Energy Policy 186 (2024) 113981

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Financial contracts for differences: The problems with conventional CfDs in electricity markets and how forward contracts can help solve them

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ARTICLE INFO

Keywords:
Contracts for differences
Electricity markets
Renewables
Nuclear power
Investment financing
Support schemes

ABSTRACT

Contracts for differences are widely seen as a cornerstone of Europe's future electricity market design. This paper is about designing such contracts. We identify the dispatch and investment distortions that conventional CfDs cause, the patches used to overcome these shortcomings, and the problems these fixes introduce. We then propose an alternative contract we call "financial" CfD. This hybrid between conventional CfDs and forward contracts mitigates revenue risk to a substantial degree while providing undistorted incentives. Like conventional CfDs, it is long-term and tailored to technology-specific (wind, solar, nuclear) generation patterns but, like forwards, decouples payments from actual generation. The proposed contract mitigates volume risk and avoids margin calls by accepting physical assets as collateral.

1. Introduction

Europe's energy crisis has triggered an intense discussion about electricity market reform, and contracts for differences (CfDs) are at the center of discussions. Commentators and policymakers have suggested that these long-term contracts should become a cornerstone of the EU's future power market.

In general, CfDs are financial contracts that specify payments from the buyer to the seller if, at maturity, the price of an underlying asset is below the agreed-upon strike price and a reverse payment otherwise. Such derivatives are used in foreign exchange, security, and commodity markets and are commonly traded between commercial entities.

In electricity markets, contracts for differences conventionally refer to long-term contracts between an electricity generator and a government; this is also how the European Commission uses the term in its recent legislative proposal. A traditional CfD such as the one applied to offshore wind in the United Kingdom (UK Government, 2014) uses the spot price as underlying and applies the payment only to the electricity actually produced by a specific asset, such as a wind park. This "weighting" of price spreads with production volumes sets electricity CfDs apart from those used in security and commodity markets, and from electricity forward contracts (which are contracts for differences between the spot and the forward price). It also makes these contracts more complex than many people realize, both in terms of incentives and risk allocation. This paper identifies problems with CfDs and proposes a new contract design to overcome them.

The main objective of CfDs has been to mitigate price risk for investors. Reducing price risk lowers the cost of capital and, hence, levelized energy costs (Gohdes et al., 2022). CfDs can be seen in the tradition of support schemes for renewable (and sometimes nuclear) energy, and hence an alternative to feed-in-tariffs, feed-in-premiums, and renewable portfolio standards (Newbery, 2023). In Europe, after being first introduced in the United Kingdom in 2014, many countries have used CfDs in recent years (Kröger et al., 2022), including Denmark, Greece, Hungary, Poland (Szabó et al., 2021), and Ireland (Government of Ireland, 2019). Outside Europe, Australia and Canada are among the countries using them (Australian Energy Council, 2019; Hastings-Simon et al., 2022). While some use the "conventional" British design, others have adapted the contracts significantly. The fact that CfDs, unlike most other support schemes, generate public income in times of high electricity prices has made them attractive to policymakers, particularly since the onset of the energy crisis (European Commission, 2023). In the current reform debate, they are increasingly seen as a cornerstone of electricity markets rather than just a support policy (Fabra, 2023). Some have proposed applying them to a broader set of technologies to include existing assets and impose them against the plant owner's will.

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https://doi.org/10.1016/j.enpol.2024.113981
Received 19 July 2023; Received in revised form 21 December 2023; Accepted 2 January 2024
Available online 13 January 2024

In this paper, we identify three problems with CfDs. First, conventional CfDs incentivize "produce-and-forget" because they mute electricity price variation such that there is no benefit in producing electricity when it is needed most (Meeus, 2023). Second, CfDs distort markets after the spot market, including intraday and balancing markets (Guidehouse and Fraunhofer, 2023). Third, while they mitigate price risks, they do not address volume risks, i.e., the uncertainty in cash flow that stems from variations in weather conditions (Kitzing, 2014). While modifications to the original CfD, notably replacing the hour-by-hour spot price with a year-average price, have mitigated the first problem, the latter issues remain unresolved. In addition, these tweaks have introduced different problems, triggering additional modifications. The first contribution of this paper is to list these problems.

The main contribution of this paper is to propose a new type of contract that solves these problems. We dub these "financial CfDs." This contract comprises two hourly payments, a fixed lump sum from the government to the generator, and a variable payment in the reverse direction. Hence, it can be classified as a fixed-for-floating swap. The payment from the generator to the government approximates spot market revenue. Rather than basing this on actual production, however, we propose using a benchmark independent of the company's behavior. For wind and solar energy, benchmark output could be derived from weather models; for nuclear energy, it could be constant. As payments are decoupled from actual generation and companies cannot influence proxy revenue, the contract avoids distortion. Because this is a property that we have borrowed from financial forward contracts, we call the contracts "financial" CfDs, although all CfDs are settled financially.

This paper is about contract design. It does not address the question of whether governments should engage in long-term contracts in the first place or if such agreements are better left to private companies and markets. We hope our thoughts on risk mitigation that avoids distortions will be valuable for both public and commercial parties. The remainder of this paper discusses the related literature, identifies the problems associated with conventional CfDs, details the proposed new contract, and draws relevant conclusions.

2. Literature review

The idea of reverting to benchmarks that are independent from a subject's behavior as a basis for payments is widespread throughout economics in general and in the fields of tax and regulatory economics in particular. By doing so, the subject cannot manipulate payments by changing their behavior; in other words, the payment becomes non-distortive. In the electricity sector, for example, yardstick regulation is often applied to grid owners.

