EXPLANATORY STATEMENT

Issued by the authority of the Assistant Minister for Climate Change and Energy

Future Made in Australia (Guarantee of Origin) Act 2024

Future Made in Australia (Guarantee of Origin) Methodology Determination 2025

The *Future Made in Australia (Guarantee of Origin) Act 2024* (**GO Act**) establishes the Guarantee of Origin (**GO**) scheme. The GO Scheme provides a nationally consistent certification mechanism to track and verify emissions associated with low emissions products and establishes an enduring certification mechanism for renewable electricity. This will support the development of markets and international trade of low-emissions products and renewable electricity.

Section 29 of the GO Act provides that the Minister may, by legislative instrument, determine one or more production pathways for a product. This is known as a methodology determination.

The *Future Made in Australia (Guarantee of Origin) Methodology Determination 2025* (**Determination**) provides that the electrolysis production pathway is a production pathway for hydrogen. The Determination then specifies a range of matters in respect of that production pathway for the purposes of subsection 29(4) of the GO Act.

In making the Determination, the Minister had regard to the matters set out under subsection 29(9) of the GO Act.

Purpose

The Determination underpins the creation of Product GO (**PGO**) certificates under the GO Act.

The GO Act requires that the holder of a production profile calculate the greenhouse gases emitted in relation to the batch and the amount of product in a batch in accordance with a methodology determination (subsection 50(2)). The GO Act similarly provides that the holder of a delivery profile calculates the greenhouse gas emissions emitted in relation to the delivery modules and the amount of product that reaches the delivery gate in accordance with a methodology determination (subsection 55(4)).

The Determination:

- provides that the electrolysis production pathway is a production pathway for hydrogen, and specifies minimum and optional production modules for that pathway;
- specifies sources of sources of greenhouse gas emissions for that production pathway and requirements for monitoring, measuring and reporting emissions from those sources;

- specifies delivery modules for hydrogen, sources of greenhouse gas emissions for those delivery modules and requirements for monitoring, measuring and reporting emissions from those sources; and
- sets out how to work out the amount of product in a batch of hydrogen and the amount of hydrogen that reaches a delivery gate.

The Determination is the first instrument made under section 29 of the GO Act. It has been designed in tandem with the *Future Made in Australia (Guarantee of Origin) Rules 2025* (made under section 160 of the GO Act) and the *Future Made in Australia (Guarantee of Origin) Measurement Standard 2025* (made under section 73 of the GO Act).

The Determination is structured so that new chapters may be inserted over time to incorporate emissions accounting approaches for other products.

Impact and Effect

The Department of Climate Change, Energy, the Environment and Water (the Department) consulted with the Office of Impact Analysis (OIA) on the making of the Determination. The OIA advised that the Determination is in scope of the original Impact Analysis prepared for the GO Scheme and additional analysis was not required as the Determination does not propose any change in policy from what was included in the Impact Analysis for the GO Scheme (OBPR21-01354). The original Impact Analysis is available at: https://oia.pmc.gov.au/published-impact-analyses-and-reports/implementing-guarantee-origin-scheme.

Consultation

The Department consulted on the Exposure Draft of the Determination between 23 June 2025 and 18 July 2025. A total of 30 submissions were received from stakeholders, with stakeholders generally supportive of the proposed emissions accounting approaches.

The Department considered the received feedback in finalising the Determination. For example, in response to stakeholders' concerns that emissions from fuels used for the production pathway may be double counted, the Determination was amended to insert a fuel use provision (section 16) to provide a centralised accounting of fuels used for the pathway, excluding fuels used by a combined heat and power (CHP) plant.

The Department also amended the Determination to provide further clarification of how to determine parameters incorporated from the *National Greenhouse and Energy Reporting (Measurement) Determination 2008*. Where stakeholders identified the complexity associated with the incorporation of parameters, the values have been included in Schedule 1 of the Determination for easier application. This is applicable for scope 3 emission factors for energy, sourced from the National Greenhouse Accounts Factors document.

Incorporation by Reference

The Determination incorporates the *Allocation of GHG Emissions from a Combined Heat and Power (CHP) Plant Guide to calculation worksheets (September 2006) v1.0* issued by the World Resource Institute and World Business Council for Sustainable Development as in force at the time the Determination commenced. This can be freely accessed at https://www.ghgprotocol.org. The Determination sets out how to apply this guide by referring to particular methods in the guide, such as the efficiency, work potential and energy content methods.

The Determination also incorporates the document titled *National Greenhouse Accounts Factors* (**NGAF**) published by the Department as existing from time to time. This document can be freely accessed on the Department's website (https://www.dcceew.gov.au).
This incorporation is authorised by subsection 29(8) of the GO Act, which provides that, despite subsection 14(2) of the *Legislation Act 2003* (Legislation Act), a methodology determination may make provision in relation to a matter by applying, adopting or incorporating, with or without modification, any matter contained in an instrument or other writing as in force or existing from time to time.

The Determination also incorporates aspects of the following legislation as in force from time to time, in accordance with paragraph 14(1)(a) of the Legislation Act:

- *National Greenhouse and Energy Reporting (Measurement) Determination 2008* (**NGER Measurement Determination**);
- *National Greenhouse and Energy Reporting Regulation 2008;*
- *National Greenhouse and Energy Reporting Act 2007;*
- *National Measurement Act 1960;* and
- *Renewable Energy (Electricity) Act 2000*.

Section 10 of the Determination provides that material contained in an instrument or other writing in respect of a batch of a product is incorporated as in force or existing at the time when production of the batch commenced. This means that, where material is incorporated as in force or existing from time to time, the version of that material that applies is the version as in force or existing at the start of the batch period. The purpose of section 10 is to ensure that any incorporated material applies consistently in relation to the batch from the start of the batch period to the delivery gate for the batch of the product.

Section 13 of the Determination applies provisions from the NGER Measurement Determination. Some of the provisions of the NGER Measurement Determination applied by the Determination in turn incorporate various Standards, including Australian Standards, related to determining the energy content factor of solid fuels. As at the commencement of the Determination, subsection 1.9(4) of the NGER Measurement Determination provides that any standards are incorporated as in force on 1 January 2020. Both the NGER Measurement Determination and this Determination provide for the use of 'equivalent' standards to promote useability and access.

Participants in the GO Scheme who choose to estimate the energy content factor in accordance with a provision of the NGER Measurement Determination which requires the use of a particular Standard would be expected to have access to that Standard, or an equivalent Standard, in order to comply with the Determination. These Standards are technical documents that are likely to be relevant to industry already measuring the energy content of fuels consistent with the NGER Measurement Determination. As a result, businesses choosing to analyse the energy content of fuels are expected to already have, or be able to easily access, a copy of these documents.

Australian Standards can be purchased from Standards Australia Ltd at https://store.standards.org.au or the relevant distribution partners identified at https://standards.org.au/access-standards/buy-standards. Non-commercial users can access Standards freely, on a limited basis, through Standards Australia's on-line Reader Room facility at https://readerroom.standards.org.au/. The Reader Room provides non-commercial access to Australian Standards for personal, domestic or household use. Another option is to access Standards without cost through the National Library of Australia, including by interlibrary loans.

Details/ Operation

The Determination is a legislative instrument for the purposes of the Legislation Act.

The Determination was made before the commencement of the GO Act, consistent with section 4 of the *Acts Interpretation Act 1901.*

Details of the Determination are set out in **Attachment A**.

Other

The Determination is compatible with the human rights and freedoms recognised or declared under section 3 of the *Human Rights (Parliamentary Scrutiny) Act 2011.* A full statement of compatibility is set out in **Attachment B**.

ATTACHMENT A

Details of the
Future Made in Australia (Guarantee of Origin) Methodology Determination 2025

Chapter 1—Introductory

Part 1.1—Preliminary

Section 1 – Name

1. This section provides that the name of the legislative instrument is the *Future Made in Australia (Guarantee of Origin) Methodology Determination 2025* (**Determination**).

Section 2 – Commencement

2. This section provides for the Determination to commence on either the start of the day after the instrument is registered or immediately after the commencement of the *Future Made in Australia (Guarantee of Origin) Act 2024* (**GO Act**), whichever is the later.

Section 3 – Authority

3. This section provides that the Determination is made under section 29 of the GO Act.

Section 4 – Definitions

4. This section defines key terms used in the Determination. Some of the definitions in this section are signpost definitions which indicate where the term is defined elsewhere in the Determination.

5. The Determination also includes definitions within specific sections. These definitions are not signposted in this section as they only apply in one specific section.

6. The term ***batch period*** is defined as the period from the time when production of the batch commenced until the time the last part of the batch left the production gate for the product. This captures the period of time taken to produce a batch of the product over which the emissions attributed to the production pathway are calculated. Consistent with subsection 50(3) of the GO Act, the batch period could be between one hour and one year.

7. The term ***CO_2-e*** has the same meaning as the term ***carbon dioxide equivalence*** in the *National Greenhouse and Energy Reporting Act 2007* (**NGER Act**). Section 7 of the NGER Act defines carbon dioxide equivalence as ‘the amount of the gas multiplied by a value specified in the regulations in relation to that kind of greenhouse gas.’ Section 2.02 of the *National Greenhouse and Energy Reporting Regulations 2008* (**NGER Regulations**) specifies the Global Warming Potential for kinds of greenhouse gases for the purposes of the definition of carbon dioxide equivalence in section 7 of the NGER Act.

8. The term ***CHP Tool*** refers to a tool used to calculate a ratio for allocating emissions between electricity and steam generated from a combined heat and power (CHP) plant. The use of this tool is required for the purposes of sections 15 (electricity supply and use) and 18 (steam supply and use) in Part 2.1 – Common production emissions. The full name of the CHP Tool is the '*Allocation of GHG Emissions from a Combined Heat and Power (CHP) Plant Guide to calculation worksheets (September 2006) v1.0*'. The document is freely accessible via the World Resources Institute: Greenhouse Gas Protocol website. This is the same tool used in sections 2.70 and 2.71 of the *National Greenhouse and Energy Reporting (Measurement) Determination 2008* (NGER Measurement Determination).

9. The term ***dedicated pipeline*** refers to a pipeline that only transports the relevant product. This term is relevant to accounting for emissions from the pipeline delivery module. At present, the term is only used to refer to a pipeline that exclusively transports hydrogen.

10. The term ***emissions*** means greenhouse gas emissions. Greenhouse gas is defined in the GO Act as having the same meaning as in the NGER Act, which defines greenhouse gas as carbon dioxide, methane, nitrous oxide, sulfur hexafluoride, specified kinds of hydrofluorocarbons and perfluorocarbons and prescribed gases.

11. The terms ***end of the delivery module***, ***final delivery module*** and ***interim delivery module*** relate to working out the amount of product that reaches a delivery gate or the end of delivery module. For hydrogen, these amounts are worked out under Division 3.2.2.

12. The ***end of the delivery module*** is the point at which all activities related to a delivery module are completed. This is the point at which the amount of product that reaches the end of that delivery module is to be measured. This definition is relevant where more than one delivery module is used to store or transport the PGO-certified product before it reached the delivery gate.

13. The ***final delivery module*** is the delivery module that ends at the delivery gate – for example, the location where the product is delivered to a consumer in Australia or exported from Australia (otherwise than by being placed on a ship). This definition is relevant for working out the amount of product that reached the delivery gate.

14. The term ***interim delivery module*** means a delivery module that is not a final delivery module. This refers to delivery modules following which further transport or storage will be undertaken before a product reaches a customer at the delivery gate. This definition is relevant in circumstances where there is more than one delivery module used for delivering the PGO-certified product and relates to working out the amount of product that reached the end of a delivery module.

15. The term ***input*** relates to the definitions of ***input supplier*** and ***parameter***. This definition does not exhaustively define the term.

