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Evolution of prices and cost for Large Consumers in the Greek Electricity market

The role of RES in alleviating the cost

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MSc Thesis
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Abstract

Energy-intensive consumers have generally enjoyed low prices regarding their electricity costs in the past decades. This was mainly since fuel prices (mainly lignite and natural gas), were relatively low as well, including the extra EUAs cost. After 2017 and with the delignitization process well under way, wholesale market prices have begun to gradually rise. At the moment Europe is at the beginning of an energy crisis that results from the volatility of Natural Gas prices and various geopolitical reasons. As an immediate impact, wholesale market prices have soared. This has been imprinted on the cost that energy intensive consumers have to face, since for the first time in the Greek Market, final prices have been directly linked to the Wholesale Market. Taking into account that Greece is still in a transitory period with the implementation of the EU Target Model still under calibration, energy intensive industries and consumers have to find alternatives to contain their energy cost.

Renewables have quickly developed during the past decade, mainly based on Government subsidy schemes. Yet as their technology matures, their actual cost has dropped significantly. Subsidies for RES are also in a new phase, as we move away from Tariffs to more market-oriented investments. Yet long term contracts are still required from investment or banking institutions to finance RES projects that are required to grow for the next years according to the National Energy and Climate Plan.

In this thesis, we explore the evolution of the wholesale market prices and their effect on the final energy prices for large consumers from 2017-2021 in both the Day Ahead Scheduling and the Target Model market formats and we present the cost of electricity as it is formulated through supplier offers linked to the market(s) in 2022. The evolution of RES Levelized Cost of Energy and the prices awarded through auctions as government subsidies are also considered and Green Power Purchase Agreements (Green PPAs) are explored in structure, scheme and portfolio as a means to mediate the impact of the current energy crisis, but also as a tool for future development of RES, the achievement of EU energy policy goals and sustainable hedging for energy intensive consumers regarding their energy mix and cost.

Contents

Introduction

European energy markets (both electricity and natural gas) are currently in an unprecedented situation. Prices mainly of the Natural Gas commodity are during the first quarter of 2022 about 4-5 times higher than those in the same period during 2021. Taking into account that in many EU countries Natural Gas serves as the transition fuel for the production of electricity towards the energy transition described in detail in Fit for 55[1], prices in the electricity markets have risen as well. At the same time emission allowances entered phase 4 in 2021, meaning a faster elimination of the freely allocated EUAs, effectively soared prices for emissions as well and while natural gas electricity production has a much lower impact than fossil fuel (such as lignite in the Greek case) still have a significant impact on the final Wholesale Market prices.

This situation is expected to last at least the next 3-4 years according to futures markets[2] as well as from the EU itself (European Commission, 2022). These increases in the wholesale electricity market, necessitated the suppliers in the Greek Market to step away from the low and stable bills offered to energy-intensive consumers and revert to billing offers linked to the Wholesale market or extremely high offers for fixed contracts. As such, Industries and Commercial facilities are facing a profound production cost regarding energy.

On the other hand, Renewables are part of both the EU targets set by Fit for 55 as well as the National Energy and Climate Plan (Hellenic Republic, 2019) and it is almost universally accepted that RES technologies can lower the electricity generation sector's carbon footprint, that is in turn responsible for almost a third of the global CO_2 emissions. Besides the obvious environmental impact, Renewables have evolved and matured as a technology and as such can also provide a very low Levelized Cost of Energy (Lai & McCulloch, 2017), which can directly have an impact on Wholesale Market Prices. The renewables market is also under significant changes. The development of Renewables in the last decades relied heavily upon Government subsidies usually with a high Feed-in-Tariff mechanism. Since 2016, Renewable have the obligation of Market Participation and subsidies are replaced with a premium awarded exclusively via auctions. Auction prices have as well dropped. The above evolutions, as well as the fact that RES market

[1] https://www.consilium.europa.eu/en/policies/green-deal/fit-for-55-the-eu-plan-for-a-green-transition/
[2] European Energy Exchange - https://www.eex.com/en/

participation will initiate balancing obligations to the stations, have created uncertainty for new investments.

Green Power Purchase Agreements are a tool that allows Renewables to directly setup contracts for the power they produce with either a supplier or a direct consumer. As such, the deployment of such an option could lead to a solution for the short as well as the long term of energy costs for industries and businesses that can contain the costs in the present and ensure competitiveness and sustainability of the operations for the future (Crispeels, Robertson, Somers, & Wiebes, 2021).

This thesis is structured as follows:

- In Chapter 1, the National Energy and Climate Plan provisions are presented as well as the relevant expectation of the impact of new Renewables on the wholesale market prices.
- In Chapter 2 the evolution of prices in the Greek Electricity Wholesale market is presented for the years 2017 up to October 2020 and from November 2020 to December 2021, distinguished between the Day Ahead Scheduling System and the full Target Model implementation. The analysis takes into account all aspects of Wholesale market costs (especially towards the suppliers), by examining components besides the DAS/DAM prices. The Forward Electricity Products Auctions System (commonly known as NOME Auctions) and its impact are also presented.
- In Chapter 3 traditional billing schemes for High and Medium Voltage are presented as well as the CO_2 emissions clause that PPC imposed on large customers according to the billing scheme.
- In Chapter 4, the evolution of final energy prices for non-household consumers are presented in clusters according to their consumption levels
- In Chapter 5, current large consumer bills for the Medium Voltage are presented and their overall outcome in wholesale market terms is calculated for the first four months of 2022 to determine the impact of the wholesale market raise in prices towards the final electricity cost an industry or a large commercial consumer.
- In Chapter 6, a detailed analysis of the evolution of prices awarded to Renewables is presented as well as a calculated Levelized Cost of Energy, according to the Regulator’s input on the Cost of New Entry of new Renewables assets.
- In Chapter 7, the concept of Green Power Purchase Agreements (PPAs) is presented and various mechanisms are analyzed, such as Physical and Virtual and relevant pricing structures, such as Fixed Price PPAs, Floor and Ceiling PPAs, PPAs