While the literature has discussed the general properties of contracts for differences for several years (Simshauser, 2019; Jansen et al., 2022), the current reform debate has triggered a particular interest in the way these contracts distort incentives (European Commission, 2023; Guidehouse and Fraunhofer, 2023). We know of six publications that relate to this paper more closely by discussing or proposing less distortive long-term contracts.

Two similar proposals for CfD designs with improved incentives were issued almost simultaneously by Newbery (2023) and Belgian system operator Elia Group (2022, unpublished). Their principal assessment is similar to ours as both papers propose decoupling payment from an asset's production. Both also suggest using individual generators' production forecasts instead, an approach Newbery calls "yardstick" and Elia "capability-based" CfD. This approach differs from ours since we avoid relying on site-specific measurements, which are technically challenging because of wake effects within wind parks and prone to manipulation. More importantly, this reduces the incentives for efficient siting. In addition, these proposals do not address weather-related volume risk.

As a brief addition to a review of Alberta's renewables auctions, Hastings-Simon et al. (2022) made a similar proposal that they called "benchmarked" CfD. The authors suggest using a weighted average of a benchmark and actual generation to balance incentives and risk exposure. The proposal is short in detail but, in particular, does not address volume risk either.

Two years earlier, Carlos Batlle provided similar reasoning in two related papers with different co-authors (Barquín et al., 2017; Huntington et al., 2017), which they present as an improved capacity-based support scheme. They propose a capacity premium re-calibrated yearly to give a reasonable return on investment of a benchmark plant. Such an arrangement provides undistorted dispatch incentives and some hedge to plant operators against volume risks if premiums are calculated ex-post based on actual weather. The main difference to our proposal is that they do not foresee any payments made from generators to governments, which makes the proposal politically much less attractive. More importantly, it implies a higher revenue risk.

These five papers discuss contract design theoretically from a policy-advice perspective; meanwhile, similar contracts seem to have been used in practice. Brozynski and Tuenter (2018), refer to a "proxy revenue swap," which is apparently common in commercial arrangements in Australia. Based on the limited detail available, this closely resembles what we are proposing.

3. Objectives of CfD design

The main reason for introducing CfDs is to provide financial stability for both contractual parties, namely, generators and governments.

Renewable and nuclear energy is very capital intensive, with high investment and low variable cost. While the inherent correlation between fuel and electricity prices provides a natural hedge for fossil generators, this is not the case for these low-carbon producers. Without longer-term contracts, they remain fully exposed to revenue risks from electricity price development and, in the case of wind and solar, meteorological conditions (volume risk). Power prices are driven to a large extent by policy decisions – a risk investors cannot hedge. De-risking such investments, provided they are desirable in the first place, leads to lower capital costs and cheaper electricity (Đukan and Kitzing, 2023).

CfDs also provide governments with revenue to support consumers during crises. The limited degree to which European consumers are hedged exacerbates the consequences of the crisis, triggering ad-hoc market interventions. Urged to support vulnerable consumers, but themselves subject to fiscal constraints, governments have introduced revenue caps for generators. Being hedged against electricity price developments by long-term contracts would allow governments to support consumers during high-price periods without such ad-hoc revenue clawback interventions that could harm long-run investments.

While the main objective of CfDs is risk mitigation, they should, at the same time, be duly designed so as not to distort the design and operation of generators. Therefore, efficiency is another objective in CfD design. This includes the following aspects.

- *Optimal utilization (operational stage)*: CfDs should incentivize plant owners to utilize their assets efficiently. The incentive should be to always produce when the price is above and never when it is below short-term variable costs. This should hold not only for the day-ahead market stage but also in intraday markets and in real-time. Plant owners should make an efficient choice, driven by price signals, between selling at different market segments (day-ahead, intraday, balancing, and system services). Power plant owners should also be incentivized to schedule the maintenance of power plants during lower-price periods.
- *Optimal design and siting (investment stage)*: Investors should be incentivized to design and locate plants so that they generate high-value electricity. In essence, plant operators should optimize the generation profile of the plant, balancing the investment costs of system-friendly design choices with their lifetime benefits. This includes wind turbines with larger rotors or at locations less correlated

with the majority of wind turbines, west-facing solar panels, and a focus on ramping capabilities for nuclear. Hourly electricity prices provide a rich set of information about the investments needed from a system perspective. In designing CfDs, it is thus often useful to expose investors to the hourly shape of prices even if the overall aim of CfDs is to provide investment stability.

- *Optimal retrofit and repowering (re-investment stage)*: Throughout an asset's lifetime, plant owners should face an efficient level of retrofit, maintenance investment, and repowering incentives. The strengths of such re-investment signals should correspond to longer-term price levels so that the incentive for output-maximizing retrofits is stronger during high-price scarcity times than during low-price oversupply periods.

In summary, price signals are relevant to guide decision-making by renewable and nuclear plant operators. With efficiently designed short-term markets, prices reflect the power system's needs. Hence, if the price signal is not muted for investors, they will be incentivized to make system-optimal choices rather than simply maximizing total output. A well-designed long-term contract should, therefore, preserve price signals.

4. Contracts for differences to date

In this section, we define conventional CfDs, outline the problems they introduce, and discuss how contract design has evolved to address them. We conclude with a comparison of CfDs to forward contracts.

4.1. The conventional CfD

There are many ways contracts for differences are specified in electricity markets. We discuss more advanced types in Section 4.3 below, but first discuss the basic specification we use as a reference point. This contract, which we refer to as "conventional CfD" and which resembles the contracts introduced in the United Kingdom in 2014 (UK Government, 2014), is characterized as follows:

- The strike price is fixed,
- the underlying is the hourly day-ahead spot price,
- the CfD is linked to a specific physical asset, and
- volumes are "as produced" in every hour.

