public interest
ADVOCACY CENTRE

Post 2025 Market Design

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About the Public Interest Advocacy Centre

The Public Interest Advocacy Centre (PIAC) is an independent, non-profit legal centre based in Sydney.

Established in 1982, PIAC tackles barriers to justice and fairness experienced by people who are vulnerable or facing disadvantage. We ensure basic rights are enjoyed across the community through legal assistance and strategic litigation, public policy development, communication and training.

Energy and Water Consumers' Advocacy Program

The Energy and Water Consumers' Advocacy Program (EWCAP) represents the interests of low-income and other residential consumers of electricity, gas and water in New South Wales. The program develops policy and advocates in the interests of low-income and other residential consumers in the NSW energy and water markets. PIAC receives input from a community-based reference group whose members include:

- NSW Council of Social Service;
- Combined Pensioners and Superannuants Association of NSW;
- Ethnic Communities Council NSW;
- Salvation Army;
- Physical Disability Council NSW;
- Anglicare;
- Good Shepherd Microfinance;
- Financial Rights Legal Centre;
- Affiliated Residential Park Residents Association NSW;
- Tenants Union;
- The Sydney Alliance; and
- Mission Australia.

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The Public Interest Advocacy Centre office is located on the land of the Gadigal of the Eora Nation.

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1. Introduction

PIAC welcomes the opportunity to respond to the Energy Security Board's (ESB) Post 2025 Market Design Issues Paper.

The National Energy Market (NEM) is in a transformation, from an energy system relying primarily on large scale, centralised, firm, mechanical, fossil-fuel generation and passive demand, to one with a small scale, decentralised, variable, electronic, low-emission generation fleet interacting with more sophisticated and active demand-side behaviour.

Real electricity prices have increased for households, becoming a major cost of living pressure. This has exacerbated energy poverty and left many people without an essential service – with impacts on their health, wellbeing and options for improving their circumstances

Against this backdrop there has been a damaging public discourse that frames emissions reduction and economic opportunity as in opposition, and the energy industry has itself been subject to major upheaval and policy uncertainty in a decade of political volatility.

The rapid transition in energy and resources presents challenges and opens potential opportunities to create more sustainable and prosperous communities.

In PIAC's view, aside from the notable absence of an enduring emissions policy, the current wholesale energy market arrangements served us well until this decade. These arrangements are not 'broken', but neither are they fit for the purpose of resolving the energy trilemma in the coming decade and beyond.

Fundamental change to energy markets, and the planning and operation of the energy system, is required to ensure energy supply remains reliable, becomes affordable, and there is steady emissions reductions.

2. Assessment framework

PIAC supports the ESB's proposed key principles with some modifications, particularly with respect to cost allocation.

2.1 Cost allocation principle

In PIAC's view, the principle 'costs are allocated to those best placed to respond to them', does not efficaciously promote the National Energy Objective (NEO).

Passive energy users and critical loads are limited in being able to respond to certain costs, but that does not mean the cost of supplying them should not be allocated to them. Similarly, an active energy user who provides benefit to the wider market would be expected to be rewarded for their actions.

PIAC suggests replacing this ‘responder-pays’ cost principle with the more efficient and fairer ‘beneficiary-pays’ principle, so that ‘costs are allocated those who benefit from a given investment or action’.

Under this principle:

- Where there are multiple beneficiaries, the costs should be recovered proportionally to their share of the benefits.
- Where it is not practical and transparent to identify the beneficiaries and measure the benefits, a causer-pays approach should be used.
- Cross-subsidies should only be permitted where they are accepted by informed consumer preferences from the providers of that subsidy, or are immaterially small.

2.2 Transparency and simplicity principle

PIAC considers the ‘transparency and simplicity’ principle should be separated into two principles. Simplicity should be optional and subordinate to principles that promote efficiency and fairness. Transparency should not be optional.

2.3 The role of scenarios and forecasts in the post 2025 market design

Forecasts are important tools for predicting the nature, magnitude and timing of emerging needs in the energy market. As the energy system becomes increasingly complex and the pace of change increases forecasting is becoming more challenging.

PIAC considers the design of future markets should cater to the range of plausible future scenarios. Furthermore, future pricing arrangements should be adaptable to changing and unpredictable conditions and needs.