16. The term ***input supplier*** allows the Determination to distinguish between inputs provided by the relevant profile holder and inputs provided by someone other than the profile holder (the input supplier), which in turn affects how emissions are accounted for. An input supplier means a person who supplies an input to a production pathway or a

delivery module but are not the profile holder. An example of a potential input supplier is a water utility or a neighbouring factory that provides steam for use in the production pathway. The definition is required because the Determination distinguishes how emissions are accounted for inputs provided by input suppliers, compared to inputs provided by the profile holder. For example, steam produced by the profile holder represents a scope 1 or direct emissions source that is worked out by measuring the fuel used to produce the steam. If steam is provided by an input supplier, then this is a scope 3 or upstream emissions source calculated using a default scope 3 emission factor or an emission factor specific to that input supplier.

17. The term ***parameter*** is defined as including an input or output for a production pathway or delivery module and a factor. This definition does not exhaustively define the term. This definition predominantly relates to section 9 which imposes requirements with respect to monitoring or measuring parameters.

<u>Section 5 – Meaning of *production emissions intensity*</u>

18. This section defines the term ***production emissions intensity***. This term is defined in relation to particular products, with the production emissions intensity of a batch of the particular product worked out in accordance with the section listed in column 3 of the table. The table format recognises that the Determination will be amended to define this term for the purpose of additional products.

19. The production emissions intensity of a batch of a product must be included on a PGO certificate under section 25 the *Future Made in Australia (Guarantee of Origin) Rules 2025* (**GO Rules**).

<u>Section 6 – Meaning of *delivered emissions intensity*</u>

20. This section defines the term ***delivered emissions intensity***. This term is defined in relation to particular products, with the delivered emissions intensity of the transported quantity of a batch of the particular product worked out in accordance with the section listed in column 3 of the table. The table format recognises that the Determination will be amended to define this term for the purpose of additional products.

21. The delivered emissions intensity of the transported quantity of a product must be included on a PGO certificate under the GO Rules (section 26).

<u>Section 7 – Meaning of *post-production emissions intensity*</u>

22. This section defines the term ***post-production emissions intensity***. This term is defined in relation to particular products, with the post-production emissions intensity of the transported quantity of a batch of the particular product worked out in accordance with the section listed in column 3 of the table. The table format recognises that the Determination will be amended to define this term for the purpose of additional products.

23. The post-production emissions intensity of the transported quantity of a product must be included on a PGO certificate under the GO Rules (section 26).

Section 8 – Meaning of *co-product reduction in emissions intensity* and *co-product*

24. Subsection 8(1) defines ***co-product reduction in emissions intensity***. This term is defined in relation to particular production pathways, with the co-product reduction in emissions intensity for a batch of the product produced in accordance with the particular pathway worked out in accordance with the section listed in column 5 of the table. The table format recognises that the Determination will be amended to define this term for the purpose of additional production pathways. The co-product reduction in emissions intensity of a batch of a product must be included on a PGO certificate under the GO Rules (section 25).

25. Subsection 8(2) defines ***co-product***. This term is defined in relation to particular products and particular production pathways. For example, oxygen is a co-product for hydrogen if the hydrogen is produced in accordance with the electrolysis production pathway. The table format recognises that the Determination will be amended to define this term for the purpose of additional products and production pathways. If the co-product reduction in emissions intensity is greater than zero, then the co-product must be included on a PGO certificate under the GO Rules (section 25).

Part 1.2—Methodology parameters and requirements

Section 9 - Monitoring and measuring requirements—general

26. Certain parameters in the Determination are required to be monitored and measured in accordance with the requirements in this section, helping to ensure the information included on PGO certificates is worked out consistently across different profile holders.

27. Where possible, parameters must be monitored or measured in a manner that is consistent with the NGER Measurement Determination. This ensures consistency between the Guarantee of Origin Scheme (GO scheme) and the scheme established by the NGER Act (NGER Scheme). Estimates under the NGER Measurement Determination must be prepared in accordance with the principles in section 1.13 of that Determination, which require consideration of transparency, comparability, accuracy and completeness.

28. For example, section 2.52 of the NGER Measurement Determination provides that the quantity of a liquid fuel may be estimated by direct measurement (termed criterion AAA). This criterion specifies that the measurement is made using measuring equipment calibrated to a measurement requirement. Applying this criterion to measure the amount of liquid fuel used for the batch would be in accordance with section 9.

29. In some cases, it may not be possible to monitor or measure a parameter in a manner consistent with the NGER Measurement Determination. For example, section 2.51 of the NGER Measurement Determination provides that the quantity of a liquid fuel may be estimated by indirect measurement (criterion AA). This criterion sets out that the amount is based on the amounts of liquid fuel delivered, evidenced by invoices, and adjusted by changes in stockpiles of the fuel. This criterion may not be in accordance with section 9 if the invoicing period does not match the batch period or if the profile holder takes receipt of fuel used for purposes other than the batch.

30. If it is not possible to measure or monitor a parameter consistent with the NGER Measurement Determination, then the parameter must be monitored or measured in a manner consistent with the *National Measurement Act 1960* or, if that isn't possible, in line with established standard industry practice.

31. To support accuracy of measurements, the equipment used to monitor or measure a parameter must be calibrated in a manner consistent with the NGER Measurement Determination. If equipment cannot be calibrated in accordance with the NGER Measurement Determination, it must be calibrated by an accredited technician in accordance with the manufacturer's specifications for the equipment. Such a technician may be an employee of the production facility as long as they are suitably accredited for the task.

Section 10 - Incorporated material

32. Subsections 10(1) and (2) provide that material contained in an instrument or other writing in respect of a batch of a product is incorporated as in force or existing at the time when production of the batch commenced.

33. For example, the ***CO_2-e*** (or ***carbon dioxide equivalence***) is defined as having the same meaning as in the NGER Act, which in turn relies on the Global Warming Potential values specified in the NGER Regulations. Subsections 10(1) and (2) ensure that the same values in the NGER Regulations would apply for calculating emissions from production emissions sources for the production pathway and post-production emissions sources for delivery modules, even if those values are amended after the start of the batch period. Other examples of incorporated material are provisions in relation to measuring and monitoring parameters under section 9, scope 1 emission factors incorporated under section 11 and provisions in relation to energy content factors incorporated under section 13.

34. Subsections 10(1) and (2) ensure that any incorporated material applies consistently in relation to the batch from the start of the batch period to the delivery gate for the product. This will minimise the administrative burden on holders of delivery and production profiles and ensure that emissions are calculated on the same basis across the production pathway and delivery modules.

35. Subsection 10(3) provides that where there is inconsistency between any incorporated material and a provision of the Determination, the Determination prevails to the extent of the inconsistency.

Section 11 – Scope 1 emission factors

36. This section sets out the provisions to work out the scope 1 emission factor for carbon dioxide, methane or nitrous oxide from combustion of a relevant feedstock or fuel.

37. A number of calculations in the Determination use the parameter $\boldsymbol{EF_{ij}}$, which is the scope 1 emission factor for each greenhouse gas type released from the use of the fuel type, in kilograms of CO_2-e per gigajoule of fuel type, determined in accordance with the provisions identified in column 3 of the table to section 11.

38. Subsection 11(1) and the table in that subsection applies relevant provisions from the NGER Measurement Determination used to calculate scope 1 emission factors used for the purposes of the parameter $\boldsymbol{EF_{ij}}$. Scope 1 emission factors are incorporated from the NGER Measurement Determination in order to ensure that these values are scientifically accurate and align with international standards. If the tables in the NGER Measurement Determination are updated, the updated value will apply in respect of a batch (as in force at the start of the batch period) (see section 10 of the Determination).

39. The tables in Schedule 1 to the NGER Measurement Determination are intended to comprehensively cover the fuels combusted in Australia's industrial sector and are updated to add in new fuels. However, if for some reason the feedstock or fuel is not listed in the applicable table in Schedule 1, subsections 11(2) and (3) set out how the scope 1 emission factor for a feedstock or fuel may be determined. Providing this option ensures that the emissions accounting provisions in the Determination can be applied where no scope 1 emission factor for the particular feedstock or fuel can be found in the relevant table in Schedule 1 to the Determination.

40. Subsection 11(3) sets out how to determine a replacement scope 1 emission factor where it is not possible to determine an emission factor for the feedstock or fuel which is being

used (the ***relevant feedstock or fuel***) in accordance with subsection 11(1). The replacement factor must be a scope 1 emission factor for a feedstock or fuel with the same state of matter as the relevant feedstock or fuel – that is, gaseous, liquid or solid. If the relevant feedstock or fuel has no biogenic carbon content, the replacement factor must be for a feedstock or fuel without biogenic carbon content. The replacement factor must also be for a feedstock or fuel with the closest comparable carbon content to the relevant feedstock or fuel.

41. Subsection 11(5) defines biogenic carbon as carbon derived from plant and animal material and not embedded in the earth as peat or fossil carbon, consistent with the definition in the NGER Measurement Determination.

42. If more than one feedstock or fuel type satisfies each of the requirements in paragraphs 11(3)(a), (b) and (c), the replacement factor is the factor for the fuel or feedstock with the closest comparable energy content factor. Subsection 11(4) provides that the energy content factor is worked out in accordance with section 13.

43. Subsection 11(3) ensures that the scope 1 emission factor used in the calculation is the emission factor for the feedstock or fuel which most closely matches the relevant feedstock or fuel in terms of the characteristics which influence its emissions when combusted. For scope 1 emissions, the most relevant characteristic is the non-biogenic carbon content that is converted to carbon dioxide when combusted.

44. For example, a profile holder might be combusting acetylene gas for stationary energy purposes. At the time this Determination commenced, the table in Part 2 of Schedule 1 to the NGER Measurement Determination did not have a scope 1 emission factor for acetylene. Acetylene is a gas with zero biogenic carbon content and all the fuels in the table in Part 2 of Schedule 1 to the NGER Measurement Determination are similarly gases with zero biogenic carbon content. The carbon content of acetylene gas is calculated as follows:
    - The molecular weight of a carbon atom is 12.011 kg/kmol.
    - There are two carbon atoms in one acetylene molecule.
    - The standard gas volume at 15 °C and 101.3 kilopascal (kPa) is 8.3145 ($m^3 \cdot Pa \cdot K^{-1} \cdot mol^{-1}$) × (273.15 + 15) (K) ÷ 101.3 (kPa) × 10^{-3} (kPa/Pa) × 10^3 (mol/kmol) = 23.65 (m^3/kmol).
    - The carbon content of acetylene is 12.011 (kg/kmol) × 2 (carbon atoms per acetylene molecule) × 10^{-3} (t/kg) ÷ 23.65 (m^3/kmol) = 10.16 × 10^{-4} (tC/m^3).

45. The gas with a carbon content value which most closely matches this value in the table in Part 2 of Schedule 1 to the NGER Measurement Determination is ethane, which has a carbon content of 9.70 × 10^{-4} tC/m^3. Therefore, the scope 1 emission factor for ethane can be used where the parameter $\boldsymbol{EF_{ij}}$ requires a scope 1 emission factor for acetylene.

<u>Section 12 – Scope 3 emission factors</u>

46. This section sets how to work out the scope 3 emission factor for a relevant feedstock or fuel.

47. A number of calculations in the Determination use the parameter $\boldsymbol{EF_{scope\ 3,i}}$, which is the scope 3 emission factor for a fuel type in kilograms of CO_2-e per gigajoule. The first

choice for determining a scope 3 emission factor for a fuel is by using the emissions intensity on a PGO certificate for that batch of fuel. This is provided for by paragraph (a) of the parameter definition of $\boldsymbol{EF}_{\boldsymbol{scope\ 3,I}}$ (this parameter definition is included in subsection 15(9), for example)

48. If there isn't a PGO certificate for that batch of fuel, paragraph (b) of the parameter definition provides that the scope 3 emission factor is worked out in accordance with section 12. The scope 3 emission factors are set out in tables in Schedule 1 to the Determination. Subsection 12(1) indicates which table applies in particular circumstances. The relevant table is determined by the fuel or feedstock's state (that is, solid, liquid or gaseous), the purpose for which its combusted and—for natural gas used for stationary energy purposes—whether the gas is consumed in an area connected to a distribution or transmission pipeline. The original source for the scope 3 emission factors in Schedule 1 is generally the *National Greenhouse Accounts Factors: 2024* (**NGAF document**), which can be found on the Department's website. The relevant values were included in the Determination due to the complexities of incorporating references to the NGAF document in a way that would ensure their correct application to working out scope 3 emissions for the batch or a delivery module. The NGAF document has been developed to assist companies and individuals report scope 3 emissions, which is a different but related purpose to the GO scheme.

