CITIPOWER

FLEXIBLE TRADING ARRANGEMENTS

COST PASS THROUGH APPLICATION

SEPTEMBER 2025

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1. Summary

In May 2022, the Australian Energy Market Operator (**AEMO**) lodged a rule change request proposing a model to enable customers to separate flexible customer energy resources (**CER**) from passive loads e.g. general power and light and have them managed and recognised in the wholesale energy market settlements, should customers choose. The proposed model applied to small and large customers as well as street furniture with in-built measurement capabilities. This rule change request comprised part of the Energy Security Board's (**ESB**) CER implementation plan. The rule became known as *Unlocking CER benefits through flexible trading* or *flexible trading arrangements* (**FTA**).

On 15 August 2024, the Australian Energy Market Commission (**AEMC**) determined 'a more preferable' rule. The final FTA rule included:

- large customers being able to engage multiple energy service providers at their premises to more easily manage and obtain value from their CER
- energy service providers for small and large customers being able to separate and manage 'flexible' CER from 'passive' loads in the energy market
- market participants being able to use in-built measurement capability in technology such as electric vehicle (**EV**) chargers and smart streetlights.

The final FTA rule is intended to make it easier for energy service providers to offer products and services that unlock the value of flexible CER. It is also intended to provide a strong foundation for CER to be delivered and integrated into the National Electricity Market (**NEM**).

The final FTA rule is part of a suite of reforms aimed at supporting the energy transition and unlocking the full potential of CER for the benefit of all customers. These include a pricing structure review, work to accelerate the rollout of smart meters, integrating price-responsive resources into the NEM, and improving consumer access to real-time energy data. This is in addition to non-rule-based reforms such as market interface technology enhancements (**MITE**) and customer data exchange (**CDX**).

Most of the final FTA rule must be implemented by 1 November 2026. Arrangements related to in-built metering at primary connection points for street furniture will be implemented earlier - 31 May 2026 - recognising the readiness of some of these participants to take up the arrangements and alignment with AEMO's work plan.

For the final FTA rule to operate in Victoria, further amendments are required to existing jurisdictional instruments. This is because the National Energy Customer Framework (**NECF**) does not automatically apply in Victoria. Further the meter contestability and classification requirements in Victoria differ from those across the wider NEM. The Victorian Government is currently consulting on the necessary changes to regulatory instruments to allow implementation of the final FTA rule in Victoria. A key difference between Victoria and other jurisdictions will be contestability of type 9 metering arrangements. In Victoria, streetlight customers will have the option to elect their local distributor to be their type 9-meter provider.

Compliance with the final FTA rule will require functionality that is beyond our existing IT system capability. Uplifts will be required IT systems, operational processes, and people. New functionality will be required for many market and back-end IT systems to facilitate compliance. This includes, but is not limited to:

- supporting new meter types, 8A, 8B, 9 in our systems
- supporting the primary and secondary national meter identifier (**NMI**) structure
- meter data receipt, retrieval, storage, and publishing

- supporting new participant roles, responsibilities, and accreditation
- new market system and transfer system (**MSATS**) data attributes and change request process
- increased transaction volumes.

The new IT system, operational processes and people requirements to comply with the final FTA rule were not contemplated, or funded, through previous regulatory allowances. However the final FTA rule does meet the pass-through eligibility requirements set out in the National Electricity Rules (**Rules**).

Table 1.1 summarises the proposed positive pass-through amounts. We note the proposed pass through amounts are consistent with the estimates provided to the AEMC throughout the Rule change consultation.

TABLE 1.1 PROPOSED POSITIVE PASS-THROUGH AMOUNT ($'000, JUNE 2026)

	FY25	FY26	F27	FY28	FY29	FY30	FY31
Capital expenditure	777	6,726	2,020	774	387	-	-
Operating expenditure	51	604	1,026	651	280	8	8
Total expenditure	**828**	**7,330**	**3,046**	**1,425**	**667**	**8**	**8**

Source: CitiPower

2. Positive change event

Chapter 6 of the Rules include cost-pass provisions for distributors allowing recovery of materially higher costs incurred in providing a direct control services triggered by an unforeseen specific event. The eligible pass-through events are defined by the Rules. For the reasons outlined in this section, the final FTA Rule change meets the requirement of a regulatory change event.