To this end, the use of scenarios that reflect the range of plausible outcome is appropriate and PIAC supports the ESB’s proposed use of the ISP scenarios.

PIAC also supports the ESB’s view that ‘… it is also important to evaluate the impact that differing market designs have on the cost of providing the resources to meet demand from consumers’. We recognise the significant challenge of finding a balanced approach to managing the impacts, real and perceived, on incumbent businesses, and the risks of making major reform to an existing energy market.

2.4 Modelling

PIAC supports the ESB’s approach to modelling. Please refer to section 4 below on market price settings.

3. Future market design options

3.1 Price settings need to be adaptable

Adaptable prices are important for the long-term interest of consumers. A future market design should ensure prices respond to changes in value as they occur, and are recovered from those who benefit.

Price adaptability is often compromised by over-reliance on forecasts, or the prioritisation of investment certainty for service providers.

The scenario described in section 3.5 below provides an example of how adaptability should be built into the market design to avoid locking in prices that are above the value placed on them or recovered inefficiently.

3.2 The wholesale market needs new flexibility, not just old capacity

The energy only market arrangements were effective when available technology and economies of scale meant the most cost-effective investments in generation were large, centralised generators, with individual units in the 100s of MW, that provided firmness as a by-product.

Solar and wind are now the most cost-effective investments. Though clean, more reliable and able to be ramped down faster than traditional generating plant, they are variable, sometimes difficult to predict, and can't be dispatched on. Batteries can ameliorate these challenges, however, the current market arrangements disincentivise their uptake. Under the current arrangements, non-scheduled and scheduled generators are paid the same spot price, and dispatchable generators of less than 30MW are allowed to remain unscheduled.

In the coming decade there will be more variable generation and with the influence of diurnal and seasonal factors on the state of charge of energy storage systems, high price events will be increasingly harder to predict on the basis of high demand and low generation alone. With this uncertainty, the type of peaking plant required to meet very occasional peaks is an increasingly risky investment in an energy-only market.

Signalling an energy-only price to a market where variable sources have no marginal cost, and dispatchability is in short supply, is inefficient.

Given the above, PIAC considers price signals are needed to ensure the availability of flexible generation, storage and demand side resources.

While eligibility of 'flexibility' payments should be extended to any generators that provide the services when needed, the design of a flexibility market should aim to incentivise new sources to enter the market where they would not have otherwise.

3.3 Flexible energy services and sources

Services provided for flexibility might include;

- fast response, either automated or centrally dispatched,

- fast ramping, up and/or down,
- reserve storage capacity,
- new ancillary services, or
- network support capability.

Flexibility is not the same as capacity. Capacity without fast, on demand ramping (up and/or down) is of little value in a market increasingly dominated by variable energy sources and should be priced accordingly. Reliability, as distinct from being a service in itself, is an essential characteristic of any flexible energy service.

Much new flexibility would be expected to come from batteries, other energy storage systems, and demand response.

Sources of flexibility within the existing generation fleet include:

- Hydro and gas generators
- Coal fired power stations with batteries. Without batteries, coal fired generation is not able to ramp up and down fast enough to participate in a market for flexibility and may actually increase the need for flexibility in the market. However, with a large battery (at least of similar power output to one of its coal units), an existing coal fired power station could conceivably participate in a flexibility market.

3.4 Design options for introducing flexibility to the energy market

An energy price signal can be retained while introducing an incentive for flexible energy services. PIAC considers there is value in retaining an energy price, however it will need to be modified, and potentially have another market layer introduced, to incentivise the products and services required in the future market.

Currently, all generators are paid the same spot price irrespective of whether they are dispatchable and scheduling depends on the outmoded measure of their nameplate capacity, not whether they are available for dispatch when needed.

Options for incentivising more fast ramping dispatchability with minimal disruption to the existing arrangements, include:

- Moving to a two-tier wholesale energy price
- Introducing a flexibility payment and reducing the market price cap.

OPTION 1: A two-tier wholesale energy price

This option involves modifying the current scheduling and settlement arrangements so that generators are classified and incentivised based on their ability to be dispatched and ramped up and down.

