Design principles for 2-way CfDs for solar-PV & onshore wind

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Trinomics B.V.
Mauritsweg 44
NL-3012 JV Rotterdam
The Netherlands

T +31 (0) 10 3414 592
www.trinomics.eu

Authors

Andrea Demurtas
Joris Moerenhout
Nora Cheikh

Contacts

Andrea Demurtas
E: andrea.dermurtas@trinomics.eu

Joris Moerenhout
E: joris.moerenhout@trinomics.eu

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Management summary & conclusions

Summary

Two-sided contracts for differences (2-way CfDs) are gaining momentum across Europe as successors of subsidy schemes for renewable electricity generation. As the costs of renewable energy technologies fall, the justification for subsidising renewable electricity becomes increasingly debatable. There is a risk that subsidised renewable energy projects can make large profits over their lifetime, similar to what occurred during the energy crisis. At the same time, solar-PV and wind generators capture increasingly lower market prices, as the share of renewable electricity generation rises (also referred to as *price cannibalisation*). Moreover, abolishing state support entirely would also raise financing costs substantially, where a sudden stop may lead to a drop in investments in renewable electricity generation. 2-way CfDs are financial contracts and offer a possible solution to lower financing costs for renewable electricity projects and potentially provide additional revenues compared to a market situation in case of profitability gaps. At the same time, 2-way CfDs limit the room for excess profits for project developers, as excess profits are transferred back to the government. In the Netherlands, support for solar PV and onshore wind is only guaranteed until end 2025. In this context, in 2023, Trinomics concluded that a 2-way CfD for solar PV and onshore wind would fit the Dutch policy objectives and situation best.[1] Hence, in this study, we focus on 2-way CfD design options.

The most relevant challenge for *conventional* 2-way CfDs[2] is that they mute price signals, which results in inefficient market behaviours. In 2-way CfDs, generators receive payments from the government if the reference price is below the strike price (like a 1-way CfD, such as the SDE++), and must pay the government (clawback) if the reference price is above the strike price (unlike a 1-way CfD). In an efficient energy system that minimises costs for consumers, price movements provide a signal to generators on *when* to generate, as well as guiding investment decisions. However, under a conventional 2-way CfD, generators always receive the same price, masking price signals and leading to inefficient investment and dispatch decisions from a system perspective. Inefficiencies include distortions to the intra-day market (e.g. self-curtailing generation at periods of high electricity prices) and the *produce-and-forget mentality*, which leads generators to produce electricity at any time (regardless of the value), as well as dispatch distortions and system unfriendly investments.[3]

There are several options to address these system inefficiencies. However, departing from the conventional design means introducing newer issues as the ones above are solved or mitigated:

- The **reference period** is the time over which the **reference price** is calculated. A conventional 2-way CfD uses a short (1 hour) reference period, which completely removes the incentive to optimise dispatch choices. To tackle this issue, longer reference periods and different averaging methods can be considered. With a yearly reference period, generators are incentivised to beat the reference price, i.e. dispatch electricity aiming to earn higher market prices, than the reference price, on average. At the same time, longer reference periods may incentivise strategic

[1] Please refer to our previous research on Policy options to upscale solar PV and onshore wind beyond 2025, for a more elaborate justification to continue with some form of government support for renewable energy.
[2] We define these as CfDs with fixed strike price, hourly day-ahead spot price as reference price, and volumes "as produced" in each hour.
[3] See The design of the European electricity market - Current proposals and ways ahead (europa.eu) for an extensive explanation of the problem and the Communication from the EC – Guidelines on State aid for climate, environmental protection and energy 2022 paragraph 123: *The aid must be designed to prevent any undue distortion to the efficient functioning of markets and, in particular, preserve efficient operating incentives and price signals. For instance, beneficiaries should remain exposed to price variation and market risk, unless this undermines the attainment of the objective of the aid. In particular, beneficiaries should not be incentivised to offer their output below their marginal costs and must not receive aid for production in any periods in which the market value of that production is negative.*

behaviours and distort electricity markets, leading generators to e.g. self-curtail when market prices are high, but below the expected clawback (see *Curtailing production during periods of high prices*). The choice of reference period creates a trade-off between optimising dispatch decisions and minimising market distortions. Some measures can minimise (but possibly not completely solve) both distortive behaviours. To optimise dispatch choices, suspending payments during negative prices (like in the SDE++), limiting the clawback to the level of the spot price and setting the reference price ex-post reduce the incentive to adopt inefficient dispatch choices.

- The **reference volume** is the amount of electricity that is remunerated via CfD payments. In a conventional 2-way CfD, volumes are based on *actual* generation. As a result, generators aim to maximise *volumes*, rather than *value*, resulting in inefficient behaviours from a system perspective. An emerging concept, currently being investigated by academics and some European countries, is to decouple CfD payments from the actual generation.[4] Under this approach, the volumes used to calculate the CfD payments are estimated, based on a *reference plant* or market averages, rather than the actual volume produced by the plant under the CfD. Generators would have an incentive to *beat* the reference plant by reacting to price signals, hence creating system benefits. A reference approach should mitigate electricity market distortions and suboptimal dispatch choices. Several institutional actors and experts seem positive about this option, although this approach has not been tested in practice. While for lower reference prices this option would be similar to an investment subsidy distributed monthly, the key difference is that the payment reverses when the reference price is high.

Aside of the choices for the reference period, price and volumes, other design choices can be considered. These elements can affect the performance of 2-way CfDs, but to a lesser extent:

- **Measures to prevent** (or lower impact of) **non-optimal generation** in conventional 2-way CfDs include suspending payments below zero prices and limiting output capacities (like in the SDE++). Other options are defining contracts in volumes (vs. years), a dynamic clawback (e.g. limiting the clawback to the spot price), and limiting payments if prices are below marginal costs.
- **The budgetary impact of a CfD scheme can be limited** by allowing carve outs, for instance by only covering a certain percentage (e.g. 80%) of the plant capacity under the CfD, or by allowing generators to sell part of their generation via PPAs after the CfD has been awarded, and to re-enter the CfD scheme if the PPA contract ends and they cannot find new buyers. Generators could also be allowed to enter the CfD after generation has started (normally, a CfD starts as soon as generation starts, but in theory it could start later, at a time chosen by the generator), or leave the scheme early.
- **There are different options to deal with inflation**. A CfD may not consider inflation at all (such as in the SDE++), consider inflation by either adjusting the strike price for inflation between the submission of the bid and the first day of generation (to cover for changes in development costs, such as raw materials and components) or fully adjusting the strike price (during every year of the contract). Inflation is more relevant in 2-way CfDs (compared to 1-way CfDs) as it does not only affect the real value of the payments received by the generator, but it also increases the likelihood of the reference price being above the strike price. This lowers the cumulative payments received by the generator and increases the payments from the generator to the government. More conservative inflation adjustments rules incentivise higher bids, as generators try to predict the level of inflation and its impact on the project's return.
- **Payments can be based on a range around the strike price** (instead of a single strike price) so that generators will take on a greater share of market risk, and governments a smaller share. A price range may not be a cost-effective solution (as it may lead to higher prices, among other negative aspects).

[4] These concepts include *yardstick CfDs, capability-based CfDs, financial CfDs.*

Conclusions & recommendations

2-way CfDs are complex instruments comprised of multiple components that interact with each other. Across Europe, countries such as Ireland, Spain and Belgium have adopted many variations of what we have here defined as the conventional design, which is closer to the UK CfD scheme. So far, no model has emerged as the absolute best. Design elements are context specific and change over time. The operating principles of CfDs have generally ensured successful outcomes for investors and consumers, even though in some specific instances the contracts have resulted in being too expensive for the consumers, or too low for developers (which then have halted construction).

In this study, we explore two concrete options for 2-way CfDs: a standard 2-way CfD and a reference-volume approach, as the key choice is between production-based and non-production based designs. Both contain combinations of design elements discussed in the technical sections. In defining the options, we aimed to include only viable design choices. We allocated the design choices closer to tested schemes to the production-based 2-way CfD, while the elements associated with the non-production-based 2-way CfD are more innovative (few or no implementations in the real world). However, various (electricity market) academics and experts are in favour of reference-volume based approaches, like the non-production based 2-way CfD below. The table below summarises key characteristics of both.

Design element	Production based 2-way CfD	Non-production based 2-way CfD
Strike price	Single strike price (no range)	
Volumes	Volumes as-produced	Reference volumes
Reference period	Monthly/weekly* reference period. Actual reference price set ex-post. Payments to generators based on expected reference price. Final settlement for week/month when final reference price is known	Annual reference period, Actual reference price set ex-post. Payments to generators based on an expected reference price. Final settlement for the year when final reference price is known
Reference price	Monthly/weekly average of the day-ahead market price, for every hour of the day. The price is set ex-post	Annual average of the day-ahead market price, for every hour of the day. The price is estimated in advance, then adjusted ex-post based on actual market prices
Contract duration	15 years contracts, with annual ceiling concerning the generation level	15 years contracts. Voluntary exit allowed when 70% of contracted capacity has been produced
Share of generation	100% generation capacity covered by CfD	70-90% generation capacity covered by CfD
Carve out	Temporary carve outs allowed (similar to Belgian offshore wind scheme)	
Inflation	No inflation adjustment	Adjustment during construction. Based on CPI (50%) and sector-specific inflation indicator (50%)
Maximum bid	Administratively-set maximum bid	
Corrections	Correction for wind speed according to current factors; 50% derating for solar PV	Optional: correction factor curtailment (full load hours decrease based on curtailment signals)
Minimum available hours	There will be a set of rules to establish when a generator is active, to minimise strategic behaviours	
Negative prices	No payments when prices are negative, or when SO sends curtail orders due to local congestion	Hours of negative prices excluded from the estimated volumes, based on technology-specific production profiles. Options to have multiple profiles per technology based on specific designs (such as in the SDE++) should be considered

** We provide two options when none seems to be clearly preferred*

A non-production based 2-way CfD should reduce dispatch and investment distortions, but it is an untested approach and presents some implementation risks. On the other hand, the production based 2-way CfD is a well-tested option, but is likely to distort market behaviours and to be less efficient from a system perspective. While distortions on the energy market of the countries with traditional CfDs have been limited so far, their impact will increase as the share of renewables under 2-way CfD contracts increases. Some of the market distortions identified for conventional CfDs can be partially mitigated by design choices concerning the reference period and reference price (such as ex-post adjustments).

Therefore, both options seem a good fit for the Dutch market, and actual differences are limited to some aspects. Ultimately, it is a choice between the severity of the remaining distortions under the production based 2-way CfD and the implementation risks posed by a non-production based 2-way CfD.

For the implementation of a non-production based 2-way CfD, there are some aspects that will require further analysis, including:

- Developing a methodology to estimate deemed generation;
- Whether to introduce locational signals;
- Dealing with negative prices when calculating the average reference price;
- Monitoring plant activity (i.e., validating when a plant is operational even though it may not be generating at a certain point in time);
- Developing a methodology to estimate an inflation adjustment index, in case the option of an inflation adjustment factor during construction is adopted (if an inflation adjustment throughout the contractual period is adopted, using a CPI or HICP index is a common solution).

Further analysis would likely involve EZK, PBL, RVO, and potentially external experts.

Lastly, we provide some more general considerations and recommendations:

- **To prevent a potential drop in investments, a relevant consideration is how comfortable developers and investors are with different design elements of the 2-way CfD.** Design elements may be adjusted over time, and adapted to new evidence and to the behaviours observed in the market, as currently done for SDE++. We recommend to discuss the design options presented in this report and other design elements with the industry, ensuring that developers and finance providers are comfortable with the details and understand the implications for their projects.
- **Whether smaller generators should be included in a 2-way CfD should also be considered.** Smaller generators are unlikely to engage with the market in real time, and therefore respond to different sets of incentives, and of a different magnitude. This aspect has not been considered in this analysis. However, other countries have minimum plant size thresholds higher than the SDE++ (for example, the UK requires a minimum plant size of 5 MW, Ireland 0.5 MW).
- **The absence of locational signals, either via market prices (multiple price zones) or via network tariffs, means that the geographical distribution of new renewable electricity generation may not occur in the most efficient way from a system perspective**. The regulator (ACM) may consider whether an amendment to network tariffs could provide locational signals so that new renewables are prioritised in areas where the transmission and distribution networks are be better able to cope with new capacity.

We did not identify unsolvable problems for 2-way CfDs. As such, the conclusion of our previous research remains relevant: a 2-way CfD seems to fit the Dutch policy targets and context best.

Managementsamenvatting & conclusies [Nederlands]

Samenvatting

Tweezijdige *contracts for differences* (contracten ter verrekening van verschillen: CfD's) krijgen steeds meer aandacht in de EU als opvolgers van subsidies voor hernieuwbare elektriciteit. Naarmate de kosten van hernieuwbare energietechnologieën dalen, wordt de rechtvaardiging voor het subsidiëren van hernieuwbare elektriciteit minder evident. Het risico bestaat dat gesubsidieerde projecten hoge winsten maken, zoals tijdens de energiecrisis. Tegelijkertijd ontvangen zon-PV- en windenergieprojecten steeds lagere marktprijzen doordat het aandeel hernieuwbare elektriciteitsopwekking stijgt (prijskannibalisatie). Bovendien zou het volledig afschaffen van ondersteuning de financieringskosten aanzienlijk doen stijgen, waarbij een plotselinge stopzetting kan leiden tot een daling van de investeringen. Tweezijdige CfD's zijn financiële contracten die een mogelijke oplossing kunnen bieden om de financieringskosten voor hernieuwbare elektriciteitsprojecten laag te houden en mogelijk extra inkomsten kunnen opleveren, in vergelijking met een marktsituatie. Tegelijkertijd beperken tweezijdige CfD's de ruimte voor overwinsten; deze vloeien terug naar de overheid. In Nederland is de steun voor zon-PV en windenergie op land gegarandeerd t/m 2025. In 2023 concludeerde Trinomics dat een tweezijdige CfD voor zon-PV en wind op land het beste zou passen bij de Nederlandse beleidsdoelstellingen en situatie na 2025.[5] Daarom richten we ons in deze studie op de ontwerpopties voor tweezijdige CfD's.

De meest relevante uitdaging bij conventionele tweezijdige CfD's[6] is dat ze prijssignalen dempen, wat leidt tot inefficiënt marktgedrag. Bij tweezijdige CfD's ontvangen producenten betalingen van de overheid als de referentieprijs onder de uitoefenprijs (*strike price*) ligt (zoals bij een eenzijdige CfD als de SDE++), en moeten ze de overheid betalen als de referentieprijs boven de uitoefenprijs ligt (in tegenstelling tot bij een eenzijdige CfD). In een efficiënt energiesysteem dat de kosten voor consumenten minimaliseert, geven prijsbewegingen een signaal aan producenten over *wanneer* ze dienen te produceren en sturen ze investeringskeuzes. Bij een conventionele tweezijdige CfD ontvangen producenten echter altijd dezelfde prijs, wat prijssignalen dempt en leidt tot inefficiënte investerings- en opwekkeuzes vanuit een systeemperspectief. Hierbij gaat het bijvoorbeeld om verstoringen van de intra-day markt (bv. *curtailment* op momenten met hoge elektriciteitsprijzen) en de "*produce-and-forget*"*-mentaliteit*, die ertoe kan leiden dat producenten op elk moment elektriciteit produceren (ongeacht de waarde), alsook verstoringen van de opwek- en investeringskeuzes.[7]

Er zijn opties om systeeminefficiënties te adresseren. Echter, afwijken van het conventionele ontwerp om bovenstaande problemen op te lossen of te beperken leidt tot nieuwe uitdagingen:

- De **referentieperiode** is de tijd waarover de **referentieprijs** wordt berekend. Een conventionele tweezijdige CfD gebruikt een korte referentieperiode (1 uur), waardoor de prikkel om de opwekkeuzes te optimaliseren volledig wegvalt. Om dit probleem te adresseren, kunnen langere referentieperioden en verschillende methoden om gemiddeldes te berekenen worden overwogen. Met een jaarlijkse referentieperiode worden producenten gestimuleerd om de referentieprijs te verslaan, d.w.z. elektriciteit op te wekken met als doel gemiddeld hogere marktprijzen te

[5] Zie vorige onderzoek over Policy options to upscale solar PV and onshore wind beyond 2025, voor een uitgebreide rechtvaardiging voor de continuering van een bepaalde vorm van ondersteuning voor hernieuwbare elektriciteit.
[6] We definiëren deze als CfD's met een vaste *strike price*, een day-ahead-marktprijs (per uur) voor de spotprijs en referentieprijs en volumes op basis van geproduceerde volumes per uur.
[7] Zie The design of the European electricity market – Current proposals and ways ahead (europa.eu) voor een uitgebreide uitleg van het probleem en de communicatie van de Europese Commissie - Guidelines on State aid for climate, environmental protection and energy 2022 paragraaf 123: *The aid must be designed to prevent any undue distortion to the efficient functioning of markets and, in particular, preserve efficient operating incentives and price signals. For instance, beneficiaries should remain exposed to price variation and market risk, unless this undermines the attainment of the objective of the aid. In particular, beneficiaries should not be incentivised to offer their output below their marginal costs and must not receive aid for production in any periods in which the market value of that production is negative.*

verdienen dan de referentieprijs. Tegelijkertijd kunnen langere referentieperiodes strategisch gedrag en verstoringen op de elektriciteitsmarkten in de hand werken, waardoor producenten bijvoorbeeld gaan curtailen wanneer de marktprijzen hoog zijn, maar onder de verwachte terugbetaling liggen (zie *Curtailing production during periods of high price*). De keuze van de referentieperiode creëert een uitruil tussen het optimaliseren van opwekkeuzes en het minimaliseren van marktverstoringen. Er zijn maatregelen die beide verstoringen kunnen minimaliseren (maar mogelijk niet volledig oplossen). Om de opwekkeuze te optimaliseren kan het opschorten van betalingen ten tijde van negatieve prijzen (zoals in de SDE++) de stimulans voor inefficiënt gedrag verminderen. Dit geldt ook voor het beperken van de terugbetaling tot het niveau van de spotprijs en het achteraf vaststellen van de referentieprijs.