- In Chapter 8, a case study of a PPA implementation is presented on two industrial consumers and the large commercial consumer. The analysis of their load profiles, the analysis of the Renewables production profiles, the appropriate PPA portfolio selection methodology and the financial benefit for a series of PPA proposals versus the actual hourly billing proposed by the suppliers is thoroughly presented.
- Finally in Chapter 9 contains a short reference to the Government backed plan for a Green Pool concept to promote and facilitate the conclusion of such agreements.

1. NECP Provisions

The amendment of the National Energy and Climate Plan (NECP), was presented by the Greek Government in December 2019. As stated within the document, the NECP serves as a detailed roadmap aiming at the realization of specific energy targets and objectives by 2030. The Greek NECP, analyses policy measures, priorities and actions on a variety of economic and social activities within the general Government strategy regarding climate change.

As such, the NECP is both a tool, as well as a reference document for the necessary energy transition that will allow a significant reduction of CO2 emissions while at the same time maintaining and enhancing the competitiveness of the national economy with the ultimate goal to achieve a climate neutral economy by 2050.

Among various provisions, the following objectives are set to be achieved by 2030:

- RES production in the energy mix will reach a 35% minimum
- In the case of electricity consumption specifically, the RES share will be significantly increased with the target set at 60%
- In the process of the energy mix transformation, the lignite plants will cease operations by 2023 except for the Ptolemaida V unit which will cease in 2028.
- Lignite production will be substituted by Natural Gas, which will serve as a transition fuel until RES joined by storage units achieve their targets
- Electricity will also play a major part in heating and cooling, with a target of 40% as well as transportation (both public and private) with a target set at 19% of the overall energy consumption.
- By 2030 Green House Gasses emissions will be reduced by 43% compared to the 1990 levels and by 56% compared to the 2005 levels.
- Regarding energy efficiency, the overall target aims for the overall energy consumption in 2030 to be lower than the consumption in 2017. This translates to an overall 38% energy efficiency improvement.

Table 1 Projection of RES shares per NECP objective

	2020	2022	2025	2027	2030
RES share in gross final energy consumption [%]	19.7%	23.4%	27.1%	29.6%	35%

RES share in final consumption for heating and cooling [%]	30.6%	33.8	36.8	38.3%	42.5%
RES share in gross electricity consumption [%]	29.2%	38.6%	46.8%	52.9%	61%
RES share in final consumption for transport [%]	6.6%	7.3%	10.1%	11.7%	19.0%

Source: NECP,2019

Regarding RES power generation, NECP projects a steady growth for the more mature technologies (both technologically and economically) of Wind Farms and Solar Parks while at the same time allowing some small growth in other, less developed technologies such as Biomass, Biogas and Geothermal.

A detailed development of RES production in both installed capacity (GWs) and energy (TWh) is presented in the following tables:

Table 2 Projection of RES installed Capacity

RES Installed Capacity (GWs)	2020	2022	2025	2027	2030
Biomass & biogas	0.1	0.1	0.1	0.2	0.3
Hydro (incl. mixed pumping)	3.4	3.7	3.8	3.9	3.9
Wind farms	3.6	4.2	5.2	6.0	7.0
Solar Parks (PV)	3.0	3.9	5.3	6.3	7.7
Solar thermal	0.0	0.0	0.1	0.1	0.1
Geothermal	0.0	0.0	0.0	0.0	0.1

Source: NECP,2019

Additional objectives are going to be deployed over the course of the decade regarding pilot facilities for the further development of premature technology such as wave energy harness, hydrogen production, combined desalination installations and dispersed small scale wind farms.

Table 3 Projection of RES Power generation

RES Energy Generation (TWhs)	2020	2022	2025	2027	2030
Biomass & biogas	0.4	0.5	0.8	1.0	1.6
Hydro (incl. mixed pumping)	5.5	6.4	6.5	6.6	6.6
Wind farms	7.3	10.1	12.6	14.4	17.2

Solar Parks (PV)	4.5	6.0	8.2	9.7	11.8
Solar thermal	0.0	0.0	0.3	0.3	0.3
Geothermal	0.0	0.0	0.0	0.3	0.6

