REGULATORY ASSISTANCE PROJECT

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How financially settled contracts can reduce the cost of electricity and improve reliability in India

Dominic Scott, Alejandro Hernández and Kumaresh Ramesh
With contributions from IDAM Infrastructure

Executive Summary

The Indian electricity system faces multiple challenges, including ensuring efficient scheduling of resources, protecting consumers from high prices, motivating generators of energy resources to be available during times of scarcity, stabilising revenues for investors in high-performing renewable energy resources and delivering a reliable power supply.

A shift in contracting practices for thermal and renewable resources – from traditional power purchase agreements to new financially settled contracts – can help address these challenges and support the achievement of multiple policy objectives in India.

Financially settled contracts are a new tool that policymakers can use to support the achievement of multiple policy objectives.

In this paper,[1] we explain what financially settled contracts are, compare them to power purchase agreements, present our primer on the operation and mechanics of financially

[1] This paper draws on expert insights from IDAM Infrastructure Advisory Private Limited, with our thanks. The authors would like to express their sincere appreciation to expert stakeholders from the regulatory sphere, distribution companies and power production who provided helpful insights into earlier drafts of this paper: Dr Sushanta Chatterjee (CERC), Daljit Singh (IIT Delhi), Ann Josey (Prayas (Energy Group)), Alok Kumar (AIDA), Ajit Pandit (IDAM), Raj Addepalli (RAP), Sushil Kumar Soonee (RAP), and Mike Hogan (RAP). Thanks to Poullette Faraon (RAP) for ongoing support and Deborah Bynum (RAP) for editorial support. All errors are the authors' own.

settled contracts – focusing on contracts for difference for renewables and call options for thermal resources – and survey the significant international experience in their deployment.

Our modelling of the Indian power market shows that, compared to power purchase agreements, a move to financially settled contracts:

- **Unlocks substantial savings through more efficient scheduling of resources.** Our modelling of illustrative distribution companies points to annual cost savings of around 7% (0.33 INR/kWh) in the procurement of flexible resources that accommodate growing shares of renewables. These savings can be used to relieve the financial stress of DISCOMs, to lower consumer bills and to invest in renewable resources.
- **Sends stronger and more targeted signals for resources to be available** when the system needs them. This lowers the cost of achieving any level of system reliability or resource adequacy, unlocking further savings for consumers.
- **Protects consumers from high prices,** meaning price caps are not required to protect consumers from high prices in wholesale markets.
- **Underpins investor confidence** by ensuring the same revenue guarantees as a high-performing resource under power purchase agreements for renewable and thermal.
- **Drives a step-change in market liquidity** to underpin informed investment choices.

Financially settled contracts therefore create value to be enjoyed by all.

All these benefits point to the importance of removing regulatory barriers and actively putting in place enablers so that DISCOMs and big energy consumers can conclude financially settled contracts with renewable and thermal resources.

To bring about these multiple wins for India, we suggest a roadmap outlining how policymakers can support the use of financially settled contracts by:

- **Supporting 'trailblazing' financially settled contract pilots** for contracting renewable and thermal resources. Promising pilots include contracts concluded by industry and commercial consumers already using captive or open access arrangements.
- **Resolving outstanding regulatory jurisdictional uncertainties.**
- **Ensuring a level playing field for financially settled contracts with power purchase agreements in resource adequacy frameworks**. This may include equal treatment of capacity secured through financially settled contracts in contributing towards resource adequacy obligations and exposure to penalties, in energy rationing scenarios, and requiring a link with physical assets. Robust penalties in the resource adequacy framework and easing wholesale price caps will help further.
- **Devising standard contracting frameworks**, including formulating procedures and guidelines, and codes for regulatory oversight and governance.

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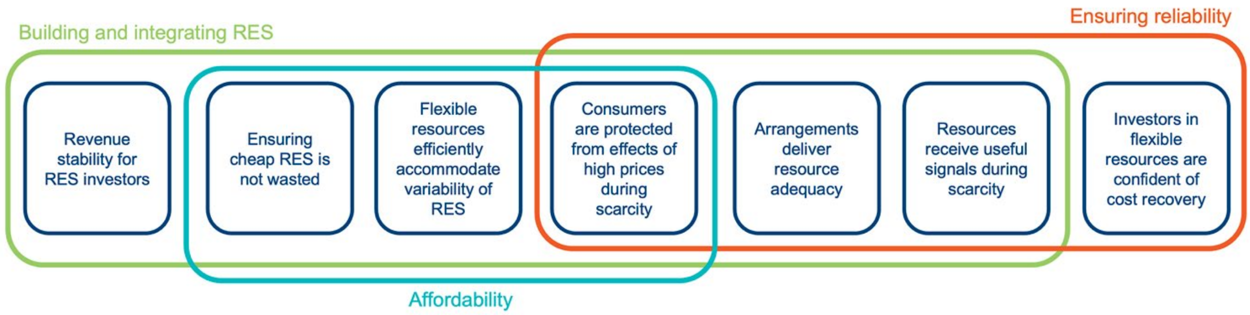
1. Introduction: India faces multiple challenges

Figure 1 presents the key challenges facing India's energy sector as it seeks to ensure reliability, integrate renewables and pursue affordability.

Figure 1. Objectives and challenges in India's energy sector



The first and last challenges link to the importance of providing confidence of cost recovery for investors, both in renewables (on the left of the figure) and for flexible resources that contribute to reliability (on the right). The second and third challenges link to the efficient scheduling of resources – to ensure cheap renewables are not wasted, and to use the cheapest resources to accommodate the variability of renewables as they grow in penetration. The fourth challenge is to protect consumers from effects of high prices during scarcity, which is currently met by imposing direct limits on price formation. The penultimate challenge – the thorny issue of how to present resources with strong signals to schedule during scarcity – has a strong reliability dimension to it. Last but not least is the challenge of delivering resource adequacy (third from end in Figure 1.)

A potential challenge that might be added to Figure 1 is the importance of stimulating liquidity in short-term physical markets – such as real-time markets and day-ahead markets – on power exchanges in order to support price discovery for buyers and sellers, assist competition and unlock accompanying benefits. Liquidity can be defined as a measure of the ability to buy or sell a product, such as electricity, without causing a major change in its price and without incurring significant transaction costs.[2] However, liquidity is also a tool that can help address the challenges identified in Figure 1, and will therefore be a cross-cutting enabler rather than a core challenge itself.

We return to these challenges in the fourth section of this paper to show how financially settled contracts (FSCs) can help deliver superior outcomes.

[2] This is the definition used by Ofgem, the British energy regulator. Ofgem. (2023, 8 December). *Call for input: Power market liquidity*. https://www.ofgem.gov.uk/sites/default/files/2023-12/Call%20for%20Input%20-%20Power%20Market%20Liquidity.pdf

The remainder of this paper presents an overview of existing Indian power procurement arrangements, introduces FSCs, surveys their use internationally, demystifies their operation and shows how promoting them can help deliver multiple policy objectives. It concludes with recommendations to facilitate their introduction.

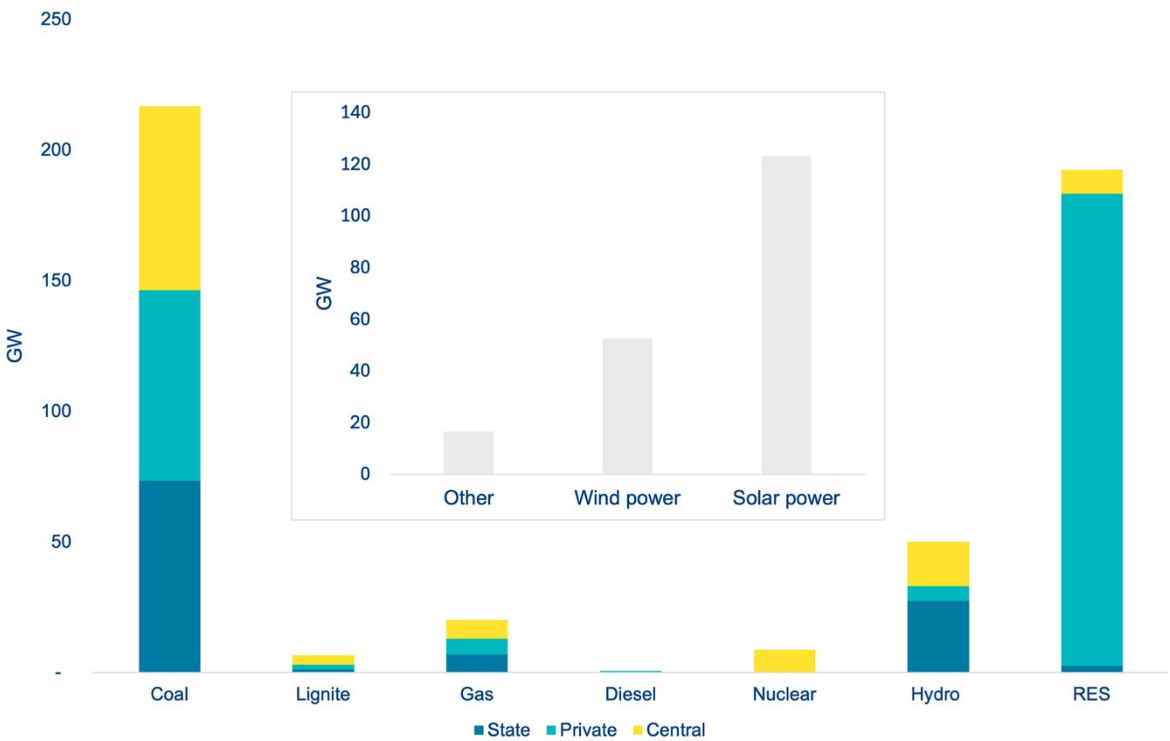
2. The road here: Capacity, contracts, energy and exchanges

Capacities and contracting routes

India has almost 500 GW of installed capacity, around half of which is low-carbon (nuclear, hydro, and renewable energy supply, (notably solar and wind, collectively referred to as RES)), and half thermal (coal, lignite, gas, diesel) – see Figure 2.

Figure 2 shows technology by capacity ownership – state government, central government and private investors. RES are massively dominated by privately owned plants. Thermal capacity is more evenly split between state, central and private ownership.

Figure 2. Installed capacity of power stations in India, ownership and technology, with renewables breakdown inset

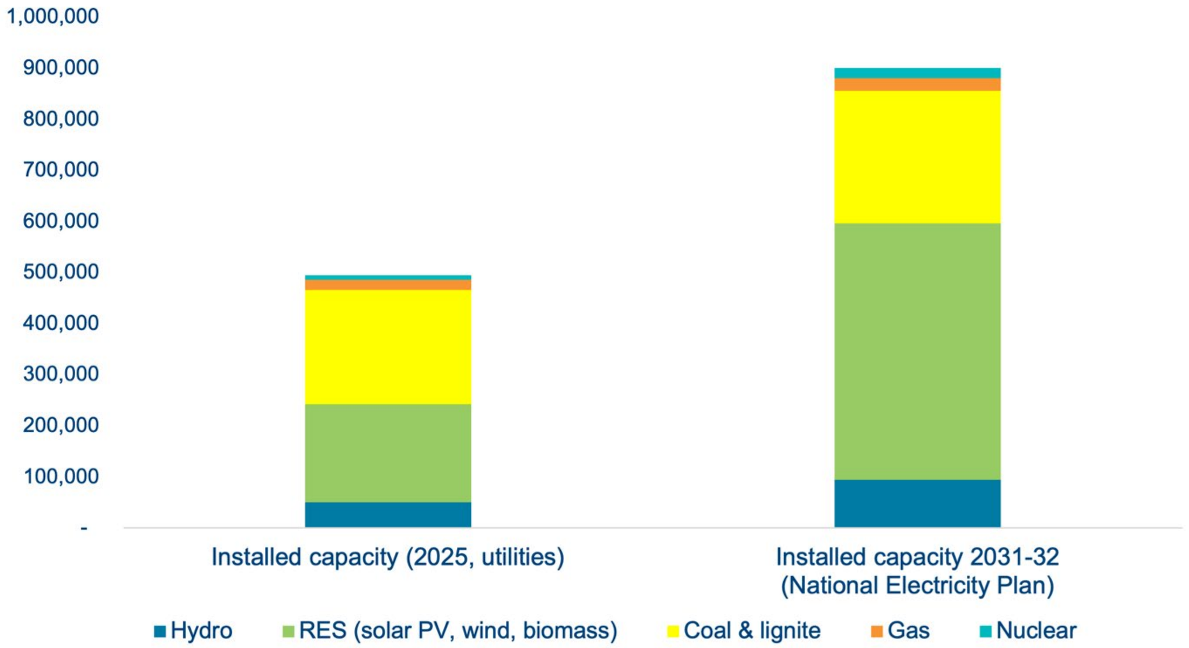


Source: IDAM Infrastructure

Figure 3 shows that the lion's share of capacity growth to 2032 is expected in renewables – solar PV, wind and biomass.[3]

[3] IDAM Infrastructure. Data sources: Government of India, Ministry of Power, Central Electricity Authority. (2025, August). *Executive summary on power sector*. https://cea.nic.in/wp-content/uploads/executive/2025/08/Executive_Summary_August_2025.pdf; and Government of India, Ministry of Power, Central Electricity Authority. (2023, March). National Electricity Plan (Volume 1) Generation. https://cdnbbsr.s3waas.gov.in/s3716e1b8c6cd17b771da77391355749f3/uploads/2023/09/20230911256071349.pdf

Figure 3. 2025 installed capacity (GW, utilities) compared with National Electricity Plan for 2031-32



Source: IDAM Infrastructure. See footnote for data sources.

Figure 4 shows contract routes – for resources with regulated tariffs, competitively determined tariffs and privately determined tariffs – by ownership type, along with guidelines and regulations underpinning the terms of these contracts. Key regulations and guidelines are the Electricity Act 2003,[4] tariff regulations for regulated tariffs,[5] Competitive Bidding Guidelines for competitively determined tariffs,[6] Transmission Open Access Regulations[7] and Green Energy Open Access rules[8] for captive,[9] open-access[10] and merchant resources.[11] Changes to these regulations and guidelines may be required to accommodate new contract types.

[4] Government of India, Ministry of Law and Justice. (2003, May 26). The Electricity Act 2003. https://cercind.gov.in/Act-with-amendment.pdf

[5] Central Electricity Regulatory Commission (CERC). (2024). (*Terms and conditions of tariff) regulations. 2024*.

[6] Ministry of Power. (n.d.) *Competitive bidding guidelines for procurement of power by distribution licensees*.

[7] CERC. (2008). *(Open access in inter-state transmission*) *regulations*.

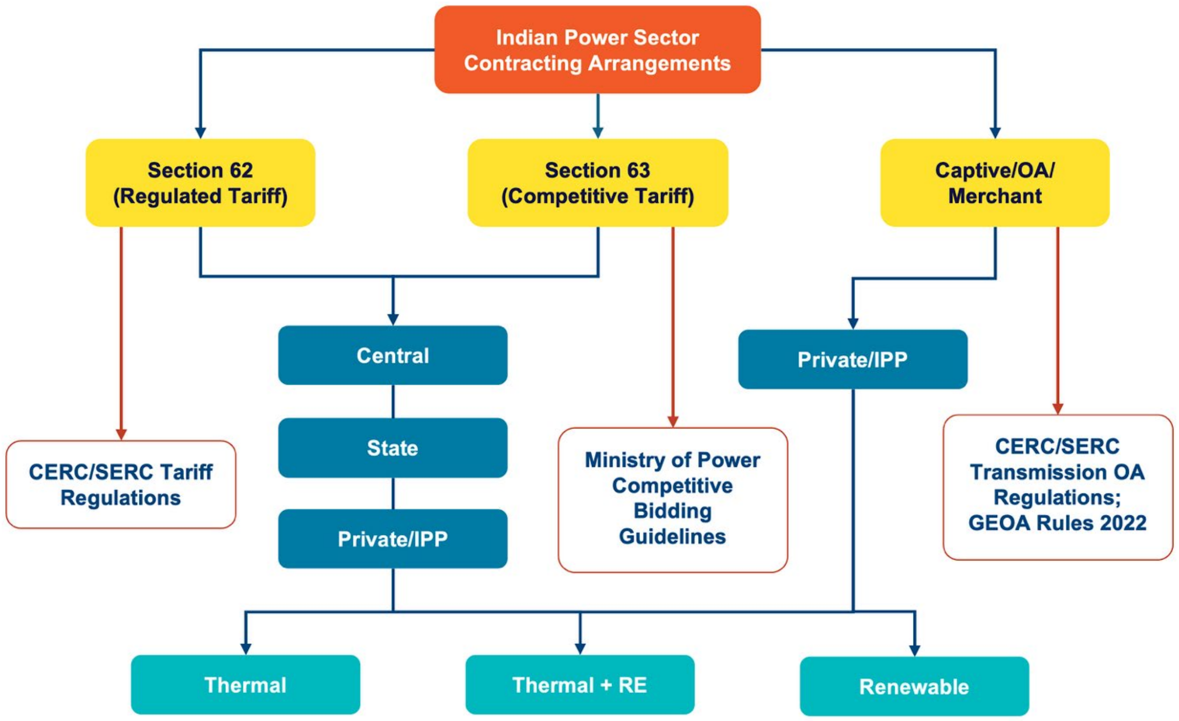
[8] Ministry of Power. (2022). *Electricity (promoting renewable energy through green energy open access) rules, 2022*. https://cdnbbsr.s3waas.gov.in/s3716e1b8c6cd17b771da77391355749f3/uploads/2023/10/20231005595469737.pdf

[9] Captive resources are renewable power plants owned wholly or partly by consumers who use most of the electricity themselves.

[10] Open-access resources allow eligible consumers – those with a contracted demand or sanctioned load of at least 100 kW – to buy renewable electricity directly from generators or traders instead of relying solely on the local DISCOM.

[11] Merchant resources are independent renewable power producers that sell electricity on a commercial basis without long-term contracts.

Figure 4. Contract routes by ownership types for selected technologies



Notes: Yellow is a contracting arrangement as defined in Electricity Act, blue is ownership, orange outline is applicable regulation, turquoise is technology.

Source: IDAM Infrastructure

Typical features of a power purchase agreement

Medium-term and long-term contracts traditionally used in India to support physical investment in new capacity and to purchase energy are typically referred to as power purchase agreements (PPAs); these are multiyear agreements concluded bilaterally between power producers and distribution companies (DISCOMs) or other large consumers. With typical durations of around 15-25 years, these long-term contracts can provide revenue certainty to underpin project bankability and finance energy resources, for purchasing entities that can demonstrate the requisite creditworthiness.

Although the terms and conditions of PPAs in India vary, they share a set of common features. Table 1 outlines how resources are paid (tariffs), scheduling processes, and penalties and incentives that apply, for both thermal and renewables, across both regulated (Section 62 of Electricity Act) and competitive procurement approaches (Section 63 of Electricity Act).

Table 1. Typical features of PPAs

	Thermal		Renewables (RES)	
	Section 62 regulated tariff	Section 63 competitive bidding	Section 62 regulated tariff	Section 63 competitive bidding
Tariff	Cost-plus (Section 62) two-part tariff with fixed capacity charges and variable charges (fuel-linked). Fixed cost recovery linked to availability norms.	Discovered through competitive auction process with (Section 63) two-part tariff with capacity charges and energy charges (fuel-linked). Capacity charges recovery linked to availability norms.	Single-part fixed tariff based on levelised cost of electricity as per regulated norms for performance and capital cost for RES.	Single-part fixed tariff, payment on actual energy delivered, no capacity charges.
Scheduling	Scheduled based on merit order of plant under PPA with DISCOM.	Scheduled based on merit order of plant under PPA with DISCOM.	RES are afforded must-run status as per Grid Code.	RES are afforded must-run status as per Grid Code.
Penalties and incentives overview	Penalties and incentives linked to performance norms under Multi Year Tariff Regulations for parameters of station heat rate, auxiliary consumption, plant load factor.	Penalties and incentives linked to performance parameters as outlined under Competitive Bidding Guidelines and Standard Bidding documents incl. PPA.	Incentives in form of excess recovery at 75% tariff, if capacity utilisation factor exceeds benchmark norms.	Incentives in form of excess recovery at 75% tariff, if capacity utilisation factor exceeds benchmark norms.
Under-performance penalty	Capacity charge reduction for availability below threshold plant load factor.	Capacity charge reduction for availability below threshold plant load factor.	Penalty in form of under-recovery if actual capacity utilisation factor is below benchmark norm and sometimes linked to RPO non-compliance charges.	Penalty in form of under-recovery if actual capacity utilisation factor is below benchmark norm and sometimes linked to RPO non-compliance charges.

	Thermal		Renewables (RES)	
	Section 62 regulated tariff	Section 63 competitive bidding	Section 62 regulated tariff	Section 63 competitive bidding
				Penalties for shortfall below minimum factors (linked to total annual energy), typically linked to tariff (potentially with multiplier) as fixed in PPA, providing blunt incentives that are divorced from the actual value of energy as reflected in market prices.[12]
Over-performance incentive	Over-generation typically yields no extra payment: sale outside of PPA is restricted or requires approval.	Over-generation typically yields no extra payment, sale outside of PPA is restricted or requires approval.	Third-party sale permitted for excess generation, with mutual consent, subject to revenue share with buyer.	Incentives and ability to over-perform vary; in many cases incentives are divorced from market value and PPA terms (requirement to secure consent to sell elsewhere) may act as an impediment to access market value.[13]

Source: IDAM Infrastructure

Overall, Table 1 points to the absence of a link between the value available to resources contracted under PPAs and market prices. PPAs fix the tariffs the resources earn, along with the penalties and incentives for under- and over-performance, so that they are delinked from markets (such as day-ahead markets and real-time markets). They dampen the incentive and ability to participate in the market.

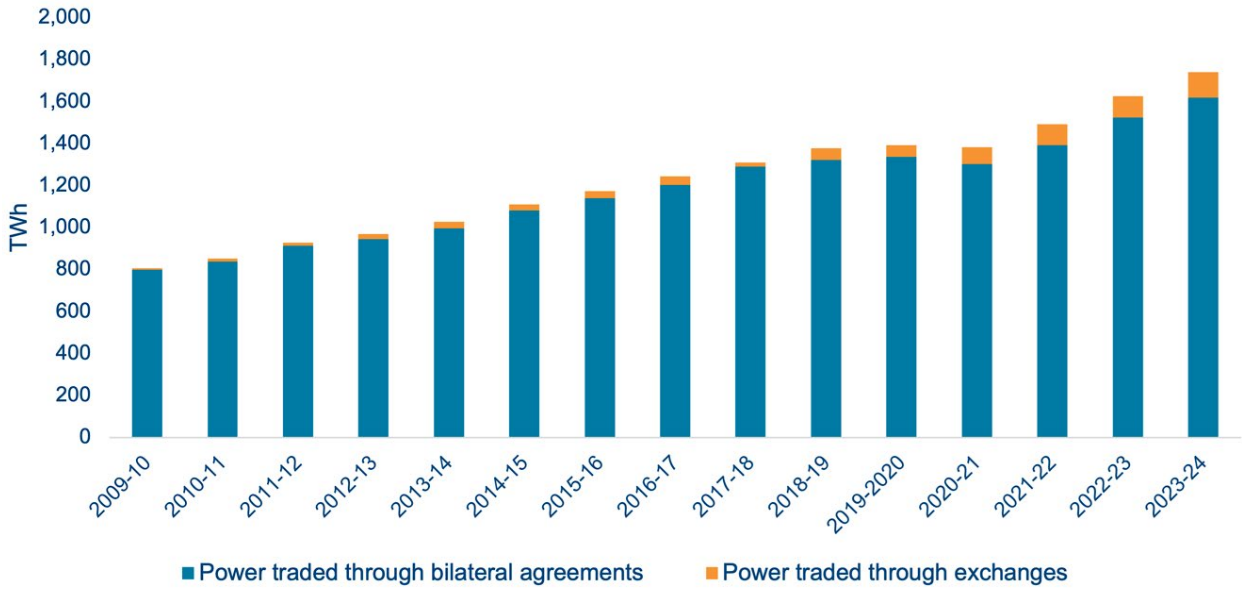
[12] Examples include: Pay compensation on energy shortfall below 15.3% capacity utilisation factor (CUF) at tariff (lower of average purchase power cost tariff or agreed tariff), shortfall in generation attracts penalty of 25% of shortfall cost at PPA tariff (sounds like they are paid 75% of tariff on each missing MWh of energy), or penalty at 150% of tariff for each MWh less than 90% CUF.

[13] Examples from contracts include "excess generation is unpaid/curtailed with no compensation," "excess generation is paid at 75% of tariff," "purchaser has first right of refusal, at 75% of tariff," "generator is barred from selling contracted capacity to third parties without consent," "prior consent is required to sell excess."

Energy and power exchanges

By 2023-24, nearly 1,740 TWh of energy was being traded in India, most of this contracted under bilateral PPAs. However, following the establishment of transparent, real-time marketplaces for electricity trading – with the India Energy Exchange (IEX) and the Power Exchange India Limited (PXIL) in 2008, and more recently the Hindustan Power Exchange (HPE) in 2022, as enabled by the CERC guidelines of 2007 – a growing portion of trade has been through power exchanges. This trade has been further accommodated with the introduction of markets for green energy trading and high-price energy trading in 2020-21 and 2023-24. Figure 5 shows that power traded through exchanges reached around 122 TWh in 2023-24, from almost nothing in 2009.

