efforts.

Our model is implemented in modern data science frameworks, including Python and Pandas, and has a user-friendly Excel interface. Our frameworks are specifically designed to improve auditing a paper trail in modelling exercises, reduce the risk of modelling error, and allow for (for example) systematic sensitivity analysis.

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[42] Australian Government, 2021. *Australia's Long-term emissions reduction* plan. Available at: https://www.industry.gov.au/sites/default/files/October%202021/document/australias-long-term-emissions-reduction-plan.pdf

B.3 Overview of the modelling framework

EYGEM is based on a substantial body of accepted microeconomic theory. Key assumptions underpinning the model are:

- The model contains a 'regional consumer' that receives all income from factor payments (labour, capital, land and natural resources), taxes and net foreign income from borrowing (lending).
- Income is allocated across household consumption, government consumption and savings so as to maximise a Cobb-Douglas utility function.
- Household consumption for composite goods is determined by minimising expenditure via a CDE (Constant Differences of Elasticities) expenditure function. For most regions, households can source consumption goods only from domestic and imported sources. In the Australian regions, households can also source goods from interstate. In all cases, the choice of commodities by source is determined by a CRESH (Constant Ratios of Elasticities Substitution, Homothetic) utility function.
- Government consumption for composite goods, and goods from different sources (domestic, imported and interstate), is determined by maximising utility via a Cobb-Douglas utility function.
- All savings generated in each region are used to purchase bonds whose price movements reflect movements in the price of creating capital.
- Producers supply goods by combining aggregate intermediate inputs and primary factors in fixed proportions (the Leontief assumption). Composite intermediate inputs are also combined in fixed proportions, whereas individual primary factors are combined using a CES production function.
- Producers are cost minimisers, and in doing so choose between domestic, imported and interstate intermediate inputs via a CRESH production function.
- Investment takes place in a global market and allows for different regions to have different rates of return that reflect different risk profiles and policy impediments to investment. A global investor ranks countries as investment destinations based on two factors: global investment and rates of return in a given region compared with global rates of return.
- Once aggregate investment is determined in each region, the regional investor constructs capital goods by combining composite investment goods in fixed proportions, and minimises costs by choosing between domestic, imported and interstate sources for these goods via a CRESH production function.
- Prices are determined via market-clearing conditions that require sectoral output (supply) to equal the amount sold (demand) to final users (households and government), intermediate users (firms and investors), foreigners (international exports), and other Australian regions (interstate exports).
- For internationally-traded goods (imports and exports), the Armington assumption is applied whereby the same goods produced in different countries are treated as imperfect substitutes. But in relative terms imported goods from different regions are treated as closer substitutes than domestically-produced goods and imported composites. Goods traded interstate within the Australian regions are assumed to be closer substitutes again.
- The model accounts for greenhouse gas emissions from fossil fuel combustion. Taxes can be applied to emissions, which are converted to good-specific sales taxes that impact on demand. Emission quotas can be set by region and these can be traded, at a value equal to the carbon tax avoided, where a region's emissions fall below or exceed their quota.

B.4 Dynamics of EYGEM

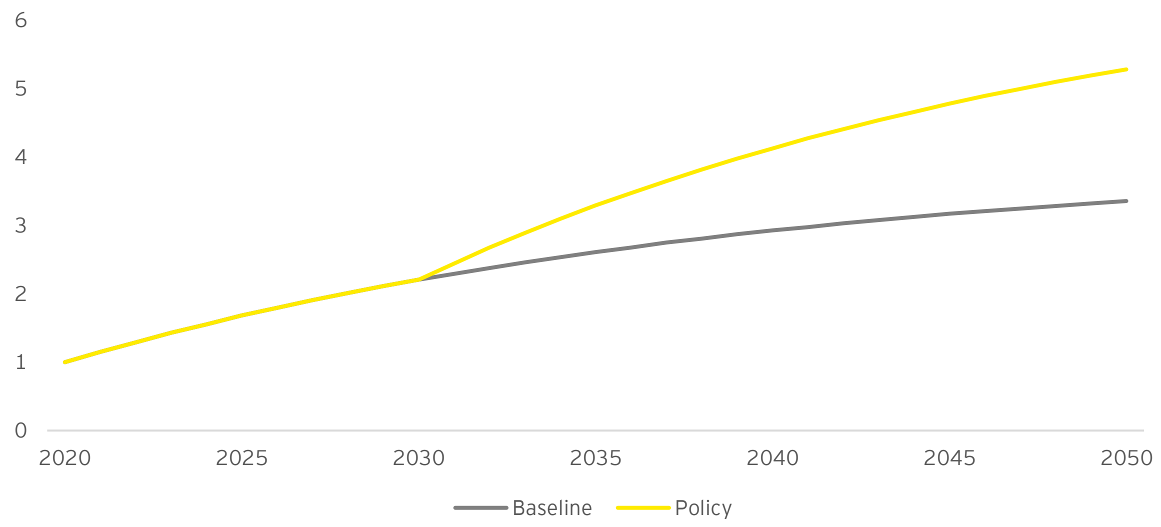
EYGEM is a recursive dynamic model that solves year-on-year over a specified timeframe. This has two main advantages. First, dynamics allows a richer specification of the model in that issues such as debt accumulation (which facilitates the ability to model international capital flows) and labour market dynamics are able to be modelled in a more sophisticated manner. Second, scenario analysis using a model such as EYGEM can be greatly enhanced by the ability to alter the baseline, or reference case, to account for key developments or uncertainties.