Source: NECP,2019

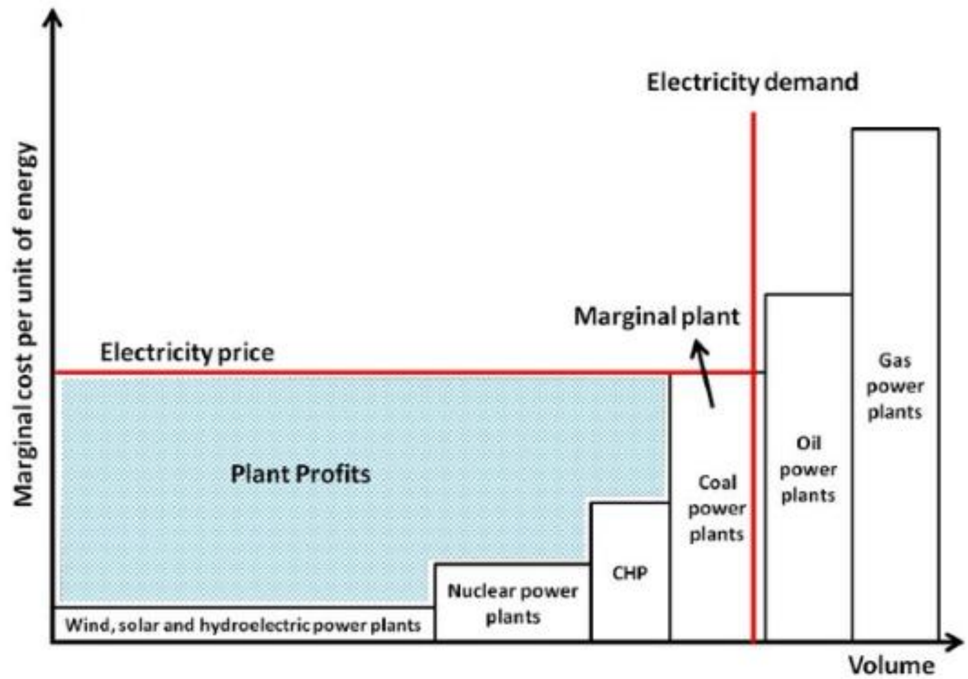
As it is evident, Solar Parks and Wind Farms, acquire the largest share in the energy mix. RES in total will reach an installed capacity of 19.1 GW. Solar farms are expected to hold 7.7 GW of installed capacity that is translated to an overall growth of 157%. Wind farms (onshore and offshore) are expected to hold a total of 7 GW, translated to a growth of 94%.

The increase of RES participation in the energy mix, is expected to have a significant effect on prices in the wholesale markets. Yet a critical factor remains the volatility of RES production and their stochastic nature. This must be adapted in an optimal way for participation in the electricity wholesale market.

The penetration of RES in the energy mix, besides being a critical path to sustainability is also expected to significantly lower the wholesale market prices. If properly combined with storage facilities and taking into account the significantly lower Levelized Cost of Energy that the mature RES technologies (Solar and Wind) enjoy, will heavily influence the overall level of electricity prices and thus enable the electrification of both transportation as well as heating and cooling Systems, as projected by the NECP (Hellenic Republic, 2019).

Although the DAM price differs from the DAS approach, as we are going to explore in the following chapters, the basic principle of Merit Order persists (Sauvage & Bahar, 2013). By the term merit order, the electricity industry describes the order in which electricity production units of any kind (base units of various fuel or renewables) are expected to produce and deliver energy to the system in the most economically viable manner. The Merit Order relies upon the marginal cost unit bidding principle, where generators provide their quotes to the market operator for each Market Time Unit. These aggregated bids, formulate the supply curve of the market. Bids are allocated according to their price component from low to high and as such the curve depicts the marginal cost of each technology.

Figure 1 Electricity Generation Merit Order effect

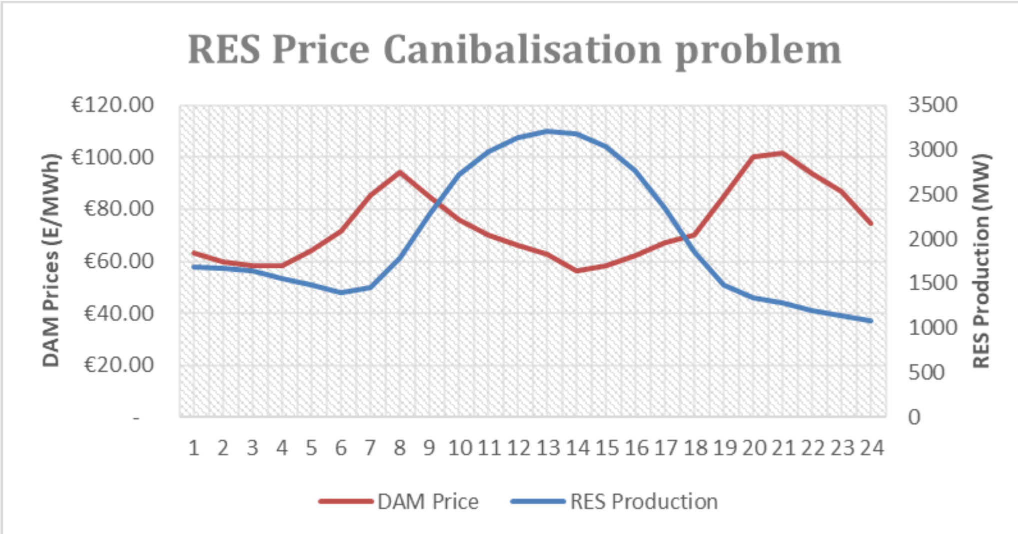


Source: OECD

On the other hand, another important parameter is the "Solar Duck Effect" or "Solar prices cannibalization effect". By Duck Effect, is described the fact that solar power plants -since they tend to simultaneously produce in the same bidding zone- heavily influence the Residual Demand Curve[3] and so the Market Clearing Price. This means that the more RES are incorporated into the system, the more significant this effect will be and thus the RES assets will tend to capture a lower market price. This contradiction regarding RES assets in the market, together with the fact that production can vary considerably in very short time frames and thus increase system instability and balancing costs, has been the topic of extensive research over the past 15 years (Sauvage & Bahar, 2013) (Kontochristopoulos, Michas, Kleanthis, & Flamos, 2021). Especially the risks of unstable production and the relevant lower capture prices of the Renewables in the market are significant factors taken into account for assessing the viability of any new RES that will have to connect to the Grid in the following years.