- Het **referentievolume** is de hoeveelheid elektriciteit die onder de CfD valt. In een conventionele tweezijdige CfD zijn de volumes gebaseerd op de daadwerkelijke productie. Als gevolg daarvan streven producenten naar maximalisatie van productievolumes in plaats van waarde, wat leidt tot inefficiënt gedrag vanuit een systeemperspectief. Een opkomend concept, dat momenteel wordt onderzocht door academici en enkele Europese landen, is het loskoppelen van de CfD-betalingen en de daadwerkelijke elektriciteitsproductie.[8] Hierbij worden de volumes die worden gebruikt om de CfD-betalingen te berekenen, geschat op basis van een *referentie-installatie* of marktgemiddelden, in plaats van het daadwerkelijke volume dat door de installatie geproduceerd. Producenten worden dan gestimuleerd om de referentiecentrale te verslaan door te reageren op prijssignalen, waardoor systeemvoordelen ontstaan. Een referentiebenadering dient de verstoringen van de elektriciteitsmarkt en suboptimale opwekkeuzes te beperken. Meerdere institutionele partijen en deskundigen lijken positief te staan tegenover deze optie, hoewel deze nog niet in de praktijk is getest. Bij lagere referentieprijzen zou deze optie vergelijkbaar zijn met een investeringssubsidie die maandelijks wordt uitgekeerd, met als belangrijkste verschil dat de overheid geld ontvangt als de referentieprijs hoog is.

Naast de referentieperiode, -prijs en -volumes, kunnen andere ontwerpkeuzes in overweging worden genomen. Deze elementen kunnen de prestaties van CfD's ook beïnvloeden, maar in mindere mate:

- **Maatregelen om niet-optimale productie** in conventionele tweezijdige CfD's **te voorkomen** (of de impact ervan te verminderen) zijn o.a. het opschorten van betalingen als de elektriciteitsprijs negatief is (zoals in de SDE++). Andere opties zijn het definiëren van contracten in volumes (in plaats van jaren), een dynamische clawback (bv. de terugbetaling beperken tot de spotprijs) en het beperken van betalingen als prijzen onder de marginale kosten liggen.
- **De budgettaire impact van een CfD-regeling kan worden beperkt** door uitzonderingen toe te staan, bijvoorbeeld door slechts een bepaald percentage (bv. 80%) van de capaciteit onder de CfD te laten vallen, of door producenten toe te staan een deel van hun productie via PPA's te verkopen nadat de CfD is toegekend, en opnieuw tot de CfD-regeling toe te treden als het PPA-contract afloopt en ze geen nieuwe kopers kunnen vinden. Producenten zouden ook tot de CfD kunnen toetreden nadat de productie is begonnen (normaal gesproken begint een CfD zodra de productie begint, maar in theorie kan dit later beginnen, op een door de producent gekozen tijdstip), of vroegtijdig uit de regeling kunnen stappen.
- **Er zijn verschillende opties om met inflatie om te gaan.** Er kan worden gekozen om geen rekening te houden met inflatie (zoals in de SDE++). Ook kan ervoor worden gekozen om rekening te houden met inflatie door ofwel de uitoefenprijs aan te passen voor inflatie tussen het moment van indiening en de eerste dag van productie (om veranderingen in ontwikkelingskosten, zoals grondstoffen en componenten, te dekken), of de uitoefenprijs volledig te indexeren (tijdens elk jaar van het contract). Inflatie is relevanter bij tweezijdige CfD's (in vergelijking met eenzijdige CfD's) omdat het niet alleen de reële waarde van de betalingen die de producent ontvangt

[8] Deze concepten zijn onder andere: *yardstick CfDs*, *capability-based CfDs* en *financial CfDs*.

beïnvloedt, maar ook de kans vergroot dat de referentieprijs boven de uitoefenprijs ligt. Dit verlaagt de betalingen die de producent ontvangt en verhoogt de betalingen van de producent aan de overheid. Terughoudend zijn in het meenemen van inflatie stimuleert hogere biedingen; producenten proberen de impact van inflatie op het rendement te voorspellen en mee te nemen.

- **Betalingen kunnen worden gebaseerd op een bandbreedte rond de uitoefenprijs** (in plaats van een enkele uitoefenprijs), zodat producenten een groter deel van het marktrisico op zich nemen en overheden een kleiner deel. Een bandbreedte is mogelijk geen kosteneffectieve oplossing (omdat het kan leiden tot hogere prijzen, naast andere negatieve gevolgen).

Conclusies & aanbevelingen

Tweezijdige CfD's zijn complexe instrumenten die bestaan uit meerdere componenten die op elkaar inwerken. In Europa hebben landen als Ierland, Spanje en België tweezijdige CfD's geïmplementeerd als variaties op het conventionele tweezijdige CfD-ontwerp (zoals gedefinieerd in dit onderzoek – vergelijkbaar de Britse CfD). Tot nu toe is geen enkel model naar voren gekomen als het beste. Ontwerpelementen zijn contextspecifiek en veranderen in de loop van de tijd. De mechanismes van de CfD's hebben over het algemeen gezorgd voor succesvolle resultaten voor investeerders en consumenten, ook al hebben de contracten in sommige specifieke gevallen geleid tot te hoge kosten voor de consumenten, of te lage inkomsten voor de ontwikkelaars (die vervolgens de bouw hebben stopgezet).

Ontwerpelement	Productie gebaseerde tweezijdige CfD	Niet-productie gebaseerde tweezijdige CfD
Uitoefenprijs	Eén uitoefenprijs (geen bandbreedte)	
Volumes	Volumes zoals geproduceerd	Referentievolumes
Referentie-periode	Maandelijkse/wekelijkse* referentieperiode. Definitieve referentieprijs achteraf vastgesteld. Betalingen aan producenten o.b.v. verwachte referentieprijs. Eindafrekening voor week/maand als definitieve referentieprijs bekend is	Jaarlijkse referentieperiode, definitieve referentieprijs achteraf vastgesteld. Betalingen aan producenten gebaseerd op een verwachte referentieprijs. Eindafrekening als definitieve referentieprijs van dat jaar bekend is
Referentieprijs	Maandelijks/wekelijks gemiddelde van de day-ahead-marktprijs, voor elk uur van de dag. De prijs wordt achteraf vastgesteld	Jaargemiddelde van de day-ahead-marktprijs, voor elk uur van de dag. De prijs wordt vooraf geschat en achteraf aangepast op basis van de werkelijke marktprijzen.
Contractduur	Contracten voor 15 jaar, met een jaarlijks plafond voor het productieniveau	Contracten van 15 jaar. Vrijwillige uitstap is toegestaan als 70% van de gecontracteerde capaciteit is geproduceerd
Aandeel van productie	100% productiecapaciteit gedekt door CfD	70-90% productiecapaciteit gedekt door CfD
Uitzonderingen	Tijdelijke uitzonderingen toegestaan (vergelijkbaar met Belgische regeling wind op zee)	
Inflatie	Geen correctie	Aanpassing tijdens bouw. Gebaseerd op CPI (50%) en sectorspecifieke inflatie-indicator (50%)
Maximaal bod	Vastgesteld maximum bod	
Correcties	Correctie windsnelheid volgens SDE++ factoren; 50% capaciteit zon-PV	Optioneel: correctiefactor curtailment (vollasturen verminderen op basis van curtailmentsignalen)
Minimaal beschikbare uren	Er komt een set regels om te bepalen wanneer een producent actief is, om strategisch gedrag te minimaliseren	
Negatieve prijzen	Geen betalingen als prijzen negatief zijn, of als NB curtailorders stuurt vanwege lokale congestie	Uren met negatieve prijzen uitgesloten van de geschatte volumes, o.b.v. technologie specifieke productieprofielen. Opties voor meerdere profielen per technologie o.b.v. specifieke ontwerpen (als SDE++) moeten worden overwogen

** We geven twee opties als geen van beide overduidelijk de voorkeur geniet.*

We hebben twee concrete opties voor tweezijdige CfD's verkend: een standaard en een referentievolume tweezijdige CfD. De belangrijkste keuze is immers die tussen op productie gebaseerde en niet-productie gebaseerde CfD's. Beide bevatten combinaties van elementen die in de technische hoofdstukken zijn besproken. Bij het definiëren van de opties hebben we ernaar gestreefd om alleen haalbare ontwerpkeuzes op te nemen. We hebben de ontwerpkeuzes die dichter bij geteste schema's liggen toegewezen aan de productie gebaseerde CfD, terwijl de elementen die geassocieerd worden met de niet-productie gebaseerde CfD innovatiever zijn (en niet/weinig zijn geïmplementeerd).

Verschillende (elektriciteitsmarkt-) academici en -experts zijn echter voorstander van referentievolume tweezijdige CfD's, zoals de niet-productie gebaseerde tweezijdige CfD. De tabel laat de opties zien.

Een niet-productie gebaseerde tweezijdige CfD dient opwek- en investeringsverstoringen te verminderen, maar is nog nergens geïmplementeerd en brengt daarom uitvoeringsrisico's met zich mee. De productie gebaseerde tweezijdige CfD is een bewezen optie, maar zal het marktgedrag verstoren en is minder efficiënt vanuit een systeemperspectief. Hoewel de verstoringen op de energiemarkt van de landen met traditionele CfD's tot nu toe beperkt zijn gebleven, zal de impact hiervan toenemen naarmate het aandeel van hernieuwbare energiebronnen onder tweezijdige CfD-contracten toeneemt. Sommige marktverstoringen die zijn vastgesteld voor conventionele CfD's kunnen gedeeltelijk worden gemitigeerd door ontwerpkeuzes met betrekking tot de referentieperiode en referentieprijs (zoals ex-post aanpassingen). Daarom lijken beide opties goed te passen bij de Nederlandse markt en zijn de verschillen beperkt. Uiteindelijk is het een afweging tussen de resterende verstoringen bij een productie gebaseerde CfD en de uitvoeringsrisico's van een niet-productie gebaseerde CfD.

Voor de implementatie van een niet-productie gebaseerde tweezijdige CfD zijn er enkele aspecten die nader dienen te worden onderzocht, waaronder:

- Het ontwikkelen van een methodologie om de referentieproductie in te schatten;
- Het beantwoorden van de vraag of locatiespecifieke signalen moeten worden ingevoerd;
- De omgang met negatieve prijzen bij de berekening van de gemiddelde referentieprijs;
- Het monitoren en de productie van installaties (d.w.z. valideren wanneer een installatie operationeel is, ook al is het mogelijk dat deze op een bepaald moment niet produceert);
- Het ontwikkelen van een methode om een inflatiecorrectie-index te schatten, indien de optie van een inflatiecorrectiefactor tijdens de bouw wordt aangenomen (bij een inflatiecorrectie tijdens de contractperiode is het gebruik van een CPI- of HICP-index gebruikelijk).

Bij de verdere analyse zijn waarschijnlijk EZK, PBL, RVO en mogelijk externe deskundigen betrokken.

Tot slot geven we nog een aantal meer algemene overwegen en aanbevelingen mee:

- **Om een mogelijke afname van de investeringen te voorkomen, is het van belang na te gaan hoe comfortabel ontwikkelaars en investeerders zijn met de verschillende ontwerp-elementen van de tweezijdige CfD.** Elementen kunnen na verloop van tijd worden aangepast, bijvoorbeeld op basis van nieuwe inzichten en geobserveerd marktgedrag, zoals momenteel ook gebeurt voor SDE++. We raden aan om de ontwerpopties die in dit rapport worden gepresenteerd en andere ontwerpelementen met de sector te bespreken, zodat ontwikkelaars en financiers bekend raken met de details en de implicaties voor hun projecten begrijpen.
- **Ook dient te worden overwogen of kleinere producenten in een tweezijdige CfD moeten worden opgenomen.** Het is onwaarschijnlijk dat kleinere producenten in dezelfde mate reageren op andere prijsprikkels. Dit aspect is in deze analyse buiten beschouwing gelaten. Andere landen hebben echter drempels voor de minimale omvang van installaties, die hoger zijn dan in de SDE++ (het VK vereist bijvoorbeeld een omvang van >5 MW en Ierland >0,5 MW).
- **Doordat locatiespecifieke signalen ontbreken in marktprijzen (meerdere prijszones) of netwerktarieven vindt de geografische spreiding van nieuwe hernieuwbare elektriciteits-opwek mogelijk niet op de meest efficiënte manier plaats vanuit systeemperspectief.** De toezichthouder (ACM) kan overwegen of een aanpassing van de nettarieven locatiespecifieke signalen kan geven, zodat nieuwe hernieuwbare energiebronnen voorrang krijgen in gebieden waar de transmissie- en distributienetten de nieuwe capaciteit beter aankunnen.

We hebben geen onoplosbare problemen voor tweezijdige CfD's vastgesteld. De conclusie van ons vorige onderzoek blijft staan: tweezijdige CfD's lijken het best te passen bij de Nederlandse doelen en context.

Table of Contents

1 Background

1.1 Reason for this research

In September 2023, Trinomics published a research on *Policy options to upscale solar PV and onshore wind beyond 2025*.[9] We concluded that a 2-way CfD fits best with the Dutch context. This conclusion was based on (1) an analysis on developments and challenges around solar PV and onshore wind projects, (2) identified policy objectives, (3) an assessment of a wide range of policy options against identified criteria, and lastly (4) a more detailed assessment on four policy instruments.

To further advance with 2-way CfDs, numerous design choices are relevant. In our previous study, we listed various preliminary design choices, which are deemed relevant when designing 2-way CfDs.

1.2 Research objectives & scope

The objective of this research is to explore design options for a 2-way CfD for solar PV and onshore wind. These design options are identified based on qualitative research, such as interviews with experts and stakeholders, as well as a literature review. The key research question is: What design elements are relevant for smart 2-way CfD designs, and what is recommended? EZK specifically asked us to assess to what extent different design elements can limit market distortions, allow to cover potential profit gaps, align with the development of a PPA market, and align with the transition towards an electricity system without support policies. The results should support the Ministry of Economic Affairs and Climate Policy (EZK) in making well informed decisions on the design of a 2-way CfD for solar PV and onshore wind, if such instrument were to be implemented. The scope is more narrow and more technical than the initial research. While we cover the most relevant design choices for this stage of policy making, we do not cover all elements, as shown in Box 1-1.

Box 1-1: Noncomprehensive list of elements out of scope

1. Maximum budget or volumes.
2. Administration and funding of the scheme.
3. Methodology for calculating administratively set maximum bid prices.
4. Analysis of different options for auction type, format and auction rules.
5. Penalties and guarantees.

1.3 How to read this report

The remainder of this report is structured as follows:

- **Chapter 2 discusses some fundamental design choices for CfDs**
- **Chapter 3 analyses other relevant design choices affecting performance**
- **Chapter 4 compares two design options**

Given the scope of this research, the main body of this report is fairly technical. This is particularly the case for Chapter 2 and 3. Chapter 4 and the management summary (through the Dutch translation) should be more accessible. In addition, a glossary can be found in Box 1-2.

[9] Trinomics (2023). Policy options to upscale solar PV and onshore wind beyond 2025.