49. The tables in Schedule 1 to the Determination cover some of the more commonly combusted fuels in Australia's industrial sector. However, at the time of commencement, the range of scope 3 emission factors in Schedule 1 to the Determination is more limited than the scope 1 emission factors available. Subsections 12(2) and (3) therefore set out how to determine a replacement scope 3 emission factor where it is not possible to determine an emission factor for the feedstock or fuel being used (the ***relevant feedstock or fuel***) in accordance with subsection 12(1). Providing this option ensures that the emissions accounting provisions in the Determination can be applied where no scope 3 emission factor for the particular feedstock or fuel can be found in the relevant table in Schedule 1.

50. If the scope 3 emission factor for the relevant feedstock or fuel is not listed in the applicable table in Schedule 1 to the Determination, the first option is to obtain the emission factor from the supplier of the relevant feedstock or fuel. For example, the supplier might be able to provide an emission factor for the relevant feedstock or fuel based on another certification scheme or emissions reporting framework.

51. If the supplier is unable to provide the emission factor of the feedstock or fuel they supply, then a replacement emission factor can be worked out in accordance with paragraph 12(3)(b). This must be done in accordance with subsection 12(1), meaning that the replacement factor must be found in the table in Schedule 1 to the Determination which applies in the particular circumstances. For example, a replacement factor for the consumption of a solid fuel must be found in the table in Part 4 of Schedule 1 to the Determination.

52. Subsection 12(3)(b) provides that the replacement emission factor must be an emission factor for a feedstock or fuel with the same state of matter as the relevant feedstock or fuel—that is, gaseous, liquid or solid.

53. If the relevant feedstock or fuel has an energy content, the replacement emission factor is the factor in the relevant table of Schedule 1 to the Determination for the feedstock or fuel with the closest energy content to that of the relevant feedstock or fuel. If the relevant feedstock or fuel does not have an energy content, then the replacement emission factor is the factor in the relevant table of Schedule 1 for the feedstock or fuel with the closest comparable carbon content to that of the relevant feedstock or fuel.

54. This approach is intended to be practical and is expected to be conservative because the feedstocks and fuels not included in the tables in Schedule 1 to the Determination will generally be novel fuels with lower scope 3 emissions than the fossil fuels listed in Schedule 1.

55. For example, ethanol is a liquid fuel and it is not listed in the table in Part 5 of Schedule 1. The scope 3 emission factor for this fuel can be estimated as follows:
    - The energy content of ethanol can be found in the table in Division 4.1 of Part 4 of Schedule 1 to the NGER Measurement Determination as 23.4 GJ/kL.
    - The liquid fuel with the closest energy content in the table in Division 4.1 of Part 4 of Schedule 1 to the NGER Measurement Determination is liquified petroleum gas (LPG) at 25.7 GJ/kL.
    - The scope 3 emission factor for LPG in the table in Part 5 of Schedule 1 is 20.2 kgCO_2-e/GJ.
    - Therefore, 20.2 kgCO_2-e/GJ should be used for the scope 3 emission factor for ethanol.

<u>Section 13 – Energy content factor</u>

56. This section sets out how to work out the energy content factor for a relevant fuel.

57. The energy content factor for a fuel is a measure of energy in gigajoules per unit of the fuel. It is a factor to convert one measurement unit to gigajoules. It allows a solid fuel to be measured in tonnes, a liquid fuel in kilolitres, and a gaseous fuel in cubic metres and converts these measurements to gigajoules (necessary to align with the units of the emission factors). When a gaseous fuel is measured in gigajoules, no conversion is needed, and the energy content factor is 1.

58. Subsection 13(1) and the table in that subsection sets out how to work out the energy content factor for a particular fuel type. The fuel types are described in column 2. Column 3 then sets out how the energy content factor is worked out. With the exception of gaseous fuels measured in gigajoules per cubic metre (item 3 of the table), this factor is worked out in accordance with the provisions of the NGER Measurement Determination specified in column 3. Some items in column 3 of the table provide options for working out the energy content factor of the relevant fuel type, including by using a standard analytical method provided for in the NGER Measurement Determination.

59. Subsection 13(3) relates to the analysis of gaseous fuels measured in gigajoules per cubic metre. One option provided in column 3 of item 2 is to estimate the energy content factor using the method set out in Subdivision 2.3.3.2 of the NGER Measurement Determination. Under item 2 of the table in section 2.25 of the NGER Measurement Determination, a reporting corporation or registered person can certify in writing that

analysing a gas (other than pipeline quality gases) on a monthly basis will cause significant hardship or expense, in which case the analysis can be undertaken at a frequency that allows an unbiased estimate to be obtained. This option is not available when applying Subdivision 2.3.3.2 for the purposes of the Determination. Instead, such gases must be analysed at least monthly. This is to ensure the energy content factor is reflective of the fuel used during the relevant batch period, which can be as short as one hour.

Section 14 - Incomplete data set for the parameter ‘y’ (year)

60. The provisions listed under subsection 14(1) would ordinarily require the holder of the delivery module to monitor certain parameters over the full period of the financial year immediately prior to the financial year in which the batch period started. This section permits the holder of the delivery profile to use a more limited data set where they do not have the data required for that full financial year.

61. A full year’s data is desirable for achieving representative calculations in these instances. However, this provision recognises that there may be circumstances when this is not achievable. Examples of when this might occur is if a facility has not been operating for the full financial year immediately prior to the start of the batch period or has not been engaging in the relevant process for that full period.

62. In these circumstances, subsection 14(2) permits the holder of the delivery profile to use data for a shorter period, provided they use all available relevant data for the facility, the period is between one month and 12 months in duration and is the period ending immediately prior to the start of the batch period. Where there is data for more than 12 months, but not for entire period of the relevant financial year, the latest 12 months of available data must be used. It is expected that using a smaller dataset will likely be a temporary situation, and a full year’s data will be available in subsequent years.

Chapter 2—Common source emissions

Part 2.1 – Common production emissions

Section 15 – Electricity supply and use

63. This section sets out the approach for calculating emissions associated with electricity purchased or acquired from the electricity market ($\boldsymbol{E_{elec,market,b}}$), and the emissions from electricity generated by the holder of the profile in a combined heat and power (CHP) plant ($\boldsymbol{E_{elec,hol,b}}$).

64. The emissions from electricity generated by the holder of the profile, other than in a CHP plant, are worked out under section 16 to streamline reporting of fuel combustion emissions across the production pathway.

Supplied electricity

65. The calculation for the emissions from electricity purchased or acquired from the electricity market to produce a batch ($\boldsymbol{E_{elec,market,b}}$) is set out in subsections 15(2) to (6) and is based on the approach termed 'method B' set out in the NGER Measurement Determination, modified for batch reporting. This calculation method accounts for the use of renewable electricity via the surrender of ***Renewable Electricity Certificates*** (**RECs**), defined in subsection 15(11). Each REC represents one megawatt-hour (MWh) of zero emissions electricity, unless otherwise specified on the certificate.

66. Subsection 15(2) provides that the emissions from electricity purchased or acquired from the market are worked out as the quantity of eligible electricity ($\boldsymbol{Q_{eligible,b}}$) minus the quantity of electricity that corresponds to surrendered RECs ($\boldsymbol{Q_{rec,b}}$), multiplied by the electricity emission factor ($\boldsymbol{EF_{elec}}$).

67. The definition of $\boldsymbol{Q_{rec,b}}$ ensures that the quantity of electricity from any REC surrenders ($\boldsymbol{Q_{rec,b}}$) cannot be greater than the eligible quantity of electricity ($\boldsymbol{Q_{eligible,b}}$). This is to prevent the equation resulting in a negative emissions number.

68. Subsection 15(3) calculates the quantity of purchased or acquired electricity used to produce the batch that can be claimed as renewable electricity via REC surrenders by the holder of the profile. This equation deducts from the supplied electricity the component that is already considered renewable electricity through REC surrenders made by others, as follows:
    - surrenders by liable entities under the renewable energy target (**RET**), represented by the renewable power percentage (**RPP**); and
    - surrenders by jurisdictions, represented by the Jurisdictional RPP (**JRPP**), which at the date this instrument commenced, is only applicable in the Australian Capital Territory.

69. The RPP is defined in subsection 15(11) as having the same meaning as in the *Renewable Energy (Electricity) Act 2000* (**REE Act**). The renewable power percentage is the percentage specified in the regulations made under the REE Act, per sections 5 and 39 of that Act. The JRPP is found in the NGAF document.

70. This equation also accounts for electricity exempt from RET liability ($\boldsymbol{Q_{elec,ex,b}}$), recognising that the profile holder may have been issued RET exemption certificates. This exempt electricity would otherwise have been incorrectly assumed to have a component of renewable electricity represented by the surrenders associated with the RPP.

71. Subsection 15(4) calculates the quantity of supplied electricity used for the batch in respect of which RECs are surrendered. It calculates this by subtracting the quantity of electricity in respect of which RECs have been created, or are expected to be created, for renewable electricity the profile holder generates and uses for the batch ($\boldsymbol{REC_{hol,b}}$), from the quantity of electricity in respect of which RECs have been surrendered for the batch ($\boldsymbol{REC_{surr,b}}$). The result is in megawatt hours so is multiplied by 1000 to correct the units to kilowatt hours.

72. Accounting for the RECs created in relation to renewable energy generated by the profile holder ensures there is no double-counting of renewable claims if those RECs are sold on the market rather than surrendered for the batch. For clarity, if a profile holder does not create RECs then $\boldsymbol{REC_{hol,b}}$ is zero.

73. Subsection 15(5) calculates the electricity market emission factor ($\boldsymbol{EF_{elec}}$) for supplied electricity used for the batch, which for the purposes of the GO Scheme includes both the scope 2 ($\boldsymbol{EF_{elec,scope2}}$) and scope 3 ($\boldsymbol{EF_{elec,scope3}}$) factors, also known as the residual mix factors (RMFs). The scope 2 RMF is found in Part 6 of Schedule 1 to the NGER Measurement Determination. While the table in Part 6 of Schedule 1 to that determination lists a residual mix factor for each State and Territory, in practice this is currently a national value because it is the same for each jurisdiction. The scope 3 RMF is 0.11 kg CO_2-e per kWh. This value comes from the NGAF document.

74. Subsection 15(6) calculates the quantity of supplied electricity used to produce the batch that was exempt from the RET liability. Since exemptions are determined on a calendar year basis, this calculation uses an apportionment of exempted electricity compared to total supplied electricity to work out the quantity for the batch. The apportionment may be performed on a calendar or financial year basis. In cases where all electricity supplied for a batch is exempt from RET liability, the apportionment equals one and all of the electricity supplied for the batch is considered exempted from RET liability.

75. Under the Government's RET scheme, liable entities are required to buy and surrender RECs to comply with their obligations under the scheme. However, entities undertaking eligible emissions-intensive trade-exposed activities may apply for exemption certificates and use these to decrease their obligations under the scheme. Examples of eligible activities are producing hydrogen by electrolysis and aluminium smelting, but not activities related to the delivery modules such as operating pipelines, vehicles or storage tanks.

Electricity generated by the holder of the production profile in a CHP plant

76. Subsection 15(7) sets out the approach for calculating emissions from electricity used for the batch that was generated by the profile holder in a CHP plant ($\boldsymbol{E_{elec,hol,b}}$).

