Annexure A: Overview of the electricity and gas regulatory regimes

1 This section of the submission provides an overview of the regulatory regime that applies to the electricity and gas sectors in Eastern Australia, focussing in particular on the regulation of electricity transmission and distribution networks and gas distribution networks in Victoria (ie, the regulatory regime as relevant to AusNet). The regulatory regime means it would be impossible for AusNet to foreclose competitors of Origin in any relevant generation or retail markets.

1 Electricity

1.1 Overview

2 This section discusses the electricity regulatory arrangements as they apply in the NEM; that is, in Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania and South Australia. It also focuses on the unique transmission arrangements in Victoria, which are particularly relevant to AusNet.

3 In broad terms, regulation of the electricity supply industry in the NEM comprises three main elements.

4 The first (and most significant) is the regulation of electricity generation, transmission and distribution under the NEL and the NER. The NEL operates across the NEM jurisdictions under a cooperative legislative scheme established via lead legislation in South Australia and subsequently adopted by application legislation in each participating jurisdiction.

5 The NEL establishes a framework under which the NER is made.

(a) The NEL establishes the institutional arrangements and regulatory principles governing the NEM, while the NER, which runs to some 1,800 pages in total, contains the detailed arrangements relating to the operation of the wholesale electricity market and the regulation of electricity transmission and distribution services. The NER operates consistently across the NEM (with some derogations) and can be divided broadly into three parts: Rules relating to the registration of NEM participants;

(b) Rules relating to buying and selling of wholesale electricity via the spot market, together with associated power system operations; and

(c) Rules relating to the regulation of TNSPs and DNSPs.

6 The NEL provides for the manner in which the NER are to be made and amended, and defines the roles of AER as regulator, AEMO as market operator, and the AEMC as rule maker. In most cases, the NER is amended by the AEMC, following detailed analysis and consultation. The NER are also sometimes amended by Ministerial order, but this requires specific legislative authorisation on a case-by-case basis.

7 The second element is the regulation of electricity retailing and the relationship of electricity distributors with retail customers. This is regulated in NEM jurisdictions other than Victoria under the Retail Law and Retail Rules. The NERL operates as a cooperative legislative scheme in a similar manner to the operation of the NEL and, like the NEL, it provides for more detailed regulatory obligations to be specified in the NERR. Victoria had not adopted the NERL and NERR and instead applies a broadly similar regulatory framework under jurisdictional legislation.

8 The third element is local requirements established under State and Territory energy legislation that operate in parallel with the national legislative scheme. This includes:

(a) local electricity participant licensing requirements;

(b) jurisdiction specific rules that supplement the NEL and NER, including in the areas of safety and technical regulation; and

(c) jurisdiction-specific rules that displace the ordinary application of the NER in that jurisdiction, such as the New South Wales Renewable Energy Zone (***REZ***) arrangements established under the *Electricity Infrastructure Investment Act 2020 (NSW).*

1.2 Electricity transmission

9 From a policy perspective, the electricity transmission sector is treated as a natural monopoly and is highly regulated. It is subject to a mandatory third party open access regime, as well as revenue regulation by AER for most participants.

10 In Victoria (where AusNet operates) a number of unique legacy transmission regulatory arrangements apply, notably that the Victorian TNSP functions are split between AusNet (which performs most of the TNSP functions) and AEMO (which has functions covering topics including planning, major augmentations and connections). For convenience, this submission adopts the following structure:

(a) this section 1.2 describes transmission regulation as it applies generally across the NEM. Where relevant, we flag topics that are materially different in Victoria.

(b) section 1.3 then describes particular features of the regulatory regimes as it applies in Victoria, where the TNSP functions are split between AEMO and AusNet.

(i) Transmission planning

11 The NEL and NER together set out a comprehensive framework for transmission and distribution planning and expansion in the NEM, both at a system-wide level and in respect of specific projects.

12 In Victoria, these arrangements largely unchanged, noting AEMO (in its capacity as TNSP) has some additional planning functions.

13 At a system-wide level, the NER requires AEMO to perform the role of national transmission planner and to publish an ISP every two years. At a project level, the NER requires TNSPs to, among other things, carry out their own network planning and a cost-benefit analysis for particular projects in their network. This planning framework is described in more detail below:

AEMO as national system planner and the ISP

14 Section 49 of the NEL together with chapter 5 of the NER confer duties on AEMO as national transmission planner. These include the publication every two years of the ISP. The first ISP was published in 2020 and replaced the National Transmission Network Development Plan, which was previously published annually by AEMO. The purpose of the ISP is:

> to establish a whole-of-system plan for the efficient development of the power system that achieves power system needs for a planning horizon of at least 20 years for the long-term interests of the consumers of electricity.[1]

15 The ISP is developed in consultation with stakeholders, including TNSPs. It identifies the network investments ('identified needs') that must be made by reference to AEMO's 30 year 'optimal development path' for the transmission system. Where the ISP identifies that a particular investment is on the optimal development path and 'actionable', the TNSP of the relevant network must undertake a cost benefit analysis known as the RIT-T to assess the available options and determine the best project to make that investment, and to request that AER approve additional funding for that project (see further below).

[1] Australian Energy Market Commission, *National Electricity Rules* (at 15 March 2023) cl 5.22.2 (***NER***).

16 In addition to the ISP, as part of its planning function AEMO publishes the:

(a) National Electricity Forecast Report, which sets out the annual energy and maximum demand forecasts over the next 10 years by NEM region;

(b) Electricity Statement of Opportunities, which provides an assessment of supply adequacy in the NEM over the next 10 years, highlighting opportunities for generation and demand-side investment; and

(c) NEM constraint reports, which provide details on interconnector capacity and constraints in the transmission network.

Planning functions of TNSPs

17 TNSPs carry out network planning for their own networks at both a network and project level. They perform some of these planning functions in their ordinary capacity as TNSPs, and others in their capacity as jurisdictional planning bodies under the NER (where applicable).

18 At a network level, the NER confers the role of jurisdictional transmission planning body on certain TNSPs (including AEMO (ie, not AusNet) in Victoria and TransGrid in New South Wales and Australian Capital Territory). Jurisdictional transmission planning bodies are required to produce Annual Planning Reports which build upon the plan set out in the ISP but draw out at a more granular level the specific investment needs and drivers for that particular network. An Annual Planning Report must cover at least the next 10 years, but there is typically an emphasis on the next two-three years.

19 At a project level, TNSPs in their ordinary capacity must identify the 'preferred option' for any 'identified need' in their network. The 'preferred option' is effectively the best project to meet an investment need, as identified through cost benefit analysis of the available options. The NER requires that the cost benefit analysis must be applied in the RIT-T (see below). Importantly, the NER expressly requires that the RIT-T include analysis of any available non-network options, to ensure that TNSPs do not favour augmentation of their own network (and the resulting increase to their regulated asset base upon which they earn a return). AER approves the RIT-T and the revenue allowance for the project to ensure that the TNSP's network prices are set such that customers are only paying for investment that is efficient (see further below).

20 Approval of a project via the RIT-T process enables the TNSP to have a streamlined path to recover the costs of that project via its regulatory TUOS charges; by adding the project to its regulated asset base.

Joint planning

21 There are a number of joint planning arrangements under the NER which require network planning between different market participants.

22 For example, TNSPs are required to undertake joint planning with other TNSPs (though these arrangements are considered 'light touch').

23 TNSPs are also required to undertake joint planning with DNSPs, and the process for this is more prescriptive than it is for joint planning as between TNSPs. For example, the NER requires that TNSPs conduct the RIT-T for projects identified under the joint planning process, in conjunction with the relevant DNSP. The RIT-T requires a broad range of market benefits be assessed, and the joint planning requirement is intended to ensure that any applicable market benefits are appropriately considered.

(ii) Transmission pricing

AER regulation

24 Electricity transmission in the NEM is achieved by TNSPs providing a variety of 'transmission services' through the 'shared transmission network'.

25 In Victoria, these arrangements apply to AusNet. AEMO (in its capacity as TNSP) is not subject to AER regulation.

26 Transmission services may be provided by a TNSP either as prescribed, negotiated or non-regulated services:

(a) **Prescribed transmission services**: Prescribed transmission services are the principal services provided by a transmission network and include the use of the system for the conveyance of electricity at required network performance standards (including a service that ensures the integrity of the transmission system). The costs for providing prescribed transmission services are recovered from network users, with the MAR that a TNSP can recover for these services regulated by AER pursuant to five yearly regulatory determinations for each TNSP. This is discussed further below;

(b) **Negotiated transmission services**: Negotiated transmission services include, most relevantly, connection services for example an entry service connecting a new generator or generators to the transmission network at a connection point. The terms for providing negotiated transmission services, including the cost, are determined through private contract between the TNSP and the party wishing to receive these services, but must be negotiated in accordance with the framework set out in chapter 5 of the NER. The process for negotiating connection services is discussed in Paragraphs 41 to 48 below; and

(c) **Non-regulated transmission services**: These services are provided by the TNSP on a contestable basis. They include augmentations such as the construction of a new line connecting a new generator to the transmission system where the construction of that new line is contestable. The price and terms are set by the market through contestability rather than being subject to regulation by AER.

27 The costs of providing prescribed transmission services are recovered from customers through TUOS charges and are subject to economic regulation by AER. This regulation includes AER determining the MAR, and in turn the aggregate annual revenue requirement (***AARR***) each TNSP can recover from its customers through TUOS for each year in the regulatory period. This is achieved by way of a regulatory determination made by AER every five years. The process for determining the MAR for each TNSP is ex-ante: TNSPs apply to AER for an assessment of their revenue requirements in advance of a new five year regulatory period, and AER is required to issue its final determination prior to the commencement of that regulatory period.

28 TUOS are not paid by generators. Rather they are paid by distributors and industrial customers connected directly to the transmission network based on their connection points with the transmission system. The distributors then pass on TUOS to retailers who in turn pass it on to customers. Generators only pay charges relating to the cost of their immediate connection to the shared transmission network and the charging regime for generation has been characterised by the AEMC as a 'shallow' connection charging approach.

29 The TUOS regulatory determination process includes a requirement for TNSPs to submit as part of their regulatory submission a proposed pricing methodology which, among other things, sets out the structure and recovery of prices for each category of prescribed transmission services, and allocates the TNSP's annual revenue requirement to transmission network connection points. The proposed pricing methodology must satisfy principles and guidelines established under the

NER and comply with the requirements of, and contain or be accompanied by, information required under the Pricing Methodology Guidelines made by AER.

30 The process for AER approval of a proposed pricing methodology is robust and set out in chapter 6A of the NER. AER undertakes a preliminary examination of the TNSP's proposed pricing methodology and must notify the TNSP if the methodology does not comply with the requirements of any relevant regulation information instrument (ie, the Pricing Methodology Guidelines), the NEL or the Rules, and provides written reasons for such non-compliance.[2] The TNSP must resubmit its proposed pricing methodology within one month of that notice, and may only make changes required to address the matters raised in AER's determination.[3] If AER determines that the methodology and information comply with the requirements under the relevant rules and guidelines, AER must then publish the proposed pricing methodology and the information submitted (or resubmitted) by the TNSP, with an invitation for written submissions from the public on such documents and information. AER must also publish an issues paper which identifies preliminary issues AER considers are likely to be relevant to its assessment of those documents, and hold a public forum on the issues paper.[4] AER must then make and publish its draft decision in accordance with the relevant requirements of chapter 6A and if AER refuses to approve any aspect of the methodology, AER's draft decision must include details of the changes required or matters to be addressed before AER will approve the methodology.[5] AER must also invite written submissions on the draft decision.[6] Within 45 business days, the TNSP may, after AER's publication of its draft decision, submit to AER a revised proposed pricing methodology which incorporates any changes required under the draft decision. The revised proposed pricing methodology must again be published by AER, and AER may invite written submissions on such revised documents.[7]

31 In making a final decision, AER must either approve or refuse to approve the proposed pricing methodology and set out reasons for its decision,[8] having regard to any written submissions and analysis undertaken by or for AER that is published prior to the making of the final decision. If AER's final decision is to refuse to approve the proposed pricing methodology, AER must include in its final decision an amended pricing methodology which is determined on the basis of the current proposed pricing methodology and amended from that basis, only to the extent necessary to enable it to be approved in accordance with the NER.[9] Once AER has approved the pricing methodology as part of the TNSP's determination (see further below), the TNSP must comply with the pricing methodology in setting and charging TUOS.

32 The process for AER to make a regulatory determination for a TNSP is set out in the NEL and NER. Section 7A of the NEL contains revenue and pricing principles that AER must apply in making a determination. These principles include:

(a) that a network service provider should be provided with a reasonable opportunity to recover efficient costs;

(b) that a network service provider should be provided with incentives to promote efficiency with respect to network investment, service provision and use; and

[2] NER, cl 6A.11.1.
[3] NER, cl 6A.11.2.
[4] NER, cl 6A.11.3.
[5] NER, cl 6A.12.1.
[6] NER, cl 6A.12.2.
[7] NER, cl 6A.12.3.
[8] NER, cls 6A.13.1 and 6A.14.1(8).
[9] NER, cl 6A.13.2(d).

(c) that prices and charges should reflect returns commensurate with the regulatory and commercial risks involved in providing network services to which the prices and charges relate.

33 In addition to the principles set out in the NEL, chapter 6A of the NER prescribes in detail the rules for the economic regulation of TNSPs, including the steps AER must follow in making a revenue determination, and the relevant timeframes. The steps may be summarised as follows:

(a) AER is required to publish a 'framework and approach' paper. The paper must set out AER's proposed approach to the TNSP's next regulatory determination.

(b) Each TNSP must submit a detailed regulatory proposal to AER. The regulatory proposal must set out the TNSP's proposed MAR for the following regulatory period using a building block approach set out in the NER and supplemented by AER's framework and approach paper (see further below).

(c) AER is subject to strict consultation and transparency requirements. It must publish the regulatory proposals it receives, together with an issues paper seeking written submissions from stakeholders and an invitation to stakeholders to attend a public forum.

(d) AER must then publish a draft determination setting out whether it refuses to approve any aspect of the TNSP's regulatory proposal (together with notice of a pre-determination conference and an another invitation for stakeholders to make written submissions).

(e) AER must ultimately publish a final determination setting out the aspects of the TNSP's regulatory proposal that it has not accepted, the approach AER proposes to take in substitution of those aspects, and AER's reasons for its determination.

34 Chapter 6A of the NER outlines a 'building block' approach to setting a TNSP's MAR. The building blocks are estimates of the various costs a network business needs to incur while efficiently providing network services to its customers over the regulatory period. They comprise:

(a) **Operating expenditure** (***OpEx***): an allowance for recovering of operating costs such as forecast labour costs, maintenance expenses and corporate expenses;

(b) **Return on capital**: an allowance for the recovery of capital expenditure (***CapEx***) invested by the TNSP together with a return on that investment, calculated by multiplying the TNSP's RAB (the value of a TNSP's assets which are used to provide prescribed transmission services) by AER's current allowed rate of return (a vanilla WACC determined by reference to a benchmark efficient TNSP entity);

(c) **Return of capital**: an allowance for the depreciation of existing assets; and

(d) **Tax**: an allowance for the TNSP's estimated corporate income tax over the period.

35 These building blocks are then added together and adjusted for incentives (see below) in order to calculate the MAR for a TNSP.

36 Under the NER, TNSPs also have the ability to seek AER approval to 're-open' certain items during the period of a regulatory determination.

STPIS and other incentives

37 In applying the building block approach to calculate a TNSP's MAR for a regulatory period, AER applies a number of revenue adjustments in order to incentivise TNSPs to improve service performance and maximise the efficiency of their spending. Incentive rewards and penalties earned in a regulatory period are determined as part of an ex post review at the end of that regulatory period and applied as a revenue adjustment to the MAR in the following regulatory period. The current incentive mechanisms are set out in the NER and supplemented by AER guidelines. The main incentives may be summarised as follows:

(a) **STPIS**: in order to incentivise TNSPs to maintain and improve their service performance, rather than to profit by reducing their expenditure on network maintenance and replacement, the STPIS is applied as an adjustment to the maximum allowed revenue by reference to metrics for reliability and service: specifically, a service component which acts as a key indicator of network reliability; a market impact component to encourage TNSPs to minimise the impact of outages on the dispatch of generation; and a network capability component that encourages TNSPs to undertake priority projects of benefit to customers that they would not otherwise undertake. These components are set out in more detail below.

(b) **CESS**: in order to incentivise TNSPs to provide the required services at a cost lower than their capital expenditure component included in their MAR, this painshare / gainshare mechanism requires a TNSP to share both the benefits of a CapEx underspend or the costs of an overspend with customers – specifically, the TNSP retains 30% of the benefit of a CapEx underspend or cost of a CapEx overspend, and consumers retain 70% of the benefit of a CapEx underspend or the cost of the CapEx overspend, provided that AER considers that the overspend was efficient. If as part of the ex post review AER determines that a CapEx overspend was inefficient, then the TNSP incurs 100% of that overspend.

(c) **EBSS**: Similar to the CESS, in order to incentivise TNSPs to achieve efficiency gains in such a way that they will not benefit from inflating their OpEx, this painshare / gainshare mechanism requires a TNSP to share both the benefits of an OpEx underspend or the costs of an OpEx overspend with customers – specifically, the TNSP retains 30% of the benefit of an OpEx underspend or cost of an OpEx overspend, and consumers retain 70% of the benefit of an OpEx underspend or the cost of the OpEx overspend.

38 Depending on the network, the MAR may also be adjusted via other less significant incentive regimes, for example, small-scale incentives and demand management innovation incentives. The same incentive regimes apply to DNSPs as they do for TNSPs.

Service Target Performance Incentive Scheme (STPIS)

39 As noted above, the STPIS incentivises service performance through the following three components:

(a) **Service component**: this component of the STPIS provides a reward / penalty of + / - 1.25% of a TNSP's MAR to incentivise the TNSP to improve network reliability, specifically by reducing the number of unplanned network outages and by promptly restoring the network where supply is interrupted by the outage. The service component uses four parameters to measure performance: the average number of times unplanned outages render circuits unavailable; the number of unplanned outages resulting in a loss of supply; the average duration (in minutes) of unplanned outages causing a loss of supply, and the number of times protection or control systems fail (as well as occurrences of incorrect operational isolation of equipment during maintenance). Each of these four parameters is assigned a weighting which determines the total amount of revenue at risk for that parameter by reference to the performance target (no penalty or bonus), cap (maximum bonus) and floor (maximum penalty) set by AER for that parameter as part of the TNSP's regulatory determination. These metrics together define the rate of incentive payment for any given level of annual performance.

(b) **Market impact component**: this component of the STPIS uses financial incentives to encourage TNSPs to minimise the effect of transmission outages on the wholesale price of electricity, specifically by counting the number of dispatch intervals when equipment outages in the TNSP's network result in binding network outage constraints with a marginal value greater than $10 / MWh. Each TNSP's annual count is measured against its target, where the target is calculated by averaging the median five of the last seven years' performance. Further, the dollars per dispatch interval (***$ / DI***) associated with the reward / penalty for each count can be directly calculated for the regulatory period using the TNSP's target and the MAR. (Both the target and the $ / DI are fixed for the regulatory period).

(c) **Network capability component**: this component of the STPIS is designed to encourage TNSPs to develop projects (up to the lesser of a total of 1% of the TNSP's proposed MAR per year, or 1.5% of the TNSP's annual average MAR) in return for a pro-rata incentive payment of up to 1.5% of MAR depending on the successful completion of proposed projects. This component encourages TNSPs to examine their networks to identify suitable low cost one-off operational and capital expenditure projects that improve the capability of the transmission network at times when it is most needed. TNSPs are required to submit a network capability incentive parameter action plan (***NCIPAP***) as part of their revenue proposals, in consultation with AEMO, which sets out the key network capability limitations on the TNSP's network, and a list of priority projects to improve those network limitations, together with the value of the improvement target for each proposed priority project. Total annual average expenditure on these priority projects cannot exceed 1% of the TNSP's proposed MAR and cannot be funded elsewhere through operating or capital expenditure from their revenue proposal. When determining whether a priority project improvement target would result in a material benefit, AER takes into account the factors outlined in the scheme, including the likely benefits to the wholesale market or to customers, specifically on spot price outcomes or improved capability of the transmission system. During the regulatory period TNSPs receive pro-rata annual incentive payments up to 1.5% of the MAR to fund priority projects outlined in the NCIPAP. In cases where TNSPs do not achieve the targets for the regulatory control period or if their priority project costs are in excess of the expenditure outlined in the NCIPAP, AER may reduce the incentive payment for that priority project.

40 TNSPs are required to report their compliance with the three components of the STPIS in accordance with the TNSP Information Guidelines or an Economic Benchmarking Regulatory Information Notice, each issued by AER pursuant to the NER. AER provides each TNSP with a customised service performance reporting template by 15 December each year to be completed by 1 February the following year. It then assesses the TNSP's performance against the STPIS parameters for the preceding calendar year and verifies the financial reward or penalty to be recovered by the TNSP and publishes this information on its website.

(iii) Transmission access

Connection applications

41 Parties wishing to connect to the transmission network (such as generators, large industrial customers, interconnectors and DNSPs) must apply to the relevant TNSP.

42 Connection arrangements are subject to detailed regulation in the NER. In Victoria, a number of additional or alternative arrangements apply.

43 Part B of chapter 5 of the NER regulates aspects of the technical and contractual arrangements needed to connect, and sets out the obligations on parties throughout the connection application process. Rule 5.3 sets out the process for establishing or modifying a connection, and while some

of the procedural details are specifically disapplied in Victoria,[10] the connection application process in all NEM Jurisdictions, including Victoria, broadly occurs as follows:[11]

(a) The connection applicant initiates the process by submitting a connection enquiry to the TNSP. In Victoria, AEMO manages the connection process and connection applications must submit their connection enquiry to AEMO.

(b) The TNSP formulates a response to the connection enquiry, with the TNSP informing the applicant about the relevant information the applicant must provide, the amount of the application fee and providing a preliminary program, including proposed milestones for the connection.

(c) The applicant makes an application for connection to the TNSP's network and pays the application fee.

(d) The TNSP makes an offer to connect to the applicant, including the commercial terms and engineering requirements for the connection. In Victoria, the offer to connect is documented in a Use of System Agreement (***UOSA***) between AEMO and the connection applicant. There is also a network services agreement between AEMO and the incumbent DTSO (or, where the connection involves a contestable augmentation, the DTSO selected through the competitive tender process). For connections that require augmentation to the network, additional contracts are required, as follows:

   (i) Where the augmentation is non-contestable (meaning AusNet as the incumbent DTSO in Victoria builds, owns and operates the augmentation), there is a connection agreement between AusNet and the connection applicant, together with any leases or easements which AusNet requires where it does not own the relevant land; and

   (ii) Where the augmentation is contestable (meaning a DTSO is selected by competitive tender to carry out the augmentation), there is a connection services agreement and lease between the selected DTSO and connection applicant, and in addition, all parties (being AEMO, the connection applicant, the incumbent DTSO and if relevant the selected DTSO) enter into a Project Construction Coordination Deed to agree the details for construction and delivery of the connection, which is typically prepared by AEMO and based on a standard form Project Construction and Coordination Deed template.

(e) The finalisation of the connection arrangements are dependent upon the applicant's acceptance of the connection offer and the execution of the relevant agreement between the connection applicant and the TNSP (and in Victoria, the additional contracts as between the applicant, AEMO, AusNet and / or a selected DTSO, as described above).

44 The connection application process is a staged negotiation with defined timeframes for key steps in the process and prescribed responsibilities for both the TNSP and applicant. In practice, it is an iterative process whereby parties exchange information in order to come to an agreement on new connections and modifications to existing connections.

45 If negotiations occur, the NSP and connection applicant must conduct such negotiations in good faith. The NER sets out the dispute resolution process or processes for disputes between connection applicants and the TNSP where they cannot agree on the proposed access arrangements or connection agreements. In Victoria, two dispute resolution processes are available: a commercial arbitration regime (grandfathered in Victoria by amendments made to the

[10] NER, cl 5.3B.
[11] NER, cls 5.3.2 to 5.3.7.

NEM in 2017 which preserve Chapter 6A from version 109 of the NER), and a more prescriptive dispute resolution process currently prescribed in Chapter 8 of the NER.[12] By contrast, in other NEM jurisdictions, only one dispute resolution process is available for connection disputes: a commercial arbitration regime, primarily set out in Part B of chapter 5, and based on the old regime in Chapter 6A but enhanced to include a process for the appointment of an independent engineer to assist in resolving technical matters. The Chapter 8 dispute resolution process has been disapplied in the other NEM jurisdictions.

46 This means that in Victoria, disputes in relation to negotiated transmission services and prescribed transmission services may be dealt with through either Chapter 6A or Chapter 8, at the discretion of the parties. In practice, while the dispute resolution processes in the NER have rarely been used, it appears that Chapter 6A may be preferred. Disputes in relation to non-regulated services are dealt with outside of the NER, and pursuant to the contractual dispute resolution mechanisms agreed between the parties.

47 Part K of version 109 of chapter 6A sets out the framework for commercial arbitration for disputes about terms and conditions of access for prescribed and negotiated transmission services in Victoria. Under the framework:

(a) on receiving notification of a transmission service access dispute, the AER must request the provider and the applicant to nominate two persons each for appointment as the commercial arbitrator to determine the dispute by a time specified by the AER. The AER must then appoint the commercial arbitrator. Importantly, a person will not be eligible for appointment as the commercial arbitrator if that person has any potential conflict of interest which may affect the impartial resolution of the dispute;[13]

(b) the arbitrator must conduct itself in accordance with the powers accorded to it under clause 6A.30.4 in relation to prescribed transmission services and negotiated transmission services. Among other things, in determining the dispute, the arbitrator may have regard to other matters it considers relevant, and hear evidence or receive submissions from AEMO and Transmission Network Users in certain circumstances;

(c) the arbitrator must determine the dispute as quickly as possible, and in any case within 30 business days after the dispute is referred to the commercial arbitrator. The arbitrator must terminate the proceedings without making a determination if it determines that the transmission service is capable of being provided on a genuinely competitive basis by a person other than the TSNP or an entity which is associated with the provider;[14]

(d) where the provider and the applicant reach an agreement (whether or not the matter is before a commercial arbitrator), the parties may execute a written agreement recording their resolution of that dispute;

(e) the commercial arbitrator must give its determination, together with reasons, to the provider, applicant and the AER for publication; and

(f) the agreement under paragraph (d) and determination under paragraph (e) are binding on the provider and the applicant. Failure to comply is a breach of the NER in respect of which the AER may take action in accordance with the NEL.[15]

[12] Prior to 2017, the dispute resolution mechanisms under both Chapter 6A and Chapter 8 were available across the NEM. Reforms in 2017 sought to clarify which process would apply to disputes regarding negotiated transmission services; the commercial arbitration process in Chapter 6A was moved to chapter 5, and amended to provide that it applies to all disputes relating to prescribed or negotiated transmission services and large dedicated connection asset services. These reforms were not applied in Victoria, so the commercial arbitration regime (contained in chapter 5) is expressed to not apply in Victoria.
[13] NER (Version 109) cl 6A.30.2.
[14] NER (Version 109) cl 6A.30.5.
[15] NER (Version 109), cl 6A.30.7.

48 Part B of chapter 8 of the NER sets out the framework for dispute resolution and prescribes the disputes to which it applies, including disputes about the two proposed access arrangements or connection agreements of a connection applicant for connection and access to the declared transmission system.[16] Under the chapter 8 framework:

(a) AER must appoint an Dispute Resolution Adviser to perform a number of functions prescribed in Rule 8.2.2, including determining the most appropriate alternative dispute resolution procedures in particular circumstances, administering Stage 1 and Stage 2 of the dispute resolution process set out in chapter 8, and establishing a pool from which members of a dispute resolution panel may be selected in accordance with Rule 8.2.6A;

(b) each registered participant (defined to include connection applicants)[17] and AEMO must each adopt and implement a dispute management system or 'DMS' to govern the administration of disputes between them;[18]

(c) a party may activate Stage 1 of the chapter 8 dispute resolution process by serving a referral notice on the other party through their respective dispute management systems within 60 days of the disputed conduct or decision, which triggers a requirement on the parties to follow certain steps and timeframes, including meeting within five business days to discuss the dispute;[19]

(d) if the dispute is not resolved within 20 business days of the issue of the referral notice, the serving party may refer the matter to the dispute resolution adviser appointed by AER, which activates Stage 2 of the chapter 8 dispute resolution process and which requires the dispute resolution adviser to attempt to resolve the dispute, or if the parties do not agree to the adviser attempting to resolve the dispute, to refer the dispute to a dispute resolution panel established by the dispute resolution adviser;[20]and

(e) a determination of the dispute resolution panel is binding on the parties.[21] A registered participant must comply with a determination of the panel, and failure to do so is a breach of the NER in respect of which AER may take action in accordance with the NEL.[22] A party to a dispute may appeal on a question of law against a decision or determination of a panel in accordance with Section 71 of the NEL.[23]

Open access regime

49 The NEM operates under an open access regime.

50 From the energy consumer perspective, State and Territory Governments set reliability standards which require TNSPs and DNSPs to withstand a certain level of risk without consequences for consumers. Put another way, the reliability standards ensure a level of redundancy in the system, such that the supply of power to total load (ie, customers) will be robust in the event of a certain level of risk or contingency. TNSPs must make investments or procure services to meet the relevant jurisdictional reliability standard. Further information about state and territory based reliability standards is described in paragraph 164 below.

51 Given this framework, customers are considered to have an implied right to access the 'shared' transmission network (being the transmission network owned, operated and controlled by the incumbent TNSP, including certain connection assets) in order to obtain their reliable supply of electricity. DNSPs (on behalf of customers) pay TUOS charges for this 'guaranteed' access.

[16] NER, cl 8.2.1(a)(4).
[17] NER, cl 8.2.1(a1).
[18] NER, cl 8.2.3.
[19] NER, cl 8.2.4.
[20] NER, cls 8.2.5 and 8.2.6A.
[21] NER, cl 8.2.9(b).
[22] NER, cl 8.2.9(d).
[23] NER, cl 8.2.11.