Box 1-2: Glossary - List of key definitions used in this research. A Dutch translation can be found in Annex II

Roles:	
Consumer	The entity that uses energy, including small households and large industrial energy users.
Generator	The entity that owns the plant and receives support.
Investor	The entity that supplies equity or a loan for a project.
Offtaker	Buyer of energy (specifically for PPAs).
Project developer	The entity that develops a project, applies for the support, and makes the final investment decision (often also the equity provider).
Supplier	The entity that sells energy to consumers; sometimes also called retailer.
Financial terms:	
Balancing market	An institutional arrangement that allow system operators to deal with the balancing of electricity demand and supply
Capture price	The electricity price that a project achieves according to its technology, which is dependent on which hours it can sell on the market.
Clawback	The amount paid to the ‘buyer’, in this case the government, when the reference price is above the strike price.
Conventional CfD	In this report, conventional CfDs are two-sided, usually the strike price is fixed, the underlying is the hourly day-ahead spot price, and the volumes are “as produced” in every hour. The payments are also called premiums, and can be positive or negative for the generator.
Curtailment	Reduction in the amount of electricity generated to maintain the balance between supply and demand, and to solve local congestion (see redispatch).
Day-ahead market	An auction where electricity for every hour the following day is traded. The auction closes at 12 for delivery the next day, at which points buy and sell positions of all participants are known.
Excess profits	Profits higher than required by the entity for a positive business case. This is different from windfall profits, as windfall profits refer to large, unexpected profits resulting from unexpected external circumstances.
Hedging	strategy that tries to limit risks in financial assets. It uses financial instruments or market strategies to offset the risk of adverse price movements.
Intra-day market	A market which opens as soon as the day ahead market is closed. Participants trade continuously, 24 hours a day, with delivery on the same day. As soon as a buy- and sell-order match, the trade is executed. Electricity can be traded up to 5 minutes before delivery and through hourly, half-hourly or quarter-hourly contracts.
Merchant/market risk	The risks associated with movements in the price of electricity that an operator has to deal with
Price cannibalisation	Phenomenon where variable renewables depress wholesale power prices at times of high output – thus in effect cannibalising their own success on the power market
Redispatch	A request issued by the transmission system operator to power plants to adjust the real power they input in order to avoid or eliminate congestion.
Reference period	The period over which a reference price is calculated (e.g., a weekly average).
Reference price	The specific defined market-price referred to in a support scheme, to be matched with the strike price to see if the government must pay out (or will receive money back in case of a 2-way CfD). Also known as ‘*correctiebedrag*’ in the SDE++.
Settlement terms	How and how often it is agreed between parties to pay out and/or payback.
Spot price	The current market price of an asset such a stock or commodity. It is used to differentiate from, for example, average market price over a certain period of the time.
Strike price	A fixed and pre-arranged price between parties in a CfD contract (often after receiving bids from project developers in a tender-offer or after negotiation). Also known as ‘*indieningsbedrag*’ and closely related to ‘*basisbedrag*’ in the SDE++.
Underlying	The asset whose price is used to set the CfD; for the purpose of this research, this is always the energy price. See reference price for more details.

1.4 Introduction to contracts for differences (CfDs)

Contracts for differences (CfDs) are *financial contracts* that specify payments from a *buyer* to (from) a *seller* if the price of an *underlying* is below (above) the agreed-upon *strike price*. In one-sided contracts for differences (1-way CfDs), payments flow in one direction: offtakers (buyers) receive payments from the seller if the market price is below the underlying In two-sided contracts for differences (2-way CfDs), payments can flow in two directions: offtakers receive payments from the seller if the market price is below the underlying, and buyers must back money to sellers if market prices increase above the underlying. Contracts for differences (CfDs) are not new. They have existed for years on financial markets, for instance as hedging product.

In the context of electricity, 2-way CfDs refer to financial contracts between generators and the government, in which generators *receive* payments from the government in periods of low electricity prices and *pay* in periods of high prices. Payments from the government to the generator are also called payouts. Payments of the generator to the government are also referred to as clawback. The underlying of a CfD on the electricity market is generally a proxy of the market price (usually the hourly day-ahead price). A 2-way CfD (as per this definition) is not a subsidy, nor a tax. Instead, it is a financial contract between two parties for hedging purposes, like any other contract. For this reason, some implementations sees a (private) intermediary, rather than the government, as the contractual counterparty.

The direct reason of the sudden attention for 2-way CfDs for electricity generation was Europe's energy crisis in 2022 and the EU's electricity market design reform. Amongst others, the extremely high energy prices for consumers were a reason for policy makers to re-think the EU's electricity market design. 2-way CfDs have had a prominent role in these discussions, mostly because they could avoid high profits of subsided renewable energy projects. There are more reasons to consider 2-way CfDs for electricity generation. Just like 1-way CfDs, they lower the exposure to price risks for investors, thereby resulting in lower financing costs, and lower overall costs. Also, they *can* cover potential profit gaps ('*onrendabele top*'), depending on the strike price (like 1-way CfDs). As such, 2-way CfDs be used to efficiently incentivise investments in renewable energy, taking into account deployment targets.

2 Fundamental design elements: calculating the premium

In this chapter, we discuss some design elements which concern the calculation of the premium that are *essential* for the effective functioning of a 2-way CfD. The calculation of the premium covers issues such as the strike price and the reference price/ period/ volumes. All of these can have substantial impacts on location and dispatch choices. Less fundamental elements are presented in Chapter 3.

2.1 The conventional 2-way CfD and its drawbacks

Defining conventional 2-way CfDs

To discuss some of the issues around 2-way CfDs, and potential mechanisms to minimise negative consequences, we define a so-called conventional 2-way CfD, which is a contract the pays the offtaker (generator) when the market price is below the strike price, and where the generator must pay back the counterpart (the government) when the market price is above the strike price. We use the word *conventional* to refer to a design which is very close to the financial product that it derives from, and because this is how the early examples of 2-way CfDs have been put in practice as a government support instrument, for example in the UK. A conventional 2-way CfD does *not* refer to the SDE++. In a conventional 2-way CfD, the strike price is fixed, the underlying is the hourly day-ahead spot price, and the volumes are “as produced” in each hour.[10] These characteristics are discussed in this section.

Figure 2-1 (next page) illustrates how the payments vary over time in a conventional 2-way CfD, depending on the strike and reference market price. Generators are supported when prices are low, but they also do not benefit when prices are higher than the strike price (as they must pay back this revenue to the government). In this sense, generators are not exposed to the risk of market price fluctuations (merchant risk) and their revenue remains relatively constant (only fluctuating based on volumes generated).

2-way CfDs should be seen as a combination of different elements, rather than a standard instrument. While we refer to a conventional CfD, in practice CfDs have evolved into many different designs, and new rules and options are still being added to the list. Some key design elements are listed in Table 2-1.

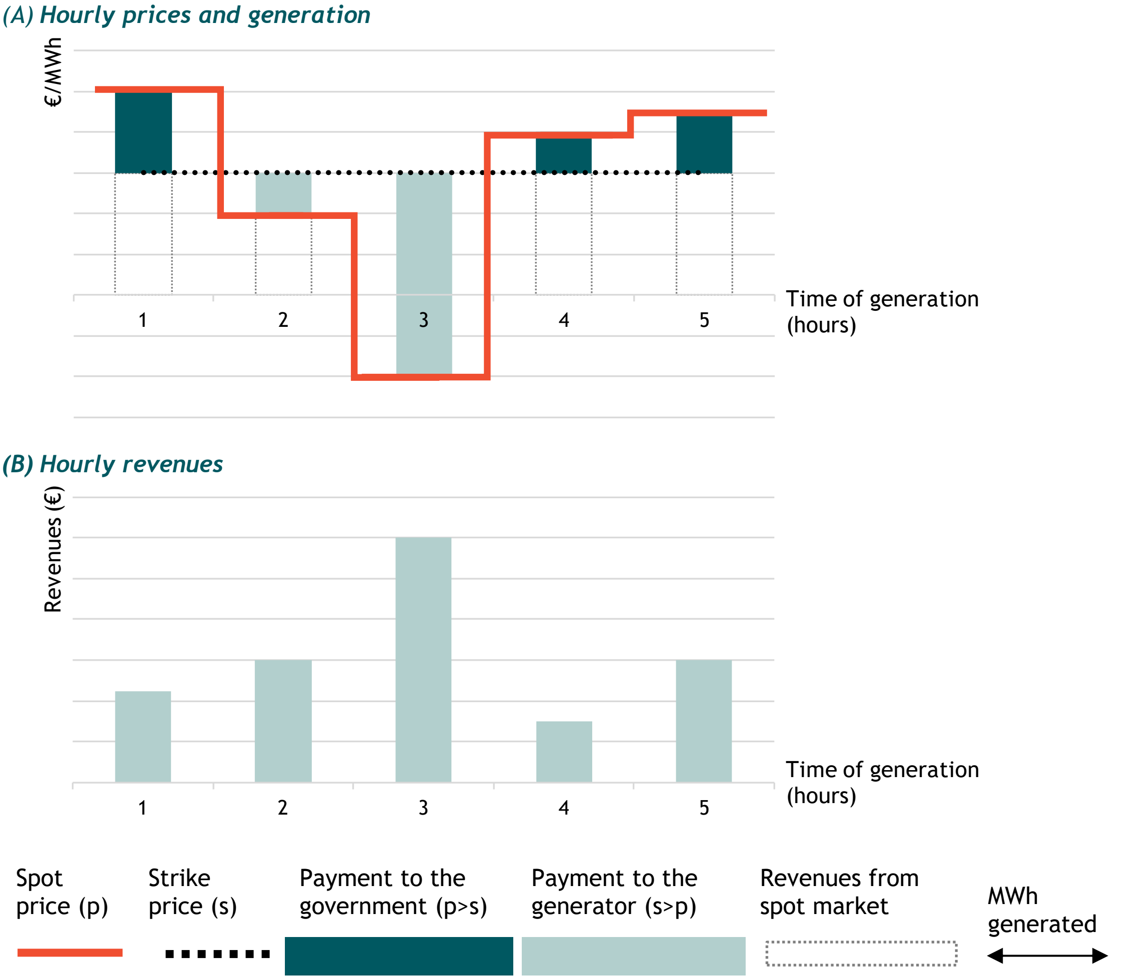
Table 2-1 Overview of key design elements

	Design element	Example options
Contract	Contracting	Auctions, negotiated or administrative procedures
	Duration	Volume-based, time-based
	Exit options	Possible (or not) ahead of end of contract
	Payment settlement	Netted, two ways
Reference price	Reference market	Spot market
	Reference period	Annual, monthly, hourly
	Referencing method	Flat average, technology-based, volumed-weighted
	Referencing timing	Ex-post, ex-ante
Strike price	Price adjustments	Inflation adjustment, technology factors
Reference volume		As produced vs estimated/reference
Safeguarding bidding distortions		Dynamic clawback, no payout at negative prices

Based on Kitzing (2024) Introduction to CfD Design.

[10] European Parliament (2023). The design of the European electricity market - Current proposals and ways ahead.

Figure 2-1 Conventional (2-way) CfD payments



Based on figure from: Schlecht, I., Maurer, C. & Hirth, L. (2024). Financial contracts for differences: The problems with conventional CfDs in electricity markets and how forward contracts can help solve them.

Drawbacks of conventional 2-way CfDs

Two of the most relevant aspects for an efficient energy system are the questions: *when* to generate and *where* to generate. An efficient system is in the public interest, as it leads to the lowest costs for consumers. Traditionally, price signals are used to decide *when to generate*. Under the EU electricity market model, as is the case in any competitive commodity market, generators would only generate when they can make a profit: when prices are above their marginal costs.[11] In general, all technologies,[12] including wind and solar, have positive marginal costs. However, the marginal cost of wind is rather low (€5-€12 per MWh), and for solar even lower (near zero).[13,14] The energy market clearing rule ensures that generators with higher marginal costs will be called to generate only when market prices are high.

Where to generate has become a more relevant issue recently, as the choice of location of variable renewables depends on geography, rather than access to and capacity of the grid. Generally, as the location has an impact on network costs, this should be addressed by signals provided by network tariffs. However, the Netherlands does not have locational or distance-based network tariffs, nor injection

[11] European Parliament (2023). The design of the European electricity market - Current proposals and ways ahead.
[12] Some specific technologies may have short-term negative marginal costs. This can for instance be the case for nuclear plants. For these plants, the costs of shut down and restart can be significant, which means that a nuclear plant may be ready to "pay" in order to stay on for short periods of time.
[13] International Energy Agency & Nuclear Energy Agency (2020) Projected Costs of Generating Electricity.
[14] Newbery, D. (2022). Designing an incentive-compatible efficient Renewable Electricity Support Scheme.

tariffs. An approach that would addresses both *when and where to generate* is Locational Marginal Pricing. However, this approach was not adopted in the EU and hence cannot be considered.

The calculation of the premium for conventional 2-way CfDs results in distorting effects in the electricity system, affecting both the issues *where* and *when* to generate, as price signals are muted. Because under a conventional 2-way CfD generators are less affected by price signals, they would make decisions based on expected CfD payments. For example, they would continue generating when the market price is below their marginal generation cost, or may stop generating during high prices because that is the most convenient time for scheduled maintenance. In Figure 2-1, the generator's revenues are directly related to hourly output (width of the bars), but completely unrelated to the market price. As the effect of market prices on the producer's dispatch choices becomes muted, generators are incentivised to maximise production, rather than maximising the value of their production, leading to an inefficient outcome at energy system level. Regulators have attempted to address some of the missing incentives (payments are stopped when prices are negative), but some inefficient behaviours remain.

The main inefficiencies at system level of conventional 2-way CfDs can be categorised as follows: [15]

- *Produce-and-forget*: Since generators' revenues are dependent on total generation, generators' dispatch choices are not affected by high/low market prices, which means the signal (compared to when there is no CfD scheme), which means the signal to increase/reduce production is not there anymore. Under a market regime, generators stop production if they cannot make a profit. More specifically, they curtail (i.e., reduce or stop completely) production when the price they can get on the market is lower than their marginal cost. However, under a conventional 2-way CfD scheme, generators have an interest in producing even when the spot price is below their marginal cost,[16] as they will still receive the full strike price. This leads to what is also known as the *produce-and-forget* mentality, an increase the likelihood of inefficient dispatch choices and negative prices.[17] This inefficiency is also an existing concern under the current SDE++ scheme.
- *System-unfriendly investments*: As payments in a conventional 2-way CfD are directly linked with production, generators will try to maximise production by opting for determinate technologies and location choices for their installation.[18] For instance, to maximise gains from the 2-way CfD scheme, an investor may decide to locate a wind turbine in a very windy location which already has a large concentration of wind turbines. The cumulative effect, with renewables covering an increasing share of generation, is to have high generation peaks followed by troughs, which increase overall system costs. This is not ideal for the system in terms of energy costs (leading to high volatility) and in terms of transmission and distribution management, leading to congestion and potential grid instability.
- *Curtailing production during periods of high prices*: a conventional 2-way CfD can even incentivise generators to curtail when prices are high. This can occur when the reference (market) price is greater than the strike price, but the *actual* market price is lower than the reference price. This could happen, for instance, because the reference price is an average market price, or because of price differences between the reference market and the market where generators choose to sell all or part of their production (day ahead vs. intra-day). This means that, if the

[15] Schlecht, I., Maurer, C. & Hirth, L. (2023). Financial Contracts for Differences.
[16] While the operational cost of solar and wind power are low, they are not zero, and some of these costs are directly related to production. For example, a wind turbine may need servicing every certain amount of hours of operation. Variable costs of production correlated to production are the marginal cost of generation.
[17] Negative prices are primarily a product of renewable support schemes and not a outcome of the market. European Parliament (2023). The design of the European electricity market - Current proposals and ways ahead.
[18] "*... renewable energy investors are incentivised to locate their power plants in regions with lower project costs (e.g. land costs), and more favourable weather conditions (to maximize their power output), without reference to the location of demand or system costs.*" Savelli, I., Hardy, J., Hepburn, C. & Morstyn, T. (2022). Putting wind and solar in their place: internalising congestion and other system-wide costs with enhanced contracts for difference in Great Britain.

producer generates during that hour, market revenue would be less than what it would have to pay back to the government. Therefore, the generator is incentivised not to generate even though price and electricity demand are high. This issue can exacerbate price fluctuations, where the curtailment from renewable producers can drive prices up for consumers (up until the market price is above the spot price). This phenomenon is explored in detail in chapter 2.2 and box 2-2.

- *Inefficient retrofitting and repowering*: Similar to the investment problem, 2-way CfDs can impact choices made during the asset's lifetime, because the contractual terms are tied to a specific asset. For example, a plant may be dismissed ahead of its end of life so that a new plant with a new CfD contract can be installed; or, old, inefficient technologies may be kept operational instead of replacing with newer technologies, as the contract is linked to the older asset. From a circular economy perspective, the latter is not considered a drawback by the Dutch government.
- *Inefficient maintenance scheduling*: generators without a CfD are incentivised to perform maintenance and planned shutdowns during low demand periods (for example, during the summer or non-peak hours), as this is when market revenues will be lower. However, linked to the produce-and-forget problem, the guaranteed payments during low demand periods no longer triggers generators to schedule maintenance based on price signals.