[3] Residual Demand is the demand that remains after taking into account RES and Hydro production and thus has to be covered by imports and thermal units. Residual demand is the key parameter in determining the price for a specific Market Time Unit.

Figure 2 RES Price Cannibalization (21/4/2021)



Source: NECP,2019

Whatever the case may be Renewables will be a vital part of the electricity production mix, both at a national and a European level. Yet, the need for accommodating Renewables in the market and creating an environment safe enough for them to deploy, while stepping away from the Government subsidies of the past with the Feed-in-Tariff or Feed-in-Premium mechanisms is of equal importance.

2. Evolution of Prices of the Electricity Wholesale market

2.1. Period 2017-2020

Until November 1st 2020, the Greek Wholesale electricity Market operated under a Mandatory Pool scheme. Mandatory Pool markets implied that all electricity produced was traded according to the Day Ahead Scheduling (DAS) provisions.

In the DAS approach, producers of electricity had to provide offers (bids) to the Market Operator for both Energy and Ancillary Services for the total of their available capacity. On the other hand, Suppliers that should procure energy from the market were obliged to procure via the Pool the whole of the consumer demand side they represented. The DAS approach was obligatory and bilateral contracts were not permitted.

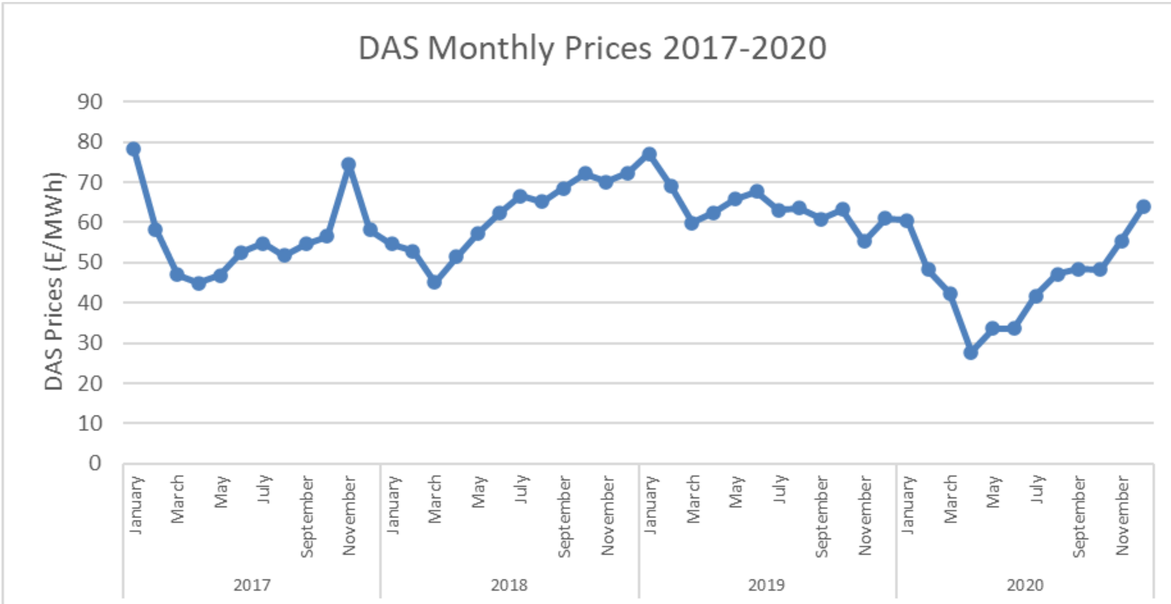
The System Marginal Price (DAS Price) was a result of an objective function optimization algorithm that sought to restrain costs for electricity production by simultaneously resolving the Electricity commodity Market and the Ancillary Services needs of the Transmission System Operator.

Thus, the DAS Model's primary feature is that essentially the Day Ahead Market (DAM) and the Day Ahead Ancillary Services Market (DAASM) were jointly optimized through the algorithmic optimization under the Mandatory Pool.

Additional components of cost outside of the market scope were: i) The Imbalances Settlement, ii) The Flexibility Remuneration Mechanism (FRM), iii) The Variable Cost Recovery Mechanism iv) The RES Floor Mechanism and v) The Additional Charge of Load Representatives for the RES Account (commonly known as PXEFEL).

Historical Market Data is provided by the Greek TSO (IPTO) (IPTO) and can be found in detail in Appendix 2.