2.1 Regulatory change event

The Rules define a *regulatory change event* as a change in regulatory obligation or requirement that:[1]

> *falls within no other category of pass-through event; and*
>
> *occurs during the course of a regulatory control period; and*
>
> *substantially affects the manner in which the Transmission Network Service Provider provides prescribed transmission services or the Distribution Network Service Provider provides direct control services (as the case requires); and*
>
> *materially increases or materially decreases the costs of providing those services.*

It is sufficient for the relevant act or decision to have any one of the effects set out in the four sub-paragraphs above, to render that act or decision a regulatory change event.

2.2 Effect of flexible trading arrangements

The final FTA rule falls in no other category of pass-through event. The cost incurred in complying with the final FTA rule will fall in the current regulatory period, will substantially impact how we provide direct control services and consequently materially increase the cost of providing direct control services.

Falls within no other category of pass-through event

The Rules consider pass through events as specific, uncontrollable, and material events that allow a distributor to recover costs that were not included in their revenue determination. These events are outlined in the Rules, and include regulatory change event, service standard event, tax change event and retailer insolvency event.

We don't consider the Final FTA rule to satisfy the definition of a tax change event or retailer insolvency event. It's arguable the final FTA rule could be considered a service standard event as it impacts the quality or reliability of network services however we prefer, and believe, the final FTA rule more closely aligns with the definition of regulatory change event given it has been triggered by the AEMC's Unlocking CER benefits through flexible trading rule change completed on 15 August 2024.

Occurs during the course a regulatory control period

The AEMC's final Unlocking CER benefits through flexible trading rule change was completed on 15 August 2024. Implementation of the final FTA rule will be required for most provisions by 1 November 2026. The exception is arrangements related to in-built metering at primary connection points for assets like street lighting and street furniture like public EV chargers which will be implemented earlier - by 31 May 2026.

Therefore we require changes in our IT systems, operational processes and people changes prior to 'go live' on 31 May and 1 November 2026. Most of our costs will be incurred in the period 2024/25 and

[1] NER, chapter 10.

2025/26 however some residual costs will be incurred over the remainder of the regulatory period. These were included in our regulatory proposal submitted 31 January 2025 but will be removed from the revised proposal.

Substantially affects the manner in which the distribution network service provider provides direct control services

We are required to ensure compliance with the Rules. Non-compliance can result in:

- financial penalties, loss of our license to operate in the market and reputational damage
- material adverse impacts on wholesale market settlement process
- loss of the customer benefits sought by AEMC and AEMO through the final FTA rule changes.

In addition, regular audits of our data, processes and systems are performed by AEMO to ensure we remain compliant with market rules and procedures. The penalties associated with non-compliance have been classified as civil penalty provisions to encourage compliance by the relevant parties.

Our identified need, therefore, is to ensure timely compliance with the final FTA rule change and continued compliance with our regulatory requirements.

The final FTA rule change introduces a range of changes to NEM processes. New IT system functionality, processes and people will be required to facilitate compliance, including, but not limited to:

- supporting new meter types, 8A, 8B, 9 in our systems
- supporting the primary and secondary NMI structure (new NMI number ranges)
- meter data receipt, retrieval, storage, and publishing
- supporting new participant roles, responsibilities, and accreditation
- new MSATS data attributes and change request process
- increased transaction volumes.

Materially increases or materially decreases the costs of providing those services

The forecast cost of implementing the final FTA rule is $13.3M. This includes $10.7M of capital expenditure and $2.6M of operating expenditure.

2.3 Event date

Based on AEMC's 15 August 2024 final unlocking CER benefits flexible trading rule announcement being the event date, the associated pass-through must be lodged no later than 20 December 2024.

We subsequently wrote to the AER on 6 November 2024[2] advising that to implement the Rule change, the market procedures and systems administered by AEMO must be modified. An outline of program of work to give effect to the Rule change has been provided by AEMO in its National Electricity Market Reform Implementation Roadmap (version 4.0). The scoping work for the Rule change is not scheduled to be completed until September 2025. This is well after the 90-day due date for submission of a cost pass-through application.