The location of a generator can have a significant impact on overall system costs, but traditional CfDs do not provide any locational signal. For example, if a wind generator decides to locate its plant in a windy and sparsely populated areas, the cost of transporting the electricity where is needed (e.g., new transmission lines) has to be borne by all consumer, and potentially result in higher total costs than if the plan was located closer to where consumption happens. However, if developers are responsible for connection cost and injection tariffs, they may be still exposed to locational signals made via network charges. This is however less the case if:

- Generators do not have to pay connection costs (as in the case of Germany);
- Network charges are not cost reflective. For example, the methodology to calculate injection charges may not provide locational signals (e.g., a flat fee across the country) or only shallow[19] connection costs methodology are applied. This is the case in the Netherlands, which is a single price zone and where locational signals are not provided via network charges for generators.

While there are several options to modify the conventional CfD design to address inefficiencies, each has its own pros and cons. Departing from the conventional design means introducing newer issues as the ones above are solved or mitigated. In the sections below, we explain the relevance of the methodology for calculating the premium, the spot (reference) price and volume for the problems identified above, as well as the potential available solutions and trade-offs that should be considered.

2.2 Reference price & period

The CfD premium is calculated based on the *reference price*, which is in conventional CfDs the day-ahead spot price. A key element of the reference price is the *reference period*, which is the period of time over which the reference price is calculated. There are various options for the reference period:

- **Hourly**, where the reference price is the actual hourly price emerging from the day ahead market, for each hour of the day;
- **Daily**, where an (weighted/unweighted) average of prices over the day is used;
- **Monthly**, where an (weighted/unweighted) average of prices over the month is used; and
- **Yearly**, where an (weighted/unweighted) average of prices over the year is used.

[19] Shallow and deep connection tariffs are used to describe tariffs that includes only the cost of the assets directly provided versus the cost of the assts plus other network reinforcement costs.

Independently from the time interval, the reference price can also be technology specific, can be set ex-ante or ex-post, and the average over different periods can return a single value or an hourly value.

An hourly reference price generally removes price uncertainty for generators to the largest extent, although it can lead to inefficient market behaviour. An hourly reference price[20] eliminates price signals to generators, reducing a generator's interest to adopt any market strategy, thus leading to inefficient behaviour from an electricity system perspective. An alternative could be to use real-time prices, but this would bring additional issues: *risk-averse generators may sell all production into the system imbalance market (where the real-time prices are set) rather than revealing and sell their available generation already at day-ahead stage. However, large amount of energy sold very close to production time would make the market more volatile and may compromise operational system security.*[21]

Using an average of prices over a length of time (daily single average/monthly/yearly), can incentivise generators to be more reactive to price signals. This is done for example in Germany and Denmark, as well as in the SDE++. While generators are more exposed to price fluctuations, the price which the CfD payments are based on remain fixed over that period of time. This means that the generator will be incentivised to optimise dispatch and maintenance, as they try to capture the higher prices within the reference period. On the other hand, risk-adverse generators may attempt to sell in the same market as the reference price, which in principle does not pose any significant issue. Even with longer period of times (i.e., daily/monthly), there are potential distortions, as these still cannot to properly account for seasonality, and the different value that power would have during the year. This distortion does not occur with an annual reference period, but analysis has shown that with monthly averages the majority of inefficiencies are already removed (for example, Prof. Dr. Kitzing's monthly technology-specific volume-weighted average offers advantages compared to an annual flat average reference price)[22].

Other elements of the methodology to set the reference price may further minimise electricity market bidding distortions, namely:

- *Setting the price ex-post* (as in the case of the current SDE++): in a conventional CfD, the reference price is set ex-ante (i.e., before generation takes place). Usually, the reference price is set by the day-ahead price, and is known to the generator before generation takes place. Generators will use this information to decide whether to generate, and will not generate if the intra-day market price minus the reference price is lower than the strike price. However, the reference price can be set ex-post, and therefore not known to the generator at the moment of generating, which means engaging in strategic behaviours is less likely. However, towards the end of the reference period, generators will be able to estimate the reference price with more and more precision, and therefore adjust their bidding behaviours, again introducing some distortions in the market. While setting the price ex-post may reduce these distortive behaviours overall, it also introduces an element of risks (generators lose out if they fail to sell at or above the reference price) that will be priced into bids.
- *Reference price averaging*: the way the reference price is calculated by averaging the spot prices over a certain period can also be adjusted to bring more optimal outcomes, such as using technology-based, volume-weighted averages. This alternative is described below in Box 2-1.

Additional adjustments to the scheme to reduce distortive market behaviour are shown in Section 3.1.

[20] This is the case for the UK, see for example: UK Government (2023). FiT contract for difference standard terms and conditions, page 105.
[21] European Parliament (2023). The design of the European electricity market - Current proposals and ways ahead.
[22] Kitzing, L. (2023). Are contracts-for-differences here to stay?

Box 2-1 Reference price averaging method

When using a reference period longer than an hour, there is also the choice of how the prices will be averaged over the period. In a conventional 2-ways CfD design, the reference price is usually settled hourly (which is, generators always achieve the strike price in every hour, if they sell in the same market as the reference price). With this option, generators have no price risk, and are incentivised to maximise production. Another frequently used option is to have a flat, unweighted average over a certain reference period (e.g., annual flat (base) average). Under this option, generators are incentivised to beat the market, i.e., to try and capture higher prices compared to the market's average; However, generators may incur in liquidity risks in case of large price swings and are exposed to higher price risks (renewable generators usually produce more in low price hours and less in high price hours), For this reason, they are likely to bid for a higher strike price.

Prof. Dr. Kitzing[23] offers an alternative using a *monthly technology-based, volume-weighted* average, where the reference price is based on a technology's production volume (e.g. *'the achievable average market price per technology group over a certain period'*).[24] With this option, the payouts vary month to month based on the ratio between own production and the production of the technology group, but overall revenues are stable and broadly similar to revenues achievable with the first option (no average). However, generators are incentivised to "beat the siblings", i.e. do better than other generators in the same technology group. Generators have much more control over this aspect compared to the annual flat base, which is based on market dynamics generators have no control of. For example, they can opt for different designs of the same technology that allows them to achieve higher rates for their generation.

However, when extending the length of the reference period, there are situations when distortions to generation choices may become more severe (see *curtailing production during periods of high prices*, above). Since generators are able to forecast their CfD payments based on the reference price, they can adjust their bidding behaviour accordingly.[25] This can lead to distortions in the bids on the day-ahead market. Schlecht et al. (2023) provide the following example: *If generators know they will have to pay €30/MWh (if the reference price is €30 above the strike price), they will no longer produce at spot prices below that threshold.*[26] *Likewise, if generators know they will get a CfD payment of €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 marginal costs by less than €30/MWh, because the CfD payment would compensate operating losses.* Setting the reference price afterwards mitigates the risk of strategic behaviours to a large extent (specifically, to the first part of the averaging year), but does not eliminate them completely. This is because, even when the price is set afterwards, generators would be able to estimate the reference price with increasing precision as the end of the averaging period ends. For example, if the price averaging period runs from January to January, by the end of September the reference price will be 75% defined, and generators may rely on month-ahead market prices to further refine the estimate. An analysis of the intraday market price for the Netherlands in 2023 reveals that, against an annual average price of €96/MWh, intraday prices were higher than €196/MWh in 151 hours (2% of the year) and higher than €146/MWh for 940 hours (11%) of the year. CfD generators with a strike price above €100 would not generate in the first case, while all generators with a strike price higher than €50 would not generate in the second case.[27]

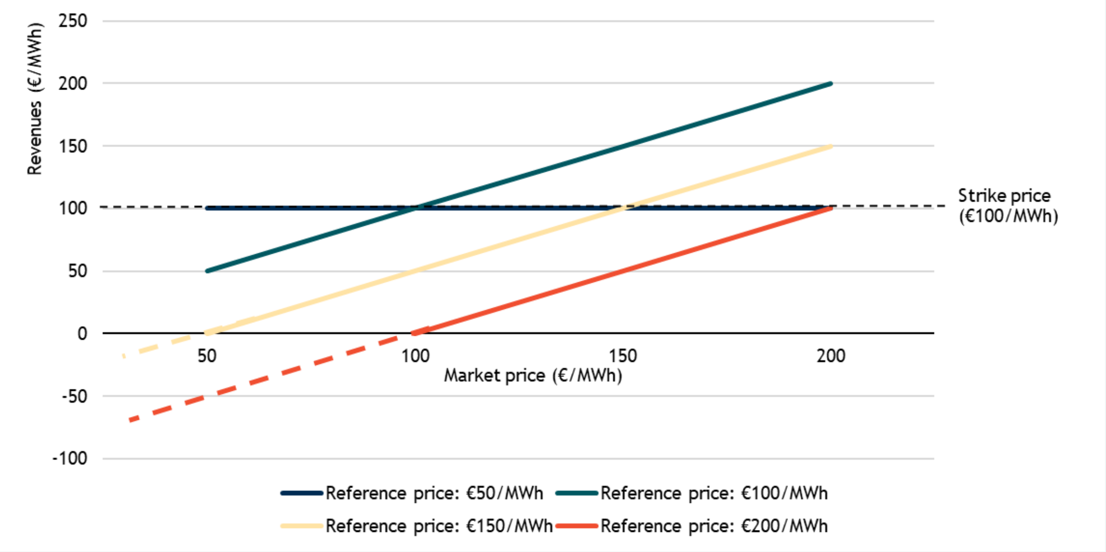
[23] Kitzing, L. (2023). Are contracts-for-differences here to stay?
[24] Kitzing, L.(2023). Introduction to Contracts-for-Difference.
[25] Schlecht, I. et al. (2023). Financial Contracts for Differences.
[26] With longer reference periods, the chance that the reference price is higher than the difference between the strike price and the spot price increases. This is because a significant difference between the reference price and the market price (necessary to trigger this issue) is more likely to occur over one year than between the day-ahead and the intraday market.
[27] These hours of high prices are more likely to happen in the morning and early evening. This would have some significant counterproductive effect; for example, it may discourage the generation from east-facing and west-facing PVs, as they are those more likely to generate in those hours.

Box 2-2 Visualising the disincentive to dispatch

The incentive not to generate that may arise in specific market situations can be visualised by plotting the net revenues of a generator with a strike price of €100/MWh when 4 different levels of the reference price are set:

- The blue line represents the revenues in case the reference price (€50/MWh) is below the strike price (reference price < strike price). In this case, the generator will always earn €100/MWh, independently from the market price it sells at. For market prices below €100/MWh, it will receive a top up, and will pay back when prices are above €100/MWh.
- The green line represents the case when strike price and reference price (€100/MWh) are the same (reference price = strike price). The generator will earn less when market price is below the reference price, and more when the market price is above the reference price. Overall, the generator is always incentivised to generate.
- The yellow and red line show instead that, when the reference price is above the strike price (€150 and €200/MWh, respectively), and when the market price minus the reference price is below the strike price (reference price < strike price & market price – reference price < strike price), generators prefer not to generate, despite the fact that that market prices are substantially higher than zero. In the case of the red line, negative revenues start already with a market price of €100/MWh.

This example illustrates that there are cases in which a CfD can result in a disincentive to generate in market situations where a generator would opt to produce electricity under normal (market) circumstances.



Deciding which reference period is ideal is a balancing act. There is a main trade-off between optimising dispatch choices and reducing the risk that generators adopt bidding strategies which distort electricity markets. Table 2-2 shows the (dis)advantages and of different reference periods:

- With a shorter reference period, dispatch and maintenance choices will be less optimal. This is because generators have less opportunities to 'beat' the reference price. However, with a shorter reference period, generators are more limited in their ability to predict the exact value of the CfD payment. Hence, shorter reference periods provide less room to impact bidding behaviour on electricity markets, and, for example, limit inefficient self-curtailment decisions to the intra-day market.
- With a longer reference period, generators will try to optimise the production and maintenance schedule within the reference period because the payments depends on average market prices, rather than the spot prices of the day-ahead market. However, a longer reference period means that the generator is more able to act on the basis of the reference price, and based dispatch choices on the expected CfD payments.[28] Hence, longer reference periods may provide more room to affect bidding behaviour on electricity markets (i.e. *bidding distortions on the day-*

[28] If the market price in a certain day is below the difference between the strike and reference price, generators may choose not to produce. See section 2.1, *Curtailing production during periods of high prices*.

ahead market), as the variation of the day-ahead market price against an annual reference price may be higher than the variation between the day-ahead price and the intra-day price.[29]

Table 2-2 Advantages and disadvantages of different reference periods

Reference period	Advantages	Disadvantages	Examples[30]
Hourly	• Generators have more certainty on revenues • No distortions in day-ahead bidding	• Produce-and-forget: generators have no interest in maximising system value	UK, Ireland[31], Spain, Italy, Poland[32]
Daily	• Generators' decisions are influenced by intra-day price fluctuations (e.g. produce more at peak hours)	• Incentives to dispatch/curtail during certain days of the week/seasons are muted (e.g. continue to maximise production on the weekends, when there is lower demand)	Poland
Monthly	• Generators' decisions are influenced by price fluctuations throughout the month	• Seasonal incentives are muted (e.g. continued maximising production in summer months) • Distortions in day-ahead bidding	France, Belgium, Greece, Hungary, Romania
Yearly	• Generators' decisions are influenced by price fluctuations throughout the year, particularly seasonal differences	• Long-term price trends can be muted • Distortions in day-ahead bidding	Denmark, Netherlands (SDE++)

2.3 Reference volumes

Conventional 2-way CfD premiums are calculated on the *actual* volume produced, this can result in behaviours which are inefficient from a whole-system perspective. Another key component of the premium calculation which affects dispatch decisions is the production volume. Conventional 2-way CfDs use the actual volume produced over a certain settlement period;[33] this can match the period over which the reference price is calculated, but can also differ. For example, in UK CfDs, the volume is measured over hourly intervals, but the reference price is calculated hourly over a 24 hour interval (day-ahead spot price); in the SDE++, the settlement period is also each hour, but the reference price is calculated over an entire year. Generators aim to maximise volumes, adopting behaviours which are inefficient from a whole-system perspective, and that, if adopted by a large share of total generation, may have significant impacts on the market.

An emerging concept, currently being investigated by experts and academics, is to decouple CfD payments from the actual production.[34] There are different options on how a non-production based CfD could be put in practice. We have identified the following relevant options:

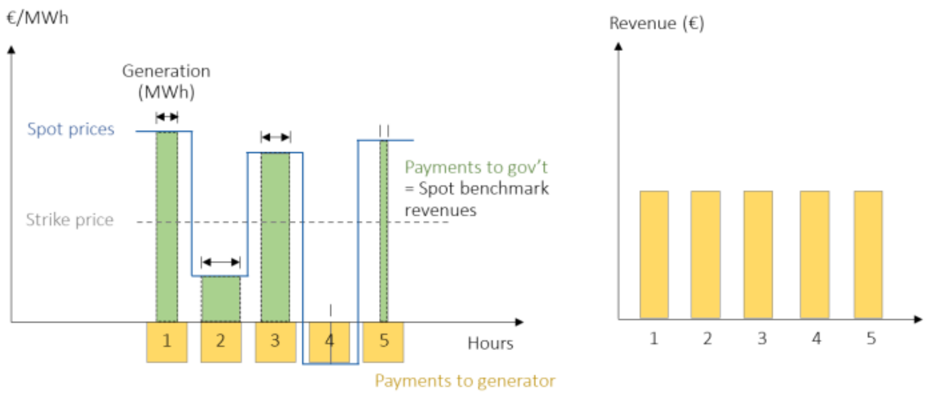
- Newbery (2023) presents a proposal for a new CfD referred to as a ***yardstick CfD***, which incentivises efficient generation and location choices by using forecasted generation instead of actual production.[35] The forecasted generation (M) can be expressed by the formula $M = \theta_{rh}K$, where θ_{rh} is the forecasted capacity factor in hour h at location r and K is the capacity. By forecasting generation based on capacity, location and time, the yardstick CfD encourages generators to efficiently locate the plant and dispatch/curtail production in line with market

[29] Schlecht, I. et al. (2023). Financial Contracts for Differences.
[30] Morawiecka, M. & Scott, D. (n.d.). Balancing act. Two-sided contracts for difference for a speedy, cost-efficient and equitable energy transition.
[31] The Day-ahead hourly price is applied only to technologies with variable output. Irish Government (2023). Renewable Electricity Support Scheme (RESS) Renewable Electricity Support Scheme (RESS)
[32] Poland adopts different approaches depending on the technology
[33] Settlement period is the length of the interval over which output volumes are measured. For example, MWh per hour or MWh per year.
[34] Schlecht, I. et al. (2023). Financial Contracts for Differences.
[35] Newbery, D. (2022). Designing an incentive-compatible efficient Renewable Electricity Support Scheme.

and network signals, while at the same time allowing for predictable and relatively stable revenues. Further, Newbery proposes additional elements to reduce locational distortions, including: using number of full operating hours instead of time for contract length; an annual limit on full operating hours; and new network access and curtailment rules.