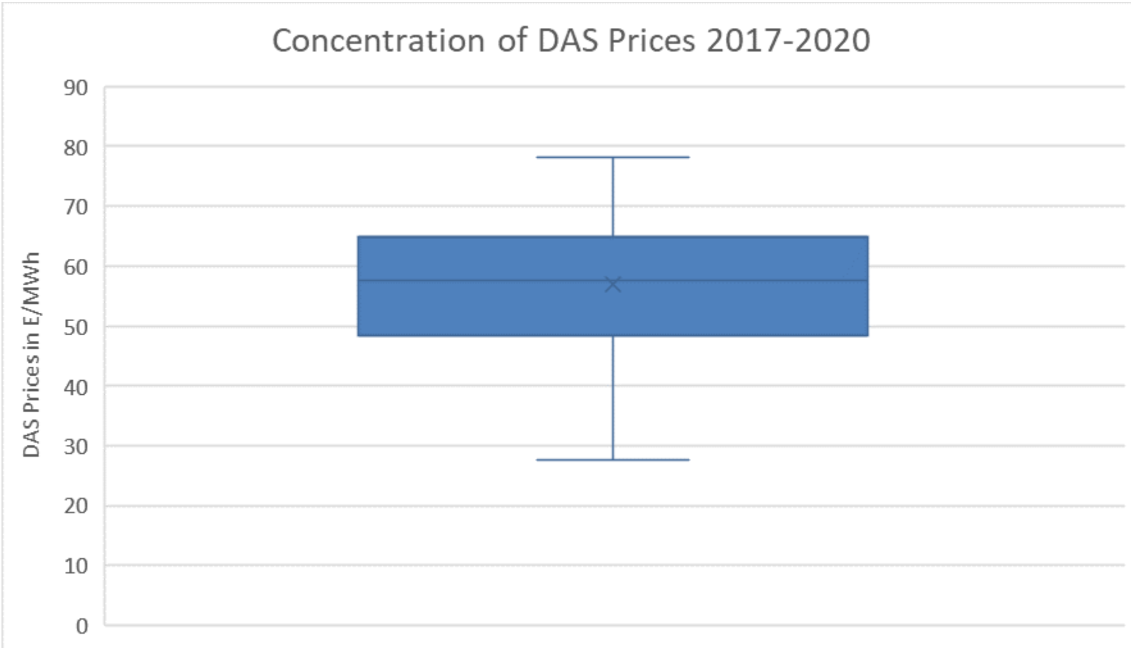
Figure 3 - Evolution of DAS/DAM prices 2017-2020



Source: IPTO

If we exclude from our analysis of the historical prices the monthly average prices from March 2020 to August 2020 (that reached historical lows due to the COVID-19 pandemic), we can observe that the lowest prices for the period in question are those of 2017. November is a seasonal transition month that depicts traditionally high prices since demand increases significantly, RES production at the same time begins to plummet and calendar forward contracts are closing. In general, the Greek Market experienced relative stability as can be seen by the distribution of the overall DAS prices over the period in question. Specifically, the Lower Quartile (Q1) is at 48,32 €/MWh, the Upper Quartile (Q3) is at 64.85 €/MWh with a Median of 57.7 €/MWh.

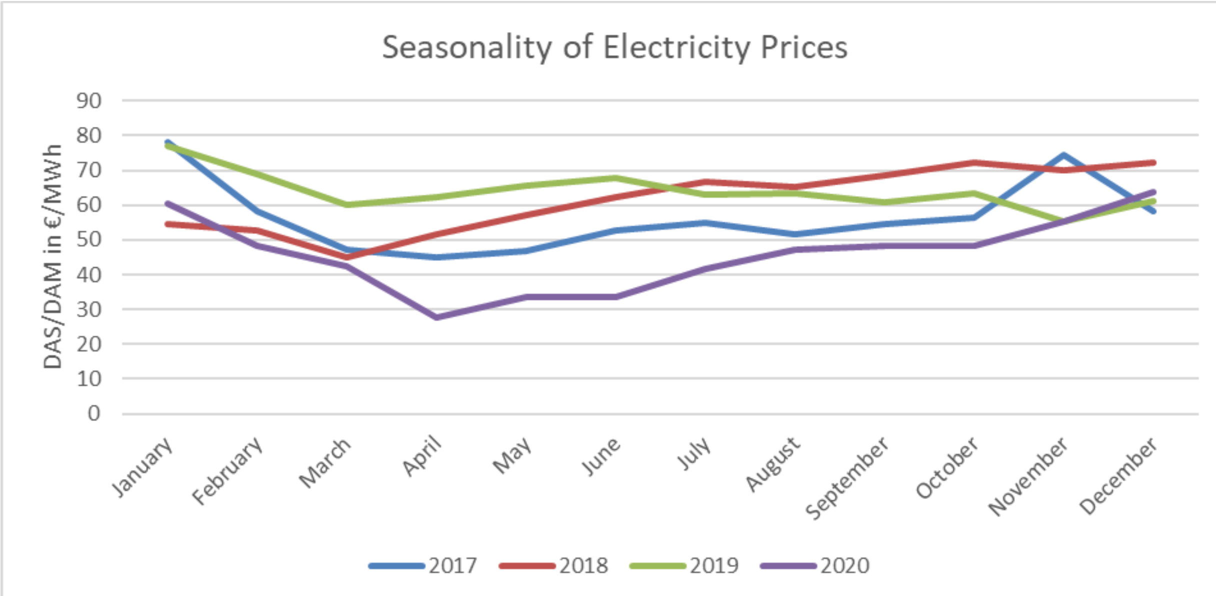
Figure 4 Concentration of DAS Prices 2017-2020



Source: IPTO

Seasonality did not appear to play any significant role in this period. On the contrary, prices were generally low in 2017 and the first quarter of 2018. Since then, a steady increase in wholesale market prices was observed mainly due to an increase in the prices of Natural Gas, though not in the degree and severity it is today, as well as the increase in prices formulated in the Forward Auctions that PPC SA was obliged to conduct (NOME).