When assessing whether to submit a cost pass-through application, we considered the trade-off between the level of certainty in developing a high-level estimate versus having more time to develop a more robust estimate. Based on this assessment, we believed that customers' long-term interests

[2] Letter from Renate Vogt to Kris Funston, Extending the timeframes for submitting a positive cost pass through application relating the rule change Unlocking CER benefits through flexible trading, 6 November 2024.

are better served by having a more robust forecast of costs, hence we sought an extension of time to submit a cost-pass through application.

Clause 6.6.1(k) of the Rules allows the AER to extend the time in which a distribution network service provider can submit a positive cost pass-through application if it is satisfied that there is 'difficulty of assessing or quantifying the effect of the relevant pass-through event. As noted above, the lack of clarity on the scope and timing of the market changes and the ensuing cost estimation process meets the criteria. It is for this reason we sought an extension through to 15 November 2025 to submit a positive cost pass-through application for this Rule change. This request was accepted by the AER on 15 November 2024[3].

2.4 Materially increases costs

The Rules definitions of ‘positive change event’, ‘service standard event’ and ‘regulatory change event’ require that an event ‘materially’ increase the costs of providing direct control services.

Chapter 10 of the Rules define ‘materiality’, for the purposes of the cost pass-through provisions, as follows:

> *[A]n event results in a Distribution Network Service Provider incurring materially higher or materially lower costs if the change in costs (as opposed to the revenue impact) that the Distribution Network Service Provider has incurred and is likely to incur in any regulatory year of a regulatory control period, as a result of that event, exceeds 1% of the annual revenue requirements for the Distribution Network Service Provider for that regulatory year.*

The table below provides the materiality thresholds.

TABLE 2.1 APPLICATION OF MATERIALITY REQUIREMENT ($'M, JUNE 2026)

DESCRIPTION	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Change in costs	0.83	7.33	3.05	1.43	0.67	0.08	0.08
Materiality threshold	3.42	3.57					

Source: CitiPower

[3] Letter from David Monk to Renate Vogt, Re: Request for extension of time – cost pass through applications – AEMO’s Foundational & Strategic Initiatives and AEMC’s rule change, Unlocking CER benefits through flexible trading, 15 November 2024.

3. Proposed pass-through amounts

The final FTA rule aims to enhance the flexibility of how CER is used and traded within the NEM. The primary objective is to enable customers to manage their energy usage more effectively and to participate actively in the market.

The Rule is about the integration of CER in the NEM. It makes a series of changes designed to allow customers or their agent to manage CER in ways that provide benefits to the customer and to the energy system.

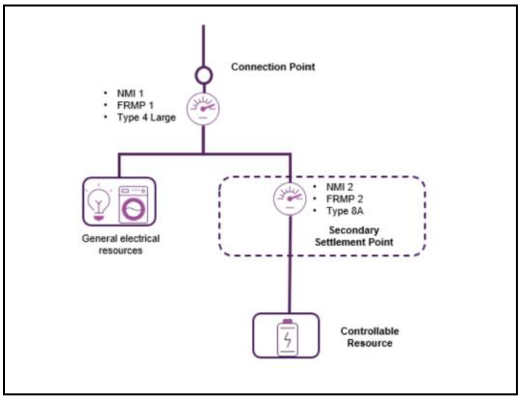
The Rule introduces changes to enable:

- flexible trading with multiple energy service providers at large customer premises
- opportunities to optimise CER flexibility for small customers
- measuring energy flows from street furniture connections (e.g. streetlights, EV chargers).

Flexible trading with multiple energy service providers at large customer premises

The changes enable large customers to establish secondary settlement points (**SSPs**) and engage multiple energy service providers to manage flexible resources at these points. The key features of this framework are:

- it is voluntary
- large customers can establish SSPs and engage multiple financially responsible market participant (FRMP) at their premises
- the relationship between financially responsible market participants (**FRMP**) is governed by existing regulatory arrangements and contractual arrangements
- a new accredited role, NMI service provider, is responsible for establishing and maintaining SSP NMIs and would have visibility of standing data from SSP NMIs
- existing subtractive settlement arrangements are used to minimise implementation costs