The hour-by-hour payment obligation is calculated as

$$\text{Payment}_t = (\text{strike price} - \text{spot price}_t) \text{ x produced volume}_t$$

If the strike price exceeds the spot price, governments make a payment to generators, and vice versa. The fact that it is physical production (metered output) that determines the payments is why these CfDs are sometimes called "injection-based." Fig. 1 illustrates payments over 5 hours. Each hour's payment is calculated as the price difference (height of the boxes) multiplied by the production (width). While this results in stable per-MWh prices, revenues remain uncertain because of the output fluctuation.

While the conventional CfD is in some ways similar to a financial derivative such as a futures or a forward contract, the fact that it is linked to a specific asset makes it different. Not only does this make it impossible to trade CfDs on secondary markets (without selling the asset as well), but more importantly, it entails that CfDs provide incentives to adjust the dispatch of the asset to manipulate payments.

4.2. Problems with the conventional CfD

There are three problems with the conventional CfD: produce-and-forget incentives, distortion on intraday and balancing markets, and the fact that volume risks remain unhedged. We discuss each in turn. Note that some of the issues of conventional CfDs outlined in this section are fixed by more advanced, though still production-based, CfD designs, which we address in Section 4.3.

The conventional CfD, as defined above, provides a simple incentive to the generator: maximize production. Because the revenues across all production hours equal the strike price, there is no incentive for the generator to maximize the value of output rather than the amount of electricity produced. In particular, the incentive to increase production at times of high prices (scarcity) is not higher than in periods with lower prices. There are no incentives to schedule maintenance when demand is low, reduce output at times of negative prices (abundance), or invest in power plants that reap above-average market prices (flexible or system-friendly plants) if they come at the cost of lower total production. This has several adverse consequences:

- *Investment choices:* When selling to the spot market, wind and solar investors can maximize their revenues, but not their electricity output by investing in what is sometimes called "system-friendly renewables" – wind turbines with higher towers and larger rotors that produce electricity more continuously, tracking solar panels with higher capacity factors, or west-facing solar that contributes more to meet increased demand during late afternoons. The conventional CfD disincentivizes such system-friendly plant designs because they typically come with lower total production and, thus, lower total revenues. For hydroelectric and thermal power plants, the incentive to simply maximize production results in plants being optimized for base load operations but lacking flexibility, including load-following capabilities, ramp rates, and part-load efficiency.
- *Retrofit and repowering choices:* Investments are not only one-off decisions. Maintenance, retrofit, and repowering investments are decided during an asset's lifetime. Conventional CfDs often distort such choices because they mute spot price variation, the core scarcity signal of power markets. This means that under such contracts, in an energy crisis, too little would be invested in maintenance and retrofitting. However, during a glut, too much would be invested simply to cling to an old contract. The same applies to repowering wind turbines, i.e., replacing older, less productive ones with larger, new designs. Since conventional CfDs end when the asset expires, an old wind turbine might not be replaced by a newer, more productive one to keep the payments of the old contract.
- *Maintenance scheduling:* Under conventional CfDs, generators have no incentive to schedule maintenance at times of low demand. Nuclear power generators may instead schedule maintenance when engineering teams are cheaper, which is often in the winter. Intermittent renewables, where imbalance settlement costs are correlated with spot prices, are incentivized to schedule maintenance when spot prices are highest to avoid high imbalance costs – which is the opposite of what they should do.
- *Dispatch:* Under the conventional CfD, generators have no particular incentive to increase production during high-price hours and no incentive at all to decrease it when prices are below their production costs. Wind, solar, and nuclear plants should curtail output whenever prices drop below their variable costs, but under the conventional CfD they keep producing – even when prices turn negative. This distortion is even more damaging for technologies with higher variable costs and/or if these costs change over time. This includes all thermal power plants (including hydrogen and nuclear power plants[1]), reservoir hydropower, and storage plants, for which the conventional CfD is particularly ill-suited. Flexible generators must

[1] Under certain conditions, the variable costs of nuclear plants are somewhat dynamic: When refueling cycles are planned and fixed some time ahead, the short-term dispatch of the plants faces opportunity costs driven by the available fuel until the next refueling. This results in opportunity costs similar to the water value of reservoir hydroplants.