Figure 5 Seasonality of Electricity Prices 2017-2020

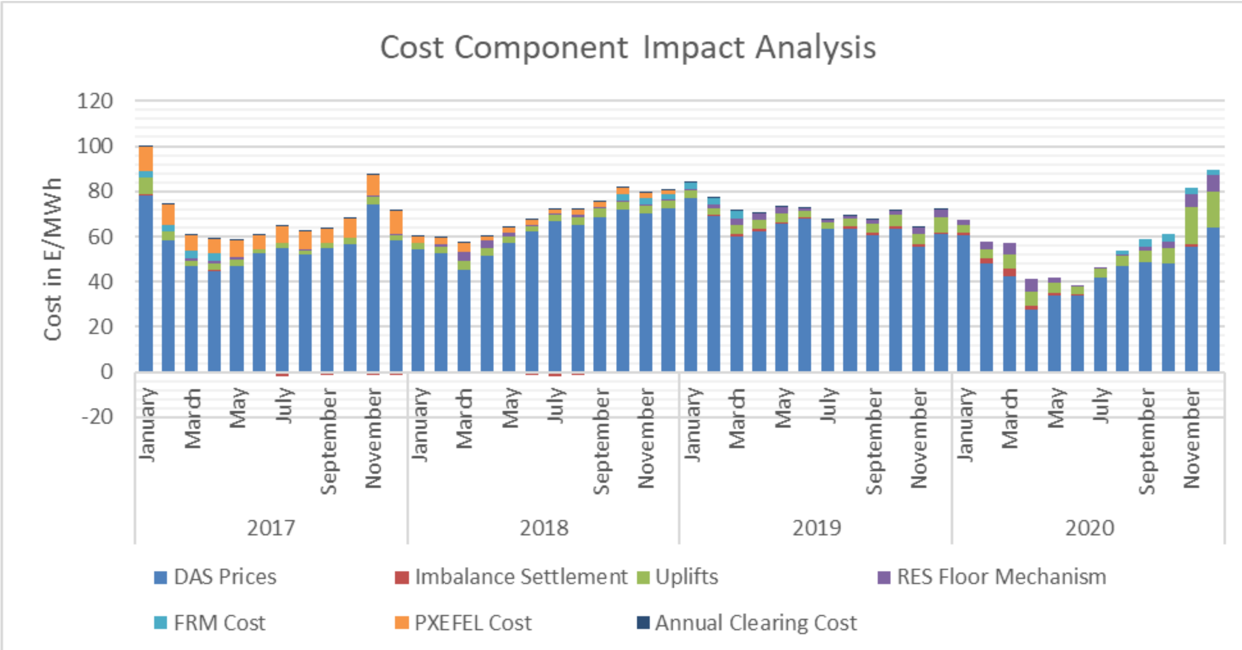


Source: IPTO

From a regulatory point of view, the wholesale market prices have a direct impact -or at least should reflect- on retail electricity billing schemes, regardless of the consumer size (household, commercial, industrial, etc) (Regulatory Authority for Energy, 2013).

Total supplier cost does not limit itself to the Wholesale spot market prices, but also includes all the various mechanisms of the Balancing Market, as well as the various levies and taxes (IPTO, 2021). Yet, by examining the impact of each cost component, it is evident that the Wholesale market prices are the primary cost component and the main driver behind the Supplier pricing policy.

Figure 6 Cost component impact analysis[4]



Source: IPTO

In effect, more than 80%- in general- of the final cost to the supplier comes directly from the wholesale market prices. The rest of the components although may vary have a much lower impact. In essence, we can argue that any differentiation in that particular component (the actual commodity), is what allows the evolvement of real competition between the market participants.

This status quo – of relatively low- energy wholesale prices, allowed the suppliers to provide competitive charges in the energy bills to the whole spectrum of energy consumers such as households, small businesses and industrial consumers (especially those connected to the Medium Voltage Grid). Whatever the fluctuations of other cost components would be, except for PXEFEL and FRM that could rise to 10% and 7% of the total cost, the fact that these 2 mechanisms especially were of a temporary nature, suppliers could absorb the extra costs and adjust their pricing policy based on the wholesale market components.

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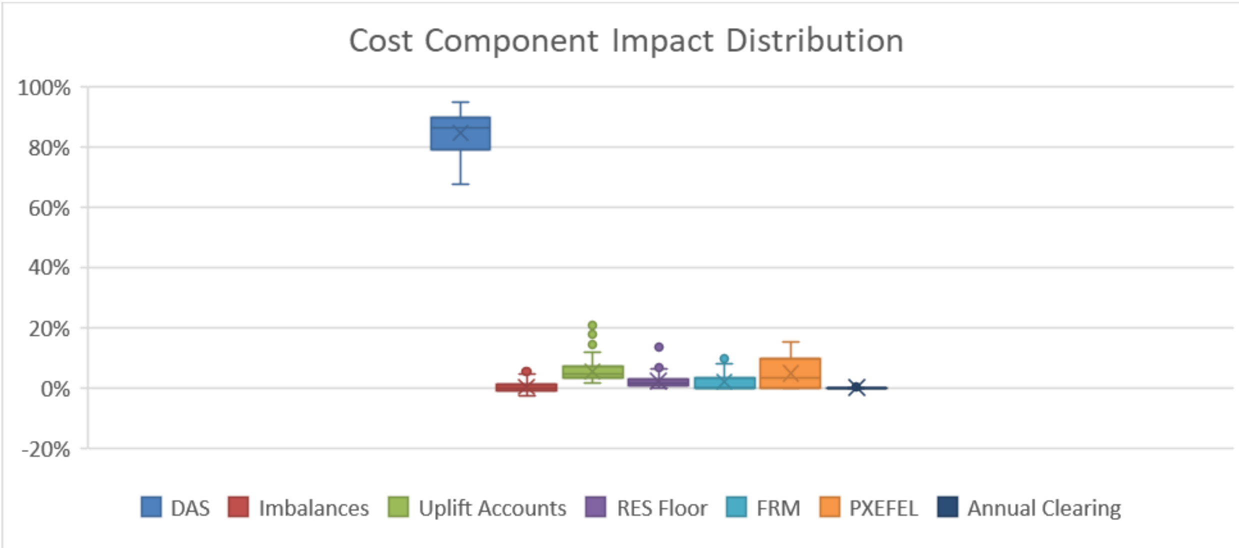
[4] November and December 2020 are the first 2 months of the Target Model and their cost components differ in nature

Figure 7 Cost Component impact distribution



Source: IPTO

Combined with the fact that PPC had to contain the held market share in the retail market, this situation allowed alternative suppliers to extract large industrial consumers and substantiate a significant market share in a short period. This was especially evident in the Medium Voltage proportion especially until 2017-2018, when the NOME auctions also came into place and allowed for Low Voltage Competition to evolve as well (Regulatory Authority for Energy, 2021).