Figure 5. Indian electricity generation by trade mechanism

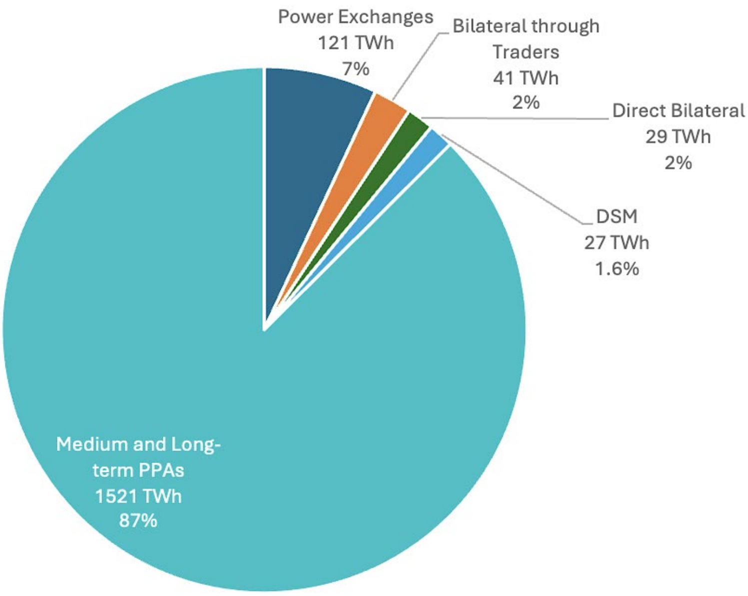


Source: CERC. (2024). *Report on short-term power market in India: 2023-24*

Although large in absolute terms (122 TWh), trade in power exchanges (at 7% of generation in FY 2023) is a small portion of the power that is traded. Contracting remains largely conducted through PPAs, at around 1,521 TWh, representing 87% of generation delivered over FY 2023-24. Figure 6 shows trades through PPAs and power exchanges as well as through other routes: bilateral through traders, direct bilateral and through the deviation settlement mechanism.[14]

[14] CERC. (2024). *Report on short-term power market in India: 2023-24.* https://www.cercind.gov.in/2024/market_monitoring/Annual%20Report%202023-24.pdf

Figure 6. Contracting and trade of electricity generation in TWh and %, FY 2023-24

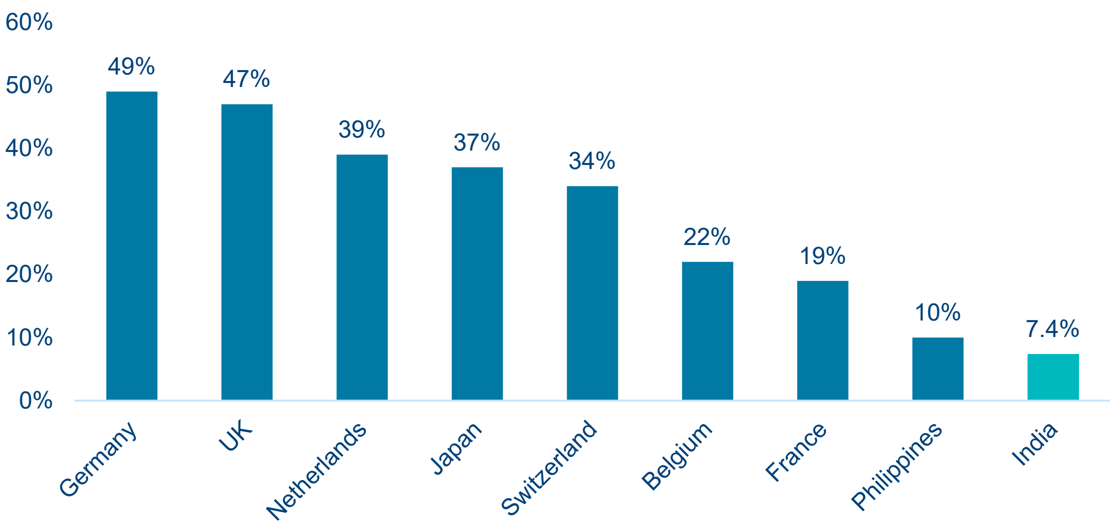


Note: DSM is deviation settlement mechanism.

Source: CERC. (2024). *Report on short-term power market in India: 2023-24*

Trade in power markets is small in India relative to other jurisdictions, as shown in Figure 7. At current rates of progress, it may take many years to reach liquidity levels of some European countries which see a share of power procured through spot markets approaching 50%.

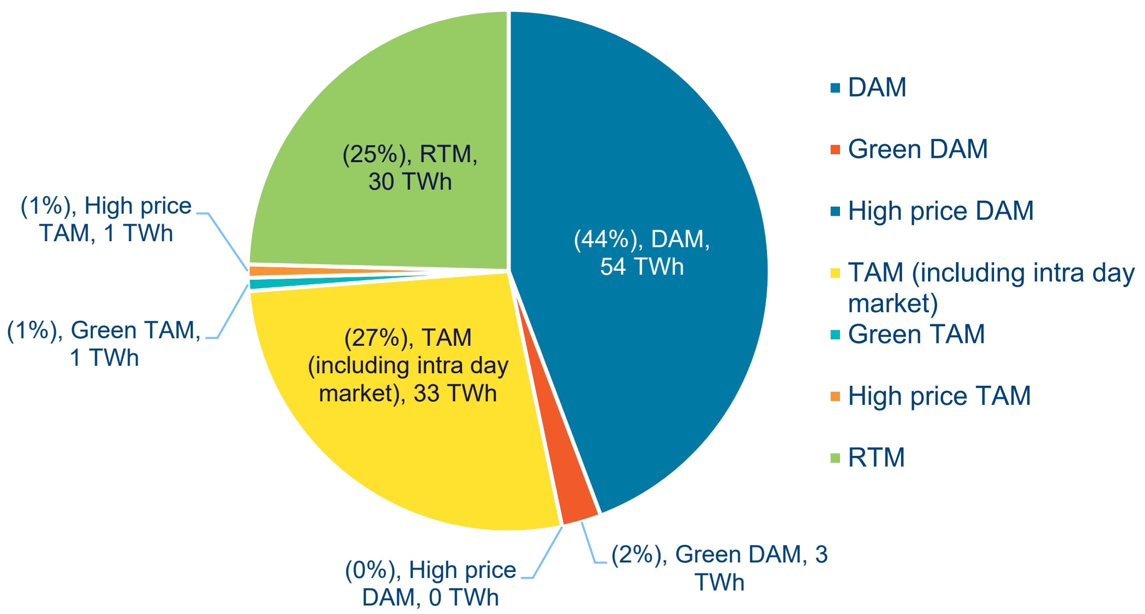
Figure 7. Share of power procured through spot power markets by country, 2022



Source: RMI. (2023). *Transforming India's electricity markets*

Figure 8 breaks down the composition of the 122 TWh of trade in power exchanges. In 2023-24, 54 TWh was traded on the day-ahead market (DAM), 33 TWh in the term-ahead market (TAM) and 30 TWh in the real-time market (RTM).[15] The green and high-price sub-markets account for the remainder.

Figure 8. Trade of electricity generation in power exchanges (short-term wholesale markets), in TWh and %, FY 2023-24



Source: CERC. (2024). *Report on short-term power market in India: 2023-24*

These different short-term physical wholesale markets are outlined in Figure 9.[16]

[15] RMI. (2023). *Transforming India's Electricity Markets: The Promise of Market-Based Economic Dispatch and the Path Forward.* https://rmi.org/insight/transforming-indias-electricity-markets/

[16] Aurora Energy Research. (2025). *Can India become the world's largest merchant power market?*

Figure 9. Short-term physical wholesale markets

TAM (term ahead market) & HPTAM & GTAM	DAM (day-ahead market) & GDAM & HPDAM	RTM (real-time market)
• Daily or weekly region-specific contracts for hourly blocks, available for trading 90 days in advance of delivery • High-price TAM (HPTAM) is a specific submarket for resources with high dispatch costs • Green TAM (GTAM) is for trading renewable energy	• Daily auctions for 96 15-minute settlement periods of the next day • High-price DAM (HPDAM) is a specific submarket for resources with high dispatch costs • The green DAM (GDAM) is for trading renewable energy	• Auctions conducted every half half hour for power to be delivered after four (15-minute) settlement periods, or an hour after auction gate closure

Uptake of green products within their separate markets remains low at around 3% of total power traded on the exchange. This share is also significantly lower than the share of renewable energy in the overall supply mix (approximately 13%), and may be the result of PPAs which do not encourage market participation.

3. Financially settled contracts: a primer

Definitions and distinctions

Figure 10 presents three high-level approaches for energy resources to sell their energy output. The first is PPAs, as already introduced in this paper, which are long-term contracts for physical energy. The third is to forego long-term contracts. The approach in the middle introduces financially settled contracts, FSCs. A resource may also choose combinations of these approaches for portions of its capacities.

Figure 10. Contracting options

Physical contracts (long-term)	Financial contracts	'Go merchant' (resist signing long-term contracts)
• These contracts signed with a consumer-facing entity (like a DISCOM) may fix payment for dispatch and set out regular contributions to be paid towards fixed cost recovery. • The physical contract thus sets the remuneration of the resource and the cost to the counter-signatory, meaning provision of energy is a bilateral affair. • Resources striking such contracts have minimal engagement in wholesale markets.	• The resource sells its output on wholesale markets (independent of the FSC counter-signatory), but the FSC builds in financial payments (positive or negative) between the two parties with a link to wholesale market prices; the DISCOM does not own the physical energy. • FSCs help fix the net revenue accrued by the energy resources and net cost to the counter-signatory DISCOM of procuring energy from the wholesale market.	• The energy resource can resist signing any long-term contracts, instead selling its physical energy on wholesale energy markets. • The resource is fully exposed to price volatility.

A defining feature of FSCs is that they include a financial flow of money that does not bring with it the physical delivery of electricity. Rather than directly purchasing physical energy, these flows of money allow the buyer and seller to finance the purchase and sale of physical energy in the market. FSCs can potentially last as long as 15-25 years or even more; like PPAs, they provide revenue certainty to underpin project bankability and stimulate build.

A Note on Terminology

Contracts for physical ownership of energy tend to be called power purchase agreements (PPAs). Note that virtual PPAs (known as VPPAs),[17] in spite of their name, do not contract for ownership of physical energy but rather provide for financial payments linking to wholesale market prices; we categorise these as FSCs.

[17] Virtual PPAs are outlined on page 3: Energy Cities. (2024, January). *Power purchase agreements.* https://energy-cities.eu/wp-content/uploads/2024/01/PPAs-Briefing_Energy-Cities_RAP.pdf

Table 2 below presents an overview of physical and financial contracts, struck in markets or bilaterally. We define 'shorter term' trades as those performed from just hours ahead of real time, to days or months ahead, and up to perhaps three years ahead. 'Longer-term' contracts we define from as little as three years to over a decade or two in length.[18]

In the top-left quadrant (1) are the short-term physical contracts for delivery in real-time and day-ahead markets. These short-term markets reveal the actual value of electricity and are the basis of an efficient market to which other contracts may refer. In the top-right quadrant (2) are long-term physical contracts, now prevalent in India. The drawback with these contracts is their tendency to drain liquidity from short-term wholesale markets.

Table 2. Contracts and markets by timeframe

	Shorter term – hours (exchanges, tradeable)	Longer term – 3 years to decades (bilateral 'over the counter', non-tradeable)
Physically settled	1. Wholesale markets which contract for actual physical energy, traded in organised physical wholesale spot markets – real time or day ahead ! Getting liquidity in these markets is crucial for revealing the true cost and value of energy resources	2. Custom bilateral contracts, physical delivery, negotiated privately, like 'classic' long-term physical PPAs x These drain liquidity from short-term markets – this matters, as prices and terms are not visible to the market
Financially settled (cash-settled with link to market prices, no physical commitment)	3. Standardised contracts traded on exchanges, settled in cash based on price differences, no delivery – for example futures contracts struck on financial exchanges (market platforms) ✓ These can be designed to stimulate participation in short-term wholesale markets (1)	4. Custom bilateral contracts, no delivery, cash-settled against a reference price, like VPPAs (in CfD or call option form) ✓ These can be designed to stimulate participation in short-term wholesale markets (1)

Financial contracts, both short-term and long-term, stimulate participation in short-term physical markets. Of these, financially settled products available on exchanges appear in the bottom-left quadrant (3). These relatively short-term products are already available on

[18] We understand – in the Indian context – that a short-term contract means up to one year, medium-term up to five years, and long-term more than five years. Our definitions therefore split the medium-term in the middle to apportion it equally into shorter-term and longer-term.

exchanges in India, for a duration of one to three months,[19] and pilots are underway to develop more products. Some over-the-counter long-term FSCs (4) – agreed by large consumers with renewable resources – are on the cusp of being unlocked with CERC's *Draft Market Regulations for VPPA Guidelines.*[20] The regulatory framework could in theory be developed so that contracts like these could also be negotiated by DISCOMs on behalf of consumers – as well as extended to a wider set of resources, notably thermal. The focus of this paper is particularly on further opportunities for FSCs in quadrant 4 above.

Table 3 below compares in greater detail features of longer-term physically and financially settled contracts (quadrants 2 and 4 of Table 2).

Table 3. Physically settled and financially settled contracts compared

Dimension	Physically settled contracts	Financially settled contracts (longer-term)
Purpose	Allow for purchase of electricity at agreed price, and provide revenue certainty and underpin bankability of energy projects	Hedge against price fluctuations in electricity markets and thereby pre-set cost of electricity purchases; can also be designed to provide revenue certainty and in so doing underpin bankability of energy projects
Ownership of electricity energy	Buyer commits to purchasing physical electricity – the buyer thus owns the electricity; called a 'physical' trade in electricity market jargon	Does not involve the physical delivery of power – the buyer does not now 'own' the electricity; financial flows in the contract rather enable buyer to purchase energy from market (anyone), with the net cost of the purchase fixed in an FSC
Duration	Typically long-term (e.g., 10-20 years), but could be (e.g.,) 3 years for a contract extension or to support refurbishment	Can range from decades (e.g., 20-year contracts are offered in Belgium's Queen Elizabeth offshore auctions) to a handful of years (e.g., for contract extension or to support refurbishment)
Bilateral or traded	Bilaterally negotiated contract between a power generator (e.g., RES) and buyer (e.g., utility or corporate off-taker)	Many forms – can be bilaterally negotiated by big consumers or DISCOMs or government

[19] TeamLease RegTech. (2025, July 4). *MCX issued a circular regarding the launch of the Electricity Futures (Monthly Base Load) Contract.* https://www.teamleaseregtech.com/updates/article/44182/mcx-issued-a-circular-regarding-the-launch-of-the-electricity-futures-/

[20] CERC. (2025). *Draft guidelines for virtual power purchase agreements.* https://cer.iitk.ac.in/odf_assets/upload_files/blog/Draft_Guidelines_for_VPPAs_2025.pdf

Illustrations of selected long-term financially settled contracts in action

Leading types of long-term FSCs are introduced in Figure 11.

Figure 11. Leading types of FSC

Contract for difference (two-sided)	Call option	Swap
• A two-sided CfD is a financial hedge where the buyer and seller agree on a fixed 'strike' price for electricity. • If the market price is above the strike, the seller pays the buyer the difference; if below, the buyer pays the seller. • Independent of physical delivery (note exception for RES which often link difference payments to own physical production). • CfDs typically cover many years; each hour is settled against the strike price and reference market price, with periodic financial payments (such as monthly). • Forwards and CfDs are similar, except instead of a continuous pay-as-you-go hedge, forwards apply a single settlement at the end of the contracted period based on the average price, similar to futures.	• Gives the buyer the right, but not the obligation, to receive the difference between the market price and a strike price when the market price exceeds the strike price. • The buyer pays an upfront premium. • Caps exposure to high electricity prices while retaining downside benefit. • A variant of the call option is the spark spread option which hedges the margin between electricity and fuel prices, to pay out if the market margin (electricity price minus fuel cost) exceeds a strike margin, protecting generators or buyers from adverse shifts in input/output price relationships.	• An agreement to exchange floating market prices for fixed prices over a defined period. • One party pays the fixed price, the other pays the floating (market) price. • Differences are settled financially. • This achieves the same result as a long-term CfD, and ensures price certainty for both DISCOM and generator. • When prices are high, the generator sells at the high price on the market, and uses this to finance payment to the DISCOM (at the high price). The DISCOM pays the fixed payment to the generator. The market rents and payments to the DISCOM net each other out, leaving the fixed price financial flows for generator and DISCOM.

In the following section, we present illustrations of long-term CfDs and call options in action, for renewables, and separately for thermal resources. We have selected these contracts because they are best suited to represent the capabilities of these technologies in simple contractual terms. Note that we do not present a call option for RES – this instrument is better suited to dispatchable plant with non-negligible variable costs. We also do not present a swap for thermal plant; like the CfD it exposes the generator to fuel price volatility and is inferior to the call option. **Our lead instrument for RES is the CfD, and for thermal it is the call option.**

Renewables

Two-sided CfD in action

Assume that a DISCOM wishes to procure renewable energy from a 10-MW-capacity wind plant for a duration of 15 years.

The DISCOM designs a two-sided CfD auction for 10 MW of wind resources to identify the generator(s) setting the cheapest strike price to meet the DISCOM's needs. In this auction, the DISCOM:

- Commits to pay the winning generator the excess of the strike price over the reference price for every unit of energy generated over the 15-year period under contract – and the generator for its part commits to pay the DISCOM the excess of the spot price over the strike price on all volumes sold.
- Defines the 'reference price' as the market clearing price – for example, as the day-ahead market (DAM) energy price.
- May wish to clarify that although it is not procuring the physical energy of the plant, it is procuring the 'renewable' attribute of the electricity.[21]

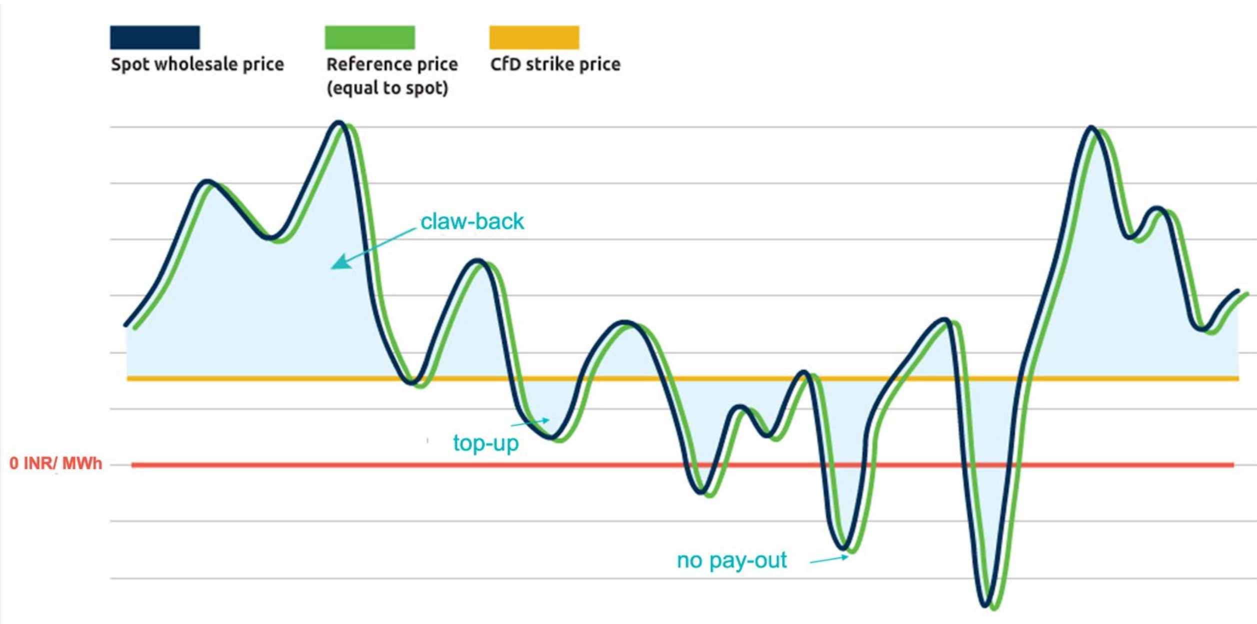
Some CfD designs clarify there will be no pay-out when reference prices dip below zero,[22] to ensure the generator has no incentive to produce when it adds no value to the system.

Figure 12 shows this illustrative CfD in action.

[21] This may not be necessary once the draft Indian VPPA regulations are confirmed.

[22] Zero may be a reasonable estimate of the marginal cost of wind production, and therefore this rule may avoid encouraging the resource to schedule when the value it adds is negative.

Figure 12. Illustration of a two-sided contract for difference



Note: time is on x-axis, energy price is on y-axis, and this illustration assumes no pay-out rule during negative prices.

Figure 12 shows that every unit of output provided by the generator in each period is sold at the DAM price in the market: the generator receives the DAM price from the market for the output sold. When the DAM price exceeds the strike price, the generator pays back to the DISCOM the associated excess market price (i.e., the DAM price minus the strike price). When the strike price exceeds the DAM price, on each unit of output the DISCOM pays the generator the difference between the strike price and the DAM price (i.e., the strike price minus the DAM price). The exception is when spot prices are zero (approximating the variable cost of production) or below zero, when top-ups are subject to the no-payout rule (if in effect), and the generator self-curtails.

The CfD motivates the generator to sell in the market in two ways:

- When the spot market price exceeds the strike price, the generator can offer and sell its output in the market, and from this, finance the claw-back payment.
- When the spot price is below the strike price (and above zero), the generator can sell its output on the market to gain the spot price (this also unlocks the accompanying top-up up to the strike price).
    - When the spot price is below zero, the generator's best strategy is to stop producing, as it will receive no payment from the off-taker, and will need to pay to inject energy into the system.

The CfD unlocks the following benefits:

- Helps provide price certainty for the plant (and buyer). The generator pockets the strike price on each unit generated (except when spot prices go negative), similar to the single-tariff PPA contracts currently largely in effect in India.[23]
- Underpins greater market liquidity, assists price discovery, and reveals important information on the value of different resources to inform investment choices.
- Allows the excess surplus renewable capacity of any DISCOM to be readily identified in the market and scheduled by other DISCOMs, ensuring resources are not operated in silos, thus supporting efficient scheduling.
- Prompts renewables to offer into the market at their marginal cost (roughly zero), which is a market behaviour that supports efficient scheduling, and can be designed to support (efficient) self-curtailment when spot prices go negative.
- Gives clear signals to renewables operators for when to take plant off for maintenance – when prices are likely to be negative for extended periods of time[24] (suitable for resource-led outage planning such as in ERCOT).
- Provides clear visibility of market schedules, assisting the system operator in forming plans to accommodate the expected energy mix (e.g., ensuring sufficient inertia).

Swap in action

Assume that a DISCOM wishes to procure renewable energy from a 10-MW-capacity wind plant for a duration of 15 years and uses a swap to do this. Features of the swap are:

- Auction determines the constant revenue stream in form of fixed monthly payments (for 15 years, for example) required by the renewable resource of the DISCOM counterparty, for 10 MW contracted.
- In return, the RES commits to pay the DISCOM revenues, calculated as the product of the energy output of a hypothetical efficiently run reference plant(s) valued at the prevailing wholesale spot price for the lifetime of the contract.
- The plant finances this payback requirement through its spot price sales, paying attention to the efficient operation of plant, such as timing maintenance during hours when the value of electricity is lowest.
- Negative prices may be treated as zero.

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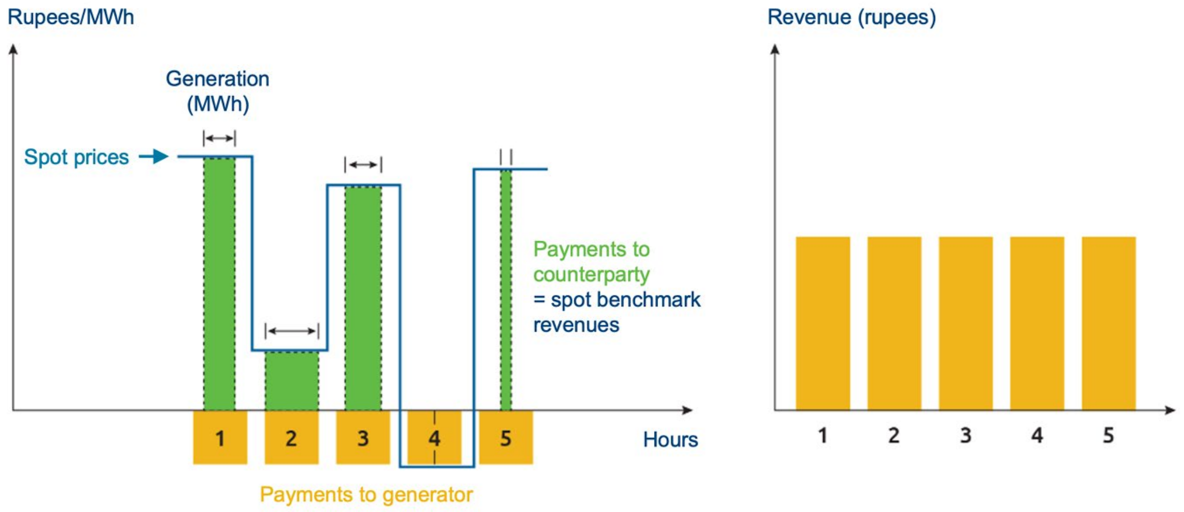
[23] We show in the next section that swaps where financial flows are delinked from own-production can deliver more than simply price stability: they can also be designed to provide overall revenue stability encompassing the combination of price and volume risk. The cost is introduction of a new basis risk.

[24] This is dependent on a rule that difference payments are turned off during negative prices. More sophisticated CfD designs – production-independent CfDs, like capability CfDs and yardstick CfDs – have been developed to send more sophisticated and market-friendly (efficient) signals to inform scheduling and investment decisions. See https://blueprint.raponline.org/deep-dive/cfd-part-ii/ for an overview.

In forming offers into the initial auction, a prospective plant must consider costs and expected deviations in performance compared to the reference plant. A plant that performs exactly as per the reference plant will simply transfer its wholesale revenues to the DISCOM, while receiving the monthly payment determined in the initial auction.

A stylised operation of the swap is presented in Figure 13, which was adapted from the original.[25]

Figure 13. Operation of a 'financial CfD' (a swap)



Source: Schlecht, I., Hirth, L. & Maurer, C. (2022). *Financial wind CfDs.*

In the left-hand schematic, the green areas show the payments the plant must make to the counter-signatory (in the case of India, the DISCOM), determined as the product of the spot price and the reference plant output (shown with horizontal arrows).