The new 'scheduled' participant category may:

- include dispatchable (on and off) sources such as batteries, hydro, some gas generators, and demand response
- apply to single or aggregated units totalling 5MW and above and be dispatched by AEMO on a 5 minute basis, and
- have the current Market Price Cap arrangements applied.

The new 'non-scheduled' participant category may:

- include generators that can't be centrally dispatched on and off as needed, such as coal, solar and wind (without batteries) and smaller generators,
- not be dispatched by AEMO, although some obligations and 'semi-scheduling' arrangements may apply in the interest of good behaviour and grid stability, and
- be subject to a lower price cap, that would apply uniformly to all generators in the category, say between $300 and $5,000/MWh.

OPTION 2: A flexibility payment and lower market price cap
Under this option, new flexible generators, storage and demand response providers could, through an appropriate competitive process, be given fixed annual payments to provide flexible services such as:

- fast ramping, up and/or down,
- fast response, either automated or centrally dispatched, and/or
- reserve capacity, including reserve storage capacity.

Participation in the market would be limited to new entrants.

Under this arrangement, a spot market would remain, but the Market Price Cap and Cumulative Price Threshold should be lowered to reflect that new generators would be incentivised by the flexibility market.

A key challenge of this model is managing the interaction between the flexibility market, the existing spot market, and RERT. Managing this may require closing the spot market to new entrants and requiring them to participate in the new market, however this would limit investor choice with respect to risk, which may increase the cost to consumers.

3.5 Inertia market

It may be appropriate for an ancillary service market for inertia to be developed, as the synchronous generators that provided inertia 'for free' exit the market and electronic (inverter based) generators that don't provide it, along with and asynchronous generators that increase demand for it, enter the market.

In developing cost recovery on a beneficiary-pays basis for inertia, the nature of benefits and to whom they accrue should be considered. Noting the need for adaptability described in 3.1, cost allocation and recovery in an inertia market would need to reflect:

- the need for inertia may not increase indefinitely and could conceivably be low again
- the distribution of benefits of inertia services may substantially change over time.

The below example demonstrates how adaptable settings could be put into practice.

The beneficiaries of inertia services in 2030 may include:

- Groups of asynchronous generators such as wind turbines (particularly older model wind turbines).
- Individual synchronous thermal generators with units of sufficient size to impact system frequency when they cut out unexpectedly (these are also the generators that have traditionally provided inertia under normal operating conditions).
- Some electronic generators that are particularly sensitive to the rate or magnitude of changes in frequency (these generators may also provide limited inertia or artificial inertia).
- Individual large energy users that have:
    - Loads, particularly motors, of sufficient size to affect system frequency when they are turned on, turned off or cut out
    - Equipment that is particularly sensitive to the rate or magnitude of changes in frequency.
- Mass-market energy users.

Under that scenario, costs could be recovered most efficaciously via energy market pool fees levied on all market participants.

A plausible later scenario is that in 2040 the grid will be characterised by smarter electronics on both the supply and mass-market demand side, including a high level of DER, and two or three remaining large thermal generators.

Under this later scenario, the main beneficiaries of inertia services – as in, those whose presence imposes a need for inertia to be provided in the market – may be:

- The remaining synchronous thermal generators that are of sufficient size to impact system frequency when they cut out unexpectedly. These may also be providing inertia under normal operating conditions.
- Individual large energy users that have:
    - Loads, particularly motors, of sufficient size to effect system frequency when they are turned on, turned off or cut out
    - Equipment that is particularly sensitive to the rate or magnitude of changes in frequency

Under this 2040 scenario, recovering costs from benefitting generators and large users with 'causer pays' payments would be more efficient and fairer than socialising the cost of an inertia market across all consumers.

3.6 Managing variable generation with negative price signals

In future, a growing portion of energy will be supplied by generators that can ramp down to zero output within seconds. High aggregate output from these generators currently coincides with low, and frequently negative, spot prices.

If most or all generators that have the capabilities to respond to negative spot price in a given region do so at once, and without coordination, system frequency may vary to the point of instability. This may be exacerbated by demand response in the form of switching on loads and charging batteries.

The current price signals alone may not be sufficient to control this 'dispatching-off' of generation as more wind and solar is connected to the NEM. This appears to already be an issue in South Australia.