52 Generators also enjoy open access rights to connect to and export electricity into the transmission system. However, they do not have an equivalent 'guaranteed access' to the 'shared' transmission network – while generators have the right to negotiate a connection to the 'shared' transmission network, there is no guarantee that they will be dispatched and able export all of their output. This is in part due to 'congestion' – put simply, the 'bottleneck' effect on the network where a line or transformer reaches its limit and cannot carry any more electricity (sometimes referred to a 'constraint'). This means that adjustments must be in made in generation and consumption across the network to ensure that the limit is not exceeded. Given that demand must still be met, adjustments are made to allow the additional electricity to flow along an alternative route from an alternative source (ie, another generator) – leaving some generators 'upstream' of the constraint unable to be dispatched (sometimes referred to as being 'constrained off').

53 While congestion is a normal feature of efficient transmission networks accommodating variable generation, transmission networks are experiencing increased congestion costs due to the increase in variable renewable generation. To deliver the energy transition at least cost to consumers while encouraging the necessary investment, policymakers are grappling with their transmission access regimes, in particular how best to manage congestion. In Australia, the ESB is driving transmission access reform, having recently released a directions paper outlining a proposed model.

54 Consistent with this lack of 'firm' access, generators do not pay TUOS (although they do pay the capital costs associated with establishing new connections or upgrading existing connections).

Connection costs and 'contestability'

55 Under the NER, connecting parties are responsible for costs associated with any new apparatus, equipment, plant and buildings to enable their connection to the transmission network.

56 The Victorian regime includes a number of important differences.

57 Under the NER, connecting parties must pay for the assets required to enable a connection, regardless of how they are provided. Accordingly, the connection services that are required to connect a party to the transmission system are negotiated or non-regulated transmission services. As noted above, they are not a prescribed transmission service and are therefore not paid for by consumers via TUOS charges.

58 As noted above, the price charged by a TNSP for either negotiated transmission services or non-regulated transmission services is not subject to the economic regulatory framework in the NER. For non-regulated transmission services they are negotiated privately between the TNSP and the party wishing to connect on a 'contestable' basis (in that there is no requirement that they be provided by the incumbent TNSP – they can be provided by any third party on commercial terms). For negotiated services, the negotiations are subject to the negotiation framework set out in chapter 5 of the NER.

59 The location of the connection point can affect which part of the services provided by the TNSP in relation to a connection are treated as negotiated transmission services (and are therefore subject to the negotiating framework in chapter 5 of the NER) and which are considered to be non-regulated transmission services. Given this, and the potential for connecting parties to be unfairly subject to the TNSP negotiating power, the NER was amended in 2017 to allow contestability for as many connection services as possible, while ensuring that incumbent TNSPs remain accountable for outcomes on the 'shared' transmission network (including operation, maintenance and access), to ensure a safe, reliable and secure network for customers.

60 Specifically, the 2017 reforms of the NER clarified the connection process and the economic regulation of services required to connect to the shared transmission network; in particular, the

reforms defined the two main types of assets that provide the service required to connect a party to the 'shared' transmission network – dedicated connection assets (***DCAs***) and IUSAs – and clarified whether the services required to provide these assets are classified as negotiated or non-regulated services (see further below).

61 The 2017 reforms also sought to strengthen a connecting party's negotiating power with a TNSP by:

(a) requiring the incumbent TNSP to publish certain information about connecting to its network on its website and to provide certain information to connection applicants on request, to enhance the transparency of the connection process;

(b) strengthening the principles that underpin negotiations for services required to connect to the shared transmission network;

(c) providing for a process by which an independent engineer can be engaged to provide advice on a technical issue related to a connection if either the connecting party or the TNSP requests it; and

(d) clarifying the process that applies to the resolution of disputes raised in relation to transmission connections.

Dedicated connection assets and identified user shared assets

62 The NER defines two types of assets that provide the services required to connect a party to the shared transmission network – DCA and IUSA:

(a) A DCA is the collection of components that are used to connect an identified user group – that is, one or more connecting generators or loads – to the shared transmission network at a single connection point. Once commissioned, the DCA can be isolated from electricity flows on the shared transmission network. An example of a DCA is the power line that connects parts of a substation to a generating system. For the purposes of registration under the NER, a DCA is defined as a transmission system. AEMO is responsible for assessing DCA applications and registration. The party who owns, operates or controls a DCA is called a Dedicated Connection Asset Service Provider, and may be a TNSP or a third party.

(b) An IUSA is the collection of components that are used to connect the connecting party to the shared transmission network. Once commissioned, the IUSA forms part of the shared transmission network as electricity flows cannot be isolated from the shared network. An example of an IUSA is a part of a substation.

63 The DCA / IUSA regime does not apply in Victoria.

64 A combination of both a DCA and IUSA will generally be needed to connect a generator or load to the transmission network, although the relative size of these different asset types can vary widely depending on the configuration of the connecting party's particular connection.

65 Following the 2017 reforms described above, the NER now provides that all services provided for new DCAs, including design, construction, ownership, operation and maintenance, can be provided by any party on commercial terms. This is because the risks of inadequate design, construction and operation of those assets fall on these parties alone, and the shared network can be protected if appropriate action is taken, such as isolating the connection.

66 By contrast, because IUSAs form part of the shared transmission network, the NER now provides that the services of detailed design, construction and ownership for certain components of IUSAs must be provided on a contestable basis (to the extent that they meet a set of criteria as to what is contestable), but the services of setting the functional specification, providing cut-in works,

operation, maintenance and control of IUSAs must be provided by the Primary TNSP as negotiated transmission services. The NER also provides that the incumbent TNSP is accountable for outcomes on the shared transmission network, which includes IUSAs, regardless of whether they are owned by the Primary TNSP or not.

Connection Agreements

67 As described above, the terms and conditions of a connection are negotiated between the connecting party and the TNSP through a connection process governed by chapter 5 of the NER. If the negotiating parties come to an agreement, the terms and conditions of an individual connection are specified in a connection agreement between the TNSP and the connecting party. Some of these terms and conditions simply reflect the commercial negotiation between the parties, and others are included or imported pursuant to chapter 5. For example, chapter 5 of the NER contains access standards for the required level of performance for the equipment that an applicant seeks to connect to the transmission system, eg, a generating plant. The agreed levels of these access standards form part of the connecting party's connection agreement and become the performance standards for the plant.[24]

68 All participants in the NEM who are registered under the NER (including generators) have the right to negotiate and form a connection to the shared transmission network (subject to the paying for the cost of their connection). TNSP have a corresponding obligation to consider and respond to connection enquiries. Provided that the applicant proceeds with the connection process and formulates a connection application (and pays the associated fees), the TNSP is required to make an offer to connect. However, given that due to levels of congestion on the transmission network, a connection to a TNSP's network does not mean that the connected party has firm access to the network – a generator, for example, has no guarantee that they can export all their output – generators do not pay any form of TUOS charge.

(iv) Transmission augmentation

RIT-T

69 As noted above, the RIT is a cost benefit analysis, the purpose of which is to identify network investments that maximise the present value of net economic benefits in the market. Before investing in a significant transmission or distribution project to meet an identified need on the network, a proponent must consider all credible options (including potential non-network solutions) to meet that need, before selecting the option that maximises the net economic benefit across the market. This reduces the risk that consumers will pay for inefficient investments and promotes efficient investment in the long-term interests of consumers.

70 The RIT regime applies in Victoria, although with several important enhancements, notably to reflect AEMO's role in procuring major augmentations.

71 The RIT is used for both transmission and distribution projects – for transmission projects, the relevant test is the RIT-T. A RIT-T proponent is required to apply the RIT-T to any project which has the purpose of meeting an identified need unless an exception applies. Exceptions to the requirement to complete a RIT-T include where the estimated capital cost of the most expensive option to address the identified need which is technically and economically feasible is less than $7 million, where the project is to address an urgent or unforeseen network issue, involves maintenance work that is not intended to augment the network, or is needed to address inadequate levels of inertia or system strength (and there is less than 18 months in which to complete the work).[25]

[24] NER, cl 5.3.4A(i).
[25] See NER, cl 5.16.3(a)(2) . While this provision refers to $5 million, this value is subject to variation in accordance with a cost threshold determination. Under the AER's most recent cost threshold determination (which took effect on 1 January 2022), the value

72 The process to be followed by RIT-T proponents is set out in chapter 5 of the NER. The first step for a RIT-T proponent is to publish a Project Specification Consultation Report (***PSCR***). (This step is not required for projects that have been identified as being 'actionable' under the Integrated System Plan – see further below). The PSCR outlines, among other things, a description of the identified need and all credible options that address this need.

73 The PSCR is consulted on, and submissions are taken into account when developing the draft RIT report – for transmission projects, the draft RIT report is the Project Assessment Draft Report (***PADR***). This report outlines, among other things, each credible option assessed and the proposed preferred option.[26] The PADR is consulted on by stakeholders, after which the RIT proponent must publish a final RIT report – for transmission projects, the final RIT report is the Project Assessment Conclusions Report (***PACR***). This final report must, among other things, outline any submissions received in relation to the PADR.

74 The NER includes a dispute resolution process that applies to all projects subject to the RIT-T. Relevant parties are able to raise disputes with AER in relation to the conclusions made by the RIT-T proponent in a PACR, on the grounds that either:

(a) the proponent has not applied the RIT-T in accordance with the NER; or

(b) there was a manifest error in the calculations performed by the TNSP in applying the RIT-T.

75 AER may then either reject a dispute, or make a determination on the dispute, and the timeframes for doing so will depend on the complexity of the dispute.

76 AER may only direct a TNSP to amend its PACR where AER has determined that one of the above grounds is made out, ie, either that the TNSP has not correctly applied the RIT-T in accordance with the NER, or where the TNSP has made a manifest error in its calculations.

Contingent projects

77 Many of the most significant projects assessed under the RIT subsequently undergo additional assessment through the contingent project process. As set out in Rules 6.6A and 6A.8 of the NER, the contingent project mechanism can be used for large discrete projects where there is uncertainty as to whether or not they will be required during an TNSP's upcoming regulatory control period.

78 Contingent projects are not included in the TNSP's ex ante revenue allowance. However, the definition of the contingent projects and their accompanying trigger events form part of the TNSP's regulatory determination. A trigger event is commonly the successful completion of a RIT. AER must determine that a project is a contingent project if it is satisfied that, among other things, the proposed capital expenditure for the project is not provided for in the forecast capital expenditure for the relevant regulatory control period and the capital expenditure exceeds either $30 million or 5% of the value of the maximum allowed revenue for the relevant TNSP.

79 Since the introduction of the ISP, contingent projects also include actionable ISP transmission projects for which (among other things):

(a) a PACR has been published;

(b) the RIT-T proponent has received confirmation from AEMO that the preferred option addresses the relevant identified need specified in the ISP, and the cost of the preferred

of this threshold is now set at $7 million for transmission projects. See also AER, Final Determination - Cost thresholds determination, November 2021.

[26] The RIT proponent is not required to publish a PADR if, among other things, the estimated capital cost of the proposed preferred option is less than $46 million: NER, cl 5.16.4(z1) and 5.16A.4(m); AER, Final Determination - Cost thresholds determination, November 2021.

option does not change the status of the actionable ISP project as part of the optimal development path; and

(c) the cost of the preferred option set out in the CPA does not exceed AEMO's cost assessment (Clause 5.16A.5 NER).

80 Where the trigger event for an actionable ISP project or other contingent project has occurred, the relevant TNSP will apply to AER to amend its revenue determination. AER will publish the TNSP's CPA and invite submissions from stakeholders on the application. AER will then determine, among other things, the total capital expenditure that is reasonably required to undertake the project.

ISP projects and RIT-T

81 As described above, an ISP is published by AEMO every two years. Each ISP presents a range of candidate projects, classed as either actionable ISP projects (for the project to be delivered to its earliest schedule) or future ISP projects (likely to become actionable in the future). Some of these projects may form part of AEMO's 30 year ODP.

82 Where the ISP classes a project as actionable, the TNSP for the network to which the project relates is the proponent for that project and is required to undertake a RIT-T assessment for that project.

83 As noted above, the RIT-T is a cost benefit analysis designed to ensure that a TNSP's decision to invest in or augment the transmission network is sufficiently scrutinised before the investment is included in the RAB of the TNSP and funded by consumers. For actionable ISP projects, TNSPs must also apply the RIT-T, but the process is modified under chapter 5 of the NER to take into account the analysis and consultation already conducted by AEMO in respect of a project as part of its publication of the ISP.

84 As noted above, for actionable ISP projects there is no requirement to publish a PSCR. Instead, the first step of the RIT-T process is for the proponent TNSP to prepare and publish for consultation a PADR which sets out the credible technical options for the project and assesses those options in order to identify a 'preferred option'. Once the proponent TNSP has considered the submissions received, the proponent TNSP must issue a PACR which responds to those submissions, updates the cost benefit assessment if necessary, and identifies the 'preferred option'.

85 Before requesting from AER a revenue allowance for an actionable ISP project (known as a CPA), the proponent TNSP must first obtain confirmation from AEMO that the preferred option, as specified and costed by the TNSP in the PACR, still addresses the identified need in the ISP as part of the optimal development path. This is known as the 'feedback loop' and confirmation from AEMO concludes the RIT-T process.

86 The TNSP may then submit a CPA to AER to confirm that the costs associated with the actionable ISP project are prudent and efficient and may therefore be recovered by the TNSP through TUOS charges. To protect consumers, the costs submitted in the CPA cannot exceed the costs confirmed by AEMO in the feedback loop.

87 AER then issues a CPA determination for the project – effectively an amendment to the TNSP's existing five-year revenue determination to reflect the revenue allowance for the actionable ISP project – at which point the proponent TNSP has the right (but not an obligation) to accept the CPA determination and carry out the actionable ISP project.

88 TNSPs may submit more than one CPA in relation to an actionable ISP project. This may occur when either AEMO (in the ISP) or the TNSP (in the RIT-T) determines that an ISP project should be developed in multiple stages, to manage uncertainty around the need for and optimal timing of

the investment. TNSPs may also submit multiple CPAs for single stage actionable ISP projects in order to seek approval of costs for different phases. The first CPA would typically seek an allowance for early works (which are undertaken to further scope and refine the actionable ISP project through more detailed cost estimates), while the second CPA would seek approval for the full cost to deliver the actionable ISP project.

(v) Transmission maintenance of existing assets

89 The maintenance of existing assets by TNSPs is regulated through performance standards that apply to TNSPs under the NER as well as through obligations imposed under connection agreements with Registered Participants. There are also planning and reporting obligations with respect to asset maintenance under the NER, and TNSPs have financial incentives to maintain their networks under the financial incentives under the STPIS.

90 These arrangements apply in Victoria, with AusNet subject to a detailed STPIS regime.

91 With respect performance standards, TNSPs are required to maintain and operate (or ensure their authorised representatives maintain and operate) all equipment that is part of their facilities in accordance with:

(a) relevant laws;

(b) the requirements of the Rules; and

(c) good electricity industry practice and relevant Australian Standards.[27]

92 TNSPs must also comply with the power system performance and quality of supply standards:

(a) described in schedule 5.1 of the NER; and

(b) in accordance with any connection agreement with a Registered Participant.[28]

Schedule 5.1 sets out the detailed planning, design and operating criteria that must be applied by all Network Service Providers to the transmission and distribution networks which they own, operate or control. It also describes the requirements on NSPs to institute consistent processes to determine the appropriate technical requirements to apply for each connection enquiry or application to connect processed by the NSP, with the objective that all connections satisfy the requirements of schedule 5.1. Together, these comprise the power system performance and quality of supply standards that Network Service Providers must comply with in accordance with Rule 5.2.3(b).

93 TNSPs are required to arrange for:

(a) management, maintenance and operation of its part of the national grid such that, in the satisfactory operating state, electricity may be transferred continuously at a connection point on or with its network up to the agreed capability;

(b) operation of its network such that the fault level at any connection point on or with that network does not breach the limits that have been specified in a connection agreement;

(c) management, maintenance and operation of its network to minimise the number of interruptions to agreed capability at a connection point on or with that network by using good electricity industry practice; and

(d) restoration of the agreed capability at a connection point on or with that network as soon as reasonably practicable following any interruption at that connection point.[29]

[27] NER, cl 5.2.1(a).
[28] NER, cl 5.2.3(b).
[29] NER, cl 5.2.3(e1).

94 In addition to these Rules requirements, TNSPs are subject to obligations with respect to network performance at specific connection points under the connection agreements entered into with connecting parties, including generators connecting to the transmission network. The requirements for connection agreements are specified in clause S5.1.1 of schedule 5.1 of the NER, including that TNSPs must fully describe the quantity and quality of network services which they agree to provide to a person under a connection agreement in terms that apply to the connection point as well as to the transmission system or distribution system as a whole, and must ensure that the quantity and quality of those network services are not less than could be provided to the relevant person if the national grid were planned, designed and operated in accordance with the criteria set out in clause S5.1.1 (recognising that levels of service will vary depending on location of the connection point in the network).

95 TNSPs are also required to ensure that the connection agreements to which they are a party require the provision and maintenance of all required facilities consistent with good electricity industry practice and must operate their equipment in a manner to (among other requirements) comply with their performance standards.[30]

96 TNSPs have a regulatory obligation under the NER to comply with connection agreements entered into with Registered participants.

97 Planning and transparency requirements applicable to network maintenance are provided for in the Transmission Annual Planning Report (***TAPR***) and the medium term and short term projected assessment of system adequacy processes (known as ***PASA***).

98 The TAPR is required to include:

(a) information in relation to the retirement, derating or replacement of network assets;[31] and

(b) information on the TNSP's asset management approach, including:

(i) a summary of any asset management strategy employed by the TNSP;

(ii) a summary of any issues that may impact on the system constraints identified in the TAPR that has been identified through carrying out asset management; and

(iii) information about where further information on the asset management strategy and methodology adopted by the TNSP may be obtained.[32]

99 In Victoria, these obligations apply to AEMO rather than AusNet, given AEMO's responsibility for planning and augmentation of the Victorian declared transmission network. AusNet is required to provide to AEMO within a reasonable period of receiving a request, such information as reasonably requested by AEMO to enable it to comply with these requirements.[33]In relation to a proposed retirement or de-rating of a network asset in Victoria, AEMO and the relevant declared transmission system operator (which includes AusNet) must conduct joint planning in respect of that proposed retirement or de-rating if an identified need arises from that proposed retirement or de-rating. In conducting this joint planning AEMO and the declared transmission system operator must use best endeavours to work together to identify the most efficient options to address the relevant identified need.[34]

100 Additional transparency with respect to maintenance is provided through the PASA that AEMO is required to administer under Rule 3.7. The PASA is a comprehensive program of information collection, analysis, and disclosure of medium term and short term power system security and reliability of supply prospects so that Registered Participants are properly informed to enable

[30] NER, cl 5.2.1(b).
[31] NER, cls 5.12.2(c)(1A) and 5.12.2(c)(5).
[32] NER, cl 5.12.2(7).
[33] NER, cl 5.12.2(d).
[34] NER, cl 5.14A.

them to make decisions about supply, demand and outages of transmission networks in respect of periods up to two years in advance.

101 Under the PASA, AEMO is required to collect and analyse, on a weekly basis, information from all NSPs (among others) about their intentions for transmission maintenance scheduling for the following 24 months.[35]In addition, NSPs are required to provide information on any planned network outages in accordance with a timetable specified by AEMO as required to enable AEMO to identify and quantify (among other things) any projected failure to meet the reliability standard and when and where network constraints may become binding on the dispatch of generation or load.[36]

102 In addition, in Victoria, the *Electricity Safety Act 1998* (Vic) (***ES Act***) places various obligations on major electricity companies (which includes distribution and transmission companies, unless declared by the Governor in Council to be excluded as a major electricity company for the purposes of the ES Act). These obligations, described in further detail below, aim to facilitate the purpose of the ES Act: to ensure the safety of electricity supply and use, the reliability and security of electricity supply, and the efficiency of electrical equipment.[37]

103 Among other things, the ES Act sets out the functions of Energy Safe Victoria (***ESV***), which is Victoria's energy safety regulator responsible for electricity, gas and pipelines safety. These functions include monitoring the use of electricity safety management schemes, investigating events or incidents which have implications for electrical safety, advising the electricity industry and community in relation to electricity safety and, importantly, monitoring and enforcing compliance with the ES Act and regulations.[38]

104 Section 98 of the ES Act imposes a general duty on major electricity companies to design, construct, operate, maintain and decommission its supply network to minimise as far as practicable:

(a) the hazards and risks to the safety of any person arising from the supply network;

(b) the hazards and risks of damage to the property of any person arising from the supply network; and

(c) the bushfire danger arising from the supply network.

Contravention of this general duty is a civil penalty which imposes 1500 penalty units on a body corporate.

105 In addition, section 99 of the ES Act requires a major electricity company to submit an electricity safety management scheme (***ESMS***) to Energy Safe Victoria for each of its supply networks before it commences to commission, or operate, that supply network. ESV may require the company to obtain an independent validation of that scheme, or any part of it, to determine whether the supply network will be fit for purpose.[39] The company must establish to ESV's satisfaction that each person undertaking the validation has the necessary competence and ability, and access to information, on the matter to arrive at an independent opinion.[40]

106 At the request of the ESV, a major electricity company must also obtain independent audits in relation to specific provisions of the ES Act.[41] This extends to the requirement to obtain an independent audit in respect of the operator's compliance with their ESMS. Failure to comply is a civil penalty which attracts 200 penalty units under section 120H of the ES Act.

[35] NER, cl 3.7.1(c).
[36] NER, cl 3.7.2(e) and 3.7.3(g).
[37] *Electricity Safety Act 1998* (Vic) s 1 (***ES Act***).
[38] ES Act, s 7.
[39] ES Act, s 100(1);(2).
[40] ES Act, s 100(3).
[41] ES Act, ss 83BJ; 90B; 90E; 120H; 120Q.

107 The electricity transmission industry is undergoing significant developments and reforms. Section 1.8 below discusses:

(a) renewable energy zone reforms;

(b) offshore wind reforms

(c) system security reforms; and

(d) NEM reforms.

1.3 Electricity transmission – AEMO's unique role in Victoria

(i) Background and regulatory framework for 'adoptive jurisdictions'

108 In Victoria the TNSP's functions are split between AusNet Services, which has responsibility for the operation, maintenance and replacement of the network and for the provision of connection services, and AEMO, which has responsibility for system planning, augmentation and the provision of shared network services to network users.

109 The structural separation of roles between AEMO and AusNet Services derives from the arrangements put in place in the mid-1990s in anticipation of the privatisation of the Victorian transmission network, and well in advance of the current national regulatory framework governing transmission planning and investment in the NEM.

110 Victoria was the first state in Australia to privatise the electricity supply industry, in the mid-1990s. Before privatisation, electricity supply in Victoria was undertaken by a fully vertically integrated state owned utility, the State Electricity Commission of Victoria (SECV). Privatisation required an extensive reform process in which the industry was restructured and new, independent economic and safety regulatory regimes were put in place.

111 The Victorian transmission model was developed as a structural solution to a perceived regulatory problem, namely the concern that a privately-owned transmission business would have an incentive to invest in new transmission assets (on which it would earn a regulated rate of return) in preference to other potential solutions to address transmission constraints.

112 In the absence of an established regulatory framework, structural separation between transmission and investment decisions (vested in an independent not-for-profit entity) and procurement; and transmission system ownership and operation (vested in the private sector owner and operator of the network) was the solution adopted.

(ii) Legislative framework

113 The current form of the Victorian transmission arrangements was introduced into the National Electricity Law in 2009 by the *National Electricity (South Australia) (National Electricity Law – Australian Energy Market Operator) Amendment Act 2009* (SA) (***AEMO Establishment Act***).

114 The AEMO Establishment Act introduced into the NEL the concepts of a 'declared power system', 'declared shared network', 'declared transmission system', and 'declared transmission system operator'. These are all defined by reference to the application legislation which applies the NEL in an 'adoptive jurisdiction'. An 'adoptive jurisdiction' is:

(a) a participating jurisdiction for which AEMO is authorised to exercise its 'additional advisory functions'; or

(b) a participating jurisdiction for which AEMO is authorised to exercise its 'declared network functions'.

115 AEMO's 'additional advisory functions' are those set out in Section 50B(1) of the NEL, and its 'declared network functions' are those set out in Section 50C(1). The effect of Section 50 of the NEL is that the additional advisory functions and declared network functions apply in a

participating jurisdiction only where the relevant jurisdiction's NEL application Act (or an instrument made under that Act) declare them to apply.

116 In Victoria the NEL application Act is the *National Electricity (Victoria) Act 2005* (Vic) (***NEVA***). Part 5 of that Act:

(a) declares Subdivision 3 of Part 5 of the NEL (which contains Section 50C(1)) to apply in Victoria, thereby activating AEMO's declared network functions;

(b) authorises the Minister, by Order published in the Government Gazette, to declare a transmission system, or part of a transmission system, situated wholly or substantially in Victoria to be the 'declared transmission system'; and

(c) authorises the Minister, by Order published in the Government Gazette, to declare a person who owns, controls or operates the declared transmission system, or part of the declared transmission system, to be a 'declared transmission system operator'.

117 Ministerial Orders made on 26 June 2009 and published in the Government Gazette on 30 June 2009:

(a) made a declaration in respect of the Victorian transmission network by reference to a system diagram scheduled to the Order; and

(b) declared AusNet Services (formerly SPI PowerNet Pty Ltd), Rowville Transmission Facility Pty Ltd and TransGrid to be transmission system operators.

118 Subsequent Orders under Part 5 have declared Transmission Operations (Australia) Pty Ltd, Transmission Operations (Australia) 2 Pty Ltd, and New South Wales Electricity Network Operations Pty Limited (in place of TransGrid) to be declared transmission system operators.

119 By virtue of these provisions and Ministerial orders, AEMO is responsible for 'declared network functions' in Victoria, defined in Section 50C(1) of the NEL as follows:

(a) to plan, authorise, contract for, and direct, augmentation of the declared shared network;

(b) to provide information about the planning processes for augmentation of the declared shared network;

(c) to provide information and other services to facilitate decisions for investment and the use of resources in the Victoria's electricity industry;

(d) to provide shared transmission services by means of, or in connection with, the declared shared network;

(e) any other functions, related to the declared transmission system or electricity network services provided by means of or in connection with the declared transmission system, conferred on it under NEL or the NER; and

(f) any other functions, related to the declared transmission system or electricity network services provided by means of or in connection with the declared transmission system, conferred on it under a law of Victoria (NEL s50C(1)).

120 For Victoria, the high level description of AEMO's declared network functions in the NEL provides only limited guidance as to how the specific functions and responsibilities of TNSPs under chapter 5 of the NER should be divided between AusNet Services and AEMO. Rule 5.1A.1 of the NER seeks to address this. It contains a general division of roles and responsibilities in that it provides that, in applying Part B of chapter 5 to transmission services provided by means of the declared transmission an adoptive jurisdiction (such as Victoria):

(a) a reference to a Network Service Provider is, in relation to the provision of connection services, to be read as a reference to a declared transmission system operator (ie, relevantly AusNet); and

(b) a reference to a Network Service Provider is, in relation to the provision of shared transmission services, to be read as a reference to AEMO.

121 This is followed in paragraphs (e), (f), (f1) and (g) by more detailed interpretative guidance as to whether particular references to 'Network Service Provider' in chapter 5 should be read as a reference to AEMO or to the relevant declared transmission system operator.

122 As stated above, the effect of these provisions is that in Victoria, the TNSP's functions are split between AusNet Services, which has responsibility for the operation, maintenance and replacement of the network and for the provision of connection services, and AEMO, which has responsibility for system planning, augmentation and the provision of shared network services to network users.

(iii) Transmission Annual Planning Report in Victoria

123 As noted above, in other NEM jurisdictions the incumbent TNSP conducts the annual planning review and publishes the TAPR. In Victoria, AEMO publishes the Victorian Annual Planning Report (***VAPR***) in its role as the Victorian transmission planner under the NEL, in accordance with clause 5.12 of the NER. In a given year the VAPR assesses the adequacy of the existing Victorian Declared Shared Network (***Victorian DSN***) to meet reliability and security needs in the past year, and plans and directs augmentation on the forecast DSN over the next 10 years.

124 The VAPR builds on the ISP in that it adopts the comprehensive system-wide plans in the ISP (including the optimal development path) and overlays them with more granular information about local congestion issues and regional performance characteristics.

125 In the 2022 VAPR:

(a) Chapter 2 reviews the performance of the Victorian DSN throughout 2021-22, including new operational challenges, notable power system incidents, performance of the network under a range of operating conditions;

(b) Chapter 3 provides an update on the network investment activities and investigations that have progressed since 2021 to facilitate the integration of new renewable generation while supporting Victorian power system security and reliability;

(c) Chapter 4 explores potential new emerging or changed limitations that may reduce system performance, impact efficient asset utilisation, or result in additional network constraints. (Identified limitations may warrant heightened monitoring, further options analysis, or trigger the need for investment); and

(d) Chapter 5 presents updated information on AusNet Services' Asset Renewal Plan, outlining expected network asset retirements, deratings, and renewals within the VAPR’s 10-year timeframe, including AEMO’s assessment of the future network needs associated with these assets.

(iv) RIT-T

126 Decisions to invest in the Victorian transmission network are made by AEMO rather than AusNet Services, the regional TNSP. AEMO identifies and defines the need for network augmentation and undertakes the RIT-T process to assess the preferred option. However, the contestability regime in Victoria means that, at the conclusion of the RIT-T process, instead of applying to AER for a revenue allowance for the augmentation, AEMO instead conducts a competitive tender process to procure a third party to build, own and operate the augmentation. It is this competitive tender process, rather than a revenue determination by AER, that determines the payments that

the asset owner will receive from AEMO for the use of the asset. This is described in more detail in the next section.

(v) Augmentations and tenders

127 In Victoria, ownership of a new transmission assets (not just design and construction, as in other NEM jurisdictions) is subject to contestability.