77. Because a CHP plant produces electricity, heat and/or cooling at the same time, the emissions from operating the CHP plant for the batch ($E_{fuel,CHP,b}$) need to be apportioned between these different products. This equation attributes emissions to the electricity output using the ratio for the electricity ($CHP_{e,b}$).

78. Subsection 15(8) requires the CHP Tool to be used to calculate the electricity ratio $\mathbf{CHP_{e,b}}$, which is consistent with section 2.70 of the NGER Measurement Determination. Paragraphs 15(8)(a) and (b) provide that one of three different methods in the CHP Tool could be used, pinpointing which outputs of the CHP Tool are used to determine the appropriate ratio. The CHP Tool is freely available online as noted under the definition of CHP Tool in section 4.

79. Subsections 15(9) and (10) set out the approach for calculating emissions from fuel used to operate the CHP plant. It requires measuring the quantity of each type of fuel used to generate electricity for the batch ($Q_{i,CHP,b}$) and multiplying this amount by the relevant fuel's energy content factor (EC_i) and emission factors representing the fuel's combustion emissions ($EF_{scope1,i}$) and the upstream emissions ($EF_{scope3,i}$). The scope 3 emission factor ($EF_{scope3,i}$) is from the PGO certificate if one has been issued for the fuel or otherwise determined in accordance with section 12 and the applicable parts of Schedule 1 to the Determination.

80. Note, a type of fuel would not include waste heat, meaning there are no emissions associated with using waste heat to power the CHP plant.

81. This equation is consistent with the approach in section 16 of this Determination as both concern the estimation of fuel combustion emissions (see the description for section 16 below for emissions from fuel combustion).

82. Subsection 15(11) defines terms used in this section. ***Renewable Energy Certificate*** (**REC**) is defined in the context of the GO Scheme to mean either:
    - Large Scale Generation Certificates surrendered under section 28A of the REE Act, which could include a GreenPower contract, other than a certificate that has been created in contravention of section 24 or 25 of that Act or was surrendered to meet a liable entity's obligations under Subdivision A of Division 1 of Part 5 or section 95 of that Act; or
    - REGO certificates, provided they were not created in contravention of section 103 of the GO Act.

83. RECs are not considered valid if they are for electricity generated more than 12 months prior to the start of the batch period, consistent with subsection 51(8) the GO Act.

<u>Section 16 – Fuel supply and use</u>

84. This section sets out the approach for calculating emissions from fuel used for the production pathway for the batch ($E_{fuel,b}$), excluding any fuel used for a CHP plant. Examples of emissions included here are emissions from combusting fuel to make electricity, steam or direct heat. Emissions from combusting fuels in a CHP plant to generate electricity and steam are accounted for separately under subsections 15(7) and 18(6) respectively. The Determination requires fuel used in a CHP plant to be measured and monitored separately to accurately attribute emissions to the various outputs of a

CHP plant. Otherwise, this section enables fuel supply for the batch to be monitored and measured for the production pathway rather than at each point fuel is used or combusted. If no fuel is used for the production pathway for the batch, then this emissions source does not need to be accounted for.

85. Subsection 16(1) provides that the emissions from the supply and use of fuels are calculated by multiplying the quantity of fuel by the corresponding default scope 1 and scope 3 emission factors. The Determination provides for a flexible approach to the unit of measurement used to measure the fuel ($\boldsymbol{Q_{i,b}}$). This could be, for example, in gigajoules, cubic metres or kilograms. Because the emission factors are specified on a per gigajoule basis, the fuel energy content ($\boldsymbol{EC_i}$) is multiplied by the quantity of fuel to ensure the quantity of fuel is also expressed in gigajoules. The summation over fuel "i" caters for a situation where more than one type of fuel is used for the batch. The scope 3 emission factor ($\boldsymbol{EF_{scope3,i}}$) is from a PGO certificate if one has been issued or otherwise determined in accordance with section 12 and the applicable Parts of Schedule 1 to the Determination.

Section 17 – Water supply

86. This section sets out the approach for calculating emissions relating to water supplied to produce the batch ($\boldsymbol{E_{water,is,b}}$).

87. Water is a significant input in hydrogen production via electrolysis. It is used in electrolysers, steam and electricity generation and cooling processes. The emissions generating activities relating to water supply are extraction, treatment, processing and transport of water. Due to the potentially high volumes of water required in the electrolyser operation, water supply and use are considered material and included as a production emissions source.

88. Recognising the importance of water used to produce the hydrogen via electrolysis, the type and quantity of water used to produce the batch of hydrogen will be included on a PGO certificate under the Go Rules (paragraph 25(1)(g) and Schedule 2).

89. This section only accounts for water supplied by an input supplier. If a profile holder sources, treats or transports water themselves for use in the pathway, then the emissions will primarily result from electricity use and would be accounted for by section 15.

90. Subsection 17(1) provides that the emissions from water used to produce the batch are calculated by multiplying the quantity of water used for the batch in kilograms ($\boldsymbol{Q_{water,b,x}}$) by the corresponding emission factor in kilograms of CO_2-e per kilogram of water ($\boldsymbol{EF_{water,x}}$). The approach has a summation over water source **x**, catering for a situation where there is more than one water source for the batch. Given the emission factors may differ depending on the water source, it is important that each water source is identified and accounted for.

91. Subsection 17(2) provides that the emission factor for a water source may be determined from default scope 3 emission factors that consider whether the water has undergone advanced water treatment. Electrolysers require extremely pure water and a number of advanced treatment processes could be used to achieve this purity. Default scope 3 emission factors are specified for the source of water in the table in Part 1 of Schedule 1

(e.g. 'Potable water from New South Wales'), and the default scope 3 emission factor *supplements* for the type of advanced water treatment are in the table in Part 2 of Schedule 1 (e.g. 'Ultrapure membrane process'). If a source of water has undergone advanced treatment, then the two default emission factors are added together (e.g. the emission factor for the water source, plus the emission factor supplement for the type of advanced water treatment).

92. As an alternative to using the default scope 3 emission factors, subsection 17(3) provides for calculating a water source-specific emission factor by using financial year data if available and voluntarily provided by the input supplier. If data is provided, then the emission factor for the water source is calculated by dividing the input supplier's scope 1 and scope 2 emissions for the most recent financial year ($\boldsymbol{E_{water,is,x,y}}$) by the quantity of water from the water source for the same financial year ($\boldsymbol{Q_{water,x,y}}$). The definition of $\boldsymbol{Q_{water,x,y}}$ clarifies that treated or untreated wastewater that has been collected and redistributed does not count towards the relevant quantity of water. This type of water is typically discharged, and as such should not be factored into the emission factor calculation.

93. The time basis of the waste-source specific equation is the most recent financial year to cater for the situation that the input supplier is required to report under the NGER scheme (**NGER reporter**). Each financial year, NGER reporters report scope 1 and scope 2 emissions from the relevant facility to the Clean Energy Regulator (CER) and it is possible that the input supplier may be able to source the data needed for this calculation from their NGER report. This helps streamline data reporting and provide confidence in the data.

94. For clarification, the Determination does not place obligations on the input supplier to provide data, and the profile holder can use the default values determined using subsection 17(2) as an alternative.

<u>Section 18 – Steam supply and use</u>

95. This section sets out the approach for calculating emissions for steam used to produce the batch ($\boldsymbol{E_{steam,b}}$). If no steam is used for the production pathway for the batch, then this emissions source does not need to be accounted for. The emissions from steam sourced from an input supplier and generated by the profile holder are accounted for under this section.

Steam from an input supplier

96. Subsection 18(2) sets out the approach for calculating emissions from a steam supplier. The total emissions from steam provided by an input supplier and used for the batch is calculated by summing up the quantity of steam from a source $\boldsymbol{x}$ in gigajoules (GJ) and multiplying it by an emission factor ($\boldsymbol{EF_{steam,x}}$) in kilograms of CO_2-e per gigajoule of steam. Where multiple sources of steam are used to produce the batch, the emission factors may differ depending on the steam source (denoted by $\boldsymbol{x}$), so it is important that each source and the quantity of steam from this source is identified and accounted for.

97. The definition of the emission factor for steam source $\boldsymbol{x}$ ($\boldsymbol{EF_{steam,x}}$) in subsection 18(2) provides that it may be either a default emission factor of 109.375 or a source-specific emission factor calculated using input supplier data under subsection 18(3).

98. The default factor has been calculated assuming that the steam is generated using diesel in a boiler with 75% efficiency. The scope 1 emission factor for diesel is sourced from the NGER Measurement Determination (70.2 kg CO_2-e per GJ), and the scope 3 emission factor is sourced from the NGAF document (17.3 kg CO_2-e per GJ). This is then divided by 75%. For example:

$$(70.2 + 17.3) \div 75\% = 109.38 \text{ kg } CO_2\text{-e per GJ of steam}$$

99. The assumptions of diesel and a boiler efficiency of 75% are plausible and reasonably conservative. Although steam could be generated using fuel with lower scope 1 and scope 3 emissions than diesel, and in a boiler with an efficiency better than 75%, the assumptions above have been used to ensure a conservative default factor is available where better information is not available. If the profile holder believes that the input supplier's steam supply has a lower emissions intensity than the default value, then they may pursue a source-specific emission factor with the cooperation of their input supplier.

100. Subsection 18(3) provides that the steam source-specific emission factor is calculated based on data from the input supplier by dividing annual scope 1 and scope 3 emissions associated with the supplier's steam generation ($\boldsymbol{E_{steam,is,y}}$) by the quantity of steam produced by the supplier ($\boldsymbol{Q_{steam,is,y}}$).

101. Subsections 18(4) and 18(5) set out how this annual emission value is calculated, which is based on the data the input supplier provides on the quantity and type of fuel used for steam production during the financial year immediately before production of the batch commenced. The emissions resulting from this fuel use is then calculated based on the default scope 1 and 3 emission factors for the fuel in kilograms of CO_2-e per gigajoule. The scope 1 emission factor is worked out in accordance with section 11 and scope 3 in accordance with a registered PGO certificate for the fuel (if applicable) or otherwise in accordance with section 12. The energy content factor is determined in accordance with section 13.

102. The equation in subsection 18(4) includes the parameter $\boldsymbol{CHP_{s,y}}$. This parameter accounts for a situation where a CHP plant is the source of steam. A CHP plant produces both steam and electricity, meaning that the emissions are apportioned between the two outputs using the CHP ratio (calculated under subsection 18(7)). The approach for calculating this ratio is set out in the CHP Tool defined in section 4. Performing the calculations to work out the CHP ratio requires additional information from the input supplier such as the respective production of electricity, heat and potentially cooling. If the necessary information isn't available, then the default value in subsection 18(2) should be used.

Steam generated by the holder of the production profile in a CHP plant

103. Subsection 18(6) set out the approach for calculating emissions from steam used for the batch that was generated by the profile holder in a CHP plant ($\boldsymbol{E_{steam,hol,b}}$).

104. Similar to calculations of electricity emissions from a CHP plant under subsection 15(7), because a CHP plant produces electricity, heat and/or cooling at the same time, the emissions from operating the CHP plant for the batch ($E_{fuel,CHP,b}$) need to be apportioned between these different products. This equation attributes emissions to the steam output using the ratio for the steam ($\mathbf{CHP_{s,b}}$).

105. Subsection 18(7) requires the use of the CHP Tool to calculate the steam ratio $\mathbf{CHP_{s,b}}$, which is consistent with section 2.70 the NGER Measurement Determination. Paragraphs 18(7)(a) and (b) provide that one of three different methods in the Tool could be used, pinpointing which outputs of the CHP Tool are used to determine the appropriate ratio.

106. Subsection 18(8) provides the approach for calculating emissions from fuel used to operate the CHP plant. It requires measuring the quantity of each fuel type used to generate steam to produce the batch ($Q_{i,CHP,b}$) and multiplying this amount by the relevant energy content factor for the fuel type (EC_i) and the corresponding default emission factors representing combustion emissions ($EF_{scope1,i}$) and the upstream emissions ($EF_{scope3,i}$) for the fuel type. The scope 3 emission factor is from a PGO certificate if one has been issued or otherwise determined in accordance with section 12 and applicable parts of Schedule 1 of the Determination.