If the plant can produce more than the reference plant, then it keeps the value of that extra output (on top of the monthly payment it receives – yellow areas under the horizontal axis). Plants that can do this when spot prices are high have a strong competitive advantage. Plants with capability below that of the reference plant are penalised for this lost output at the spot price. They must still make payments to the DISCOM according to the output of the reference plant, but their spot market sales will not fully finance this. This is particularly costly during high spot price periods.

The right-hand schematic of Figure 13 shows the net revenues of a hypothetical plant. In this illustration, output is assumed exactly to match the output of the reference plant; its revenues

[25] Schlecht, I., Hirth, L. & Maurer, C. (2022). *Financial wind CfDs. ZBW – Leibniz Information Centre for Economics*. https://www.econstor.eu/bitstream/10419/267597/1/Financial_wind_CfDs.pdf. Figure adapted as follows: 'Payments to Government' is amended to 'Payments to counterparty', currency is changed, and the strike price is removed.

are the same in every period. For such a plant, the swap not only hedges price risk, but also hedges volume risk – annual variations in ambient wind – and can help to stabilise revenues and thus reduce further the cost of capital.[26] In terms of stabilising revenues, the swap thus compares favourably with a CfD that fixes the price captured per unit sold but that nevertheless, to varying degrees, leaves the investor exposed to low wind harvests in some years and high wind in others.

The swap brings about the following benefits from a public policy perspective:

- Hedges both volume and price risk for an efficiently-run plant (one that performs as per the hypothetical reference plant) which could support low-cost deployment.
- Underpins market liquidity.
    - The swap stimulates market participation – the cost of not participating in the market is set by the market price.
    - This assists price discovery and reveals important information about the value of different resources to inform investment choices.
- Allows surplus renewable capacity of any DISCOM to be readily identified in the market and scheduled by other DISCOMs, ensuring resources are not operated in silos, thus supporting efficient scheduling.
- Prompts renewables to offer into the market at marginal cost (roughly zero), a market behaviour that supports efficient scheduling, and (efficiently) to self-curtail when spot prices go negative.
- Gives clear signals to renewables operators for when to take plant off for maintenance – when prices are lowest.
- Fixes the cost of contracting with renewable capacity to the DISCOM at the constant stream of payments made to the renewable plant.
- Provides clear visibility of market schedules, assisting the system operator in forming plans to accommodate the expected energy mix (e.g., ensuring sufficient inertia).
- Motivates renewable resources to pay particular attention to being available to the best of their capability for given environmental conditions when prices peak, such as during moments of scarcity, if the reference plant suggests the resource ought to be able to generate output at that moment.[27]
- Provides generators with strong incentives to choose technologies and locations whose production profiles allow the resource to add the most value as revealed by market prices. This should support investment in the optimal mix of capacity over time.

[26] Against this, it should be noted that the use of a reference plant introduces a new basis risk.

[27] In this respect, the swap is superior to the CfD design outlined previously. This stems from the swap's decoupling of financial flows from own-output. It should be noted however that the CfD could also be designed to link to a reference plant rather than own-output to achieve the same effect.

The swap is the most complex FSC instrument. It entails construction of a reference plant, which will be subject to deliberation and critique and will introduce a new basis risk.

The swap has also only recently been put forward for consideration.[28] Perhaps for these reasons it has not yet been deployed (to our knowledge) for public long-term contracting of renewables on behalf of consumers.

Thermal plant

Call option in action

Here we present an illustration of a call option in action.

We imagine the DISCOM wishes to ensure it has resources to buy energy when prices exceed a certain threshold to meet the demand of its consumers, and determines that 100 MW of dispatchable capacity, contracted for 15 years, will meet its needs.

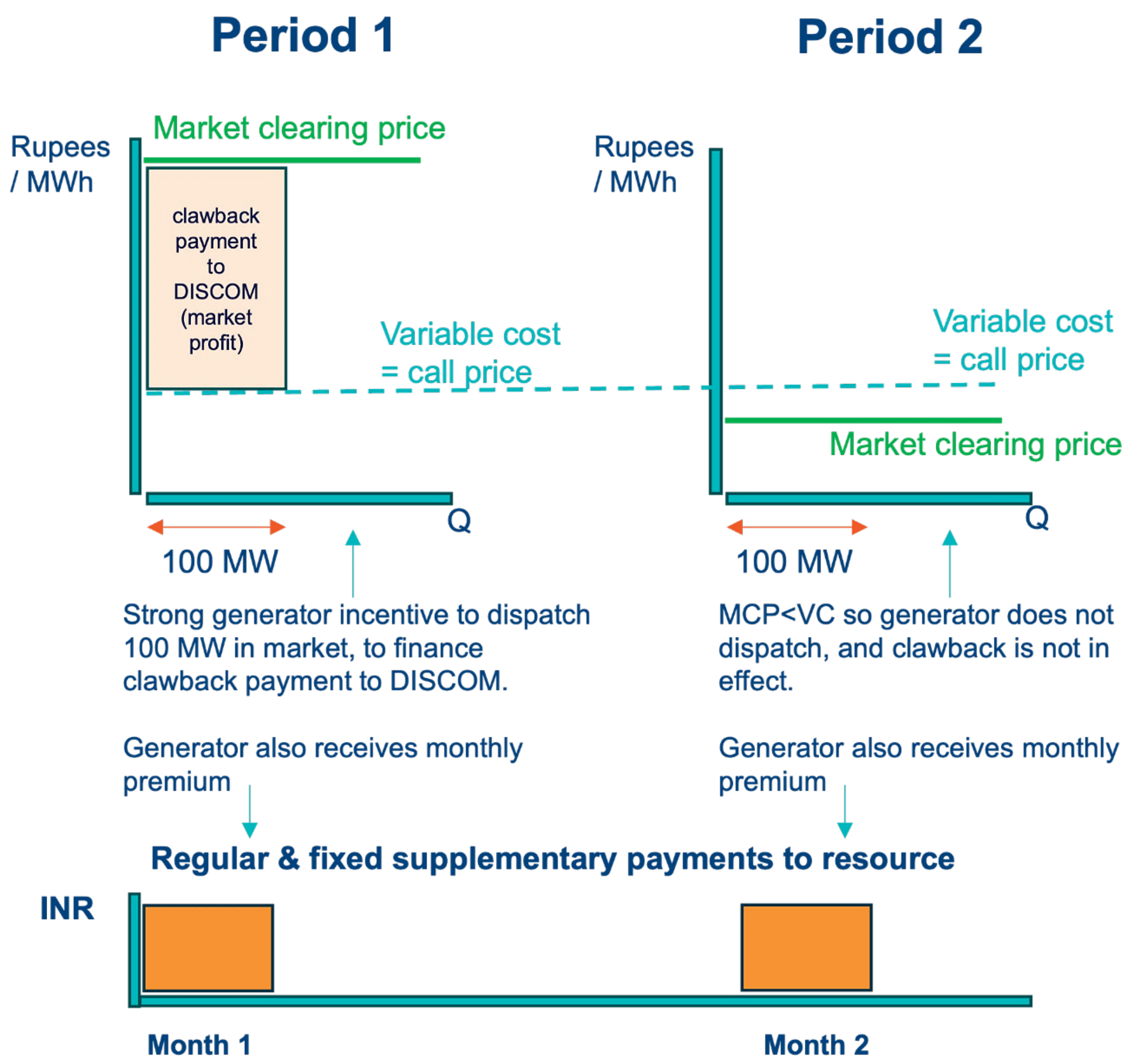
The DISCOM designs and conducts an auction for 100 MW of capacity with the following characteristics:

- The DISCOM stipulates a call price above which a 'clawback' mechanism applies. To avoid unintended consequences, the DISCOM ensures that this is no less than the marginal cost of the winning resource (this may entail indexation to input fuel prices).
- A clawback mechanism requires the contracted resource to pay the excess of market prices over the call price on the contracted capacity whenever market prices exceed the call price.
- Resources compete in the auction for the lowest monthly premium they would accept as payment from the DISCOM to forego all rents above the call price as part of the clawback mechanism.

Figure 14 shows an illustrative call option in action, with the call price set at variable cost.

[28] Schlecht, I., Hirth, L. & Maurer, C. (2022). *Financial wind CfDs. ZBW – Leibniz Information Centre for Economics.* https://www.econstor.eu/bitstream/10419/267597/1/Financial_wind_CfDs.pdf

Figure 14. Illustration of a call option for a peaking plant in action



Note: MCP is market clearing price and VC is variable cost.

Looking at the two periods in Figure 14:

- In period 1, the market clearing price exceeds the call price. This activates the clawback mechanism, where the contracted capacity is obliged to pay the difference between the prices on all 100 MW of contracted capacity. To finance this the resource needs to earn the market clearing price on the contracted capacity by offering (and being cleared) in the market. The higher the market price, the greater the motivation to be available.
- In period 2, the market clearing price is below the generator's marginal cost and the call price, meaning the clawback mechanism is not in effect. The generator chooses not to generate; the resource has (efficiently) self-curtailed.

The bottom of Figure 14 shows the regular, fixed supplementary payments that are made to the resource to recover fixed costs and profit. These are assumed to be monthly.

Note that the contracted resource does not supply physical energy to the DISCOM. Rather, the contract gives the DISCOM confidence that it will be able to purchase energy in the market when it wants (the concern here is moments of high price and especially system scarcity), at or below the price of the call option. This is thanks to the clawback payment, which finances the portion of the purchase cost (at the spot price) above the call option.

The call option brings about the following benefits:

- Creates greater market liquidity, which assists price discovery, reveals important information on the value of different resources and informs investment choices.
- The winning resource is assured of a monthly premium, giving it confidence of recovering its fixed costs (and any profit built into its offer), which serves to keep the resource on the system, available for moments of system scarcity. Capacity contracted under a call option can therefore contribute to resource adequacy (and can be further boosted by making physical capacity a requirement of the contract).
- With efficient price formation, the contracted resource has well-formed incentives to overperform when it matters – if it can offer more than 100 MW during system scarcity, it gets to pocket the entire market clearing price on those marginal units of production. As we show later, it also has well-formed incentives to avoid poor performance or unscheduled outages during moments of scarcity (and to schedule maintenance away from moments of scarcity), as the penalty (the market clearing price) for being unavailable during system scarcity can in principle be significant. The strength of these signals depends on the extent to which market prices are allowed to reflect scarcity.

Two-sided CfD

Assume a CfD is concluded for a given volume of capacity between a buyer (DISCOM) and a seller (e.g., a thermal plant), with a strike price (SP) that is above the resource's variable cost (VC), assumed the same as marginal cost. Assume a design such that financial flows are independent of actual physical scheduling of the contracted resource – rather, financial flows link only to the difference between the strike price and the market clearing price.

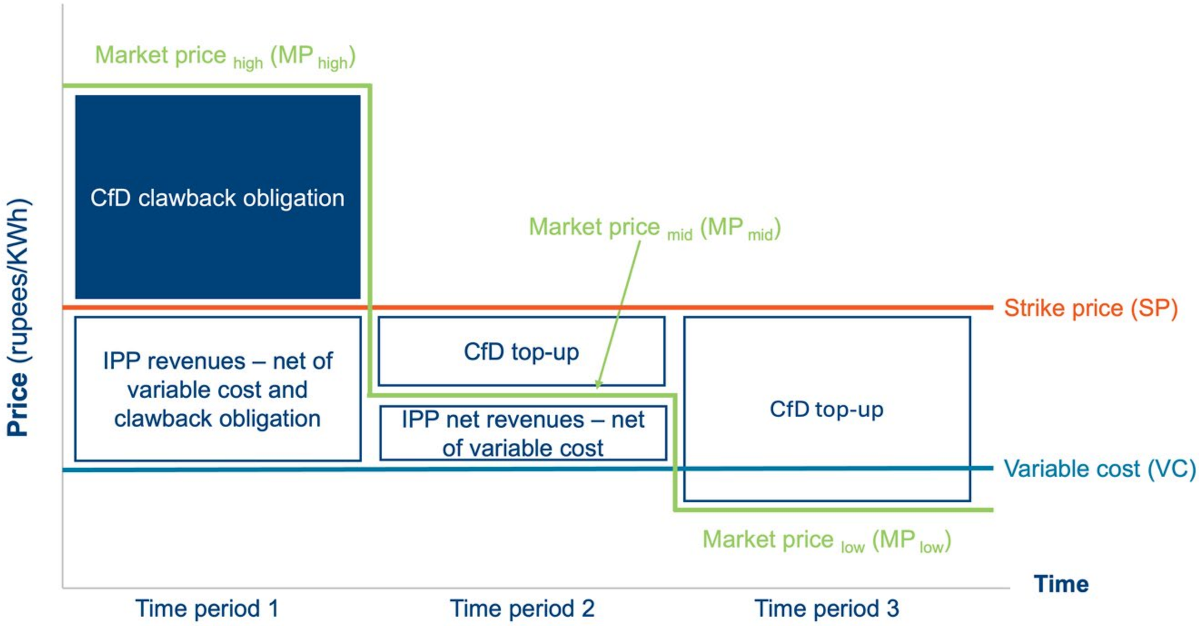
With reference to Figure 15 below, we present three scenarios: first where the market price is higher (MP_{high}) than the strike price, second where the market price (MP_{mid}) is lower than the strike price but above variable cost (VC), and third where the market price (MP_{low}) dips below variable cost. We discuss the implications below for both the buyer and seller.

- When the market price is higher than the strike price, the contracted resource will have an incentive to offer and sell its output in the market. This is because under the CfD it has a 'clawback' obligation, regardless of whether it offers to the market or not, to return to the buyer the difference between the market price and the strike price (MP_{high} - SP) for each unit of capacity contracted in the CfD. Selling on the market at the high market price means it enjoys net revenues of that high market price minus the variable cost (MP_{high} - VC), from which it can finance the cash outflows for the difference between the high market price and the strike price (MP_{high} - SP). Thus, the contracted resource retains as a margin the difference between the strike price and variable cost (SP - VC) that will help cover its fixed costs. The buyer on the other hand has a cash outflow for purchasing power from the market at a price (MP_{high}) that exceeds the strike price and receives a cash inflow of the market price minus strike price (MP_{high} - SP) from the contracted resource, for a net price of SP. Thus, the buyer and seller have effectively hedged and the contracted resource has the correct incentive to operate.

- When the market price is lower than the strike price but higher than the variable cost (MP_{mid}), the contracted resource receives from the buyer a 'top-up' payment of the strike price minus market price (SP - MP_{mid}), irrespective of whether it offers to the market. This maintains the incentive for the contracted resource to offer and sell its output in the market. Then the seller's net cash inflow will be the market price minus the variable cost (MP_{mid} – VC) from the market and from the buyer the strike price minus market price (SP - MP_{mid}). The contracted resource retains as a margin the difference between the strike price and the variable cost (SP and VC) that will help cover its fixed costs. The buyer, on the other hand, has a cash outflow for purchasing power from the market at this market price (MP_{mid}) and pays to the contracted resource an amount of the strike price minus the market price (SP- MP_{mid}), for a net price of the strike price (SP). Thus, the buyer and seller have effectively hedged and the contracted resource has the correct incentive to operate.

- When the market price (MP_{low}) is below variable cost (VC), the contracted resource receives from the buyer a 'top-up' payment of the strike price minus market price (SP - MP_{low}), irrespective of whether it offers to the market or not. The value to the contracted resource to offer and sell its output in the market is negative, as the variable cost exceeds the market price. So the resource is, correctly, not scheduled in the market. Thus, the seller's net cash inflow from the market is zero, and the buyer provides the contracted resource with a margin of the strike price minus market price (SP- MP_{low}) that will help cover its fixed costs. The buyer, on the other hand, has a cash outflow for purchasing power from the market at the strike price (SP). In summary, the buyer has effectively hedged, the contracted resource has the correct incentives to operate (in this case this means not scheduling), and the contracted resource has a margin to contribute towards fixed cost recovery. The bumper margins for the contracted resource in period 3 may be to some extent captured by consumers through competition in setting the strike price.

Figure 15. Illustration of a two-sided CfD for a thermal plant



Note: In all scenarios, the DISCOM can buy the contracted volume of energy at the strike price, and the power plant receives rents of at least the difference between strike price and variable cost. 'IPP' is independent power producer.

In sum, the FSC allows for:

- Revenue certainty for the contracted resource if it operates in alignment with market price signals.
- Consumers to enjoy a hedge against high prices.
- Greater market liquidity, which assists price discovery, and reveals important information on the value of different resources to inform investment choices.
- Signals for contracted resources to ensure they are available to schedule when prices are high.
- Surplus capacity of any DISCOM to be identified in the market and to be scheduled by other DISCOMs, ensuring resources are not operated in silos, thus supporting efficient scheduling.
- Contracted resources to have an incentive signal to offer their output into the market at their marginal cost and (efficiently) to self-curtail when market prices are below their variable costs.
- Signals to contracted resources for when to take a plant off for maintenance – when market prices are lowest (or negative).

- More visibility of market schedules, assisting the system operator in forming plans to accommodate the expected energy mix (for instance ensuring sufficient inertia).
- Minimised potential for exercise of market power in the market for generators as higher market prices beyond the strike price do not benefit the CfD contracted capacity.

The CfD tends to expose the generator more to fuel price volatility than the call option with strike price indexation. This can be overcome with the CfD if the generator hedges its fuel costs in contracting with fuel suppliers. Overall, the call option may be better suited to thermal resources than the CfD, and this may be why real-world examples of FSCs for thermal resources tend to be in call option form rather than CfDs, and why CfDs are more commonplace for resources with fixed (at zero) variable costs like renewables or relatively steady variable costs like nuclear.

Use of FSCs may focus attention on wholesale market design issues

Start-up costs, minimum run times and minimum down times of energy resources may focus attention on limitations of least-cost scheduling, as enabled by the roll-out of FSCs, to ensure resources recover all their costs and thus to help meet the reliability needs of the system. U.S. markets overcome this issue by accommodating a richer set of data in bids to reflect the multifaceted cost structures of energy resources, including start-up cost, no-load cost, minimum generation level and ramp limits, and subsequently providing uplift payments (make-whole payments) to ensure resources recover these fixed operating costs. Europe uses a 'block bids' solution. A classic block bid is an all-or-nothing order of a given amount of electric energy in multiple consecutive hours. Block bids were introduced because the simple bidding format does not allow generators to account for non-linear costs, in particular startup costs and minimum run levels. The European block bids solution is considered more computationally complex and less efficient than the U.S. uplift approach.[29]

[29] Eicke, A., & Schittekatte, T. (2022). Fighting the wrong battle? A critical assessment of arguments against nodal electricity prices in the European debate. *Energy Policy*, 170. https://doi.org/10.1016/j.enpol.2022.113220

Selected international experiences

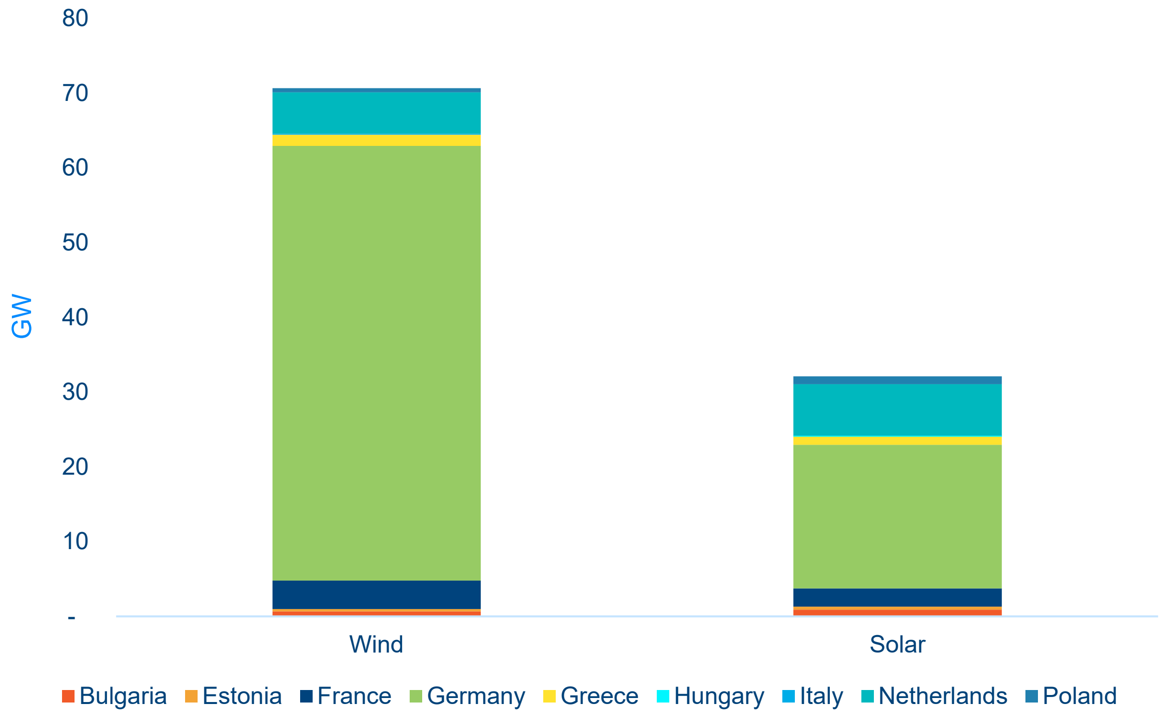
CfDs for renewables

Government-backed CfD contracts are well established in Europe, having been used for many years to stimulate new build and hedge price risk for investors.

Selected continental European countries

Figure 16 shows 70 GW of wind and 30 GW of solar PV under CfD contracts (one-sided[30] and two-sided) in a selection of European Union Member States in 2021.[31] These resources generated in total around 150 TWh of energy in 2021.

Figure 16. Capacity receiving support under CfD (one-sided or two-sided) in 2021, selection of European Union countries



Source: CEER. (2023). *Status review of renewable support schemes in Europe for 2020 and 2021*

FSCs are successfully used in some jurisdictions, such as Denmark, to underpin cost recovery confidence and to support investment. The Danish energy regulator, for example,

[30] One-sided CfDs apply a top-up when market prices dip below the strike price, but unlike two-sided CfDs, do not impose a clawback when market prices exceed the strike price.

[31] CEER. (2023). *Status review of renewable support schemes in Europe for 2020 and 2021*. https://www.ceer.eu/publication/status-review-of-renewable-support-schemes-in-europe-for-2020-and-2021/

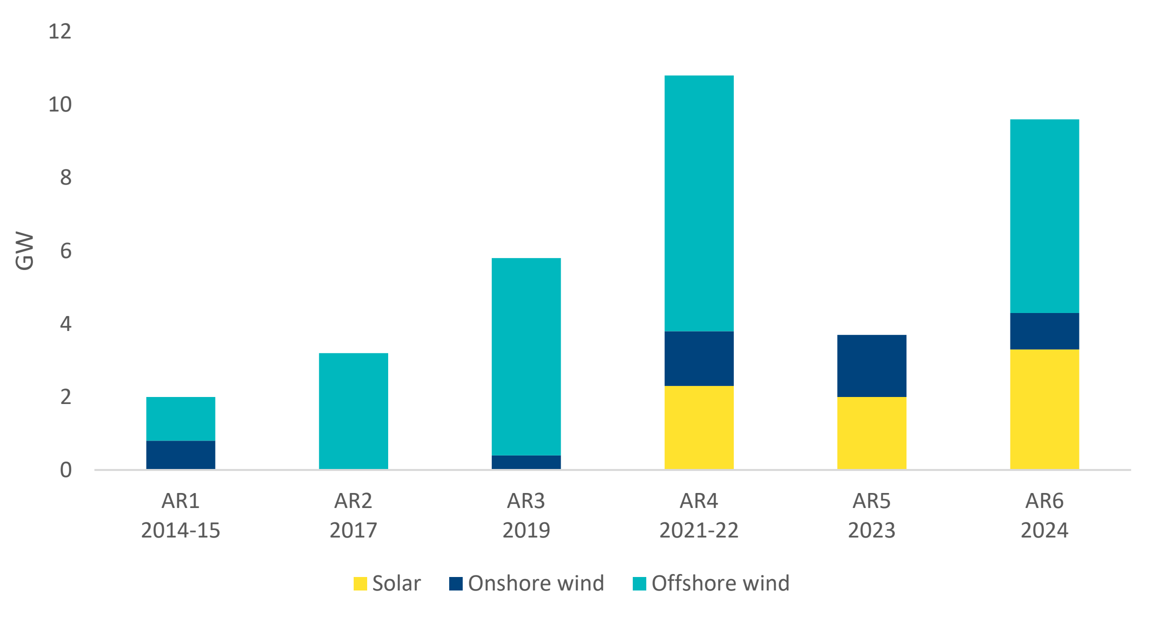
states: "In the Nordics over the last decade the norm has become 10-15 years financial contracts (often in the form of financial power purchase agreements…), in order to secure financing from the bank… The forward market creates a foundation for a steady cash flow for both consumer and production units because they can establish the future terms and prices at which they will transact. This provides stability and allows for better financial planning and certainty regarding future cash flow."[32]

"In the Nordics over the last decade the norm has become 10-15 years financial contracts … in order to secure financing from the bank."

Great Britain

Great Britain has also relied extensively on (two-sided) CfDs to finance new build for renewables. British CfD auctions have awarded contracts of over 22 GW for offshore wind, 5 GW for onshore wind, and 7 GW for solar PV, totalling in excess of 35 GW (see Figure 17).[33]

Figure 17. New renewables capacity secured in Great Britain's CfD auction rounds 1-6



Note: AR is action rounds.

[32] The Nordics include Denmark, Sweden, Norway, Finland. Danish Energy Agency. (2023). *Lessons Learned on Forward Markets.* https://ens.dk/media/5024/download

[33] Government of the United Kingdom, Department for Energy Security and Net Zero. (2024, 3 September). Contracts for Difference Allocation Round 6 results. https://assets.publishing.service.gov.uk/media/66d6ad7c6eb664e57141db4b/Contracts_for_Difference_Allocation_Round_6_results.pdf

Features of the British CfDs (representative of European practice) include:

- CfDs are typically 15-year contracts for renewables.
- Contracts are auctioned by the government on behalf of consumers using a government-owned counterparty (the Low Carbon Contracts Company, or LCCC) and agreed with the counter-party generator – typically a project company that owns and will operate a specific renewable-generating asset.
- Contracts are project-specific – the generator must have a licensed generation asset and metered output in Britain – therefore, **a 'paper' CfD, a pure financial agreement with no physical project, is not allowed under the statutory CfD regime.**
- When market reference prices dip below the strike price, the LCCC tops up renewable generators, recovering these costs from consumers. When reference prices exceed strike prices, the LCCC charges renewables generators the difference and passes this back to consumers.

