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SWEET Call1-2020:
PATHFNDR

Policy recommendations for linking markets across spatial scales and on incentivizing system-friendly renewable generation

Deliverable Report
Task 7.1, Deliverable D1.3.2

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Summary

This deliverable report derives policy conclusions from different works performed on **linking markets across spatial scales** and on **incentivizing system-friendly renewables**.

We approach the topic of linking markets across spatial scales from two angles concerning the electricity and the gas market.

First, we study the case of embedding **local electricity flexibility markets in zonal wholesale** markets. We highlight that local flexibility markets that remunerate flexibility providers for grid relief provide perverse incentives to first increase grid congestion to subsequently get paid to relieve grid congestion again. We point out that dynamic grid tariffs are a solution to the problem and are thus preferable over a flexibility market. This is because dynamic grid tariffs do not discriminate between those who provide grid relieve and those who don't and thereby avoid the perverse incentives of flexibility markets.

Second, in response to SFOE request to investigate solutions for the energy crisis, we study incentive problems in a **local fossil gas market embedded in a global fossil gas** market in the presence of import constraints. Specifically, we look at the European fossil gas market during the energy crisis of 2021-2023 preceding and following Russia's invasion of Ukraine. First, we show that tradeable gas consumption allowances can be a solution for Europe to lower the domestic gas price and re-patriate import congestion rent that would otherwise accrue to exporting countries and import capacity holders. Second, we show that vis-à-vis Russia, an import price cap dominates a tariff as a foreign trade instrument from a European welfare perspective. Third, through game theory, we show that through strategic actions, Europe can make Russia accept a price cap more likely.

On the topic of incentivizing system-friendly renewables, we propose **financial contracts for differences** as a desirable evolution of support mechanisms. The advantage of these contracts over conventional renewable support policies, in particular over conventional contracts for differences, is that they do not distort dispatch incentives and yield optimal incentives for designing renewable power plants to maximize the market value of the electricity generated, and thereby follow price signals indicating scarcity or abundance on electricity markets.

1 Introduction

This deliverable report summarizes work performed on overcoming **incentive problems in linking markets across spatial scales**. This task was originally part of WP1 and has been moved into the first task of WP7 since it falls under the umbrella of policies for flexibility more than on the WP1 modelling of energy pathways at the national and international scale.

In this report, we approach the topic of linking markets across spatial scales from two angles concerning the electricity and the fossil gas market.

First, we study the case of embedding **local electricity flexibility markets in zonal wholesale** markets. We highlight that local flexibility markets that remunerate flexibility providers for grid relief provide perverse incentives to first increase grid congestion to subsequently get paid to relieve grid congestion again. We point out that dynamic grid tariffs are a solution to the problem and are thus preferable over a flexibility market. This is because dynamic grid tariffs do not discriminate between those who provide grid relieve and those who don't and thereby avoid the perverse incentives of flexibility markets. Another solution would be to introduce nodal prices and reduce the size of price zones to individual distribution grid nodes when congestions appear.

Second, we study incentive problems in a **local fossil gas market embedded in a global fossil gas** market in the presence of import constraints. Specifically, we look at the European fossil gas market during the energy crisis of 2021-2023 preceding and following Russia's war on Ukraine. First, we show that tradeable gas consumption allowances can be a solution for Europe to lower the domestic gas price and re-patriate import congestion rent that would otherwise accrue to exporting countries and import capacity holders. Second, we show that vis-à-vis Russia, an import price cap dominates a tariff as a foreign trade instrument from a European welfare perspective. Third, through game theory we show that through strategic actions, Europe can make Russia accepting a price cap more likely.

2 Local electricity flexibility markets in zonal wholesale markets

In this chapter, we study the case of embedding local electricity flexibility markets in zonal wholesale markets. The increasing expansion of decentralized renewable energies and the electrification of the transport and heating sector lead to a considerable increase in the need for grid expansion in the case of conventional grid planning and operation. To reduce the costs of integrating renewable energies, the revision of the Swiss electricity law under the umbrella "Mantelerlass" law thus foresees grid operators to be obliged, to use flexibility as an alternative to grid expansion, and to compensate flexible loads for this. However, to avoid undesirable side effects, the grid operators should also take into account the interactions on different grid levels as well as the spot market and the system balance. The development and testing of suitable approaches for flexibility dispatch that make this possible is therefore of high strategic and political relevance.

In the past years, flexibility markets were often discussed as a solution for DSOs to dispatch flexibility. Flexibility markets are local electricity markets where the DSO may request upward or downward flexibility from distributed resources and pays for the up or down activation. However, such markets suffer from a fundamental incentive problem. Local flexibility markets which remunerate flexibility providers for grid relief provide perverse incentives to first increase grid congestion to subsequently get paid to relieve grid congestion again. This problem is called increase-decrease gaming and has gained significant attention in recent years (see e.g. Hirth & Schlecht, 2020).

In the following, we first recapitulate the problem of increase-decrease gaming. Second, we outline a solution to the increase-decrease problem in the form of dynamic grid tariffs. They do not suffer from the problem of increase-decrease gaming while achieving time-variant dispatch of local flexibilities and are thus preferable over a flexibility market. We then outline a concrete dynamic tariff proposal which we test in a separate pilot and demonstration (P&D project) called NEDELA.