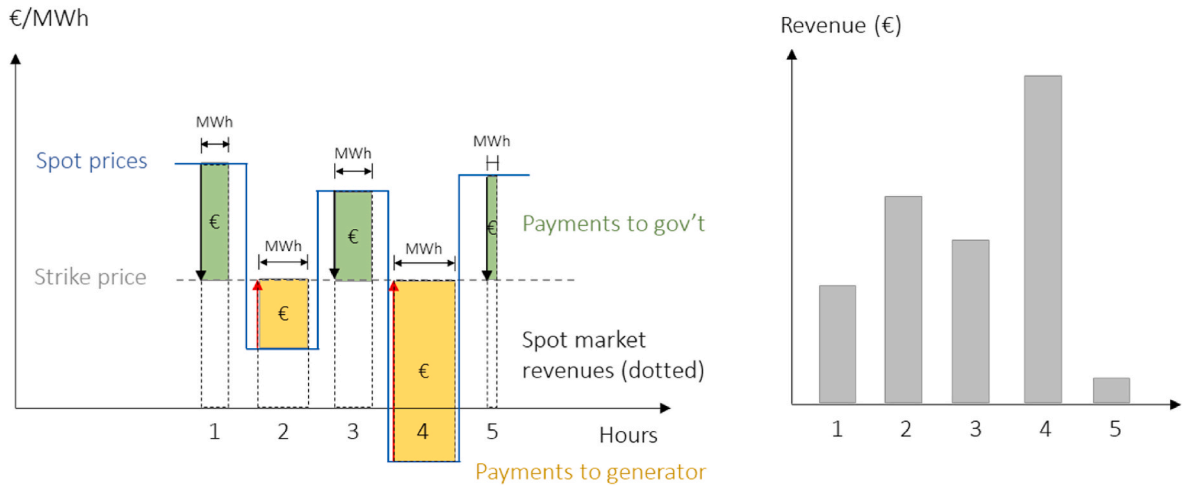

Fig. 1. Payments (left) and revenues (right) under the conventional CfD.

follow prices to make economic sense. Providing an incentive to generate electricity continuously would obliterate their economic value as a flexible asset. Such distortions tend to become more damaging if CfDs apply to larger proportions of the market.

Some (but not all) of the "produce-and-forget" issues of the conventional CfD are fixed in more advanced CfD specifications that have been proposed or implemented in recent years, particularly monthly or yearly reference periods, as discussed in the following section. However, these resolve only part of the misaligned incentives, reduce the quality of the hedge, and come with their own issues.

A second problem with conventional CfDs is the distortion of intraday and balancing markets. This is because the day-ahead price is used as the underlying of the contract. After that auction has cleared, the price of the hourly CfD payment is fixed and known to the generator. From then on, it constitutes an opportunity cost and will be priced like any other variable cost component. This has implications for the subsequent market stages, the intraday and balancing markets. The effect has different signs in high-price and low-price hours:

- During high-price hours, the payment obligation works like a tax. If, say, the strike price is €80/MWh, and the day-ahead price is €200/MWh, generators must pay €120/MWh for every MWh they produce that hour. If the intraday or imbalance price drops to €119/MWh, it is rational for generators to curtail output to avoid payment and buy the power they sold day-ahead back on the intraday market. This implies the waste of low-cost (and low-carbon) energy and an upward pressure on intraday prices, which arbitrage trading will transmit back to day-ahead prices.
- The opposite effect occurs in low-price hours when governments make payments to generators. Here, the payment works like a subsidy, and plant owners deduct it from their optimal intraday bids. This means they inefficiently bid into intraday markets below their own variable costs, even at negative prices. In this way, CfDs put downward pressure on already low prices.

This issue could be addressed using real-time (balancing) prices as underlying rather than day-ahead prices. However, this would make risk-averse generators dump all production into the real-time system imbalance rather than revealing their available generation at the day-ahead stage, compromising operational system security.

A third shortcoming of conventional CfDs is that while they hedge price risk to a considerable degree, volume risk remains unmitigated, for example, owing to variations in wind speeds between years. In the end, it is revenue and not price that determines cash flow. To make things worse, CfDs mute a natural hedge that is otherwise implicit in power markets: When selling to spot markets, the negative correlation between prices and wind availability mitigates the volume risk – years with little wind tend to have higher prices. In a CfD context, a low-wind year comes with particularly low revenues because above-average prices no longer balance out the lower volume. A more complete hedge would account for volume risk, too.

4.3. Tweaks for production-based CfD-designs

We are not the first to have observed these problems. Several CfD designs – proposed and implemented – aim to tweak the contracts so that some of these problems are resolved while maintaining the concept of difference payments based on actual production. However, most of these changes create problems of their own that must be addressed in follow-up fixes.

For example, suspending payments at negative prices is a frequently employed tweak. Amongst others, this was applied in Ireland (Government of Ireland, 2019). Although eliminating the incentive to generate power during periods of negative day-ahead prices, this fix does not necessarily eliminate the incentive to bid negatively on day-ahead markets (Roberts et al., 2020). It also comes at the cost of revenue uncertainties for generators, whose lifetime revenues will then depend on the frequency of negative prices – a factor beyond their control. Besides, while the zero threshold works for wind and solar power, for plants with variable (opportunity) costs such as hydro, biomass, hydrogen, or nuclear, these variable costs will have to be estimated and used as a threshold, which is problematic given asymmetric information.

Another modification is to use a different underlying: Rather than the hourly spot price, another reference price is used, typically the monthly or yearly weighted or unweighted average of spot prices, for example, the average capture price of a more comprehensive set of wind turbines. The payment is then calculated as:

$$\text{Payment}_t = (\text{strike price} - \textit{reference price}_{year}) \text{ x produced volume}_t$$

Longer reference periods are used in sliding feed-in premium schemes (one-sided CfDs, where there will be no payments from the generator in periods with high prices) in Germany and other countries. By calculating the CfD payment based on longer reference periods, intra-period price differences are no longer muted for the generator and create incentives again. Therefore, dispatch and maintenance incentives within these periods are optimized to capture the highest prices again, and design choices at investment are made to generate power at the highest-priced hours within the reference periods (Klobasa et al., 2013; Schmidt et al., 2013).