2.1.1. NOME Impact

Law 4389/2016 introduced the auctions of forwarding physical electricity products by PPC to electricity suppliers and energy traders active in the Greek Market. Formally the name of these procedures was Forward Electricity Products Auctions System (FEPAS), but the French term was eventually adopted in the industry, NOME (Nouvelle Organisation du Marché de l'Electricité). The rationale, behind these auctions, was the Greek Government's obligation to reduce PPC's retail market share to less than 50% and allow the access of independent electricity suppliers to lignite and hydroelectric power plant (100% controlled by PPC and the cheapest form of energy production after RES at the time) with a final objective to lower prices for consumers.

Details for the deployment of the auctions were administered by RAE decisions according to Forward Electricity Product Auction Code (FEPAC) (Regulatory Authority for Energy, 2016), which also included the quantities and reserve prices for each auction. The Market

Operator was responsible for conducting the auctions as well as clearing and settling the final auctioned electricity products. The auctions took place quarterly within a calendar year and the products from these auctions were annual baseload expressed in MWh/h.

The methodology for determining the Reserve Price can be expressed as follows:

Auction Reserve Price = α* Variable Costs of Lignite Production + β* Variable Costs of Hydro Production

Where:

Variable Cost of Lignite Production: Mining Costs+ Fuel Purchased Third Party Costs+ Special Lignite Fees +Special Commencement Cost+ Variable Operation and Maintenance Cost + EUA Cost

Variable Cost of Hydro Production: Variable Costs of Hydroelectricity Power Generating Units

$\alpha = P_{min}$ (Lignite)/ (P_{min} (Lignite) + P_{min} (Hydro))

$\beta = P_{min}$ (Hydro)/ (P_{min} (Lignite) + P_{min} (Hydro))

P_{min} (Lignite) = Average minimum Daily Lignite Hourly Production of the last 4 quarters prior to the aution

P_{min} (Hydro) = Average minimum Daily Hydro Hourly Production of the last 4 quarters prior to the aution

The NOME auctions were abolished by the Government in 2019, yet their effect remained until 31/8/2020. The auction quantities and weighted average prices can be found in the following table:

Table 4 NOME Auction results

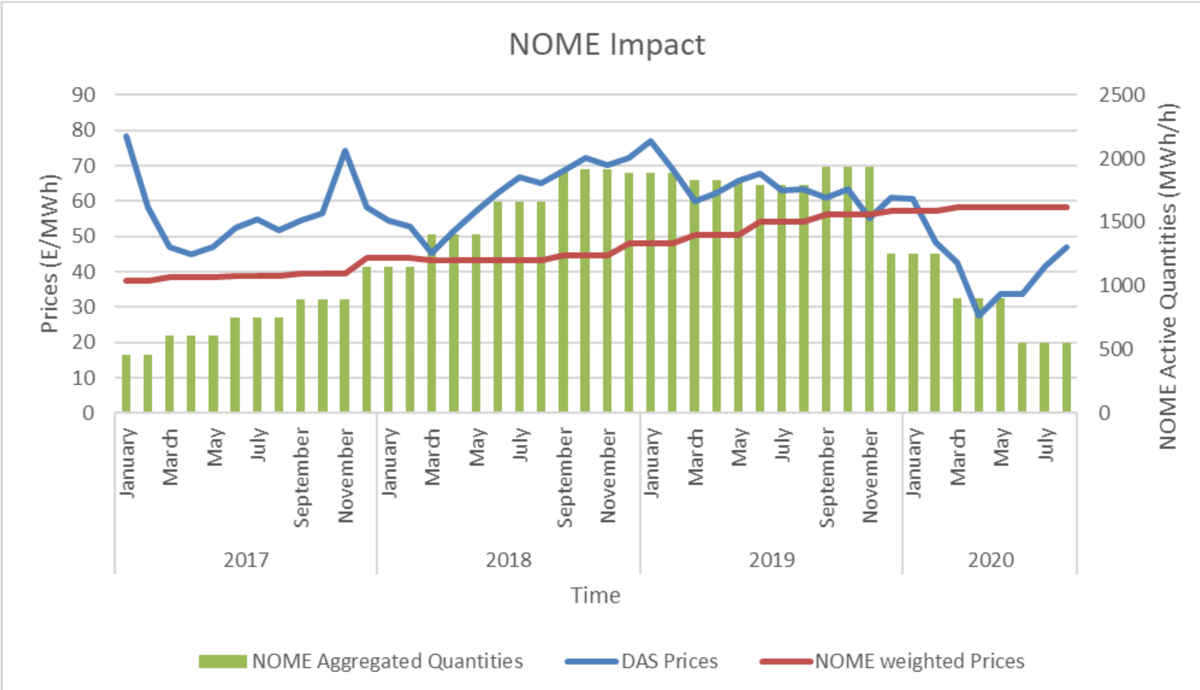
Forward Product	Quantity (MWh/h)	Volume (MWh)	Delivery Period	Reserve Price (€/MWh)	Closure price (€/MWh)
2016A01P01	460	4.029.600	2016.12.01-2017.11.30	37.37	37.5
2017A01P01	145	1.270.200	2017.03.01-2018.02.28	37.37	41.14
2017A02P02	145	1.270.200	2017.06.01-2018.05.31	37.37	40.02