In summary, CfDs have been used in Europe, including in Great Britain, to stimulate new build of renewables in excess of 100 GW.

CfDs have stimulated more than 100 GW of renewables build in Europe.

Figure 18 presents an overview of European experience and lessons learned with CfDs.[34, 35]

[34] Drawing from multiple sources, including: Scott, D. & Morawiecka, M. (2024, January 2). *The search for two-sided CfD design efficiency – a Shakespearean history.* RAP Power System Blueprint. https://blueprint.raponline.org/deep-dive/cfd-part-ii/; Pototschnig, A., & Hancher, L. (2024, December 14). *The future electricity market design.* European University Institute Florence School of Regulation. https://fsr.eui.eu/the-future-electricity-market-design/; Scott, D., & Claeys, B. (2023, July 20). *Solar and wind only cannibalise prices if you let them.* RAP Power System Blueprint. https://blueprint.raponline.org/deep-dive/price-cannibalisation/; Morawiecka, M., & Scott, D. (2023, November 17). *Balancing act: Two-sided contracts for difference for a speedy, cost-efficient and equitable energy transition.* RAP Power System Blueprint. https://blueprint.raponline.org/deep-dive/contracts-for-difference/; and Monahan, K., & Beck, M. (2023, February 14). *The United Kingdom's contracts for difference policy for renewable electricity generation*. Canadian Climate Institute. https://climateinstitute.ca/publications/uk-contracts-for-difference-policy-for-renewable-electricity-generation/#:~:text=The%20two%2Dway%20design%20characteristic,April%202022%20and%20March%202023.

[35] Note the Belgian system operator is conducting 20-year auctions for new offshore wind, where financial flows in the contracts for difference are divorced from physical production. The volume applied to difference payments and clawbacks is instead linked to a reference simulating the plant capability.

Figure 18. European experience with CfDs

Contracts for difference can help to lower cost of capital.

- This can unlock significant savings.
- For instance, a 2% reduction in cost of capital from 8% to 6% allows a 17% reduction in investment costs (capex plus opex plus financing).

Auctions are crucial in driving value for money.

- Noting the cost of schemes with administratively set payments, the EU mandated in 2014 that support should in principle be awarded based on competitive auctions.

Two-sided contracts for difference have especially gained in favour.

- This owes to the twin merits of providing price protection for consumers while underpinning investor confidence.

Difference payments (payouts and clawbacks) are recovered through consumer bills and through tax in Europe.

- Both approaches are used.

A robust carbon price helps to avoid price cannibalisation and thus large CfD payouts.

- Large CfD payouts can present cash flow challenges.
- The European carbon price in 2024 was around Euro 70/tCO_2.

Attention is increasingly focused on the merit of de-linking the CfD mechanism from own-production

- This can be achieved through use of an independent reference with link to forecast environmental conditions, such as:
  - Own technical capability (bespoke to each unit).
  - A forecast of actual local renewable output in a geographic area.
  - A simulation of energy output of a hypothetical reference plant(s).

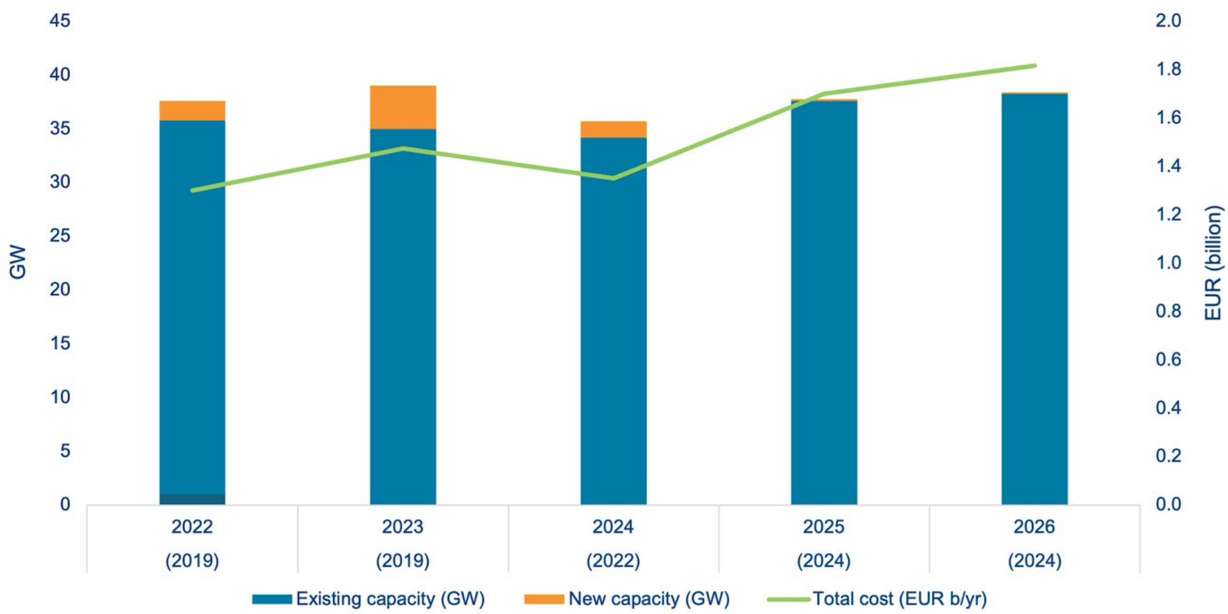
Call options for peaking resources

Italy

Italy employs a ‘reliability options’ style of capacity remuneration market, with a centralised single-buyer capacity auction and physical obligations. The product employed is therefore a call option. Although auctions are run centrally by a single buyer in Italy, these contracts could also be employed in a decentralised manner, for instance by individual DISCOMs in India, and as such may be of interest to Indian policymakers.

Capacity providers undertake to offer the committed capacity in the day-ahead market for each hour of the delivery period. What is not bought in the day-ahead market must be offered in the balancing market. Offer prices are at the discretion of resources. However, they are obliged to return to the transmission system operator (TSO) any positive difference between the reference market price (day-ahead or balancing) and the strike price (payback obligation).[36] The strike price is to be set by the system operator as the variable cost of the reference peak technology.[37] There is no stop-loss – no cap to their liability for poor performance.[38] New build capacity is awarded 15-year contracts, and existing capacity one-year contracts.[39] The first auctions were held in 2019, for delivery in 2022 and 2023.[40] Capacity market data is provided in Figure 19.[41]

Figure 19. Capacity and cost in Italy of capacity markets, reliability option design (call option), by delivery year and auction year (in parentheses)



Source: Terna (2022, February 22). *Capacity market – Results of main auction with delivery period 2024*

[36] Details of the payback obligation and strike price and setting of spot price can be found here: Lindboe, H.H., Björn Hagman, B., & Christensen, J.F. (2016). *Regional electricity market design*. Nordic Council of Ministers. https://norden.diva-portal.org/smash/get/diva2:1039397/FULLTEXT01.pdf

[37] In practice, this has been set at the variable cost of a peaker open-cycle gas turbine. See: Vargiolu, T. (2017). *Capacity markets and the pricing of reliability options*. University of Padova. https://www.efc.pwr.edu.pl/assets/EFC17/Vargiolu_EFC17.pdf

[38] Additional incentives are in place to motivate availability of capacity providers. If non-delivery is systematic (e.g., three months in a row), capacity payments of the last three months must be returned. Papavasiliou, A. (2021). *Overview of EU capacity remuneration mechanisms*.

[39] Enel. (2022, February 23). *Enel: 12.9 GW awarded in Italy's 2024 capacity market auction* [Press release]. https://www.enel.com/content/dam/enel-common/press/en/2022-february/PR%20capacity%20market%20auction%202024.pdf

[40] The old capacity payment will start disappearing from 2022. Lightbox. (2020). *The first auctions on the capacity market – this is how it went*. https://lightbox.terna.it/en/capacity-market-auctions-recap

[41] Terna. (2022, February 22). *Capacity market – Results of main auction with delivery period 2024*. https://www.terna.it/en/electric-system/publications/operators-news/detail/capacity-market-results-main-auction-2024; Cottle, S. (2022, May 31). *Insight Weekly: Asian banks' tepid bond issuance; insurer losses from Ukraine war; SPAC slowdown*. S&P Global. https://www.spglobal.com/marketintelligence/en/news-insights/blog/insight-weekly-may-31-2022

Other markets

Ireland employs a similar capacity market design to Italy, typically procuring around 6-8 GW, and Belgium is introducing one too. Colombia (with roughly 17.5 GW installed capacity in 2020)[42] has run a reliability option capacity market since 2008. Ireland and Colombia run a centralised dispatch (a pool), while Belgium and Italy run self-dispatch systems, showing that the choice of centralised dispatch or self-dispatch need not affect the adoption of call option FSCs.

Summary of findings

The experience of this selection of countries shows that:

- Financial contracts are widely used to stimulate new build, for instance:
    - CfDs have been used to stimulate the build of over 100 GW of renewables in Europe.
    - Call options have been used to procure more than 7 GW of dispatchable ‘peaking’ capacity in Italy since the first auction in 2019.
- Option contracts and CfDs tend to be complemented with physical elements, such as a requirement for the contracted party to build a physical plant,[43] strengthening confidence in resource adequacy and increasing decarbonisation impact.
- **India’s self-dispatch system need not be an obstacle to the roll-out of these instruments, as FSCs are used widely in self-dispatch systems,** for instance:
    - Italy and Belgium both use self-dispatch, with options in organised capacity markets.
    - Privately struck financial contracts are reportedly widespread in Nordic countries, also using self-dispatch.
    - CfDs are used to stimulate renewables build in self-dispatch systems, such as in Great Britain.

[42] BNAmericas. (2020). *Colombia’s power generation project pipeline*. https://www.bnamericas.com/en/features/colombias-power-generation-project-pipeline

[43] Each participant can submit offers for an amount no greater than its expected available capacity defined by Terna for each power plant. Terna (2015, April 14). *Italian capacity market*. https://competition-policy.ec.europa.eu/document/download/0caa1366-0615-4a1e-8e05-79d246dbcdc2_en?filename=capacity_mechanisms_2nd_working_group_TERNA.pdf&prefLang=bg

4. How financially settled contracts can help India meet multiple challenges

This section shows how FSCs – two-sided CfDs and call options, in over-the-counter (OTC)[44] form – can help address the challenges (outlined in Figure 1) facing the Indian electricity system during the clean energy transition.

It draws on simple what-if historic simulations using Indian DAM electricity prices from FY 2023-2024 to illustrate the potential impacts of employing FSCs had they been in effect.

Revenue stability for investors in renewable energy

DISCOMs tend to contract renewables using PPAs with single-part tariffs, which provide investors with price certainty and help secure financing.

However, two-sided CfDs can also underpin investor confidence.

The argument for using two-sided CfDs is therefore that they can provide revenue stability, like PPAs, but crucially without the drawbacks of PPAs which dry up liquidity in markets.

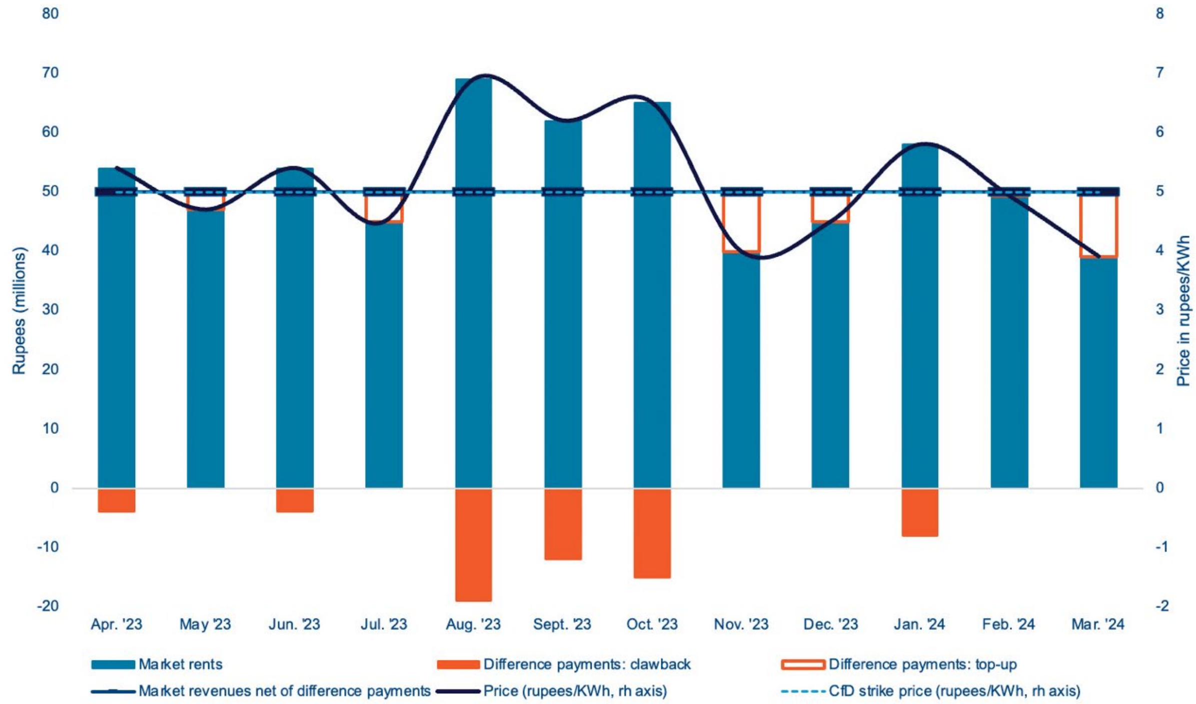
Figure 20 shows (right-hand axis) the monthly average of Indian DAM prices from April 2023 to March 2024 and imagines a (generous) CfD strike price of INR 5/kWh.[45, 46] This is comparable to a PPA with a single-part tariff set at the same price. Figure 20 also shows the monthly revenues (left-hand axis) that a renewables plant under a CfD contract generating an illustrative total of 10 GWh each month would gain after selling output on the market and net of the difference payments.

[44] OTC means 'over-the-counter,' and is a direct, bilateral contract between two parties. These are off-exchange, direct negotiations where the contract terms, including price, volume, and delivery period, are customised.

[45] This strike price was selected in order to be high enough to show occasional top-up payments as well as payback payments in the context of 2023/24 prices.

[46] Indian Energy Exchange. (n.d.). *Day ahead market prices 2023-2024* [database]. https://www.iexindia.com/market-data/day-ahead-market/market-snapshot?interval=ONE_FOURTH_HOUR&dp=SELECT_RANGE&showGraph=false&toDate=30-04-2023&fromDate=01-04-2023

Figure 20. Illustrative two-sided CfD for a renewables project generating 10 GWh each month, showing revenues (left-hand axis) and average (nominal) monthly DAM prices, April 2023 to March 2024



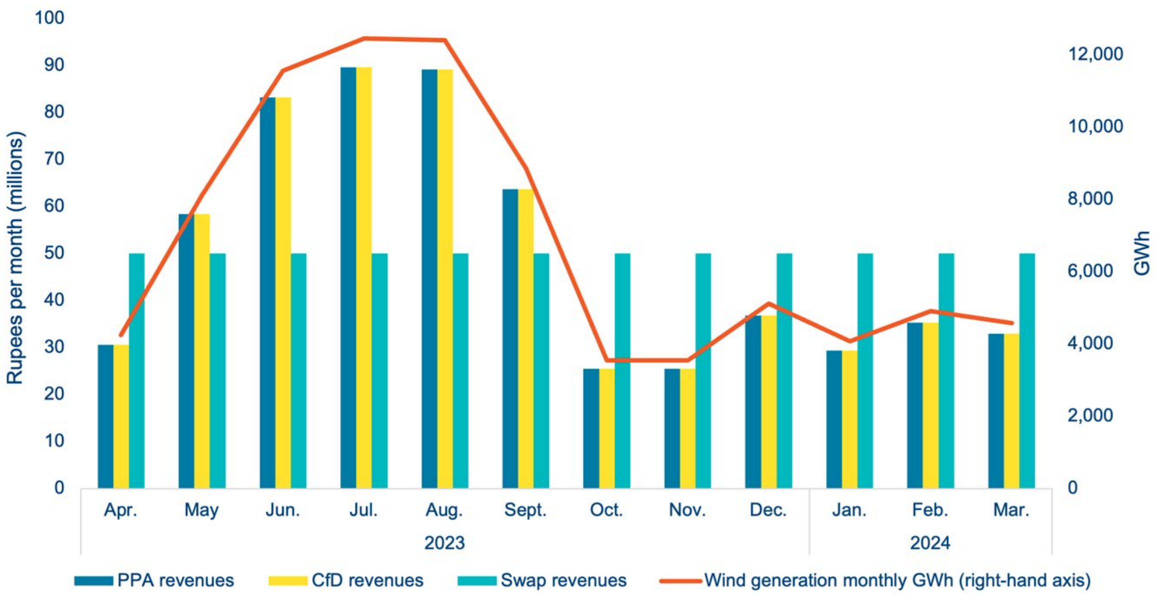
Source: RAP analysis. Data source: Indian Energy Exchange.

Net revenues are flat each month. This follows from the effect of the CfD, which fixes the price the plant earns per unit of output. The CfD therefore achieves the same effect as a typical single-part-tariff PPA: It fixes the price for each unit of energy of the contracted plant. This means the CfD can offer the same price stability as a PPA, while being superior in other ways such as stimulating market liquidity.

However, renewables output is not steady in reality – some months are windier than others, for example. This means that even though the price per unit remains fixed at INR 5/kWh, net revenues under the CfD and the PPA can vary each month as output varies. Figure 20 shows monthly wind generation in India over FY2023-2024, with bumper months from June to August. It also shows how this variability impacts monthly revenues under both a PPA and the CfD contract outlined, introducing significant revenue variability. For renewable resources, this revenue variability is the drawback of contracts that fix the price when output is variable.

Figure 21 also presents monthly revenues under another FSC – a swap – net of the obligation to pay market rents to the DISCOM, of a plant that performs exactly as per the efficiently-run reference unit. Revenues are now steady each month.

Figure 21. Monthly revenues under PPA, CfD, and swap contracts (illustrative)



All of this suggests that for the same performance:

- Swaps can be superior to PPAs in underpinning investor confidence for efficiently run plants.
- **CfDs can deliver at least the same level of revenue certainty as PPAs for efficiently run plants.**

At the same time, FSCs unlock other benefits associated with market liquidity.[47]

Ensuring cheap renewable energy is not wasted

The 2010 Indian Electricity Grid Code places a statutory duty on load dispatch centres to make all efforts to accommodate available solar and wind power. The code considers these variable renewables 'must run' (subject to the security of the grid, personnel and equipment), and frames avoidance of curtailment as an obligation. The load dispatch centre is expected to conduct planning to minimise the necessity for curtailment, and to exercise other options such as flexibility in available conventional generation before initiating curtailment of variable renewable energy. This has since been bolstered further by the Forum of Regulators' (2022) model guidelines for the management of renewable energy curtailment.

In spite of this, FSCs may help drive better outcomes than the existing PPA-based approach, on two counts:

[47] Although in theory swaps (or CfDs with financial flows decoupled from own-production) could deliver even better outcomes, given their complexity and a relative lack of international experience in deployment, implementing CfDs may be a prudent first step.

- Visibility: under the existing PPA approach, scheduling of renewables is conducted by DISCOMs bilaterally and therefore remains outside of the more transparent power exchanges. This means that system operators may have less timely information to prepare the system and avoid unnecessary last-minute curtailments than they would under an FSC contracting approach. This may lead to more instances where curtailment is identified as essential for system security (and is therefore allowed) than would be the case under an FSC approach where the system operator has more visibility.[48]

- Leveraging competitive advantage: a feature of PPAs as deployed in India is that they tend to remunerate renewables with a single tariff at levelised cost. This means in forming schedules their energy is costed to the DISCOM well above their (effectively zero) marginal running cost, removing their natural competitiveness. In turn this requires the imposition of 'must-run' status to ensure preference in scheduling. However, this may be inferior to an approach that leverages the natural market competitiveness of renewables to support market utilisation. For instance, in 2021 a tribunal found that curtailment by TNERC of solar developers had been largely commercially motivated (to reduce payment of costlier solar purchases), not driven by physical grid security.[49]

In summary, **by institutionalising market visibility of renewables schedules and leveraging competitive advantage, FSCs may be superior to PPAs in ensuring cheap renewable energy is not wasted**.

Flexible resources efficiently accommodate the variability of renewable energy sources

DISCOMs tend to use their own flexible resources contracted through PPAs. The reasons for this may include:

- A lack of liquidity in markets, as other DISCOMs have similarly tied up their resources in PPAs, which impedes price discovery and confidence in the market, feeding the cycle of low liquidity[50] (indeed some PPAs expressly prohibit the contracted resource from participating in the market).

- Weak incentives for DISCOMs to minimise cost, as they are not exposed to retail competition – they have an exclusive licence to supply electricity to customers[51] in their jurisdiction – and thus using PPA-contracted resources has the attraction of simplicity and familiarity, even if they are more costly than more market-oriented routes.

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[48] Indeed, if the system operator has good visibility of RES, they can take actions to minimise or eliminate curtailment. For example, the California ISO is taking actions to facilitate the sale of excess energy to neighbouring balancing areas, to support hydrogen production that can potentially be used as a dispatchable emission-free resource, to encourage battery storage participation in energy and ancillary service markets, and to proactively identify and evaluate solutions to potential pockets for RES congestion to prevent or minimise curtailment.

[49] Appellate Tribunal for Electricity (APTEL) at New Delhi. (2021). Appeal No. 197 of 2019 & IA No. 1706 of 2019. https://aptel.gov.in/sites/default/files/Jud2021/A197of1902.08.2021.pdf

[50] Energinet, for example, states that: "Electricity spot prices in the emerging electricity markets, such as in India, are generally volatile (for example, Volatility in the DA market for 2022 was around 16%), due to smaller market size (6% of total electricity generation)" Source: Energinet. (2023). *Lessons Learned on Forward Markets.* https://ens.dk/media/5024/download

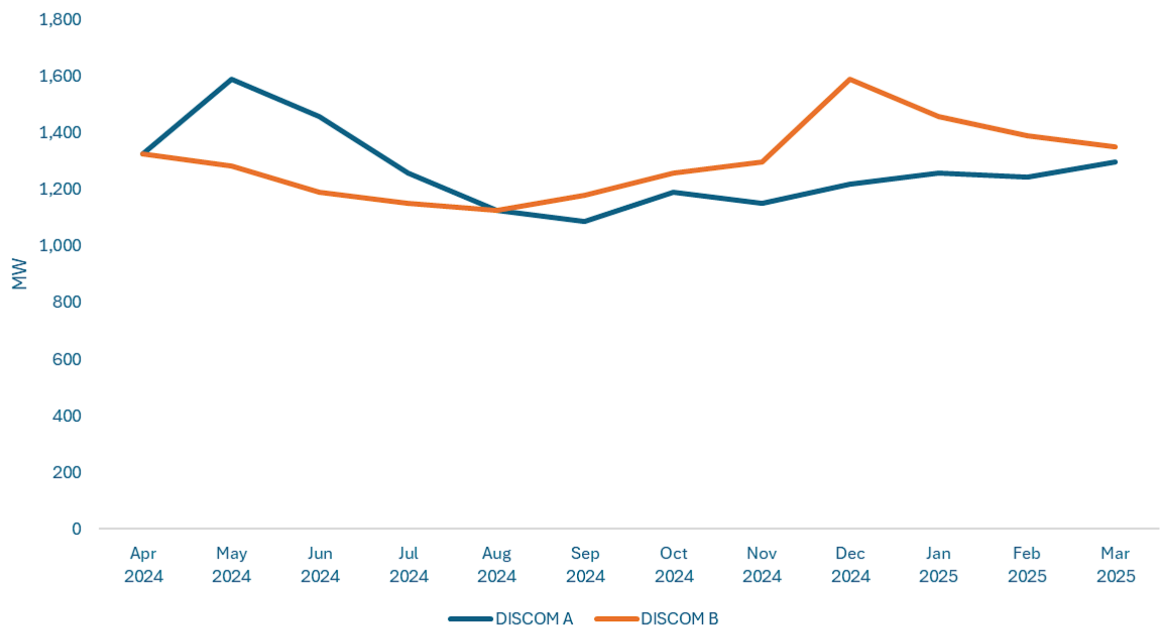
[51] Some competition has been introduced for big customers.

- The 'sunk cost fallacy': if DISCOMs have already committed to pay the fixed costs of these resources, they may perceive an impetus to use them, even if other resources are cheaper.

The key drawback of operating in silos – where each DISCOM self-schedules its own resources with limited recourse to the market – is underutilisation of cheaper generation options, which ultimately inflates consumer bills. On top of this, operating in silos weakens competition. And as the penetration of renewables grows, and with it a requirement for flexible resources to accommodate their variability, the drawbacks of the existing approach (i.e., the scheduling of resources in silos) may become even more significant.

To explore the scheduling efficiencies that can be unlocked by a shift from PPAs to FSCs, we present a simple simulation[52] building on illustrative demand profiles of two DISCOMs over the 35,040 quarter-hour time blocks of financial year 2024-2025. Figure 22 shows simulated DISCOM demands.

Figure 22. Illustrative monthly average DISCOM demand by 15-minute time block, financial year 2024-25



Note: presentation of monthly averaging means the significant volatility in hourly demand in the model is not visible.