2.1 The problem of increase-decrease gaming

As we showed in previous work (Hirth & Schlecht, 2020), a two-stage electricity market where the two stages have a different geographical granularity offers arbitrage opportunities and incentives for strategic bidding behavior. In scarcity regions, producers will anticipate that higher profits can be generated by selling their production on the flexibility (redispatch) market rather than the zonal market. They therefore offer higher prices on the zonal market to price themselves out of the market. Conversely, producers in surplus regions will anticipate profits from being downward-redispatched. To achieve this, they place low bids on the zonal market to push themselves into the market. On the flexibility (redispatch) market, they buy the energy back at a price below the zonal price and thus meet their delivery obligation. One can understand these strategies as an optimization between two markets or as arbitrage trading. They are also known as increase-decrease (inc-dec) gaming.

Such strategic bidding has problematic side effects: it exacerbates congestion, creates windfall profits, and gives rise to perverse investment incentives. The problem is not limited to large-scale redispatch on transmission grid level. The same incentives apply in local distribution grids when flexibility markets which pay distributed energy resources for grid relief are used.

For simplicity, in the following we provide an example. We assume a case where the local DSO needs load-reduction flexibility at 19:00 of a particular day to avoid transformer overload, as that is a time when load on distribution grids is high. We further assume an electric vehicle (EV) arrives home at 15:00 and would – from own preferences – start to charge directly when coming home. The problem of increase decrease gaming in flexibility markets now is the following: If the EV owner anticipates that the DSO needs downward flexibility at 19:00 and is willing to pay for that downward flexibility, then there is an incentive for the EV owner to pretend postponing to charge its EV to exactly 19:00, so that it is available when the DSO asks for and is willing to pay for load reduction. However, by doing so, the EV owner had made the problem worse, namely it has increased congestion at 19:00 – just to relieve the caused congestion afterwards at a payment from the DSO to the EV owner.

More recently, Ehrhart et al. (2022a) have analyzed multiple ways that are often claimed could mitigate inc-dec gaming, however, they find that the problem is fundamental and none of the potential mitigation mechanisms could solve the fundamental problem of increase-decrease gaming in locational flexibility markets.

2.2 Dynamic grid tariffs as a solution

Given the problems of market-based flexibility procurement, alternatives are necessary. Dynamic grid tariffs, can be a solution to the problem and are thus preferable over a flexibility market. This is because grid tariffs are charged on the actual metered consumption, and not on the load reduction compared to hypothetical load levels which a customer may request in the day-ahead market. Hence, dynamic grid tariffs do not discriminate between those units who provide grid relief and those who do not and thereby avoid the perverse incentives of flexibility markets to increase congestion before solving it.

Dynamic tariffs can provide an incentive to shift flexible loads from periods with high prices to periods with lower prices. In contrast to flexibility markets, the level of grid tariffs is specified by the grid operator and not by the market. Another difference to flexibility markets is that the grid tariffs affect all units in the grid area and not only the ones who actively help solve the grid congestion – this is the main reason why grid tariffs do not suffer from the inc-dec problem. By contrast to direct load control by a single network operator, control via dynamic prices can simultaneously take into account congestion in different network levels and markets by over-laying the corresponding price signals.

As preparation for the Pilot and Demonstration (P&D) project NEDELA (which is part of the PATHFNDR family of P&D projects), we specified a dynamic 15-min network tariff as an optional tariff and different other approaches for dynamic tariffs. We propose that the tariff signals will be published on the Internet and home-energy-management-systems (HEMS), which optimize flexible devices of end-users (such as batteries, electric cars, heat pumps) could retrieve the tariffs and use the flexibility in a way that benefits the grid. In addition to grid tariffs, HEMS can also consider revenues from other markets (such as spot market, system service markets) to efficiently balance between different uses of flexibility.

In the NEDELA project, loads are controlled exclusively by the HEMS systems of various commercial suppliers, which optimize the use of flexibility based on a dynamic tariff signal published by the distribution system operator, as well as price signals from other market, if applicable. This is associated with several advantages. On the one hand, the tariff introduction is associated with a low effort for the distribution system operator, since it must only send the tariff signal, which depends on the network state. On the other hand, HEMS providers often have more detailed knowledge of the technical parameters of various controllable loads than distribution system operators, which improves the efficiency of control and minimizes the risk of damaging the controlled equipment. Furthermore, from a legal point of view, aggregators - in contrast to the grid operator - are also allowed to earn additional revenues from marketing the flexibility in other markets, which further improves the efficiency of load control.

Within the scope of the NEDELA project, a network tariff proportional to the D-1 forecast network load is to be implemented on a large scale. The following possible further developments are to be analyzed, simulated and partially tested with individual customers (see also the final report of the NETFLEX project):

i. Network tariff proportional to the network load measured in real time: this would avoid rebound peaks and enable load reductions during unplanned grid outages.
ii. Grid tariffs that are constant outside of grid congestion: this increases the incentive to use flexible loads elsewhere when they are not needed to relieve grid congestion.
iii. Grid tariffs dependent on regional grid load: this limits load shifting to those regions where it helps to relieve local grid congestion.
iv. Feed-in tariffs that take on the same value as the grid tariff in the event of congestion: this creates an incentive to use storage to serve the grid rather than just to maximize own power consumption.

Depending on the tariff approach, the introduction of the tariff is associated with different challenges, which will be analyzed within the scope of the project.