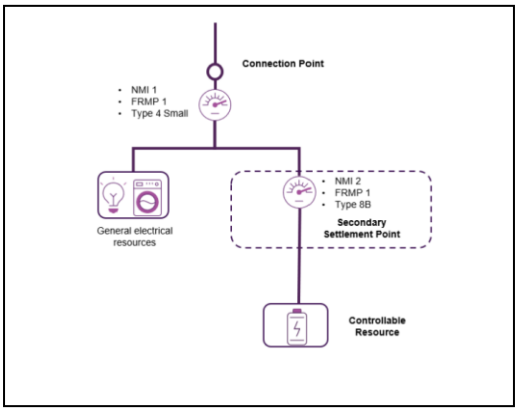


- distribution network charges are allocated to the FRMP at the premises connection point (**PCP**)
- new meter type 8A can be used for any SSP at a large customer premises, or at the PCP
- any meter co-ordinator (**MC**) wishing to provide services at a type 8A metering installation must include this metering type in their meter asset management strategy and have that strategy approved prior to the commissioning of any type 8A metering installation
- installation of type 8A metering installation devices can be carried out by any person qualified under applicable law, not necessarily meter provider (**MP**), however the commissioning of a type 8A metering installation must only be performed by an appropriately accredited MP
- an MP must maintain the type 8A metering installation, consistent with the appointing MC's meter asset management strategy, that must have received prior approval for the inclusion of type 8A metering installations from AEMO.

Opportunities to optimise CER flexibility for small customers

The changes enable small customers to identify and manage flexible CER separate from inflexible or passive energy use and allow flexible CER to be better recognised in the energy market. The main features of this framework are:

- small customers can establish a SSP without a separate connection to the distribution network for their flexible CER which would be assigned a NMI
- flexible CER energy consumption would be separately metered through either a meter (a new type 8B metering installation) integrated into the customer's CER or wired externally to the device (type 4 metering installation or a new type 8B metering installation)
- the new arrangements are voluntary and based on consumer choice
- small customers continue to only have one FRMP at their premises
- subtractive settlement arrangements would apply between the PCP and SSP(s) at small customer premises
- distribution network charges would remain the same given there is only one FRMP
- a new accredited role, NMI service provider is responsible for establishing and maintaining the NMI for the consumer's retailer
- the FRMP can choose a different contestable MC at the SSP compared to the PCP



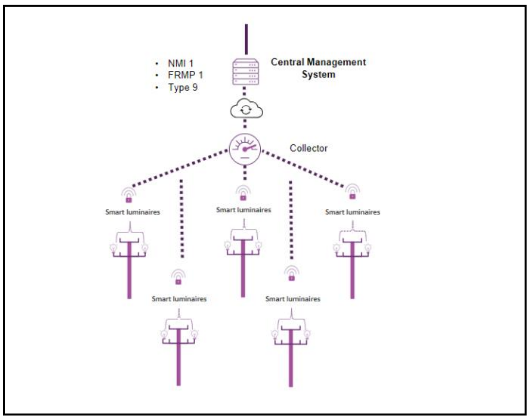
- any MC wishing to provide services at a type 8B metering installation must include this metering type in their meter asset management strategy, and have that strategy approved prior to the commissioning of any type 8B metering installation
- installation of type 8B metering installation devices can be carried out by any person qualified under applicable law, not necessarily an MP, however the commissioning of a type 8A metering installation must only be performed by an appropriately accredited MP
- an MP must maintain the type 8B metering installation, consistent with the appointing MC's asset management strategy, that must have received prior approval for the inclusion of type 8B metering installations from AEMO
- distributors can access metering data from SSP NMIs if they choose to.

Measuring energy flows for street furniture connections

The changes introduce the type 9 metering installation, designed to allow for street furniture connections such as smart streetlighting systems, kerbside EV charging points, and some existing unmetered connections where traditional metering cannot be practically accommodated.