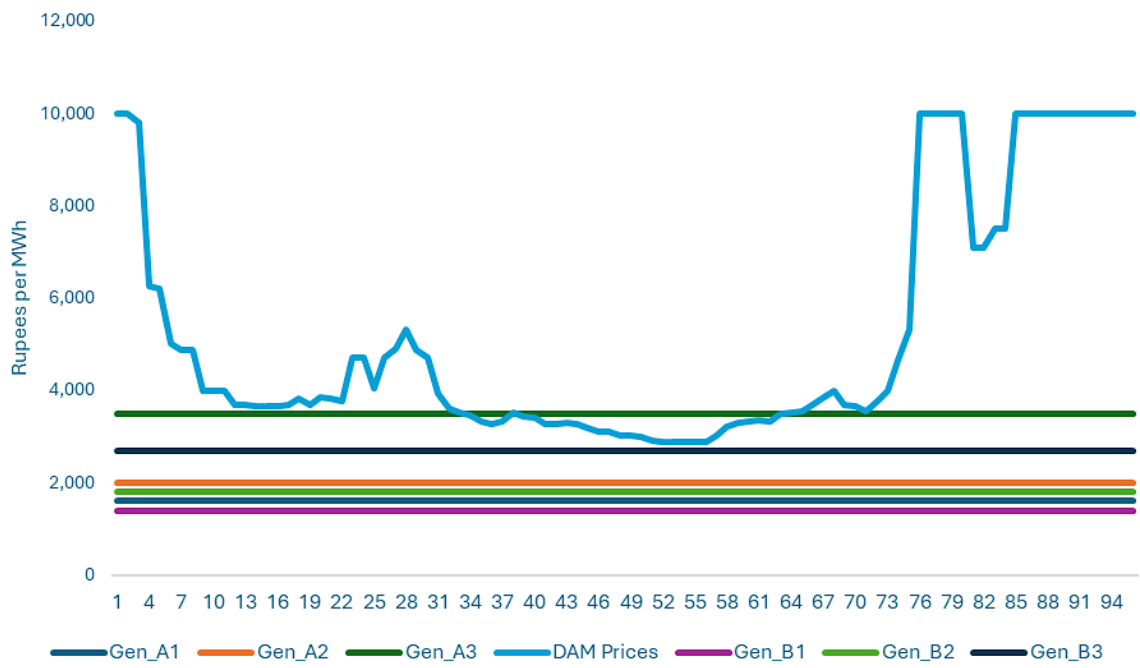
Under both the PPA and the FSC scenario, each DISCOM contracts with three thermal plants, one wind plant and one solar plant. For further detail on selected elements of the modelling set-up, including assumed capacities, see "Annex 4: Set-up of scheduling efficiency modelling."

DISCOMs also have access to the day-ahead market. Day-ahead prices (IEX) for the financial year of 2024-2025 are used to simulate the costs of market purchases. These prices

[52] This draws on analysis by IDAM Infrastructure.

exceed the assumed variable cost of generators contracted with DISCOM A and DISCOM B in some hours, and dip below the costs of some generators in others. Figure 23 shows the variable costs of thermal plant against market prices for the 96 time blocks of sample day 1 April 2024. Renewables with zero marginal costs are not shown.

Figure 23. Assumed variable costs of illustrative thermal plant and actual day-ahead market prices over 96 time blocks of financial year 2024-25



In fixing market prices, rather than allowing them to be influenced by offer prices and the scheduling patterns of the modelled generators, the analysis effectively assumes the demand and generation volume of the broader system (beyond DISCOM A and B) are sufficiently large to remain unaffected by the changes in contracting patterns of DISCOM A and B. Since the costs of meeting this wider demand are not modelled, and given our simplifying assumptions of a fixed price, they are treated as unaffected by the contracting scenario. This allows our model focusing on DISCOM A and B to capture all the potential economic benefits of their transition to FSCs.

The set-up of the model is developed further to ensure it sheds light on scheduling efficiencies alone (see "Annex 4: Set-up of scheduling efficiency modelling" for further detail) and not on any savings from the strengthened availability incentives of FSCs (which we explore in the later section "Resources receive useful signals during scarcity").

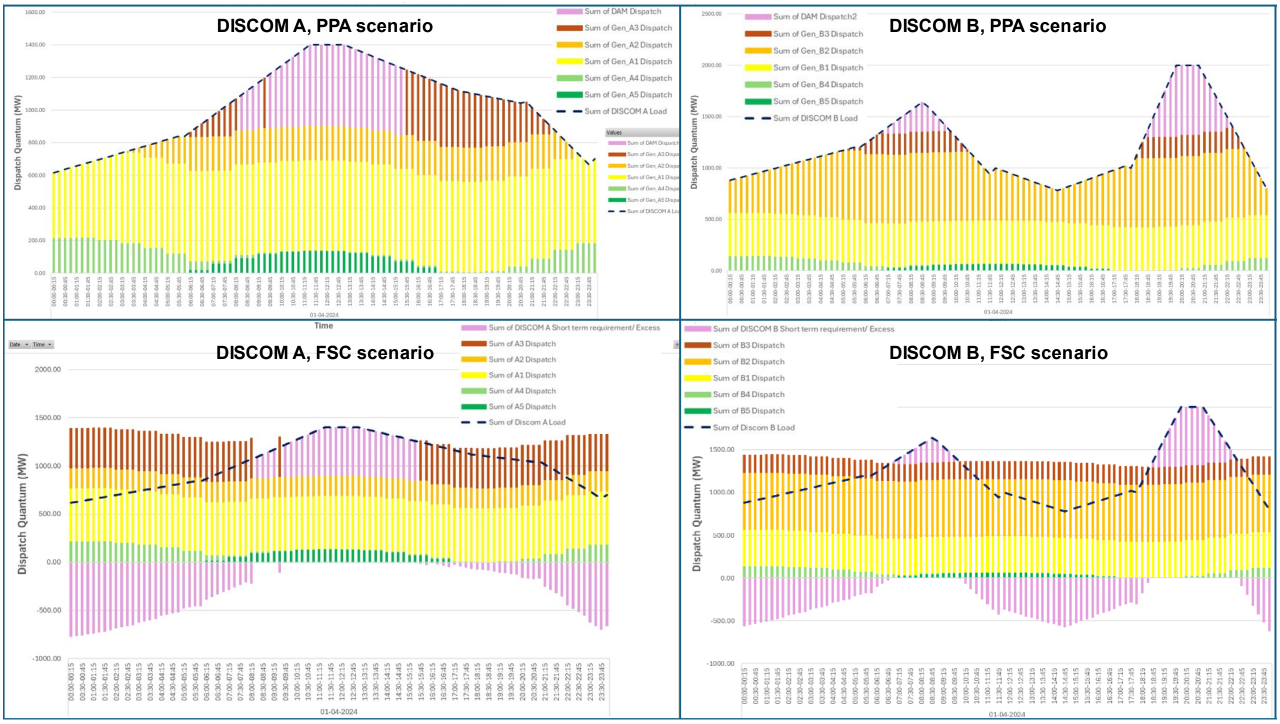
In the PPA scenario, generators contracted by DISCOMs are scheduled based on internal merit order – where resources are dispatched from lowest to highest marginal cost – to meet the demand of their respective DISCOM. DISCOMs do not have access to the other DISCOM's resources here, but dip into wider market resources at day-ahead prices when their own contracted resources are insufficient to meet their demand, or when market resources are cheaper than their own generation.

In the FSC scenario, renewables are contracted through CfDs rather than PPAs. Neither scenario however shows renewable curtailment. All six thermal generators are now contracted under call options. Their strike prices are set equal to variable cost, the price at which they offer their capacity to the market. Instead of operating in silos, all generators are scheduled by the market operator in system-wide merit order. This optimisation considers the offers of generators from both DISCOMs alongside the wider market, ensuring that total demand is met collectively through the most cost-efficient allocation.

The source of the modelled efficiency benefit is therefore in the variable cost savings enabled by FSC optimisation across all resources. By scheduling generation based on a system-wide merit order under the FSC framework, the model minimises the total cost of meeting the combined demand of DISCOM A, DISCOM B and the rest of the market, ensuring that the most efficient plants are prioritised regardless of ownership or contracting boundaries.

Figure 24 shows how dispatch of the contracted resources of DISCOM A (left-hand side) and DISCOM B (right-hand side) evolves as PPA contracts (top row) are replaced with FSCs (bottom row) for sample day 1 April 2024. In the PPA scenario, both DISCOMs curtail their more expensive contracted thermal plant (in orange and red) at the start and end of the day. The FSC scenario allows the full energy capability of these generators to be scheduled when they are cheaper than market clearing prices, even when the contracting DISCOM has satisfied its own demand. The accompanying clawback payments flow to the contracting DISCOMs and sharpen the incentives for the generators to offer to the market. Turning to the market price dip in the middle of the day, with the shift to FSCs, DISCOM A continues to curtail its most expensive generator A3 (in red) and to procure from the market. Now DISCOM B helps meet DISCOM A’s needs at least cost by offering to the market the excess capability of generator B2 (orange) and B3 (red). Clawback payments flow to DISCOM B.

Figure 24. Dispatch of generators contracted with DISCOM A and B on sample day 1 April 2024



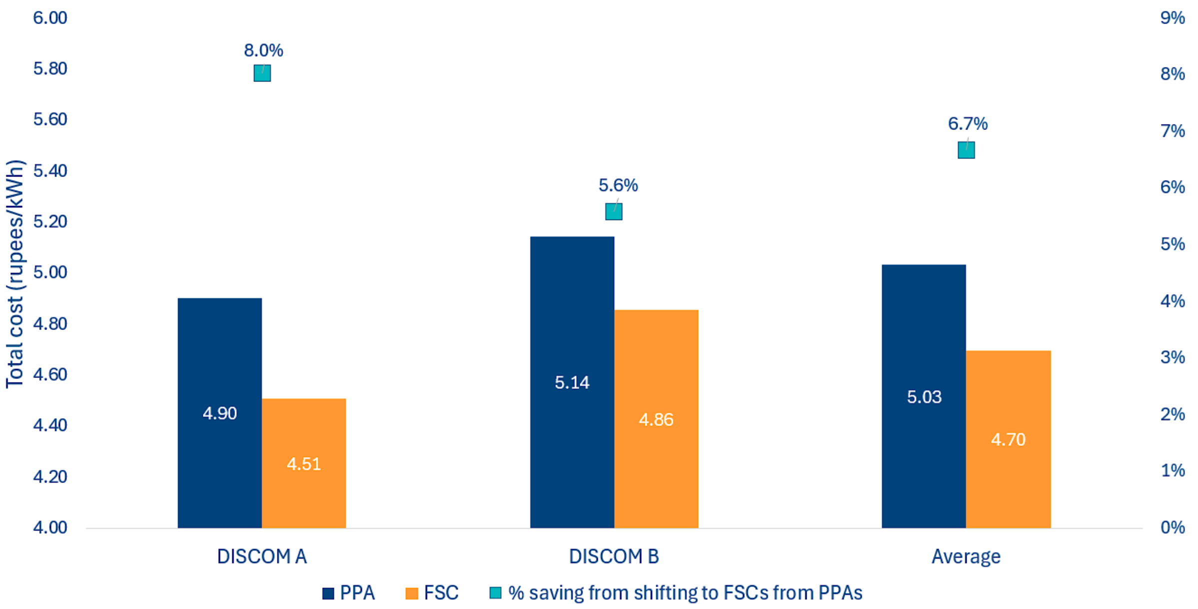
Note: The x-axis shows the 96 quarter hour time blocks on sample day 1 April 2024, the y-axis shows dispatch volumes in MW, the dashed line shows DISCOM demand, the purple area shows the requirement of energy from the market (positive) and excess sold to market (negative), green areas represent generation of renewable resources, yellow represents the cheapest thermal, orange the mid-priced thermal and red the most expensive thermal.

The modelling simulates a reduction in annual total power procurement cost of 0.46 rupees per kWh, or 9.5% of total annual procurement costs for the two DISCOMs collectively.

We conducted a scenario which assumes that, instead of 100% availability, generators incur outages for a duration of around 10% of the year. To focus on scheduling efficiency savings alone, we set the net contribution to fixed cost recovery in the FSC scenario to that achieved in the PPA scenario. This scenario yields savings of 0.33 rupees per kWh or 6.7% of DISCOM total annual procurement costs (see Figure 25). This smaller number reflects the elimination of some efficiency enhancing opportunities through the outage.

Overall, it suggests that scheduling efficiency savings may be conservatively estimated at 6.7% for thermal energy. These savings can be passed on to consumers in the form of reduced electricity bills, used to alleviate DISCOM financial stress or invested in renewables.

Figure 25. Total costs of power procurement of illustrative DISCOMs, by contracting scenario



The size of the savings will depend on factors including the actual relative costs of contracted capacity, market prices and correlation of demand between DISCOMs. The analysis does not capture dynamic savings stemming from the evolution of a capacity mix that better meets system needs and benefits from improved availabilities during system tightness.

Finally, even without accounting for dynamic benefits, the modelling underscores the finding that **all DISCOMs see a reduction in energy procurement costs with a shift in contracting from PPAs to FSCs. In the example above, the savings to DISCOM A are 8% and to DISCOM B 5.6%.** Table 4 spells out the mechanics, showing that in each period, depending on market prices, variable costs, capacities and other factors, one of four effects will materialise, two of which unlock efficiency savings for the DISCOM.[53]

[53] Note that, as the model fixes prices, the effect in the top right quadrant is not modelled – the modelling instead captures all benefits in the bottom left. Thus, there is no impact on DISCOM procurement costs for energy that was previously procured through the market by the DISCOM under PPA arrangements and that continues to be procured through the market under FSCs.

Table 4. Impact on DISCOM energy procurement costs with shift from PPAs to FSCs

Scenarios		FSC arrangements	
		Plant contracted to DISCOM **is scheduled** under an FSC	Plant contracted to DISCOM **is not scheduled** under an FSC
PPA arrangements	Plant contracted to DISCOM **was scheduled** under PPA arrangements	**No change in cost**: DISCOM gets clawback payment which fixes the net price it pays at the variable cost as previously under the PPA	**Cost saving**: if no longer scheduled under FSCs, market price must have fallen below variable cost of that resource, meaning the DISCOM can buy the energy more cheaply from the market than previously
	Plant contracted to DISCOM **was not scheduled** under PPA arrangements	**Cost saving**: DISCOM enjoys a new clawback payment, lowering its costs of energy procurement (this scenario occurs when merit order scheduling enabled by FSCs allows DISCOM's plant to displace the more expensive plant of another DISCOM or on the wider market)	**No change in cost**: DISCOM buys energy from market at unchanged price

Consumers are protected from effects of high prices during scarcity

PPAs typically fix the variable cost of dispatch for the counter-signatory (the DISCOM) and provide for steady payment of fixed costs (so long as plant achieves target load factor). They therefore give the DISCOM some certainty over the costs they will incur and avoid exposure to sudden jumps in cost associated with market prices. This helps them to smooth prices and bills, and especially to limit exposure to high-price periods of concern for consumers.

Our analysis turns first to contracting structures in the context of thermal resources. We conduct a historic simulation using observed FY 2023/24 DAM prices,[54] imagining a DISCOM seeking to buy an illustrative unit of energy in each period of the year, to assess the performance of three contracting approaches to protect consumers from effects of high prices:[55]

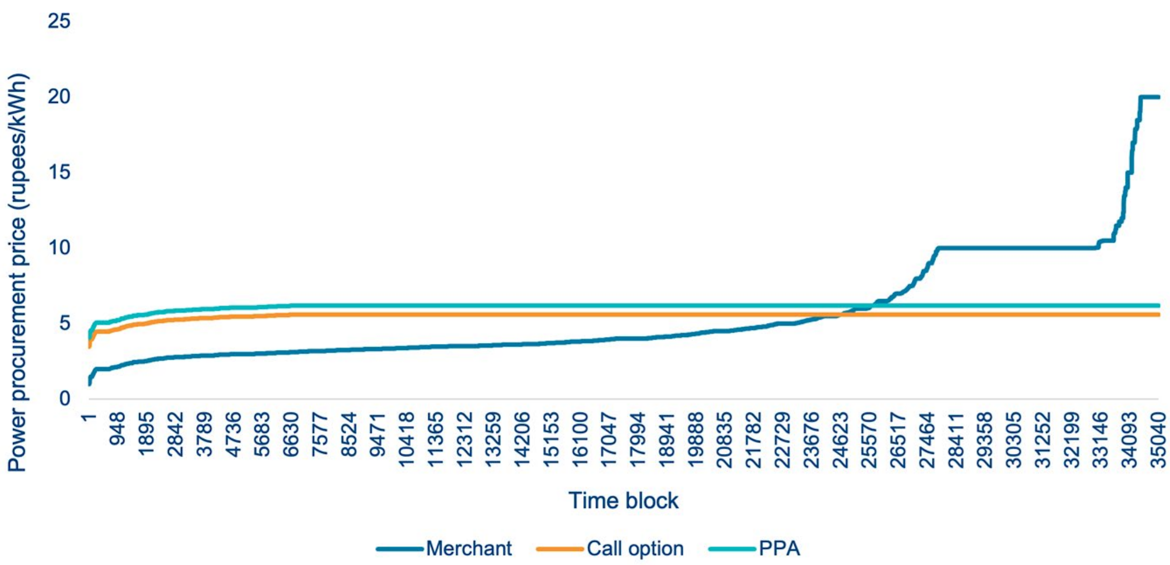
- Merchant: A DISCOM that relies on merchant (no-contract) resources will be fully exposed to the volatility of market prices, peaking at a price for an additional unit of energy at INR 20/kWh during moments of greatest scarcity. The merchant cost is therefore the same as the market price duration curve.
- PPA: We assume a simplified PPA which has a variable tariff equal to an illustrative variable cost of generation of INR 3.125/kWh. We assume the DISCOM buys from the market (merchant) when market prices dip below the variable cost of the thermal plant, but otherwise uses the PPA contracted plant, compensated at variable cost. On top of this a fixed charge payment is paid to the plant that we calibrate to recover the fixed cost of the thermal plant as implied under the merchant approach above. Although fixed cost charges are typically presented as a fixed payment per month, we spread it over each time block equally to present an 'effective power price exposure' to the DISCOM, to allow comparability across different contracting approaches. This results in a steady payment of INR 2.48/kWh on top of the energy cost (capped at INR 3.125/kWh).
- Call option: Setting the strike price at variable cost, the call option approach ensures that whenever the market price exceeds the strike price – equal to the variable cost of generation of INR 3.125/kWh – the DISCOM is compensated for the excess. Again, supplementary payments (the premium awarded to the signatory of the call option) amount to INR 2.48/kWh. As with the PPA approach this results in a maximum effective power price exposure of only INR 5.61/kWh under the call option.

Figure 26 shows the effective power price to the DISCOM of the three approaches.

[54] We complement these with high-price DAM prices when DAM prices hit the cap of INR 10/kWh. This provides for a set of prices with greater peaks than just using DAM prices. Note the broad thrust of analytical findings would be directionally the same without their inclusion.

[55] See Annex 1 RAP historical model to assess availability incentives.

Figure 26. Effective power price exposure of procuring a unit of electricity



Note: The effective price exposure under the call option and the PPA is identical (i.e., the lines would fully overlap), but we have placed one above the other to ensure visibility.

Figure 26 shows that there is significant cost volatility for the DISCOM with the merchant approach. Both the call option approach and the PPA, on the other hand, cap DISCOM exposure to high prices once market prices hit variable cost. The call option and PPA also allow for low prices to be enjoyed by consumers. Like a PPA, therefore, the call option approach protects consumers from high prices; but it avoids causing the issues associated with PPAs (such as poor availability incentives, scheduling inefficiencies and market illiquidity).

As for renewables, the effective price paid will be capped at the strike price under a CfD.

In conclusion, **FSCs like the call option and CfDs protect consumers from high prices. Price caps in wholesale markets are not required to protect consumers.** FSCs achieve this outcome in spite of the fact that resources contracted through them are scheduled in the market, rather than bilaterally as is the case with PPAs.

Resources receive useful signals during scarcity

Thermal resources

PPAs send weak and imprecisely-targeted signals to stimulate performance during scarcity. Under the ‘Terms and Conditions of Tariff’ regulation, PPAs typically require a normative availability of 85%.[56] This means the contracted plant may be allowed up to 15% of non-availability without any reduction to the fixed cost payments of the PPA. Unavailability beyond this threshold leads to a reduction in fixed cost payments.

To support availability when it matters, it is helpful for the contract structure to send signals that align with system need. FSCs can incentivise resources to schedule planned outages when there is excess supply,[57] and they can also incentivise resources to incur cost to minimise the risk of an unplanned outage when demand stretches the limit of supply.

To show how these incentives can be strengthened under FSCs we return to the model used in the section on protecting consumers from high prices, to simulate financial outcomes under three contracting types – no-contract (merchant), call option and PPA – of an illustrative 15% and a 30% contiguous loss-of-generation event (outage), using historic prices from FY2023-24.[58] These are roughly equivalent to a 55-day outage and a 110-day outage respectively.[59] Each of the two outages is simulated for three possible windows – the lowest market prices, the middle market prices, and the highest market prices.

Given that market prices can shed light on the real-time value of resources, and therefore act as an efficient guide for decisions like scheduling of outages, this means the no-contract merchant type (fully exposed to market prices) provides an efficient benchmark against which PPAs and call options can be compared.

Figure 27 and Figure 28 indicate, respectively, the 15% and 30% outage windows simulated for each contract type.

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[56] This is the value of the Normative Annual Plant Availability Factor for thermal power plants in the CERC Terms and Conditions of Tariff Regulations (cercind.gov.in/regulations/notification-2024.pdf, p. 127). Other notable regulations include India’s resource adequacy framework, which places an obligation on DISCOMs to contract sufficient capacity and ensure that performance-based incentives or penalties are built into those contracts.

[57] Note that outage scheduling is currently centralised, and de-linked from price, and therefore that these benefits would be greatest if India transitions to decentralised outage scheduling. Jurisdictions such as Texas (ERCOT) employ decentralised outage scheduling. Britain has generator-led planning, which is then reviewed and coordinated by the National Energy System Operator.

[58] See Annex 1. RAP historical model to assess availability incentives for further background on the approach employed here.

[59] These windows are illustrative rather than reflecting existing practice – the typical planned outage window under current arrangements is targeted to be around 21 days.

Figure 27. Availability schedules for 15% outage during the low-, medium- and high-price periods

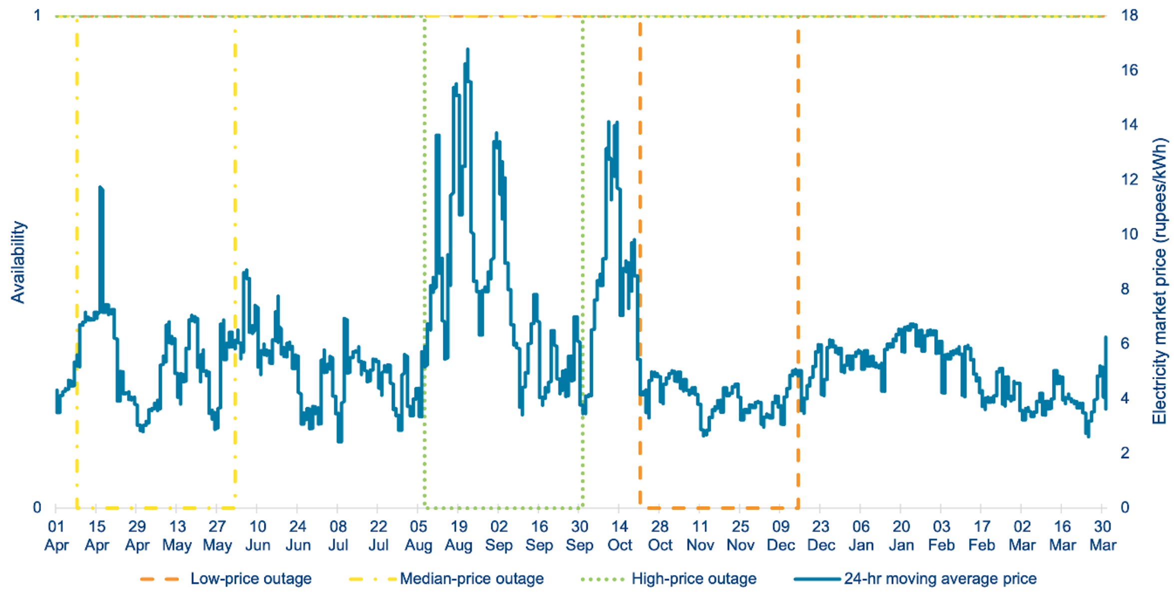


Figure 28. Availability schedules for 30% outage during the low-, medium- and high-price periods

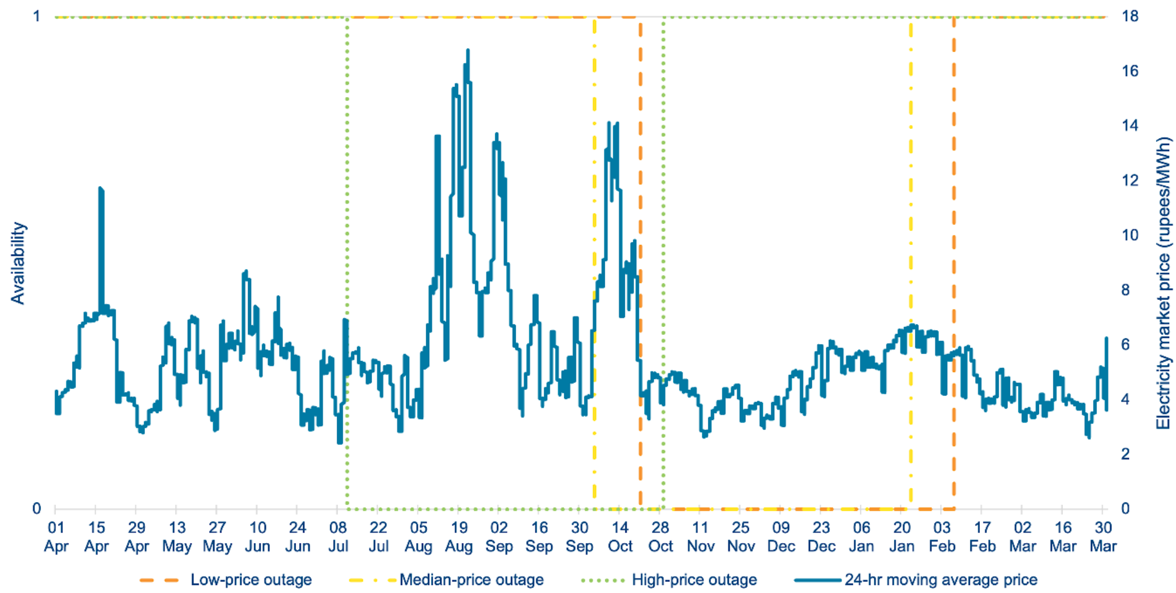


Figure 29 quantifies the net revenue reduction as a share of total net revenue of the two simulated durations of outage.