The model is then used to project the relationship between variables under different scenarios, or states, over a pre-defined period. This is illustrated in Figure 30, where a reference case or 'baseline' forms the basis of the analysis undertaken using EYGEM. The model is solved year-by-year from time 0 which reflects the base year of the model (2020) to a predetermined end year (in this case 2050).

The 'Variable' represented in the figure could be one of the hundreds or thousands represented in the model ranging from macroeconomic indicators such as real GDP to sectoral variables such as the exports of iron and steel from Australia. In the figure, the percentage changed in the variables have been converted to an index (= 1.0 in 2020) and is projected to increase by 2050.

Set against this baseline is, in Figure 30, a 'Policy' scenario. This scenario represents the impacts of a policy change or different assumptions about economic development that results in a new projection of the path of the variable over the modelled horizon. The impacts of the policy/assumption change are reflected in the differences in the variable at time T. It is important to note that the differences between the baseline and policy scenario are tracked over the entire timeframe of the simulation.

Figure 30: Dynamic simulation using EYGEM



B.5 Detailed interdependencies

The model is underpinned by a detailed, global database. The model's database is 'benchmarked' or 'calibrated' so that initial equilibrium solution exists that replicates actual sectoral production, consumption, trade and factor usage. It contains 141 regions and 64 sectors for a base year of 2007, and is the benchmark dataset for applied, global general equilibrium modelling. This database produced by the Global Trade Analysis Project (GTAP) at Purdue University is the most detailed and comprehensive database of its type in the world. Used by some 700 researchers globally, the database is a truly international, collaborative research effort that is fully documented and transparent.

The EYGEM model is primarily based on input-output or social accounting matrices, as a means of describing how economies are linked through production, consumption, trade and investment flows. For example, the model considers:

- direct linkages between industries and countries through purchases and sales of each other's goods and services; and
- indirect linkages through mechanisms such as the collective competition for available resources, such as labour, that operates in an economy-wide or global context.

Appendix C Acronyms and abbreviations

Table 15: List of abbreviations used in this report

Abbreviations	
$b	Billions of dollars
2-4-C	EY's in-house wholesale electricity market dispatch modelling software suite
ABARE	Australian Bureau of Agriculture and Resource Economics
AEMO	Australian Energy Market Operator
BP	Basis points
CCGT	Closed Cycle Gas Turbine
CDE	Constant Differences of Elasticities
CES	Constant Elasticities of Supply
CGE	Computable General Equilibrium
CO_2-e	Carbon dioxide equivalent
CQ	Central Queensland
CRESH	Constant Rations of Elasticities Substitution Homothetic
EY	Ernst & Young
EYGEM	Ernst & Young General Equilibrium Model
FCAS	Frequency Control Ancillary Services
GSI	Gross State Income
GSP	Gross State Product
GTAP	Global Trade Analysis Project
GW/GWh	Gigawatt/gigawatt hour
IASR	Inputs, Assumptions and Scenarios Report
ISP	Integrated System Plan
kV	Kilovolt
LGA	Local Government Authority
LGC	Large-scale generation contract
MW/MWh	Megawatt/Megawatt hour
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NPV	Net Present Value
NSW Roadmap	New South Wales Electricity Infrastructure Roadmap
OCGT	Open Cycle Gas Turbine
POE	Probability of Exceedence
PVNSG	Small non-scheduled generation solar PV
QLD	Queensland
QNI	Queensland-New South Wales interconnector
QRET	Queensland Renewable Energy Target
QTC	Queensland Treasury Corporation
REZ	Renewable Energy Zone
SEQ	South East Queensland

Abbreviations	
SWQ	South West Queensland
VNI	Victoria-New South Wales Interconnector
VPP	Virtual Power Plant
VRET	Victorian Renewable Energy Target
WACC	Weighted Average Cost of Capital

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Our report may be relied upon by the Department for the purpose of describing modelling outcomes of the Queensland Government's Queensland Energy Plan on the electricity sector and the Queensland economy pursuant to the terms of our engagement letter dated 24 November 2021. We disclaim all responsibility to any other party for any loss or liability that the other party may suffer or incur arising from or relating to or in any way connected with the contents of our report, the provision of our report to the other party or the reliance upon our report by the other party.

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