107. This equation is consistent with the approach in section 16 as both concern the estimation of fuel combustion emissions (see section 16 above regarding emissions from fuel combustion).

108. If the input supplier or profile holder produces steam from waste heat, then this waste heat does not constitute a relevant quantity of fuel used to generate steam (e.g. is not considered $Q_{i,is,y}$ or $Q_{i,CHP,b}$). In this way, there are no emissions associated with steam produced from waste heat. The same applies for electricity generated from waste heat. The treatment of waste heat is consistent with a number of international emissions accounting frameworks, including the International Partnership for Hydrogen and Fuel Cells in the Economy (**IPHE**), which assign no emissions to production inputs that are wastes or residues.

109. For completeness, steam generated from electricity sources are to be included in the accounting under the relevant electricity supply and use section.

<u>Section 19 – Synthetic gas use</u>

110. Subsection 19(1) sets out the approach to calculating the scope 1 emissions from synthetic gas usage by the profile holder. Synthetic gases include hydrofluorocarbon gases for refrigeration and cooling, and sulphur hexafluoride used in electricity supply equipment. If no synthetic gas is used for the production pathway for the batch, then this emissions source does not need to be accounted for.

111. Due to the high greenhouse gas potential of many synthetic gases, any use of synthetic gas by a profile holder is deemed a material source of emissions that should be accounted for. It is expected that many hydrogen production and delivery processes will not use synthetic gases given there may be alternatives.

112. The approach to calculating the emissions from synthetic gas use depends on default annual leakage rates ($\boldsymbol{L_{jk}}$) sourced from the NGER Measurement Determination, specified for typical equipment ($\boldsymbol{k}$) like air conditioners, refrigeration and gas insulated switchgear.

113. The default leakage rate is multiplied by the stock of synthetic gas ($\boldsymbol{Stock_{jk}}$), estimated in subsection 19(2) based on the nameplate capacity of how much synthetic gas could be contained in the relevant equipment. Since this approach estimates emissions for a year in tonnes CO_2-e, the equation in subsection 19(1) includes an apportionment factor that divides the batch period in hours by 8760 hours in a year, multiplied by 1,000 to convert tonnes to kilograms CO_2-e (e.g. $\boldsymbol{t_b}$ ÷8.76).

Part 2.2—Common post-production emissions

Section 20 – Pipeline delivery module—pipeline emissions

114. Section 20 sets out the approach for calculating emissions associated with transport of a PGO product, termed the ***transported quantity*** ($\boldsymbol{Q_{b,transported}}$), in accordance with the pipeline delivery module ($\boldsymbol{E_{pipe,transported}}$).

115. Paragraph 34(1)(a) of the Determination defines ***pipeline delivery module*** to be transport by a ***dedicated pipeline***, which is defined in section 4 to mean a pipeline that only transports hydrogen. As such, pipelines that transport hydrogen blended with other products are excluded. This restriction reflects that the emissions accounting includes the emissions sources relevant for hydrogen, but potentially not for other products, such as fugitive emissions of natural gas.

116. Dedicated pipeline emissions are calculated with a pipeline-specific emission factor ($\boldsymbol{EF_{pipe,y}}$) multiplied by the ***transported quantity*** of hydrogen ($\boldsymbol{Q_{b,transported}}$) (subsection 20(1)). The transported quantity is a term that refers the batch or the part of a batch (one or more functional units of the batch) being transported by the delivery module, recognising that the product in a batch could be delivered at different times or to different customers.

117. Paragraph (a) of the parameter $\boldsymbol{Q_{b,transported}}$ specifies that the amount of product in the transported quantity is to be measured at the production gate if the pipeline delivery module is immediately after production is completed. For hydrogen, this formula or method is set out in section 24. If, instead, the pipeline delivery module is after another different delivery module, then the transported quantity of a product is measured at the end of the delivery module that is immediately prior to the pipeline delivery module. For hydrogen, this formula or method is set out in subsection 35(3) of the Determination. Measuring the quantity of the product at the end of previous module is required to accurately account for any losses of hydrogen that may occur in the delivery module(s) before the pipeline delivery module.

118. Subsection 20(2) provides that the pipeline-specific emission factor ($\boldsymbol{EF_{pipe,y}}$) is calculated as the emissions associated with the operation of the pipeline over a year, divided by the total amount of hydrogen that was injected into the pipeline in the same year ($\boldsymbol{Q_{pipe,y}}$). If no electricity or fuel is used in the delivery module, then there are no emissions associated with these sources.

119. The emissions associated with the supply of electricity to operate the pipeline over a year ($\boldsymbol{E_{pipe,elec,y}}$) are calculated in accordance with section 15, modified so as to apply to the pipeline delivery module. Specifically, section 15 applies as though references to 'production pathway' refer instead to 'pipeline delivery module', references to 'batch' refer to 'year (y)', and references to 'production profile' refer to 'delivery profile'. For example, the parameter $\boldsymbol{E_{elec,market,b}}$ in subsection 15(1), as applied for the parameter $\boldsymbol{E_{pipe,elec,y}}$ in subsection 20(2), would refer to 'the emissions from purchased or acquired electricity used for the *delivery profile* for the *year (y)* in kilograms of CO_2-e, worked out in accordance with subsection (2)', with the italicised terms representing the substituted terms.

120. Subparagraph (a)(ii) of the parameter $\boldsymbol{E_{pipe,elec,y}}$ provides that the reference to 'batch' in the parameter $\boldsymbol{EF_{scope3,i}}$ is not modified. This is because it refers to the batch of the fuel used to operate the CHP plant for the delivery module, not the batch of the product produced in accordance with the production pathway.

121. Paragraph (c) of the parameter $\boldsymbol{E_{pipe,elec,y}}$ provides that, when calculating the eligible quantity of electricity purchased from the grid ($\boldsymbol{Q_{eligible,b}}$), the exemption from RET liability under subsection 15(6) is not applicable for calculating the pipeline emissions. This reflects the fact that pipelines would not be exempt from RET liability.

122. The parameter $\boldsymbol{E_{pipe,fuel,y}}$ similarly provides that the emissions from the fuel used for the pipeline delivery module for the year (y) are worked out in accordance with section 16, modified so the provisions apply to the delivery module.

123. A full year's data is desirable for achieving representative calculations in these instances. However, the provision in subsection 14(2) recognises that there may be circumstances when this is not achievable. Examples of when this might occur is if a facility has not been operating for the full previous financial year, or has not been engaging in the relevant process for that full period.

<u>Section 21 – Vehicle delivery module—vehicle emissions</u>

124. Section 21 sets out the approach for calculating vehicle emissions ($\boldsymbol{E_{veh,transported}}$) associated with transport of a PGO product, the ***transported quantity*** ($\boldsymbol{Q_{b,transported}}$), between a production gate and a delivery gate. Subsection 21(1) recognises there may be several journeys in the delivery module and the emissions from each journey need to be added together to work out the emissions for the vehicle delivery module. For example, within the delivery module, a transported quantity could be delivered to a customer in several consignments, or the transported quantity could be delivered using different vehicle types, such as by a truck then a train.

125. This section provides the option to calculate the emissions for a journey using either the no apportionment method, the apportionment method or the load distance method. These methods differ in terms of monitoring and measuring requirements.

No-apportionment method

126. The no-apportionment method in subsection 21(2) accounts for the emissions of the journey, which relate to the fuel ($\boldsymbol{E_{veh,fuel,J}}$), electricity ($\boldsymbol{E_{veh,elc,J}}$) and synthetic gas ($\boldsymbol{E_{veh,leaks,J}}$) used for the vehicle delivery module. Emissions from the use of fuel, electricity and synthetic gas are calculated using the approach in sections 15, 16, and 19 respectively.

127. The emissions associated with the supply of electricity to operate the vehicle ($\boldsymbol{E_{veh,elec,J}}$) are calculated in accordance with section 15, modified so as to apply to the vehicle delivery module. Specifically, section 15 applies as though references to 'production pathway' refer instead to 'vehicle delivery module', references to 'batch (b)' refer to 'journey (J), and references to 'production profile' refer to 'delivery profile'.

128. The parameter $\boldsymbol{E_{veh,fuel,y}}$ similarly provides that the emissions from the fuel used for the vehicle delivery module for the journey (J) are worked out in accordance with section 16, modified so the provisions apply to the delivery module.

129. The parameter $\boldsymbol{E_{veh,leaks,J}}$ similarly provides that the emissions from the fuel used for the vehicle delivery module for the journey (J) are worked out in accordance with section 19, modified so the provisions apply to the delivery module.

Apportionment method

130. The apportionment method in subsection 21(3) caters for the weight of the vehicle's load changing during the journey. For example, the vehicle might load or unload goods other than the transported quantity of the product during the journey, leading to changes in the vehicle's total load. It does this by considering the journey in sections, which are distinguished by points in the journey where the load changes. For vehicles that are carrying materials in addition to the transported quantity, this method allows a profile holder to reduce the total emissions of the journey by attributing emissions to the part of the load that is not the transported quantity and its packaging. For journeys consisting of several sections, the apportionment method has the potential to be complex, and the load distance method may be a more straightforward approach for estimating emissions.

131. Subsection 21(3) provides that the emissions for the vehicle delivery module ($\boldsymbol{E_{veh,J}}$) are calculated as the sum of the emissions for each section of the journey ($\boldsymbol{E_{veh,s}}$) multiplied by the proportion of the total load transported ($\boldsymbol{Q_{product,s}}$) that is the transported quantity ($\boldsymbol{Q_{b,transported}}$), including the weight of packaging. The total load does not include the weight of the vehicle itself.

132. Paragraph (a) of the parameter $\boldsymbol{Q_{b,transported}}$ specifies that the amount of product in the transported quantity is to be measured at the production gate if the vehicle delivery module is immediately after production is completed. For hydrogen, this formula or method is set out in section 24. If, instead, the vehicle delivery module is after another different delivery module, then paragraph (b) provides that the transported quantity of a product is measured at the end of the delivery module that is immediately prior to the vehicle delivery module. For hydrogen, this formula or method is set out in subsection 35(3). This amount is then added to the product's packaging to work out the $\boldsymbol{Q_{b,transported}}$ in kilograms.

133. Subsection 21(4) provides that the emissions for the section of the journey are worked out in a similar way to the no-apportionment method in subsection 21(2), except that the basis for estimating the emissions is the section, not the entire journey. The emissions from fuels, electricity and synthetic gases are to be calculated in accordance with sections 16, 15 and 19 respectively, modified so the provisions apply to the delivery module.

Load distance method

134. The load distance method in subsection 21(5) provides an alternative approach for calculating the emissions from the vehicle transporting the ***transported quantity*** that uses default or vehicle-specific emission factors.

135. The vehicle emissions are calculated by multiplying the transported quantity including the product's packaging ($\boldsymbol{Q_{b,transported}}$), distance travelled ($\boldsymbol{D_J}$) and the emission factors for the relevant vehicle ($\boldsymbol{EF_{veh}}$).

136. The parameter $\boldsymbol{EF_{veh}}$ provides for both default and vehicle-specific emission factors. A profile holder can choose which approach to use. Paragraph (a) provides for the use of default emission factors. These factors do not account for synthetic gas leakage. The default emission factors are provided in Part 3 of Schedule 1. This means that, if paragraph (a) is used, the emissions from synthetic gas leakage must be worked out under paragraph (b) of the parameter $\boldsymbol{E_{veh,leaks,J}}$. Emissions from synthetic gas use are worked out using section 19, modified so that it applies to the sample journey.

137. In contrast, paragraph (b) of the parameter $\boldsymbol{EF_{veh}}$ provides for the calculation of a vehicle-specific emission factor in accordance with subsection 21(6). This emission factor accounts for synthetic gas leakage. As a result, the parameter $\boldsymbol{E_{veh,leaks,J}}$ is not needed, with paragraph (a) of the parameter $\boldsymbol{EF_{veh}}$ providing that it is 'zero' in these circumstances.