128 As noted above, AEMO is not required to apply to AER for preferred option and revenue assessment as part of the RIT-T process. Instead, AEMO must conduct a competitive tendering process in accordance with chapter 8 of the NER to build, own and operate the relevant network augmentation if:

(a) the cost of the project is reasonably expected to exceed $10 million; and

(b) the project is considered to be a 'separable augmentation', meaning that it will provide a distinct and definable service to AEMO and will not materially adversely affect the services provided to AEMO by an incumbent service provider.

129 The competitive tendering process determines the payments that the asset owner will receive from AEMO for the use of the asset.

130 The competitive tendering process follows a typical public sector procurement model commencing with a call for expressions of interest followed by the issue of an invitation to tender, submission of formal proposals, evaluation of tenders, appointment of preferred supplier, contract negotiation and contract award. Depending on the size and nature of the project this process typically takes at least five months and generally commences after completion of the RIT-T process for the project.

(vi) Regulated revenue and TUOS

131 As explained above, in Victoria both AusNet Services and AEMO are responsible for the electricity transmission network, and each are economically regulated by AER.

132 Unlike other TNSPs, AEMO is not required to have a revenue determination issued by AER. This is because the contestability regime in Victoria means the price of augmentations is set not by AEMO but instead by the market through a competitive procurement process, removing the need for AER approval of forecast expenditure. Instead, AEMO manages its investments and augmentations pursuant to the private contractual arrangements it enters into pursuant to the competitive procurement processes it runs for each augmentation. Instead of submitting a regulatory proposal to AER and receiving a determination, AEMO is instead required to publish a revenue methodology setting out the method for calculating AEMO’s maximum allowed revenue for the provision of prescribed services for each regulatory year. In substance, the arrangements provide for a pass through of the payments AEMO is required to make to DTSOs (including AusNet Services) plus recovery of AEMO’s own costs in carrying out its declared network functions on a simple cost recovery basis (see further below).

133 By contrast, AER's regulation of AusNet Services is more similar to its regulation of other TNSPs in that AusNet Services is required to submit a regulatory proposal and receive a determination. As for other TNSPs, the regulatory determination includes approval of AusNet Services MAR, using the same building block methodology and applying the same incentive regimes. As AEMO is responsible for investment and augmentations, whereas AusNet Services is responsible for the ongoing replacement and maintenance of the network, the RAB in an AusNet Services determination includes the augmentations commissioned by AEMO in the immediately preceding regulatory period (referred to in the determination for AusNet as 'growth assets'). The reason for this treatment is that the growth assets provide prescribed transmission services, but their associated capital expenditure does not fall within AusNet's revenue determination (as AusNet is

not responsible for the planning of these assets). The other DTSOs in Victoria do not currently maintain a RAB of assets which provide prescribed transmission services.

134 As part of its regulatory proposal, like other TNSPs AusNet Services is also required to submit for AER's approval a pricing methodology which allocates its revenue to its prescribed transmission services, and to the connection points of its network users. The pricing methodology determines the structure of prices that are charged for each category of prescribed transmission service. The pricing methodology for AusNet Services addresses only the pricing matters for which AusNet Services has responsibility: certain categories of prescribed transmission services known as 'prescribed entry services' and 'prescribed exit services' (because in Victoria, the pricing of all other prescribed transmission services is the responsibility of AEMO – see further below).

135 In Victoria, in addition to AusNet Services and AEMO, the Murraylink interconnector also provides transmission services for which it recovers its costs through transmission charges.

136 Pursuant to the NER, AEMO therefore acts as the coordinating TNSP and is responsible for allocating all AER-determined regulated revenue in Victoria, and calculates the final Victorian TUOS which it recovers from network users (including DNSPs) pursuant to use of system agreements entered into between AEMO and network users. DNSPs then pass on the TUOS (together with their own distribution use of system (***DUOS***)) to retailers in accordance with their regulatory determinations (see further below).

137 This means that, in Victoria, the transmission component of customers' bills includes:

(a) AusNet Services' transmission charges, as permitted by its regulatory determination;

(b) Murraylink's transmission charges, as permitted by its regulatory determination;

(c) AEMO's costs incurred as part of its planning responsibilities in Victoria;

(d) AEMO's future costs associated with the ISP; and

(e) the Victorian Government's easement land tax (a portion of which is also recovered through AusNet Services' regulated transmission charges).[42]

138 In Victoria, TUOS accounts for about 5.5% of the total electricity bill for a typical residential customer.[43]

(vii) Connection applications

139 In Victoria, the regulatory and legislative framework for how parties connect to the transmission network differs from the framework that applies in other NEM jurisdictions. In other jurisdictions, the process is regulated by the NEL and chapter 5 of the NER. In Victoria, it is regulated by the NEL and certain provisions of chapters 5 and 8 of the NER.

140 Generally, AEMO is responsible for assessing and coordinating all new connections against the NER requirements, but is not responsible for providing the assets associated with connection. As a result, the following process applies to transmission connections in Victoria:

(a) If a connection requires an augmentation to the declared shared network, eg, the construction of a new substation, AEMO will determine whether the augmentation is contestable, non-contestable, or some combination of both.

(b) If AEMO determines that the augmentation is contestable, then the connection applicant can either nominate a DTSO of its choice to build, own and operate the contestable assets (essentially it would conduct a private tender to determine who it wishes to appoint

[42] AER, *AusNet Services Transmission Determination 2022 to 2027* (January 2022), pages 3 and 4 <https://www.aer.gov.au/system/files/AER%20-%20Final%20Decision%20-%20AusNet%20Services%20transmission%202022-27%20-%20Overview%20-%2028%20January%202022.pdf> (***AusNet Transmission Determination (January 2022)***).
[43] AusNet Transmission Determination (January 2022), page 17.

to provide these services), or ask AEMO to select the DTSO, with AEMO running a competitive tender process to select the most appropriate party.

(c) If AEMO determines that an augmentation is not contestable, the services will be provided by the incumbent DTSO, eg, AusNet Services. Typically, these are the interface works because they are considered 'not separable' from the incumbent's network.

(d) Regardless of whether the augmentation is contestable or not, AEMO provides the equivalent of a 'functional specification' that the provider of the assets must use.

141 As a result of these differences, the contractual agreements for a connection in Victoria also differ from other jurisdictions. Currently, in other jurisdictions, only one connection agreement or contract is likely to be required ie, that between the connection applicant and the TNSP. However, in Victoria, the contestability framework means that more complex contractual arrangements are often required, especially where the augmentation is contestable and AEMO runs a competitive tender process to select the DTSO.

142 Given AusNet is (in most cases) the incumbent DTSO, it is required to perform a number of functions for new and expanded connections, even if it is not selected as the DTSO for the connection works. In performing these functions, which primarily relate to the unavoidable interfaces with the AusNet transmission network, AusNet is subject to regulatory obligations under Rule 8.11 to provide information and negotiate in good faith.

143 Depending on the nature and scale of the new connection, AusNet's functions may include:

(a) negotiating and performing a Project Coordination Deed with AEMO and the selected DTSO;

(b) negotiating and performing a connection agreement with the connection applicant (covering the cost of necessary connection works);

(c) lease and land access agreements with the connection applicant or selected DTSO; and

(d) variations to the network services agreement with AEMO.

144 If the applicant cannot agree with AEMO or AusNet the terms and conditions of access for the provision of prescribed transmission services or negotiated transmission services, then a transmission services access dispute process may be initiated under the NER. As explained above, in Victoria the relevant dispute resolution process is set out in chapter 8.

(viii) Provision of transmission services

145 As noted above, AEMO's declared network functions include the provision of shared transmission services. In order for AEMO to provide these services to network users (generators and distributors), it procures the use of transmission assets from asset owners / DTSOs (eg, AusNet). This is achieved by entering into a network support agreement with DTSOs to provide the necessary services to allow operation of all DTSO equipment as a single network. Through these contractual arrangements, AEMO controls the networks and sets network performance standards and requirements for the DTSOs.

1.4 Electricity distribution

(a) Distribution planning

Annual planning process

146 In addition to the framework for annual transmission network planning described above, Part D of chapter 5 of the NER also establishes an annual planning and reporting cycle for distribution network planning, which includes the distribution annual planning review, distribution annual planning report (***DAPR***) and demand side engagement obligations.

147 For the purposes of the distribution annual planning review, each DNSP must undertake an annual planning process covering a minimum forward planning period of five years for its distribution assets (and 10 years for dual function assets), commencing on a date deemed appropriate by the DNSP. The annual planning process applies to any distribution assets and activities of the DNSP that are expected to have a material impact on the DNSP's distribution network during that minimum five year period. In carrying out the annual planning process, DNSPs are, at a minimum, required to:

(a) prepare forecasts of maximum demands for the relevant network assets;

(b) identify (based on those forecasts) system limitations; and

(c) take into account non-network options when considering investment options.

148 Once a DNSP has undertaken the annual planning process described above, it must publish a DAPR setting out the results of the distribution annual planning review for the forward planning period. DNSPs must publish their DAPR by the date specified in jurisdictional electricity legislation or, if no such date is specified, by 31 December. The DAPR must include the information specified in schedule 5.8 of the NER.

149 For the purposes of demand side engagement obligations, DNSPs must develop a demand side engagement strategy for engaging with non-network providers and considering non-network options in order to address system limitations. DNSPs must prepare a document which sets out the strategy and meets the requirements for content set out in schedule 5.9 of the NER. The document must be published, and it must also be reviewed and revised at least one every three years.

150 DNSPs are also required to establish and maintain a demand side engagement facility by which parties can register their interest in being notified of developments related to distribution network planning and expansion.

Joint planning

151 As noted above, there are a number of joint planning arrangements under the NER which require network planning between different market participants, including prescriptive requirements for joint planning as between TNSPs and DNSPs.

152 In addition, just as TNSPs are required to undertake 'light touch' joint planning with other TNSPs, DNSPs are require to undertake joint planning with owners of any connected networks where there are issues affecting multiple networks, and the requirements for this joint planning are not as prescriptive as they are for joint planning as between TNSPs and DNSPs.

(b) Distribution pricing

AER regulation

153 The regulatory framework for distribution pricing is similar to the regulatory framework for transmission pricing as described above.

154 Electricity distribution in the NEM is achieved by DNSPs providing a variety of 'distribution services' through their respective distribution networks. Distribution services may be provided by a DNSP either as direct control, negotiated or non-regulated services:

(a) **Direct control services**: these services comprise 'standard control services' and 'alternative control services'. The costs for providing direct control services are regulated by AER through its five yearly distribution determinations. In practice, most DNSP services comprise direct control services;

(b) **Negotiated distribution services**: Negotiated distribution services are distribution services which are not direct control services and have been deemed to be negotiated network services (in either the NER or by AER in a distribution determination). This means that the revenue or prices for these services is not regulated by the relevant distribution determination. Instead, as for negotiated transmission services, the terms for providing negotiated distribution services, including the cost, are determined through private contract between the DNSP and the party wishing to receive these services. The terms however must be negotiated in accordance with the relevant negotiation framework prescribed in the NER – for distribution services, this is found in Part D of chapter 6 of the NER (noting that negotiations with a DNSP for a connection contract must instead be conducted pursuant to Part C of chapter 5A (Section 5A.C.1(A)(e)). As noted above, in practice, very few distribution services have been deemed to be negotiated network services, either in the NER or in distribution determinations, and consequently many DNSPs do not currently provide any negotiated distribution services; and

(c) **Non-regulated distribution services**: These services, which are relatively uncommon, are typically provided by the DNSP on a contestable basis and as such are not subject to price and terms regulation by AER.

155 The framework for distribution pricing is similar to the framework for transmission pricing in that AER makes five yearly determinations which determine the amount of revenue the DNSP can recover from its customers in the next regulatory period (and for direct control services, this involves the application of a building block approach very similar to that used for prescribed transmission services).

156 However, the framework for distribution pricing differs from the framework for transmission pricing to reflect the fact that, unlike the costs of prescribed transmission services, which as explained above are recovered through TUOS, the costs of distribution services are recovered through a variety of charges and tariffs which differ depending on the type of distribution service provided and the type of customer receiving the service.

157 For this reason, instead of imposing a MAR, which effectively caps the total revenue a TNSP can recover through TUOS in a regulatory period, a distribution determination imposes controls over the prices of direct control services. AER has a range of control mechanisms to choose from in making a distribution determination, including a schedule of fixed prices, caps on the prices of individual services, tariff basket price control, or a combination.[44]

158 As for TNSPs, the process for AER to make a regulatory determination for a DNSP is set out in the NEL and NER: AER is required to apply the pricing principles set out in Section 7A of the NEL (in the same way as it does for TNSPs), and chapter 6 of the NER prescribes in detail the rules for economic regulation of DNSPs, including the steps AER must following in making a revenue determination, and the relevant timeframes. These steps are very similar as for a transmission determination (refer above), with the key difference being that at the same time as submitting to AER its regulatory proposal, a DNSP must also submit a proposed tariff structure statement in relation to the direct control services it proposes to provide.

159 The proposed tariff structure statement must meet the requirements of Part I of chapter 6 – for example, it must include the tariff classes into which retail customers for direct control services will be divided, the policies the DNSP will apply for assigning retail customers to tariffs and the charging parameters for each tariff. The tariff structure statement must also comply with the pricing principles set out in Rule 6.18.5, which include the principle that the revenue expected to be recovered from each tariff must reflect the DNSP's total efficient costs of serving the retail customers that are assigned to that tariff. Once the proposed tariff structure statement has been approved by AER, the DNSP is required to comply with the tariff structure when setting the prices

[44] NER, cl 6.2.5(b).

it will charge for direct control services.[45] A DNSPs sets these prices through the annual pricing proposals it is required to provide to AER in advance of each year in a regulatory period.[46] The pricing proposal sets out, among other things, the proposed tariffs for each tariff class specified in the tariff structure statement.

160 Where a retailer and a shared customer (ie, a person who is a customer of the retailer and whose premises are connected to the distributor's distribution system) enter into a contract for the sale or purchase of electricity only, the retailer must notify the DNSP as soon as reasonably practicable after commencement of the contract.[47] The retailer must pay the DNSP the network charges payable in respect of each shared customer by the due date for payment.[48] When a customer switches energy retailers, the customer will still receive the same electricity and / or gas supply from the distributor. As a distributor services certain areas, the new retailer uses the existing distribution network, and the distributor which connects the customer to the network does not change. Where works are required for a new or upgraded connection, these are subject to a specific connection policy (discussed further below).

161 As for TNSPs, in order to determine a DNSP's revenue requirement in respect of standard control services, AER applies a building block approach. AER uses the same building block approach as for transmission determinations (refer above). As for transmission determinations, these building blocks are then added together and adjusted for incentives. Like TNSPs, DNSPs are subject to CESS, EBSS and STPIS incentive mechanisms to guard against inefficient CapEx and OpEx and to incentivise import service performance.. The AER has been consulting on its approach to incentivising and measuring export service performance. In its final report published on 10 March 2023,[49] the AER determined that in the immediate term it would not extend the STPIS to export services. However, as a transitional measure, the AER announced that it will introduce a new small-scale incentive scheme for export services which will give DNSPs the option to enter into bespoke incentive schemes with customers. The final export services incentive scheme will be published in July 2023.

Cost allocation method

162 The regulation of cost allocation supports the price determination process by ensuring that prices accurately reflect the DNSP's cost of providing distribution services, as well as avoiding cross-subsidisation. Each DNSP is required to comply with the 'Cost Allocation Method' approved in respect of that DNSP by AER from time to time.[50] This is because each DNSP is responsible for developing the detailed principles and policies for attributing costs to, or allocating costs between the categories of distribution services that it provides. These detailed principles and policies must be included in the proposed Cost Allocation Method that the DNSP submits to AER for approval.

163 Specifically, Part F of chapter 6 requires that a DNSP's Cost Allocation Method must comply with the Cost Allocation Guidelines published by AER, which are binding on both AER and DNSPs and which give effect to the Cost Allocation Principles prescribed in Rule 6.15.2. The principles include, for example, the principle that only costs which are directly attributable to the provision of distribution services, or which are incurred in providing those services, may be allocated to a particular category of distribution services.

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[45] NER, cl 6.18.1A(c).
[46] NER, cl 6.18.2.
[47] NER, cl 6B.A2.2.
[48] NER, cl 6B.A2.1.
[49] AER, *Incentivising and measuring export service performance: Final report (March 2023)*, page 4 <https://www.aer.gov.au/system/files/AER%20-%20Incentivising%20and%20measuring%20export%20service%20performance%20-%20Final%20report%20-%20March%202023_0.pdf>.
[50] NER, cl 6.15.

(c) Distribution access

Open access regime

164 As noted above, the NEM operates under an open access regime in that TNSPs and DNSPs must each make investments or procure services to meet the reliability standard imposed on them by the State or Territory Government in their jurisdiction. This adherence is considered to provide customers with some level of access to their network, in return for which customers pay network charges – transmission customers (like DNSPs) pay TUOS to the TNSP, and retailers pay DUOS to the DNSP.

165 DUOS charges relate to the conveyance of electricity from the shared transmission network (or from generators embedded in the distribution network) to customers. Under the NER, DNSPs are required to submit for AER approval a tariff structure statement outlining the proposed DUOS pricing structure for the next regulatory period and an indicative pricing schedule for each regulatory year.

(d) Electricity Distribution Connections

166 In addition to the general economic regulation of distribution revenues and tariffs under chapter 6 of the NER (discussed above), a key issue for distribution customers is the process and pricing for new (or expanded) connections to the distribution network. This includes both new premises and expansions of existing connections.

167 These connections are subject to a detailed regulatory regime.

Legislative Framework

168 Electricity distribution connection is regulated in Victoria pursuant to a suite of regulatory instruments at both a NEM and State level, with the effect that electricity distributors are subject to both the NER connection regime and a number of Victorian-specific requirements.

169 The regulatory instruments relevant to electricity distribution connection and this submission are set out below.

NER Chapter 5A; National Electricity (Victoria) Act 2005 (NEVA)

170 Chapter 5A of the NER regulates the terms on which distributors must offer to provide new retail customer connections and connection augmentations. It applies to the electricity connections of retail customers and certain small-embedded generators.

171 The chapter 5A rules were developed and introduced as part of the National Energy Customer Framework (***NECF***) legislative package. Chapter 5A was introduced into the NER by the National Electricity (National Energy Retail Law) Amendment Rule 2012, and not through the usual AEMC rulemaking process.

172 Victoria has not adopted the NECF. However, in Victoria, chapter 5A came into force via the National Electricity (Victoria) Further Amendment Act 2016, and is included at schedule 2 of the NEVA (with some derogations acknowledged under Sections 16S and 16SA of the NEVA).

173 As a result, chapter 5A applies in Victoria and may be amended in accordance with the usual AEMC process. As chapter 5A has been implemented through Victorian legislation, it is legally possible for Victoria to implement changes to chapter 5A through Victorian legislation.[51]

174 AER is responsible for administering the national electricity legislation, and is tasked with monitoring, investigating and enforcing compliance with the NEL and the NER in jurisdictions that

[51] The usual mechanism for making amendments to chapter 5A would be for Victoria to submit a rule change proposal to the AEMC. The AEMC would then undertake a consultation process on the proposed rule change and make the change if satisfied that it was consistent with the National Electricity Objective set out in the NEL.

have adopted the national framework. Under Section 11A of NEVA, AER's functions and powers extend to operation of chapter 5A of the NER in Victoria as set out in schedule 2 of NEVA.

175 Any references to chapter 5A in this section are to schedule 2 of the NEVA as implemented.

*Electricity Distribution Code of Practice (**Distribution Code**)*

176 At a State level, the supply, and physical connection, of electricity by a distributor to its customers is also regulated under the Distribution Code.[52] The Distribution Code is made under Section 47(1) of the *Essential Services Commission Act 2001 (Vic)* by the ESC. Version 1 of the Distribution Code took effect on 1 October 2022. An objective of the Distribution Code is to regulate the distribution of electricity by a distributor for supply to its customers, and the connection of an electrical installation or embedded generating unit to the distribution system, so that such activities are undertaken in a safe, efficient and reliable manner.

177 Importantly a DNSP must comply with its obligations under *both* chapter 5A and the Distribution Code. The Distribution Code works alongside chapter 5A, and expressly provides that a distributor must comply with the Distribution Code *and* its obligations under chapter 5A (Electricity connection for retail customers) of the NER.[53] The Distribution Code contains obligations that apply in addition to the chapter 5A obligations on distributors under the NER. Notwithstanding, under clause 1.5.1, a distributor may enter into a written agreement with a large customer to expressly vary their respective rights and obligations under the Distribution Code.[54] Distributors are required to comply with the Distribution Code as part of their licence conditions under the *Electricity Industry Act (Vic) 2000* (***EI Act***) (see paragraph 182 below).

178 The ESC is responsible for administering, monitoring and reporting on compliance with, the Distribution Code under Part 6 of the ESC Act (see paragraph 179 below).

*Essential Services Commission Act 2001 (Vic) (**ESC Act**)*

179 The ESC Act establishes the ESC under Section 7, with its functions and regulatory powers outlined in the ESC Act and EI Act. The objective of the ESC is to promote the long-term interests of Victorian consumers,[55] having regard to the price, quality and reliability of essential services. In seeking to achieve the ESC's objective, the ESC must also have regard to (among other things) the efficiency in the industry and incentives for long term investment, the financial viability of the industry, and the degree of, and scope for, competition within the industry, including countervailing market power and information asymmetries.[56]

180 The ESC functions include administering, monitoring and reporting on compliance by electricity distributors and retailers with provisions of the Distribution Code under Part 6 of the ESC Act, and must investigate and commence and conduct proceedings in relation to any contraventions of the Distribution Code.[57]

Electricity Industry Act (Vic) 2000

181 The EI Act regulates certain aspects of the Victorian electricity supply industry, and the main relevant provisions relate to licences; the EI Act requires persons who generate, transmit, distribute, supply or sell electricity to obtain a licence from the ESC or a licence exemption.[58]

[52] The Distribution Code defines 'customer' as a person whose electrical installation is connected to, or who may want to have its electrical installation connected to, the distributor's distribution system, and includes an embedded generator.
[53] Essential Services Commission, *Electricity Distribution Code – Version 1* (1 October 2022) cl 3.1 <https://www.esc.vic.gov.au/sites/default/files/documents/Electricity%20Distribution%20Code%20of%20Practice%20%28version%201%29%20-%20FINAL_1.pd.>.
[54] The Distribution Code defines 'Large Customer' as a business customer to whom peak demand of not less than 500kVa, or consumption of not less than 160 MWh per annum is distributed, supplied or sold for commercial or industrial purposes.
[55] *Essential Services Commission Act 2001* (Vic) s 8 (***ESC Act***).
[56] ESC Act, s 8A.
[57] ESC Act, s 10AA.
[58] *Electricity Industry Act 2000* (Vic) s 16 (***EI Act***).

182 The ESC is also responsible for granting licence applications, and determining the term and conditions of the licence. Relevantly, specific licence conditions on a distributor may include provisions:

(a) requiring a distribution company to have agreements with retailers as are necessary to ensure that electricity is distributed or supply to enable the retailers to sell electricity to their customers.[59] Under section 11 of the AusNet licence, AusNet must enter into a Use of System Agreement with each Retailer in accordance with the requirements of the Distribution Code; and

(b) requiring the licensee to observe the Distribution Code.[60] Section 10 of the AusNet licence contains this specific condition. The ESC may also amend the industry code for the purposes of their application under a particular licence application.[61]

183 For completeness, the following conditions are not currently contained in the AusNet licence. However, the ESC may impose other specific licence conditions on a distributor:

(a) requiring a distribution company to prepare standard agreements for the purpose above, to submit the standard agreements to the ESC for approval, and to offer a standard agreement approved by the ESC to a retailer; [62]

(b) preventing the licensee from engaging in or undertaking specified business activities;[63] and

(c) specifying methods or principles to be applied by the licensee in determining prices or charges, or in the conduct of activities authorised by the licence.

Regulation of Distribution Connections

184 Chapter 5A of the NER regulates electricity connections for retail customers. These comprise three types of connection services, set out in the below table.

Figure 1: Connection Service Types – Chapter 5A NER

NER connection service type	AusNet example [64]
Basic connection services: a connection between a distribution system and a retail customer's premises (excluding a non-registered embedded generator's premises) in the following circumstances: (a) either (1) the retail customer is typical of a significant class of retail customers who have sought or are likely to seek the service or (2) the retail customer is, or proposes to become, a micro-embedded generator; and (b) the provision of the service involves minimal or no augmentation of the distribution network; and	AusNet offers two classes of basic connection service: (a) A basic connection service, where connection between the distribution system and the customer's premises requires minimal or no augmentation of the distribution network. (b) A basic micro embedded generation connection service, which is for the connection of micro embedded generators with a maximum capacity less than 5 kVA per phase, or more than 3.5 kVA if connected to a single-wire earth return (SWER) powerline.

[59] EI Act, s 21(c).
[60] EI Act, s 21(l).
[61] EI Act, s 25.
[62] EI Act, s 21(e).
[63] EI Act, s 21(o).
[64] Examples are drawn from the AusNet Services *Distribution Connection Policy*, Effective 1 July 2021.

NER connection service type	AusNet example [64]
(c) a model standing offer has been approved by AER for providing that service as a basic connection service.	
Standard connection services: a connection service other than a basic connection service for a particular class (or sub-class) of connection applicant and for which a model standing offer has been approved by AER.	AusNet offers only one standard connection service: for underground connections in specified circumstances.
Negotiated connections: where a connection service is: (1) neither a basic connection service nor a standard connection service; or (2) a basic connection service or a standard connection service but the connection applicant elects to negotiate the terms and conditions on which the connection service is to be provided.	This covers all other connections. The AusNet connection policy notes that most negotiated connection services are classified as a standard control service, meaning that the connection charges are approved by AER. The main exception is enhanced connection services (for example with a higher reliability standard), which are classified as alternative control services. An example of such work is reserve feeder installation and maintenance (ie, when a customer requests continuity of electricity supply should the feeder providing normal supply to their connection experience interruption). Standard control and alternative control services are discussed further below.

Source: Applications for Connection Services

185 A distributor can only install a new connection service after it has received a connection application. Connection applications are addressed under Division 3 of Part D, chapter 5A.

186 Information: A DNSP must publish on its website an application form for a new connection[65] or a connection alteration[66] and describe how an application is to be made.[67] It must also describe the basis for calculation of connection charges, a description of the DNSP's basic and standard connection services, and explain the applicant's right to negotiate a negotiated connection contract with the DNSP.

187 Connection enquiries: A DNSP must provide an enquirer with the information required to make an informed application within five business days of receiving a connection service enquiry.[68] The information must include possible costs, a statement of possible site inspection charges and an indication of whether any aspects of the proposed connection are likely to be contestable.

188 Connection applications: A connection application can be made by a retail customer, a retailer acting on a customer's behalf, or a real estate developer who seeks connection services for multiple premises in a real estate development.[69]

189 Response to connection applications: Once a complete connection application has been received, including the receipt of any further information requested, the DNSP must:

[65] A new connection refers to the establishment of a connection where there is no existing connection.
[66] A connection alteration refers to an alteration to an existing connection (including an addition, upgrade, extension, expansion, augmentation or any other kind of alteration).
[67] NER, r 5A.D.1.
[68] NER, r 5A.D.2.
[69] NER, r 5A.D.3.

(a) advise the connection applicant whether the proposed connection service is a basic or standard connection service, or neither; and

(b) if the proposed connection service is neither a basic nor standard connection service, the DNSP must provide the applicant with the process for negotiated connections and possible costs and expenses related to the negotiated.

(c) the DNSP must provide the above response within 10 business days, or another period of time agreed between the DNSP and connection applicant.

190 Expedited applications: Expedited applications can be made for basic and standard connection services subject to approval by the relevant DNSP.[70]

Terms and conditions of new connection services

191 Basic and standard connection services: The terms and conditions for basic and standard connection services are set by model standing offers, which are a set of model terms provided by the distributor and approved by AER. A distributor is obliged to have a model standing offer for basic services.[71] Basic connection services are of two classes: (i) basic connection services for retail customers who are not embedded generators; and (ii) basic connection services for retail customers who are micro embedded generators.

The same express obligation requiring a DNSP to have a model standing offer does not exist for standard connection services.

192 The model standing offers must be approved by AER, and cover a range of requirements. This includes the timeframes for commencing and completing the work, (although the NER is silent as to what these timeframes should be), details of the connection charges (or the basis on which they will be calculated) including the costs of any necessary extensions to the distribution system, the cost of any other relevant premises connection assets, the costs of common components of minor variations from the standard specifications and any other incidental costs.

193 In determining whether to approval model standing offers for basic or standard connections, AER must have regard to the National Electricity Objective, and be satisfied that:

(a) the terms and conditions are fair and reasonable;

(b) the connection charges are consistent with the DNSP's distribution determination including the connection policy; and

(c) the terms and conditions comply with applicable requirements of the energy laws. In Victoria, this includes the Distribution Code.[72]

194 For basic connection services, AER must also be satisfied that there is adequate demand for the services,[73] and have regard to the basis on which the DNSP has provided relevant services in the past, and the geographical characteristics of the area service by the relevant distribution network.[74]

195 A DNSP may apply to AER for the amendment or substitution of a model standing offer to provide basic connection services or standard connection services under Rule 5A.B.6. In each case, the DNSP must publish its model standing offers for basic connection services or standard connection services on its website.

196 Under section 40A of the EI Act, a DNSP may from time to time (and subject to the conditions of its licence) give notice of terms and conditions applying in respect of the distribution or supply of

[70] NER, r 5A.F.3.
[71] NER, r 5A.B.1.
[72] NER, rr 5A.B.3 and 5A.B.5.
[73] NER, r 5A.B.3(a)(1).
[74] NER, r 5A.B.3(b).

electricity by the DNSP to retail customers or a class of retail customers. Such terms and conditions must be approved by the ESC before the notice is given, and the terms and conditions must be consistent with the Distribution Code or a licence condition imposed by the Minister.