However, longer reference periods introduce a new problem, namely, distortion of bids on the day-ahead market, similar and in addition to the intraday distortion discussed above. This is because generators optimize their bidding behavior against the CfD payment. If they are expecting they will have to pay 30 €/MWh due to a CfD in a clawback (high price) period, they will no longer produce at day-ahead spot prices below that threshold. Likewise, suppose generators expect a CfD payment of €30/MWh during a support (low price) period. In that case, they will produce power even if spot prices are below variable costs by less than €30/MWh because the CfD payment will compensate for the losses. These incentives distort the ranking of plants dispatched and decrease overall welfare, potentially placing carbon-intensive fossil fuel plants ahead of zero-carbon plants in the merit order. With the recent tender for the Thor offshore wind farm, Denmark combined a yearly reference period with a modification to the rule of symmetric payments such that even during clawback periods, there is no payment from the operator when spot prices are below the payment otherwise owed (European Commission, 2021). While such modifications maintain an incentive to produce whenever day-ahead prices exceed marginal costs, such modifications do not solve the remaining problematic bidding incentives on intraday markets and introduce new downsides. In particular, they decrease the quality of the hedge. In this case, the average revenue per kWh produced by a plant will be higher than the strike price as soon as the modification becomes binding. In a competitive bidding environment, bidders will consider such (possible but uncertain) mark-ups in their bid prices. In so doing, they become at least partially exposed to price risks, which is contrary to the goals of CfDs.

Instead of extending the reference period, May (2017) proposes adjusting strike prices based on the expected production value of an individual asset compared to a benchmark. To limit risks for investors, the adjustment should be calculated before the actual investment based on a forecast for an hourly power price profile provided by the regulator. However, this makes system-friendly design dependent on the accuracy of the regulator's forecast.

All these changes and improvements still mean that payments are based on actual production. For contracts where this is the case, we are unaware of any amendments to address distorted intraday/balancing bids, the volume risk, or the new revenue risk introduced by suspending payments. Indeed, we believe in particular the intraday distortion to be highly relevant in the case of large-scale application of CfDs.

4.4. Forward contracts

Financial forward and futures contracts have been a core feature of electricity markets for many years. Utilities use them on a large scale to hedge price risks. While they bear a different name, financial forwards are also "contracts for differences," defining payments as differences between the spot price during the settlement period and the forward price. The same holds for futures contracts, the exchange-traded equivalent.

The fundamental difference between conventional CfDs and forwards is that the latter are asset-independent: Payments are due regardless of any individual asset's production (or even the existence of an asset). Asset independence has the crucial advantage that payments cannot be manipulated through investment and operation decisions (of any specific asset) and hence do not distort those decisions, but the contracts still fulfill the purpose of providing long-term financial stability for the asset owner.

However, forward and futures contracts have three significant shortcomings limiting their use as an instrument to provide investment stability for low carbon generators.

- Maturity**:** In most markets, commercial forwards are only traded for a relatively short time horizon of 1–3 years, which is insufficient to hedge investments in assets with a lifespan of decades.
- Profile**:** Existing futures products (such as "base" or "peak" contracts) do not match wind or solar generation profiles well. Therefore, they are a poor hedge for those generators.
- Margining**:** Futures contracts require margin payments to be deposited as collateral, which can become very large in times of high and volatile prices. This is a problem for liquidity-constrained generation firms, as became apparent during the recent energy crisis.

In the following section, we develop a contract that combines financial forward features with conventional CfDs to overcome these shortcomings.

5. Financial CfD

This section introduces the financial CfD contract. We discuss possible profiles and the use of physical assets as collateral and then compare these contracts to conventional CfDs.

5.1. The instrument

The financial CfD is intended to mitigate revenue risks for low carbon power plant investors while avoiding distortions to dispatch, investment, and repowering decisions. The essential difference to conventional CfDs is that the contract is asset-independent in the sense that payments are unaffected by the asset's output. As a second and independent innovation, we suggest hedging not only price risk but also volume risk. Essentially, the instrument is designed around two objectives:

- Hedging revenue risk (both price and volume risk).
- Full price structure exposure (for efficient dispatch, investment, and repowering incentives).

The government sets up an auction to procure financial contracts called "financial CfDs." The auction volume, i.e., how many such contracts are procured, can either be set ex-ante, or a demand curve for the auction can be set. A demand curve reduces market power and leads to the government buying more such contracts if there is plenty of supply at low prices and less if there is only a limited supply at high prices.

The contract size is standardized for a 1 MW reference generator. The contract is a homogenous product because it does not depend on an individual asset's output. Generators can choose the desired contract volume (in MW), subject to collateral requirements. Contracts run for a long time, roughly reflecting the technical lifespan of the generator – for example 20 years for wind and solar.

A payment between the government and the contracting generator is triggered for each hour. The hourly net payment is the difference between:

1. Payment to the generator: The government pays the producer a fixed hourly lump sum, independent of output or prices. The level of the hourly remuneration is determined competitively in the initial procurement auction but then does not change during the contract's lifetime.
2. Payment to the government: The generator pays the hourly profit of a reference generator to the government. The hourly profit of a reference generator is defined as the day-ahead spot price minus benchmark variable costs multiplied by the hourly output of the reference generator. If this profit is negative, it is set to zero instead. Importantly, the reference generator is *not* the specific asset for which the generator concludes the contract. The reference generator is discussed in more detail below in Section 5.2. For wind and solar with essentially zero production costs, hourly profits equal hourly revenues, so these generators simply pay the reference generator's revenues to the government.

We illustrate both payment directions (left) and the resulting stable revenue stream (right) in Fig. 2. The resulting revenue stream for generators is very stable because the contract provides them with a fixed payment from the government while the variable payment back to the government closely matches the revenues the generator earns on the market by selling its output. Therefore, the generator is left with essentially only the fixed payment, plus or minus some basis risk (not depicted) arising from mismatches of own output from the reference output. In this way, the contract also serves as a volume hedge, e.g., hedging wind availability for a wind power plant. The stability of revenues depends on the match between the reference generation and the generator's own output, as we discuss in Section 5.2.