138. To calculate a vehicle-specific emission factor ($\boldsymbol{EF_{veh}}$), subsection 21(6) requires a profile holder to measure the emissions from electricity, fuel and synthetic gas over a sample journey ($\boldsymbol{E_{fleet,SJ}}$), which is defined as at least 5 separate trips with a combined distance of at least 1,000 kilometres. These settings are intended to result in a representative emission factor for the fleet of vehicles.

139. The emissions for this sample journey are then divided by the load conveyed (in kilograms) ($\boldsymbol{Q_{fleet,SJ}}$) multiplied by the total distance travelled (in kilometres) ($\boldsymbol{D_{fleet,SJ}}$), for the same sample journey. This equation ensures that the default and vehicle-specific emission factors is specified in kg CO_2-e per kilogram-kilometre, which are the same units as the default emission factors.

140. Subsection 21(7) provides that the emissions from the relevant vehicles of the fleet used for the sample of the journey (***SJ***) are to be calculated in accordance with sections 16, 15 and 19, modified so the provisions apply to the vehicle delivery module.

141. Subsection 21(8) provides that a reference to vehicle in this section includes a reference to more than one vehicle. For example, the transported quantity might be transported simultaneously by a fleet of vehicles, or transported for part of the journey by one vehicle and then transported for the remainder of the journey by a different vehicle.

Section 22 – Storage vessel delivery module—storage vessel emissions

142. This section sets out the approach to calculating the storage vessel emissions ($\boldsymbol{E_{store,product}}$). A profile holder may calculate emissions by using the direct reporting method or the quantity storage method. The term ***stored quantity*** refers to the functional units in a batch of product that is stored, catering for the situation that a batch may be stored in its entirety or split to be delivered to different customers.

Direct reporting method

143. Subsection 22(2) sets out the direct reporting method. The emissions from the storage vessel delivery module are the sum of the emissions from the electricity ($\boldsymbol{E_{store,elec,t}}$),

steam ($\boldsymbol{E_{store,steam,t}}$), synthetic gas ($\boldsymbol{E_{store,leaks,t}}$) and fuel ($\boldsymbol{E_{store,fuel,t}}$) used for the storage vessel delivery module.

144. The basis for calculating the emissions is the time period (t), which encompasses the time during which the stored quantity is loaded, unloaded, compressed, cooled, dried and purified. This reflects the fact that these activities, done for the purposes of the storage vessel delivery module, may cause emissions (noting that the actual residence of the stored quantity in the storage vessel is unlikely to cause emissions). The emissions for electricity, steam, synthetic gas and fuel use are calculated in sections 15, 18, 19, and 16 respectively, modified so the provisions apply to the delivery module.

Quantity storage method

145. Subsection 22(3) sets out the quantity storage method. Under this method, emissions are calculated by using an emission factor specific to the storage vessel for the year (y) ($\boldsymbol{EF_{store,y}}$) and multiplying it by the stored quantity ($\boldsymbol{Q_{store,product}}$).

146. Paragraph (a) of the parameter $\boldsymbol{Q_{store,product}}$ specifies that the amount of product in the stored quantity is to be measured at the production gate if the storage vessel delivery module is immediately after production is completed. For hydrogen, this formula or method is set out in section 24. If, instead, the storage vessel delivery module is after another different delivery module, then paragraph (b) provides that the stored quantity of a product is measured at the end of the delivery module that is immediately prior to the storage vessel delivery module. For hydrogen, this formula or method is set out in subsection 35(3).

147. Subsection 22(4) provides that the emission factor ($\boldsymbol{EF_{store,y}}$) is calculated by reference to the profile holder's storage emissions from the previous financial year (y) ($\boldsymbol{E_{store,y}}$) divided by the total quantity of product stored for the same year ($\boldsymbol{Q_{store,y}}$).

148. A full year's data is desirable for achieving representative calculations in these instances. However, the provision in subsection 14(2) recognises that there may be circumstances when this is not achievable. Examples of when this might occur is if a facility has not been operating for the full previous financial year or has not been engaging in the relevant process for that full period.

149. The emissions for storage of the product for the past financial year include electricity ($\boldsymbol{E_{store,elec,y}}$), steam ($\boldsymbol{E_{store,steam,y}}$), synthetic gas ($\boldsymbol{E_{store,leaks,y}}$) and fuel ($\boldsymbol{E_{store,fuel,y}}$) used during the previous financial year. Emissions from the electricity, steam, synthetic gas and fuel use are to be calculated using the approach in sections 15, 18, 19 and 16 respectively, modified so the provisions apply to the delivery module.

Chapter 3—Hydrogen production pathway

Part 3.1 – Production of hydrogen

Division 3.1.1 – Hydrogen functional unit and batch size

Section 23 – Hydrogen functional unit

150. Section 23 provides that the functional unit of hydrogen is one kilogram (1 kg). Mass has been used because it is a common industry standard and is a consistent measure of hydrogen across different physical states, temperatures and pressures.

151. Subsection 49(2) of the GO Act provides that one PGO certificate may be created for each whole functional unit of the product in the batch. Therefore, the number of PGO certificates created is rounded down to whole numbers. For example, 10 PGO certificates would be registered for a batch of 10.9kg of hydrogen.

Section 24 – Hydrogen batch size

152. Section 24 sets out a method for working out the amount of hydrogen in a batch of hydrogen produced in accordance with any production pathway for hydrogen under the Determination. This method must be used to work out the amount of hydrogen in a batch and that amount must be included on a PGO certificate pursuant to subsection 50(2) and paragraph 50(1)(g) of the GO Act, respectively.

153. The batch quantity is required to be monitored and measured at the production gate for the product and in accordance with section 9, meaning, where possible, in a manner consistent with the NGER Measurement Determination. The current provisions of the NGER Measurement Determination relevant for measuring hydrogen are Division 1.2.1, Division 4.3.7 and Schedule 4, Part 4, source 6.

154. The meaning of production gate is set out in subsection 28(1) of the GO Act. If the Regulator has determined a production gate in relation to the facility under subsection 28(3) of the GO Act, the amount of product in a batch must be measured at that location. If the Regulator has not made such a determination, the amount of product in the batch is measured at the point at which a production module has been completed in relation to the product, and the product is ready to be delivered. For example, this may be where the hydrogen is inputted into a pipeline leaving the production pathway or loaded into tubes or cannisters for vehicle delivery.

155. For clarity, paragraph 25(1)(g) and Schedule 2 to the GO Rules provide that additional product-specific attributes for hydrogen must be included on PGO certificates. For gaseous and liquid hydrogen, the certificate must state the purity of the hydrogen as a percentage of the total volume. For gaseous hydrogen, the PGO certificate also needs to state the pressure of the hydrogen in kPa. These attributes could be measured at the same time as measuring the batch size.

Division 3.1.2 – Production pathway—electrolysis

Section 25 – Electrolysis production pathway

156. Subsection 25(1) provides that the ***electrolysis production pathway*** is a production pathway for hydrogen, which is the method of producing hydrogen through the conversion of water by electrolysis. The description of the pathway does not prescribe the use of particular electrolyser technologies. This ensures new technologies are captured by the description of the pathway provided they produce hydrogen from water by electrolysis. Examples of existing electrolysis systems are alkaline, polymer electrolyte membrane and solid oxide.

157. When a registered person applies to register a production profile, the profile must include a production pathway for the product pursuant to paragraph 30(2)(g) of the GO Act. Under paragraph 29(4)(b) of the GO Act, if the Minister determines a production pathway, the determination must specify a minimum module. For the electrolysis production pathway, the ***electrolysis production module*** is the minimum module, as described in subsections 25(2) and (3) of the Determination.

158. For this minimum module, the profile holders must monitor, calculate and report the sources of greenhouse gas emissions associated with the supply and use of electricity, fuel, water, steam, and synthetic gas, in accordance with sections 15, 16, 17, 18, and 19, respectively. The sources of emissions specified in subsection 25(4) are specified for the production pathway and are therefore ***production emissions sources*** for the purposes of subsection 29(6) of the GO Act.

159. The sources set out in subsection 25(4) encompass the potential material sources of emissions associated with hydrogen production from electrolysis. Electricity and water are the key inputs to the production process, and steam and fuel may be used for supplementary energy needs. Synthetic gas may be used for cooling the hydrogen gas or associated with electricity supply.

Section 26 – Optional modules—electrolysis

160. Section 26 sets out two optional modules for the electrolysis production pathway – the ***intermediate storage tank production module*** and the ***gas conditioning production module***. These modules represent equipment or process steps that are not always necessary in the production of hydrogen by electrolysis. However, if one or both optional modules are included in the production pathway for the product, the associated emissions must be accounted for under the Determination.

161. The intermediate storage tank production module is defined in subsection 26(1). It refers to the use of a storage tank after the minimum production module has been completed, but within the production process captured by the production pathway. In this way, it is distinct from a storage vessel used in the storage vessel delivery module. The presence of an intermediate storage tank is, for example, relevant for the calculation of the production emissions intensity calculation for the batch (see section 30 below).

162. The gas conditioning production module is defined in subsection 26(2). ***Conditioning*** is defined in subsection 26(4) as including purifying, drying, compressing, pumping and

cooling. The definition of ***conditioning*** does not exhaustively define the term. Such processes may be performed to meet the specifications for delivery. The purpose of defining gas conditioning as an optional module provides flexibility to cater for different set ups of the production activities, such as compressing the gas after storing it in an intermediate storage tank.

163. If included in the production profile, the optional modules form part of the production pathway. The sources of emissions set out in subsection 25(4) are specified for the production pathway. This means that these sources of emissions apply equally to the optional production modules. This is explained in the note to subsection 26(3).

Division 3.1.3 – Hydrogen emissions

<u>Section 27 – Hydrogen production emissions</u>

164. Section 27 provides that the production emissions for a batch of hydrogen are calculated by adding together all the emissions for the production pathway. For the electrolysis production pathway this means the total greenhouse gas emissions associated with the supply and use of electricity, fuel, water, steam and synthetic gas calculated for the production pathway in accordance with Part 2.1 of Chapter 2.

165. Particular production pathways for hydrogen may provide for a reduction of the total production emissions in limited circumstances. For the electrolysis production pathway, this can occur in accordance with section 29, which relates to the sale of oxygen as a co-product. Section 27 has been drafted so that further paragraphs may be added if future production pathways for hydrogen similarly allow for a reduction in production emissions.

<u>Section 28 – Hydrogen post-production emissions</u>

166. Section 28 provides that the total post-production emissions associated with the transport and storage of the transported quantity of hydrogen are calculated by adding together the emissions from all post-production emissions sources associated with any delivery modules the transported quantity passes through between the production gate and the delivery gate. For hydrogen, the relevant delivery modules are set out in section 34 as the pipeline, vehicle and storage vessel delivery modules. The emissions from post-production emissions sources for these modules are calculated in accordance with the provisions in Part 2.2 of Chapter 2.

<u>Section 29 – Co-product reduction of emissions for electrolysis production pathway</u>

167. Oxygen sales are an eligible co-product for the electrolysis production pathway. This section sets out how to work out the emissions reduction associated with oxygen sales for a batch. If such a reduction is calculated, then this amount is subtracted in the calculation of the production emissions in section 27.

168. Subsection 29(1) sets out the calculation for the emissions attributable to the production of oxygen ($\boldsymbol{E_{O2sale,b}}$). In this formula:

- The factor of 7.5% is the portion of emissions from a kilogram of hydrogen produced by electrolysis that is attributable to oxygen sales. This factor is determined based on a 'system expansion with displacement' approach aligned with the IPHE, which considers the electricity needed to produce oxygen using air separation technology and comparing to the electricity needed to make an equivalent amount of oxygen in an electrolyser. The reduced amount of electricity needed for making oxygen in an electrolyser compared to the air separation technology underpins the 7.5% value. The suitability of this approach is a supported by there being an existing market for high quality oxygen for use in laboratories, hospitals and industrial applications, and the prevalent technology for supplying oxygen is air separation technology.