The main features of this framework are:

- arrangements are voluntary and cover a range of use cases, including kerbside EV chargers and streetlights
- the minimum specifications will be determined by AEMO in procedures, guided by principles in the NER; the specification is generally expected to be lower than for a type 4 small customer metering installation
- they require National Measurement Institute Pattern Approval



- street furniture connection arrangements can include the aggregation of multiple metering points (i.e. multiple streetlights) under one NMI using a central management system (**CMS**) – a new definition in the NER which is ‘a device or system that collects electronic signals from measurement elements and packages it into trading intervals’
- MPs and meter data provider (**MDP**) require new accreditation requirements for each new metering installation type
- the MC role is contestable – i.e. no party is mandated to provide MC services, with appointment responsibility residing with the FRMP, as is standard for type 1-4 metering installations
- the MC for type 9 metering installations can propose alternative testing and inspection arrangements to AEMO for approval through an asset management strategy.

Changes to procedures

The Rule has two commencement dates: 31 May 2026, and 1 November 2026. This staggered implementation allows for the introduction of type 9 metering, which includes street furniture and public lighting, into the NEM before the full FTA rule takes effect.

31 May 2026

Arrangement for type 9 metering being on 31 May 2026. Material procedural impacts:

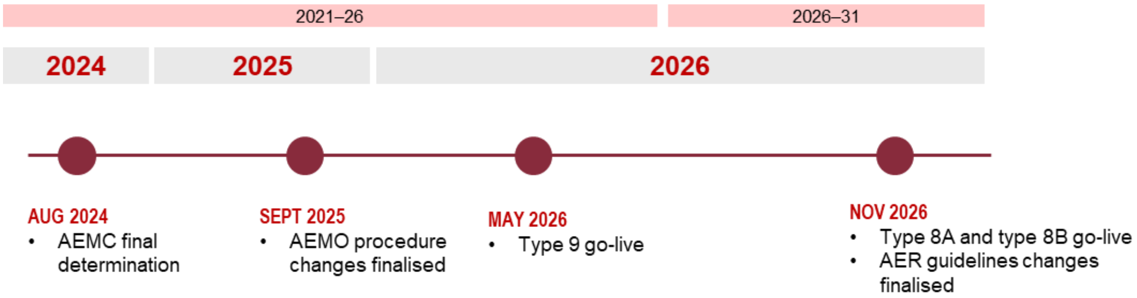
- changes to MSATS Principles
- changes to Standing Data for MSATS
- change to Metrology Procedure Part A
- changes to Metrology Procedure Part B

1 November 2026

Arrangement for type 8 metering being on 1 November 2026. Material procedural impacts:

- changes to MSATS Principles
- changes to Standing Data for MSATS
- change to Metrology Procedure Part A
- changes to Metrology Procedure Part B
- new NMI Service Level Procedure
- MDFF NEM12 and NEM13
- Guide to the Role of the Metering Coordinator
- Service Level Procedure Metering Provider.

FIGURE 3.1 FTA RULE CHANGE TIMELINE



Source: CitiPower

To support the final FTA rule, new functionality will be required to our IT systems, operational processes and people to facilitate compliance, including, but not limited to:

- supporting new meter types, 8A, 8B, 9 in our systems
- supporting the primary and secondary NMI structure (new NMI number ranges)
- meter data receipt, retrieval, storage, and publishing
- supporting new participant roles, responsibilities, and accreditation
- new MSATS data attributes and change request process
- increased transaction volumes.

Assessment of the final FTA rule on our network involved undertaking an impact analysis, applying the criteria outlined in figure 3.2.

FIGURE 3.2 IMPACT ASSESSMENT FRAMEWORK

RATING	DESCRIPTION
Low	• Impact: low but noticeable • Effort: requires some effort but remains manageable • Examples: small feature enhancements, routine updates, or training a few individuals
Medium	• Impact: moderate impact on processes, systems, or users • Effort: requires more time and coordination but doesn't significantly disrupt operations • Examples: introducing a new tool for a single team or minor process changes, minor software version release
High	• Impact: significant, with widespread influence • Effort: demands substantial resources, planning, and possibly cross-functional collaboration and significant testing and training • Examples: migrating a system component, implementing a major new feature
Very high	• Impact: affecting multiple teams, departments, or systems • Effort: requires significant investment in terms of time, resources, and careful management, training, and extensive internal and bi-lateral testing • Examples: overhauling an IT system or major code re-write or re-structure, a major version release of software, new technology platform, introducing new capability

Source: CitiPower

The impact assessment identified impacts on 7 of our system core domains. Further information on the IT system functionality please see the Appendix.