197 Negotiated connection services: Where the connection service is neither a basic nor a standard connection service, a distributor and connection applicant must negotiate the terms and conditions of the connection contract. The negotiations are governed by the negotiation framework set out in Part C of chapter 5A.

198 As noted above, most new and enhanced connections above the 'basic connection' threshold comprise negotiated connections.

199 Each party must negotiate in good faith, and provide the other with information reasonably required in order to negotiate on an informed basis. For the DNSP, this includes providing the connection applicant with an estimate of the amount to be charged by the DNSP for assessment of the application and the making of a negotiated connection offer, an estimate of connection charges and a statement of the basis on which connection charges are calculated. In addition, the DNSP must assess the technical requirements for the proposed new connection or connection alteration, the extent and costs of any necessary augmentation of the distribution system, and any possible material effect of the proposed connection service on the network power transfer capability of the distribution network.

200 The DNSP has a reasonable endeavours obligation to make a connection offer that complies with the connection applicant's reasonable requirements. The negotiation framework does not contain time limits or guidelines for setting timeframes for connection work in negotiated arrangements.

Connection offer and acceptance

201 Different timeframes for the offer and acceptance of connection offers apply depending on the type of connection service.

202 Basic or standard connections (normal): A DNSP must use best endeavours to make an offer within 10 business days of receiving a complete connection application. The connection offer must be in accordance with the relevant model standing offer, and include a statement of the connection charges payable by a connection applicant. The offer remains open for acceptance for 45 business days from the date of offer, unless extended by agreement.

203 Basic or standard connections (expedited): A DNSP is taken to have made the offer, and a connection applicant is taken to have accepted the offer, on the date the full application was received.

204 Negotiated connections: A DNSP must use best endeavours to make an offer within 65 business days after the full connection application was received. The offer must open for acceptance for 20 business days, unless extended by agreement.[75]

Minimum content requirements – Connection offers

205 Schedule 5A.1 of chapter 5A sets out minimum content requirements for a connection offer, and distinguishes between content required for connection offers not involving embedded generation (Part A), and connection offers involving embedded generation (Part B).

206 In each case (Part A and Part B), a connection offer must contain an undertaking to complete the work required to establish the connection within a specified time frame, details of the DNSP's monetary obligations to the retailer customer or embedded generator, and a provision requiring the DNSP to provide information about the connection to the retail customer or embedded generator.

[75] NER, r 5A.F.4.

Connection Charge Principles, Policy and Guidelines

207 The regulatory regime for connection charges comprises two overlapping regimes.

(a) Connection services are covered by AER distribution determinations made under chapter 6 of the NER, typically as either 'direct control' or 'alternative control' services.

(b) However, connection charges are also regulated under the DNSP's connection policy (established via AER's Connection Charge Guidelines), which govern the most controversial issue, being the capital costs payable by customers for new or expanded connections.

208 For completeness, section 15D of the EI Act provides that the Governor in Council may, by Order published in the Government Gazette, specify the principles to be applied by an operator of a relevant distribution system in determining connection charges for connection to, and use of, the relevant distribution system by a relevant generator in relation to electricity supplied from a generation facility opened by that generator so as to enable that operator to recover the capital costs that operator has incurred or may incur in respect of a relevant augmentation. As at the date of this application, the Governor in Council has not made an Order to that effect.

209 Rule 5A.E.1 of the NER outlines connection charge principles which a DNSP must apply in determining connection charges in accordance with its connection policy. Generally, if an extension to the distribution network, or augmentation of premises connection assets at a retail customer's connection point or of the distribution system, is necessary to provide a connection service, the connection charge may include a reasonable capital contribution towards the cost of such extension or augmentation as necessary to provide the service. A capital contribution may only be required if provision for the costs has not already been made through existing distribution use of system charges or a tariff applicable to the connection.

210 Part DA of chapter 6 of the NER requires a DNSP to prepare a connection policy setting out the circumstances in which it requires a retail customer or real estate developer to pay a connection charge for the purposes of chapter 5A.

211 The connection policy must comply with the connection charge principles set out in Rule 5A.E.1 above, and the connection charge guidelines, which are developed and published by AER under Rule 5A.E.3.

212 AER released its proposed updated Connection Charge Guidelines for Electricity Customers on 11 October 2022 (***Connection Charge Guidelines***) (the changes were modest, and related to micro embedded generators) and invited submissions on the Connection Charge Guidelines by 21 November 2022.

213 The Connection Charge Guidelines apply to connections of retail customers to both the interconnection national electricity system, as well as for connections to Regulated Stand-alone Power Systems.

214 An aim of the Connection Charge Guidelines is to ensure that connection charges are reasonable (taking into account the efficient costs of providing the connection services), to limit cross-subsidisation of connection costs between different classes (or subclasses) of retail customers, and, if the connection services are contestable, are competitively neutral.[76]

215 The treatment of connection charges under the Connection Charge Guidelines can be broadly described into five categories, set out in the below table.

[76] NER, r 5A.E.3.

Figure 2: Connection charge treatment – Connection Charge Guidelines

Category	Description	Connection charges
Ongoing connection or energisation	Ongoing connection of existing customers of the distribution network Energisation of existing connection without any works.	Capital contribution is not required. As a connection charge principle under chapter 5A (see above), connection charges may only be required in circumstances where the augmentation or extension of the distribution network is required to facilitate the connection service.[77]
New connection with minimal capital cost	New or modified connection requiring Capital contributions below the DNSP's shared network augmentation charge threshold	Capital contribution is not required. Retail customers will not be required to make a capital contribution towards the cost of an augmentation (insofar as it involves more than an extension) if it is below the shared network augmentation charge threshold. *See further discussion below.*
New connection with substantial capital cost	New or modified connection requiring Capital contributions above the DNSP's shared network augmentation charge threshold for standard control connection services	For customers above the shared network augmentation charge threshold, customers must pay the total capital contribution payable to the DNSP for services classified as standard control services in accordance with Rule 6.2 of the NER. *See further discussion below.*
Negotiated distribution services	AER classifies a connection service as a negotiated distribution service in accordance with clause 6.2.1 of the NER. In practice these are very unusual services, such as undergrounding power lines.	The treatment of negotiated distribution services is set out in Section 3 of the Connection Charge Guidelines. If AER classifies a connection service as a negotiated distribution service in accordance with clause 6.2.1 of the NER, the charge for these connection services will be agreed by the connection applicant and relevant service provider.[78] AER note that it considers that these service classifications are likely to be applied in circumstances where the connection service is provided in a competitive or contestable market. The terms and conditions applied to connection services which are classified as negotiated must be in accordance with any applicable requirements of chapter 5A and be consistent with the Connection Charge Guidelines.[79] Charges for components of a real estate developers, Registered Participant's, Intending Participant's, or embedded generator's connection that are classified as negotiated services will be calculated in accordance with Section 3 of the Connection Charge Guideline.[80]
Unclassified distribution services	It is possible some connection services are not classified by AER. In practice, these are rare.	The treatment of unclassified distribution services is also set out in Section 3 of the Connection Charge Guidelines. If a distribution service is not classified in accordance with Rule 6.2.1 of the NER, the charge for unclassified distribution services will be agreed by the connection applicant and relevant service provider.[81]

[77] NER, r 5A.E.1.
[78] Australian Energy Regulator, *Connection charge guidelines for electricity retail customers*, draft version 3 (October 2022) s 3.1.2 (***Connection Charge Guidelines***).
[79] Connection Charge Guidelines, s 3.1.3.
[80] Connection Charge Guidelines, ss 7.1.2 and 8.1.3.
[81] Connection Charge Guidelines, s 3.1.2.

Category	Description	Connection charges
		AER note that a service may be unclassified if the DNSP is preventing from performing these services by jurisdictional requirements or ring-fencing arrangements. The terms and conditions applied to connection services which are unclassified must be in accordance with any applicable requirements of chapter 5A and be consistent with the Connection Charge Guidelines.[82] Charges for components of a real estate developer's, Registered Participant's, Intending Participant's, or embedded generator's connection that are unclassified will be calculated in accordance with Section 3 of the Connection Charge Guideline.[83]

Connections below the DNSP's shared network augmentation charge threshold

216 A DNSP's connection policy must include a threshold or thresholds (referred to in the Connection Charge Guidelines as a 'shared network augmentation charge threshold'). Retail customers will not be required to make a capital contribution towards the cost of an augmentation (insofar as it involves more than an extension) if it is below the shared network augmentation charge threshold.

217 This shared network augmentation charge threshold applies to any connection offer made under chapter 5A, regardless of the manner in which augmentation (insofar as it involves more than an extension) is classified.[84]

218 All shared network augmentation charge thresholds must be based on a measure of demand, and fixed for the duration of the regulatory control period.[85]

219 The characteristics which a shared network augmentation charge threshold should have includes the requirement that the threshold is set so that no undue cross subsidies are created between new connection applicants and existing network users.

Connections above the DNSP's shared network augmentation charge threshold

Payment of incremental capital cost

220 For customers above the shared network augmentation charge threshold, customers must pay the total capital contribution payable to the DNSP for services classified as standard control services in accordance with Rule 6.2 of the NER.

221 A DNSP may seek the capital contribution for standard control connection services if the incremental cost of the standard control connection service exceeds the estimated incremental revenue expected to be derived from the standard control connection service.[86]

222 The amount of any capital contribution is to be calculated as the difference between the incremental revenue and the incremental cost attributable to the standard control services required by the connection applicant. Where the capital contribution is less than zero, no capital contribution is payable by the connection applicant, or the DNSP.[87]

[82] Connection Charge Guidelines, s 3.1.3.
[83] Connection Charge Guidelines, ss7.1.2 and 8.1.3.
[84] Connection Charge Guidelines, s1.1.1.
[85] Connection Charge Guidelines, s1.1.2.
[86] Connection Charge Guidelines, s 5.1.2.
[87] Connection Charge Guidelines, s 5.1.3.

223 A DNSP's connection charge policy must also ensure that operational and maintenance costs have no net impact on the capital contribution payable by the connection applicant.[88]

Principles for determining incremental cost

224 In determining the incremental cost, a DNSP should:

(a) determine the cost in a fair and reasonable manner and ensure that the cost estimate is reflective of the efficient costs of performing the service; and

(b) calculate the cost based on the least cost technically acceptable standard necessary for the connection service.[89]

225 If jurisdictional regulations permit, a DNSP should provide an option of conducting a tender process on behalf of the connection applicant, or allow a connection applicant to conduct a tender process, to procure those connection services that can be provided by a third party.[90]

226 Further, if a DNSP prepares a technical specification to allow a connection service to be performed on a contestable basis, then the technical specification cannot require the connection service to be performed to higher than the least cost technically acceptable standard or a capacity greater than the connection applicant's requirement, unless the DNSP makes arrangements to fund the additional cost of achieving the higher standard, or capacity.[91]

Pre-calculated capital contributions for basic and standard connection offers

227 If a DNSP considers that all connection applicants receiving a basic or standard connection offer have substantially the same connection service and expected usage characteristics, then the DNSP may charge a pre-determined capital contribution charge from each connection applicant within the class.[92]

228 The amount of the pre-calculated charge must be included in a DNSP's basic or standard connection offers and should:

(a) not create unreasonable cross subsidisation within the class; and

(b) be reflective of the average or typical capital contribution that would be charged to connection applicants within the class, if the cost-revenue test was individually applied to each connection applicant's connection service.[93]

At the State level, the ESC has the power to regulate prescribed prices in respect of prescribed goods and services in respect of charges for connection to, and use of, any distribution system.[94] The Minister may also determine, by notice published in the Government Gazette, the fees and charges specified in respect of a licence, including the minimum, maximum and scales of fees and charges according to the value of services provided.[95]

Contractual performance

229 The DNSP must use best endeavours to ensure that connection work is carried out within the applicable time limits fixed under the connection contract.

230 It is not obliged to commence or continue the connection work if the connection applicant fails to comply with conditions that are to be complied with by it.[96] For example, if the connection applicant fails to pay connection charges, comply with technical or safety requirements, complete

[88] Connection Charge Guidelines, s 5.1.5.
[89] Connection Charge Guidelines, s 5.2.1.
[90] Connection Charge Guidelines, s 5.2.3.
[91] Connection Charge Guidelines, s 2.1.5.
[92] Connection Charge Guidelines, s 5.5.1.
[93] Connection Charge Guidelines, s 5.5.2.
[94] EI Act, s12(1)(b).
[95] EI Act, s 22.
[96] NER, r 5A.F.6.

work that is to be carried out on the connection applicant's premises, or to provide safe unhindered access to the connection applicant's premises.

231 At the state level, these provisions are mirrored in the Distribution Code. Section 3.2 provides that where a connection application has been made by a customer, or by a retailer on behalf of a customer, a distributor must comply with its obligations under the NER in responding to the connection application and carrying out the connection work. Similarly, section 3.6 provides that where a connection application has been made by an embedded generator, a distributor must comply with its obligations under the NER in responding to the connection application (including making a connection offer and entering into a connection contract).

232 Further to chapter 5A, under section 3.5 of the Distribution Code, a distributor's obligations in relation to new connections are subject to:

(a) an adequate supply of electricity being available at the required voltage at the boundary of the new supply address;

(b) the customer complying with its obligations regarding equipment and access to the customer's premises under the Distribution Code;

(c) the customer providing acceptable identification; and

(d) the customer complying with the conditions for connection set out in its connection contract.

233 The Distribution Code otherwise provides that a DNSP must comply with its obligations 'as soon as reasonably practicable' after the removal or elimination of the reason for which connection was not made above.[97]

234 If the timeframe for carrying out connection work is specified in a connection contract by reference to the Distribution Code, the distributor must connect the supply address within 10 business days after the connection application.[98]

235 Under the EI Act, the ESC may specify requirements on a distributors licence relating to the connection of supply of electricity, including timeframes for the completion of: (i) connections or classes of connections of the supply of electricity under negotiated connection contracts; and (ii) specified steps for the completion of connections or classes of connections under negotiated connection contracts.[99]

236 Further to the specific conditions which the ESC may impose on a distributor's licence, the Minister may also specify conditions on a particular licence or class of licences as it thinks fit.[100] This may relate to the connection of supply of electricity to premises, including timeframes for completion of connections under negotiated connection contracts. The specific licence conditions imposed by the Minister would take precedence over those imposed by the ESC to the extent of any inconsistency.[101] For completeness, on 18 November 2021, the Minister published an Order in the Government Gazette specific to the AusNet licence. The Order modified parts of the application of an historical version of the Distribution Code (version 13) to the AusNet licence, which related to timing for payments required for guaranteed service levels, and supply restoration and low reliability payments to customers.

[97] Distribution Code, s 3.5.2.
[98] Distribution Code, sch 5, s 3.
[99] EI Act, s 21(v).
[100] EI Act, s 33AB.
[101] EI Act, s 33AJ.

Energisation[102]

237 Under Rule 5A.F.7 of the NER, a distributor is not required to energise a new connection unless a request to energise the new connection is submitted by a retailer, or the distributor is otherwise satisfied that there is a relevant contract with a retailer in relation to the premises.

238 Under the Distribution Code, where a customer only requires energisation, a distributor must use best endeavours to energise a customer's supply address within:

(a) one business day (if the request is made to the distributor by 3pm); or

(b) within two business days (if the request is made after 3pm, provided that the customer gives acceptable identification to the distributor or the customer's retailer).[103]

239 'Best endeavours' under the Distribution Code means, in relation to a person, the person must act in good faith and do all that is reasonably necessary in the circumstances.

240 Similar to chapter 5A, a distributor must *not* energise a customer's supply address (except in situations where there is an emergency or as expressly required by the Distribution Code) unless the request to energise has been made by the customer's retailer, or the request is made by a customer and the distributor is satisfied that the customer has engaged a retailer or the customer is a market customer.[104]

Contestable connection services in Victoria – Requirements

241 Under the AER's Connection Charge Guidelines, if jurisdictional regulations permit, a DNSP should provide an option of conducting a tender process on behalf of the connection applicant, or allow a connection applicant to conduct a tender process, to procure those connection services that can be provided by a third party.[105]

242 In Victoria, section 12A of the NEVA provides that the Governor in Council may make regulations requiring a distribution company to call for tenders for works to augment or extend a distribution system for the purpose of connecting generating units or customer premises to the system. As at the date of this submission, the Governor in Council has not made regulations or declarations to that effect under the NEVA.

243 Instead, section 5.2 of the Distribution Code provides that a DNSP must call for tenders for any construction works if it proposes to augment its distribution network in connection with its provision of the following services:

(a) a connection service requested by a connection applicant;

(b) undergrounding;

(c) services to other distributors such as power transfer capability services; and

(d) public lighting services.

244 The DNSP must invite at least two other persons who compete in performing works of that kind (or are capable of so competing) to provide (i) information as to their availability to do the works; (ii) information as to the price of the works; and (iii) any terms and conditions which may apply to such works.[106]

[102] Energisation refers to the activation of an existing connection point to allow for the flow of energy through the electricity transmission and distribution system to or from a customer's point of supply.
[103] Distribution Code, cl 3.4.1.
[104] Distribution Code, cl 3.3.1.
[105] Connection Charge Guidelines, s 5.2.3.
[106] Distribution Code, cl 5.2.2.

245 The DNSP may call for tenders in advance of the services being required, and provide the person to whom the offer is made with contact details and prices of services of persons who have participated in the tender process.[107]

246 The DNSP's obligation to call for tenders does not apply:

(a) if, despite the DNSP's best endeavours, it is not able to identify two other persons who compete in performing works of that kind (or are capable of so competing);

(b) to the extent that the augmentation involves design services;

(c) to the extent that the augmentation involves services that cannot be safely or lawfully carried out by a third party; or

(d) if the person to whom the offer is to be made agrees with or instructs the distributor that no tenders should be called for.[108]

Tendering policies

247 A DNSP must develop a tendering policy and publish it on its website and provide a copy to any person on request. The DNSP must also notify the ESC of any change to its tendering policy.[109]

248 Under clause 5.3.1, the tendering policy must:

(a) state the objectives of the DNSP's tendering policy;

(b) specify when the DNSP is obliged to call for tenders;

(c) specify any augmentation works or services relating to augmentation that will not be tendered;

(d) set out a timeframe for the tender process;

(e) specify any accreditation or other pre-conditions a person must satisfy if that person is to be eligible for performing any particular type of augmentation works or services;

(f) not unreasonably discriminate and must not allow for unreasonable discrimination, against persons who may compete with the DNSP in performing augmentation works (or who are capable of so competing);

(g) specify the basis on which the distributor may recover the costs it incurs in conducting the tender (or participating in a tender that a customer may prefer to conduct), including payment terms; and

(h) include a process for handling disputes. See further detail regarding the dispute resolution requirements from section 260 to 271 below.

249 AusNet's tendering policy, approved in September 2022, describes the policy which applies for tenders for the AusNet electricity distribution network, and has been developed in accordance with the Distribution Code (***AusNet Tender Policy***). Relevantly, the AusNet Tender Policy sets out the circumstances where a retail customer, real estate developer or other authorised party may seek contestable work practices, including a call for tenders, to occur as part of their required connection services and network alterations.

250 Part 3 of the AusNet Tender Policy provides that certain tasks can only be undertaken by AusNet for safety and operational reasons (such as auditing third party network system designs and connection assets). Contestable services which can be undertaken by a third party include:

(a) project management and running a tender;

[107] Distribution Code, cl 5.2.3.
[108] Distribution Code, cl 5.2.4.
[109] Distribution Code, cl 5.4.

(b) some design (including surveying and drafting services); and

(c) construction (which includes the provision of all materials and 'as constructed' plans).

251 AusNet maintains a list of approved accredited service providers for work on its electricity distribution network, which have demonstrated the necessary qualifications, training, experience and quality systems of work to provide the contestable services lawfully and safely (***Approved Contractors***), and from which a customer can elect to use (instead of AusNet) to provide contestable services. The list of AusNet's approved accredited service providers is available through the EnergyConnect portal on the AusNet website. The AusNet Tender Policy provides that AusNet have approved multiple service provides across the full range of work types, including electric construction capability, complex civil construction capability, fibre optics/comms, design and drafting, and project management. When conducting a tender process, AusNet requires that its publicly available technical standards apply, with a design AusNet has approved, and that the appointed service provider be an Approved Contractor, as applicable.

252 If the customer elects to use an Approved Contractor appointed by tender, the customer can request an Approved Contractor project manager undertake the tender or that AusNet conduct the tender exercise on their behalf, prior to establishing a connection agreement and requesting an Authority to Commence Contestable Construction with AusNet.

253 Part 5 of the AusNet Tender Policy sets out the contestable options which AusNet provides, and provides that AusNet is committed to not unreasonably discriminate against accredited service providers. AusNet typically offers customers the choice to have:

(a) AusNet provide design and construction services;

(b) AusNet provide design only and an Approved Contractor to provide construction services; or

(c) Approved Contractors to provide design and construction services.

254 In some instances, AusNet advises customers to conduct part of construction works (such as civil works, excavation, and trenching) with a contestable service provider to avoid delays due to a lack of available resources.

255 All contestable service designs are subject to AusNet's approval, as AusNet must ensure that designs are technically appropriate and consider the overall impact and potential future needs of the electricity network.

256 Where the customer appoints an Approved Contractor to provide construction services, the customer must also appoint a project manager from the Approved Contractor list. The appointed project manager will typically run any tender processes the customer instructs, as it is often less costly and more timely than AusNet running a tender. If AusNet is requested to undertake the construction works, AusNet will typically use its master service provider that was tendered in advance of the services being requested.

257 AusNet does not provide connection or network alteration applicants with contestable work that cannot be safely or lawfully carried out by an Approved Contractor. The AusNet Tender Policy provides that such work would typically include work inside AusNet's station assets or on highly specialised equipment. AusNet may also preclude the use of contestable work on augmenting existing shared network assets. In those circumstances, AusNet may use a master service provider that is tendered in advance.

258 AusNet currently has appointed a master service provider that undertakes nearly all augmentation, extension and networks alterations construction work on its electricity distribution network. The current appointed service provider was engaged by tender process with, at least, two capable service providers.

259 Compliance audits of the Approved Contractor's work must be completed to ensure it complies with AusNet's construction standard prior to connection. The customer must pay an audit fee for the inspection, and any necessary subsequent inspections.

Dispute resolution – Sequence

260 Part G of Chapter 5A (as implemented under the NEVA) sets out the dispute resolution procedure between a DNSP and customers (being a retail customer or a real estate developer) for relevant disputes. A 'relevant dispute' includes a dispute between a DNSP and a customer regarding:

(a) the terms and conditions on which a basic connection service or a standard connection service is to be provided;

(b) the proposed or actual terms and conditions of a negotiated connection contract; or

(c) connection charges.

261 Under the NEVA, a 'relevant dispute' is treated as an 'access dispute' under the access determination regime in the NEL (as adopted by the NEVA, with some modifications under section 47). Under the NEVA, 'access dispute' refers to a dispute between a network service user (or prospective network service user) and a network service provider about an aspect of access to an electricity network service or a dispute between a retail customer (or other person specified by the Rules) and a regulated distribution system operator about an aspect of access to a connection service.

262 The AER must make a determination on access by (as the case requires) the prospective network service user or network service user. The determination must be in writing, include a statement of reasons for making the determination, and be given to the parties without delay.[110]

263 In determining a dispute, the AER must give effect to the relevant connection policy, the model standing offer (as relevant for basic or standard connection services), Chapter 5A and any other applicable regulatory instrument (such as the Distribution Code).

264 The AER may also have regard to other matters it considers relevant, hear evidence or receive submissions from the DNSP and the customer and, if the dispute relates to a negotiated connection contract, have regard to the negotiation framework set out in clause 5A.C.3 of Chapter 5. Notably, the negotiation framework includes the requirements for each party to negotiate with each other in good faith and to share information reasonably required so as to negotiate with each other on an informed basis.

265 The AER may require the parties, in accordance with the NER, to mediate, conciliate, or engage in another alternative dispute resolution process for the purpose of resolving the access dispute.[111] In certain circumstances, the AER may terminate an access dispute without making an access determination. For example, if the AER considers the notification of the access dispute was vexatious, or the subject matter of the dispute is trivial, misconceived or lacking in substance.

266 An access determination may, but need not, require a network service provider to provide an electricity network service to a prospective network service user.[112]

267 If the AER considers that the dispute could be effectively resolved by other means, the AER may give the parties notice of such alternative. For example, the AER may give notice if the AER believes that the dispute could be dealt with more efficiently, and with less expense, by a jurisdictional ombudsman (ie, the Energy and Water Ombudsman (Victoria)) who administers a customer dispute resolution scheme approved by the ESC.[113] The giving of such a notice is a

[110] NEVA, s 128.
[111] NEVA, s 129(1).
[112] NEVA, s 134.
[113] NEVA, s 5A.G.3.

'specified dispute termination circumstances' for the purposes of section 131(3) of the NEVA, which entitles the AER to terminate an access dispute without making an access determination.

268 In addition, section 18 of the Distribution Code provides that a DNSP must handle a complaint by a customer in accordance with the *Australian Standard ISO 10002:2018* (Quality management – Customer satisfaction – Guidelines for complaints handling in organisations) and must include information on its complaint handling processes in its website. When a DNSP responds to a customer's complaint, the DNSP must inform the customer that the customer has a right to raise the complaint to a higher level within the DNSP's management structure and, if the customer is still not satisfied with the DNSP's response, to refer the complaint to the energy ombudsman or other external dispute resolution body.

269 Under the EI Act, a distribution licence must include a condition requiring the licensee to enter into a customer dispute resolution scheme approved by the ESC. In approving a customer dispute resolution scheme, the ESC must have regard to (among other things) the need to ensure that the scheme is accessible to the licensee's customers and that there are no cost barriers to those customers using the scheme, and the need for the scheme to undertake regular reviews of its performance to ensure that its operation is efficient and effective. In Victoria, the Energy and Water Ombudsman (Victoria) is the independent industry-based dispute resolution scheme which has been approved by the ESC.

270 If a distributor contravenes the Distribution Code, the ESC may also vary the distributor's licence or licence condition without the licensee's consent under the EI Act. The ESC must specify the action that the licensee is required to take to rectify a contravention, and to prevent any future contravention of the licence condition or provision of the Distribution Code.

271 In addition, the AusNet Customer Complaint and Dispute Resolution Policy, approved in July 2019, sets out the process which AusNet follows when it receives a complaint or dispute (***Dispute Resolution Policy***). Importantly, in accordance with the requirements of the Distribution Code, the Dispute Resolution Policy acknowledges that AusNet will handle disputes and complaints in accordance with the principles of international industry standards, and alerts customer's to their right to raise the complaint to a higher level within AusNet's management and otherwise to the Energy and Water Ombudsman (Victoria) or other external dispute resolution body.

(e) Distribution augmentation

RIT-D

272 As noted above, the RIT is a cost benefit analysis used for both transmission and distribution projects – for DNSPs, the relevant test is the Regulatory Investment Test for Distribution (***RIT-D***). A RIT-D proponent is required to apply the RIT-D to any project which has the purpose of meeting an identified need, though there are a number of exceptions to this requirement, including where the estimated capital cost of the most expensive option to address the identified need which is technically and economically feasible is less than $6 million, and where the project is to address an urgent or unforeseen network issue or involves maintenance work that is not intended to augment the network.[114]

273 As noted above, the process to be followed by RIT proponents is set out in chapter 5 of the NER. For distribution projects, the first step for the RIT-D proponent is to publish a non-network options report. As with the PSCR for transmission projects, the non-network options report is consulted on, and submissions are taken into account when developing the draft RIT report – for distribution

[114] See clause 5.17.3(a)(2) for RIT-Ds. While this provision refers to $5 million, this value is subject to variation in accordance with a cost threshold determination. Under the AER's most recent cost threshold determination (which took effect on 1 January 2022), the value of this threshold is now set at $7 million and $6 million for transmission and distribution projects respectively. See: AER, Final Determination - Cost thresholds determination, November 2021.

projects, this is the Draft Project Assessment Report (***DPAR***). Like the PADR for transmission projects, this report outlines, among other things, each credible option assessed and the proposed preferred option.[115] The DPAR is consulted on by stakeholders, after which the RIT proponent must publish a final RIT report – for distribution projects, this is the Final Project Assessment Report (***FPAR***). Like the PACR for transmission projects, the FPAR must, among other things, outline any submissions received in relation to the draft RIT report.

274 The dispute resolution process that applies to the RIT-T process (refer above) applies in the same way to the RIT-D process. Relevant parties are able to raise disputes with AER in relation to the conclusions made by the RIT-D proponent in a FPAR, on the grounds that either:

(a) the proponent has not applied the RIT-D in accordance with the NER; or

(b) there was a manifest error in the calculations performed by the DNSP in applying the RIT-D.

275 As noted above, AER may then either reject a dispute or make a determination. AER may only direct a DNSP to amend its FPAR where AER has determined that one of the above grounds is made out, ie, either that the DNSP has not correctly applied the RIT-D in accordance with the NER, or where the DNSP has made a manifest error in its calculations.

(f) Distribution maintenance of existing assets

276 The regulation of existing asset maintenance of the distribution network operates in largely the same manner as regulation of the transmission network, as described in 1.2(v) above. In particular:

(a) the requirements with respect to performance standards for transmission network assets described in paragraphs 89 - 91 apply equally to distribution network assets;

(b) the requirements in relation to connection agreements described in paragraphs 94 - 96 apply to DNSPs in the same way as they apply to TNSPs;

(c) the information required to be included in the TAPR in relation to asset retirements and de-rating and the TNSP's asset management approach is in similar terms in the DAPR; and

(d) the obligations with respect to the provision of information on planned network outages (but not planned maintenance) to AEMO for the purposes of the PASA described in paragraph 101 apply in the same way to DNSPs as to TNSPs.

The principal difference between the regimes is that AEMO does not exercise a unique planning and augmentation function in relation to the Victorian distribution network in the same way as it does in relation to the Victorian transmission network, and so AusNet (rather than AEMO) has principal responsibility for the preparation of the DAPR in relation to its distribution network.