One of the most important hurdles in practice is the lack of standards and implementation examples. This hurdle is to be overcome through the exchange with the relevant HEMS providers and the implementation of an elective tariff at the DSO.

In addition to this, tariff approaches i) to iv) are associated with further technical and legal challenges. For example, tariff approach i) may require adaptation of the load control algorithms used in commercial HEMS. Tariff approach i) requires timely, and tariff approach iii) regionally disaggregated network condition measurement and tariff calculation. The latter is not currently permitted for legal reasons. In addition, the different tariff approaches can cause more or less severe acceptance problems (for example, in the case of regional tariff differentiation in approach iii), or the more steeply rising prices in the case of congestion in tariff approach ii). Moreover, for many of these tariff variations, robust simulation results quantifying the added value of the tariff approach are lacking.

In the NEDELA project, the efficiency of the different tariff variations will be determined by simulation. In addition, qualitative interviews will be conducted in 2024 and a quantitative survey in 2025 with customers who have subscribed to the optional tariff and, if necessary, a group of customers who have not yet subscribed to the tariff will be asked whether / which of the implementation variants they would accept and, if necessary, test as part of a pilot group in the run-up to the tariff introduction. At the same time, a corresponding survey will be conducted among HEMS providers, and any implementation costs and legal permissibility will be clarified. While the optional tariff of Groupe E will test a constant tariff approach over an entire calendar year, customers will have the option to join a pilot group with shorter-lasting tests (e.g., monthly or quarterly tariff changes). The detailed test plan will be developed during the course of the project based on simulation results, customer preferences, and the preferences of the implementation partners.

3 Local fossil gas market embedded in a global market

Here we study incentive problems which arise if the European fossil gas market is embedded in a global fossil gas market in the presence of import constraints. Specifically, we look at the European fossil gas market during the energy crisis of 2021-2023 preceding and following Russia's invasion of Ukraine. First, we show that tradeable gas consumption allowances can be a solution for Europe to lower the domestic gas price and re-patriate import congestion rent that would otherwise accrue to exporting countries and import capacity holders. Second, we show that vis-à-vis Russia, an import price cap dominates a tariff as a foreign trade instrument from a European welfare perspective. Third, through game theory we show that through strategic actions, Europe can make Russia accepting a price cap more likely.

3.1 Tradeable gas usage allowances to lower European gas price

In large parts of Europe, the gas import capacity was at its limits during the winter 2022, restricting the overall amount of gas available. To balance demand with scarce supply, European gas prices have risen substantially above world LNG prices. This is because gas users effectively outbid each other on domestic gas markets – for a resource that is physically limited by import constraints. Gas exporting countries and LNG regasification capacity owners benefit from this domestic scarcity, while European consumers paid high prices and faced a challenging and uncertain winter. Various regulatory interventions were being discussed to remedy the gas crisis, but many failed to combine the intention to provide financial relief with the need to limit demand to the physically available quantity.

Therefore, in the midst of the crisis, we (Schlecht et al., 2022)[1] proposed introducing tradeable gas certificates, which are freely allocated to European industrial gas users based on, e.g., 80% of last year's consumption. Under the policy, industrial gas users within the import-constrained region are required to own a gas usage certificate to be allowed to use one unit of natural gas. The actual gas continues to be traded separately such that all gas contracts and hedging arrangements remain valid, making the intervention legally lightweight. The total amount of issued certificates is based on the physically possible import capacity (plus current storage), and the initial allocation of the certificates is proportional to last year's consumption. The idea is to first distribute the overall gas available within Europe on the certificate market, and then allow gas customers to buy and sell certificates. As the volume of gas certificates is set at a slightly lower level than European import capacity, gas prices in Europe would fall to the international LNG price, while the additional value of gas in Europe would be captured by the certificate market. The regulator can react flexibly to supply changes by releasing some certificates only month-by-month as winter progresses and gas demand by households is realized.

The proposed policy has four attractive properties. First, it transfers the scarcity premium away from gas exporters to the EU industry and thus provides financial relief. Second, the possibility to trade certificates between firms ensures that the necessary savings in gas consumption will take place where they cause the least economic costs. Third, the policy does not interfere with existing gas purchase contracts and is thus likely to prevent the legal problems from which other proposals suffer. Fourth, households will benefit from lower gas prices.

3.1.1 The price in Europe's import-constrained region

For the winter 2022/23, a large part of Europe will be import-constrained. This means that LNG import terminals and non-Russian pipelines into the region will be fully used at capacity, following Russia's almost complete supply stop. The region of European countries affected by the binding import constraint then effectively constitutes a "high price island" in which higher prices cannot attract more supply in the short term, i.e., until further LNG terminals come online. The region includes, amongst others, the Netherlands, Germany, Poland, Denmark, Italy, Austria, and the Czech Republic (but not Spain or France). In that region, there will be physical limits to the amount of gas available next winter.

[1] The paper on gas allowances as well as the text in the section is joint work with the co-authors Ali Darudi, Beat Hintermann and Sebastian Schäfers, see Schlecht et al (2022).