A cost of zero is assumed for technologies with very low generation costs, including wind and solar energy. Payment to the government is, therefore, the entire benchmark revenue. For technologies with highly stable generation costs, such as nuclear power, a constant strike price could be determined ex-ante in the contract – for example, €10/MWh. For other technologies, variable and opportunity costs would need to be estimated and frequently adjusted, in which case financial CfDs would be ill-suited. An advantage of the financial CfD is that even if the variable costs assumed in the contract (e.g., zero for wind and solar) are not accurate, this only reduces the hedge quality, i.e., the degree of risk-reduction achieved, and would not distort bidding incentives in power markets.

Resulting hourly net payments in a financial CfD for a wind farm would be as follows. In hours of high prices and/or high wind speeds, there would be a net payment from the wind farm to the government. In times of low prices and/or little wind, there would be a net payment from the government to the wind farm. The instrument stabilizes the generator's total revenue near the fixed payment from the government for every hour and is thus a hedge for both the price and weather risk. Depending on the evolution of spot prices during the duration of the contract, the net present value of the contract could become positive or negative for the investor. Even if the expected net present value was negative ex-ante, the contract might attract investors because of the value that risk hedging has.

Two key parameters of the instrument merit further discussion: the reference generator and the collateral.

5.2. Reference generator

The reference generator is essentially a method to determine an hour-by-hour generation profile that closely matches the production from contracted assets without being the actual output of that asset. Separating payment obligations from physical production prevents the distortive incentives that come with asset pegged CfDs. At the same time, it should be highly correlated to the individual asset, so it serves as a good proxy hedge and leaves little remaining basis risk. The choice of this reference generator methodology and its hourly profile is a critical parameter in financial CfDs. The closer the individual asset's production is to the reference, the better the hedge. The only remaining source of revenue risk is the basis risk originating from the reference production profile vs. the asset's production profile.

There are at least five different approaches – three for wind/solar and two for nuclear power:

- A mathematical model that derives reference output from weather data. Measured, regionally aggregated weather data, representative for the contracted asset pool, could be used. A similar approach was followed by energy exchange EEX when they introduced a wind future (this has since been abandoned). Certainly, averaging a larger region's weather means it will not be a perfect hedge for any specific turbine, but it could be a good enough hedge for many plants. Using weather data as a basis has the advantage of being independent of any individual power plant's (possibly strategic) utilization decisions. Still, given that large money flows would depend on weather measurement, it also poses a risk if weather measurement techniques change over time or if strategic players try to influence weather models.
- A sample of actual physical wind/solar farms could be used. However, there would be a financial incentive to manipulate the dispatch of these reference plants, especially if the sample was small.
- A third possibility would be to use a country or bidding zone's aggregate wind/solar generation as a reference. This would be comparable to the concept of market value used for example in existing German support schemes. However, it would need to be defined on a capacity basis (EUR of revenue per MW) rather than an energy basis (EUR/MWh). The possibility of gaming the reference is quite limited for large bidding zones, but that is not the case for small zones with few large generators, such as offshore bidding zones.

For dispatchable generators, more straightforward references seem feasible:

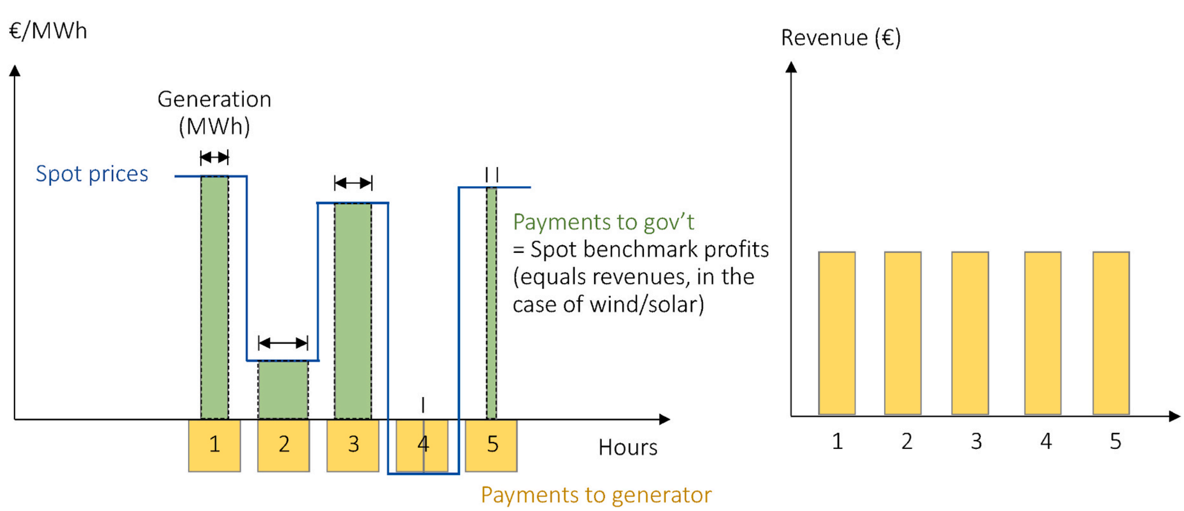

Fig. 2. Revenue stream in a financial CfD for a wind or solar park with benchmark costs of zero (left). Generators receive a fixed hourly payment (yellow) but must pay the revenues of a reference generator (green) to the government. If a generator's market revenues match the reference revenues to be paid to the government, then the remaining revenue for a generator is stable and equals the fixed payment from the government (right).