Electricity licences and registrations

277 Given the importance of the electricity supply industry, the key industry functions are subject to licensing and registration requirements, both under the NER and under State and Territory laws.

(i) Transmission licensing

278 In all NEM jurisdictions, a licence or authority is required to engage in the transmission or distribution of electricity.

[115] The RIT proponent is not required to publish a DPAR if, among other things, the estimated capital cost of the proposed preferred option is less than $12 million: clause 5.17.4(n)(2) of the NER; AER, Final Determination - Cost thresholds determination, November 2021.

279 Section 11(2) of the NEL provides that a person must not own, control or operate a transmission system or distribution system that forms part of the interconnected national electricity system or that forms part of, or is connected to, a Regulated Stand-alone Power System, unless that person is registered by AEMO as a Registered Participant or an exemption applies. Failure to register attracts civil penalties. Likewise, Rule 2.5.1 of the NER provides that a person must not engage in the activity of owning, controlling or operating a transmission system (or distribution system) unless that person is registered by AEMO as a Network Service Provider.

280 A prospective NSP must apply for registration in the NEM as a 'Network Service Provider', which is a category of a Registered Participant, in accordance with Rule 2.9 of the NER. If AEMO is satisfied that the applicant meets the eligibility criteria for an NSP and has demonstrated an ability to comply with the NER, AEMO will determine that an applicant is to be registered as a Registered Participant. Further information regarding the registration process is available in the 'Guide to Registering as a Network Service Provider in the NEM'[116] published by AEMO.

281 If the applicant is successfully registered, the TNSP will be subject to various specific obligations under the NEL and NER, including to (among other things) build, maintain, plan and operate the network transmission networks in the NEM, as well as comply with reporting (including to AEMO and AER) and ring-fencing obligations (see section 1.5 of this application for further information).

282 In addition to the NEM legislation, the Australian states and territory have their own laws which regulate the generation, transmission, distribution, supply and sale of electricity, specific to that state or territory. In Victoria, Section 16 of the *Electricity Industry Act 2000* (Vic) (***EIA***) provides that a licence is required to engage in the transmission, distribution, generation, supply or sale of electricity, unless an exemption or waiver applies.[117] The licensing regime is administered by the ESC of Victoria. Similarly, a failure to obtain a state licence attracts civil penalties.[118]

283 The grant of the licence may be subject to conditions determined by the ESC, which may include preventing the licensee from engaging in or undertaking specified business activities, or specifying methods or principles to be applied in the conduct of activities or in determining prices or charges.[119] The ESC must not grant an application for the issue of a licence unless the ESC is satisfied that the applicant has the technical capacity to comply with the conditions of the licence.[120] These specific conditions are in addition to standard conditions which are deemed to be included under all licences, such as the requirement for the licensee to give information to the ESC.[121]

(ii) Distribution licensing

284 With respect to the NEM registration process under the NEL and NER, the same licensing requirements for a TNSP above apply to a DNSP.[122]

285 Likewise, in Victoria, the licensing regime for transmission and distribution are identical, and captured by the same provisions under the EIA. The ESC may similarly impose specific licence conditions on a distribution licensee (see paragraph 283 above).

[116] AEMO, *Guide to Registering as a Network Service Provider in the NEM* (2021) <https://aemo.com.au/-/media/files/electricity/nem/participant_information/nem-network-service-provider-registration-guide.pdf>.
[117] EI Act, s16.
[118] EI Act, s 16(1B) provides that s16(1) is a civil penalty requirement for the purposes of the *Essential Services Commission Act 2001* (Vic). S16(1A) of the EI Act provides that contravention attracts a penalty of 1000 penalty units and 100 penalty units for each day after the day on which a notice of contravention of that subsection is served on the person by the ESC.
[119] EI Act, s 21.
[120] EI Act, s 19(2)(b).
[121] EI Act, s 23A.
[122] NEL, s11(2); NER, cl 2.5.1(a).

(iii) Generation licensing

286 The regulatory framework which governs electricity generation also requires generators to register as a Generator in the NEM and obtain all required state-based licences and approvals to operate as a Generator.

287 Section 11(1) of the NEL provides that a person must not own, control or operate a generating system connected to the interconnected national electricity system, or connected to a Regulated Stand-alone Power System, unless that person is registered by AEMO as a Registered Participant, or an exemption applies. An automatic exemption applies for generating units with less than 5 MW nameplate capacity. Penalties apply for failing to register. Likewise, Rule 2.2.1 of the NER provides that a person must not engage in the activity of owning, controlling or operating a generation system that is connected to a transmission system or distribution system unless that person is registered by AEMO as a Generator.

288 The applicant must be registered with AEMO before the commissioning phase in which energy is sent out to the national grid from the generating system. A prospective Generator must apply for registration in the NEM in accordance with Rule 2.9 of the NER. To be eligible for registration as a Generator, among other things, the applicant's generating systems must be capable of meeting or exceeding AEMO's performance standards.[123] Further information regarding the registration process is available in the 'Application Guide for Registration as a Generation in the NEM'[124] published by AEMO.

1.5 Ring-fencing

289 Given the perceived monopoly-like position of NSPs in a variety of settings, there has a been a long history of ring-fencing requirements in the electricity transmission and distribution sectors.

290 The key purpose of ring-fencing is to address potential risk arising from vertical integration in the energy market. Ring-fencing in the energy market seeks to prevent NSPs from using their status as monopoly-like service providers to distort outcomes in contestable markets where vertical integration exists. The ring-fencing guidelines, discussed in further detail below, therefore implicitly contemplate that vertical integration is a feature of the energy market structure, and mitigates such risk by placing restrictions on NSP behaviour to prevent them from taking advantage of their position.

291 This purpose is achieved by the regulatory framework contained in the ring-fencing guidelines, which seeks to both promote the development of competitive markets in which a NSP operates and address anti-competitive conduct through regulations on NSPs around cross-subsidisation and discriminatory behaviour. These regulations range from functional control, legal separation requirements, and compliance reporting obligations. Through these measures, the ring-fencing guidelines target and limit the ability of a NSP from using their market power in favour of related entities which operate in other competitive areas of the electricity supply chain.

(g) NSP Ring-fencing Guidelines

292 Under the NER, all Network Service Providers are required to comply with ring-fencing guidelines. A TNSP must comply with the TRFG,[125] and a DNSP must comply with the DRFG[126] (together, the ***NSP Ring-fencing Guidelines***). Each of the guidelines are prepared by AER.[127] The AER amend and update the NSP Ring-fencing Guidelines, as required. This importantly

[123] NER, cl 2.2.1(3).
[124] AEMO, *Application Guide for Registration as a Generator in the NEM* (2022) <https://aemo.com.au/-/media/files/electricity/nem/participant_information/nem-network-service-provider-registration-guide.pdf>.
[125] NER, cl 6A.21.1.
[126] NER, cl 6.17.1.
[127] NER, cl 6A.21.2 in respect of the TRFG; NER, cl 6.17.2 in respect of the DRFG.

allows AER to take an active role in addressing new or potential competition concerns and changes in circumstances through the regulatory framework.

293 Ring-fencing refers to the separation of monopoly services (such as those offered by a TNSP or DNSP) and contestable services where a regulated business also offers services into a competitive market. An aim of ring-fencing is to prevent regulated business from using revenue earned from regulated services to cross-subsidise contestable services, and discriminating in favour of their related parties to disadvantage competitors operating in the same market. Accordingly, the key objectives of the NSP Ring-fencing Guidelines are to:

(a) promote the National Electricity Objective by providing for the accounting and functional separation of the provision of Prescribed Transmission Services (by a TNSP) or Direct Control Services (by a DNSP), from their (or their affiliates) provision of Other Services; and

(b) promote competition in the provision of electricity services.

294 In respect of the TRFG, AER published Version 4 of the guidelines in March 2023. A TNSP is required to comply with the guidelines by 1 March 2024, or otherwise continue to comply with Version 3 of the guideline.[128] Notwithstanding, the instances listed below require a TNSP's immediate compliance with the TRFG:

(a) compliance breach reporting within 15 days to AER;[129]

(b) prohibition against TNSP entry into new agreements, or against agreeing to a material variation to an existing agreement, for the leasing of excess capacity from batteries (as a protection for the development of competition in the grid-scale battery market);[130]

(c) annual compliance reporting;[131] and

(d) requirement for service providers (which assist a TNSP in providing Prescribed Transmission Services) under any new or varied agreements with a TNSP to comply with the same functional separation obligations as the TNSP.[132]

295 In respect of the DRFG, AER published Version 3 of the guidelines in November 2021. A DNSP was required to comply with the guidelines from 3 February 2022, subject to any waivers.

296 The NSP Ring-fencing Guidelines offer several common protections against anti-competitive conduct by a TNSP or DNSP (as relevant under the TRFG or DRFG), summarised below:

Prevention of cross subsidies

(a) **Legal separation**: Legal separation aims to provide transparency and assurance around the accounting and cost allocation measures between different services which are offered by an NSP.[133]

A TNSP may provide Transmission Services but must not provide Other Services without a waiver from AER.[134] If a TNSP is also a regulated DNSP it can provide Distribution Services, as long as it also complies with the DRFG.[135] Transmission Services include

[128] AER, *Ring-fencing Guideline Electricity Transmission Version 4* (March 2023) cl 7 <https://www.aer.gov.au/system/files/AER%20-%20Electricity%20Transmission%20Ring-fencing%20Guideline%20Version%204%20-%20Clean.pdf> (***TRFG***).
[129] TRFG, cl 6.3.
[130] TRFG, cl 3.1(c) .
[131] TRFG, cls 6.2.1 and 6.2.2.
[132] TRFG, cl 4.4.1(a).
[133] AER, *Electricity transmission Ring-fencing Guideline - Explanatory Statement Version 4* (March 2023) s 2.1 <https://www.aer.gov.au/system/files/AER%20-%20Electricity%20Transmission%20Ring-fencing%20Guideline%20%28explanatory%20statement%29.pdf> (***TRFG Explanatory Statement***).
[134] TRFG, cls 3.1(b) and 3.1(f).
[135] TRFG, cl 3.1(d)(ii).

prescribed, negotiated and non-regulated transmission services.[136] In effect, this prevents a TNSP from providing generation, contestable distribution services and electricity retail supply services within the same legal entity, and captures other types of contestable electricity services and non-electricity services (with some exceptions)[137]. This does not prevent an Affiliated Entity of a TNSP from providing Other Services.[138] This is broadly consistent with the approach taken for distribution, whereby a DNSP may provide Distribution Services and Transmission Services, but must not provide Other Services.[139]

(b) **Separation of accounts**: A NSP must establish and maintain internal accounting procedures so that it can demonstrate the extent and nature of transactions between the NSP and its Affiliated Entities.[140] In addition, a NSP must allocate or attribute costs for Transmission or Distribution Services (as relevant) in accordance with the 'Cost Allocation Principles' under the NER, and its 'Cost Allocation Methodology' which is approved by AER.[141] The NSP must keep records (which may need to be provided to AER) which demonstrate compliance with this cost allocation obligation.

Functional separation mechanisms

(c) **Protection against discrimination**: The non-discrimination obligations seek to target a NSP from using its monopoly position in regulated markets and, for a DNSP, information obtained through the provision of services to favour itself (or an Affiliated Entity) to discriminate against competitors in contestable markets. Specifically, a NSP is prohibited from discriminating between a Related Electricity Service Provider and a competitor (or potential competitor) of a Related Electricity Service Provider in connection with the provision of Prescribed Transmission Services (by a TNSP) or Direct Control Services (by a DNSP). In addition, for distribution, a DNSP must not discriminate between a Related Electricity Service Provider and a competitor (or potential competitor) of a Related Electricity Service Provider in connection with the provision of contestable electricity services by any other legal entity; [142] this is targeted at the actions of a DNSP in dealing with contestable providers in their provision of negotiated connection services.

While this same obligation does not expressly extend to a TNSP under the TRFG, the TRFG Explanatory Statement provides that a TNSP must avoid providing to its Related Electricity Service Provider information that it has obtained from a Related Electricity Service Provider's competitor. This is intended to avoid a Related Electricity Service Provider from receiving an advantage in contestable markets in which it competes by reason of its relationship with the TNSP, and to address the access the TNSP may have to information from other parties by virtue of its monopoly position in the transmission network.[143]

In Victoria, non-regulated transmission services are also subject to the contestability regime under Chapter 8 of the NER and AEMO's declared functions (described in paragraphs 45 and 127 – 130). Importantly, this contestability framework requires a TNSP to negotiate in good faith with a potential contestable provider with respect to changes to a proposed augmentation connection agreement that are sought or

[136] TRFG Explanatory Statement, s 2.1.2.
[137] TRFG, cl 3.1(e) .
[138] TRFG, cl 3.1(d)(i).
[139] AER, *Ring-fencing Guideline Electricity Distribution Version 3* (November 2021) (cl 3.1(c)) <https://www.aer.gov.au/system/files/AER%20-%20Ring-fencing%20Guideline%20Version%203%20-%20%28electricity%20distribution%29%20%20-%203%20November%202021.pdf> (***DRFG***).
[140] TRFG, cl 3.2.1(a); DRFG, cl 3.2.1(a).
[141] TRFG, cl 3.2.2(a); DRFG, cl 3.2.2(a).
[142] DRFG, cl 4.1(b) .
[143] Explanatory Statement, s 3.1.2 TRFG.

suggested by that potential contestable provider.[144] AEMO must evaluate, assess and negotiate responses to the invitation to tender in accordance with its published tender and evaluation process (which process includes provision for the declaration and management of conflicts of interest),[145]and may only proceed with a contestable augmentation on the basis of a tender accepted after evaluation and assessment in accordance with that published tender and evaluation process.[146] The agreement related to the contestable augmentation must also be consistent with the contractual requirements and principles set out in Schedule 8.11 of the NER which, among other things, sets out risk allocation principles and minimum requirements for such agreements (for example, relating to performance standards).[147]

Under the NSP Ring-Fencing Guidelines, the non-discrimination protections include (but are not limited to) the requirement for a NSP to deal with Related Electricity Service Providers and a competitor on substantially the same terms and conditions, and to offer each of them the same level of service, as well as not disclose information obtained through a NSP's dealings with a competitor to provide a competitive advantage to the NSP's Related Electricity Service Provider.[148]

Under the DRFG, this non-discrimination obligation extends to the prohibition against discrimination between any two legal entities in connection with the supply of Contestable Electricity Services by those entities (and not just discrimination in favour of a DNSP's affiliate and against non-affiliates). A DNSP must not discriminate between any two legal entities based on the use by one or both of those entities of assets owned, operated or controlled by the DNSP.[149] AER have noted that increased third party use of a DNSP's batteries (and other assets) increases the potential for DNSPs to discriminate between non-affiliates who are using the DNSP's batteries and those that are not. Accordingly, this non-discrimination requirement was introduced to prevent a DNSP from discriminating between two parties where a DNSP owns the particular asset.[150]

A NSP cannot apply to have the non-discrimination obligation waived by AER.[151]

(d) **Information access and disclosure**: A NSP must keep Ring-fenced Information confidential, and only use such information for the purpose for which it was acquired or generated.[152] The NSP can only disclose Ring-fenced Information to a person, including a Related Electricity Service Provider, in certain circumstances (such as where disclosure is required by law, or where disclosure is solely for the purpose of providing assistance to respond to an emergency that is beyond a NSP's reasonable control).[153] Where a NSP has shared Ring-fenced Information with a Related Electricity Service Provider, the NSP must provide equal access to that information to other legal entities which have requested it and are competitors (or potential competitors) of the NSP or a Related Electricity Service Provider of the NSP in relation to Contestable Electricity Services.[154] In addition, the requirement for a NSP to maintain a publicly available information register aims to

[144] NER, cl 8.11.7(c)(2).
[145] NER, cl 8.11.7(a)(1).
[146] NER, cl 8.11.7(c)(2) and cl 8.11.7(d).
[147] NER, cl 8.11.9(a).
[148] TRFG, cl 4.1(c); DRFG, cl 4.1(c).
[149] DRFG, cl 4.1(d).
[150] AER, *Electricity distribution Ring-fencing Guideline – Explanatory Statement Version 3* (November 2021) (s3.6.2) <https://www.aer.gov.au/system/files/AER%20-%20Ring-fencing%20Guideline%20Explanatory%20Statement%20%28Electricity%20distribution%29%20Version%203%20-%20November%202021.pdf> (***DRFG Explanatory Statement***)
[151] TRFG, cl 4.1(d); DRFG, cl 4.1(e).
[152] TRFG, cl 4.2.1; DRFG, cl 4.3.1.
[153] TRFG, cl 4.2.2; DRFG, cl 4.3.2.
[154] TRFG, cl 4.2.3; DRFG, cl 4.3.3.

ensure transparency regarding all entities (including the NSP's Related Electricity Service Providers) who have requested access to Ring-fenced Information, and the kind of information which has been requested.[155]

(e) **Conduct of service providers**: Any new or varied agreements between a NSP and a Service Provider, for the provision of services that enable the NSP to provide Prescribed Transmission Services (for a TNSP) or Direct Control Services (for a DNSP), must contain provisions which require that Service Provider to equally comply with certain of the NSP's functional separation obligations (including with respect to the obligation to not discriminate, and the protection of Ring-fenced Information).[156] The guidelines also prohibit a NSP from encouraging or incentivising the Service Provider from engaging in conduct which would breach such obligations.[157]

(f) **Staff and office separations**: Under the TRFG, a TNSP must ensure that its Marketing Staff involved in the provision of prescribed transmission services are not staff involved in the provision of contestable electricity services by a Related Electricity Service Provider (and vice versa).[158] Likewise, a DNSP must ensure that its staff involved in the marketing of Direct Control Services are not also involved in the marketing of Contestable Electricity Services by a Related Electricity Service Provider.[159] Physical separation is also required under the DRFG. In providing Direct Control Services, a DNSP must use offices that are separate from which a Related Electricity Service Provider provides Contestable Electricity Services (with exceptions, such as for staff who do not have access to electricity information or do not have any opportunity to use such information).[160]

297 A functional separation protection which is unique to the DRFG is the prohibition against a DNSP to cross-advertise or cross-promote Direct Control Services and Contestable Electricity Services together.[161] In addition, a DNSP must use independent and separate branding for its Direct Control Services from the branding used by a Related Electricity Service Provider for Contestable Electricity Services.[162]

Compliance procedures and reporting

298 A NSP must establish and maintain appropriate internal procedures to ensure it complies with its obligations under the NSP Ring-fencing Guidelines.[163] It must also prepare and submit to AER an annual ring-fencing compliance report, which must be independently verified for compliance with each provision of the applicable NSP Ring-fencing Guideline by a qualified auditor.[164] The report, which may be made publicly available by AER, must identify the measures the NSP has taken to ensure compliance with the relevant NSP Ring-fencing Guidelines, any compliance breaches, all Other Services provided by the NSP, and the purpose of all transactions between the NSP and an Affiliated Entity.[165]

299 In addition, under the DRFG, a DNSP must maintain a publicly available register in respect of each Regulated Stand-alone Power System used by the DNSP to provide Other Services.[166] AER have noted the importance of the transparency of such information to ensure a competitive SAPS resource provider market. The view is that access to this information will allow third parties to

[155] TRFG, cl 4.2.4; DRFG, cl 4.3.4.
[156] TRFG, cl 4.4.1; DRFG, cl 4.4.1.
[157] TRFG, cl 4.4.1(b); DRFG, cl 4.4.1(b).
[158] TRFG, cl 4.3.
[159] DRFG, cl 4.2.2(a).
[160] DRFG, cl 4.2.1(a).
[161] DRFG, cl 4.2.3(a)(ii).
[162] DRFG, cl 4.2.3(a)(i).
[163] TRFG, cl 6.1; DRFG, cl 6.1.
[164] TRFG, cl 6.2.1; DRFG, cl 6.2.1.
[165] TRFG, cl 6.2.1(b); DRFG, cl 6.2.1(b).
[166] DRFG, cl 6.2.3 .

understand the design and economics of the systems being offered by DNSPs, and plan for their future provision of generation services.[167] The required information includes the local government area in which the system is deployed, the number of premises served by the system, the revenue earned by the DNSP by means of the Regulated Stand-alone Power System, and whether the DNSP has requested for the supply of the Other Services by another Legal Entity (other than an Affiliated Entity of the DNSP).[168]

1.6 Electricity generation

300 In contrast, the electricity generation sector is a competitive sector, with a mandatory 'spot market' for almost all electricity generation in the NEM, being across Queensland, New South Wales, Australian Capital Territory, Victoria, Tasmania and South Australia. The NEM is a wholesale electricity market in which generators sell electricity, and retailers buy it to on-sell to consumers. AEMO is responsible for the settlement of all electricity bought and sold through the NEM's wholesale electricity pool. All electricity in the wholesale electricity market is bought and sold at the spot price (as between the generator, AEMO and the retailer).

301 As electricity cannot be easily stored, and the amount of electricity generated must match demand in real time, the spot market allows for power supply and demand to be matched instantaneously through a centrally coordinated dispatch process. Accordingly, prices fluctuate based on supply (ie, the offers by generators to supply electricity into the NEM at particular volumes and prices at set times) and demand (ie, from consumers) at any point in time.

302 At a high level, generators compete to be dispatched by making price bids to AEMO for each five-minute dispatch interval. The generator's bid comprises the price and quantity of electricity that they are willing to generate for set time periods. From all the bids offered by generators in the NEM, AEMO decides which generators will be deployed to produce electricity to meet demand. AEMO dispatches the cheapest generator bids first, then progressively dispatches more expensive offers until enough electricity can be produced to meet demand. The dispatch price is determined every five minutes by AEMO and the price paid to all dispatched generators is the price in each five-minute dispatch interval. A separate price is determined for each of the five regions in the NEM.

303 Under the NER, prices are capped at a maximum of $15,500 per MWh in 2022-23 (referred to as the maximum price cap), and a price floor of -$1,000 per MWh also applies (referred to as the market floor price). The maximum price cap increases with CPI each year.

304 As flagged above, retailers and wholesale customers pay AEMO the spot price for the supply of electricity, and AEMO subsequently pays generators the spot price for generating electricity into the NEM. To mitigate against spot price volatility, the contract market provides generators and retailers with a consistent price for electricity and a steadier stream of income. Generators, retailers and large energy users can enter into wholesale hedging contracts (commonly referred to as power purchase agreements or offtake agreements) that fix the price of future electricity sales. This allows retailers to manage their financial risks and have certainty over wholesale energy costs, and also increases the certainty of a generator's revenue stream. For generators, this in turn allows them to obtain funding for their business operations from financial institutions.

[167] DRFG Explanatory Statement, s2.8.
[168] DRFG, cl 6.2.3(a).

1.7 Electricity retail

(i) Retail market

305 The electricity retail market is the interface between electricity retailers and their customers, and through which energy retailers sell electricity and energy services to residential and business customers.

306 The National Energy Customer Framework (***NECF***) offers energy-specific consumer protections for small customers, which regulate the rights and obligations of retailers and consumers in retail energy markets. The NECF is comprised of a suite of legal instruments that regulate the sale and supply of electricity and gas to retail customers:

(a) the National Electricity Retail Law (***Retail Law***);

(b) the National Energy Retail Rules (***Retail Rules***); and

(c) the National Energy Retail Regulations (***Regulations***).

307 The NECF is applied in participating jurisdictions through state or territory laws (being the Australian Capital Territory, South Australia, Tasmania, New South Wales and Queensland (collectively, the ***NECF Jurisdictions***)). AER regulates the energy retail market in respect of the NECF Jurisdictions. Victoria has not adopted the NECF, except for chapter 5A of the NER on electricity connection for retail customers. In Victoria, the key sources of obligations for retailers are under the EIA and the Energy Retail Code of Practice, which provide a range of similar consumer protections. The ESC regulates the Victorian energy retail market.

308 The Retail Law and Retail Rules set out retailer obligations to small customers. This includes model terms and conditions which must be included in standard retail and market retail contracts, protections for customer hardship and payment plans, and procedures for dealing with customer complaints. The NECF also applies to some aspects of the relationship between the distributor and customer. For example, with respect to limitations on disconnections of a customer's premises. Mandatory reporting obligations also apply to each NECF Jurisdiction (to AER) and Victoria (to the ESC and pursuant to the 'ESC Compliance and Performance Reporting Guideline'[169]).

(ii) Consumer protections

309 There are several mechanisms under which consumers are protected, including through the regulatory bodies for the NECF Jurisdictions and in Victoria.

310 In addition to regulation of the retail electricity market by AER and ESC, the ACCC monitors and enforces the *Electricity Retail Code* for electricity retailers, and parts of the *Competition and Consumer Act 2010* that prohibit misconduct in the electricity market. The code sets out how prices and discounts must be advertised, published and offered, and establishes requirements for the presentation of energy price information so that consumers can easily compare energy prices.

311 In Victoria, the ESC formally exercises its responsibilities under the *Essential Services Commission Act 2001*. Its mission is to promote the long-term interests of Victorian consumers with respect to the price, quality and reliability of essential services.[170] Further consumer protections are offered under the default offer regime, price and data protection regulations.

Default offers

312 Under the *Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019*, the Default Market Offer (***DMO***) was introduced to prevent retailers from charging excessive prices

[169] ESC, *Compliance and Performance Reporting Guideline - Version 7* (16 February 2022, corrigendum 27 April 2022) <https://www.esc.vic.gov.au/electricity-and-gas/electricity-and-gas-codes-guidelines-policies-and-manuals/compliance-and-performance-reporting-guideline>.
[170] ESC, *What we do* <https://www.esc.vic.gov.au/about-us/what-we-do>.

on electricity to standing offer customers. The DMO applies to small business and residential customers in South Australia, New South Wales and South East Queensland.

313 The DMO, which is set by AER is a maximum price that retailers can charge electricity customers on standing offer contracts. It is intended as a 'fall back option' (as opposed to a low-priced offer) for standing offer customers. The price is set annually by AER, and is set at a level that protects customers against high prices, enables retailers to recover their costs to service customers, but is high enough to encourage competition among retailers.[171] The DMO also works as a 'reference price' against which retailers must show the price of their market offer in their promotions and advertisements. This allows customers to easily compare electricity prices.

314 Similarly, in Victoria, the ESC sets a Victorian Default Offer (***VDO***) each year under the EIA. Households and small businesses can request to be put on the VDO, and retailers must notify customers how they can access the VDO on their electricity bill. The VDO applies to standing offers, and retailers must make the VDO available to customers who request it.

Price regulation

315 AER does not set retail energy prices. Some State and Territory Governments remain responsible for control of energy prices. For example, in Queensland, the ACT and Tasmania, customers can ask for a contract with an offer or tariff that is 'regulated' and which is set by the government.

316 In New South Wales, South Australia and South East Queensland, there is no retail price regulation, and electricity standing offers must comply with the DMO price described above. Likewise, in Victoria, electricity standing offers are capped by the VDO price, described above. Market offers or tariffs (for electricity or gas) are not capped, which means that energy retailers set their own prices in those jurisdictions. [172]

317 AER has developed RPIG under the Retail Law, which apply to the NECF Jurisdictions. The purpose of the RPIG is to provide guidance to retailers on the presentation of their standing and market offer prices to customers. The RPIG contains requirements on retailers which ultimately aims to increase customer engagement with energy market information by ensuring it is presented in a clear, consistent and accessible way to customers, and to thereby assist customers to compare energy plans in the market. For example, retailers must use clear, simple and widely understood words in their advertising and marketing materials.

318 Further, under the Retail Rules, AER has recently released a Draft Version 2 of the Better Bills Guideline (***BBG***). The BBG contains obligations on retailers in respect of their energy bills for small customers, and requires retailers to use simple language and structure throughout the bill. The Energy Retail Code of Practice also contains price obligations on retailers. For example, a requirement that retailers can only increase prices once a year, so as to ensure price certainty for its customers.[173] If a customer has signed up to a market retail contract for a discount, rebate or credit, the retailer must also offer that benefit for the entire duration of the contract.[174]

(iii) Consumer data protections

319 Customers are entitled to protections and rights over their energy usage and payment information. Customers can access and request a transfer of their information to an accredited

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[171] AER, *Final Determination - Default Market Offer Prices 2022-23 - Fact Sheet* (26 May 2022) <https://www.aer.gov.au/system/files/AER%20-%20Default%20Market%20Offer%20-%20Price%20determination%202022-23%20Final%20Determination%20-%20Fact%20sheet%20-%2026%20May%202022_0.pdf>.
[172] AER, *Tariff and fees explained* <https://www.aer.gov.au/consumers/my-energy-bill/tariff-and-fees-explained>.
[173] ESC, Energy Retail Code of Practice – Version 2 (1 October 2022) (s94) <https://www.esc.vic.gov.au/sites/default/files/documents/energy-retail-code-of-practice-version-2-20220908.pdf> (***Energy Retail Code of Practice***).
[174] Energy Retail Code of Practice, s96.

service provider under the Consumer Data Right (***CDR***), an amendment to the *Competition and Consumer Act 2010* (Cth) (***CCA***),[175] which was recently extended to the energy sector.[176]

320 The data caught by this scheme includes customer details, account information, metering data, billing and payment arrangements, and customer eligibility for concession measures.[177] The CDR is a voluntary scheme, contingent upon customers opting into the service and requesting that their information is transferred.[178] At present, obligations to transfer data only apply to the AEMO, the AGL Energy Group, the Origin Energy Group and the Energy Australia Group.[179]

(iv) Metering

321 Historically, most residential and small business consumers in Australia have used basic 1950s style electricity meters with limited functionality. This technology did not promote access to metering information in a way which would enable consumers to make informed decisions about their electricity consumption decisions.

322 The AEMC have recognised that the deployment of advanced metering technology in the market could lead to greater system efficiencies and cost savings for consumers.[180] Advanced meters enable consumers to access a range of potential benefits, including:

(a) greater accuracy and detail of real-time information regarding a customer's electricity usage, allowing customers to track their usage more frequently and accurately to save on costs;

(b) no more manual meter readings or estimated bills, and therefore more accurate network charges and bills that better reflects the cost of supplying electricity for customers;

(c) increased ability of retailers to offer more innovative pricing, service and product options;

(d) faster detection of faults and outages, allowing DNSPs to identify power outages and therefore streamline power reconnections for customers; and

(e) the ability to monitor and control electricity consumption and conditions in the distribution network during peak demand periods, allowing customers to make informed decisions about their electricity usage.