PIAC recommends the ESB considers the risk of this becoming a wider systemic issue, and what proportionate arrangements may be needed to address it. Arrangements could include a market-based merit order for dispatching off, targeted dynamic regional pricing, changes to calculation of spinning reserve, or AEMO having last-resort powers to instruct or direct generators to remain on.

3.7 The role of the market in storage management

The ability of energy storage systems to discharge (or generate) and charge (or pump) is limited by their state of charge (SoC) at a given time.

Storage systems in the energy-only market would optimise their SoC with respect to their own market position which may not be aligned with system-wide needs. When energy storage systems become a significant portion of the market, such that the market relies on them for capacity at times, this could result in a protracted lack of total capacity in the system.

In an energy system reliant on high amounts of solar, wind and storage, instantaneous gross energy consumption (total demand supplied by all sources, centralised and behind-the-meter) is likely to continue to peak in summer. This will often correlate well with seasonally higher generation supply from solar energy, allowing SoC to be maintained or 'topped up' day to day. However, storage constraints may result in a shortage of capacity in one of more regions in winter. Sustained periods of instantaneous net system demand (a determinant of wholesale peak prices, and distinct from instantaneous gross energy consumption) may occur in winter, resulting in price responsive discharge of batteries. During protracted cold, cloudy periods over multiple days, the SoC of batteries may not be maintained or 'topped up' day to day, resulting in a lack of total capacity in the system.

Consequently, PIAC recommends the ESB considers the degree of risk of this becoming a wider systemic issue, and what proportionate arrangements may be needed to address it.

It may be appropriate to develop a competitive ancillary service market for centrally determined management of the SoC. Alternatively, backstop arrangements may be put in place until the materiality and nature of SoC management issues are better understood. This could include an extension of RERT provisions or AEMO having last-resort powers to instruct or direct a reserve of SoC.

3.8 Notice of reforms

Considering the National Electricity Objective, when developing or changing the energy market the impact on business should be examined through the lens of how impacts flow through to consumers, particularly with respect to the costs of supply and the risks associated with the investment and recovery of those costs.

Often a ‘no-loser’ principle is applied in the transition to the new market, either expressly or implicitly, so that existing participants are protected from, or compensated for, future costs or loss of revenue. This also plays out through some ‘grandfathering’ arrangements.

At worst, this results in windfall gains to business such that the ‘size of the pie’, or overall cost of the new market, grows larger than that which it replaced, defeating the purpose of reform.

There will be ‘losers’ in any major energy reform. If incumbent businesses are protected from losses, the losers will be consumers (and potentially taxpayers). If, all else being equal, reform was implemented that did not lead to efficiency gains that lower the ultimate cost of energy supply, it would be a failure in the promotion of the long-term interest of consumers.

As both a matter of principle and a design choice, PIAC considers that, as far as practicable, sufficient notice to the market of a pending reform must serve in in lieu of financial compensation, including ‘grandfathering’, for perceived cost impacts of changes to market design.

What constitutes sufficient notice is subjective. PIAC considers that, generally:

- for minor changes, such as setting prices or changes requiring non-major upgrades to systems, 2 years is adequate.

- for a substantial reform to market design as much as 5 years may be required to avoid impacts on investment certainty that compromise the long term interests of consumers. This notice should include description of the nature of changes to market design including the nature of services, procurement or dispatch processes and price structures, however actual setting of prices, as noted above, 2 years is generally sufficient.

4. Market price settings

The notional primary role or function of the Market Price Cap (MPC) is sending efficient price signals for investment. The secondary role of MPCs is managing participant exposure to price risk.

PIAC considers that, in the context of historical, current and anticipated changes in the NEM, the MPC has become less a factor in the investment decisions of generation businesses than when it was first established. In PIAC’s view, the notion that the MPC is prominent in the signal for new investment is increasingly outdated and urgently needs to be reconsidered.

Since the establishment of the MPC, a number of other factors, such as high demand forecasts, low demand forecasts, oversupply, fuel prices, renewable energy incentives, the lack of long-term carbon policy, have all played an increasingly material part in incentivising (and disincentivising) new investment and signalling the exit to market of existing generators.