- The parameter $\boldsymbol{R_{O2sale,b}}$ is the ratio that represents the proportion of oxygen produced in the course of producing a batch of hydrogen that was sold. Paragraph (b) of the parameter $\boldsymbol{R_{O2sale,b}}$ ensures that the ratio cannot exceed 100%. That is, the holder of a production profile is prevented from claiming a reduction in production emissions for the sale of more oxygen than it is possible to when producing the batch of hydrogen. This cap accounts for the fact that oxygen sales during a batch period could theoretically exceed the amount of oxygen produced in a hydrogen batch (for example due to sales of oxygen produced outside the batch and kept in storage tanks).
- The parameter $\boldsymbol{E_{minM,b}}$ represents the emissions from the minimum module for the electrolysis production pathway. Emissions associated with optional modules are not relevant to the production of oxygen. If the pathway only includes the minimum module, then $\boldsymbol{E_{minM,b}}$ will equal the production emissions for the batch $\boldsymbol{E_{pathway,b}}$.

169. Subsection 29(2) sets out the calculation of the ratio $\boldsymbol{R_{O2sale,b}}$, as oxygen sales for the batch ($\boldsymbol{S_{O2}}$) divided by the amount of oxygen produced in the batch. The amount of oxygen produced in a batch is worked out as 7.94 multiplied by the amount of hydrogen produced in the batch ($\boldsymbol{Q_{pathway,b}}$). 7.94 represents the fact that oxygen is produced at a ratio of 7.94 kg per 1 kg of hydrogen, calculated based on the molar mass of the hydrogen and oxygen and the fact that a molecule of water produces two molecules of hydrogen and one molecule of oxygen.

170. $\boldsymbol{Q_{pathway,b}}$ intuitively equals the hydrogen batch size worked out in section 24, which is provided for in paragraph (b) of the parameter. However, if there is an intermediate storage tank sufficiently large that the measurement of the hydrogen batch size may not reflect the amount of hydrogen produced by the electrolyser during the batch (for example, due to the intermediate storage tank storing part of the produced hydrogen), then paragraph (a) provides that $\boldsymbol{Q_{pathway,b}}$ is measured after the minimum module is completed and before the intermediate storage tank. This approach is technically required if the batch period is less than the time it took to fill the storage vessel.

171. The quantity of oxygen sales for the batch ($\boldsymbol{S_{O2}}$) refers to the quantity of oxygen produced in the course of producing a batch of hydrogen in accordance with the electrolysis production pathway. This quantity must meet two requirements to fall within the parameter $\boldsymbol{S_{02}}$: first, it must have been sold by the holder of the production profile to another person; second, it must have been sold for an amount not less than market value at the time of the sale. The intent of this definition is to ensure only genuine sales of oxygen contribute to a lower emissions intensity on PGO certificates. This requirement is important because oxygen may be considered a residue which is inelastically produced

through no extra effort in the course of making hydrogen by electrolysis. The producer could choose to discard or sell oxygen at an unduly low price, foregoing potential revenue, as the costs incurred are not significant. The requirement for the sale to another party supports that the sale is genuine. This approach is consistent with the IPHE, however other international frameworks do not provide for an emissions reduction for oxygen sales. A profile holder could elect not to account for an emissions reduction for oxygen sales if seeking consistency with other frameworks

172. Section 56A of the GO Act enables the Regulator to request further information from the holder of the production profile where the holder has made a request to register a PGO certificate. Under subsection 56(8) of the GO Act, the Regulator may refuse to register a PGO certificate is the Regulator is not satisfied that the emissions stated in the certificate in relation to a production emissions source for the product have been worked out correctly in accordance with the applicable methodology determination. The Regulator could, for example, request additional information in order to determine whether the parameter S_{O2} has been correctly calculated, including whether the quantity of oxygen has been sold for market value. This could include a commercial contract or invoices for the sale of the oxygen, along with evidence that the sales price in the contract or invoice is consistent with market value of oxygen at the time of sale. Evidence of market value might include one or more of the following:

- price/market analysis or data on co-products from third party sources;
- quotes or other forms of pricing information from other suppliers in the market; or
- price data collected to inform forecasts of potential revenue streams from co-product sales, which informed decisions regarding the commercial viability of investing in the production facility.

Division 3.1.4 – Hydrogen emissions intensity

Section 30 – Production emissions intensity—hydrogen

173. Section 30 sets out the approach for calculating the emissions intensity of a batch of hydrogen (EI_b).

174. The section provides two approaches, with the applicable approach depending on whether the production pathway includes a storage tank (termed an ‘intermediate storage tank’) with the capacity to impact the emissions intensity calculation. The storage tank has the potential to impact this calculation if the batch period is less than the time it takes to fill up the storage tank. This is, in turn, is dependent on the capacity of the storage tank and the hydrogen production rate. For example, if 100kg of hydrogen is produced in a batch period and the intermediate storage tank has the capacity to hold 50kg of hydrogen, then the tank is not considered as impacting the emissions intensity calculation and the method in subsection 30(5) may be used. However, if the tank’s capacity is 120kg of hydrogen, then the tank could potentially impact the emissions intensity calculation (because 100kg is less than 120kg) and the method in subsection 30(2) must be used.

175. Alternatively, subsection 30(5) sets out the approach for calculating the emissions intensity of a batch (EI_b) where there is no need to account for an intermediate storage tank. The emissions intensity in these cases is worked out simply by dividing the production emissions for the batch ($E_{pathway,b}$) by the batch quantity (Q_b).

176. Where it is necessary to consider the effect of an intermediate storage tank, subsection 30(2) sets out the two approaches for calculating the emissions intensity of a batch of hydrogen ($\boldsymbol{EI_b}$). In order to work out which approach applies, it is necessary to measure the quantity of hydrogen for the batch after completion of the minimum module but before the intermediate storage tank module ($\boldsymbol{Q_{pathway,b}}$). $\boldsymbol{Q_{pathway,b}}$ is defined in subsection 30(6). This value is then compared to the amount of product in a batch ($\boldsymbol{Q_b}$).

177. Paragraph 30(2)(a) accounts for a situation where the amount of hydrogen produced for the batch measured after completion of the minimum module ($\boldsymbol{Q_{pathway,b}}$) is *more than* the amount in the batch measured in accordance with section 24 ($\boldsymbol{Q_b}$). This indicates that some of the produced hydrogen was stored in the intermediate storage tank and did not reach the end of the production pathway.

178. Subsection 30(3) sets out the approach for calculating the emissions intensity of a batch ($\boldsymbol{EI_b}$) for the situation described in paragraph 30(2)(a). In these circumstances the emissions intensity is worked out by dividing the production emissions ($\boldsymbol{E_{pathway,b}}$) by the quantity of product measured after the minimum production module is completed but before the intermediate storage tank module has commenced ($\boldsymbol{Q_{pathway,b}}$).

179. Paragraph 30(2)(b) is for the converse situation, where the hydrogen produced for the batch measured after completion of the minimum module ($\boldsymbol{Q_{pathway,b}}$) is *less than* the amount measured at in accordance with section 24 ($\boldsymbol{Q_b}$). This indicates that the amount of hydrogen measured at the end of the production pathway included the hydrogen produced in the batch plus a quantity of hydrogen stored in the intermediate storage tank at the start of the batch.

180. Subsection 30(4) sets out the approach for calculating the emissions intensity of a batch ($\boldsymbol{EI_b}$) for the situation in paragraph (2)(b). In this situation, the production emissions attributable to the batch quantity ($\boldsymbol{E_{pathway,b}}$) need to be adjusted to account for the additional product that was released from the intermediate storage tank at the beginning of the batch period—that is, the difference between $\boldsymbol{Q_b}$ and $\boldsymbol{Q_{pathway,b}}$. Based on the assumption that the additional product was produced in the batch immediately preceding the current batch, the emissions are increased by multiplying the quantity of additional product by the emissions intensity of the previous batch of hydrogen produced ($\boldsymbol{EI_{b-1}}$). The resulting emissions are divided by the batch quantity ($\boldsymbol{Q_b}$) to calculate the batch emissions intensity ($\boldsymbol{EI_b}$).

<u>Section 31 – Delivered emissions intensity—hydrogen</u>

181. Section 31 sets out the equation for calculating the emissions intensity of the quantity of the product in the ***transported quantity*** that reaches the delivery gate ($\boldsymbol{EI_{del,product}}$), which accounts for both production and post-production emissions sources. In other words, it is the overall emissions intensity of the delivered product.

182. The delivered emissions intensity ($\boldsymbol{EI_{del,product}}$) is calculated by adding together the production emissions for the transported quantity ($\boldsymbol{EI_b \times Q_{b,transported}}$) and the post-production emissions for that same quantity ($\boldsymbol{E_{del,product}}$), divided by the quantity of the product that reached the delivery gate ($\boldsymbol{Q_{del,product}}$). Dividing by the quantity that reached

the delivery gate (rather than the transported quantity) ensures that any product that was lost or used during delivery is accounted for.

Section 32 – Post-production emissions intensity—hydrogen

183. Section 32 sets out the equation for calculating the emissions intensity of the delivered amount of the ***transported quantity*** ($EI_{postprod,product}$), which only takes account of post-production emissions sources from applicable delivery modules. This emissions intensity is calculated by subtracting the production emissions intensity for the batch (EI_b) calculated under section 30 from the delivered, or total, emissions intensity for the transported quantity ($EI_{del,product}$) calculated under section 31.

Section 33 – Co-product reduction in emissions intensity—hydrogen by electrolysis

184. Section 33 sets out the equation for calculating the emissions intensity reduction represented by oxygen sales ($EI_{O2saleb}$). The amount by which the emissions intensity of the batch can be reduced is calculated by dividing the emissions apportioned to oxygen sales in the batch calculated in accordance with section 29 ($E_{O2sale,b}$) by the batch quantity calculated under section 24 (Q_b).

Part 3.2 – Delivery of hydrogen

Division 3.2.1 – Delivery modules

Section 34 – Delivery modules

185. Section 34 sets out the three delivery modules for hydrogen:
    - the ***pipeline delivery module***;
    - the ***vehicle delivery module***; and
    - the ***storage vessel delivery module***.

186. The different modules reflect the fact that hydrogen could be delivered by a pipeline or loaded into cannisters or tubes to be delivered by a truck, train or ship (collectively covered by the vehicle delivery module). The storage vessel delivery module recognises that the hydrogen could be stored in a tank at some point during delivery, such as if the delivery involves transporting by pipeline, storing in a tank, then loading into tubes for delivery to the customer.

187. The definition of the 'pipeline delivery module' includes injecting the hydrogen into the pipeline, ensuring that emissions from associated compressor stations or other conditioning processes are captured, if relevant to pipeline delivery. Similarly, the 'vehicle delivery module' includes loading and unloading activities. This would cover the emissions from forklifts moving and lifting cannisters of hydrogen on and off vehicles. The 'storage vessel delivery module' definition doesn't expressly include loading and unloading activities, however the definition of 'time period' in subsection 22(2) provides for the emissions from these activities to be accounted for when calculating the storage vessel emissions.

188. Subsections 34(2) and (3) specify the post-production emissions sources relating to these delivery modules as pipeline emissions, vehicle emissions and storage vessel emissions, and provide that these emissions sources are monitored, measured and reported in accordance with sections 20, 21 and 22 respectively.

Division 3.2.2 – Delivered amount—hydrogen

Section 35 – Amount of hydrogen that reaches the delivery gate or end of delivery module

Amount that reaches the delivery gate

189. Subsection 35(1) sets out the approach for working out the amount of hydrogen that reaches a delivery gate. This amount may be included on a PGO certificate pursuant to subsection 55(1) and paragraph 55(3)(b) of the GO Act. The approach for measuring the amount of hydrogen that reaches the delivery gate ($Q_{del,product}$) is specific to the type of delivery module:

    - If a dedicated pipeline is used to deliver hydrogen, then paragraph 35(1)(a) requires the direct measurement to be used for single access pipelines (section 36) and a pipeline-specific loss factor described in the module-specific loss method is used for other types of pipelines (section 38). The direct measurement approach is the most accurate accounting approach for single access pipelines because there is only one input and output location. It is not practical or accurate for pipelines with multiple input and output locations.