- A base profile where all hours are weighted equally. Financial CfDs would essentially become conventional financial forward contracts with a very long lifetime.
- System load could be used as a profile. This comes with the benefit of being a good hedge for the buyer.

One could also use base profiles for wind and solar energy, creating technology neutral financial CfDs. This has several benefits, including the fact that it introduces cross-technology competition, aligns well with existing forwards/futures, and is much simpler to define. However, a base profile comes at the expense of a more significant basis (profile/shaping) risk for renewable investors.

5.3. Collateral and contract volume

The government would require collateral to back up financial CfD contracts. Financial futures need cash or other liquid securities as collateral. At times of high and/or volatile prices, the resulting margin calls can be dangerously large. An important lesson from the 2022 energy crisis is that margin calls can quickly deplete even the deepest pockets, let alone those of cash-constrained project developers and smaller investors. We therefore suggest that the government could accept physical generation assets as collateral. Indeed, the collateral requirement would be the only relationship between the financial contract and the physical asset.

Accepting financial collateral as an option could also be considered. Should the generator wish to dismantle or repower its asset, it should be able to exchange the initial turbine put down as collateral for financial collateral or transfer the contract to a new, repowered asset. Allowing such exchange of collateral avoids distorting disinvestment and repowering decisions.

Governments could introduce certain de-rating factors so that, for example, a wind power plant can only be counted as collateral for a maximum of 90 percent of expected capacity. This ensures plant owners have enough cash even if their plant produces less than the reference plant and to pay for imbalance costs even in high price periods, despite imbalance costs being correlated to the spot price.

The collateral requirements limit the contract volume a generator can sign for any asset. In the simplest case introduced above, we suggest leaving the decision of the desired contract volume to the generation firm subject to the collateral requirements. Governments could set up limits on the number of contracts per asset based on either nominal capacity or, for example, expected annual generation of the specific plant setup. Collateral requirements must be set carefully because they could yield incentives during the investment phase. If the expected net present value of financial CfDs is zero, investors will be incentivized to sign the contract volume that minimizes risk. However, investors are incentivized to inflate contract volume if the contract is expected to yield a profit. If contract volume is pegged to nominal capacity, investors would be incentivized to maximize capacity without considering quality, availability, capacity factors, and siting. Governments can reduce that risk by designing financial CfDs mainly as a (profit-neutral) hedge rather than a subsidy. The risk can also be reduced by ensuring adequate reward for system-friendly designs in collateral requirements.

5.4. Risk allocation

Financial CfDs allocate risks differently from conventional CfDs as they systematically allocate risks to those parties who can best influence that risk to create desirable incentives. Risks that no party can control are assigned to the party that can absorb the risk at the lowest costs, in line with risk allocation principles (Irwin, 2007). Therefore, while the power price risk and the weather risk are allocated to the government, the risk of actually producing (i.e., availability risk) is fully assigned to the investor. The choices influence the overall risk profile for the investor in both directions.

Unlike conventional CfDs, financial CfDs target the absolute amount of revenue, not the per-MWh revenues, which is risk-reducing for the investor. In other words, financial CfDs take out the weather (volume) risk for renewables by making the government payment to generators a fixed payment rather than a per-MWh payment. The absence of periods where CfD payments are suspended, which many tweaked CfD designs introduce to avoid specific distortive incentives, further stabilizes revenues vis-à-vis alternative CfDs.

At the same time, financial CfDs add a new basis risk. This is because the underlying for the volume of financial CfDs is an independent reference generator and not the actual asset. Therefore, payment obligations from the financial CfD can deviate from actual revenue. The risk is symmetric, which means it can lead to lower and higher-than-expected income for the generator, but it is now correlated to electricity price levels. This means underperforming relative to the reference is particularly expensive during high-price times and vice versa. This feature is desirable to generate the right investment and operation decisions and is shared with tweaked CfD designs that use longer reference periods. Furthermore, generators can minimize their basis risk by choosing a contract size most appropriate for their asset.

Whether financial CfDs are risk-reducing for investors (as the weather risk and periods of payment suspension are gone) or risk-increasing (due to increased basis risk) overall is ultimately an empirical question. However, the benefits of undistorted intraday and balancing markets as well as undistorted plant investment and operation remain either way.

5.5. Discussion

Compared to conventional CfDs, the proposed financial CfDs have the benefit of avoiding distortive effects and mitigating volume risks to reduce risk premia further. Compared to forwards, they have the advantage of lowering basis risk through a better-matching profile, avoiding margin calls, and longer maturities.

One can think of financial CfDs as contracts that, in a novel way, use and combine properties from four different types of contracts (Fig. 3): They use generation volumes tailored to specific generation types and have a long lifetime, like conventional CfDs. They are asset-independent, like financial forwards/futures and accept physical assets as collateral, like mortgage loans. They also provide a hedge against volume risk, similar to capacity-based subsidy schemes such as investment tax credits.

Financial CfDs are much more suitable for some power generation technologies than others, mainly because of differences in production costs. The following section discusses these with a rough order of technologies, starting with those more suited to financial CfDs.

- For wind and solar energy, variable costs are constant and known quite accurately ex-ante because they are very close to zero.
- For nuclear energy, fuel costs are relatively stable; however, the opportunity cost of re-fueling introduces some inaccuracy.
- Fossil-fueled condensing plants see their production costs change daily with fluctuating fuel and carbon prices. The financial CfD strike price would need to be specified as benchmark costs, e.g., by calculating spreads from commodity price benchmarks and a reference conversion efficiency. Unobserved prices, contracts, and fuel transport costs would introduce significant inaccuracies and extra risks.
- Plants that burn fuel for which observable commodity markets do not (yet) exist – including hydrogen and biomass – are even more challenging to parameterize.
- Generators with unobserved opportunity costs, including cogeneration and storage plants, are even less suited to financial CfDs.