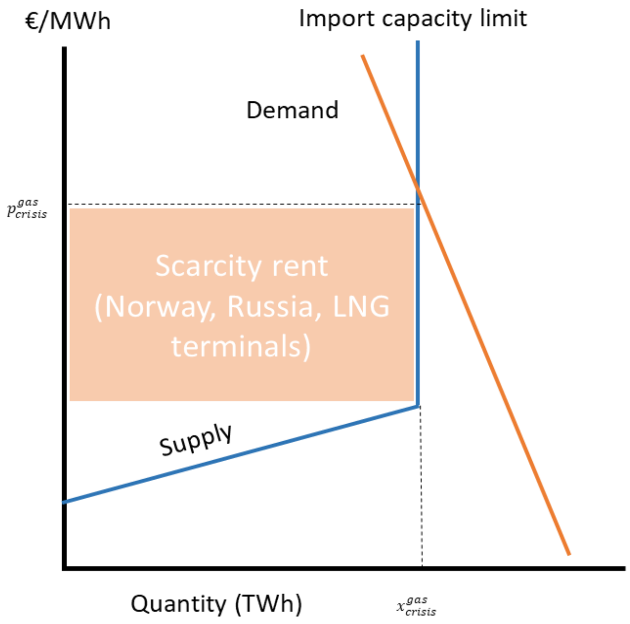

Figure 1: Gas market in crisis: binding import capacity limit. Prices are set by demand and exceed world prices for LNG.

Problem of buyers-competition on the gas market

Faced with limited available supplies, gas consumers outbid each other on the gas market (**Figure 1**), such that the demand entities with the highest willingness to pay continue to consume gas (at high prices), while those with lower willingness to pay drop out. Firms differ in how well they can substitute away from gas, and prices serve an important function to allocate overall supply to the most efficient uses. Industrial gas demand in Western Europe has already dropped by 21.7% in 2022 compared to the 2018-2021 average, according to market analysis firm ICIS – an effect that is likely to be attributable to high prices. However, managing the existing scarcity solely through high gas prices has important downsides. The unprecedented price increase has resulted in large windfall profits for gas exporters, including Russia, Norway, but also to LNG terminal capacity holders, at the cost of EU industry and households. The regressive incidence of rising energy costs across the income distribution imposes significant hardship on poor households.

We proposed to manage the domestic (import-constrained) scarcity no longer through the gas price, but through a separate instrument. This distributes the available gas volumes efficiently within Europe first and thus avoids overbidding on the gas market and reduces payments to supplier countries.

3.1.2 Proposed solution: Cap-and-trade for gas usage

We propose a “tradable gas usage certificates” policy, similar to the European Emissions Trading System (EU-ETS), which leads to the abatement of CO2 emissions where it is least costly for the economy (for a review, see Ellerman et al., 2016). For each unit of natural gas (e.g., 1 MWh) consumption, firms covered by the obligation must surrender one gas usage certificate. Importantly, the certificates only provide the right to use gas that a firm already owns. The gas itself still must be procured additionally such that gas trading and existing forward contracts are unaffected. The regulator issues a total amount of certificates that is below the sum of current storage plus the gas import capacity, thus replacing the physical constraint with a regulatory constraint. As a result, the scarcity rents are shifted away from the current suppliers to the EU. By allocating most certificates free of charge based on firms’ historical consumption levels, the rents are distributed across the economy.

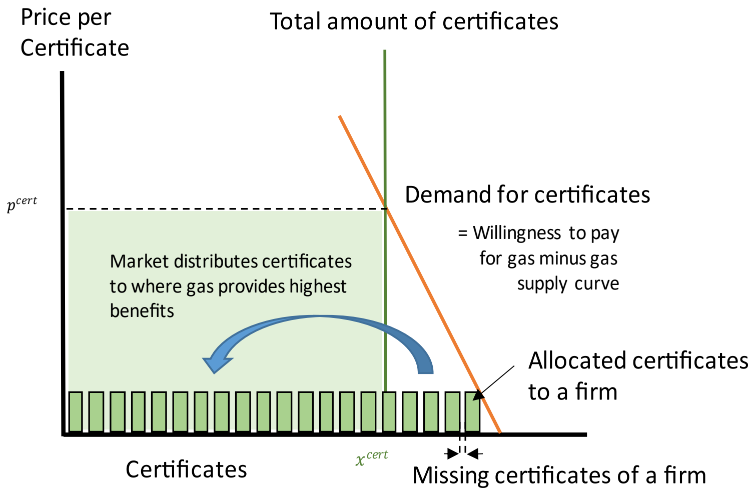

Figure 2: Trade in the certificate market

Since the certificates are tradable, gas consumption will be allocated efficiently across firms (illustrated by **Figure 2**). On the demand side, a firm's willingness to pay for a certificate is equal to its total willingness to pay for gas minus the price in the gas spot market. The market allocates certificates (and thus gas consumption) to the firms that create the most value and therefore have the highest willingness to pay. In other words, gas usage is reduced where it creates the least economic value.

The scheme would apply to the countries that comprise the "high price island" and could also be expanded to include others. Households are not included in the scheme but will profit from the lower resulting market prices. The certificate market covers gas usage until the end of winter, e.g., through March 2023. After that, the import capacity limit is not expected to be binding anymore (or, at any rate, the scarcity is less than in winter). Alternatively, the system could be left in place, but in this case, it would be crucial not to allow borrowing certificates from future months. To incentivize the increase of import capacity, any firm that would expand import capacity would get newly generated gas usage certificates as remuneration for expanding import capacity.