- If a vehicle is used to deliver hydrogen, then paragraph 35(1)(b) requires either the direct measurement approach (section 37) or a vehicle-specific loss factor described in the module-specific loss method (section 38) to be used.
- If hydrogen is delivered from a storage vessel, then paragraph 35(1)(c) specifies that the storage vessel-specific loss factor described in the module-specific loss method must be used (section 38). Direct measurement isn't possible because of the need to cater for the situation that the storage tank will be holding product other than the ***stored quantity*** (e.g. other than the functional units of a batch of product).

190. Determining the delivery gate is significant as this is the point at which the amount of product that reaches the end of that delivery module is to be measured, and any losses associated with the delivery module are to be calculated.

191. Subsection 35(2) provides for the situation where there is no delivery module, which means that the hydrogen is delivered directly to the customer from the production gate. Examples of this situation is an electrolyser site that injects the hydrogen into a shared pipeline or delivers it directly to the customer 'over the fence' e.g. into the customer's storage tank or pipeline (section 39).

Amount that reaches the end of the delivery module

192. Subsection 35(3) sets out the approach for measuring the quantity of hydrogen that reaches the end of delivery module that is an interim delivery module. This is relevant to circumstances where more than one delivery module is used to store or transport hydrogen before it reached the delivery gate that is at the end of the final delivery module.

193. This subsection specifies that the same measuring approaches for working out the quantity of hydrogen that reach the delivery gate (set out in subsubsection 35(1)) apply for working out the quantity that reaches the end of the module. However, the approaches set out in sections 36 to 38 are modified such that the references to 'delivery gate' are replaced with 'end of the delivery module'.

Section 36 – Single-access pipeline delivered amount

194. Section 36 provides that if the pipeline is a single access pipeline, a profile holder must measure the amount of hydrogen in the ***transported quantity*** by direct measurement at the closest practicable point to the delivery gate using the same length of time that elapsed while the hydrogen was injected into the pipeline. For example, if the gas was injected over a three-month period, then using a flow meter at the point where the hydrogen leaves the pipeline also over a three-month period.

195. This approach is suitable for a single access pipeline because this type of pipeline has only one input location and only one output (which is the delivery gate assuming there

are no subsequent delivery modules). If the pipeline is anything other than a single access pipeline, a profile holder must use the 'Delivered amount – module specific loss method' set out in section 38.

Section 37 – Vehicle transport delivered amount

196. Section 37 requires a profile holder to measure the amount of hydrogen in the ***transported quantity*** delivered by vehicle at the closest practicable point to the delivery gate, less any 'returned hydrogen' that relates to the delivery. 'Returned hydrogen', described in subsection 37(2), is any hydrogen that is not delivered at the gate. As hydrogen delivered by a vehicle will need to be contained, for example in a tube, cannister or some other portable vessel, it will be possible to accurately measure the amount of hydrogen contained, such as via pressure, temperature or weight measurements.

197. 'Returned hydrogen' is the hydrogen remaining in the container when it is collected. This returned hydrogen should not count towards the delivered quantity. In practice, this will require measuring the amount of hydrogen in the container when it is picked up and subtracting this amount from the amount of hydrogen in the container when it was delivered.

198. A profile holder may alternatively choose to use the 'module-specific loss method' set out in section 38 below, which does not include the concept of 'returned hydrogen'.

Section 38 – Module-specific loss method delivered amount

199. Section 38 provides the calculation for working out the amount of hydrogen in the transported quantity that reaches the delivery gate ($Q_{del,product}$) taking into account estimates of the product lost or used in the delivery module. This approach is required for storage vessels and pipelines that are not a single access pipelines, and is optional for vehicles.

200. Subsection 38(1) provides the equation for estimating the amount of hydrogen in the transported quantity that reaches the delivery gate ($Q_{del,product}$), by applying a loss rate factor (LR_m) to the transported quantity of hydrogen ($Q_{b,transported}$) and deducting any hydrogen in that relevant quantity that was self-consumed ($Q_{self,product}$). Reasons for self-consumption include using the hydrogen as an energy source for activities in the module.

201. The loss rate factor (LR_m) represents the proportion of hydrogen that enters the delivery module and is not delivered, or 'lost'. The definition of LR_m in subsection 38(1) provides that pipelines may choose to use a default value of 0.0035, representing that 0.0035kg of hydrogen are assumed lost per 1kg hydrogen entering the module. This loss rate was derived by adjusting the natural gas loss rate used in the NGER Measurement Determination based on the relative mass flow rates of natural gas and hydrogen. Otherwise, the loss rate factor should be calculated in accordance with subsection 38(2) or (4).

202. Subsections 38(2) and (3) clarify that the loss rate factor (LR_m) is to be calculated by measuring all quantities of hydrogen inputs ($Q_{in,m,y}$) and outputs ($Q_{out,m,y}$) to the delivery module for the most recent financial year (y). In subsection 38(2), the year's outputs are

deducted from the year's inputs and divided by the year's inputs. $\boldsymbol{Q_{out,m,y}}$ includes any quantities of hydrogen deliberately used by the profile holder, such as to power activities in the delivery module. The resulting percentage is the total losses during the financial year on a per kilogram of hydrogen basis. Subsection 38(2) ensures that the loss rate isn't less than zero. This could result if the hydrogen output is measured to be greater than the hydrogen input but is implausible as hydrogen can't be created in a delivery module.

203. In subsection 38(4), the amount of hydrogen in the vessel delivery module at the start ($\boldsymbol{Q_{m,start,y}}$) and end ($\boldsymbol{Q_{m,end,y}}$) of the year is also measured in addition to measuring the inputs ($\boldsymbol{Q_{in,m,y}}$) and outputs ($\boldsymbol{Q_{out,m,y}}$) to the delivery module. This version of the loss rate calculation is required for a large hydrogen storage vessel because if a significant amount of hydrogen is stored at the start or end of the year then this could result in the loss rate being over- or under-estimated. A large hydrogen storage vessel is defined as one with a capacity exceeding 1,000 kg.

204. The default period for calculation of an emission factor is the previous financial year. Section 14 sets out the approach for using a smaller dataset if a profile holder does not have a full year's worth of data.

Section 39 – Direct delivery delivered amount

205. Section 39 provides that if hydrogen reaches a delivery gate without being stored or transported in accordance with a delivery module, for example where there is no delivery module and the hydrogen is delivered directly to the delivery gate, then the amount of hydrogen in the ***transported quantity*** that reaches the delivery gate is the same amount of hydrogen that reaches the production gate, which is measured in section 24 as the hydrogen batch size. If the batch is delivered to different customers, then the amount is the transported quantity of hydrogen measured at the production gate. For example, the quantity of hydrogen that is inputted to a cannister or tube at the production gate, for vehicle delivery.

206. The hydrogen in this case effectively reaches the production and delivery gate at the same time.

Schedule 1 – Emission factors

Part 1—Scope 3 emission factors for water sources

207. The table in Part 1 of Schedule 1 lists the scope 3 emission factors for calculating the emissions for water sources as referenced under paragraphs 17(2)(a) and (b).

208. The potable water scope 3 emission factors specified for each state and territory in Australia are listed in items 4 to 11 of the table in Part 1. These are sourced from the '*AusLCI (V1.45) Carbon Emissions Factors Updated June 2025'* spreadsheet published on the Australian National Life Cycle Inventory Database (AusLCI), which is an initiative delivered by the Australian Life Cycle Assessment Society, accessed September 2025, available at auslci.com.au/index.php/EmissionFactors.

209. Some values in the table in Part 1 are assigned a scope 3 emission factor of zero. This reflects the policy intent that waste, wastewater and unprocessed environmental sources are not considered to have embodied emissions, consistent with the IPHE.

Part 2—Scope 3 emission factor supplements for advanced water treatment processes

210. The table in Part 2 of Schedule 1 lists the default scope 3 emission factors for advanced water treatments as referenced in paragraph 17(2)(b) and subsection 17(4).

211. The NGAF document does not contain the scope 3 emission factors for advanced water treatment processes, and factors in the table in Part 2 are derived from scientific and technical publications, taking an average of relevant values.

Part 3 –Emission factors for vehicles

212. The table in Part 3 of Schedule 1 lists the default emission factors for transport by vehicle used in subsection 21(5). The data used in the calculation of these emission factors are from the '*Australian Infrastructure and Transport Statistics—Yearbook 2024'* (**2024 Yearbook**), published by the Bureau of Infrastructure and Transport Research Economics, accessed September 2025, available at https://www.bitre.gov.au/publications/publications.

213. The emission factors were calculated by dividing the greenhouse gas emissions for the relevant vehicle type, by the total goods or freight moved by the corresponding vehicle type, sourced from the 2024 Yearbook. The emission factor was then worked out as the average of the emission factor for the most recent three years (e.g. 2021-22, 2022-23 and 2023-24).

214. Note that the emission factor for a train in item 1 of the table is applicable for any type of train, including electric and diesel-electric trains.

Part 4—Scope 3 emission factors for solid fuel consumption

215. The table in Part 4 of Schedule 1 lists the default scope 3 emission factors for consumption of solid fuels as referenced in paragraph 12(1)(a). The source of these values is Table 4 of the NGAF document, accessed September 2025, available at

https://www.dcceew.gov.au/climate-change/publications/national-greenhouse-accounts-factors.

Part 5—Scope 3 emission factors for liquid fuel consumption

216. The table in Part 5 of Schedule 1 lists the default scope 3 emission factors for consumption of liquid fuels as referenced in paragraph 12(1)(b). The source of these values is Table 8 of the NGAF document.

Part 6—Scope 3 emission factors for gas consumption for transport energy purposes

217. The table in Part 6 of Schedule 1 lists the default scope 3 emission factors for consumption of gaseous fuels for transport energy purposes as referenced in paragraph 12(1)(c). The source of these values is Table 9 of the NGAF document.

Part 7—Scope 3 emission factors for natural consumption for stationary energy purposes

218. The table in Part 7 of Schedule 1 lists the default scope 3 emission factors for consumption of natural gas for stationary energy purposes as referenced in paragraphs 12(1)(d) and (e). The source of these values is Table 6 of the NGAF document.

<u>**ATTACHMENT B**</u>

Statement of Compatibility with Human Rights

Prepared in accordance with Part 3 of the Human Rights (Parliamentary Scrutiny) Act 2011

<u>*Future Made in Australia (Guarantee of Origin) Methodology Determination 2025*</u>

This Legislative Instrument is compatible with the human rights and freedoms recognised or declared in the international instruments listed in section 3 of the *Human Rights (Parliamentary Scrutiny) Act 2011*.

Overview of the Legislative Instrument

The *Future Made in Australia (Guarantee of Origin) Methodology Determination 2025* (Methodology Determination) establishes the framework for the certification of products under the Guarantee of Origin (**GO**) scheme. Product Guarantee of Origin (PGO) production profile holders must comply with the requirements of the Methodology Determination in order to create PGO certificates.

The Methodology Determination sets out the electrolysis production pathway, its minimum and optional modules, material emissions sources and how emissions are proposed to be calculated. A production pathway is a set of production modules for a product, and a production module is an emissions-generating step in the production which includes use of particular equipment and process. The instrument is structured so that new chapters may be inserted over time to incorporate emissions accounting approaches for other products.

Participation in the GO Scheme is intended to be voluntary.

Human rights implications

The Methodology Determination does not engage any of the applicable rights or freedoms. It is a technical instrument that provides a framework for accounting methods for production of hydrogen by electrolysis and is part of a voluntary scheme.

Conclusion

This Legislative Instrument is compatible with human rights as it does not raise any human rights issues.

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