323 Following the AEMC's 'Power of Choice' review in 2013, the AEMC made a 'Competition in Metering Rule Change' to promote competition in metering services, and to lead a market-led deployment of advanced meters. This Rule was initiated by a broader market reform program to give consumers opportunities to better understand and take control of their electricity usage and costs. The Rule commenced from 1 December 2017.[181] The Rule applies to customers in New South Wales, Queensland, Tasmania, the Australian Capital Territory and South Australia.

324 The roll out of the smart meter regime is led by electricity retailers. Retailers must install smart meters for new connections and if a customer's meter is fault, has reached the end of its life, or needs replacing. The retailer must disclose all upfront costs to customers before installing the new meter. Customers are able to opt out of a smart installation (if they have not waived their right to opt out under their electricity contract with the retailer), and may also shop around for different retailers to compare prices.

[175] *Competition and Consumer Act 2010* (Cth) pt IVD (***CCA***).
[176] *Consumer Data Right (Energy Sector) Designation 2020* (Cth) (***CDR Designation***).
[177] CDR Designation, paras 7-9.
[178] Commonwealth of Australia, *What is CDR* <https://www.cdr.gov.au/what-is-cdr>.
[179] Commonwealth of Australia, *CDR in the energy sector* <https://www.cdr.gov.au/rollout/cdr-energy-sector>.
[180] AEMC, *Final rule to increase consumers' access to new services* (26 November 2015) <https://www.aemc.gov.au/sites/default/files/content/29328539-8eb5-4c34-952d-2a44ab5d12c5/Information-sheet-consumer-benefits.PDF>.
[181] Victorian customers are covered by state regulation that places responsibility for metering with the local distribution businesses.

325 Since then, advanced meters have been deployed to customers where new and replacement meters are required, or where energy businesses and consumers request access to advanced metering services. Where retailers seek to deploy advanced meters, the Rule also provides that retailers must allow consumers to opt out of having their existing meter replaced with an advanced meter. The Rule contains minimum requirements for such new and replacement meters for small customers.

326 Under the Rule, a retailer is required to appoint a Metering Coordinator to provide the metering services (unless a large customer appoints its own Metering Coordinator). This ensures that retailers retain the overall responsibility for metering services and are the single point of contact for customers, and allows prospective service providers to compete to provide metering services to retailers. Any person can become a Metering Coordinator subject to satisfying certain registration requirements. This aims to incentivise innovation and investment in metering where, previously, only the local network service provider could be responsible for such services.

327 On 3 November 2022, the AEMC released a draft report for the 'Review of the Regulatory Framework for Metering Services' (***Review***).[182] In the Review, and as part of broader movement to prioritise customers throughout the energy transition, the AEMC put forward a recommendation for a 100% update of smart meters by 2030. This would involve the progressive retirement of legacy accumulation and manually read interval meters by DNSPs under a legacy meter retirement plan, and require retailers to replace such retired meters within a set time frame. The Review provides that achieving a 'critical mass' of customers with smart meters will bring forward new and innovative services by retailers and third parties, and network benefits that participants will pass through to customers.[183] The AEMC is currently working with stakeholders to accelerate the smart meter rollout in the NEM. The Review is currently open to submissions, and the AEMC expect to release a final report by early to mid-2023.

328 The Rule above does not apply in Victoria. In 2006, the Victorian Government mandated the roll out of smart electricity meters to all households and small businesses across Victoria under the Advanced Metering Infrastructure (***AMI***) program and pursuant to the *National Electricity Amendment (Victorian Jurisdictional Derogation, Advanced Metering Infrastructure Roll Out) Rule 2009 No.2.* The Rule establishes the local distribution businesses in Victoria as exclusive responsible party for small customer metrology and for the roll-out of advanced metering infrastructure. Victoria has already achieved a near-universal uptake of smart meters and the AMI program finished in 2014.

1.8 Electricity Transmission Reforms

REZ reforms – NSW and Victoria

329 REZs are high-quality renewable energy resource areas where clusters of large-scale renewable energy projects can be developed. REZs connect multiple renewables projects in a centrally defined area, and enable a planned approach to infrastructure development. The development of REZs in Australia is intended to keep electricity reliable as ageing coal-fired generation plants retire.

(a) In Victoria, the ISP has identified 6 Victorian REZs –

(b) Central North

(c) Gippsland

(d) Murray River

[182] AEMC, *Draft Report – Review of the Regulatory Framework for Metering Services* (3 November 2022) <https://www.aemc.gov.au/sites/default/files/2022-11/Draft%20report.pdf> (***Review***).
[183] Review, para 4.

(e) Ovens Murray

(f) South Victoria

(g) Western Victoria

330 The Victorian Government released a preliminary design of the Victorian Transmission Investment Framework in June 2022 to establish how transmission infrastructure will be planned and developed to deliver REZs in Victoria. The framework sets out the government's proposed approach to developing Victoria's REZs, and introduces a strategic process to ensure the coordinated development of electricity transmission and renewable energy generation infrastructure in Victoria. The framework also seeks to integrate land use considerations, environmental impacts and community views into the planning process. VicGrid is a state body established within the Department of Energy, Environment and Climate Action to lead the development of REZs in Victoria. It is proposed that VicGrid's role would include identifying the optimal REZ pathways, overseeing investment decisions relating to the $540 million REZ fund and administering access rights in REZs. There is currently no REZ access right / connection regime in Victoria and VicGrid will, based on feedback on the preliminary design consultation paper, determine the most appropriate access option to apply to Victoria's REZs. It was noted in the preliminary framework that further consultation will be needed to determine how such new functions undertaken by VicGrid would operate in conjunction with the existing functions currently performed by AEMO.[184] In particular, in flagging the need to consider AEMO's existing functions, the preliminary framework notes that it may be appropriate in the future to have a single entity be responsible for all Victorian transmission planning and investment functions to ensure a holistic, end-to-end transmission planning process.[185] Public consultation on the preliminary framework closed in August 2022, and a report summarising feedback from stakeholders was published in December 2022.

331 In NSW, the 'NSW Electricity Infrastructure Roadmap', which is enabled by the *Electricity Infrastructure Investment Act 2020 (NSW)* (***EIIA***), sets out the plan for REZs in NSW, which will be developed by the Energy Corporation of NSW (***EnergyCo***). The EIIA and the *Electricity Infrastructure Investment Regulation 2021* (***EIIR***) are the key instruments that govern the development of, and investment in, REZs in NSW. The objects of the EIIA include to improve the affordability, reliability, security and sustainability of electricity supply, and to encourage and co-ordinate investment in new generation, storage, network and related infrastructure, as well as reduce risk for investors.[186] The EIIR provides for the membership, functions and procedures of the NSW renewable energy sector board established by the Minister under section 7 of the EIIA.

332 The AER is the regulator for the REZ regime in NSW. The Commonwealth and NSW have entered into a conferral agreement which formally sets out the AER's functions, duties and powers in accordance with the CCA.

333 Under the EIIA, the Minister may declare that an access scheme is to apply in a REZ at any time after a REZ has been declared.[187] EnergyCo, as the 'Infrastructure Planner', is the body which is intended to administer the access scheme for the first 5 REZs outlined below. A REZ may have more than one access scheme.

334 An access scheme sets out the rules, terms and conditions which authorise or prohibit access to, and use of, network infrastructure in a REZ by network operators and operators of generation and

[184] Department of Environment, Land, Water and Planning, *Victorian Transmission Investment Framework Preliminary Design Consultation Paper* (July 2022), page 63 <https://engage.vic.gov.au/victorian-transmission-investment-framework> (***VTIF Consultation Paper***).
[185] VTIF Consultation paper, page 63.
[186] EIIA, s3.
[187] EIIA, s24(1).

storage infrastructure.[188] This scheme is intended to benefit generators and investors by controlling how projects connect to a REZ and defining their rights to access the REZ scheme network.

335 The scheme may include an access rights regime (which authorises access to specified network infrastructure in a REZ according to the terms in the Minister's declaration), and an access control mechanism (which places limits on how specified network infrastructure in a REZ is accessed and used).

336 Under an access rights regime, parties who wish to connect to network infrastructure in a REZ are required to hold access rights, awarded up to an initial aggregate maximum capacity cap within the REZ, and pursuant to subsequent headroom assessments (ie, for increases in maximum capacity that can be accommodated without exceeding the target transmission curtailment level, calculated by EnergyCo) and/or market-led augmentations (ie, augmentations proposed and funded by one or more eligible proponents and approved by EnergyCo). If an access scheme includes an access rights regime, the Minister may include (among other things) persons that the access rights regime applies to (ie, eligible proponents seeking to connect to the network), the duration of the access right, and any pre-conditions to the grant of access rights. Further information regarding access scheme declarations is available in the 'Guidelines for Access Scheme Declarations'.[189]

337 In NSW, the first five proposed REZs are –

(a) **Central-West Orana REZ**: This is NSW's first REZ formally declared by the Minister under section 19(1) of the EIIA.[190] It will be approximately 20,000 square kilometres centred by Dubbo and Dunedoo, and is expected to unlock 3 gigawatts of network capacity and bring up to $5 billion in private investment to the region.

In August 2022, the NSW Government released the draft 'CWO REZ Access Scheme Declaration'[191] for consultation. Clause 5(2) provides that a person may only connect generation or storage plant to the access rights network where the plant is an eligible project, and an access right has been granted for the eligible project. Part 3 of the draft declaration sets out the procedure for the grant of such access rights (by Energy Co to an eligible operator), as well as the procedure for increases to the maximum capacity of an approved project.

Under clause 6 of the draft declaration, an access right authorises the access right holder to (1) submit an application to connect the relevant project to the network in accordance with the terms of any applicable access right agreement (which must be entered into with EnergyCo or a scheme financial vehicle and the eligible operator) and the NER; and (2) send out generation from the approved project into the access rights network in accordance with the access right agreement, the relevant connection agreement, and the NER;

(b) **New England REZ**: The NSW Government is in the early stages of planning a REZ in this region, which will be centred around Armidale. The REZ was formally declared on 17 December 2021. It has an intended network capacity of 8 gigawatts and is expected to

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[188] EIIA, s 24(2).

[189] NSW Government, Minister for Energy, Guidelines for Access Scheme Declarations (July 2022) <https://www.energy.nsw.gov.au/sites/default/files/2022-08/guidelines-for-access-scheme-declarations-220308.pdf.>.

[190] The REZ declaration is the first step in formalising the REZ under the EIIA. The declaration sets out the size/capacity, location and infrastructure that will make up the REZ. This enables and sets the scope of key legislative functions under the EIIA, including access schemes and REZ network infrastructure projects.

[191] Minister for Energy, Draft Renewable Energy Zone (Central-West Orana) Access Scheme Order (15 July 2022) <https://www.energy.nsw.gov.au/sites/default/files/2022-08/draft-cwo-rez-access-scheme-declaration.pdf>.

deliver up to $10.7 billion in private sector investment. EnergyCo is currently developing an access scheme for this REZ;

(c) **South West REZ**: This REZ, which will be centred around Hay, was formally declared by the Minister on 4 November 2022. It is *expected* to receive up to $2.8 billion in private investment by 2030.

(d) **Hunter-Central Coast REZ**: The NSW Government is in the early stages of planning a REZ in this region. This REZ was formally declared on 9 December 2022. It has an intended network capacity of 1 gigawatt.

(e) **Illawarra REZ**: EnergyCo is also in the early stages of planning for this REZ. The REZ was formally declared on 27 February 2023. It has an intended network capacity of 1 gigawatt.

Offshore wind

338 The development of the offshore wind sector in Australia is still in its formative stages. Australia's national regulatory framework for Offshore Electricity Infrastructure (***OEI Framework***) came into effect in June 2022, and is comprised of the following:

(a) *Offshore Electricity Infrastructure Act 2021* (***OEI Act***) – The OEI Act establishes a regulatory framework to enable the construction, installation, commissioning, operation, maintenance and decommissioning of offshore electricity infrastructure in the Commonwealth offshore area;

(b) *Offshore Electricity Infrastructure (Regulatory Levies) Act 2021* – allows for the imposition of levies on regulated entities to recover the regulatory costs; and

(c) *Offshore Electricity Infrastructure (Consequential Amendments) Act 2021* – provides for consequential amendments to various Acts arising from the enactment of the above Acts, including the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cth).

339 On 2 November 2022, the Australian Government released the following regulations after consultation with industry:

(a) *Offshore Electricity Infrastructure Regulations 2022* (Cth); and

(b) *Offshore Electricity Infrastructure (Regulatory Levies) Regulations 2022* (Cth).

340 The above regulations, which commenced on 2 November 2022, outline the methodology that the Commonwealth will apply in awarding licences for the development of offshore electricity infrastructure. The Offshore Infrastructure Registrar administers licences for offshore renewable energy and transmission projects.

341 At a high level, the offshore electricity licensing regime is as follows:

(a) **Feasibility licence** – permits licence holders to conduct initial studies and assess the feasibility of a project for up to 7 years. The Minister must first declare the area as suitable for offshore renewable electricity infrastructure before this licence can be obtained.

(b) **Commercial licence** – allows offshore renewable energy infrastructure projects for up to 40 years. Licence holders need a feasibility licence before they can apply for a commercial licence.

(c) **Research and demonstration licence** – enable short-term projects (up to 10 years) to trial and test new offshore renewable energy technologies. The Minister must first declare the area as suitable for offshore renewable electricity infrastructure before this licence can be obtained.

(d) **Transmission and infrastructure licence** – permit installation and operation of undersea interconnectors to transmit electricity. These licences do not need to be in a declared area.

342 Further regulations are expected in early 2023, which will provide additional information on financial security obligations, management plans and work health and safety obligations.

343 As the Commonwealth only has jurisdiction in the Commonwealth offshore area, participating states and territories must develop their own legislative framework to enable relevant infrastructure to cross through their coastal waters and connect into the NEM.

344 In Victoria, the 'Victorian Offshore Wind Policy Directions Paper' (March 2022) and the 'Offshore Wind Implementation Statement 1' (October 2022) outlines Victoria's vision to host the first offshore wind farms in Australia. The plan includes procuring an initial offshore wind tranche of at least 2 GW, aiming for first power to come online by 2028 (following a competitive process), with targets of 4 GW of offshore wind capacity by 2035 and 9 GW by 2040. The 'Offshore Wind Implementation Statement 2' (March 2023) provided an update on Victoria's progress and confirmed that the Victorian Renewable Energy terminal will be located at the Port of Hastings.

345 In December 2022, the Minister declared an area in the Bass Strait off Gippsland as Australia's first offshore wind zone. Feasibility licence applications for this declared area will be accepted from 23 January 2023 to 27 April 2023. The Minister is currently in the consultation process for an offshore wind zone in the Pacific Ocean off the Hunter region of NSW.

Reliability

346 Reliability refers to the resource capability of the power system to supply electricity to users within acceptable standards and in the amounts demanded. The target Reliability Standard under the NER, a percentage of met or unmet electricity demand, requires at least 99.998 percent of forecast customer demand to be met each year, or at most 0.002 percent Unserved Energy. Reliability is influenced by levels of generation, storage, demand response and major transmission assets.

347 Within the NEM, each State and territory has a separate framework for setting reliability standards for TNSPs, described at a high level below. This is a legacy of jurisdictional electricity development prior to the NEM, as the jurisdictions sought to retain control of reliability settings in their networks. The frameworks vary in the type and level of standards applied, the body responsible for setting the standards and the instruments used to specify them:

(a) **Victoria**: In Victoria, AusNet Services is responsible for ensuring that reliability in the transmission network in Victoria is maintained, subject to the investment decisions made by AEMO to expand the transmission network. AusNet Services aims to meet the reliability targets set by the AER each year. The supply reliability targets distinguish between the average minutes off supply per customer, the average number of supply interruptions per customer longer than 3 minutes, the average duration of an unplanned customer interruption, and the average number of momentary interruptions per customer less than 3 minutes. The reliability targets apply to 'urban feeders', 'short rural feeders' and 'long rural feeders', each as defined by the AER. Further information about the targets are available on the AusNet Services website.[192]

(b) **NSW**: Under the ESA, the Minister must impose conditions which specify performance standards for the reliability of operation of a transmission system, and provide for reliability performance monitoring and reporting, on a licence. IPART is the safety and reliability regulator for NSW electricity networks, and recommends reliability standards for

[192] AusNet, *Reliability* <https://www.AusNetservices.com.au/electricity/network-information/reliability>.

electricity transmission.[193] TransGrid is also subject to the NSW Electricity Transmission Reliability and Performance Standard 2017,[194] which sets out the permissible levels of redundancy and the Unserved Energy allowances per year.

(c) **Queensland**: In Queensland, the 'Transmission Authority – No. T01/98'[195] allows Powerlink to plan and develop the transmission network.[196] Clause 6.2 of the Transmission Authority prescribes that during a critical outage, the maximum forecast of electricity that is not able to be supplied cannot exceed more than 50MW at any one time and 600MWh in aggregate.

(d) **South Australia**: In South Australia, the South Australian Electricity Transmission Code (***ETC***) is regulated by the Essential Services Commission of South Australia and operates in addition to the technical standards prescribed in the NER. ElectraNet must plan and develop its transmission system to ensure that each exit point or group of exit points meet certain minimum reliability standards.[197] Compliance with the ETC is a condition attached to ElectraNet's transmission licence.

(e) **Tasmania**: In Tasmania, TNSPs must be licensed by the Tasmanian Economic Regulator (***TER***) and provide the TER with information on the transmission network's reliability. The information required is specified in the TER's *Electricity Supply Industry Performance and Information Reporting Guideline September 2014*. In addition, a TNSP must meet the requirements of the *Electricity Supply Industry (Network Planning Requirements) Regulations 2018* , which specify the minimum network performance requirements that a TNSP must meet for its transmission network.

348 As the NEM is transitioning from a fleet of largely coal fired generation to more variable renewable generation, the reliability of the NEM has been a general concern. The ESB has developed a reform pathway, 'Resource adequacy and ageing thermal generation retirement', to manage this transition and address the concern of maintaining reliability within the system.[198] This pathway is aimed at ensuring that the system has an efficient mix of capacity (generation, storage and demand response) required to support the exit of coal generation.

349 One of the ESB's recommendations to address challenges of resource adequacy is to implement a T-3 Ministerial lever for Retailer Reliability Obligation (***RRO***), which is currently in place in South Australia, across all regions in the NEM.[199] The proposed amendment is designed to give the relevant Minister an option to trigger the RRO to address reliability concerns in the NEM. The reforms received assent on 23 March 2023 and comes into operation on a day fixed by proclamation.[200]

350 Further, a key proposal of the ESB to address reliability concerns was to introduce a capacity mechanism. The capacity mechanism reform is discussed at paragraphs 371 and 371 below.

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[193] Independent Pricing and Regulatory Tribunal, *Electricity Transmission Reliability Standards* <https://www.ipart.nsw.gov.au/Home/Industries/Energy/Reviews/Electricity/Electricity-Transmission-Reliability-Standards>.
[194] Minister for Energy and Utilities, NSW Electricity Transmission Reliability and Performance Standard 2017 (1 June 2017) <https://www.ipart.nsw.gov.au/sites/default/files/documents/nsw-electricity-transmission-reliability-and-performance-standard-2017_0.pdf>.
[195] Powerlink Queensland, 2023-2027 Revenue Proposal – Asset Planning Criteria Framework (23 December 2020). <https://www.aer.gov.au/system/files/Powerlink%20-%20Asset%20Planning%20Criteria%20Framework%20-%20January%202021.pdf>.
[196] Powerlink, Transmission Annual Planning Report (2016), Chapter 1, <https://www.powerlink.com.au/sites/default/files/2017-12/Transmission%20Annual%20Planning%20Full%20Report%202016.pdf>.
[197] ElectraNet, Transmission Annual Planning Report (October 2021). <https://www.electranet.com.au/wp-content/uploads/2021-ElectraNet-Transmission-Annual-Planning-Report.pdf>.>.
[198] Energy Security Board, *Post 2025 Market Design Final Advice to Energy Ministers Part A* (27 July 2021), page 13 <https://www.datocms-assets.com/32572/1629944958-post-2025-market-design-final-advice-to-energy-ministers-part-a.pdf>.
[199] Energy Security Board, *T-3 Ministerial level for the retailer reliability obligation draft bill and initial Rules* (August 2022) <https://www.datocms-assets.com/32572/1659397866-esb-t-3-ministerial-lever-rro-consultation-paper-final.pdf>.
[200] *National Electricity (South Australia) (Ministerial Reliability Instrument) Amendment Act 2023*.

System security

351 System security relates to the technical strength of the power system to operate within electrical parameters and withstand unexpected contingency events. These electrical parameters include characteristics such as frequency and voltage. An unexpected contingency event typically involves the failure or sudden removal of a generator or transmitter from operation. The target system security standard is measured by frequency (at 50 hertz or cycles per second).

352 The ESB's Health of the NEM report noted that system security is the most critical issue at present.[201] Frequency, inertia, operating reserves and system strength are services that are essential for the security of the electricity system and are inherently provided as a by-product of synchronous generation (such as coal, gas and hydro plants). Non-synchronous plants (which typically include solar, wind and batteries) do not generate those essential system services in the same way. The NEM is undergoing a significant transformation with a changing generation mix and as synchronous generation is exiting the market, a challenge that arises is effectively maintaining system security within the NEM. In the future, the power system of the NEM will need to accommodate periods of very high, or very low instantaneous penetration of renewables and sudden changes that comes with the weather dependence. Further, as noted in page 50 of the ESB Post 2025 Market Design Final Advice to Energy Ministers, Part B:[202]

> 'the present system is designed around one-way flows and provision of power from a small number of large synchronous generators that are centrally located. There are now new modes of operation with more dispersed non-synchronous generation, a situation never seen before.'

353 Without the tools to effectively schedule the market to meet these changing dynamics, AEMO may be required to intervene in the market and direct participants to come online.

Frequency, Inertia, Reserves and System Strength

Frequency

354 Frequency is a measure of how many times voltage cycles every second, and is influenced by the supply and demand for electricity at any point in time. In Australia, voltage cycles 50 times in one second, meaning the system frequency is 50 hertz (**Hz**).

355 Frequency control is one important indicator of the health of the power system. When the NEM operates at a frequency range close to 50 Hz, the power system can operate safely and securely to transmit power from generators to consumers without damaging connected equipment.

356 A key challenge in operating the NEM is to ensure that supply and demand are balanced in order to keep the system frequency as close as possible to 50 Hz. As the NEM transitions to a lower emissions power system and changes its generation mix, frequency control may be comprised. Synchronous generators use turbines or spinning parts which are phase locked to rotate at speeds which match the grid frequency. In contrast, wind and solar systems connect to the grid through non-synchronous inverters, which produces a different amount of electricity depending on the energy available at any given time.

357 One of the frequency control frameworks which AEMO relies on to keep grid frequency close to 50 Hz is the ancillary services markets known as FCAS, which operates in addition to the electricity market. Ancillary services are used by AEMO to manage the power system safely, securely, and reliably, and involves sending price signals to participants to adjust generation

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[201] Energy Security Board, *Post 2025 Market Design Final Advice to Energy Ministers Part A* (27 July 2021), page 48 <https://www.datocms-assets.com/32572/1629944958-post-2025-market-design-final-advice-to-energy-ministers-part-a.pdf>.
[202] Energy Security Board, *Post 2025 Market Design Final Advice to Energy Ministers Part B* (27 July 2021), page 50 <https://esb-post2025-market-design.aemc.gov.au/32572/1629945809-post-2025-market-design-final-advice-to-energy-ministers-part-b.pdf>.

output to correct frequency deviations. AEMO operates eight separate markets for the delivery of FCAS.[203]

358 Frequency control frameworks have recently been introduced to further address this issue. On 15 July 2021, the AEMC introduced fast frequency response services (***FFR services***). FFR services involve financial rewards for fast energy providers (such as batteries) for reacting at short notice when the system requires frequency control. On 8 September 2022, the AEMC published a final determination and final rule to introduce the primary frequency response incentive arrangement. This arrangement aims to support power system frequency and incentivise plant behaviour that reduces the overall cost of frequency regulation during normal operation.[204]

Inertia

359 Inertia is an object's resistance to any change in its velocity. In a power system, inertia refers to the kinetic energy stored in the spinning parts within generators. Inertia is important to a power system because it is the first line of defence to a disturbance and acts to reduce the impact of imbalances in supply and demand within the system. For example, if there is a sudden disturbance and generators lose power, its parts will continue spinning to produce electricity and keep frequency within an acceptable range until the system rebalances.

360 Inertia is provided by synchronous generators with large spinning rotors (typically hydro, coal or gas plants). Conversely, inverter-based renewable energy, such as wind and solar, do not inherently provide inertia. One challenge of the energy transition will be to effectively manage and operate a system which has lower inertia levels.

Operating Reserves

361 Reserves are capacity that can be relied upon in short notice to balance supply and demand and maintain system reliability. Practically, this involves generators 'ramping up' where required, including to respond to high prices.[205]

362 Under the current system, there are in-market and out-of-market reserves. In-market reserves are made up of capacity that has been offered but not dispatched into the energy market or FCAS market. Out-of-market reserves, such as the Reliability and Emergency Reserve Trader, are separate functions which can be relied on as a last resort. The costs of providing reserves are bundled into the cost of providing energy as there is no separate reserves market.

363 Reserves are important to maintain system reliability and there is a concern that the current reserve arrangements will not be sufficient to manage reliability risk in the future. One option to address this concern is to create a separate market which would explicitly value the provision of reserves and unbundle this service from the energy and FCAS markets. The AEMC received two rule change requests relating to reserves and are currently considering its options. It is expected to publish its draft determinations on 30 June 2023.

System strength

364 System strength is an indicator of the resilience of the grid, and the ability of the power system to maintain a stable voltage waveform at any given location in the power system. Voltage waveforms are the 'pressure rhythms' that pump power through the transmission lines. Where the voltage waveform is strong or stable, it will be represented in a smooth and consistent sine wave.

[203] AEMO, Ancillary Services <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services>.
[204] AEMC, Primary frequency response incentive arrangements <https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements>.
[205] AEMC, Primary frequency response incentive arrangements https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements>.

365 High system strength means that the system is equipped to manage disturbances and return to normal operation. On the other hand, a lack of system strength means that the system can become unstable following a disturbance. In the short term, this makes it more difficult to effectively operate the system as more intervention from AEMO is required. In the long term, a lack of system strength causes difficulty for generators to connect to the grid.

366 Traditionally, synchronous generators provide system strength as a by-product of their electricity generation as they are physically connected to the grid. On the other hand, wind and solar generation connects to the grid through inverters, which does not inherently facilitate system strength.

OSM proposals

367 The AEMC is considering options to improve arrangements for maintaining security in the power system. In response to rule change requests from Hydro Tasmania and Delta Electricity, the AEMC has released a draft rule that would establish an 'Operational Security Mechanism' (**OSM**) to value, procure and schedule security services in the NEM.[206]

368 The draft determination was published on 21 September 2022 and the submissions to the draft determination closed on 17 November 2022. The final determination is expected to be released in July 2023.

NEM reforms

369 There are a number of significant reform processes underway in the NEM.

ESB / AEMC NEM 2025 reforms, eg, capacity markets, congestion management

370 The ESB, the peak body comprising the AER, AEMC and AEMO, is developing and delivering a package of post 2025 National Electricity Market (NEM) design reforms.[207] In March 2019, the Council of Australian Governments (COAG) Energy Council requested the ESB review the NEM framework and develop recommendations for reform.[208] In July 2021, the ESB made its recommendations on the post 2025 redesign to the Energy National Cabinet Reform Committee.[209] In September 2021, the Energy Ministers agreed a final package of reforms based on the ESB's recommendations. There are five directions for reform – resource adequacy and reliability; transmission and access; essential system services; integration of distributed energy resources (***DERs***) and flexible demand (see further below) ; and data strategy.[210]

371 Two key reforms are a CM and a CMM. The ESB proposed a CM as one of the reform pathways in its recommendations to the Energy Ministers. The CM is a resource adequacy and reliability reform. According to the ESB, the CM seeks to 'create a clear, long-term signal for investment, in both existing and new dispatchable capacity' to 'ensure reliable supply is maintained as the share of renewables grows rapidly'.[211] The ESB initially progressed the development of the CM. In June 2022, the ESB published a consultation paper.[212] It proposed to task AEMO with forecasting energy requirements for each year and procuring capacity from the market for that year through centrally run auctions, providing generators and capacity providers with an additional revenue stream. In August 2022, the Energy Ministers announced that they would take a more active role

[206] AEMC, Operational security mechanism <https://www.aemc.gov.au/rule-changes/operational-security-mechanism>.
[207] Energy Security Board, Post 2025 electricity market design <https://esb-post2025-market-design.aemc.gov.au>.
[208] Energy Security Board, Post 2025 electricity market design <https://esb-post2025-market-design.aemc.gov.au>.
[209] Energy Security Board, Final advice July 2021 <https://esb-post2025-market-design.aemc.gov.au/final-advice-july-2021>.
[210] Energy Security Board, Post 2025 electricity market design <https://esb-post2025-market-design.aemc.gov.au>.
[211] Energy Security Board, Resource adequacy mechanisms and ageing thermal retirement <https://esb-post2025-market-design.aemc.gov.au/resource-adequacy-mechanisms-and-ageing-thermal-retirement>.
[212] Energy Security Board, Capacity mechanism High-level Design Paper (June 2022), <https://www.energy.gov.au/sites/default/files/2022-06/Capacity%20mechanism%20high-level%20design%20consultation%20paper.pdf>.

in developing the CM, whilst the ESB would collaborate with the Ministers going forward.[213] The ESB previously aimed to develop a draft detailed design by December 2022 and make a final recommendation to Energy Ministers in February 2023.[214]

372 In December 2022, the Energy Ministers announced that they endorsed in principle a new Commonwealth Capacity Investment Scheme (***CCIS***). The CCIS is a Commonwealth revenue underwriting scheme and builds on the ESB's work in developing the CM. The CCIS aims to reduce investment uncertainty, suppress market volatility through Australia's transition to net zero, and result in lower energy prices in the medium to long-term. Only zero emissions dispatchable technologies will be eligible and this will include projects currently eligible under existing state-based schemes as well as on-grid, public and private utility scale projects that achieve financial close from 8 December 2022. The CCIS will involve a tender process to determine the optimal mix of generation and storage for reliability. Further consultation on the detailed design will occur, with a view to having the CCIS operational in the second half of 2023.