The price for a certificate will depend on the cap. Ideally, the cap is set such that total gas consumption (the sum of the cap and household demand) is only slightly less than the capacity limit. If the cap turns out to be too high such that more certificates exist than can be used (as there is simply not enough gas), the certificate price will drop to zero, thus making the instrument ineffective. An unnecessarily low cap, on the other hand, would lead to high certificate prices and thus to a total marginal price that is significantly above the current market price. While the scarcity rent now accrues to domestic entities rather than to suppliers abroad, some economically valuable production would not take place, leading to a welfare loss.

Household gas consumption depends on weather conditions and is therefore not known with certainty in advance. Because getting the quantity right is crucial, the policy implementation needs to provide the regulator with enough flexibility to perform possible fine-tuning and respond to economic or political realities. For instance, the regulator may allocate the certificates on a periodical basis (e.g., monthly) and reserve the right to adjust the amount based on import updates and realized household demand. Because current storage is part of the cap, the system can absorb mean-reverting shocks by increasing or decreasing the rate at which the reservoirs are depleted.

In theory, the certificate price will be equal to the marginal cost of reducing gas usage to one unit below the cap. Evidence from the EU ETS suggests that allowance prices have, in fact, been driven by marginal abatement costs (Hintermann et al., 2016). Since many firms covered by the proposed gas usage market are also covered by the EU ETS, they already have experience with a cap-and-trade market.

To enforce the policy, a penalty for noncompliance is needed, which should be set high enough such that firms have a strong incentive to comply with the system. This is because if enough firms do not comply, gas consumption will reach the capacity limit and the scarcity rents revert to the gas suppliers. The penalty for noncompliance additionally serves as an upper limit for the certificate price.

3.1.3 Benefits of a cap-and-trade approach

The tradable gas usage scheme directly affects the spot gas market (**Figure 3**). Provided that the total gas consumption from households and industry is below the capacity limit, the spot gas price will decline to the LNG world market price.

To use natural gas, firms must pay both the gas spot price and the certificate price, the sum of which will be (slightly) above the spot-only market price in the crisis. Therefore, the firms still face a high marginal cost for gas consumption and thus remain incentivized to reduce gas consumption.

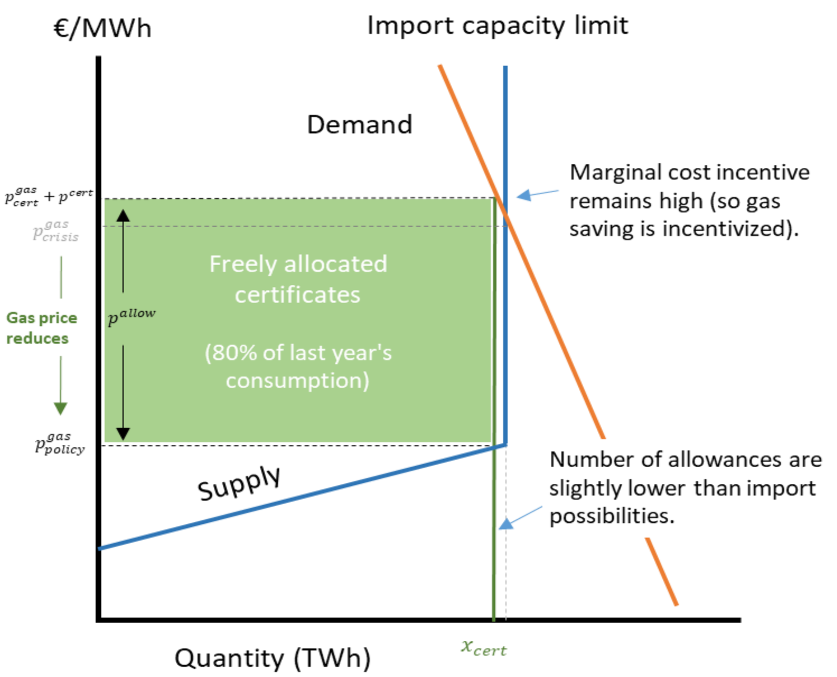

Figure 3 Gas market after implementation of the policy

The proposed scheme repatriates the scarcity rent, which corresponds to the light green areas in **Figure 2** and **Figure 3**. Short-term market trades and long-term supply contracts (to the extent that they are indexed to the spot market) will clear at lower prices. The firms with the lowest willingness to pay for gas are expected to sell some (or all) of their certificates and benefit from a "shutdown compensation" by obtaining the certificate market price. Compared to the current situation, certificate buyers are also better off as they benefit from some free-of-charge certificate allocations, e.g., equivalent to 80% of the previous year's consumption. For the remaining share, they pay about the same as in the current conditions.

3.2 Dominance of an import price cap

In a separate paper, we (Ehrhart et al., 2022b, Ehrhart et al. 2023) analyze trade policies vis-à-vis Russia in the gas market. We show that, an import price cap dominates a tariff as a foreign trade instrument from a European welfare perspective.

Many scholars point to tariffs to reduce Russian oil and gas profits. While this makes sense for oil, for gas we find that a price cap on Russian gas is the better policy, as depicted in Figure 4. This is due to Russia's monopoly power over EU residual gas demand. As a residual monopolist, Russia benefits from price increases following supply reductions. Even if Russia had cut supplies already beyond their optimum, it meant they can still harm Europe at low costs. A price cap removes the monopolist incentives, while a tariff does not.