- Newbery's proposal is also similar to the proposal for a **capability-based CfD**[36], where the payment is based on the volumes that *could* be produced by the installation, based on technical characteristics and local weather conditions. This approach is already implemented by some TSOs in balancing products.[37] With this design, the CfD is still coupled with the asset itself, meaning that it could still hinder the optimisation of (re)investment time horizons.[38] Further, this method heavily relies on the modelling of production potential, which can be difficult to establish objectively.
- Schlecht et al. (2023) propose a scheme called ***financial CfDs***,[39] which is not asset-dependent.[40] An important element of this scheme is the use of a reference generator instead of the actual generator, to determine benchmark volumes. For wind and solar, there are several methods proposed to determine the volumes produced by the reference generator, namely using a mathematical model based on weather data; a sample of actual wind/solar farms; or using aggregated national/regional wind/solar generation. Figure 2-2 illustrates how this scheme works: payments to the generator (in yellow) are fixed and independent of production or price; they are based on the strike price (determined via an auction) and remain constant throughout the contract (potentially inflation indexed). On the other hand, the generator must pay to the government benchmark profits ([day ahead spot price] x hourly output of a *reference generator*) (in green). In this case, the generator's behaviour will not be related to the payments from the government, but rather the expected generation based on the reference generator. In this sense, their revenue should remain fairly constant as they try to outperform the reference generator (increase production during high prices, curtail production during low prices). However, if the generator consistently performs worse than the reference generator, this will reduce revenues for the generator. Risk-adverse generators may try to compensate for this risk by bidding for a higher strike price.

Figure 2-2 Illustration of a financial CfD



Source: Schlecht, I. et al. (2023). [Financial Contracts for Differences](#).

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[36] ENTSO-E Response to European Commission "Public consultation: Revision of the EU's Electricity Market Design"
[37] Forward electricity markets - Emissions-EUETS.com
[38] Schlecht, I. et al. (2023). Financial Contracts for Differences..
[39] Financial CfDs described in this research or not the same as tradeable CfDs in our previous research, to which we also referred as 'financial CfD'.
[40] Schlecht, I. et al. (2023). Financial Contracts for Differences.

The table below provides an overview of advantages and disadvantages of the different ways to decouple CfDs from actual production to allow for less market distortions.

Table 2-3 Advantages and disadvantages of various options to decouple CfD payments from actual production

Options to decouple CfD payments from production	Reference volume	Advantages	Disadvantages
Yardstick CfD / Capability-based CfD	Based on site-specific (potential) production forecasts	• Removes dispatch inefficiencies • Incentivises system-friendly location choices	• Lack of optimisation of (re)investment time horizons • Risk of manipulation of forecasted production data/modelling
Financial CfD	Based on benchmark production (of reference generator(s))	• Removes dispatch inefficiencies • Completely asset-independent (minimal impact to investment decisions)	• Increased risk in case of badly performing generator (worse than the reference generator)

The advantage of a non-production based CfDs is that, by removing the incentive to only maximise quantity, generators will aim to maximise total system value in their investment and dispatch choices, and the chances to engage in strategic bidding are reduced. By removing the need to maximise quantities, a non-production based CfD solves the issues identified for conventional CfDs to a large extent:

- *Produce and forget*: while generation is not a requisite to obtaining the support payment, generators must be able to earn sufficient revenues from the market, in particular in case of high reference prices (as they would have to pay back government). In order to earn these revenues, they would aim to maximise the value that they can extract from the market, which means maximising for volumes *and prices* at the same time - also bearing in mid their marginal generation cost. The need of generators to consider the latter would reduce the distortion introduced by conventional CfDs on bidding behaviours, bringing CfD generators to bid at their true costs. This would also mean that technologies with lower marginal costs can take their appropriate place in the merit-order effect.[41]
- *System-friendly investments*: in a conventional CfD, generators will consider expected zero price hours, but will not be concerned about period of low prices (price cannibalisation). This is because their revenues will not change, whether they produce at period of high prices or low prices. In a non-production based approach, generators will aim to invest in a plant that can generate when prices are, on average, higher for that same technology. This would support designs such as east- or west-facing PVs, and wind turbines design that maximise operating hours rather than output.
- *Production curtailment during periods of high prices*: the incentive to stop generating to avoid paying back more than what can be earned is completely removed. On the opposite, as high market prices would affect the reference price, generators will be more incentivised to produce during high-price hours (with system-friendly investment and optimal dispatch choices, as discussed in the previous points).

[41] The merit-order effect is the mechanism used to rank offers in the electricity market. For each hour, the offers from generators are ranked from the cheapest to the most expensive, and their production offer is cumulated. Once the demanded amount of energy is reached, the market price is set by the price offered by the last generator whose bid was accepted. CfD generators would bid at zero price (as the CfD payment would ensure they still get their strike price) and would push technologies cheaper to run further down the ranking, potentially pushing them out of the list of accepted offers.

- *Inefficient maintenance scheduling:* as all market incentives remains intact, generators will aim to minimise the loss revenues due to down time for maintenance. To do so, they will schedule downtime for when market price is low.

However, a non-production based CfD will expose generators to more market risk, and will not reduce the inefficiencies in retrofitting and repowering (unless new mechanisms to deal specifically with these are introduced). As CfD revenues and production are unlinked, the generator risks not to be able to earn sufficient revenues from the market to complement CfD revenues (or to pay back in case of high reference prices). However, this risk replaces volume risks that is present in a conventional CfD (the risk that an installation does not produce as much as expected), so it is not expected to be a significant issue for generators, unless in periods of sustained high reference prices and consistent underperformance of the plant compared to the reference plant. In terms of inefficient retrofitting (e.g., shutting down plant ahead of time so that a new CfD can be placed in the same site), a non-production based CfD would not solve the issue. This can be achieved (as discussed in the next chapter) by solutions such as having contracts length set by generated quantities, rather than years.

Institutional actors are also warming up to the concept of reference volumes CfDs:

- The ITRE committee recently signalled its position in regards to CfDs, stating that options such as having "*CfD payments be decoupled from the amount of electricity generated by the plant, so that only the specific specification proposals that take such an approach (i.e. capacity, yardstick or financial CfD)"*[42] should be considered.
- ACER and CEER stated that they "*would have less concerns with smarter design of CfDs, which could entail … the settlement based on predefined volume or reference volume (e.g. reference wind turbine)*".[43]

None of these options to decouple CfD payments from the actual production has been implemented or tested; the actual performance and implications of these schemes have not been assessed yet.[44] However, it is possible to identify some proposed or limited applications of a deemed output approach in specific circumstances:

- The tender principles for the **Princess Elisabeth Zone**,[45] published by Belgian government earlier this year, propose a CfD with *variable price premium is applied monthly to each MWh that would have been possible, in particular the Available Active Power , including among others the curtailment requested by the system operator, as well as the negative Day-Ahead-Market and imbalance prices, after correction for non-operational hours due to, for example, O&M reasons*.[46] However, the details of the methodology have not yet been published.
- The third iteration of the **Irish CfD scheme** (RESS 3)[47] includes the Unrealised Available Energy Compensation which compensates, at the Strike Price, for availability not converted to generation for reasons of either curtailment or oversupply. The compensation however does not cover for availability that is constrained, as is considered that transmission constraints remain an important locational signal. The Available Energy is calculated based on physical measurements and a methodology yet to be defined by the Regulatory Authority.[48]
- The Pennsylvania-New Jersey-Maryland **(PJM) Interconnection**, a regional transmission organisation in the US, uses modelled theoretical output in some particular contracts.

[42] European Parliament (2023). The design of the European electricity market - Current proposals and ways ahead.
[43] ACER-CEER (2023). Reaction to the European Commission's public consultation on electricity market design.
[44] European Parliament (2023). The design of the European electricity market - Current proposals and ways ahead.
[45] Belgian Government (n.d.). Belgian offshore wind energy.
[46] Belgian Government (2023). Summary of tender principles for the Princess Elisabeth Zone.
[47] Irish Government (2023). Renewable Electricity Support Scheme (RESS).
[48] Ireland Department of the Environment, Climate and Communications (2022). RESS 3 Auction Design and Implementation Project.

The yardstick approach includes a locational element, to drive investments towards the less congested parts of the network. However, such approach may be less effective under the current zonal configuration in the Netherlands. The Netherlands is currently a single bidding zone, but there are proposals to split it into three bidding zones, mostly because of large electricity flows from the north to the south of The Netherlands.[49] If these proposals go ahead, having locational signals in the Netherlands (alongside the model of outlined for the Yardstick CfD) would be easier. To some extent, locational factors are already included in the SDE++, for example the locational adjustments to the base amount based on wind speed. However, these are not based on network congestion and generation scarcity, but only a reflection of different load factors achievable by wind turbines in different locations.[50]

Given the specific configuration and challenges of the Dutch power network, and the novelty of the non-production based CfD approach, a simpler methodology for the calculation of the reference volume may have lower risks than using more sophisticated calculation approach. This excludes the more detailed methodology suggested by Newbery (yardstick approach). At the same time, grouping all generators into a single volume category may discourage some applications. Therefore, a middle-ground approach (simplified capability-based CfD) may be preferable, which in practice may mean more than one reference volume per technology, but not at the level of individual plants; the formula to calculate the reference volume may include some elements to keep into account the location of the plant (similar to the wind factors in SDE++), and historic performance of plants using the same technology. See chapter 4 for an example of how the reference volumes can be estimated.

[49] TenneT (2022). TSOs propose methodology, assumptions and alternative configurations for the upcoming European bidding zone review.
[50] RVO (2023). SDE++2023 - Stimulation of Sustainable Energy Production and Climate Transition.

3 Other relevant design choices affecting performance

In addition to the essential design elements, there are numerous design choices that would affect the performance of the 2-way CfD. In this chapter, we elaborate on some of these elements: measures to prevent or lower the impact of sub-optimal dispatch choices, options to reduce the level of government support, remaining risks, inflation corrections, and a strike price range.

3.1 Measures to prevent or lower the impact of sub-optimal dispatch choices

As described in Chapter 2, in a conventional 2-way CfD (with volumes as-produced), various measures can be considered to incentivise efficient behaviours, where additional adjustments can alleviate some inefficiencies. Namely, mechanisms to address 'generate & forget' during low/negative prices and curtailment during high prices are considered in this section.

Firstly, many issues related to inefficient behaviour can be tackled by using a reference volume approach (described in Section 2.3). With reference volumes, generators are fully exposed to market signals and are hence incentivised to maximise generation value, with fewer system distortions. Under a conventional 2-way CfD, generators have no interest in curtailing their output until the market price is negative and higher (in absolute terms) than the strike price (e.g. a generator with a strike price of 50 €/MWh would generate until the reference price reaches -50 €/MWh). In this section, we describe five options to prevent distortive market behaviour in conventional 2-way CfDs.

Although these measures provide some resolution to inefficient system behaviour, they cannot be considered a full solution. Firstly, these mechanisms only target behaviour at certain price points, therefore only addressing market distortions partially. Further, they can also bring their own problems, namely increasing the risk for generators (in the case of no support for negative prices) and the risk for the government (limiting payments to the government). Therefore, these should not be considered as *solutions*, but rather *additional* mechanisms to further incentivised system-friendly behaviour.

1: Suspend payments when prices are below zero

It is common practice to suspend payments when prices are negative, as already established in the Dutch SDE++ scheme and almost all CfD schemes[51], as well as required by State Aid rules. This measure is intended to discourage generators from producing when prices are below zero. However, this partially removes the risk hedging element of the CfD scheme, by making generators more exposed to the uncertain frequency of negative prices.[52] Generators will react to the rule by increasing the bid price, so to compensate the lower load factor achievable because of this rule.

Currently, generators (>200 kW) contracted with SDE++ receive no top up payment when prices are negative.[53] However, the hours when the payment is suspended are added at the end of contract period: for each hour where the payment is suspended, the payment period is extended by an additional hour. This is called banking. This provision ensures a minimum level of compensation for generators, although some of these supported hours will happen later in time and only up to the banking limit. This does not

[51] This is not the case for some schemes, such as Ireland's RESS, which does compensate generators when prices are below zero

[52] Schlecht, I. et al. (2023). Financial Contracts for Differences.

[53] Since the SDE++ round of 2023, generators with a capacity of at least 200 kW do not receive SDE++ when prices are negative. However, this is only the case for new projects. Projects that received SDE+(+) support in earlier years still receive support at times of negative prices. Projects that participated in the SDE++ rounds between 2020-2022, do not receive support if prices are negative for at least six hours in a row. This also counts for SDE+ projects from rounds after 2015. SDE+ projects from previous years get the full compensation, even during negative prices. Renewable electricity projects receive SDE+(+) support for 15 years. For more information, click here and here.

ensure that the return expected will be realised (the revenues will arrive at the end of the contract, so more discounted than those received during the contract), but it allows a level of fairness. If the number of below-zero energy price increase (as it is expected to happen in the future, with more simultaneous generation being added), this clause could weight more heavily on investment choices and pricing strategies. There is a chance that, especially for new solar projects, this occurrence may happen regularly in the future, which means that, in practical terms, CfD contracts will be extended proportionally to the number of below zero price hours, but only up to 1 year.

Overall, a CfD should consider:

- **Distinguishing between curtailment for oversupply at system level and curtailment because of local congestion.** There is an argument to compensate generators in the first case, but not in the second case, as this would send a locational signal to new installations (avoid congested areas of the network). However, in order not to negatively affect installations already existing in an area, curtailment should be applied as “last-in first to be curtailed”, as suggested by Newbery.[54] Currently, when the DSO has to curtail generation in an area, it would do so via equi-proportional reduction, based on connection capacity (for example, the maximum injection capacity of all generators in a certain area will be reduced by 10%). With a “last-in first to be curtailed” approach, the first to be curtailed will be the generator that has come online last, then the one before it and so on.
- **Curtailment rules will play an increasingly important role in the business case of new wind and especially solar PV installations.** The way in which curtailment is compensated would significantly affect bidding strategies, although in theory the overall results should be the same: an operator that is able to perfectly predict the amount of curtailed hours would offer a strike price that would provide the same revenue whether negative-price hours are compensated or not. This can be presented as:

  $$h_f * SP_1 = (h_f - h_c) * SP_2$$

  Where:
  - SP_x = Strike Price
  - h_f = full operating hours
  - h_c = hours curtailed

  To balance the equation, the strike price offered in case curtailed hours are not compensated (SP_2) would be higher than the strike price offered when curtailed hours are compensated (SP_1).

  However, as bidders cannot predict with confidence h_c, the rational choice for a risk-adverse investor is to over-estimate the number of curtailed hours, which may result in strike prices higher than necessary.

2: Gradually reduce payments when prices are between marginal costs and zero

In addition to suspending payments during below zero prices, it is possible to introduce a mechanism to reduce the incentive to generate below marginal cost (but above zero), for example by phasing-out payments as market prices near zero. In this case, there would be a bottom range where compensation would (progressively) decline as the market price moves closer to zero. This is similar to having a price floor, in the sense that it can reduce the maximum budget reservation for the government and address to some extent the produce-and-forget dilemma. However, it differs in the sense that it gradually unmutes price signals as the market price decreases to zero in order to provide further incentives for

[54] Newbery suggest this approach to be set in connection contracts, rather than the CfD mechanism: Designing an incentive-compatible efficient Renewable Electricity Support Scheme. The SDE++ already sets a connection limit, for example for the max connection capacity of solar set at 50% of nameplate capacity of the installation.

generators to inject power when the market needs it most (for example, incentives to install storage or alternative technologies). Although this is an interesting concept, this type of phasing-out price floor is less explored in literature. Further, marginal costs for solar and wind are rather low, meaning the bottom range could be very small, and result in the measure adding unnecessary complexity to scheme and being ineffective. However, as the energy transition moves forward, the frequency of periods with low prices (above zero, below marginal costs) is expected to increase, which could make this concept more relevant.

The increase in likelihood of reduced revenues because of the mechanism described above may support the business case for e.g. storage located with solar and wind farms, so that revenue-stacking and arbitrage may become a feasible opportunity. Revenue stacking entails procuring additional equipment (such as batteries) and operate the plant so to sell additional services other than power generation. These services (commonly referred as ancillary services[55]) yield a much higher revenue for unit of power used, but also require equipment to be held in stand-by for the majority of time.