373 The CMM is a transmission access reform. It seeks to 'promote investment certainty, manage access risk, boost operational efficiency and incentivise technologies that alleviate congestion'.[215] The ESB is currently undertaking a detailed design of a CMM and proposed rule changes. In May 2022, the ESB published a consultation paper which shortlisted four models. The models are based on investment and operational timeframes. In the investment timeframe, there are two options – congestion zones with connection fees or a transmission queue.[216] In the operational timeframe, there are two options – a congestion management model with universal rebates or a congestion relief market ***(CRM)***.[217] In November 2022, the ESB published a directions paper which developed a preliminary hybrid model of enhanced information and a transmission queue or congestion fees in the investment timeframe, and the CRM in the operational timeframe.[218] Based on its preliminary assessment, the ESB prefers the hybrid model with priority access but believes the merits of both variants warrant further consideration.[219] On 24 February 2023, the Energy Ministers decided on a way forward with transmission access reforms and the ESB published a Project Update to outline their next steps.[220] The ESB will progress the implementation of 'enhanced information' reforms and will work with stakeholders to develop a voluntary CRM and priority access model.[221] The ESB aims to put forward its detailed design recommendations in mid-2023. The ESB aims to recommend a rule change for a preferred

[213] Energy Minister, Meeting Communique (12 August 2022) <https://www.energy.gov.au/government-priorities/energy-and-climate-change-ministerial-council/meetings-and-communiques>.
[214] Energy Security Board, Capacity mechanism High-level Design Paper (June 2022), <https://www.energy.gov.au/sites/default/files/2022-06/Capacity%20mechanism%20high-level%20design%20consultation%20paper.pdf>.
[215] Australian Government Department of Climate Change, Energy, the Environment and Water, Transmission access form Consultation paper (May 2022) <https://www.energy.gov.au/government-priorities/energy-and-climate-change-ministerial-council/priorities/national-electricity-market-reforms/post-2025-market-design/transmission/transmission-access-reform-consultation-paper-may-2022>.
[216] Australian Government Department of Climate Change, Energy, the Environment and Water, Transmission access form Consultation paper (May 2022), page 7 <https://www.energy.gov.au/government-priorities/energy-and-climate-change-ministerial-council/priorities/national-electricity-market-reforms/post-2025-market-design/transmission/transmission-access-reform-consultation-paper-may-2022>.
[217] Australian Government Department of Climate Change, Energy, the Environment and Water, Transmission access form Consultation paper (May 2022), page 7 <https://www.energy.gov.au/government-priorities/energy-and-climate-change-ministerial-council/priorities/national-electricity-market-reforms/post-2025-market-design/transmission/transmission-access-reform-consultation-paper-may-2022>.
[218] Energy Security Board, Transmission access reform Directions paper (November 2022), page 35 <https://www.datocms-assets.com/32572/1667984730-tar-directions-paper-final-for-web.pdf>.
[219] Energy Security Board, Transmission access reform Directions paper (November 2022), page 35 <https://www.datocms-assets.com/32572/1667984730-tar-directions-paper-final-for-web.pdf>.
[220] Energy Security Board, ESB Project Update – Transmission Access Reform, page 1 <https://www.datocms-assets.com/32572/1677794660-transmission-access-reform-project-update.pdf>.
[221] Energy Security Board, ESB Project Update – Transmission Access Reform, page 1 <https://www.datocms-assets.com/32572/1677794660-transmission-access-reform-project-update.pdf>.

transmission access model to Energy Ministers by June 2023.[222] The time to implement reforms will depend on the model but the ESB has flagged that changes to the dispatch engine and accompanying market systems will involve 'substantial, multi-year lead times'.[223]

DER

374 The integration of DERs is a flexible demand reform. DERs are distributed small-scale energy resources, including, for example, rooftop solar and home batteries which generate power that can be exported back to the grid. The integration of DERs seeks to 'unlock the full potential of distributed energy through arrangements that reward customers with flexible demand for responding to market conditions'. In December 2021, the ESB published its DER Implementation Plan Scope of Work and Forward Project Plan for Horizon One over the next three years. Horizon One activities include, for example, developing the flexible trading arrangement rule change proposal; developing policy and regulatory framework for Dynamic Operating Envelopes; developing technical standards and policy advice; and implementing a ministerial lever for emergency backstops.

Essential system services

375 As noted above, essential system service is another of the five key areas of reform in the ESB's Post 2025 package. Essential system services are services critical to maintaining overall power system security. They include inertia, frequency control and system strength.

376 As part of its 2025 reform package, the ESB has identified that the changing energy mix will have implications for how essential system services are provided and, as a result, how power system requirements are satisfied now and in the future.

377 The NEM's regulatory and market frameworks were originally designed based on a power system consisting primarily of synchronous generators (coal-fired, gas-fired and hydro generators) which are electromagnetically coupled to the power system. These generators inherently provide essential system services like inertia, reactive power support and system strength as a by-product of energy generation when they are committed, in operational timeframes, into service.

378 By contrast, non-synchronous generators (which typically include solar PV, wind generators and batteries), are connected to the power system through power electronics. This means that while these inverter-connected generators could be configured to provide some services that were previously provided by synchronous generators, they do not necessarily do so automatically as a by-product of their generation. Because these essential system services have been historically provided in abundance by synchronous generators, there was little need in the original market design to explicitly value them so that market participants had an incentive to provide them. While some efforts have been made to explicitly value some of these services (eg, system strength), this is not the case for all services.

379 Consequently, under the current market design, which does not explicitly value all essential system services, the changing generation mix is providing fewer of these services. According to the ESB this is pressing the limits of current system security and operational experience; the ESB points to the fact that in order to ensure system security, AEMO is increasingly having to direct generators that provide essential system services to come online (where they would otherwise be offline). Directions are intended to be used as a last resort; increasing reliance on these and other AEMO tools increases costs to consumers, puts system security at risk, and fails to send

[222] Energy Security Board, Transmission access reform Directions paper (November 2022), page 13 <https://www.datocms-assets.com/32572/1667984730-tar-directions-paper-final-for-web.pdf>.
[223] Energy Security Board, Transmission access reform Directions paper (November 2022), page 11, 35 <https://www.datocms-assets.com/32572/1667984730-tar-directions-paper-final-for-web.pdf>.

appropriate and transparent investment and operational signals to participants about what equipment, resources and services are needed at a particular point in time.

380 In order to address this issue, as part of its post 2025 reform package the ESB is working with the AEMC on a number of Rule changes aimed at providing power security at lower costs to consumers, as well as incentivising parties to provide these services. Current or recent Rule change projects relate to, for example, fast frequency response market (establishing new markets to financially reward participants for reacting at short notice when the system needs frequency control); mandatory primary frequency response (to require all scheduled and semi-scheduled generators in the NEM to support the secure operation of the power system by responding automatically to changes in power system frequency), the introduction of ramping services, and a capacity commitment mechanism for system security and reliability services.

National emissions objective

381 The *Climate Change Act 2022 (Cth)* (***Climate Act***) and the accompanying *Climate Change (Consequential Amendments) Act 2022 (Cth)* commenced on 14 September 2022. The Climate Act operates as the foundational 'umbrella' legislation for Australia's greenhouse gas emissions reduction. There are three key features: greenhouse gas (***GHG***) emissions reduction targets, the requirement for an annual climate change statement and the Climate Change Authority's functions.

382 First, the *Climate Act* legislates Australia's GHG emissions reduction targets, including a net zero emissions target. The legislated targets are 43% below by 2030 as a point target and an emissions budget for 2021-2030, and net zero by 2050.[224] These targets are aligned with and codify Australia's NDC under the Paris Agreement.[225] Importantly, a new or adjusted NDC and GHG emissions reduction targets must be more ambitious than the preceding NDC.[226]

383 Secondly, it creates a new accountability regime for the GHG emissions reduction targets. The Minister for Climate Change and Energy to prepare and provide an annual climate change statement to parliament, including an update on progress made towards achieving the targets.[227]

384 Thirdly, the Climate Act restores the Climate Change Authority as an independent and expert advisor on the statement and new or adjusted NDC and GHG emissions reduction targets.[228]

385 Separately, on 12 August 2022, the Energy Ministers unanimously agreed to enshrine an emissions objective into the National Energy Objectives.[229]

Other reforms

386 Further, the Energy Ministers announced that they are also collaborating with the states and territories (together known as the National Energy Transformation Partnership) to progress a First Nations Clean Energy Strategy and a National Renewable Energy Supply Chain Action Plan. The First Nations Clean Energy Strategy aims to ensure that First Nations Australians will have a central role in participating in the design, development and implementation of energy policies and programs. The National Renewable Energy Supply Chain Action Plan is set to be developed by the end of 2023, and seeks to alleviate supply chain pressures, address vulnerabilities in national capabilities, and identify potential opportunities within the renewable energy supply chain.

[224] Climate Act, s 10(1).
[225] Climate Act, s 10(2).
[226] Climate Act, ss 10(5),(6).
[227] Climate Act, s12.
[228] Climate Act, ss 14, 15 .
[229] Energy Minister, Meeting Communique (12 August 2022) <https://www.energy.gov.au/government-priorities/energy-and-climate-change-ministerial-council/meetings-and-communiques>.

2 Natural gas

2.1 Overview

387 This section discusses the gas regulatory arrangements as they apply on the East Coast of Australia. It focusses principally on gas distribution regulation in Victoria, given AusNet owns one of the three gas distribution networks but does not own any gas transmission assets.

2.2 Distribution

(i) Pipeline access and declaration regime

Pipeline regulation

388 Gas pipeline networks transport gas from upstream producers to residential, commercial and industrial customers. Australia's gas pipeline networks consist of:

(a) long haul transmission pipelines, which carry gas from producing basins to major population centres, power stations, and large industrial and commercial plants

(b) smaller urban and regional distribution networks, which receive gas from transmission pipelines and transport gas to customers in local communities.

(c) Both transmission and distribution pipelines are regulated by a cooperative legislative scheme comprising the National Gas Law (***NGL***) and National Gas Rules (***NGR***).

(d) Through these instruments, AER sets access prices for six distribution networks in New South Wales, Victoria, South Australia and the Australian Capital Territory, including the AusNet distribution network in Victoria.230

Coverage of pipelines

389 Under the NGL and NGR, pipelines are classified as either Scheme Pipelines, which are regulated by Parts 8 -12 of the NGR, or Non-scheme Pipelines which are regulated by Parts 10-12of the NGR. A pipeline's classification is related to the level of regulation that the pipeline and its operator are subject to, including the pipeline's required 'access arrangement'.

390 Scheme Pipelines are those to which a scheme pipeline determination' applies or a designated pipeline or a pipeline in respect of which a scheme pipeline election takes effect .[231] Pipelines which were deemed to be covered pipelines under s 2 of the NGL in force immediately before the commencement of the 2 March 2023 amendments (***Covered Pipelines***) are also deemed to be a scheme pipeline.[232]

391 A scheme pipeline determination is made by AER under Part 1 of Chapter 3 of the NGL and Division 1 of Part 4 of the NGR.

392 The AusNet distribution network was deemed a Covered Pipeline in the previous scheme and was subject to the 'full regulation' pipeline regime. Due to this characterisation, it is considered to be a scheme pipeline under the most recent amendments.[233] As a result, it is in the category of pipelines that is subject to the strictest pipeline access regulation in Australia.

Access Arrangements (Scheme Pipelines)

393 An access arrangement sets out the terms and conditions about access to pipeline services. A pipeline's form of regulation (ie, scheme or non-scheme) will affect the type of access

[230] AER, *State of the Energy Market 2022*, page 159 <https://www.aer.gov.au/system/files/State%20of%20the%20energy%20market%202022%20-%20Full%20report.pdf>. (***State of the Energy Market 2022 Report***).
[231] NGL, s 2.
[232] NGL, s 105.
[233] NGL, s 105.

arrangement required. For a scheme pipeline, the pipeline operator has to prepare and submit an access arrangement or revisions to an applicable access arrangement.[234]

394 Prior to submitting an Access Arrangement Proposal, a service provider must submit to AER a Reference Service Proposal' in respect of a forthcoming 'access arrangement proposal'. The Reference Service Proposal must:[235]

(a) identify the relevant pipeline and include a reference to a website at which a description of the pipeline can be inspected;

(b) set out a list of all the pipeline services that the service provider can reasonably provide on the pipeline and a description of those pipeline services;[236]

(c) from the list of pipeline services, identify at least one of those pipeline services that the service provider proposes to specify as 'reference services' having regard to the 'reference service factors' (as set out below) including any supporting information required by AER; and

(d) if the service provider has engaged with pipeline users and end users in developing its Reference Service Proposal, describe any feedback received from those users about which pipeline services should be specified as 'reference services'.

395 The 'reference service factors' that must be considered in preparing a Reference Service Proposal are:[237]

(a) the actual and forecast demand for the pipeline service and the number of prospective users of the service;

(b) the extent to which the pipeline service is substitutable with another pipeline service to be specified as a reference service;

(c) the feasibility of allocating costs to the pipeline service;

(d) the usefulness of specifying the pipeline service as a reference service in supporting access negotiations and dispute resolution for other pipeline services; and

(e) the likely regulatory cost for all parties (including AER, users, prospective users and the service provider) in specifying the pipeline service as a reference service.

396 Following receipt of a Reference Service Proposal, AER may undertake further consultation but must make and publish (together with reasons) a decision to approve or refuse a Reference Service Proposal (***Reference Service Proposal Decision***).[238]

397 After a Reference Service Proposal has been approved, the service provider can submit to AER, an Access Arrangement Proposal which (among other things):[239]

(a) identifies the pipeline to which the access arrangement relates and include a reference to a website at which a description of the pipeline can be inspected;

(b) describes all of the pipeline services that the service provider can reasonably provide on the pipeline, which must be consistent with Reference Service Proposal Decision, unless there has been a material change in circumstances;[240]

[234] NGL, s 113.
[235] NGR, r 42(1).

[237] NGR, r 47A(15).
[238] NGR, r 47A(10).
[239] NGR, r 48(1).
[240] If the information provided in the access arrangement proposal is different to the Reference Service Proposal Decision, the service provider must describe the material change in circumstances that necessitated the change having regard to the 'reference service factors'.

(c) specifies for each 'reference service' the terms and conditions on which each service will be provided, including the 'reference tariff';

(d) sets out any relevant queuing requirements;[241] and

(e) sets out the capacity trading requirements, extension and expansion requirements, and the terms and conditions for changing receipt and delivery points.

398 When submitting an Access Arrangement Proposal, the service provider must include with the proposal, any information that is reasonably necessary for users and prospective users to understand the background to the access arrangement and the basis and derivation of the various elements of the access arrangement.[242]

AusNet Access Arrangement

399 In November 2017, AER made decisions on the access arrangements for Victorian gas distributors including AusNet, covering the period 1 January 2018 to 31 December 2022.

400 On 20 October 2020, the *National Energy Legislation Amendment Act 2020* (Vic) was enacted to change the timing of Victorian gas distribution access arrangement periods. The effect of the Act is that regulatory determinations for affected businesses will now be made for financial years rather than calendar years. To facilitate this, the 2018-22 access arrangement period for Victorian gas distributors have been extended by six months to 30 June 2023.[243] Prices for the extension period (1 January to 30 June 2023), have been set by us in accordance with Orders in Council made on 30 September 2021.[244]

401 In July 2022, AusNet submitted a gas access arrangement proposal for the period 1 July 2023 to 30 June 2028, and specifies the reference services it will provide, the tariffs for those services and the other terms and conditions on which they will be provided. AER published its draft decision on AusNet's proposal on 9 December 2022.[245] It is expected that AER will publish a final decision in the first half of 2023.

402 The draft decision approves the majority of AusNet's proposed access arrangements, albeit with some required amendments. Key features include:

(a) AER has endorsed AusNet's reference service proposal – see below.

(b) AER has approved a revenue required of between $226 million and $255 million per annum.

(c) The AER has approved AusNet's non-tariff terms and conditions for reference services, with some minor variations.

403 The AusNet access arrangement adopts the following service categories:

(a) The main reference service category in the is its haulage reference services, which allow the injection of gas at transfer points, the conveyance of gas from transfer points to distribution supply points and allowing withdrawal of gas at distribution supply points.

(b) In addition, there are four 'ancillary reference services', such as 'meter & gas installation test'.

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241 Queuing requirements are necessary if the access arrangement is for a transmission pipeline but, if the pipeline is a distribution pipeline, queuing requirements are not necessary unless the AER has given prior notification of the need to include queuing requirements: See NGR, r 68D.

242 NGR, rr 42–44.

243 *National Gas (Victoria) Act 2008* (Vic), s61.

244 AER, *AusNet Services – Access arrangement 2023–28* <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausnet-services-access-arrangement-2023%E2%80%9328#:~:text=In%20July%202022%2C%20AusNet%20Gas,on%20which%20they%20will%20be.>.

245 AER, *Draft Decision – AusNet Gas Services Access Arrangement 2023 t0 2028 (1 July 2023 to 30 June 2028)* (December 2022) <https://www.aer.gov.au/system/files/AER%20-%20AusNet%202023-28%20-%20Draft%20Decision%20-%20Overview%20-%20December%202022.pdf>.

(c) The access arrangement includes a list of non-reference services, for which there are no published tariffs. AusNet expects these services, which include items such as disconnection and meter upgrades, represent between 1% and 2% of its total revenue.[246]

Non-scheme Pipelines

404 For completeness we note that under Part 10 of the NGR, owners of all pipelines are required to comply with the information provision requirements specified in this part, unless an exemption applies under Division 2, Subdivision 2 of this Part.

405 Non-scheme Pipelines are able to seek exemption from some requirements and AER is able to grant three types of exemption:[247]

(a) Pipelines that do not provide third party access can be exempted from all (information and arbitration) provisions set out in Division 2, Subdivision 1 of Part 10 of the NGR.

(b) Pipelines that are single user pipelines can be exempt from the financial, historical demand and cost allocation methodology the information disclosure requirements set out in rule 101D of the NGR.

(c) Pipelines with a daily capacity of less than 10 terajoules can be exempt from the financial, historical demand and cost allocation methodology information disclosure requirements set out in rule 101D of the NGR.

(ii) Pricing

406 As part of AER's assessment of a Pipeline Operator's access arrangement proposal, it forms a view as to the reasonableness of the forecasts and the efficiency of proposed expenditure contained in the proposal. If AER determines the proposal is likely to be unreasonably costly, it may ask for more detailed information or a clearer business case. Subsequently, AER may amend the amount of revenue proposed by a gas pipeline to ensure the approved cost forecasts are efficient.[248]

407 AER uses a 'building block' approach to assess a gas pipeline business's revenue needs. Specifically, it forecasts how much revenue the business will need to cover:[249]

(a) a return on the projected capital base;

(b) depreciation on the projected capital base;

(c) and the estimated cost of corporate income tax;

(d) increments or decrements resulting from the operation of an incentive mechanism to encourage cains in efficiency; and

(e) a forecast of operating expenditure.

408 AER's final decision sets an access price (reference tariff) for the relevant reference service for the duration of the access arrangement. That reference tariff provides a basis for access seekers to negotiate prices to other services. If a dispute arises, a frustrated access seeker can apply to AER to determine a tariff and other conditions of access.[250]

(iii) Connection Applications

409 As with the electricity distribution sector, the provision of connections is an area of potential disputes and is subject to a specific regulatory regime.

[246] AusNet Gas Services, *Gas access arrangement review 2024-28 – Revised AA Proposal* (24 January 2023) page 8 <https://www.aer.gov.au/system/files/ASG%20-%20Gas%20Access%20Arrangement%20review%202024-28%20-%20Revised%20Proposal%20-%2024%20January%202023%20-%20PUBLIC.pdf>.
[247] NGR, r 102.
[248] State of the Energy Market 2022 – Report, page 164.
[249] NGR, r 76.
[250] NGR, Pt 15C. See also State of the Energy Market 2022 – Report, page 164.

410 Part 12A of the NGR provides for three types of connection services: basic connection services, standard connection services and negotiated connection contracts. Each services relates to the provision of gas connection services between distribution and retail customers.[251]

(a) **Basic connection services:** A basic connection service provides a connection between a distribution pipeline and a retail customer's premises where the provision of the service involves minimal or no extension to the distribution pipeline.[252]

(b) **Standard connection services**: A standard connection service is a connection service (other than a basic connection service) for retail customers, retailers, or real estate developers.

411 In the case of both 'basic connection services' and 'standard connection services' the distributor is required to have a 'model standing offer', which must be approved by AER and contain the terms and conditions on which the service is provided. The terms and conditions must cover a description of the connection, timeframes for commencing and completing the work, details around connection charges and safety and technical requirements.[253]

(a) **Negotiated connected contracts:** The connection applicant may elect to negotiate the terms and conditions on which a connection service is to be provided, in which case, the applicant and distributor may negotiate a connection contracts, which may, if the applicant elects, extend to supply services offered by the distributor.[254]

Rule 119K of the NGL sets out the negotiation framework which governs negotiations for a connection contract. Each party must negotiate in good faith and provide the other party with information it reasonably requires to negotiate on an informed basis.[255]

412 The application process for connection services is set out in Division 5 of Part 12A of the NGR. The distributor is require to publish on its website an application form for connection services, as well as relevant descriptions and explanations of the services and the basis for calculating connection charges.[256] An applicant may make a preliminary enquiry, following which a distributor must, within five business days, provide the enquirer with information required to make an informed application.[257]

413 Following an application in the appropriate form (determined by the distributor), the distributor makes a connection offer to the applicant, which must be in accordance with the relevant 'model standing offer' (in the case of basic and standard connection services), or in accordance with the negotiated terms (in the case of a connection contract).[258]

(iv) Contestability – Customer connections and augmentations in Victoria

414 Under the NGR, where a distributor receives an enquiry about a connection service, the distributor must provide the enquirer with such information required to make an informed application, including:[259]

(a) a description of the distributor's basic and standard connection services and the terms and conditions of the model standing offers to provide such services;

(b) a description of the process for submission of a connection application;

[251] A 'retail customer' is a person to whom has is sold for premises by a person who is the holder of a retailer authorisation issued under the National Energy Retail Law in respect of the sale of gas.
[252] NGR, r 119A.
[253] NGR, rr 119C(2) and 119E(3).
[254] NGR, r 119I.
[255] NGR, r 119K(1).
[256] NGR, r 119P.
[257] NGR, r 119Q(1).
[258] NGR, rr 119S and 119V.
[259] NGR, r 119Q.

(c) a statement of an applicant's right to negotiate the terms of a connection contract; and

(d) an indication of whether any aspects of the proposed connection are likely to be contestable.

415 A service is contestable if the laws of the participating jurisdiction in which the service is to be provided permit the service to be provided by more than one supplier as a contestable service or on a competitive basis.[260]

416 Where contestable services are being provided as part of a model standing offer, the terms and conditions of that model standing offer must outline the qualifications and safety and technical requirements required for carrying out the work involved in that contestable service.[261]

417 In Victoria, gas connection services are contestable, and this is supported by the imposition of obligations on gas distributors under the Gas Distribution System Code of Practice (***Gas Distribution Code***). The Gas Distribution Code is made under the *Essential Services Commission Act 2001* (Vic) and applies to gas distributors that hold a distribution licence under the *Gas Industry Act 2001* (Vic) (***GI Act***).[262]

418 Under the Gas Distribution Code, a distributor must, upon the request of a customer, connect that customer's gas installation to its distribution system, provided that:[263]

(a) the gas installation at the supply address complies with the relevant regulatory requirements;

(b) the customer has a contract for:

(i) haulage of gas with the distributor; or

(ii) purchase of gas with a retailer that has a contract for haulage with the distributor; and

(c) in respect of a new connection, the customer provides a notice of installation from a gas installer.

419 If a distributor proposes to recover the costs of any augmentation (including in relation to connection applications) to their distribution network from another person, the distributor must undertake a tender process. The distributor must request offers to perform the augmentation works from at least two persons, other than the distributor itself, who compete in performing (or are capable of performing) works of that kind and comply with any guidelines published by the ESC in relation to the request for offers.[264]

420 The distributor is exempt from complying with the tendering process if it has received written consent from either the person who costs are being recovered from, or the ESC.

421 There are no guidelines currently on issue by the ESC that provide further guidance on how requests for offers are to be conducted by distributors.

422 While AusNet has published the AusNet Tender Policy and a Distribution Connection Policy on its website in relation to electricity distribution and connections, there are no corresponding policies relating to gas distribution.

(v) Dispute resolution – Sequence

423 The dispute resolution procedures as they relate to gas distribution substantially mirror the procedures applicable to electricity as discussed above.

[260] NGR, r 119A.
[261] NGR, r119C.
[262] Gas Distribution Code, s1.1.
[263] Gas Distribution Code, s3.1(a).
[264] Gas Distribution Code, s 3.2(a).

424 Division 7 of Part 12A of the NGR sets out the dispute resolution procedure between a distributor and customers (being a retail customer or a real estate developer) for relevant disputes. A 'relevant dispute' includes a dispute between a distributor and a customer regarding:[265]

(a) the terms and conditions on which a basic connection service or a standard connection service is to be offered;

(b) the proposed or actual terms and conditions of a negotiated connection contract; or

(c) connection charges.

425 A 'relevant dispute' is treated as an 'access dispute' for the purposes of Chapter 5 of the NGL.[266] Under the NGL, 'access dispute' refers to a dispute between a user (or prospective user) and a service provider about an aspect of access to a pipeline service provided by means of a scheme pipeline,[267] but the operation of rule 119Y(2) expressly includes 'relevant disputes' between distributors and customers.

426 The AER must make a determination on access by (as the case requires) the prospective user or user.[268] The determination must be in writing, include a statement of reasons for making the determination, and be given to the parties within 20 business days after the final access determination is made.[269]

427 In determining a relevant dispute between a distributor and customer in relation to a connection service, the AER must apply the connection charges criteria (in relation to connection charges), the model standing offer (as relevant for basic or standard connection services), Part 12A and any other applicable regulatory instrument (such as the Gas Distribution Code).[270]

428 The AER may also have regard to other matters it considers relevant, hear evidence or receive submissions from the distributor and the customer and, if the dispute relates to a negotiated connection contract, have regard to the negotiation framework set out in rule 119K of the NGR.[271] Notably, the negotiation framework includes the requirements for each party to negotiate with each other in good faith and to share information reasonably required so as to negotiate with each other on an informed basis.

429 The AER may require the parties, in accordance with the NGR, to mediate, conciliate, or engage in another alternative dispute resolution process for the purpose of resolving the access dispute.[272] In certain circumstances, the AER may terminate an access dispute without making an access determination. For example, if the AER considers the notification of the access dispute was vexatious, or the subject matter of the dispute is trivial, misconceived or lacking in substance.[273]

430 An access determination may, but need not, require a service provider to provide a pipeline service to a prospective user.[274]

431 In addition, section 10 of the Gas Distribution Code provides that a distributor must handle a complaint by a customer in accordance with the *Australian Standard ISO 10002:2022* (Quality management – Customer satisfaction – Guidelines for complaints handling in organisations), or the 'Benchmark for Industry Based Customer Dispute Resolution Schemes' published by the

[265] NGR, r119Y(1).
[266] NGR, r 119Y(2).
[267] NGL, s 2.
[268] NGL, s 161(1).
[269] NGR, rr 113X(4)-(5).
[270] NGR, r 119Z(1).
[271] NGR, r 119Z(2).
[272] NGL, s 155(2).
[273] NGL, s 169(b).
[274] NGL, s 161(1).

Commonwealth Government.[275] A distributer must make readily available to customers information on its complaint handling processes.[276] When a distributor responds to a customer's complaint, the distributor must inform the customer that the customer has a right to raise the complaint to a higher level within the distributor's management structure and, if the customer is still not satisfied with the distributor's response, to refer the complaint to the Energy and Water Ombudsman (Victoria) Ltd or other external dispute resolution body.[277]

432 Under the GI Act, a distribution licence must include a condition requiring the licensee to enter into a customer dispute resolution scheme approved by the ESC.[278] In approving a customer dispute resolution scheme, the ESC must have regard to (among other things) the need to ensure that the scheme is accessible to the licensee's customers and that there are no cost barriers to those customers using the scheme, and the need for the scheme to undertake regular reviews of its performance to ensure that its operation is efficient and effective. In Victoria, the Energy and Water Ombudsman (Victoria) is the independent industry-based dispute resolution scheme which has been approved by the ESC.

433 If a distributor contravenes the Gas Distribution Code, the ESC may also vary the distributor's licence or licence condition without the licensee's consent under the GI Act.[279] The ESC must specify the action that the licensee is required to take to rectify a contravention, and to prevent any future contravention of the licence condition or provision of the Distribution Code.

434 In addition, AusNet's Dispute Resolution Policy (as defined and discussed in section 271 above) applies equally to disputes in relation to both electricity and gas customers.

(vi) Ring fencing

435 Part 2 of Chapter 4 of the NGL and Part 5 of the NGR regulate the structural and operational separation requirements, also known as 'ring fencing', in relation to pipelines and pipeline services. The provisions operate to:

(a) impose minimum ring fencing obligations on Covered Pipeline Service Providers;

(b) provide AER with powers to impose additional ring fencing requirements in certain situations;

(c) provide AER with powers to grant exemptions to the minimum ring fencing requirements; and

(d) restrict the entry into, variation of, and giving effect to associate contracts.