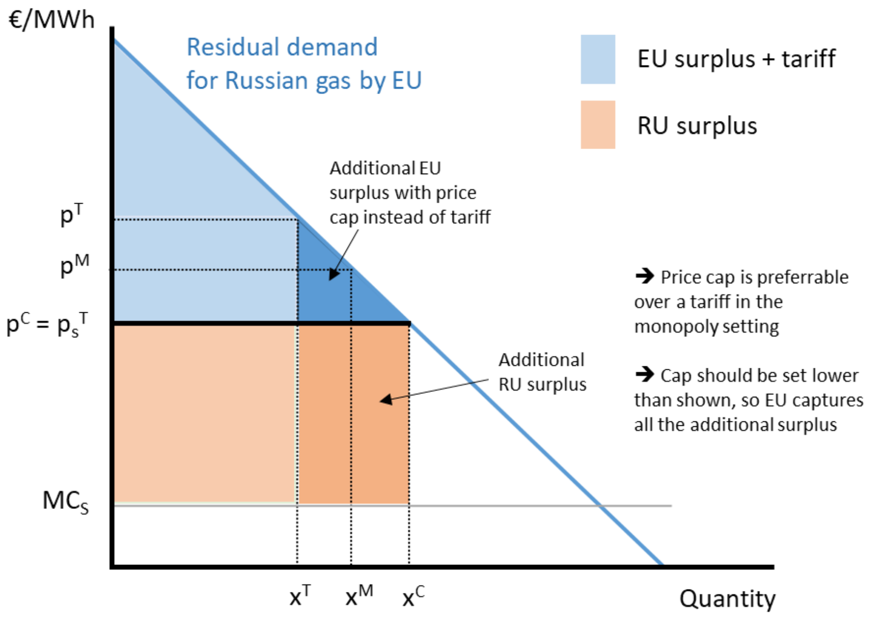

Figure 4: Price cap vs. tariff in the EU-Russia gas market

Figure 4 shows the welfare comparison, where MCs means marginal cost of supplier, Pc means price under a price cap regime, PsT means the price of the supplier und the tariff regime, pT means price for consumers under the tariff regime, pM is the price under a monopoly absent an import policy, xT is the quantity under a tariff, xM is the monopoly quantity absent an import policy, xc is the quantity under a cap.

We show that for any tariff there exists a price cap that makes both the EU and Russia better off. Consequently, compared to imposing a tariff, the EU can always design a price cap that gives RU the same welfare (so it is equally likely to accept), but makes the EU better off.

To impose a price cap, we conclude that the EU should exercise its own market power, appointing a single EU entity buying gas from RU and re-selling domestically in EU spot markets.

It is important to note that this is not a typical price cap in a typical market. It is an import policy vis-à-vis a single supplier, of which the costs are well known from historical deliveries. Therefore, typical risks of price caps (such as excess demand) do not apply here. This would be very different if the price cap was designed as a price cap on the EU's domestic gas market.

3.3 Strategic options to increase chances of a price cap acceptance

In another paper on the same topic (Ehrhart et al., 2022c)[2], we study using game theory, which strategic options Europe obtains, which can make Russia accepting such a price cap more likely. We outline which strategic actions Europe can use to make Russia accepting a price cap more likely.

In September 2022, Russia stopped virtually all gas supplies to the main EU markets. Thereafter, leaks were discovered in the Nord Stream pipelines, preventing their use. The paper examines interactions between the EU and Russia using a game-theoretic approach that incorporates the resumption of Russian gas supplies and various EU policy options, including an import price cap. The resumption of gas supplies under a price cap can be achieved if the EU (i) makes a continuing gas embargo costly for Russia, (ii) makes the Russian gas embargo more bearable for itself, (iii) credibly commits to staying firm after Russia rejects the price cap, and (iv) renders a price cap acceptable to Russia. A tariff threatened by the EU could further increase the chances of success.

The basic game is depicted by the game tree in Figure 5. The two circles with EU1 and EU2 denote the decision nodes of the EU, and the two circles with RU1 and RU2 are those of Russia. The individual utilities of the EU and Russia at the end nodes of the game are denoted by ei and rj, respectively, i, j = 1,2, … The individual utilities are ordinal and not intersubjectively comparable.