3: Limited max output capacity

The 2023 SDE++ rules impose a restriction for solar PV projects concerning additional contracted feed-in capacity. This measure mitigates the impact of generate and forget. The rule specifies that any additional connection request (including the request for a new connection) may be granted only for 50%[56] of the peak power output of the installation (with the exception of solar tracking projects).[57] The rule is aimed at preventing peak solar generation at system level on sunny afternoons, when ensuring system stability is more complex and expensive. A direct consequence of the rule is that these plants will have to forego a part of their revenues (much less than 50%),[58] but this provides significant consumer benefits as it reduces electricity system costs (compared to a situation with a 100% connection). This option also incentivises the installation of on-site storage, as well as the installation of east- or west-facing solar arrays. Further, it may encourage co-location with energy-using facilities (self-consumption) which will again have a positive impact on total system costs.

Theory suggests that the response from bidders would be to increase the strike price to ensure that the loss of revenues during peak generation is compensated by increased revenues during off-peak hours.

4: Defining contracts in volume rather than years

Contracts based on years reinforce the incentive to maximise volumes (rather than value), and bring investors to select high-load factor technologies with optimal exposure to wind or sun. Conventional 2-way CfDs are specified in years, i.e., the strike price is valid for the entire duration of the contract, for any amount of output generated by the facility defined in the contract. While this provides some certainty in terms of the length of government support and incentivise innovation that increase load factor, it also creates some inefficiencies. These inefficiencies end-up over-rewarding projects that deliver quantities above expectation, which is likely to happen when other plants of the same technology are already generating, and penalising those that opt for alternative technologies and siting that may optimise for market value rather than output. In the SDE++, banking (partially) addresses the missed revenues due to suspended payment during periods of negative prices.

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[55] These include services such as frequency response, Balancing reserves, Reactive power, Redispatch, and Black start facility.

[56] Compensation for the 50% loss in revenue is paid by less full-load hours and a higher base amount. Where full-load hours (in hours/year) are the maximum number of production hours during which subsidy is received, and base amount (in EUR/product) is the maximum amount of subsidy possible for solar PV.

[57] RVO (2023). SDE++2023 - Stimulation of Sustainable Energy Production and Climate Transition.

[58] In practice, the amount of loss revenues depends on the amount of generating hours over the 50% capacity threshold, which is rather limited in the Netherlands, to the point that developers themselves rarely request a connection for the full 100% capacity. Overall, it is estimated that the 50% cap may reduce generation by 10%-15%. Revenue reduction is likely to be even lower, as electricity prices tend to be relatively in peak production periods. See for instance: WattisDuurzaam (2022). Alleen nog subsidie voor zonneparken met 50% piekbegrenzing.

A potential solution to the problems related to contracts based on years is to specify contract life in terms of output, so MWh/MW capacity. This approach, adopted in the past in predecessors of the SDE++ and recommended by Newbery in connection with yardstick CfDs,[59] has a number of advantages. For example, it would not over-reward projects that generate excessive volumes, while allowing projects with lower load factors to stay in the contract for longer. This may also be a better match for the technical aspects of the project, where for example a wind turbine with a lower load factor may last longer than the equivalent turbine with a higher load factor. The Belgian government included a maximum amount per year that can be paid by the government as support, and are considering whether to introduce a maximum number of full-load hours to which the 2-sided CfD applies.[60] A limit to the annual amount of generation per MW installed is also included in the current SDE++.[61]

However, a volume-based contract length may generate a new risk: inefficient and outdated technologies with lower load factors may end up winning contracts not because they maximise value, but because they minimise costs. To discuss this risk, we can consider the case of a generator that can choose between a new technology with a 50% load factor and an old one with a 40% load factor. In a fixed-term contract its interest would be to maximise generation during the contractual term. In this case, there is a clear incentive to produce as much as possible during the years the contract is active: if the cost increase of the new technology is less than the revenue generated by the additional 10% over the length of the contract, it would opt for the new technology. In a MWh-defined contract, the higher the load factor, the earlier the contract will end, and the revenue received via CfD will be the same whether it installs the new or the old technology. The additional cost of the new technology will have to be recovered by more market revenues after the contract has ended, but these are far off in time and uncertain. To avoid this risk, other market incentives must remain available, as well as entry requirements that specify minimum technical requirements, for example nameplate load factor.

Specifying a contract in MWh rather than years means annual budget allocation may have to be more flexible, and it may result on the financial commitment to the programme having to be extended beyond 15 years. However, specifying contract duration in MWh (rather than years) could be a fairer solution, as support will be more equal across generators.

A MWh contract should count towards the hourly balance the number of hours curtailed because of local congestion, as this would send an important locational signal to new entrants. As for other options, it is important to consider how to deal with negative price periods. In the SDE++ (where contracts have a maximum duration expressed both in years and maximum volume per year), banking is allowed for under delivery, including because of curtailment due to negative prices, which reduces the incentive to optimally site and dispatch to reduce the risk of zero prices. By default, if generators stop injecting during negative price hours, they would be automatically compensated (the hours do not count towards the total). This means there will be no incentives for generators to install solutions that aim to minimise generation during zero price hours. Newbery suggests a solution for this problem:[62] '*making constraining-down for congestion management first-in last out, rather than as in most schemes, equi-proportional reductions. The defence of this discriminatory scheme is that at each auction, bidders can estimate the current level of congestion, and may base their bids on assuming that this rate will continue.*'

[59] Newbery, D. (2022). Designing an incentive-compatible efficient Renewable Electricity Support Scheme.
[60] Belgian Government (2023). Summary of tender principles for the Princess Elisabeth Zone.
[61] RVO (2022). Brochure SDE++ 2022.
[62] Newbery, D. (2022). Designing an incentive-compatible efficient Renewable Electricity Support Scheme.

5: Limiting clawback

One way to reduce the incentive to curtail generation during peak hours is to limit the payback to the spot price (or to just under the spot price, so to cover their variable operational costs). With this clause, generators would never have to pay back more than they can earn on the market, maintaining the incentive to generate. For example, if the reference price is €150 per MWh, the strike price is €50 per MWh and the spot price is €80 per MWh, generators may self-curtail, as for each MWh they produce they would lose €20. However, if the payback is limited to, for example, the spot price minus €10, generators would earn €10 per MWh (€80 from the market minus €70 payback) and still have an incentive to generate. Another option is to limit the payback to a certain percentage of the payback amount, which would allow to share the benefits of high market prices with generators.

An alternative, also with limited implementation in European countries to date, is a partial clawback above the fixed strike price. With this option, when the reference price is above the strike price, the payback due is not the full amount. For example, the generator would have to payback only 90% of the difference between the reference price and the strike price. A similar solution can be found in the Danish CfD scheme, where total payments both to and from the generators are capped at a maximum amount per year. This means that generators can earn additional revenues only in case of sustained periods of high prices during the year.

Overall, these options are rather similar, but with a partial clawback, generators start earning additional revenues earlier:

a. *Retained revenue when payback > spot price (fixed):* a fixed payment in absolute terms (e.g., €5 or €15/MWh) could be provided to generators when the amount they must pay back is higher than the market price. This amount would stay the same, independently of the market price.
b. *Retained revenue when payback > spot price (as a percentage of payback amount):* when the amount to be retained is set in percentage terms, it would increase as the market price increases, acting as a form of revenue sharing. Under this option, payments would start only after the payback amount is higher than the market price. For example, these could be set so that generators retain 10% of the total payback amount,
c. *Partial clawback when spot price > strike price (as a percentage of payback amount):* this option is also a form of revenue sharing, but instead of allowing generators to retain revenues only when there is no incentive to generate (when payback > spot price), they would retain revenues as soon as the spot price is above the strike price. While the market conditions for payments for option *b* are rather rare, with this option they would be very frequent. However, retained revenues per MWh when payback > spot price would be identical to option *b*, for the same percentage of revenue sharing.

See Table 3-1 for an example for a generator when the spot price is €50/MWh. As previously discussed, the possibility to earn additional revenues may encourage more aggressive bids, but only to a certain point, given the limit to financing terms (finance providers will require developers to ensure that revenues are sufficient to cover the loan repayment).

Table 3-1 Comparison of clawback options (€/MWh), with a spot price of €50/MWh

		a. Retained revenue when payback > spot price (fixed)			b. Retained revenue when payback > spot price (as % of payback amount)			c. Partial clawback when market price > spot price (as % of payback amount)		
		Extra revenue retained under different implementation options of a, b, c (in €/MWh, % of payback amount)								
		5	10	15	30%	20%	10%	30%	20%	10%
		Amount to be paid back by the generator (€/MWh)								
Initial clawback (€/MWh)	**10**	0*	0	0	0*	0	0	3***	2	1
	20	0	0	0	0	0	0	6	4	2
	30	0	0	0	0	0	0	9	6	3
	40	0	0	0	0	0	0	12	8	4
	50	0	0	0	0	0	0	15	10	5
	60	5	10	15	18**	12	6	18	12	6
	70	5	10	15	21	14	7	21	14	7
	80	5	10	15	24	16	8	24	16	8
	90	5	10	15	27	18	9	27	18	9
	100	5	10	15	30	20	10	30	20	10

**In options a and b, retained revenue start when the initial clawback is above the spot price €50/MWh. Hence, payments are zero when the initial clawback <50. ** In option b, the retained revenue equals a percentage of the initial clawback (e.g. 30% of 60=18). ***In option c, revenue retainment starts right away (also if clawback < spot price (50) and equal a percentage of the initial clawback (e.g. 30% of 10=3).*

3.2 Options to reduce the level of government support

An accepted principle behind government support schemes for renewables, is that government support for renewable technologies should phase out as the technology advances, with the ultimate goal of renewable technologies competing freely in the energy market. This is also an explicit aim of EZK. To some extent, CfD schemes (auctions more specifically), can already exploit the cost reduction of new technologies in the form of lower strike prices in subsequent auctions. A recent analysis from Baringa[63] shows that, in several European countries, the CfD prices awarded over time have significantly decreased, with reductions varying between 3% and 47%. However, there are also reasons why government support may not decrease over time:

- While the *strike* price may be lower, the *capture* price may also be lower. As more of the same technology comes online, *cannibalisation* increases, and this leads to higher government support. This has already been observed. In the SDE++ for instance, PBL estimates that PV plants captured only 67% of the average market price in 2021.[64]
- While the strike price has decreased, the contract duration has not, and it is likely that new CfDs for solar and wind will keep spanning between 15 years.
- Current decarbonisation targets, together with electrification trends, will require continuation of the pace of deployment. This is likely to result in even lower capture price for traditional designs, and therefore the need for higher government support.

Therefore, a new 2-way CfD scheme may consider practical options to reduce government involvement, while at the same time ensuring protection from market risk that allows the financing of new generation. two options are considered below.

1: Carve outs

In order to limit the overall payment, and allow to support more generation capacity for the same budget envelope, it is possible to consider an option where only part of the peak capacity is contracted. We identified two options:

1. **Awarding CfDs only for a part of the installed capacity (mandatory carve out):** Similar to the limitation to peak output for solar PV, a limit could be imposed on wind generators. However,

[63] Baringa (2023). The Future of European CfDs.
[64] PBL (2023). Eindadvies SDE++, page 35.

it will not make sense imposing a physical capacity limit, as wind generation is less synchronised than solar energy (wind speeds differ across areas at a certain time). Given the current provision for solar, this should be applied to wind only. The limit could be applied, for example, by awarding a CfD only for 80%[65] of the nameplate capacity of the installation. This could then be implemented in two ways:

a. CfD payments (to and from the generator) are due only on 80% of the power injected;
b. Based on the 80% capacity, a maximum annual subsidy amount is calculated (80% of the typical production for that type of plants over one year); anything produced above that amount will have to be sold on the market.

The latter option may have some advantages in addressing the generate-and-forget incentives (as it brings in the concept of the notional generation plant), but may introduce some strategic effects based on when the 80% threshold is reached that are difficult to foresee.

2. **Allowing generators to sell part of their generation via PPAs after the CfD has been awarded, and to re-enter the CfD scheme if the PPA contract ends and they cannot find new buyers.** While the option to sell part of their generation via PPAs is attractive to many generators, as normally they are able to obtain better prices, the challenges and risks are considered too high. A key challenge is to find a buyer ready to purchase power for a significant number of years, and the major risk is that if the contracts ends ahead of time, the generator may not be able to find another buyer. The Belgian Offshore CfD scheme solves this problem by allowing a temporary carve outs (at regulated price). Generators can stop the CfD on a part of their generation and sell power to private buyers via PPAs, even for short periods of time. Once the PPA contract ends, generators must try to find a new buyer, but in case they cannot, they are allowed to return to the CfD regime (only once). Generators can combine different PPA contracts of different maturity, so to provide more competitive sale offer.

2: Allowing generators to enter the scheme late/leave the scheme early

The Spanish CfD scheme includes a clause where projects must sell a defined amount of electricity to the market under the CfD, but once a threshold is reached, they can opt selling their electricity with full merchant risk (either on the market or via PPA). This means that generators can exit the contract ahead of the 12 years of the contract duration, if they have managed to reach the expected amount of generation.[66] Another example is the Irish RESS scheme, which allows generators to exit the CfD at any point in time, as long as they give a 12 months' notice.[67] Out of the 22 projects that have won a contract and have begun generation, five projects (representing 55% of installed capacity) have exited the scheme and now operate under commercial terms (PPAs or sale on the market).

While the current implementation in the Spanish context allows exit only after a certain generation target has been reached, in theory different options are possible. Table 3-2 shows the pros and cons. Either option can be tied up (or be completely independent) from a generation target being met.

Unless budget constraints are significant, allowing flexibility in contracts' length does not appears to be a good option. Allowing an early exit has the advantage to potentially reduce the time commitment of government support (freeing up early budgets for new auctions), but risks penalising the consumers as generators will trigger the clause only when they have an expectation that market prices will be above the strike price. Allowing generators to trigger an early exit clause does not seem to generate benefits for the consumer.

[65] This percentage has been chosen randomly, for the sake of the example.
[66] Balkan Green Energy News (2021). Spain gets Europe's lowest wind energy price with CfD auction model.
[67] https://electroroute.com/ress-1-terms-conditions/

Table 3-2 Advantages and disadvantages of allowing voluntary late entry/early exit.

	Advantages	Disadvantages
Enter the CfD only after PPA contract has expired	A key issue with PPA is the contract duration: very few buyers are ready to sign a 15-years contract, but shorter contracts pose challenges with the financing of the project. With this option, generators can sell shorter term PPA and still access third-party finance at good terms, as the sale price is guaranteed for the entire financing terms (although the price may vary between the PPA and the CfD).	There is a risk of excess profits in the case of the PPA being negotiated in periods of high energy prices. The identified general drawbacks of PPAs in our previous study also remain relevant (e.g., a PPA may not close potential profit gaps).
Voluntary exit only when a certain amount of total generation has been reached.	Depends on the level of the threshold. This can be set so to allow the recovery of a significant portion of costs, so at a rather high level. At which point, generators will take the option only if they have the expectation of high market prices for the remaining life of the contract.	
Exit only in early part (e.g., first 5 years of the contract)	Generators will have to take a significant risk and forecasts prices over 10 years, which could be a fair deal for the consumer	Unlikely that the option will be taken by any generator. If price expectation for following 10 years are high, investors will opt for investing in new capacity
Exit only at set times (e.g., mid-point in the contract)	Is still a significant gamble for generators, but some may decide to take the risk	Also likely to result in very low take up
Exit only in late part (e.g., last 5 years of the contract)	If prices are high, many generators may opt for an early exit	Generators will trigger this clause only towards the end of the contract and once they are confident they will not lose out. This means the consumers are likely to lose
Exit at any time		Generators are likely to take the option only towards the end of the contract and only in case where price are expected to stay high

3.3 Remaining risks under 2-way CfDs

While 2-way CfDs limit the generator's exposure to merchant risks, various risks remain present, and these may affect the profitability of their project. 2-way CfDs aim to support renewable generation while reducing the risk of overcompensating renewable generators and minimising market distortions. In particular, 2-way CfDs can shield generators from merchant risks, i.e. the risk that the price they are able to obtain in the market is not sufficient to cover their costs (financing, construction and operational). Remaining risks include:

- Some element of **merchant risk** remains even in the presence of CfDs (see sections above)
- **Development risks**, covering the phase of planning and pre-construction.
- **Volume risks**, i.e., risks that the production is below expectations. This can happen because of different underlying factors:
  - Technology risk;
  - Weather risk;
  - Curtailment;
  - Third party risks, e.g., failures in the transmission network.
- **Financing risk.** In project finance, with fixed terms for the entire duration of the financing periods (as it will be the majority of projects expected for SDE++), this risk is limited to the period between the submission of the bid and the final investment decision, when loan terms are formalised between the developer and the financing party. This risk can be mitigated by signing pre-financing agreements.
- **Political/policy risks.** A change in government policy or regulation may negatively affect some or all generators under a CfD contract. An example of political risk is the decision of the German government to close all nuclear power plants; investors in these plants had to face significant loss of their investment. An example of an policy risk is the introduction, in future years, of a high injection tariff for generators, which would increase their costs and reduce profits.