Minimum ring fencing requirements

436 There are three minimum ring fencing requirements which must be complied with by Service Providers on and after a date that is six months after Compliance Date:

(a) **Carrying on related businesses prohibited:** A Service Provider must not carry on a Related Business.[280]

(b) **Restrictions on marketing staff**: A Service Provider must ensure that, where one or more of its associates are carrying on a Related Business, its marketing staff are not officers, employees, consultants, independent contractors or agents of the relevant associate(s) (or vice versa).[281]

[275] Gas Distribution Code, s 10(a).
[276] Gas Distribution Code, s 10(b).
[277] Gas Distribution Code, s10(c).
[278] GI Act, s 36(1).
[279] GI Act, s 38A(1).
[280] NGL, s 139.
[281] NGL, s 140. A person is marketing staff if the person is an officer, employee, consultant or independent contractor or agent of the Covered Pipeline Service Provider (or its associate) and is directly involved in the sale, marketing or advertising of pipeline services (whether or not the person is also involved in other activities). A person is not marketing staff if: (a) their role is only to provide

(c) **Preparation of accounts:** A Service Provider must prepare, maintain and keep: (a) separate accounts in respect of pipeline services provided by means of every Covered Pipeline owned, operated or controlled; and (b) a consolidated set of accounts in respect of its business.[282]

Exemptions from minimum ring fencing requirements

437 Section 127 of Schedule 1 of the NGL provides that service providers who held an exemption to the ring fencing requirements before the exemptions were removed from the NGL will still hold an effective exemption. AER, upon application from the Service Provider, may also grant an exemption from any or all of the minimum ring fencing requirements set out above.

438 AER will grant an exemption from the prohibition of carrying on a Related Business if it is satisfied that:[283]

(a) either: (i) the relevant pipeline is not a significant part of the pipeline system for any participating jurisdiction; or (ii) the relevant service provider does not have a significant interest in the relevant pipeline and does not actively participate in the management or operation of the pipeline;

(b) the cost of compliance with the requirement for the service provider and its associates would outweigh the public benefit resulting from compliance; and

(c) the service provider has, by arrangement with AER, established internal controls within the service provider's business that substantially replicate, in AER's opinion, the effect that would be achieved if the Related Business were divested to a separate entity and dealings between the service provider and the entity were subject to the controls applicable to associate contracts (as outlined below).

439 AER will grant an exemption from the restrictions on marketing staff, or the preparation of accounts outlined above if it satisfied that the cost of compliance with the relevant requirement for the service provider and its associates would outweigh the public benefit resulting from compliance.[284]

440 Furthermore, in relation to all minimum ring fencing requirements, if in the opinion of AER, compliance with a relevant requirement would lead to increased competition in a market, AER must, in carrying out an assessment of whether or not to grant an exemption, disregard costs associated with losses arising from increased competition in upstream or downstream markets.

Additional ring fencing requirements

441 Without limitation to the minimum ring fencing requirements, section 143(1) of the NGL empowers AER to make a determination requiring a Service Provider to comply with an Additional Ring Fencing Requirement.

442 Additional Ring Fencing Requirements may take the form of requirements on the Service Provider to:[285]

(a) ensure that its business is conducted, structured and arranged in a specified, particular manner (eg, putting in place electronic, physical and procedural security measures in officers and computer systems); and / or

technical, administrative, legal and accounting services; or (b) the persons involvement in the sale, marketing or advertising of pipeline services is only an incidental part of their role.

[282] NGL, s 141.
[283] NGR, r 34(3).
[284] NGR, r 34(4).
[285] NGL, s 145.

(b) disclose, in a specified manner, to AER and to the public, specified information in a specified manner about its business operations, structure and arrangements, and its business activities.

443 In making a determination in relation to an Additional Ring Fencing Requirement, AER must have regard to the extent to which services are provided between associates (or business units) on an arm's length basis, as well as the extent to which users and prospective users have sufficient information to understand the Service Providers compliance with ring fencing requirements.[286] AER must also have regard to the likely costs that will be incurred by an efficient Service Provider (or its associates) in complying with any Additional Ring Fencing Requirements.[287]

444 AER must give a Service Provider a period of at least 10 days to comply with any Additional Ring Fencing Requirements.[288]

Associate Contracts

445 In addition to the above ring fencing requirements, the NGL imposes further restrictions on contracts, arrangements or understandings:

(a) between a Service Provider and their associates in connection with the provision of pipeline services; or

(b) between a Service Provider and any person in connection with the provision of pipeline services that: (a) provides a direct or indirect benefit to an associate; and (b) that is not at arm's length,

(together, ***Associate Contracts***).[289]

446 A Service Provider must not enter into, vary, or give effect to a provision of, an Associate Contract that:

(a) has the purpose, or would have (or be likely to have) the effect of substantially lessening competition in a market for natural gas services unless approved;[290] and

(b) is inconsistent with the competitive parity rule unless approved.[291]

447 AER can, upon application by a service provider approve an Associate Contract (or a variation) if it is satisfied that it does not have the purpose, and is unlikely to have the effect, of substantially lessening competition in a market for natural gas services, and is not inconsistent with the competitive parity rule.[292]

448 If AER is not satisfied that the contract (or a variation) should be approved based on the grounds above, it may nevertheless approve the contract or variation if it is satisfied that the resulting public benefit would outweigh any resulting public detriment.[293]

449 An approval of an Associated Contract (or variation) may be subject to conditions AER considers appropriate (eg, conditions limiting the duration of the approval or providing that the approval will lapse on a material change of circumstances; and imposing reporting requirements on the service provider).[294] If AER fails to make a decision on an application for approval within 20 business

[286] NGL, s 143(2).
[287] NGL, s 144.
[288] NGL, s 143(5).
[289] An Associate Contract does not include a contract in relation to pipeline services provided by means of a Greenfields pipeline to which a 15-year no coverage determination applies: NGL, s 2.
[290] NGL, s 147.
[291] NGL, s 148. The competitive parity rule is the rule that a Service Provider must ensure that any pipeline services that it provides to its associates are provided as if the relevant associate were a separate unrelated entity.
[292] NGR, r 32(2).
[293] NGR, r 32(3).
[294] NGR, r 32(4).

days after receiving it, AER is taken to have approved the relevant contract or variation unconditionally.[295]

(vii) AEMO's unique role in Victoria

450 The AEMO functions under the NGL include controlling the security and operation of the Victorian Gas Declared Transmission System (***DTS***) and scheduling the Victorian Declared Wholesale Gas Market (***DWGM***). These functions include gas quality and emergency management, and reviewing the adequacy of gas supply and pipeline capacity for the DTS.

Declared Wholesale Gas Market

451 Part 19 of the NGR set out the rules that govern the operation of the DTS and the DWGM. The DWGM is a wholesale market that enables competitive and dynamic trading of gas injections and withdrawals from the DTS, which links producers, storage providers, interconnected pipelines, major users and retailers.[296]

452 The DWGM, which relates mainly to the transmission system in Victoria (rather than the distribution systems) incorporates a 'market carriage' transportation model, under which gas shippers (typically gas retailers or large wholesale customers) do not need to sign long term gas transportation agreements with the transmission system owner. Instead, shippers bid to buy and sell gas from a central market operated by AEMO, which in turn arranges transport to the relevant delivery points, including flows into the Victorian distribution networks.

2.3 Gas wholesale

(i) Wholesale gas market

453 The East coast gas market comprises several separate spot markets, supply hubs and bilateral contract markets operating across the eastern Australian states of New South Wales, Victoria, Queensland, South Australia and Tasmania. Separate wholesale markets operate in Western Australia and the Northern Territory. These are not covered in this summary.

454 Unlike the NEM – where the vast majority of electricity is traded through the wholesale spot market administered by AEMO under the NEL and NER – in the gas wholesale market, the majority of gas is traded under confidential bilateral contracts. The AER estimates that around 20% of gas is traded through spot markets, with the balance traded through the contract market.[297]

455 Typically, wholesale gas trading involves two contracts:

(a) a gas supply agreement, under which the supplier (for example, a gas producer) agrees to sell gas to the buyer (for example, a gas retailer or large gas user) – gas is normally sold on an energy content basis (and priced in dollars per GJ) measured on a daily basis (often by reference to a maximum daily quantity, or MDQ); and

(b) a gas transportation agreement, under which the gas pipeline operator agrees to transport gas for a shipper (for example, a gas retailer or large gas user) from an agreed receipt point to an agreed delivery point.

456 There are three wholesale spot markets administered by AEMO in accordance with the NGL and NGR:

(a) the Declared Wholesale Gas Market, which operates in Victoria and is governed by Part 19 of the NGR;

[295] NGR, r 32(5).
[296] AEMO, *Declared Wholesale Gas Market (DWGM)* (2022) <https://aemo.com.au/en/energy-systems/gas/declared-wholesale-gas-market-dwgm>.
[297] State of the Energy Market 2022 – Report, page 122.

(b) the Short Term Trading Market (***STTM***), which has hubs in Sydney, Brisbane and Adelaide and is governed by Part 20 of the NGR; and

(c) the Gas Supply Hub (***GSH***), which currently has hubs at Wallumbilla in Queensland, Moomba in South Australia and Culcairn and Wilton in New South Wales. The GSH is governed by Part 22 of the NGR.

457 These spot markets are discussed in sections (ii), (iii) and (iv) below.

458 In addition to these spot markets, AEMO administers two mechanisms designed to facilitate trading in pipeline capacity. These mechanisms are governed by Parts 24 and 25 of the NGR and are discussed further in section (v) below.

459 AEMO also maintains the Natural Gas Services Bulletin Board, which facilitates trading in natural gas and natural gas services by providing current information on gas production, storage and transmission pipelines in Eastern Australia. The operation of the Bulletin Board is governed by Part 18 of the NGR and is discussed further in section (vi) below.

460 The contract market is not subject to direct market regulation but (together with the broader wholesale market) is subject to monitoring activities by the ACCC and AER.[298] The broader wholesale market is also subject to a range of government interventions aimed primarily at ensuring the adequacy and security of gas supply to the domestic market. These comprise:

(a) the Australian Domestic Gas Security Mechanism;

(b) the Gas Price Cap and Mandatory Code of Conduct; and

(c) the Gas Supply Guarantee.

461 These interventions are discussed further in section (vii) below.

(ii) Declared Wholesale Gas Market

462 Victoria's DWGM manages gas flows across the Victorian transmission system.[299] It is a mandatory market and participants wishing to ship gas via the Victorian transmission system must bid that gas into, and out of, the DWGM.

463 The DWGM is operated and administered by AEMO in accordance with the Declared Wholesale Gas Market Rules, which are contained in Part 19 of the NGR. Participants in the DWGM submit daily bids ranging from $0 per gigajoule (GJ) (the floor price) to $800 per GJ (the price cap). Participation in the DWGM requires registration with AEMO. The main participants are retailers, traders, transmission customers and distribution customers. The prices bid by market participants results in both the supply of gas as well as transmission pipeline delivery. AEMO selects the least cost bids needed to match demand to establish a clearing price.[300]

464 In addition to operating and administering the market, AEMO's roles in the DWGM include:

(a) operating Victoria's gas transmission system (referred to as the Declared Transmission System or 'DTS');

(b) maintaining system security for the DTS so as to minimise the threats to system security;

(c) monitoring trading activity in the DWGM; and

(d) undertaking gas transmission planning functions through the publication of the Victorian Gas Planning Report.[301]

[298] The Australian Government directed the ACCC to use its compulsory information gathering powers to inquire into wholesale gas markets in eastern Australia. The inquiry was initially tasked to run until 30 April 2020, but in July 2019 the Treasurer extended it to 2025: ACCC, *Gas Inquiry 2017-2030:Interim Report* (27 January 2023).
[299] State of the Energy Market 2022 – Report, page 121.
[300] AEMO, *Declared Wholesale Gas Market (DWGM) Technical Guide* (1 January 2023), page 14.
[301] AEMO, *Declared Wholesale Gas Market (DWGM) Technical Guide* (1 January 2023), page 9.

465 The AER's principal role in relation to the DWGM is to monitor, investigate and enforce compliance with relevant provisions of the NGL and NGR relating to the DWGM. The AER is also required under the NGR to monitor trading activity in the DWGM with a view to ensuring that the trading activity is in accordance with Part 19 and to identify and report on any significant price variations.[302]

(iii) Short Term Trading Market

466 The STTM is a short-term trading market for gas with which allows gas trading on a day-ahead basis.[303] The STTM currently has hubs in Sydney, Brisbane and Adelaide. It is a mandatory market that operates at the entry points (city gates) of the relevant gas hub. Participants wishing to inject gas into the hub (distribution system) must bid that gas into, and out of, the STTM.

467 The STTM is operated and administered by AEMO in accordance with the Short Term Trading Market Rules, which are contained in Part 20 of the NGR. Participants in the STTM must register with AEMO. The main participants are gas facility operators, shippers, distributors and users.[304] AEMO sets a clearing price at each hub based on scheduled withdrawals and offers by shippers to deliver gas, with a price floor of $0 per GJ and a cap of $400 per GJ.[305] Pipeline operators schedule flows to supply the necessary quantities of gas to each hub.

468 In addition to administering the market, AEMO manages the balancing of what was scheduled by the pipeline operator for each pipeline at each hub on each gas day with the actual quantities of gas flowed on the gas day. This is designed to ensure that the physical demand on each pipeline continues to be met. This physical balancing, known as a market operator service (***MOS***), is managed by AEMO through supply arrangements established with shippers and pipeline operators that have the capability of increasing or decreasing the gas flow on a gas day.[306]

469 As for the DWGM, the AER's principal role in relation to the STTM is in monitoring, investigating and enforcing compliance with relevant provisions of the NGL and NGR relating to the STTM. The AER is also required under the NGR to monitor trading activity in the STTM with a view to ensuring that the trading activity is in accordance with Part 20 and to identify and report on any significant price variations.[307]

(iv) Gas Supply Hub

470 The GSH is a voluntary exchange for the wholesale trading of natural gas. The GSH currently operates through trading locations at Wallumbilla in Queensland, Moomba in South Australia and Culcairn and Wilton in New South Wales.[308] The GSH is operated and administered by AEMO in accordance with Part 22 of the NGR. Participation in the GSH requires membership of the exchange, which involves satisfying the criteria for membership specified in the Rules and entering into an exchange agreement with AEMO.[309] The GSH enables participants to trade (through an electronic platform) standardised, short-term physical gas products at each of the GSH trading locations. AEMO centrally settles transactions, manages prudential requirements and provides reports to assist participants in managing their portfolio and gas delivery obligations.[310]

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[302] NGR, r 354.
[303] State of the Energy Market 2022 – Report, page 121.
[304] Australian Energy Market Operator, *Overview of the Short Term Trading Market for Natural Gas – Version 4.2* (2011), page 7 <https://aemo.com.au/-/media/files/gas/sttm/overview-sttm-gas.pdf?la=en>.
[305] State of the Energy Market 2022 – Report, page 121.
[306] Australian Energy Market Operator, *Overview of the Short Term Trading Market for Natural Gas – Version 4.2* (2011), page 14 <https://aemo.com.au/-/media/files/gas/sttm/overview-sttm-gas.pdf?la=en>.
[307] NGR, r 498.
[308] State of the Energy Market 2022 – Report, page 122.
[309] NGR, r 537.
[310] AEMO, Energy Systems, About the Gas Supply Hub <https://aemo.com.au/energy-systems/gas/gas-supply-hub-gsh/about-the-gas-supply-hub-gsh>.

471 As for the DWGM and STTM, the AER's principal role in relation to the GSH is in monitoring, investigating and enforcing compliance with relevant provisions of the NGL and NGR relating to the GSH. Part 22 of the NGR does not give AEMO a specific role of monitoring trading and significant price variations in the GSH, however the AER includes the GSH in its general function of monitoring and reporting on wholesale gas markets.[311]

(v) Pipeline Capacity Trading

472 Pipeline capacity refers to the right to transport gas through a transmission pipeline. Pipeline Capacity Trading (***PCT***) allows gas market participants to trade spare pipeline capacity. PCT is facilitated by AEMO through a Capacity Trading Platform and a Day-Ahead Auction in accordance with Parts 24 and 25 of the NGR and the Capacity Transfer and Auction Procedures.[312] These arrangements apply to gas transmission pipeline and compression services (which are jointly referred to as 'transportation services') outside of the Victorian Declared Transmission System.[313] Trading of pipeline capacity through either mechanism requires participants to be registered with AEMO for that purpose in accordance with the Rules and Procedures.

473 In addition to its general compliance monitoring and enforcement responsibilities, the AER is required to monitor day-ahead nominations, renominations and activity in the capacity auction with a view to ensuring that transportation service providers, auction participants and transportation facility users comply with the market conduct and nomination rules.[314] The AER may request AEMO to suspend or limit the access of a participant to the capacity auction if the AER considers that continued participation by that person may materially and adversely affect the financial position of auction participants or facility operators or the integrity of the capacity auction.[315]

(vi) National Gas Services Bulletin Board

474 The Gas Bulletin Board is an open access website providing current information on gas production, storage and transmission pipelines in eastern Australia. The Bulletin Board is maintained by AEMO in accordance with Part 18 of the NGR and is comprised of information provided to AEMO by gas market participants in accordance with Part 18 and the Bulletin Board Procedures.[316] In broad terms, the operators of relevant gas facilities that meet reporting thresholds specified in the Rules are required to register with AEMO and provide standardised reports in relation to those facilities.[317] Relevant facilities include production facilities, pipelines, storage facilities, compression facilities, large user facilities and LNG processing facilities.[318]

475 The objective of the Bulletin Board is to facilitate improved decision making and trade in gas commodity and pipeline capacity, through the provision of readily accessible and up-to-date gas system and market information.[319] The Bulletin Board includes information such as:

(a) pipeline capabilities (maximum daily flow quantities, including bidirectional flows), pipeline and storage capacity outlooks, and nominated and actual gas flow quantities;

(b) daily production capabilities and capacity outlooks for production facilities; and

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311 State of the Energy Market 2022 – Report, page 120.
312 AEMO, *Capacity Transfer and Auction Procedures – Version 1.2* (2021) <https://aemo.com.au/-/media/files/gas/pipeline-capacity/capacity-transfer-and-auction-procedures.pdf?la=en>.
313 AEMO, *About Pipeline Capacity trading (PCT)* <https://aemo.com.au/energy-systems/gas/pipeline-capacity-trading-pct/about-pct>.
314 NGR, r 664(1).
315 NGR, r 664(2).
316 AEMO, *BB Procedures – Version 11.0* (2022) <https://aemo.com.au/-/media/files/gas/natural_gas_services_bulletin_board/site-content/gbb-documents/guides-and-procedures/bb-procedures-effective-nov-2022.pdf>.
317 NGR, r 150.
318 NGR, r 141 - definition of 'facility operator'.
319 AEMO, *About the Gas Bulletin Board* <https://aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb/about-the-gas-bulletin-board-gbb>.

(c) gas stored, gas storage capacity (maximum daily withdrawal and holding capacities) and actual injections / withdrawals.[320]

476 The bulletin board includes an interactive map showing gas plant capacity and production data, and gas pipeline capacity and flow at any point in a network.

477 The AER's principal role in relation to the Bulletin Board is compliance monitoring and enforcement of participant obligation with relevant NGL and NGR obligations.

(vii) Gas market interventions

478 The Australian Government has implemented a number of measures that aim to influence the outcomes in the wholesale gas market. These interventions are primarily directed at ensuring the adequacy and security of gas supply to the domestic market. This is an area which is subject to recent reform initiatives prompted by concerns about potential shortfalls in gas supply to the domestic market and significant increases in gas prices.

(A) Australian Domestic Gas Security Mechanism

479 The Australian Domestic Gas Security Mechanism (***ADGSM***) has been in effect since 1 July 2017. The objective of the ADGSM is to ensure that there is a sufficient supply of natural gas to meet the forecast needs of Australian gas consumers by controlling, if necessary, LNG exports. The Minister for Resources has the power under the ADGSM to require LNG projects to limit exports, or find offsetting sources of new gas, if a supply shortfall is considered to be likely. This power is exercised through provisions contained in Division 6 of Part 3 of the *Customs (Prohibited Exports) Regulations 1958* (Cth).

480 The government has recently implemented reforms to the ADGSM designed to make the mechanism more responsive and to better secure enough gas is made available for supply to the domestic market to meet domestic demand. These reforms are reflected in Guidelines (the *Customs (Prohibited Exports) (Operation of the Australian Domestic Gas Security Mechanism) Guidelines 2023* (Cth)) made under regulation 13GF of the *Customs (Prohibited Exports) Regulations 1958* (Cth). A draft of the Guidelines was released for consultation on 9 February 2023, and submission of the draft closed on 23 February 2023. The reforms commenced on 1 April 2023.

(B) Gas Price Cap and Mandatory Code of Conduct

481 On 22 December 2022 the Australian Government introduced a $12/GJ cap on wholesale gas prices. The cap took effect on 23 December 2022 and will remain in effect for a period of 12 months. The cap is given effect through the *Competition and Consumer (Gas Market Emergency Price) Order 2022* (Cth) (***Price Cap Order***), made pursuant to section 53M of the *Competition and Consumer Act 2010* (Cth) (***CCA***).

482 The Price Cap Order prohibits producers of natural gas and their affiliates from entering into agreements to supply gas, supplying gas under such agreements, or making offers on a gas trading exchange at a price above $12/GJ. The price cap applies in all jurisdictions except for Western Australia, and to all agreements made after 23 December 2022. While agreements entered into before this date are not subject to the price cap, pre-existing agreements which are varied after 23 December 2022 will be subject to the Order where the relevant variation includes a provision determining price.[321]

[320] State of the Energy Market 2022 – Report, page 122.
[321] This is subject to a number of exemptions specified in the Price Cap Order. These include agreements where the recipient of gas intends to export it as LNG; agreements for the storage of gas; subordinate contracts or transactions notices under a pre-existing master gas supply agreement, where the subordinate contract does not contain a provision determining price; agreements resulting from transactions on the Declared Wholesale Gas Market (DWGM) or Short Term Trading Market (STTM).

483 In addition to the Price Cap, the government has stated its intention to introduce a mandatory Code of Conduct via regulations made under Part IVBB of the CCA.

484 In May 2023, the Commonwealth government released a consultation draft of the Code of Conduct, which included the following proposed features.

(a) The gas price cap will be continued beyond the initial 12 month period; and will apply until at least 1 July 2025.

(b) The price cap is initially set at $12/GJ and will be reviewed by 1 July 2025. The ACCC will be responsible for setting future prices.

(c) An automatic exemption applies to small producers (ie those who produce less than 100PJ of gas in the previous financial year) who exclusively supply the domestic market.

(d) Some conditional exemptions to the price cap are available at the discretion of the Minister for Climate Change and Energy and the Minister for Resources (acting jointly), to other producers who have given satisfactory voluntary enforceable domestic supply commitments.

(e) Mandatory 'conduct requirements' have been introduced, which establish minimum conduct and process standards for commercial negotiations. These standards apply for sales involving a tender process with buyers being invited to make expressions of interest to purchase gas and general bilateral negotiations.

(f) The consultation draft of the Code of Conduct proposes to introduce a requirement for gas producers to publish details about available uncontracted gas, including information relating to when this gas will be brought to the domestic market.

(C) Gas Supply Guarantee

485 In March 2017, production facility operators and pipeline operators made commitments to the Australian Government to make gas available to meet peak demand periods in the NEM. The Gas Supply Guarantee is a mechanism developed by the gas industry to facilitate the delivery of these commitments.[322] The mechanism was formalised through the development by AEMO, in consultation with industry, of Gas Supply Guarantee Guidelines.[323] The Guidelines set out a process for AEMO to initiate the Guarantee to facilitate an industry response to anticipated gas supply shortfall events. However, the Guideline does not have legislative or regulatory force. The mechanism was originally scheduled to finish in March 2020, but the Australian Government extended the guarantee to March 2023. It expired on 31 March 2023.

486 In August 2022, the Energy Minister announced that new functions would be conferred on AEMO. . Under these new functions AEMO will be given broad powers to monitor and manage system reliability and supply adequacy in the east coast gas market, including the power to give binding directions to gas market participants when necessary to address a threat to the reliability or adequacy of gas supply. These reforms are contained in the *National Gas (South Australia) (East Coast Gas System) Amendment Act 2023,* which commenced on 27 April 2023. The corresponding rule amendments came into effect on 4 May 2023. AEMO is in the process of consulting with relevant market participants on the draft Procedures and Guidelines which underpin the East Coast Gas System Framework.

[322] AEMO, *Gas Supply Guarantee* <https://aemo.com.au/en/energy-systems/electricity/emergency-management/gas-supply-guarantee>.
[323] AEMO, *Gas Supply Guarantee Guidelines – Version 2.0* (2020) <https://aemo.com.au/-/media/files/gas/emergency_management/gsg-guidelines-v2-final.pdf?la=en&hash=F81F0A68F83F08B5B06D4208CCEA28AE>.

2.4 Gas retail

(i) Retail market

487 The gas retail market is regulated in a substantially similar way to the electricity retail market outlined at section 1.7. This section comments on the extent to which the regulation of retail gas markets differs to the regulation of retail electricity markets in Victoria.

488 As with electricity regulation, the NECF is applied in participating jurisdictions through state or territory laws in the Australian Capital Territory, South Australia, Tasmania, New South Wales and Queensland. The NECF does not apply in Victoria, except for Part 12A of the NGR which deals with gas connections for retail customers. The Victorian gas retail market is regulated by the AEMO and the ESC, primarily in accordance with the Energy Retail Code of Practice (***Energy Retail Code***) and the GI Act.

489 The AEMO provides the retail gas market services to gas industry participants and delivers the infrastructure that provides gas consumers with the ability to contract for the supply of gas with any licensed retailer of their choice.[324] In Victoria, the AEMO administers the Retail Market Procedures (Victoria) (***VRMP***), which governs, among other things, the customer transfer process.[325]

(ii) Consumer protections

490 There are several mechanisms under which consumers are protected, including through the ESC and the AEMO.

491 In Victoria, the ESC formally exercises its responsibilities under the *Essential Services Commission Act 2001*. Its mission is to promote the long-term interests of Victorian consumers with respect to the price, quality and reliability of essential services.[326] Further consumer protections are offered under the standing offer regime, price and data protection regulations.

Standing offers

492 Under the Energy Retail Code, a retailer licensed under the GI Act must offer a 'standard retail contract' on model terms and conditions that is subject to certain minimum requirements.[327]

493 As with the VDO in relation to electricity, the ESC sets a 'standing offer tariff' (***Standing Offer***) applicable to domestic (residential) and small business customers each year under the GI Act.[328] Retailers must publish the applicable Standing Offer on its websites and advise households and small businesses of the availability of the retailer's Standing Offer.[329]

494 Households and small businesses can request to be put on the Standing Offer, and retailers must notify customers how they can access the Standing Offer on their gas bill.[330]

Price regulation

495 AER does not set retail energy prices. Some State and Territory governments remain responsible for control of energy prices. For example, in Queensland, the Australian Capital Territory and Tasmania, customers can ask for a contract with an offer or tariff that is 'regulated' and which is set by the government.

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[324] AEMO, *About the gas retail markets* <https://aemo.com.au/energy-systems/gas/gas-retail-markets/about-the-gas-retail-markets>.
[325] AEMO, *Retail Market Procedures (Victoria)* <https://aemo.com.au/-/media/files/gas/retail_markets_and_metering/market-procedures/vic/2021/retail-market-procedures-victoria--version-160-clean.pdf?la=en>.
[326] ESC, *What we do* <https://www.esc.vic.gov.au/about-us/what-we-do>.
[327] ESC, Energy Retail Code of Practice – Version 2 (1 October 2022) <https://www.esc.vic.gov.au/sites/default/files/documents/energy-retail-code-of-practice-version-2-20220908.pdf> (***Energy Retail Code***), cl 18.
[328] GI Act, s 21.
[329] Energy Retail Code, cl 24.
[330] Energy Retail Code, cl 30.

496 In Victoria, market offers or tariffs are not capped, which means that energy retailers set their own prices in those jurisdictions.[331]

497 The Energy Retail Code contains price obligations on retailers. For example, it contains a requirement that retailers can only increase prices once a year, so as to ensure price certainty for its customers.[332] If a customer has signed up to a market retail contract for a discount, rebate or credit, the retailer must also offer that benefit for the entire duration of the contract.[333]

(iii) Consumer data protections

498 The data protection rights available under the CDR was extended to the energy sector, but only to the extent of electricity data sets.

499 Under the VRMP, the AEMO is responsible for creating, maintaining and administering a database to store customer details that is provided to it by gas retailers.[334] This data must be stored in a secure database.[335]

(iv) Metering

500 Metering in the gas market is not regulated as heavily as in the electricity market. The VRMP require distributors to create, maintain and administer a database in relation to all of their distribution supply points that includes information related to the gas meter at that distribution supply point.[336]

501 Distributors are required to provide to retailers a schedule setting out the dates on which it will read all its meters each month.[337] Distributors must also ensure that meter readings are validated with a validation methodology approved by AEMO.[338]

(v) Customer transfers

502 In Victoria, the AEMO facilitates the customer transfer process between retailers under the VRMP.[339] A customer will submit a request to transfer to a prospective retailer which will then deliver a notice of the transfer in relation to the customer's supply point to the AEMO. The AEMO will register the transfer of retailer in the metering register for the relevant supply point.

[331] AER, *Tariff and fees explained* <https://www.esc.vic.gov.au/about-us/what-we-do>.
[332] Energy Retail Code, cl 94
[333] Energy Retail Code of Practice, cl 96.
[334] AEMO, Retail Market Procedures (Victoria) – Version 16.0 (30 April 2021) (***VRMP***), cls 5.1.1(a)-(b).
[335] VRMP, cl 5.1.1(c)(ii).
[336] VRMP, cl 2.1.1.
[337] VRMP, cl 2.2.1.
[338] VRMP, cl 2.3.1.
[339] VRMP, Chapter 4.