Figure 29. Reduction in net revenue with simulated outages

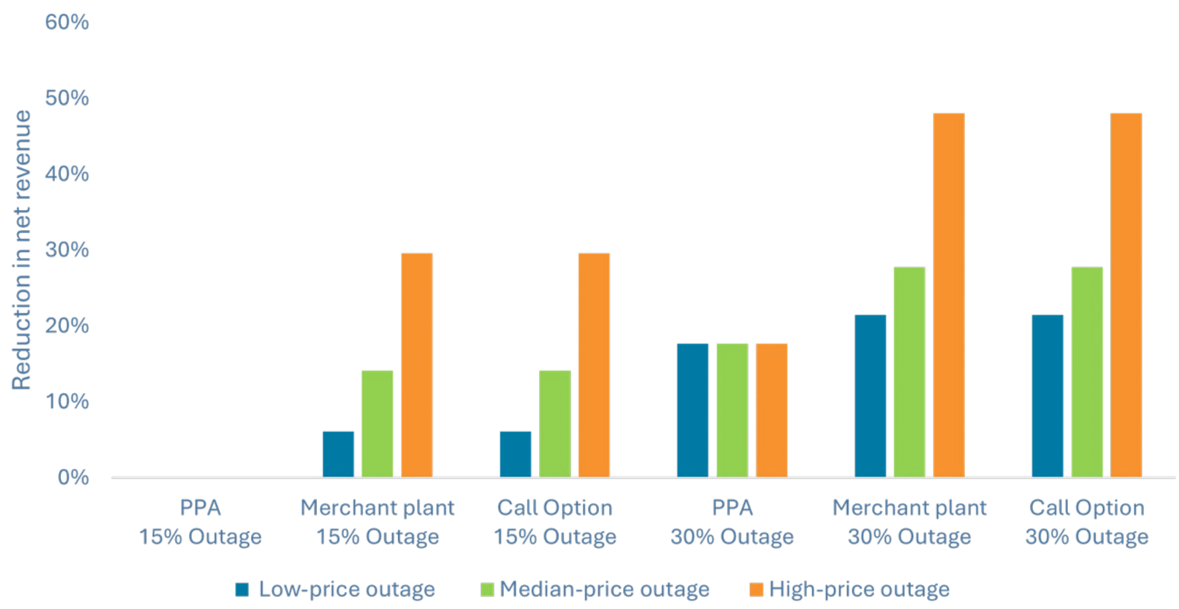


Figure 29 shows that the penalty (the loss of revenue) under the call option contract aligns with our efficient benchmark – the merchant plant. Thus, the call option supports efficient decisions in scheduling planned outages and avoiding unscheduled outages at moments of high system need.

For example, a 15% (55-day) outage when market prices are highest would result in the plant losing 30% of its net revenue under the call option. In contrast, the net revenue reduction is only 6% if there is an equivalent loss of generation in the low-price period. This is partly because in some of those hours the plant does not generate at all, and partly because of the low margins in the rest of the hours.

This is in significant contrast to the PPA, where all risks are borne by the DISCOM or off-taker. In the case of the PPA, there is no impact on plant net revenues with a 15% outage. This is because the variable (energy) component of the PPA price covers the variable cost of generation and the plant does not suffer any reduction in the fixed (capacity) component of the PPA at this availability level. Thus, the plant receives the same capacity charge at 100%, 90%, or 85% availability.

It is then penalised for any further drops: the capacity charge component falls linearly as plant availability falls below Normative Plant Availability of 85%. A 30% outage level therefore means the plant would be paid ~(70%/85%) or 82% of the total capacity charges, implying an 18% drop in net revenues.

Under the PPA contract, net revenue reduction is the same for a given level of outage irrespective of when it occurs in the year. Although the Terms and Conditions Regulations have peak and off-peak periods, with the former weighted more in the calculation of capacity charges payable, their impact in the case of multi-day outages is minimal. Peak hours, as defined in these regulations, refer to a predetermined period of four hours each day. A planned outage for maintenance spanning across days or weeks is likely to impact availability in a similar share of peak and off-peak hours. As each month is treated identically, an outage of a given duration will have the same financial impact on the generator whether it occurs in the high-demand season like summer or low-demand season like winter. Further, the generator is allowed to compensate for low availability in one month with high availability in any subsequent month in the year. The PPA therefore does not encourage contracted parties to schedule outages for the moments of lowest impact on the system.

A shift from PPAs to FSCs can motivate market-friendly outage scheduling and motivate efforts to avoid unintended outage when it matters most – especially when prices are allowed to reflect scarcity.

In summary, compared with PPAs, the call option approach sends stronger and more targeted signals for plant to be available when the system needs it. FSCs can motivate contracted parties to schedule maintenance in periods of overall surplus for economic reasons and to undertake action to minimise the risk of unplanned outages in the moments of greatest importance.

FSCs can help deter abuse of market power and limit 'manufactured' scarcity

FSCs can be designed to deter abuse of market power, and in so doing limit 'manufactured' scarcity.

This can be achieved by setting the FSC strike price – using a call option example – close to the variable cost of the resource. Under these circumstances, when wholesale prices spike to reflect scarcity in the market, the value at risk to the energy resource of not being available during scarcity also grows. This motivates the operators of the resource to ensure availability when it matters, and helps to limit the incentive to act upon market power when there is resource scarcity in the system.

Although market power is not currently perceived as a pressing concern in India, having in place arrangements that align incentives of resources with the public interest can help underpin public confidence in markets to deliver desired outcomes, and could be valuable in future. **Implementing FSCs could provide a more effective tool for policymakers to protect consumers, allowing price caps to be relaxed and letting prices show the scarcity and abundance of energy, without these prices impacting consumers.**

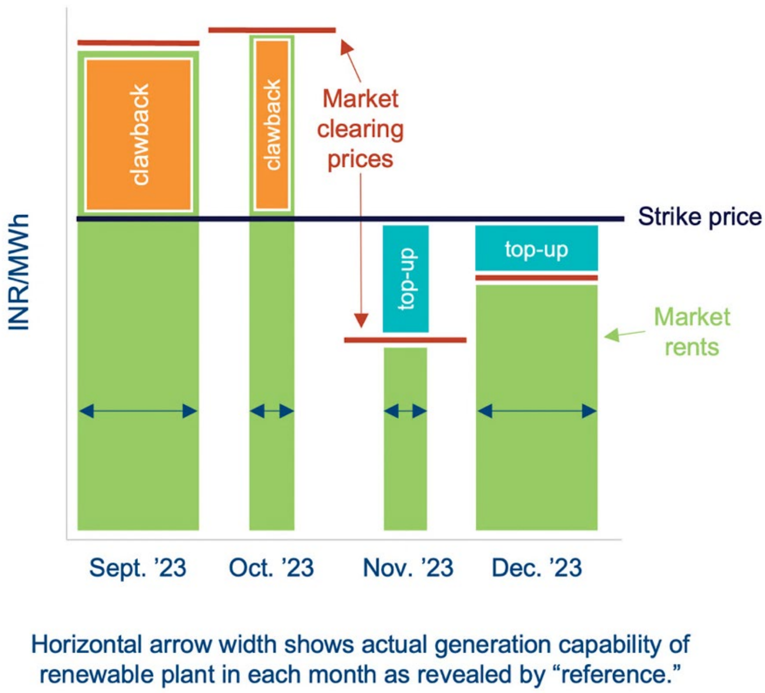
Renewables

As with call options for thermal, renewables contracted under FSCs – specifically a design that delinks financial flows from own-output[60] through use of a reference output such as a capability CfD[61] – can motivate operators of renewable resources to maximise availability (subject to their capability) when it matters most. This is because payback obligations are most significant when prices are high, and because this obligation applies regardless of the operators' own output, depending only on the reference plant assessment of capability.

This is illustrated in Figure 30, which sketches the relative magnitude of monthly average day-ahead prices based on observed prices for September to December 2023. It draws on observed wind generation across India over these months to simulate the monthly generation capability of a wind plant according to prevailing environmental conditions. Contract possibilities considered are:

- A PPA with a single-part tariff set at a levelised cost (imagined equal to the illustrative strike price).
- A production-dependent CfD.
- A production-*in*dependent CfD (see Annex 2: Decoupling renewable contracts for difference from own-production).

Figure 30. Average day-ahead market prices in late 2023 with stylised wind generation capability drawing on historic observed wind production data



[60] For the purposes of this paper, we use the terms 'own-output' and 'own-production' interchangeably.

[61] See Annex 2. Decoupling renewable contracts for difference from own-production.

Now, assume the renewables operator needs to go offline for maintenance for a whole month within the four-month period, and has a reasonable idea that prices will be high until the end of October while wind generation capability will dip in October and November.[62] Figure 30 shows:

- Under a PPA (or a production-dependent CfD, where difference payments are linked to own-output), the operator of the renewables plant will elect to go offline in October or November, when the wind harvest is low. Of these two months, it makes no difference to the operator whether they schedule maintenance in October or November, as the foregone revenues from each unit of undelivered energy are set at the strike price (levelised cost), even though market prices are signalling that energy is much more valuable in October.
- Under a production-independent CfD where difference payments are linked to the deemed output of a reference, the operator of the renewables plant compares foregone market rents determined by market clearing prices in October and November, to conclude that maintenance should be scheduled in November and not October. The actual average DAM prices in October and November were around INR 6.5 and 4/kWh. The production-independent CfD presents the difference between the two prices (INR 2.5/kWh) as an incentive to schedule maintenance in a way that serves the needs of the system as expressed by prices.

This example shows that production-independent CfDs align the interests of the renewables operator with the system as indicated by market prices, unlike existing PPAs (or production-dependent CfDs).[63]

This means that CfDs can be designed to motivate renewables operators to ensure their resources perform to the best of their capabilities, subject to environmental conditions, when it matters most, and that simpler CfD designs fare no worse on this score than existing PPAs.

Effectively incentivising renewables operators will grow in importance as renewables penetration grows. As experience with contracting through CfDs in India increases, attention may turn to production-independent designs.

Investors in thermal resources are confident of cost recovery

A frequently cited attraction of PPAs is that they can offer confidence of cost recovery, providing for a steady stream of fixed payments and for the recovery of variable costs of production. We explore the potential for FSCs to do the same.

[62] The analysis can also be reimagined to show how this CfD supports efficient planning of a one-day (or one-hour) outage over a forthcoming period of four days (or four hours), by reimagining the four months on the x-axis as four days (or four hours).

[63] The swap design can also yield the same desired incentives. See 3. Financially settled contracts: a primer.

We return to the model first introduced in the section on protecting consumers from high prices to simulate the accrual of rents (net of variable costs – in other words, to cover fixed costs)[64] using historic market prices from FY 2023-24 earned under the PPA, the merchant contract, and the call option. We imagine the performance of the resource complies with the incentives provided by the contract structure, and therefore always schedules when economic to do so. Figure 31 shows the results for each contracting approach.

Figure 31. Simulated share of annual revenues (net of variable costs) by month by contract types, and monthly average DAM prices, FY 2023-24

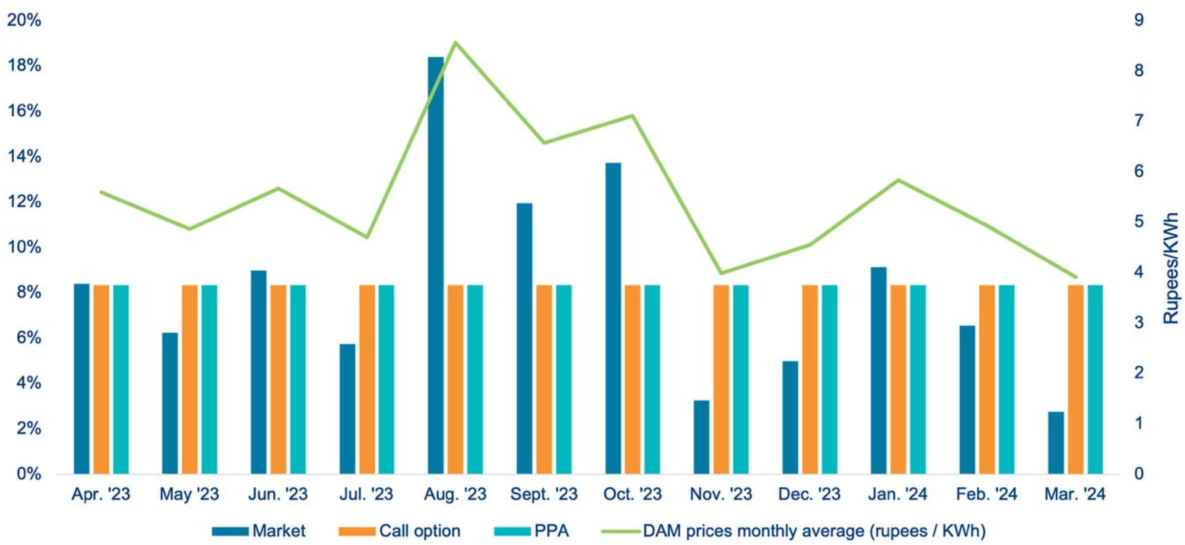
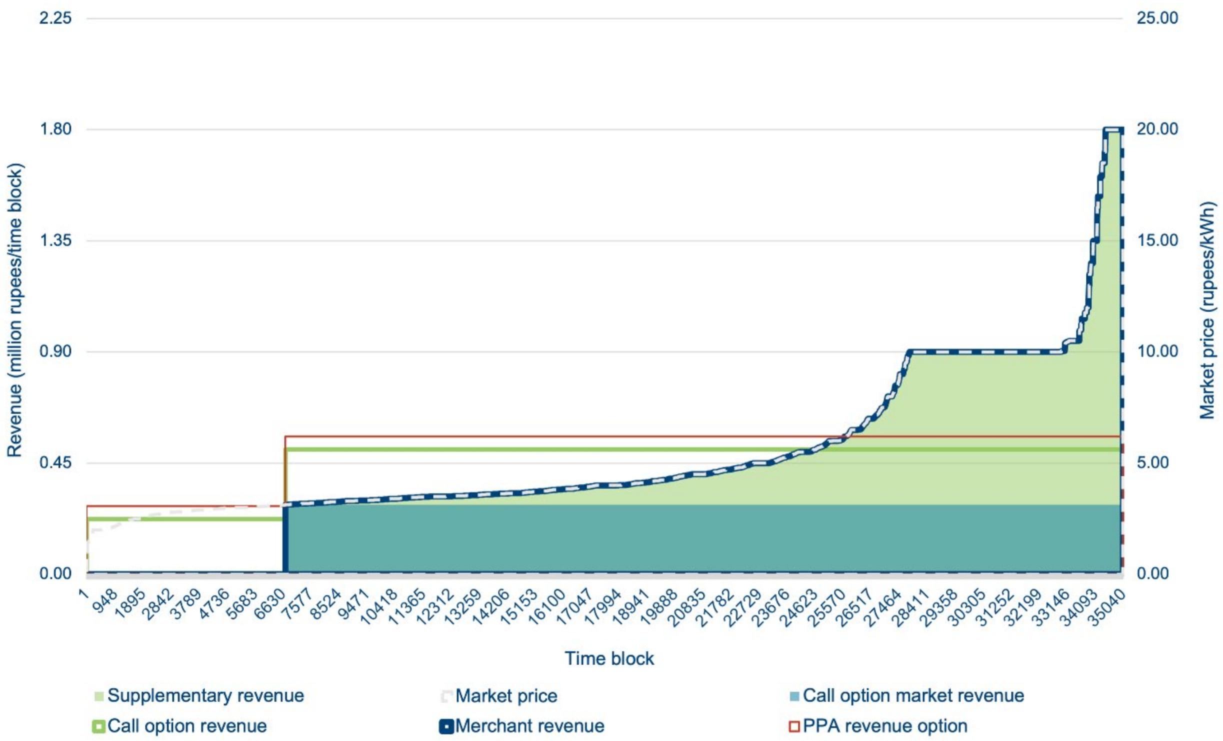


Figure 31 shows that, like the PPA, the call option provides steady net revenue accrual for the generator. This can be compared with the variability in net revenues under the merchant approach. The call option result is attributable to the strike price, which is set to the variable cost of generation, such that any variation in the market price above the variable cost of generation is offset by the clawback payments that the generator must make to the utility. As a result of this call option design choice, the plant earns exactly the variable cost of generation. When market prices fall below the variable cost of generation, the plant does not produce – thus the net revenue for the power plant is simply the supplementary payment, which, by design, is constant.

Figure 32 breaks down the different components of the revenue for a 100 MW coal plant (after losses) against a price duration curve under the merchant approach, PPA contract and call option contract. For simplicity, it assumes constant input costs (coal prices).

[64] We abstract out other elements like the impetus to recover a fair profit.

Figure 32. Simulated breakdown of annual revenues by contract type



Revenues are shown by contracting approach:

- Merchant plant: Dashed blue line
    - Zero when the market price (in grey) is below the variable cost of generation and perfectly aligned with the market price (dashed grey line) otherwise.
    - The shaded green and turquoise portions are the total revenues earned by the plant in the market.
    - The green portion represents the portion of revenue exceeding variable cost. In the long run, competition will ensure that this exactly covers the fixed costs of the plant.
- Call option: Solid green line
    - Under the call option, the shaded green portion – market rents above variable cost – are paid back to the utility.
    - The remaining energy-related revenue of the plant is represented by the turquoise-shaded region – this exactly covers the variable cost of production.
    - The plant also receives supplementary payments which cover fixed costs. Competition helps limit this so the sum is equal to the green shaded area (as per the merchant plant).

- The total revenue stream for the plant – the sum of market revenues and supplementary payments – is represented by the area under the solid green line. While this is the same as the area under the dashed blue line (the merchant total revenues), it is notable that the call option has much lower variation in revenue.

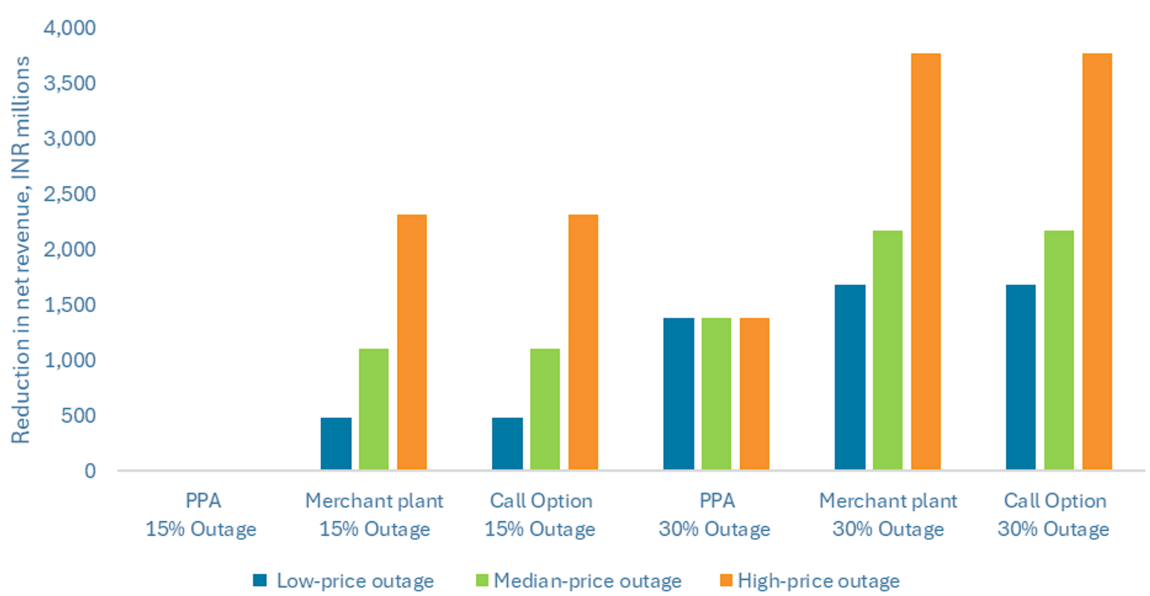
- PPA: Solid red line
  - The PPA provides the same revenue profile as the call option (although it is set slightly above the green call option line, to ensure visibility).
  - **In summary, call options can deliver a steady stream of revenue for well-run thermal resources. This can give greater confidence of cost recovery than under a merchant approach**. Note that although the PPA approach can provide the same confidence, it only achieves this by delinking remuneration from the value the resource provides in real time to the system, and comes with multiple drawbacks including inefficient scheduling incentives and market illiquidity.

Arrangements deliver resource adequacy

FSCs improve the performance of contracted resources, and therefore allow for a higher level of reliability to be attained for any given cost. Another way of thinking about this is that FSCs allow any given level of reliability to be achieved at lower cost.

To explore how these benefits may materialise we show Figure 33 the absolute loss in value to the contracted generator under different contracting arrangements, outage duration scenarios and market prices (low, medium and high), from the model presented in the earlier section on “Resources receive useful signals during scarcity.”

Figure 33. Annual absolute loss in net revenue under outage scenarios for 500 MW plant



Assume the PPA contracted plant is not available to the DISCOM for 15% of the year, coinciding with a period of sustained high prices. The net cost to the DISCOM of procuring this missing energy from the market is the market price minus the variable cost payments it would have made to the PPA contracted resource had it been available. This cost is equal to the net revenue foregone by a merchant plant (and indeed a plant contracted under a call option) if it were unavailable at this moment. From Figure 33 we can deduce that the cost borne by the DISCOM, and ultimately consumers, for this outage scenario under PPAs is over INR 2.3 billion (about $25 million).

Under the call option, this loss of value is borne by the generator and its owners rather than the DISCOM. This offers a direct cost saving to the DISCOM, to be shared with consumers.

It might be argued that the generator could still pass on all the expected cost to the DISCOM and consumer when negotiating the strike price. However, by placing the risk on the party best placed to manage it, the FSC motivates the generator to exhaust all economic avenues to ensure availability in a way that the PPA contract does not. For instance, if the generator could spend INR 20 million to reduce by half an estimated 5% probability of a sustained 15% outage occurring during a period of high prices this year, under an FSC the generator would be motivated to pursue this opportunity and thereby unlock an expected net saving of INR 37.5 million.[65] Under a PPA contract, the generator would not choose to pursue this opportunity – indeed, it would have little motivation even to look for such opportunities.

FSCs therefore create value by aligning incentives with consumer interests, and placing risk on the party best placed to manage it.

Applied across the entire fleet, the efficiency savings unlocked by FSCs in achieving a given level of reliability at lower cost could be significant. Note that although we do not estimate the absolute value of these savings, they should in theory be added on top of the savings calculated earlier from more efficient scheduling.

[65] This is the 2,300 million rupee cost saving * 2.5% probability reduction – (minus) 20 million rupee cost.

Levelling the playing field in the resource adequacy framework

For these positive effects to materialise, it is important that FSCs are accommodated in the resource adequacy framework on a level playing field with PPAs.

If penalties are weak, some DISCOMs may not adequately contract forward, either through PPAs or FSCs. This can aggravate the extent of energy shortage on the market during periods of scarcity. This might not worry DISCOMs that have adequately contracted forward through PPAs, owing to the physical energy ownership attribute of PPAs (momentarily disregarding their weak performance incentives). DISCOMs that have contracted forward adequately through FSCs on the other hand might be concerned that during moments of system tightness, the absence of ownership of energy in the long-term contract will leave them scrambling unsuccessfully to buy the energy from the market (even if assisted by the financial flows of the FSC). This in turn may dampen the value that DISCOMs place on FSCs, and could put a brake on the volume of FSC contracts that are struck.

The key to enabling FSCs will be to ensure a level playing field with PPAs in:

- Counting the contribution of FSCs to meeting resource adequacy obligations, and in assessing their exposure to resource adequacy penalties.
- Applying equal prioritisation in rationing of energy between DISCOMS who have and who have not contracted forward, whether in PPA or FSC form.
- Applying equal contracting requirements such as an obligation to tie the contract to a physical asset, or to require securities similar to those in a PPA contract for a plant that is promised but not yet built.

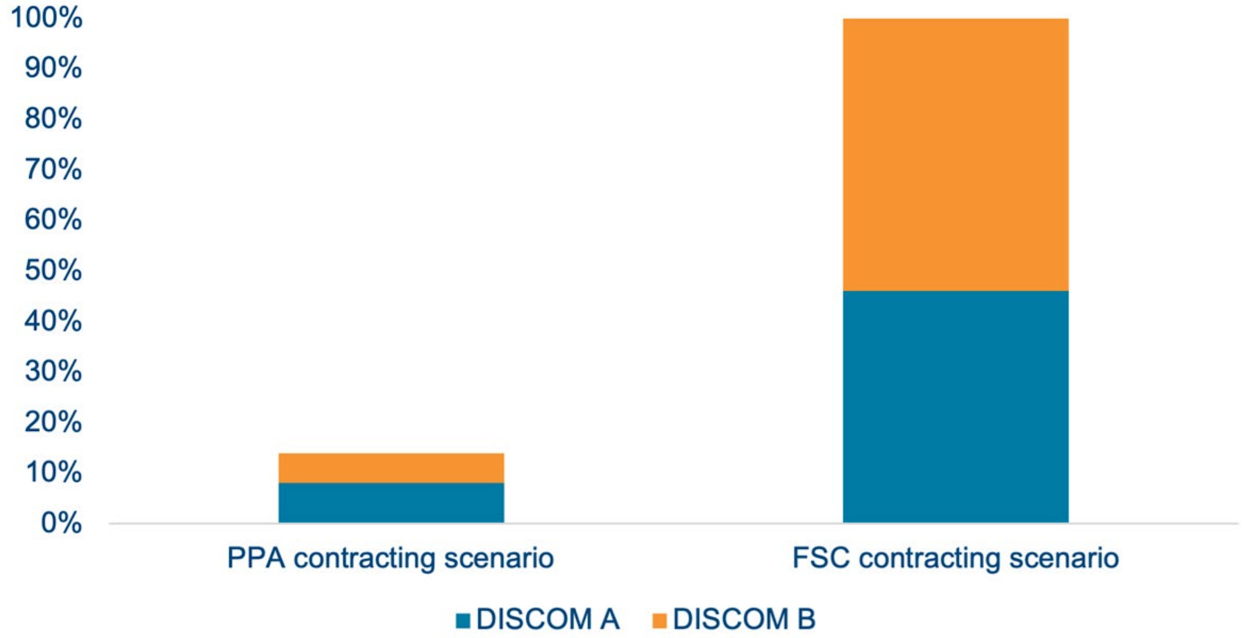
In addition, to ensure the resource adequacy framework more broadly achieves its intended goal, it will be important to ensure sufficiently robust penalties are in place – this will help both FSCs and PPAs to underpin reliability – and to ease wholesale price caps to allow prices to express scarcity.