- **Cost-related risks**. This macro-category includes all the cases where costs deviates from expectations. This could be due to many different reasons:
    - Erroneous estimates of the cost drivers, for example concerning technology, operational or planning aspects.
    - External factors that deviate significantly from the norm and unforeseen circumstances, e.g. supply chain disruptions force developers to take more expensive options, lack of financing options due to sudden changes in the markets.
    - Inflation. For solar PV and wind, inflation risk can be broken down in two elements:
        - Implementation phase (from CfD bid submission to the end of the construction period).
        - Generation phase.

    These are discussed in the next section.

It is more effective to allocate risks to the party that is best able to manage them, and if management is not possible, they should be allocated so to ensure an overall fair and efficient outcome. Hence, it is not desirable to remove all risks from generators, even though some of these may end up pushing up the prices. Of the risks listed above, we note that:

- Leaving some merchant risks with developers provides opportunities to retain dispatch incentives, and address issues arising from generate-and-forget mentality.
- Developers are best placed to manage development risks and technology risks. Weather risks are generally of a short-term nature (i.e., while weather variation may affect the output in a given period, these are expected to even out during the lifetime of the contract. This means that weather risks may pose a liquidity risk in some cases, but this can be managed with appropriate reserves or financing repayment flexibilities).
- Political and policy risks are broadly outside the control of developers, but the nature of the scheme gives them contractual rights that a change in policy will have to abide to. Therefore, developers are broadly protected against these by appropriate contractual clauses.
- A CfD protects developers against the combined policy and market risk that future auctions support increasing amount of the same generation sources, depressing the capture price.
- Cost risks could be allocated entirely to developers, or shared with consumers. In particular, inflation risk is generally beyond the control of developers, which means there is an argument to share (or pass entirely) this risk to consumers; a similar argument can be made for exceptional circumstances.[68] However, risks deriving from an erroneous estimate of cost drivers should be left with developers. We elaborate on options for inflations adjustments in section 3.4.

Box 3-1 Guarantees of Origin

The SDE++ premium considers the price of Guarantees of Origin (GOs). Essentially, the risk associated with the variability of GO prices is passed from the generator to the consumer. However, as the price of GOs continues to decrease in the Netherlands, it is worth to question what is the best approach to deal with it under a CfD scheme. There are two options:

a. Maintain the same approach as the SDE++. The top-up payment that generators will receive will be net of GO revenues but if the price is sufficiently low, it is valued at zero.
b. CfD projects may be excluded from receiving GOs. This approach is adopted in some Member States.

Overall, there are advantages and disadvantages in both approaches: a. add complexity to the scheme, while b. creates a disparity of treatment between SDE++ and the 2-way CfD, but may be a better option to support the GO price (as new CfD generators start production, the offer for GOs will increase, further depressing the market - therefore not awarding GOs for new plants would keep the supply tighter). However, the value in pursuing such as objective is not clear, given the decreasing importance that GOs are expected to play.

[68] Contractually, these would be dealt with by reopening clauses, i.e. the contract could specify under which exceptional circumstances the parties agree to renegotiate the strike price.

3.4 Inflation adjustment

When developing a solar PV or wind project, there is a significant delay between the time when a bid into a CfD auction is submitted, and the time when revenues start to come in. This creates a number of risks:

a. Increased construction costs may make the project unprofitable for the strike price awarded (the risk affects the entire project);
b. Increased operational costs reduce the profit margin and diminish the revenues available to service the debt (the risk may materialise only in some years);
c. Due to inflation the reference price is more likely to often surpass the strike price.

Because of a. and b., finance may be more difficult to find, or more expensive (usually only relevant during development phase, but depending on the financing structure may create problems later on).

Given the cost structure of wind and solar PV (high upfront costs, generally financed at fixed terms throughout the duration of the CfD), the most significant problem is a. Recent inflationary trends, combined with supply chain disruptions and pressure on raw materials, made this a very relevant issue for projects currently being developed (see text box on UK). Some existing CfD schemes consider inflation to be a risk to be shared with consumers, and annually adjust the strike price according to a specific methodology, generally linked to inflation (indexation, see Table 3-3)[69].

If a CfD is not inflation-adjusted, bidders have two choices:

- Consider possible inflation when submitting their bid, and increase their offered strike price accordingly; risk adverse generators will tend to align to the worst case (high inflation), rather than to the central forecast.
- Bid aggressively, and then decide to withdraw once the construction costs are known (at the start of the construction period). This may have been one of the reasons behind the significant number of projects called off in SDE++.

The problems created by the lack of inflation indexation are more significant in case of a two-sided CfD compared to the current SDE++ design: inflation increases the likelihood of generators having to pay back, instead of receiving payments. Under the SDE++, generators can retain the additional revenues from the market at times of high inflation (high energy prices are more likely in a period of high inflation). However, under a 2-way CfD, an increase in nominal market prices increases the frequency at which the reference price is above the strike price and thus the frequency at which the generator should pay back, rather than receive payments.

As mentioned in section 4.3, a good approach to this type of contractual issues is that the risk should be allocated to the party that is best able to manage them. Project developers can have some control over inflation (for example, signing long-term supply agreements or options ahead of investment decision), but they have no control on the price of raw materials. Further, generators may be affected throughout the loan period if their investment is made at fixed or variable rate. If at fixed rate, inflation will have a limited effect on their return (high inflation will result in lower strike price, but loan repayments are also fixed), but if the loan repayment is at variable rate, high inflation and low market price means that the strike price may not be sufficient to repay the loan and earn the required profit.

There is no clear best practice when it comes to dealing with inflation in CfDs. As shown in Table 3-4, various countries apply different methods on indexation. **However, we note that:**

[69] However, it is doubtful that current methods for inflation adjustments (usually, CPI related) would have been able to capture the exponential increase in the cost of material recorded in the last few years.

- **No indexation may increase the nominal strike price, but may result in lower overall costs for the consumers over the duration of the contract.** This would be in case of energy prices higher than expected by developers at the moment that they submit their bid in the CfD auction.
- **No indexation leads to higher nominal strike prices:** If developers must bid for a non-indexed strike price, the offer they put forward will have to ensure a certain project return even when inflation goes up, which means a higher strike price. If instead the strike price is inflation-adjusted, developers know that an increase in construction or operational costs because of inflation will results in an adjusted strike price, and therefore they can bid at a lower price.
- **No indexation may also incentivises aggressive bidding of less risk-adverse developers, which in turn may lead to high rates of non-delivery (see for example realisation rates in the SDE++ following high inflation in 2021 and 2022).** An excessive amount of project withdrawing after having won a CfD penalises developers with more viable projects, and increases the risk that the Netherlands may miss its renewable targets.
- **The risk of non-delivery can be mitigated with penalties:** If there is no penalty for withdrawing once a CfD has been awarded, some bidders may bid strategically with the aim of actually delivering the installation only if inflation and construction costs increase less than expected.
- Besides the indexation of the strike price, **inflation must be considered when estimating administratively set maximum bid prices** (see UK AR5 in text box). While in the past technology costs have decreased regularly over time, in the last few years the trend has inversed, mostly driven by issues in the supply chain. Therefore, setting realistic maximum prices, bearing in mind the delivery period, is essential in order to receive viable projects.

Table 3-3 Main options for an inflation adjustment mechanism

Possible solutions	No adjustment. Investors take inflation risk	The strike price is Inflation adjusted up to the first day of generation (implementation period)	The strike price is adjusted annually including during the generation phase
Main advantages and disadvantages	• Low risk for the consumer • Developers may bid higher strike price to protect themselves against high inflation OR developers may decide not to participate in the CfD round and rely on market • High number of low bids may be retracted if inflation above expectations after the award of the contract	• Consumers take in inflation risk up to the construction date, developers take it afterward. • Usually, inflation during construction may be significantly different from CPI rate, so a dedicated index should be considered[70]	• Consumers take inflation risk (if prices increases, the payout to generators will increase in line with inflation) • May generate excess returns in those project financed at fixed rate throughout the financing period

[70] See for example the case of Vattenfall in the UK. Even though the UK scheme offers a strike price indexed to inflation for the entire contract period, the company decided to withdraw when construction costs increased more than 40% compared to the expectations. Twidale, S. (2023). Vattenfall halts project, warns UK offshore wind targets in doubt.

Box 3-2: Inflation adjustment in the UK CfD scheme and the result of AR 5[71]

The 5th allocation round of the UK CfD scheme has recently made the news because no new offshore wind projects entered in the auction. While inflation is one of the key reason for why this has happened, this is related by how maximum bid allowed were calculated, rather than an issue with the adjustment of the strike price over time

One of the key conditions imposed by government for the participation in the auction is the administratively-set maximum bid price, which is the maximum amount that bidders can offer per kWh. This ensures that, in case of undersubscribed auctions, some unnecessarily high bid ended up winning a contract. This strike price is set by an official methodology[72], and it varies by technology and by delivery year.

The maximum price for offshore wind for delivery between 2025 and 2028 was set at £44 per MWh in 2012 prices (around £60 per MWh at 2023 prices[73]), slightly below the threshold set in AR4, which happened in 2021 (the maximum price for offshore wind was set at £46 per MWh for delivery between 2025 and 2027[74]). On the other hand, the max price for solar PV (£47) and onshore wind (£53) has remained the same. The bolder assumption for offshore wind was in part driven by the significant cost savings seen in the past (AR3 in 2018 the administrative maximum was £56).

However, some of the assumptions used by the government to set the maximum price for offshore wind in AR5 where flawed. In particular, the government underestimated the inflation experienced by some of the key materials and inputs required for offshore wind projects (partly related to supply chain crunch, still affected by the post-covid recovery), as well as the effect that interest rate increases were having on financing costs.

For these reasons, potential bidders decided not to participate in the auction, deeming the maximum price too low. In response, in November 2023, the UK government raised the administratively-set maximum price for offshore wind by 66% for offshore wind projects, from £44/MWh to £73/MWh, and by 52% for floating offshore wind projects, from £116/MWh to £176/MWh ahead of Allocation Round 6 (AR6) next year.[75]

Table 3-4 Inflation indexation in CfD schemes in Europe[76]

Country/scheme	Description
The Netherlands, SDE++	No inflation indexation. Projects are expected to factor in inflation throughout the project, from investment decision to completion
Belgium	Yes, annually. The inflation adjustment is limited to 30% of the strike price (30% of the strike price will be inflated according to inflation), related to O&M portion, for 20 years[77]
Denmark	No[78]
France	Yes, technology-specific formula incl. PPI and wages growth
Greece	No
Hungary	Yes, CPI-1%
Ireland	• $Strike\ Price_N = Strike\ Price_{Bid} + I_N\ where\ I_N = 0.70 + (\frac{HICP_N}{HICP_{Bid}} x\ 0.30)$ HICP (*Harmonised Index of Consumer Prices)* for the EU 27 published by Eurostat, or such other replacement index as the Minister may from time to time designate in writing.[79] • For Offshore wind only: Indexation of the strike price, differently before (steel price and HICP) and after construction commencement (HICP only)
Italy	No
Poland	Yes, CPI
Portugal	Yes
Romania	Yes, Eurozone CPI
Spain	No
UK CfDs	Full inflation correction from bid to the end of the contract. Strike price is indexed according to CPI

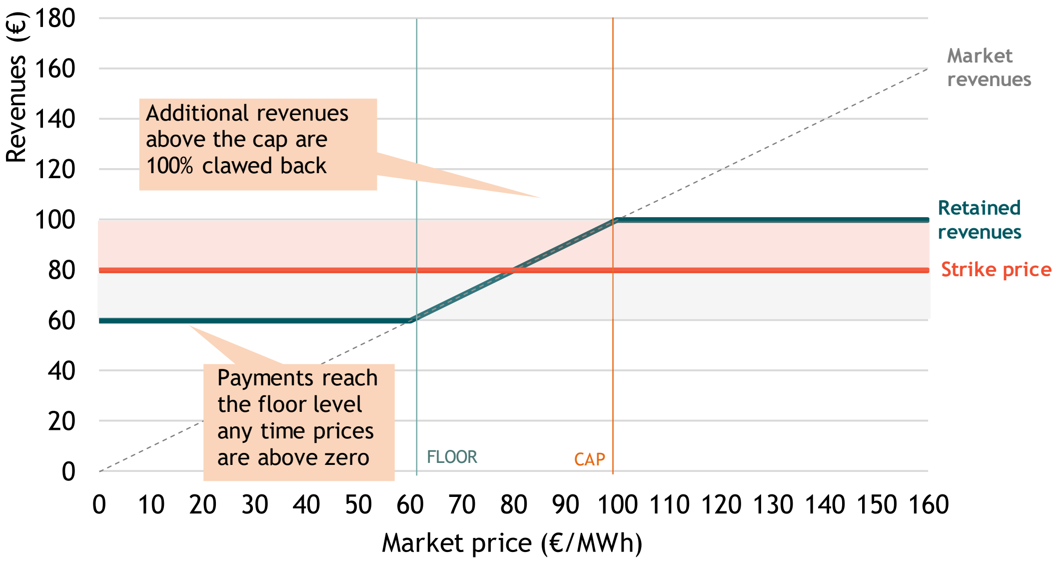
[71] Energy UK (n.d.). Energy UK Analysis: Allocation Round 5.
[72] UK Department for Business, Energy & Industrial Strategy (2022). Contracts for Difference: Methodology used to set Administrative Strike Prices for CfD Allocation Round 5.
[73] Converted using the 1.3736 factor set in the AR6 Core Parameters.
[74] UK Department for Business, Energy & Industrial Strategy (2022). Contracts for Difference: Methodology used to set Administrative Strike Prices for CfD Allocation Round 4.
[75] UK Government (2023). Boost for offshore wind as government raises maximum prices in renewable energy auction.
[76] Morawiecka, M. & Scott, D. (n.d.). Balancing act. Two-sided contracts for difference for a speedy, cost-efficient and equitable energy transition.
[77] Belgian Government (2023). Summary of tender principles for the Princess Elisabeth Zone.
[78] European Commission (2021). State Aid SA.56831 (2021/N) – Denmark - Multi-technology RES tenders 2021-2024.
[79] Irish Government (2023). Renewable Electricity Support Scheme (RESS).

3.5 Strike price: single value & ranges

Instead of having a single strike price, it is possible to set a range around the strike price, so that payments to or from the generators are triggered when different wholesale prices are reached. In a conventional 2-way CfD, payments invert the direction once the market price reaches the strike price. In a CfD with ranges (also known as cap and floor), the generators are fully exposed to market price when this is within a certain cap (maximum level) and floor (minimum level). Any revenues above the cap price must be paid back, but the generator will receive a top up to the floor level when market prices are below the floor (Figure 3-1).

The advantage of using a price range instead of a single strike price is that generators will take on a greater share of market risk. A price range pushes more risk on to the developer by exposing them to prices when market price varies with certain thresholds (the cap and floor), instead of entirely transferring the risk to the state (or consumers). This means that generators will be supported by government only when the market price is too low and put at risk debt repayment, while at the same time ensuring consumers are protected in case of exceptionally high prices (the cap avoids the issue of windfall profits). Rationally, a risk-neutral generator would favour a range if the expected long-term market price is above the equivalent single strike price, and would prefer a single strike price in the opposite case. A cap and floor system is supported by some (but not all) key institutions (see ACER-CEER[80] supporting “*smarter design of CfDs, which could entail […] cap and floor instead of single strike price. The floor price can replace the system of subsidies, whereas the cap price can replace the inframarginal revenue cap to channel excessive revenues back to consumers*”) and is also being recommended by experts (for example, Baringa[81]: “*a cap and floor revenue support mechanism […] puts more risk on supported generators – capping only extreme financial upsides and downsides – but allows generators to use their own information and skills to operate efficiently in wholesale energy markets*”).

Figure 3-1 Illustration of strike price range



However, a strike price range may not be an overall cost-effective solution.

- Assuming that generators are bidding at their true cost, **it is unlikely that the outcome will improve for the consumer, due to the risk aversion of project financed projects**. For example, if it is assumed that a developer bids for 55 EUR/MWh into a traditional CfD, knowing

[80] ACER-CEER (2023). Reaction to the European Commission’s public consultation on electricity market design.
[81] Baringa (2023). The Future of European CfDs.

that this allows it to service its debt and operational costs (50 EUR) and retain a revenue of 5 EUR per MWh for profits. In a CfD with a cap & floor, the revenues of the generator are free to vary around the 55 EUR/MWh, but the generator knows that any revenue that does not allow it to cover its costs (debt servicing and operational costs) puts the entire operation in danger of default. Therefore, the generator cannot bid any lower than 50 EUR per MWh. If, for example, the range is administratively set at +/- 10 EUR MWh, the generator will have to bid at 60 EUR/MWh, with an overall loss of welfare for the consumer. Further, for technologies such as solar PV, price cannibalisation is expected to increase significantly; if the reference price varies hourly, the rational bidding behaviour will be to bid so that the floor allows a recovery of costs and the required profit margin, which means a cap & floor system is likely to lead to higher bid prices, and unlikely to generate benefits for the consumer. With a reference price calculated over longer reference periods, some generators may opt for technology designs that allows to capture more revenues compared to the reference price (and so may accept a floor below their cost), but risk-adverse generators will still aim for a price floor that allows to achieve the needed margin.