New markets, such as for demand response and inertia, will also incentivise future investment, further diminishing the role of MPC in signalling to investors. Further, governments are investing in energy generation and storage to maintain reliability, and are unlikely to alter these decisions on the basis of the level of the MPC or CPT.

PIAC recommends that in a post 2025 energy market, the MCP should not be primarily calculated as an investment signal, but for managing exposure to risk associated with high price events

As the Reliability Panel recently noted in setting the market prices in 2018, over the past 6 years, scheduled generation investments have principally been to withdraw capacity. It follows that an assessment of the MPC should consider its effectiveness at influencing the decisions of existing generation.

Notwithstanding that high and volatile wholesale energy prices will still occur in a well-functioning and balanced market, PIAC is concerned that many high price events, including in the current 2016-2020 market price period, have been caused or exacerbated by strategic bidding behaviour, and even gaming, by existing generators.

Irrespective of the cause of this disparity, the Panel itself notes that:

> In 2016, the relationship between price and demand in South Australia is weaker; high prices regularly occurred at levels of demand as low as 1,000 MW

More recently, AEMO has been required to instruct generation to dispatch during negative events in South Australia

In this context, PIAC considers the primary function of the MPC should be managing participant exposure to price risk.

4.1 Reflective market price settings

A number of recent rule changes and reviews, including this one, suggest new ancillary service markets, secondary markets and other incentives for energy services will likely be introduced in coming years.

These new markets will, importantly, send financial signals for investment in the services that are valued in the system at a given time and, in some cases, location.

Some services, particularly inertia, have historically been provided by generators that are paid through their participation in the wholesale energy market, with behaviour and investment influenced by the MPC and CPT accordingly.

PIAC considers it is appropriate that as markets evolve to reward the services that are most needed in the system, it is efficient and cost-reflective to shift some of that cost-recovery from wholesale energy to new markets. Doing so should entail lowering MPC and CPT to avoid increasing 'the size of the pie' as markets for new services are introduced.

PIAC is concerned that the MPC is adjusted up each year by CPI for a number of reasons. On one hand, this suggests that if the MPC and CPT is to be lowered - as may be appropriate for reasons discussed here - the Reliability Panel may be restricted from smoothing that reduction over a number of years to avoid sudden changes that might diminish the clarity the MPC and CPT as a signal to investment decisions. On the other hand - and of more concern - including indexation as a minimum requirement would suggest an assumption that the MPC and CPT would only ever be sustained or increased, with no intention to adjust them downwards.

Without regular recalculation of MPC and CPT, adjusting for inflation would produce increasingly inefficient price signals that fail to reflect changes in the market or consumer preferences. This outcome would represent a failure to promote the NEO.

Further, with increasing demand response potential in the NEM[1], it is likely that new capacity will come in the form of 'negawatts' from demand response rather than new megawatts from dispatchable generation.

Given this, PIAC considers continuing to set the MPC or CPT based on creating or sustaining an investment signal for OCGT generators, without considering more efficient new demand response, is misguided and inefficient. Some new demand response brought to the market requires a markedly lower price signal than new generators. This may make a lower MPC appropriate, and it is imperative to give weight to the cost of largely untapped demand response.

4.2 MPCs and CPTs in different NEM regions

In PIAC's view, it is inconsistent with the intent and function of the price settings to maintain a common MPC across all jurisdictions.

While there is some link between wholesale prices in neighbouring jurisdictions, constraints in interregional trading and the lack of coincident price peaks between regions may limit the extent that would efficiently act as an investment signal.

Further, it is possible that the lack of distinction between regions with respect to MPC and CPT has led to the perverse outcome of favouring investment in regions that are less in need of generation capacity to meet the reliability standard.

In any case, wholesale prices have clearly differed over the long term between jurisdictions. The reasonable expectation that price outcomes over such different ranges would naturally be expected to have different upper and lower bounds reinforces the need to consider setting different prices in different regions.

5. Continued engagement

PIAC looks forward to continued constructive engagement to further explore issues around post 2025 market design. We view this as a valuable opportunity to ensure that all consumers benefit in a future energy system.

1 A number of estimates have put the potential NEM demand response market at over 2GW.