TABLE 3.1 FINAL FTA RULE IMPACT ASSESSMENT

DOMAIN	SYSTEM	ENABLING TYPE 8A	ENABLING TYPE 8B	ENABLING TYPE 9
Market systems	CISOV	Very High	Very High	High
	IEE	Low	High	Medium
	MTS	High	Very High	High
	UIQ	N/A	N/A	Medium
Network systems	Map Insights	Low	Low	Medium
	SNAP	Medium	Medium	Medium
	GIS	Medium	Medium	N/A
	NDP	Medium	Medium	Medium
	ADMS	N/A	Very High	N/A
	OMS	N/A	Very High	N/A
Integration	API Gateway	N/A	Medium	High
Customer systems	SF eConnect	High	Very High	High
	SF MyEnergy	High	High	Low
Field services	SFS	Low	Low	High
Reporting	SAP BI/BW	High	High	Medium

Source: CitiPower

TABLE 3.2 SYSTEM EXPENDITURE TO COMPLY WITH FINAL FTA RULE ($'000, JUNE 2026)

SYSTEM	FY25	FY26	FY27	FY28	FY29	FY30	FY31
CISOV	74	603	194	74	37	-	-
IEE	89	730	234	90	45	-	-
MTS	105	856	274	105	53	-	-
UIQ	8	68	22	8	4	-	-
SF eConnect	50	406	130	50	25	-	-
SF myEnergy	66	540	173	66	33	-	-
API Gateway	25	203	65	25	12	-	-
SAP BI/BW	73	592	190	73	36	-	-
SFS	33	270	87	33	17	-	-
SNAP	50	406	130	50	25	-	-
ADMS	25	203	65	25	12	-	-
OMS	25	203	65	25	12	-	-
NDP	50	406	130	50	25	-	-
Map Insight	50	406	130	50	25	-	-
GIS	50	406	130	50	25	-	-
Infrastructure capacity	4	427	-	-	-	-	-
Total	**777**	**6,726**	**2,020**	**774**	**387**	**-**	**-**

Source: CitiPower

The take up of FTA by customers does not drive system costs as may be expected. The system costs are instead driven by the complexity and cost of changes to AEMO's procedures and data requirements that have flow on impacts to our systems. In considering the system costs, consideration was given to whether a simpler solution could be implemented if the AEMC's projections of FTA take up were not realised. On reviewing the operational impacts, it was determined that a spreadsheet option would be to resource intensive to facilitate hence a decision was made to proceed with a system-based solution.

In addition to the system or capital costs, there are operating costs to support the systems development, implementation and on-going operation. Operating costs have been separated into 3 categories, project management, user assurance testing and on-going maintenance.

TABLE 3.4 OPERATING EXPENDITURE TO COMPLY WITH FINAL FTA RULE ($'000, JUNE 2026)

SYSTEM	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Project management	51	348	264	137	69	-	-
On-going maintenance	-	52	151	106	8	8	8
User assurance testing	-	204	611	407	204	-	-
Total	**51**	**604**	**1,026**	**651**	**280**	**8**	**8**

Source: CitiPower

4. Key assumptions

TABLE 4.1 PASS THROUGH APPLICATION ASSUMPTIONS

DESCRIPTION	ASSUMPTION
Real dollars	All dollars presented in June 2026 dollars
Actual vs forecast	All actual data is at 31 July 2025
Operating expenditure	We will incur some project specific incremental operating costs associated with project management, testing, AEMO engagement and preparation of this application. There are on-going maintenance costs associated with new system functionality
Labour rates	A blended labour rate has been applied to labour forecasts based on $155.36 per hour ($ June 2026) as approved in the 2026-2031 draft determination
Cost sharing	Powercor and CitiPower operate off the same IT platforms. Costs have been shared between the two distributors based on 70:30 split consistent with their relative sizes of their customer bases
Exclusions	This application does not include any costs associated with MITE/CDX implementation
Bill impact	We recognise this pass-through application is unprecedented. Typically pass-throughs are recovered over the remainder of the regulatory period. Therefore, we have smoothed recovery over the entire 2026-2031 regulatory period
Final determination	For the current regulatory period, we received some IT expenditure allowance that could be argued contributes to FTA readiness. Therefore, we have removed $1.3M in costs to avoid over recovery of costs

Source: CitiPower

5. Implementation timeline

Work has commenced to ensure we meet the compliance timeframes as determined by the AEMC.