Liquidity – a cross-cutting issue

FSCs stimulate market liquidity by motivating contracted resources to offer capacity into short-term power markets.

Figure 34 revisits the earlier DISCOM A – DISCOM B modelling analysis of thermal plant to present the effect of a shift from PPAs to FSCs on market liquidity.

Figure 34. Portion (%) of combined energy requirement of DISCOM A and DISCOM B on a simulated day procured through short-term power markets: PPA and FSC scenarios



This shows **a shift from PPAs to FSCs can support a step-change from 14% of energy procured through short-term markets to 100%.** Similarly, the use of CfDs or other FSCs for renewables can jump-start market participation by these resources.

5. Accommodating and operationalising FSCs in India

This section explores how longer-term FSCs could be introduced in India.

Dimensions and routes

Important dimensions to consider in accommodating FSCs in Indian arrangements include:

- Consumer type – large 'designated' consumers[66] or DISCOM (representing all other consumers, especially small consumers).
- Technology – RES versus thermal (other technologies are beyond the core focus of this paper).
- Procurement approach – auctioning by the DISCOM/consumer directly, or sourcing through an OTC platform, or using an intermediary agent who signs contracts with the DISCOM/consumer and an additional contract with the resource.
- New versus existing 'legacy' resources either under contract or up for renewal.
- Contract tenure – from, for example, three years up to multiple decades.

Figure 35 presents existing and potential routes for the introduction of long-term FSCs.

[66] The open-access route allows designated consumers – typically large electricity users such as industrial or commercial entities – to purchase power directly from generators or traders rather than solely from their local DISCOM. Enabled under the Electricity Act 2003, this mechanism promotes competition and consumer choice by granting eligible consumers non-discriminatory access to the transmission and distribution network for wheeling electricity. Open access can be short-, medium- or long-term and is subject to applicable charges such as wheeling, transmission and cross-subsidy surcharges.

Figure 35. Existing routes for striking longer-term FSCs

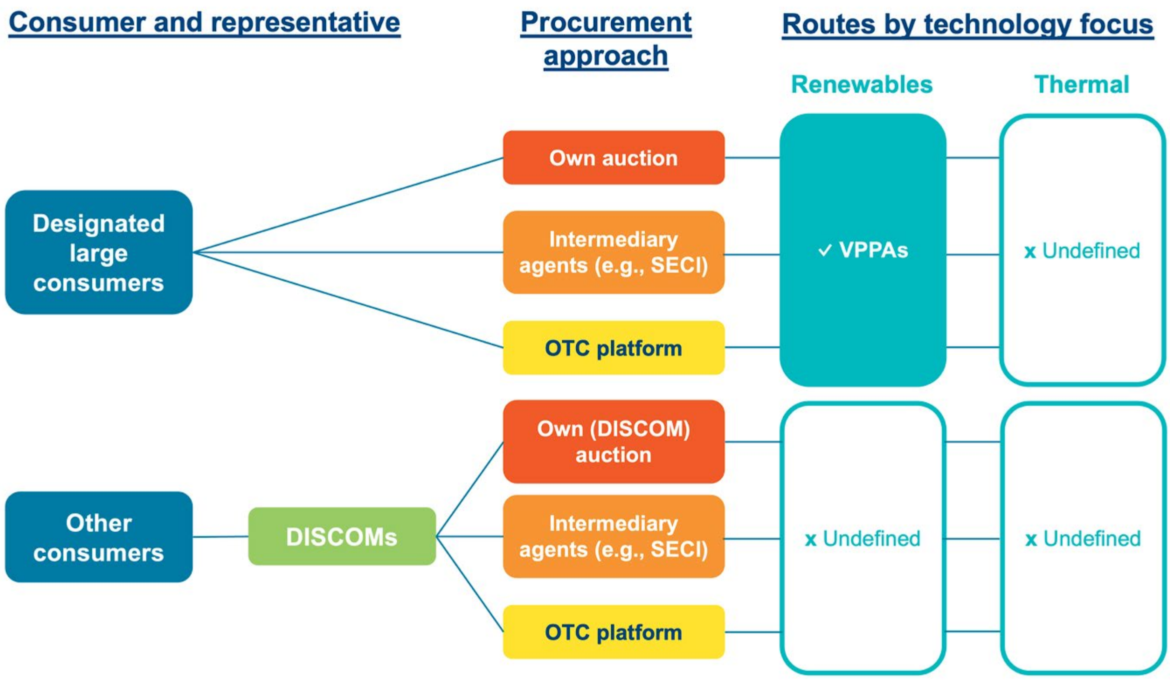


Figure 35 shows that CERC's 2025 draft VPPA guidelines[67] are the key existing route to unlocking longer-term CfDs. These guidelines apply for the contracting of renewables by designated large consumers who conclude a VPPA with the renewable generator either directly or by listing on an OTC platform or through a trader (intermediary agents). VPPAs might be applied most straight-forwardly here in the contracting of new renewable resources. There is a question of whether existing renewables under contracts will voluntarily renegotiate and convert existing PPAs into VPPAs and whether an obligation will be necessary. Note it is also not clear that the VPPA regulation could be used to agree a swap instead of a CfD, and that other FSC routes through DISCOMs and broadly for resources such as thermal remain undefined.

Barriers

Indeed, barriers need to be addressed to facilitate the wider use of FSCs. A selection of these barriers are summarised in Table 5.

[67] CERC. (2025). *Draft guidelines for virtual power purchase agreements*. https://cer.iitk.ac.in/odf_assets/upload_files/blog/Draft_Guidelines_for_VPPAs_2025.pdf

Table 5. Selected barriers to wider deployment of FSCs

Misalignment of Power Market Regulations with FSC non-physical requirements
▪ The CERC Power Market Regulations (2021) mandate physical delivery for OTC contract settlement – this creates a direct conflict with FSCs requiring financial settlement. ▪ Draft 2025 amendments – broadening scope to include non-delivery instruments, enhancing reporting protocols, and clarifying the CERC's inspection and audit powers over trading platforms – partially address framework for VPPAs but lack completeness and clarity for FSCs.
Jurisdictional ambiguity between CERC and SEBI
▪ Pure financial contracts with no physical delivery may fall outside CERC's traditional mandate under the Electricity Act 2003, potentially requiring regulation from the Securities and Exchange Board of India (SEBI) or a joint regulatory mechanism. Clarity is required for different scenarios (for instance some FSCs may require a physical asset). ▪ Could cover strike price indexation, collateral requirement, settlement cycles and default provisions.
Absence of standardised FSC contract templates
▪ The absence of legally vetted standardised FSC contract templates increases negotiation complexity and legal risk.
Lack of recognition of FSCs in resource adequacy
▪ Clarification is required that capacity procured under FSCs contributes to resource adequacy planning. Premiums could be made contingent on satisfactory availability performance, and securities may be required to deter actors with no intention of contributing to adequacy.

- May require separate verification mechanisms for recognition towards adequacy obligations.

Insufficient OTC platform regulatory authority

- Power Market Regulations restrict OTC platforms from negotiating, executing, clearing or settling contracts, limiting FSC operational readiness.
- Current OTC platform regulations do not provide authority for comprehensive market facilitation of financial instruments such as negotiating, executing, clearing or settling contracts.

Conversion of existing capacity to FSC structure inhibited by legacy PPA and regulatory overburden

- DISCOMs have tied up existing capacity through long-term PPAs under Section 63 (competitive bidding route) or under Section 62 (regulated tariff route), and their annual revenue requirement is secured under cost-plus regulated administered retail tariff regime with expenses allowed as pass-through subject to regulatory norms.
- On the other hand, sellers/generators are assured of fixed cost (including profit) recovery under PPA arrangements and are not exposed to any offtake risk/market risk.

Lenders’ and banks’/financial institutions’ concerns to be addressed to finance new capacity additions under FSC

- Lenders, banks and financial institutions are typically 70% stakeholders to fund project investments and are wary of exposure to market-linked instruments.
- Standard legal contracts (CFDs for renewables or FSCs with call option) approved by regulators or covered as part of the Competitive Bidding Guidelines notified by the Ministry of Power would help give lenders confidence to consider such products for bankable project finance purposes.

Source: IDAM Infrastructure

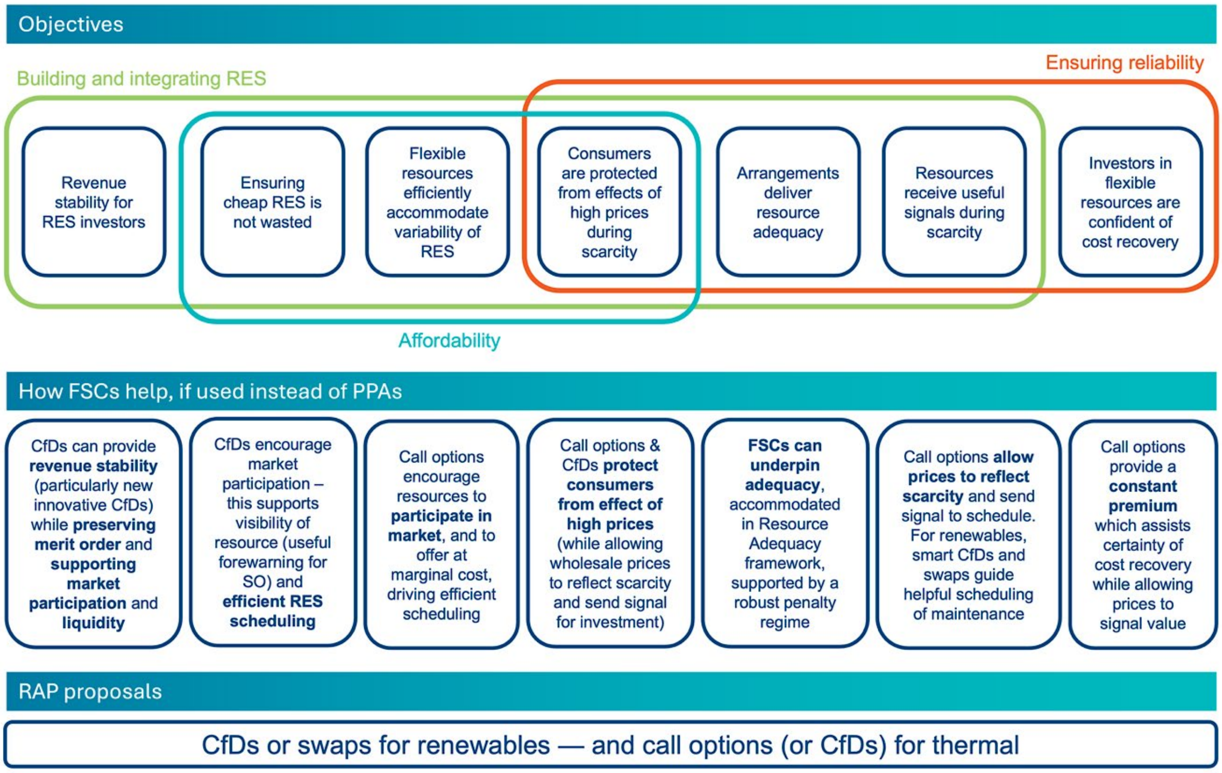
In addition, limited experience and expertise in implementing FSCs may restrain their roll-out. For existing contracts, the absence of defined legal mechanisms to convert Section 62 (cost-based) and Section 63 (competitively bid) physical PPAs into FSCs acts as an impediment: rigid termination provisions create risks of forfeited guarantees and liquidated damages.

Finally, greater market liquidity would bring different patterns of financial flows. DISCOMs would make upfront payment to a market platform for their energy needs under the market's weekly settlement rather than PPA payment cycles of up to 45 days. Buyers and DISCOMs would also have to pay upfront margins to the market platform. On the other hand, financial inflows under FSCs should help them manage these variations, and while DISCOMs might be expected to make more frequent payments, these should be for smaller sums. The transition need not necessarily be a barrier.

Recommendations and road map

Figure 36 presents a summary of the analysis. It shows how FSCs can help and lists RAP's recommended FSCs, building on the analytical findings above that FSCs bring about superior (and at worst comparable) outcomes versus PPAs across every analytical dimension considered.

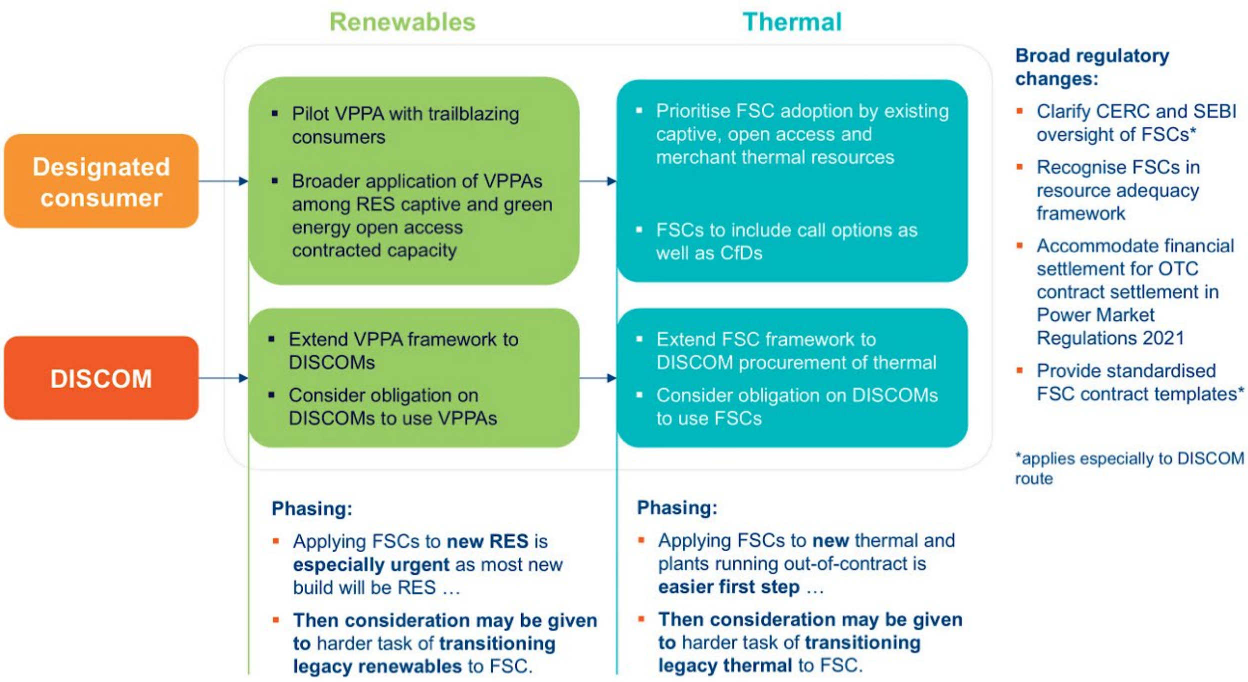
Figure 36. RAP's recommendations



Note: SO is system operator.

Introducing FSCs will require change. Figure 37 introduces the high-level changes that are needed for the implementation of FSCs. We explore these in greater detail in the following sections.

Figure 37. Changes to implement FSCs



Renewables

An early step is to **pilot a VPPA** with a **trailblazing designated consumer** for an existing renewable resource that is reaching contract end and looking for a new one, for example, for three to five years. This can establish the feasibility of FSCs in India.

An early step is to pilot a VPPA with a trailblazing designated consumer for an existing renewable resource reaching contract end.

Next, broader **existing** renewable captive capacity and renewable/green energy open access contracted capacity by industrial consumers (in particular, those resources nearing the end of contract) may be considered as priority candidates for the introduction of FSCs. All enabling provisions to encourage and target this capacity should be taken up.

Subsequent efforts may focus on **new** renewables, including as contracted by DISCOMs. Implementing FSCs for the procurement of new renewables capacity could be a significant win, given that India's 2032 ambitions for 365 GW of solar capacity and 122 GW of wind require additions of around 276 GW of new solar capacity and 75 GW of new wind capacity.[68] To support this, it may be helpful to extend the duration of VPPAs in the draft guidelines

[68] Ember. (2025). *Navigating risks to unlock 500 GW of renewables by 2030.* https://ember-energy.org/app/uploads/2025/02/India-RE-500-GW_21022025.pdf

beyond the currently envisaged 10 years, up to 25 years, for example – longer-term CfD contracts may be helpful to cover the duration of debt payments. Unlocking DISCOMs' procurement of new renewables through FSCs is important, as the lion's share of new resources is expected to come from renewables. Clarifying oversight responsibility here will be necessary, and providing standardised FSC contract templates will help. It will also be helpful to clarify that renewable resources contracted under CfDs can in principle count towards resource adequacy requirements. CfDs, rather than more complex swaps, are likely the optimal instrument for early stages of FSC deployment.

Thermal

Making the switch to FSCs for the contracting of thermal resources is important, as the efficiency benefits of scheduling in market-based merit order may be particularly significant. The shift to FSCs can begin with existing plants approaching the end of their existing contracts. Again, an early step is to **pilot a VPPA** with a **trailblazing designated consumer** and thermal resource that is reaching the end of its contract and looking for a new one, for three to five years, for example. Call options rather than CfDs are likely the optimal instrument for thermal.

Next, **existing** thermal captive capacity and thermal open access capacity contracted by industrial consumers (in particular, those resources at end of contract) are prime candidates for the priority introduction of FSCs. As with renewables, all enabling provisions to encourage and target captive and open access thermal capacity should be taken up.

Subsequent attention may focus on contracting **new** thermal resources. All of this can be enabled by establishing clarity over regulatory jurisdiction, recognising FSCs on a level playing field with PPAs in the resource adequacy framework,[69] accommodating financial settlements in the CERC Power Market Regulations, and providing standardised FSC contract templates. Specific reforms may be necessary to ensure all contracting routes are enabled, including through OTC platforms and intermediary agents.

Authorities can clarify in regulation that FSCs may also be used in contracting thermal resources, may take multiple forms such as call options, and can contribute to resource adequacy obligations.

[69] Resource adequacy itself will be supported by well-designed penalties that link with the value consumers assign to secure supplies, embodied in resource adequacy framework penalties and deviation settlement mechanism design. It is therefore broader than long-term contract design. Nevertheless, a potential area for research is whether penalty regimes that are set below the value of secure supplies might embed a preference for PPAs.

Obligations and encouragements

As well as removing barriers, DISCOM contracting through FSCs can be supported through obligations and encouragements:

- Obligations could include that new resources are contracted through FSCs, or that a growing portion of resources are contracted through FSCs over time. For renewables, the Ministry of Power's Section 63 renewable competitive-bidding guidelines/standard bidding documents could be amended to require use of a two-sided CfD, potentially reinforced in the National Tariff Policy, with respective SERCs enforcing it under Section 86(1)(b) when approving DISCOM procurements.[70]
- It might be possible to afford priority to resources contracted under FSCs. This could include renewal of contracts for existing resources reaching the end of their current contracts, or new procurement.
- A weaker option would be the introduction of an 'expectation' for DISCOMs that future procurement of renewable energy resources will be through FSCs.

A starting point may be to afford FSCs priority in renewal of contracts for existing renewables reaching the end of their current contracts.

As the benefits of FSCs (as opposed to PPAs) accrue not just to the contracting DISCOM but have positive spillovers which are enjoyed by all consumers, the introduction of an obligation may be justified on public policy grounds, once FSC routes to market are enabled. Policy mandates could be covered through amendments to the National Electricity Policy or amendment to tariff policy. Further, as the Electricity Act (Amendment) Bill 2025 is under consideration, FSCs may be specifically recognised as regulatory instruments under Section 66 (Development of Market), bringing the oversight of FSC contracts under the jurisdiction of the electricity market regulator.

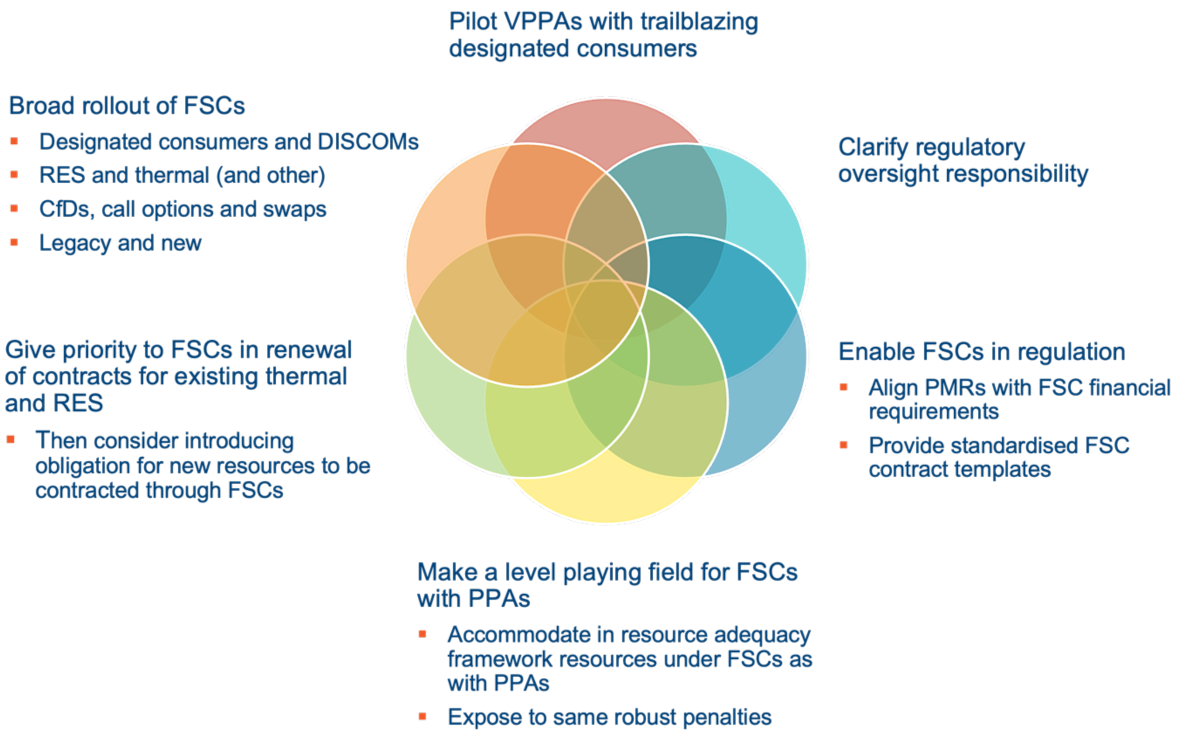
An obligation on DISCOMs to procure renewables through FSCs may be considered on public policy grounds in the future.

[70] DISCOMs could potentially still be allowed to use PPAs if they can present a compelling public policy case to the regulatory authority.

Overview of facilitating measures

Figure 38 presents key measures to facilitate the introduction of FSCs.

Figure 38. Facilitating measures



Due diligence

While FSCs provide the many benefits articulated above, measures should be in place to assess and address potential risks. We consider risks in the selection of the reference price, in the composition of the strike price, and in the manipulation of market prices; and we consider the risk of having purely ‘paper’ contracts that are not backed with a physical asset. We conclude with broad recommendations for a pilot phase.

The design of FSCs will require determination of a reliable liquid **reference price**. As there are multiple potential reference prices – day-ahead and real-time prices in several exchanges produce more than a dozen prices – care is required in selecting one that is efficient and relevant to both buyer and seller. Regulatory price caps are imposed on several of these prices, which could affect the take-up of FSCs and may require specific rules in the event of energy rationing. Selecting the day-ahead price as the reference for renewable CfDs can stimulate distortive behaviours in subsequent markets. [71] These in turn can be remedied by delinking the FSCs from own-production through the use of a benchmark plant, for instance based on the capability of the resource.

Indexing the **strike price** to input cost provides a valuable hedge for the volatile fuel costs of thermal generators. In agreeing the strike price design with contracted resources, DISCOMs must take care to ensure this mechanism is not 'spiked,' recognising that the generator has an incentive to overstate input cost to inflate the strike price and thereby reduce the clawback. There may be a role for the regulator in evaluating the prudence of DISCOM contracts and in resolving disputes between buyer and seller.

There may be concerns that resources will manipulate **market prices** under FSCs. It is, however, a challenge to specify scenarios where FSCs enhance the potential to manipulate market prices. This is because FSCs return the excess of market price over strike price back to the buyer through the clawback mechanism, and thus tend to reduce the ability to abuse market power (as outlined earlier).

There is a risk that the introduction of purely financially settled contracts leads to contracts with generators and other resources that are **purely 'paper.'** To mitigate this, suitably significant guarantees may be required of prospective counter-signatories that cannot yet point to a physical asset, or a simple obligation could be introduced that the counter-signatory must have a physical asset. Clauses could be added for contract termination and the return of supplementary payments upon failure to build or sustained poor performance (unavailability). These solutions are similar to those already employed in jurisdictions like Great Britain for capacity market payments for new build capacity and for CfD payments. A clearing house for FSCs backed by physical assets could provide confidence on the financial flows between off-takers and generators, while reducing systemic risks.