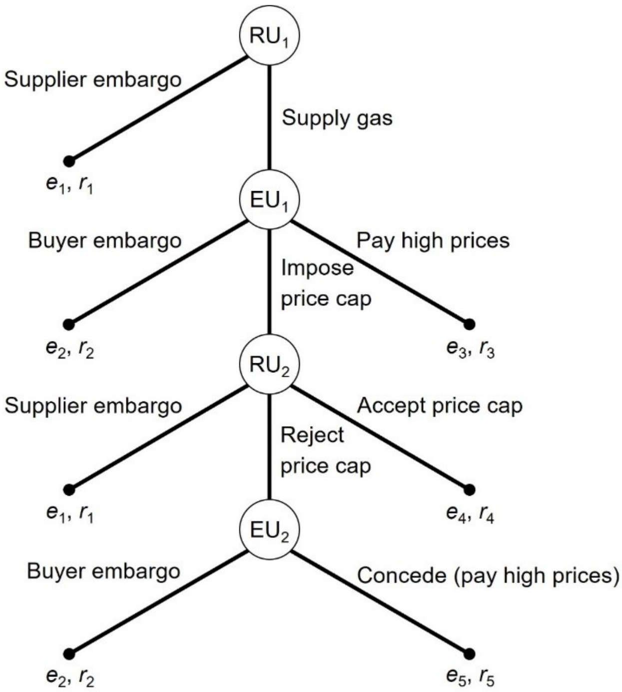

Figure 5: Game tree of the basic game

Starting from decision node RU_1, two options for Russia are considered. First, Russia does not supply gas, which corresponds to the supplier embargo before the leaks, resulting in e_1 for the EU and r_1 for Russia. Alternatively, Russia is ready to supply gas, which is apparently possible via the still intact pipe of Nord Stream 2 or via other Nord Stream pipelines after their repair or via pipelines through Turkey or Ukraine. It is assumed that Russia will continue acting as a monopolist as it did before the embargo. This leads to decision node EU_1, where the EU has three options: not to import Russian gas (buyer embargo) leading to e_2 and r_2, to import Russian gas and pay high prices leading to e_3 and r_3, or to

[2] This section is based on the joint paper Ehrhart et al., 2022c with co-authors.

import Russian gas, but only on condition that it pays no more than a maximum price, i.e., the EU imposes a price cap. The third option, impose a price cap, leading to decision node RU_2, where Russia then has three options: not to supply gas (supplier embargo) leading to e_1 and r_1 or to comply with the EU price cap leading to e_4 and r_4 or to reject the price cap and to continue to charge high prices leading to the EU decision node EU_2. Here the EU has two options: either to stand firm and decide on a buyer embargo leading to e_2 and r_2 or to concede and to pay high prices leading to e_5 and r_5.

According to our analysis in Ehrhart et al., 2022c, it is rational for Russia to resume gas supplies and even comply with an EU-imposed price cap on Russian gas under certain conditions. Russia will do so if the EU can make the continuation of the gas embargo costly for Russia and credibly commit to staying firm following a Russian rejection of the price cap. A tariff threatened by the EU that makes Russia worse off than complying with the EU price cap increases the likelihood of Russia's acceptance of a price cap. This allows EU policymakers to consider actions that will strengthen their hand in a standoff with Russia. Figure 6 shows where EU policy could potentially make a difference in achieving Russian compliance with an EU gas import price cap (see intervention points with arrows).

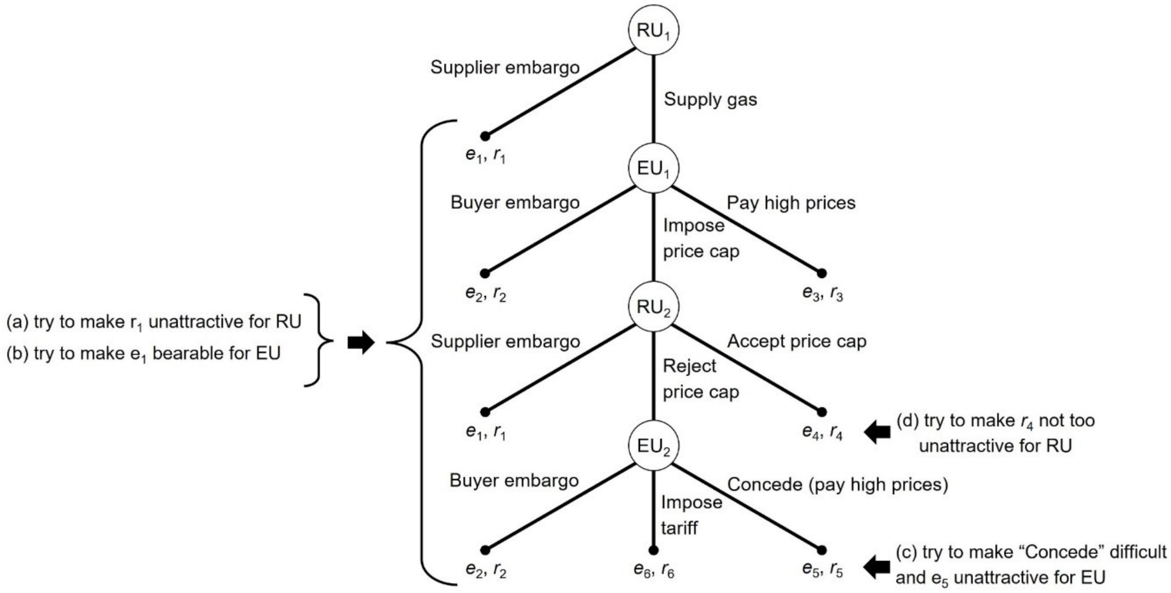

Figure 6: Game tree with policy action points for the EU

Four possible policy intervention areas were at the time considered as increasing the likelihood of the desired outcome, i.e., Russian resumption of gas deliveries and compliance with an EU-imposed price cap on Russian gas. These policy intervention points were:

(i) The EU should make the continuation of the Russian gas embargo costly for Russia. The analysis suggests that the EU can influence the Russian calculus to supply or not to supply by altering the Russian payoffs in the strategic interactions. The EU can, for example, threaten or implement additional economic sanctions or other political measures, thereby changing the *relative* payoffs for Russia.