In summary, we view the financial CfD as an instrument that makes sense for wind, solar, and nuclear generators but less for other

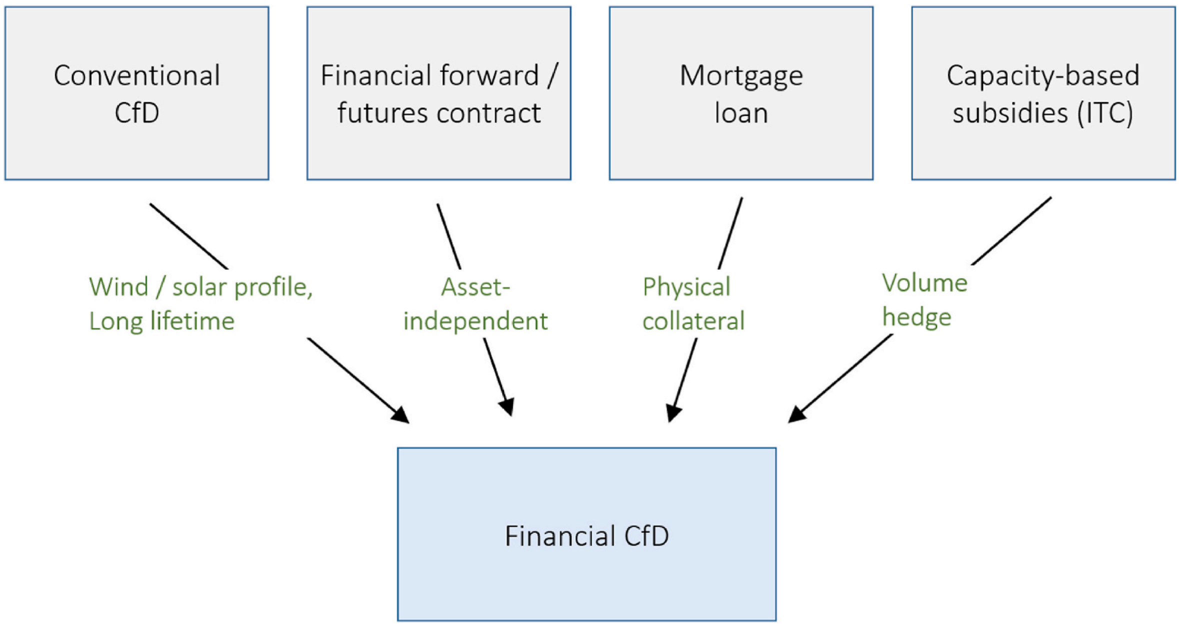

Fig. 3. Financial CfDs borrow and combine properties from different types of contracts.

technologies.

6. Conclusion and policy implications

Contracts for differences in the form currently used offer problematic incentives, and these tend to be more severe if applied (a) to non-zero variable cost technologies and/or (b) in larger volumes. The tweaks and fixes introduced to avoid such distortions often bring their own problems that require further patches. Some issues, such as distorted intraday markets, remain unsolved in all conventional, generation-based CfDs. Given these flaws, applying them to large parts of future power generation seems unwise.

This paper proposes a new form of contract that draws on a key feature from financial forwards/futures contracts to avoid such distortions, namely, asset independence. Instead of linking payments to the output of an individual generator and hence providing the opportunity for manipulating them by adjusting output, we propose to link them to an objective benchmark. For effective risk mitigation, that benchmark must be highly correlated with power generation, such as, for wind and solar energy, a profile derived from weather observations. Unlike other contracts for differences, the financial CfD also hedges volume (not just price) risk, stabilizing revenues. In contrast to financial futures, the contract avoids liquidity squeezes by allowing physical assets as collateral.

Financial CfDs can be interpreted in different ways: one can understand them as an improvement of (renewable and nuclear energy) support schemes. Alternatively, one can seem them as a hedging instrument where the government provides risk mitigation. Financial CfDs can also be regarded as an evolution of futures/forward contracts and think of financial CfDs being signed by commercial parties and even traded on secondary markets.

The core idea of the contract is to mitigate risk while preserving incentive by specifying payments that are highly correlated with cash flow but are independent from the behavior of the contract party and hence cannot be manipulated. In that sense, they are similar to reliability options (Bidwell, 2005), which also provide stability for investors without distorting the incentives to operate in markets.

Maybe the most important remaining question that stands in the way of introducing financial CfDs in practice is the extent to which they reduce or increase risks for power generators compared to alternative CfD designs. On the one hand, financial CfDs introduce a new basis risk by tying volumes to a reference generator. On the other hand, they provide a hedge against volume risk, and they do not require specific provisions to stop payments in periods of negative or low positive prices (which represents a risk, too). How these effects compare is an empirical question, which we hope future quantitative research will answer.

CRediT authorship contribution statement

Ingmar Schlecht: Conceptualization, Writing – original draft. **Christoph Maurer:** Conceptualization, Writing – original draft. **Lion Hirth:** Conceptualization, Writing – original draft.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

No data was used for the research described in the article.

Acknowledgements

Ingmar Schlecht's work on this paper was funded by the Swiss Federal Office of Energy's "SWEET'' programme as part of the PATHFNDR project under Grant Number SI/502259. The funding source was not involved in the conduct of the research or preparation of the article.

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