Whenever a new programme or product is introduced, it is advisable to start with a **pilot phase** – for a limited period, with a limited number of participants and caps on volume of energy or capacity – to provide regulators with insights on potential risks and regulatory gaps. Regulatory oversight may help to identify risks for mitigation. For that purpose, DISCOMs should build capacity for valuation and risk accounting as they engage in these contracts. Broadly, we expect FSCs to shift the risk of poor performance from DISCOMs to generators. Generators, who are best-placed to manage this risk, will therefore need to employ smart risk management techniques. To improve transparency and limit the potential for manipulation, mandatory disclosure in regulatory filings may be required for FSC hedges that exceed defined regulatory thresholds, subject to confidentiality provisions where there is sensitive competitive commercial information.

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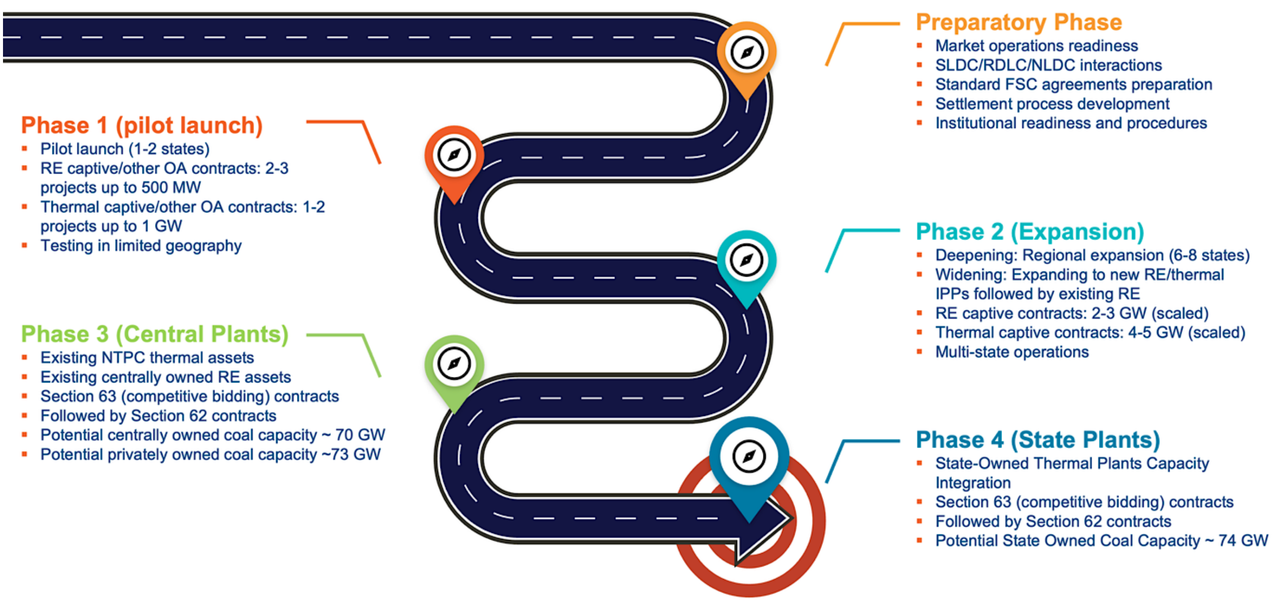
[71] After the auction has cleared, the price of the hourly CfD payment is fixed and known to the generator. From this moment on, it constitutes an opportunity cost and will be priced in, just as any other variable cost component. This has implications for the following market stages, the intraday and balancing markets. If, for example, the strike price is EUR 80/MWh and the day-ahead price was EUR 200/MWh, generators must pay EUR 120/MWh for every MWh they produce in that hour. If the intraday or imbalance price drops to EUR 119/MWh, it is rational for the generator to curtail output. This implies the loss of low-cost (and often zero- or low-carbon) production, an upward pressure on intraday prices and potentially more CO_2-intensive production substituting for the reduction of output from low-carbon generators under CfDs. Schlecht, I., Hirth. & Maurer, C. (2022). *Financial wind CfDs*. ZBW – Leibniz Information Centre for Economics. https://www.econstor.eu/bitstream/10419/267597/1/Financial_wind_CfDs.pdf

Implementation roadmap for the introduction of an FSC framework

Figure 39 illustrates how an FSC framework can be introduced in India in a phased manner, starting with preparatory activities, before moving on to a pilot stage, and later deepening and widening the FSC framework to cover the wide range of stakeholders and contract structures to which it may be best suited.

Figure 39. FSC implementation roadmap



Note: SLDCs, RDLCs and NLDCs are state, regional and national load dispatch centres. OA is open access. IPPs are independent power producers. NTPC is National Thermal Power Corporation.

Source: IDAM Infrastructure

The roadmap for implementing FSCs in India follows a phased approach, starting with preparatory actions and moving through pilot testing, regional expansion, and integration with central and state-owned thermal assets.

Key Implementation Phases

0. **Preparatory phase:** Focuses on market operation readiness, institutional procedures, and preparing standard FSC agreements along with the necessary settlement processes and stakeholder coordination.

1. **Phase 1 (Pilot):** Launches limited testing in one or two states with selected renewables and thermal captive contracts, piloting two or three renewables projects up to 500 MW and one or two thermal projects up to 1 GW.

2. **Phase 2 (Expansion):** Scales up operations regionally to six to eight states, enabling multi-state operations, expanding renewables captive contracts to 2-3 GW and thermal captive contracts to 4-5 GW, plus expanding to new renewables/thermal independent power producers.
3. **Phase 3 (Central Plants):** Integrates National Thermal Power Corporation (NTPC) thermal assets using competitive bidding under Section 63, subsequently moving to Section 62 contracts.
4. **Phase 4 (State Plants):** Expands the framework to state-owned thermal plants, with capacity integration through competitive bidding and standard contracts as per Section 62.

This step-wise roll-out ensures preparedness, allows gradual expansion, and combines both central and local plant contracts to support strong FSC deployment in India.

Annex 1: RAP historical model to assess availability incentives

The design of the contract between the generator and the utility sets the incentives for both parties in the transaction. These incentives, in turn, impact how the parties make decisions about generating and procuring electricity. Ideally, the contract should encourage market participation and efficiency in the system by lowering costs while minimising volatility in cash flows.

To demonstrate how the contract structure influences outcomes, we compare three structures – a fixed-price PPA, a merchant plant that sells all its electricity on the market, and a call option – in dispatch of a single 500 MW coal-fired thermal power plant in 15-minute time blocks over the 2023-24 financial year. Historic market prices from that year are used from the day-ahead market and the high-price day-ahead market, with prices ranging from INR 1/kWh to INR 20/kWh. The variable cost of the plant is assumed at INR 3.125/kWh of net electricity.[72]

Set-up under the three types of contracting is outlined below.

The merchant plant sells all its generation into the wholesale electricity market when the market price exceeds variable cost, and power is procured by the utility at the market price. Thus, there are no physical or financial linkages between the plant and the utility. The modelling assumes that the rents recovered in the market – beyond those recovering variable costs – exactly cover fixed costs.

Under the PPA contract, the utility agrees to procure electricity generated by the plant at set 'PPA prices.' These are a variable tariff covering variable cost[73] plus a tariff that recovers fixed costs, together allowing for full cost recovery so long as the plant achieves the target load factor specified in the PPA (here assumed at 85%), and in accordance with the Terms and Conditions of Tariff Regulations. The total PPA variable cost plus fixed cost is calculated such that the returns for a plant meeting its target load factor are the same as those of the merchant plant, and therefore just recover all costs.

In the call option, electricity is bought and sold at market prices, and the generator is obliged to pay a 'clawback' of the excess of the market price above the strike price in time blocks when market prices exceed the strike price. The strike price for the call option is set at the variable cost of generation. In exchange for the one-sided hedge, the utility provides a constant 'supplementary payment' in each time block. We set this so it exactly covers the fixed costs allowed for under the other scenarios (assuming plant achieves its target load factor), building on an assumption that both PPAs and FSCs are struck efficiently, and that

[72] The heat rate varies from 11 MJ/kWh (full load) to 13 MJ/kWh (no load). The price of coal is assumed to be INR 5,000/tonne and the calorific value 25 MJ/kg. The variable operation and maintenance cost is set at INR 0.05/kWh. Auxiliary and techno-commercial losses are assumed to be 10% and 20% respectively.

[73] These are assumed constant for simplicity, as outlined earlier, but in reality would be indexed to fuel costs.

there is no missing money in market prices for merchant plant. Under the FSC, therefore, if the power plant is unavailable in a period when the market price is higher than the strike price, the plant cannot finance the clawback obligation from market rents. As with a merchant plant, the loss of value to the plant is set at the market price minus variable cost (strike price).

Annex 2: Decoupling renewable contracts for difference from own-production

Attention is increasingly focusing on existing CfD designs that link difference payments to own-output – and the unintended consequences that these have introduced. This link means that the CfD signatory earns the same price on each unit of energy produced, and that as a result the signal to schedule or dispatch is delinked from the system value as revealed by the wholesale price.

This does not provide efficient incentives for the timing of maintenance – choosing between moments of high wholesale prices and low prices makes no difference to the CfD signatory, even though high prices signal that the energy is particularly valuable to the system during these moments. It also contributes to sub-optimal siting and design choices. For instance, even if prices signal that the greatest value of new solar panels would be to point east, to capture lower-harvest but higher-value market rents, the design of the CfD would still encourage new panels to point south if this allows for a greater harvest of energy, even at a consistently low (and non-negative) wholesale market value.

Policymakers have experimented with basing reference prices on an average of spot prices over a period such as a month. Although this may helpfully deter the scheduling of maintenance while prices are high during the period being referenced, for example, it leaves signals between reference periods distorted. Monthly averaging, for example, distorts seasonal incentives. Longer periods introduce distortions to bidding on day-ahead markets.[74]

A growing recognition of the drawbacks associated with own-output CfDs is driving further evolution in design – through the de-coupling of financial flows from own-output – to tackle the root cause of the distortions of these CfDs.

De-coupling financial flows from own-output can be achieved by using the hypothetical output of a reference[75] as proposed in new CfD designs:

- The **'capability CfD'** uses own capability as assessed by the manufacturer. It decouples difference payments from actual output by calculating the theoretical output capability of a plant in given environmental conditions such as wind and sun, guided by manufacturer specifications. Capability CfDs are now being rolled out in Europe: Belgium is auctioning 20-year capability-based CfDs in the Queen Elizabeth offshore auctions, and Denmark is

[74] "This is because the CfD payment is already known (or a reasonable estimate can be made) at day-ahead stage, and it is mostly independent of the day-ahead price. Consequently, generators optimise their bidding behaviour against the CfD payment. If they know they will have to pay EUR 30/MWh due to a CfD in a clawback period, they will no longer produce at spot prices below that threshold. Likewise, if generators know they will get a CfD payment of EUR 30/MWh during a support period (i.e., in periods in which the reference price is below the strike price), then they will produce even if spot prices are below variable costs by less than EUR 30/MWh, because the CfD payment would compensate operating losses." See Section 2.4 of Schlecht, I., Hirth, L., & Maurer, C. (2022). *Financial Wind CfDs*. ZBW – Leibniz Information Centre for Economics, Kiel, Hamburg. https://www.econstor.eu/bitstream/10419/267597/1/Financial_wind_CfDs.pdf

[75] Note that decoupling from own-production through introduction of a reference introduces a new *basis* risk, which emphasises the importance of paying particular attention to the design of the reference plant.

now planning to use capability-based CfDs for offshore wind.[76] A notable merit of this CfD is its relative simplicity.

- The **'yardstick CfD'** uses forecast local renewable output in a geographic area. It supports efficient dispatch and location decisions.[77] The yardstick CfD appears to address a potential weakness of the capability CfD by using a reference that is not bespoke to each plant, which opens up the possibility of beating the reference that is not achievable under the capability CfD, and it better supports investment in an optimal capacity mix. The cost is a greater basis risk.

An assessment of the relative merits of these approaches and how they compare to own-output CfDs is presented in RAP's deep dive on CfDs.[78] This also touches on the swap developed by Schlecht et al.,[79] another new design that overcomes these issues.

[76] OER International. (2025). *Introduction capability-based two-way CfD in Denmark.* https://ocean-energyresources.com/2025/10/06/introduction-capability-based-two-way-cfd-in-denmark/

[77] All else being equal, the wider the geographical area of the reference plant the more efficient the incentives.

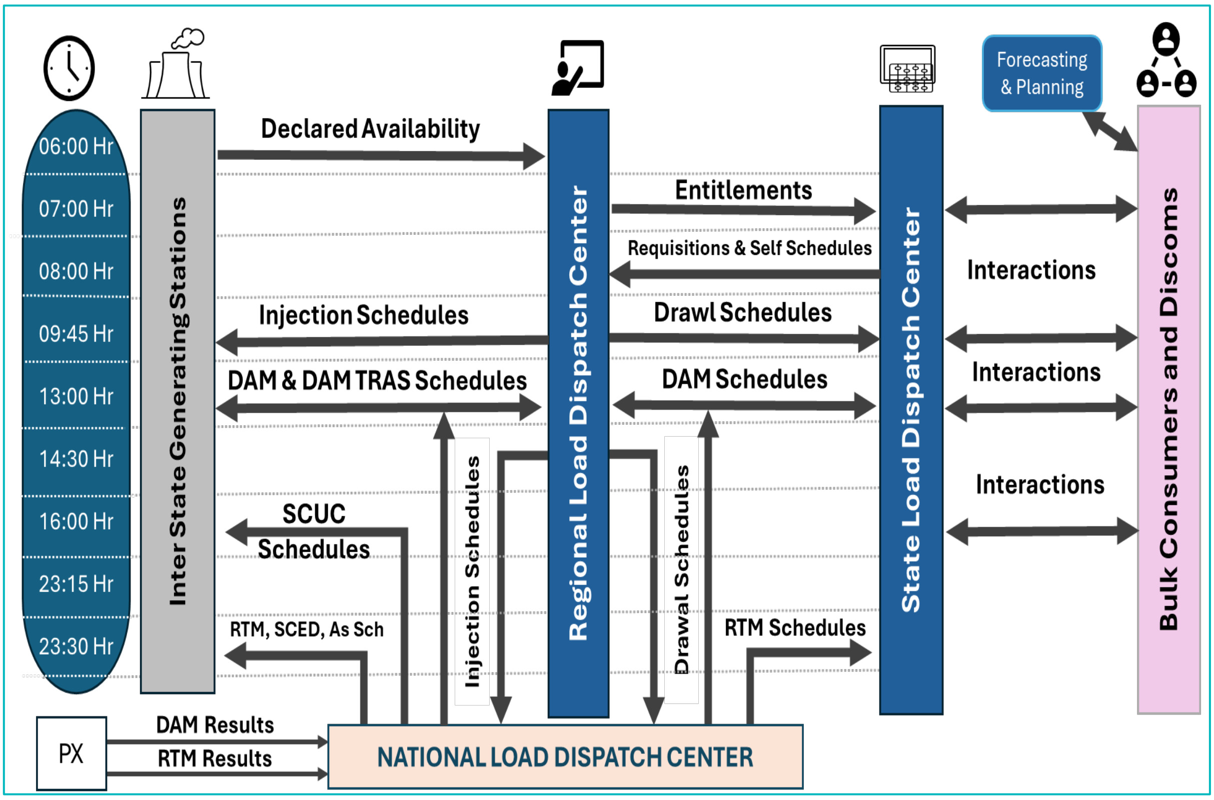
[78] Scott, D., & Morawiecka, M. (2024). *The search for two-sided CfD design efficiency – a Shakespearean history.* RAP. https://blueprint.raponline.org/deep-dive/cfd-part-ii/

[79] Schlecht, I., Hirth, L., & Maurer, C. (2022). *Financial Wind CfDs.* ZBW – Leibniz Information Centre for Economics, Kiel, Hamburg. https://www.econstor.eu/bitstream/10419/267597/1/Financial_wind_CfDs.pdf

Annex 3: DISCOM operations

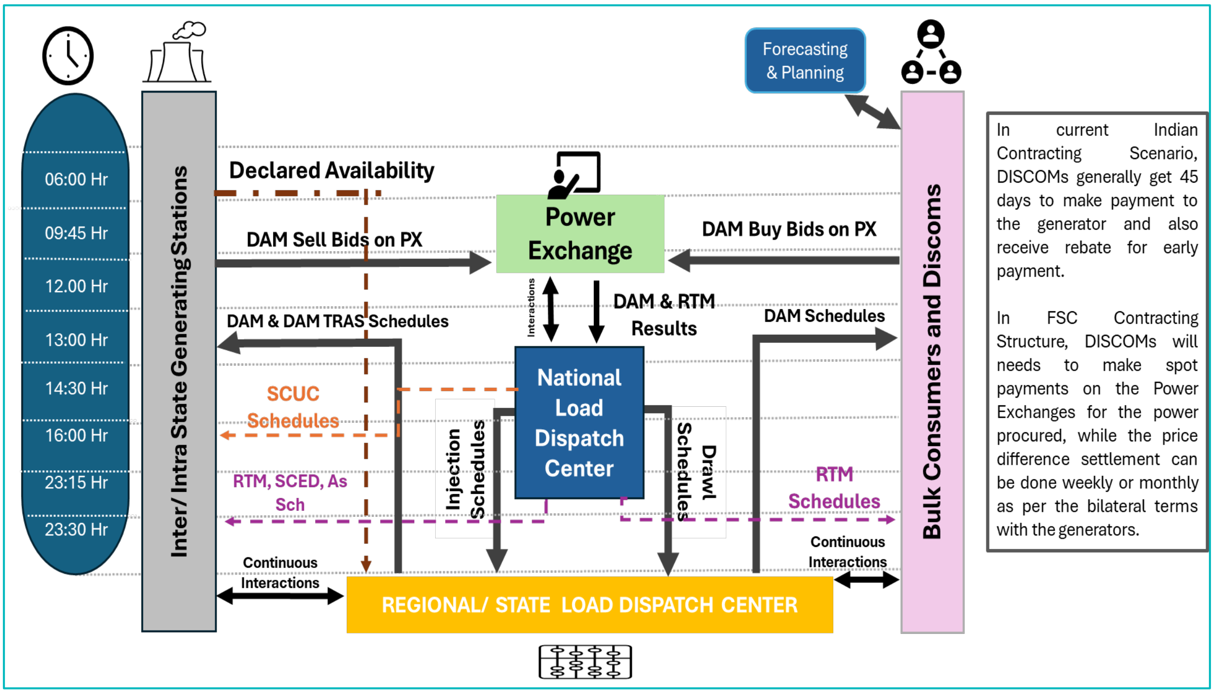
Figure 40 and Figure 41 illustrate the day-to-day operations of DISCOMs under the current PPA structures, and how they might appear where contracting is conducted under FSCs.

Figure 40. Day-ahead operational planning in the current PPA structure



Source: IDAM Infrastructure

Figure 41. Day-ahead operational planning in the FSC (call option) structure



Source: IDAM Infrastructure

Under the current regulatory framework:

- Load dispatch centres run merit order dispatch and schedule power as per requisition of DISCOMs.
- DISCOMs procure additional power through a power exchange under DAM, RTM and the like.

All commercial settlement is based on actual physical schedule vs. actual drawal (withdrawal).

Under a financially settled call option contract:

- The call option gives the DISCOM the right to receive the difference between the strike price and the spot price, without requiring physical scheduling.
- Hence, no mandatory scheduling obligation is tied to the contract.

Annex 4: IDAM Infrastructure two-DISCOM model of scheduling efficiency

Introduction

This section sheds light on selected elements of the modelling used to explore scheduling efficiencies of FSCs. It presents model input capacities, renewable generation and costs, outlines the two contracting scenarios (PPAs and FSCs) and explains how the modelling abstracts out savings from stronger incentives to be available to focus on scheduling efficiencies alone.

Capacities and renewable generation

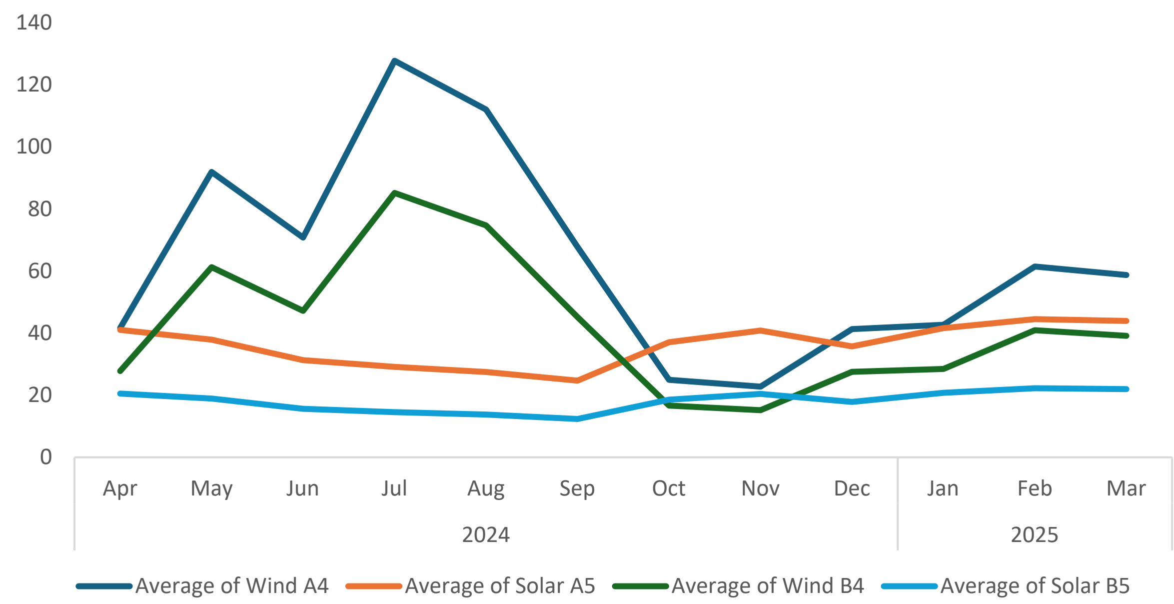
Table 6 shows the capacities of generators used in the model.

Table 6. Capacities of generators

	DISCOM A - GENERATORS					DISCOM B - GENERATORS				
Parameter	**Gen A1**	**Gen A2**	**Gen A3**	**Gen A4**	**Gen A5**	**Gen B1**	**Gen B2**	**Gen B3**	**Gen B4**	**Gen B5**
Type	Thermal	Thermal	Thermal	Wind	Solar	Thermal	Thermal	Thermal	Wind	Solar
Capacity (MW)	660	250	500	300	200	500	800	250	200	100
Contracting party	**DISCOM A**					**DISCOM B**				

Figure 42 shows the assumed electricity generation patterns of the renewable energy resources. Note that these monthly averages mask the hourly variation simulated in the model.

Figure 42. Quarter-hourly renewables generation in MW, averaged by month



PPA scenario

Table 7 shows the variable costs and fixed charges of the generators under PPAs. Note that the PPA sets the fixed charge for renewable resources at zero and sets variable cost charges well above the true value of zero.

Table 7. Terms of power purchase agreement by contracting party

	DISCOM A - GENERATORS					DISCOM B - GENERATORS				
Generator	**Gen A1**	**Gen A2**	**Gen A3**	**Gen A4**	**Gen A5**	**Gen B1**	**Gen B2**	**Gen B3**	**Gen B4**	**Gen B5**
Type	Thermal	Thermal	Thermal	Wind	Solar	Thermal	Thermal	Thermal	Wind	Solar
Variable Cost (INR/MWh)	1,600	2,000	3,500	3,000	2,500	1,400	1,800	2,700	3,000	2,500
Fixed Charge (INR/MWh)	2,400	2,000	1,200	0	0	2,600	2,200	1,300	0	0

FSC scenario

Under the FSC scenario, the renewable CfD strike price is set at the variable cost used in the PPA. The call option strike price is also set at the variable cost. The option premium is set so it ensures the same net contribution to fixed cost recovery as the PPA. Table 8 below shows strike price and option premia for the 'no outages' iteration of the model.

Table 8. Call option and CfD parameters ('no outages' model iteration)

	Gen_ A1	Gen_ A2	Gen_ A3	Gen_ A4	Gen_ A5	Gen_ B1	Gen_ B2	Gen_ B3	Gen_ B4	Gen_ B5
Call Option/ CfD Strike Price INR/MWh	1,600	2,000	3,500	3,000	2,500	1,400	1,800	2,700	3,000	2,500
Option premium (assumed same as fixed cost in PPA)	2,400	2,000	1,200	-	-	2,600	2,200	1,300	-	-

Focus on scheduling efficiencies, not availability incentives

The first iteration of the ('no outages') model assumes generators are fully available for all periods when economic to schedule.[80] This means under the FSC scenario, which sets strike prices for thermal call option contracts at the variable cost, thermal generators are always able to finance their clawback obligations through market rents. The model therefore recovers thermal fixed costs through FSC supplementary payments equal to the fixed costs recovered in the PPA scenarios. As the renewable CfD strike price is set at the PPA 'variable cost,' and there is no curtailment in both scenarios due to must-run status, the total cost paid to renewable generators is the same in both scenarios. This set-up ensures that the savings resulting from comparing DISCOM costs under PPAs and FSCs reflect only the more efficient scheduling of thermal resources under FSCs.

The second iteration incorporates plant outages and reduced plant availability for approximately 10% of the year. During some of these outage periods, market clearing prices exceed variable cost. As strike prices are set at variable cost in call option contracts, this

[80] We explore the impact of unavailability in section "Resources receive useful signals during scarcity" for an analysis of the impact on fixed cost recovery of poor performance under PPAs and FSCs.

exposes the thermal generator to a financial clawback obligation without the corresponding generation revenue to fund it. In order to focus on scheduling efficiency savings – and not those stemming from reliability penalties – the model adjusts call option premia upwards to fully cover these unfinanced clawback obligation payments.

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+1 802 223 8199
info@raponline.org
raponline.org