(ii) The EU should try to make a Russian gas embargo more bearable for itself. Undoubtedly, a cessation of Russian gas deliveries is a challenge for the EU economy and a test of EU Member States internal and intra-EU cohesion. However, measures that at least partially alleviated economic and social hardship could help limit the damage that a Russian gas embargo has on the EU. These could include efforts to replace Russian gas with as much non-Russian gas as possible and to accelerate the transition of the energy mix to non-Russian fossil fuels and renewable energy sources, as well as energy saving including domestic and intra-EU solidarity emergency plans.

(iii) The EU should try to make its own backpedalling from a price cap as difficult as possible. This could be achieved by credible political signalling to both the EU domestic audience and Russia that once it has announced the price cap, the EU will not waver ('locking in policy choices').

(iv) The EU should try to make a price cap acceptable to Russia. This could, for example, be achieved by a reasonably price cap that covered the Russian extraction costs and left a profit margin or a commitment to phase out Russian gas later than the announced deadline of 2030. The EU could also support this by credibly threatening a tariff as an alternative to a price cap that would make Russia worse off than the price cap. Other policies, such as non-aggressive communication regarding the price cap, could help the Russian leadership lose as little face as possible vis-à-vis its domestic and international audience if they accepted the cap.

The above non-exhaustive list was by no means an automatic recipe for shaping the gas trade between the EU and Russia, especially concerning the successful implementation of an import price cap. Nevertheless, despite its simplicity, this analysis could help structure the debate regarding a potential resumption of the EU-Russia gas trade, while keeping Russian revenue from such trade in check. However, since the explosions affecting the Nord Stream pipeline, Russian gas trade with Europe has diminished and the analysis therefore is no longer of direct policy relevance any more.

4 Financial contracts for differences for renewables support

Contracts for differences (CfDs) are widely seen as a cornerstone of Europe's future electricity market design. Europe's energy crisis has triggered an intense debate on electricity market reform, and CfDs were at the centre of discussions. Commentators and policymakers suggested that these long-term contracts should become a cornerstone of the EU's future electricity market. The journal article by Schlecht et al. (2024) discusses the design of such contracts and proposes a new form of such contracts. It highlights the dispatch and investment distortions that conventional CfDs cause, the patches used to overcome these shortcomings, and the problems these fixes introduce. We therefore introduce an alternative, a "financial" CfD.

The financial CfD proposed in the article draws on a key feature from financial forwards/futures contracts to avoid the distortions otherwise associated with conventional CfDs, namely asset independence. Instead of linking payments to the output of an individual generator and hence providing the opportunity for manipulating them by adjusting output, the concept of financial CfDs proposes to link them to an objective benchmark. For effective risk mitigation, the benchmark must be highly correlated with electricity generation, such as (for wind and solar energy) a profile derived from weather observations. Unlike other CfDs, the financial CfD also hedges volume risk (not just price risk) and thus stabilizing revenues. In contrast to financial futures, the contract avoids liquidity squeezes by allowing physical assets as collateral. The hybrid between conventional CfDs and forward contracts mitigates revenue risk to a substantial degree while providing undistorted incentives. Like conventional CfDs, it is long-term and tailored to technology-specific (wind, solar, nuclear) generation patterns but like forwards, it decouples payments from actual generation. The proposed contract mitigates volume risk and avoids margin calls by accepting physical assets as collateral.

In general, CfDs are financial contracts that specify payments from the buyer to the seller if, at maturity, the price of an underlying asset is below the agreed-upon strike price and a reverse payment otherwise.

Such derivatives are used in foreign exchange, security, and commodity markets and are commonly traded between commercial entities.

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

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

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

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

The full paper with recommendations on renewable policy design and the details on financial contracts for differences can be accessed in the published paper, which is available open access (Schlecht et. Al, 2024).

5 Conclusion

In this report we dive into the topic of overcoming incentive problems in linking markets across spatial scales in different domains and the topic of support policies to incentivize system-friendly renewables.

On local electricity flexibility markets in zonal wholesale markets, we conclude that the incentive problems of increase-decrease gaming are fundamental and therefore suggest going for dynamic grid tariffs or nodal distribution grid prices instead of flexibility markets. Therefore, this first analysis shows the importance of careful design in implementing local electricity flexibility incentives, emphasizing the need for dynamic grid tariffs to mitigate perverse incentives.

On local fossil gas market embedded in a global fossil gas market we conclude that tradeable gas allowances could have helped Europe during the import-constrained situation to bring down gas prices. Furthermore, we show theoretical evidence that when facing an external monopolist, an import price cap can be a dominant policy over an import tariff. Lastly, we point out strategic options how such a price cap can be made more likely to succeed. Examining today's fossil gas market in the context of import constraints provides policy recommendations that might be actionable also in the future. In fact, also in the future, introducing tradeable consumption allowances to address domestic price concerns on certain energy carriers and the strategic use of import price caps in foreign trades could be a solution when needed. In fact, future energy systems will still require the import of certain fuels from countries where their production will be cheaper than in Switzerland.

On the topic of incentivizing system-friendly renewables, we propose **financial contracts for differences** as a desirable evolution of support mechanisms. The advantage of these contracts over conventional renewable support policies, in particular over conventional contracts for differences, is that they do not distort dispatch incentives and yield optimal incentives for designing renewable power plants to maximize the market value of the electricity generated, and thereby follow price signals indicating scarcity or abundance on electricity markets.

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