- **Bidding strategies for a CfD with range would be more complicated to predict**. In a setting with significant scarcity (i.e., when the demand for contracts is higher than the offer), bidders are more likely to bid near their true cost. If instead they expect low competition, it is more likely they will try to bid near the administrative-set maximum (strategic behaviour).[82] A price range is unlikely to change this behaviour if the ranking is done on a single price (either strike price to which the range is then retroactively applied, or midpoint of the range bid for), but would change if the ranking methodology is more complex.
- **A price range introduces significant complexity in the ranking methodology**:
  - If the range is administratively set, this has to be set ex-post (after bids have been submitted), as setting the range in advance would be equivalent to setting up a cap & floor regime and the price-discovery advantage of the auction will be lost. However, if the range is set ex-post, bidders need to know in advance the methodology that will be used. Practical approaches may include a fixed +/- amount in Euros, or a percentage around the central strike price.
  - If bidders are free to bid for their preferred range, there is no straightforward way to rank projects based on the range. The ranking methodology may assign equal or different weight to the cap and to the floor prices,[83] which may result in significantly different outcomes. There is however evidence that when bidding rules are too complex, actors tend to perform poorly and do not engage in rational behaviours, leading to inefficient bidding behaviours. Another option is to rank bids according to the middle-point of the range, but if this is the case, strategic behaviour may happen, for example with bidders presenting a rather tight range around their strike price, which would have almost equivalent results to a single strike price. On the other hand, this could even be a positive aspect, for example leaving bidders the possibility to choose whether engage in this aspect or not.

[82] Note that provisions for penalties for non-delivery have also a significant impact on bidding strategies
[83] For example, the regulator may set these based on the likelihood of reference prices being above a certain level, but this is an extremely uncertain assessment as it has to cover the entire length of the contract.

4 Comparison of two designs

Based on the analysis in technical chapters above, we combine certain design choices to elaborate on two concrete options which may be considered by the Ministry. These options include:

- **A production-based 2-way CfD** uses the SDE++ and conventional 2-way CfDs as starting point. Still, several changes are proposed, but more fundamental changes are not included;
- **A non-production based 2-way CfD**: An innovative design recommended by (academic) experts.

We chose to elaborate on these two options as the key choice for a 2-way CfD for solar PV and onshore wind in the Netherlands is between production-based and non-production based designs. Both contain combinations of design elements discussed in the previous chapters. In defining the options, we aimed to include only viable design choices. Options that offer no clear benefits have not been considered. When multiple options are suitable, without a clearly preferred option, we mentioned both options (for instance the reference period in the production based 2-way CfD). We allocated the design choices closer to tested schemes to the production based 2-way CfD, while the elements associated with the non-production-based 2-way CfD are more innovative (few or no implementations in the real world). We note that various (electricity market) academics and experts are in favour of reference-volume based approaches, like the non-production based 2-way CfD below. Table 4-1 summarises the characteristics of the two design options.

Table 4-1 Characteristics of two design options

Design element	Production based 2-way CfD	Non-production based 2-way CfD
Strike price	Single strike price (no range)	
Volumes	Volumes as-produced	Reference volumes
Reference period[84]	Monthly/weekly* reference period. Actual reference price set ex-post. Payments to generators based on expected reference price. Final settlement for week/month when final reference price is known	Annual reference period, Actual reference price set ex-post. Payments to generators based on an expected reference price. Final settlement for the year when final reference price is known
Reference price	Monthly/weekly average of the day-ahead market price, for every hour of the day. The price is set ex-post	Annual average of the day-ahead market price, for every hour of the day. The price is estimated in advance, then adjusted ex-post based on actual market prices
Contract duration	15 years contracts, with annual ceiling concerning the generation level	15 years contracts. Voluntary exit allowed when 70% of contracted capacity has been produced
Share of generation	100% generation capacity covered by CfD	70-90% % generation capacity covered by CfD
Carve out	Temporary carve outs allowed (similar to Belgian offshore wind scheme)	
Inflation	No inflation adjustment	Adjustment during construction. Based on CPI (50%) and sector-specific inflation indicator (50%)
Maximum bid	Administratively-set maximum bid	
Corrections	Correction for wind speed according to current factors; 50% derating for solar PV	Optional: correction factor curtailment (full load hours decrease based on curtailment signals)
Minimum available hours	There will be a set of rules to establish when a generator is active, to minimise strategic behaviours	
Negative prices	No payments when prices are negative, or when SO sends curtail orders due to local congestion	Hours of negative prices excluded from the estimated volumes, based on technology-specific production profiles. Options to have multiple profiles per technology based on specific designs (such as in the SDE++) should be considered

** We provide two options when none seems to be clearly preferred*

[84] The discussion on the reference period in chapter 2 describes the trade-offs between longer and shorter periods. The periods recommended in this table for the production-based CfDs are based on implementation in other countries and by expert recommendations (see page 22). On the other hand, for non-production based CfDs, the reference period is less important, as the incentives to dispatch efficiently are already provided by the reference volumes. An annual reference period would be simpler to implement, and is generally used by the academics in their proposals of non-production based CfDs examined in this report.

4.1 Production based 2-way CfD

The main advantage of the production based 2-way CfD scheme is that it allows for a smooth transition from (or even integration in) the SDE++, and minimise the need for additional rules. Such a scheme should be rather simple for investors to understand and be comfortable with. This minimises the risk of a drop in investments.

The choice for the reference period (with volumes as-produced) is a trade-off between incentives for system optimisation (long periods) and preventing electricity market distortions (short periods). In conventional 2-way CfDs, the standard approach to set the reference price (based on the day-ahead spot price) generates suboptimal investment and dispatch choices (produce-and-forget problem) and distorts behaviour in the intraday market. In some circumstances, generators may find it more convenient to stop generating when prices are high because it is cheaper for them not to generate, and buy their output on the spot market to cover their imbalances (curtailing production during periods of high prices, see section 2.1). At the same time, reference periods determine the period in which generators can maximise revenues by dispatching at times of the highest electricity prices within that given reference period. Hence, the longer the reference period, the more room for the generator to optimise dispatch choices. The optimal reference period in a production based 2-way CfD thus depends on the size of the market distortions and negative system incentives in all options. However, to completely eliminate the risk, a rule that deals with this should be introduced: the maximum amount of money that generators may be asked to pay back should be equivalent to the day ahead spot price. With this rule, generators would always be incentivised to generate by providing bids at just above the expected reference price.

All other aspects of the scheme reflect designs currently utilised in other countries. This means that the production based 2-way CfD may still present the following issues, associated with conventional CfDs:

- *System-unfriendly investments*: developers would choose the technologies and setup (siting, orientation) to maximise generation, rather than market value. This could be particularly significant for solar PV: developers will keep installing new solar plants even though the capture price will keep decreasing. This effect will be dampened to some extent by the non-remuneration when prices are below zero (developers are likely to opt for higher strike prices to compensate for the reduced load factor, which would make, for example, wind comparatively more convenient than solar).
- *Dispatch distortions*, in so far as generators will choose to generate when market price is below their marginal cost (as discussed, this is negligible for solar PV and low for wind, which means this is a relatively minor issue for this option).
- *Inefficient retrofitting and repowering and inefficient maintenance scheduling*. As generators will always receive the same price, they have little incentive to schedule maintenance when market prices are low, and may make inefficient retrofitting choices. For example, they may decide to decommission a plant at the end of the contractual period so to access new contract, or may decide to keep running an inefficient turbines as replacing some part of the equipment may not be allowed under the CfD.

4.2 Non-production based 2-way CfD

A non-production based 2-way CfD is a novel approach but appears to offer significant benefits for generators and consumers. It would remove some of the market distortions which affects traditional designs, and simplify the scheme for generators. The revenue generators expect to receive will be broadly known at the moment of bidding, and generators can choose whether to opt for strategies that minimise risks versus strategies that maximise potential for earning revenues.

The main drawbacks of a reference volume approach are the following:

- It is an untested approach, meaning that it may have some drawbacks which are not yet clear.
- It will require to put in place a series of monitoring rules to establish when a plant is operations, and avoid strategic behaviours.

Building on the example provided in the text box below, there are several viable options for choosing the non-production based methodology. A methodology with fewer elements would minimise the scheme complexity, but may result in unintended effects in some circumstances. Adding more elements (for example, more technology categories, zonal adjustment factors, more sophisticated rules to estimate curtailment) would add complexity to the scheme, and may reduce overall cost-effectiveness of the scheme. They may however allow to achieve additional objectives, such as reducing overall system costs or land use, and support new promising technologies. The full methodology to estimate the reference volume will have to be defined by the Ministry, or a dedicated study. Box 4-1 summarises here provide some options for a simple estimate.

Box 4-1: Key elements of methodology to estimate the reference volume (simplified capability-based approach)

The volume of the reference plant will be based on the historical performance of similar plants in the Netherlands. Reference volumes can for instance be calculated on the previous five years, updated annually, and differentiated by technology. The most practical solution would be to follow the same categories as in the SDE++ for solar PV (30 in total) and onshore wind (18 in total). However, it could also be considered to reduce the number of categories significantly.

The methodology can consider below-zero hours and measure the actual load factor, based on market conditions. Essentially, the load factor can consider standard down times for generators and expected negative hours for that technology:

$$R_v = (h - N) * C$$

R_v = Reference volume
h = standard operating hours, including downtime
N = hours of negative prices (during generating hours)
C = capacity of the installation

Calculating the reference volumes in this way will retain the incentive to select technologies less affected by price cannibalisation (lower incidence of *N*, negative market prices). For example, in the Netherlands it is likely to make onshore wind more competitive compared to solar PV (*N* for solar will be higher than *N* for onshore wind).

While generating hours for solar PV are rather straightforward to set, for wind there are two main options:

- Having a **plant-specific load factor**, based on wind measurements at the plant location. The standard operating hours can be determined by a minimum threshold for wind speed.
- Having a **single national indicator** for wind. Wind operating hours can be determined by the number of hours when total wind generation within the Netherlands is above a certain threshold.

The formula may also include an element that considers grid constraints:

$$R_v = \left(H - N - k_j\right) * C$$

K_j = curtailment hours per year at location j

The term k measures the number of hours where the system operator had to intervene to curtail generation from a certain area. This can incentivise generators to select locations / technologies for which curtailment is less likely.

The reference volume should be calculated once and remain the same for the duration of the contract, but the methodology should be reapplied at each round of contracts. Having a contractually agreed reference volume for the duration of the contract will provide greater certainty to investors, reducing their risks and finance cost. Further, exposing generators to volume risks they are unable to control would not produce any benefit, as their investment choices cannot be reconsidered once the plant is in operation. On the other hand, the reference volume should be recalculated for every contract, so to ensure the evolution of the energy system is reflected in the reference volume and also provides an investment signals. For example, if curtailment hours are excluded from the load hours, and curtailment hours for a certain technology increase over time, the new estimate of the reference volume would return a lower value than the previous year. This would increase the bid of generators of that technology in a new auction round, favouring alternative technologies that are less exposed to curtailment.

Annex I – consulted experts & stakeholders

As part of our research, we have consulted various experts through interviews and/or a workshop. We are thankful for their time and contributions.

Organisation
Belgium government - *Federale Overheidsdiensten - Economie*
Energie Nederland
Holland Solar
Nederlandse Vereniging van Duurzame Energie (NVDE)
Ministerie van Economische Zaken en Klimaat
Nederlandse WindEnenergie Associatie (NWEA)
Planbureau voor de Leefomgeving (PBL)
Prof. Dr. David Newberry
Prof. Dr. Lena Kitzing
Prof. Dr. Ingmar Schlecht & Prof. Dr. Lion Hirth
United Kingdom Government – Department for Energy Security & Net Zero

Annex II – Translation of glossary [Nederlands]

Rollen	
Consumer	Consument: De entiteit die energie gebruikt, inclusief kleine huishoudens en grote industriële energieverbruikers.
Generator	Producent: De entiteit die eigenaar is van de installatie en steun ontvangt.
Investor	Investeerder: De entiteit die eigen vermogen of een lening voor een project levert.
Offtaker	Afnemer: Koper van energie (specifiek voor PPA's).
Project developer	Projectontwikkelaar: De entiteit die een project ontwikkelt, de steun aanvraagt en de uiteindelijke investeringsbeslissing neemt (vaak ook de verstrekker van eigen vermogen).
Supplier	Leverancier: De entiteit die energie verkoopt aan consumenten.
Financiële begrippen	
Balancing market	Balanceringsmarkt: Een institutionele regeling waarmee systeembeheerders het balanceren van vraag en aanbod van elektriciteit regelen.
Capture price	Afvangprijs: De elektriciteitsprijs die een project behaalt. Deze is afhankelijk van de technologie en uren dat het project op de markt elektriciteit kan verkopen.
Clawback	Het bedrag dat aan de 'koper', in dit geval de overheid, wordt betaald wanneer de referentieprijs boven de uitoefenprijs ligt.
Conventional CfD	Conventionele CfD's: In dit onderzoek zijn conventionele CfD's tweezijdig, meestal is de referentieprijs vast, de onderliggende waarde is de day-ahead spotprijs per uur en de volumes zijn "zoals geproduceerd" in elk uur. De betalingen worden ook wel premies genoemd en kunnen positief of negatief zijn voor de producent.
Curtailment	Vermindering van de hoeveelheid opgewekte elektriciteit om het evenwicht tussen vraag en aanbod te bewaren.
Day-ahead market	Een veiling waar elektriciteit voor elk uur van de volgende dag wordt verhandeld. De veiling sluit om 12 uur voor levering de volgende dag. Op dat moment zijn de koop- en verkoopposities van alle deelnemers bekend.
Excess profits	Overwinsten: Winsten die hoger zijn dan wat de entiteit nodig heeft voor een positieve business case. Dit verschilt van onverhoopte winsten, aangezien onverhoopte winsten verwijzen naar grote, onverwachte winsten als gevolg van onverwachte externe omstandigheden.
Hedging	Afdekkingsstrategie die risico's in financiële activa probeert te beperken. Hierbij wordt gebruik gemaakt van financiële instrumenten of marktstrategieën om het risico van ongunstige prijsbewegingen te compenseren.
Intra-day market	Een markt die opent zodra de day ahead-markt gesloten is. Deelnemers handelen continu, 24 uur per dag, met levering op dezelfde dag. Zodra een koop- en verkooporder overeenkomen, wordt de transactie uitgevoerd. Elektriciteit kan tot 5 minuten voor levering worden verhandeld via uur-, halfuur- of kwartiercontracten.
Merchant/market risk	Marktrisico: De risico's in verband met schommelingen in de elektriciteitsprijs waarmee een producent/leverancier te maken heeft
Price cannibalisation	Prijskannibalisering: Een fenomeen waarbij variabele hernieuwbare energiebronnen de groothandelsprijzen voor elektriciteit drukken in tijden van hoge productie, waardoor ze in feite hun eigen succes op de elektriciteitsmarkt kannibaliseren en een lagere afvangprijs realiseren dan de gemiddelde afvangprijs van andere technologieën.
Redispatch	Een verzoek van de transmissiesysteembeheerder aan elektriciteitscentrales om het werkelijke vermogen dat ze invoeren aan te passen om congestie te voorkomen of te beperken
Reference period	Referentieperiode: De periode waarover een referentieprijs wordt berekend (bijv. een wekelijks gemiddelde).
Reference price	Referentieprijs: De specifieke gedefinieerde marktprijs waarnaar wordt verwezen in een steunregeling, die moet worden vergeleken met de strike price om te zien of de overheid moet uitbetalen (of geld terugkrijgt in het geval van een 2-way CfD). Ook bekend als correctiebedrag in de SDE++.
Settlement terms	Hoe en hoe vaak tussen partijen wordt afgesproken om uit te betalen en/of terug te betalen.
Spot price	Spotprijs: De huidige marktprijs van een product of dienst. Het wordt gebruikt om onderscheid te maken met bijvoorbeeld de gemiddelde marktprijs over een bepaalde periode.
Strike price	Uitoefenprijs: Een vaste en vooraf overeengekomen prijs tussen partijen in een CfD-contract (vaak na ontvangst van biedingen van projectontwikkelaars in een tender-offer of na onderhandeling). Ook bekend als 'indieningsbedrag' en nauw verwant aan 'basisbedrag' in de SDE++.
Underlying	Zie referentieprijs

Trinomics B.V.
Mauritsweg 44
3012 JV Rotterdam
The Netherlands

T +31 (0) 10 3414 592
www.trinomics.eu

KvK n°: 56028016
VAT n°: NL8519.48.662.B01