Most work will be completed in the current regulatory period. This includes application upgrades and infrastructure builds. The project will extend into the next regulatory period. This will include testing and application support activities.

Our FTA project implementation comprises:

- **scoping**: identifying the system and process changes required to achieve compliance. It defines the inclusions and exclusions from the project
- **requirements**: gathering and documenting the needs and expectations of stakeholders the project is required to fulfill
- **technical**: this is the technical aspect of the project. It includes the architecture, design, and technical specifications needed to build the solution
- **build**: this is the phase where the actual development and construction of the project deliverables takes place
- **test**: this involves verifying and validating that the project deliverables meet the specified requirements and are free of defect.

6. Proposed positive pass-through amount in each regulatory year

The Rules require a pass-through application include the proposed positive pass-through amount that will be imposed on customers. Based on the post tax revenue model, the proposed positive pass-through amounts are outlined in table 6.1.

All revenue is proposed to be recovered over the next regulatory period. The incremental bill impact for a typical residential customer is approximately $0.39 per annum over the next regulatory period.

TABLE 6.1 PROPOSED POSITIVE PASS-THROUGH AMOUNT ($ MILLION, 2026)

	FY26	FY27	FY28	FY29	FY30	TOTAL
Proposed positive pass-through amount	2.57	2.57	2.57	2.57	2.57	12.87

Source: CitiPower

A.1 Compliance checklist

TABLE A.1 NATIONAL ELECTRICITY RULES COMPLIANCE CHECKLIST

CLAUSE	REQUIREMENT	SECTION
6.6.1(c)	To seek the approval of the AER to pass through a positive pass-through amount, a Distribution Network Service Provider must submit to the AER, within 90 business days of the relevant positive change event occurring, a written statement which specifies the details of the positive change event	3.0
	The date on which the positive change event occurred	2.3
	The eligible pass-through amount in respect of that positive change event	1.0
	The positive pass-through amount the Distribution Network Service Provider proposes in relation to the positive change event	1.0
	The amount of the positive pass-through amount that the Distribution Network Service Provider proposes should be passed through to Distribution Network Users in the regulatory year in which, and each regulatory year after that in which, the positive change event occurred	3.0
	Evidence of the actual and likely increase in costs referred to in subparagraph (3); and that such costs occur solely as a consequence of the positive change event	3.0
	Such other information as may be required under any relevant regulatory information instrument	-

Source: CitiPower

A.2 System overviews

DOMAIN	SYSTEM	DESCRIPTION
Market systems	CISOV	Customer information system, maintaining addresses, billing, creation of service point, service order management, meter read schedules for manually read meters, upload/download to FCS, including substitution for basic meters
	IEE	Meter data store for all meter types, managing validation/estimation/substitution, sends meter data to MTS. Note: Substitution for basic meters is done in CIS OV
	MTS	System responsible for interacting with market (B2B/B2M), provides a gateway for market transactions and handles service orders, change requests and meter data provision
	UIQ	System responsible for communicating with smart meters through mesh network and control and retrieval of consumption/generation meter data
Network systems	Map Insights	Visualisation tool working in conjunction with GIS
	SNAP	Strategic network analytics platform providing real-time analytics from various network systems
	GIS	Geographical information system and Small World Enterprise Gateway interface for GIS data
	NDP	Network data platform hosted in the cloud
	DER management system	Manage and control the stability of the network during low demand by controlling the amount CER generation
	OMS	Outage management system
Customer systems	SF eConnect	Online platform for managing electrical work requests
	SF MyEnergy	Online customer energy portal to view energy usage
Field services	SFS	Mobile field works management platform
Integration	API gateway	Server that acts as an intermediary between clients and backend services, performs routing, authentication, rate limiting and logging and interface to external systems
Reporting	SAP BI/BW	Reporting and analytics tool

Source: CitiPower

A.3 Confidentiality template

TABLE A.3.1 CONFIDENTIALITY TEMPLATE

None.

TABLE A.3.2 PROPORTION OF CONFIDENTIAL INFORMAITON

None.

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For further information visit:

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