2017A03P03	145	1.270.200	2017.09.01-2018.08.31	32.05	43.05
2017A04P04	718	6.289.680	2017.12.01-2018.11.30	32.05	45.2
2018A01P01	400	3.504.000	2018.03.01-2019.02.28	32.05	41.25
2018A02P02	400	3.504.000	2018.06.01-2019.05.31	32.05	42.05
2018A03P03	400	3.504.000	2018.09.01-2019.08.31	36.34	48.84
2018A04P04	683	5.983.080	2018.12.01-2019.11.30	36.34	54.74
2019A01P01	350	3.074.400	2019.03.01-2020.02.29	36.34	54.04
2019A02P02	355	3.118.320	2019.06.01-2020.05.31	36.34	58.74
2019A03P03	549	4.822.416	2019.09.01-2020.08.31	58.12	58.12

Source: Enexgroup

As it can be observed, both the quantities of the FEPAS in the Market as well as their weighted price, had an impact on the realization of the average DAS prices. This was since these quantities although produced by PPC, were not necessarily injected into the market to cover the load of the system but were also eligible for exports. This meant that the demand had to be covered by additional production (by PPC and other IPPs) which resulted in higher prices.

Figure 8 NOME impact on the market



Source: Enexgroup

Whatever the case, the actual price captured by a supplier in the market was eventually discounted by the NOME portfolio of each supplier and resulted in a lower wholesale cost in comparison to the "native" DAS price. This had as a result sustained prices for the period in question for the majority of the suppliers. It is worth noting, that in 2020, due to the COVID-19 pandemic, wholesale market prices were so much lower than the NOME products, that most suppliers elected to absolve their right to use them and pay a penalty according to the provisions of FEPAC.

2.2. The Target Model Period (2020-)

In contrast to the Mandatory Pool model, the EU Target Model cornerstone is the deployment of four distinct (yet consecutive markets) to determine the Formulated price in each Market Time Unit (MTU). These markets are in order of occurrence (i) The Forward market, (ii) The Day-Ahead Market, (iii) the Intraday Market and (iv) the Balancing Market. The first three Markets are operated by Hellenic Energy Exchange (HEnEx) and the Balancing Market is operated by the Greek TSO (IPTO).

The DAM Price, more formally referred to as Market Clearing Price (MCP) is the DAS equivalent in the new market structure.

In contrast to the DAS model, what the Target Model achieves is the separation of the actual product -that is the electricity as a commodity- from all the other aspects necessary for the operation of the market, effectively the Ancillary Services.

In contrast to Mechanisms present in the DAS approach, such as i) The Flexibility Remuneration Mechanism (FRM), ii) The Variable Cost Recovery Mechanism and ii) The RES Floor Mechanism, the Target Model, applies three distinct Uplift Accounts as follows (IPTO, 2021):

- Uplift Account 1 (Hellenic Transmission System Losses)

The UA-1 is used to allocate the cost emerging from the losses in the Transmission System and is the sum of all Markets (Day Ahead, Intra Day and Balancing) losses due to the physical constraints. Losses refer to the difference between energy produced form a producing unit and the energy delivered at the end of the Transmission Grid. The Cost of these losses is allocated to Balance Responsible parties participating in the Market according to the metered offtake of their customers (effectively suppliers).

The Uplift Account is calculated for each Imbalance Settlement Period as follows:

$$UPLIFT1p,t = LOSSESt * \frac{MQ_{p,t}}{\sum_p MQ_{p,t}} \quad [1]$$

Where

$LOSSESt$ are the actual losses expressed in € for the Imbalance Settlement Period t and $MQ_{p,t}$ is the customer offtake of Balance responsible Party p for the Imbalance Settlement Period t

- Uplift Account 2 (Balancing Capacity)

The UA-2 is used to allocate the cost of Balancing Capacity provided by Balancing Service Providers to the System Balancing Capacity refers to the reservation of unit power for the unit to be able to respond to TSOs orders for System stability. This cost is allocated to Balance Responsible parties participating in the Market according to the metered offtake of their customers (effectively suppliers).

The Uplift Account is calculated for each Imbalance Settlement Period as follows:

$$UPLIFT2p,t = BALCAPt * \frac{MQ_{p,t}}{\sum_p MQ_{p,t}} \quad [2]$$

Where

$BALCAPt$ is the total remuneration of all Balancing Service Providers expressed in € for the Imbalance Settlement Period t and
$MQ_{p,t}$ is the customer offtake of Balance responsible Party p for the Imbalance Settlement Period t

- Uplift Account 3 (TSO financial Neutrality)

The UA-3 is used to allocate any remaining balance borne by the TSO after the calculation of credits and debits for activated Balancing Energy for manual and automatic Frequency Response (mFRR and aFRR), the activated energy for purposes other than Balancing and the Imbalance Settlements. This cost is allocated to Balance Responsible parties participating in the Market according to the metered offtake of their customers (effectively suppliers).

The Uplift Account is calculated for each Imbalance Settlement Period as follows:

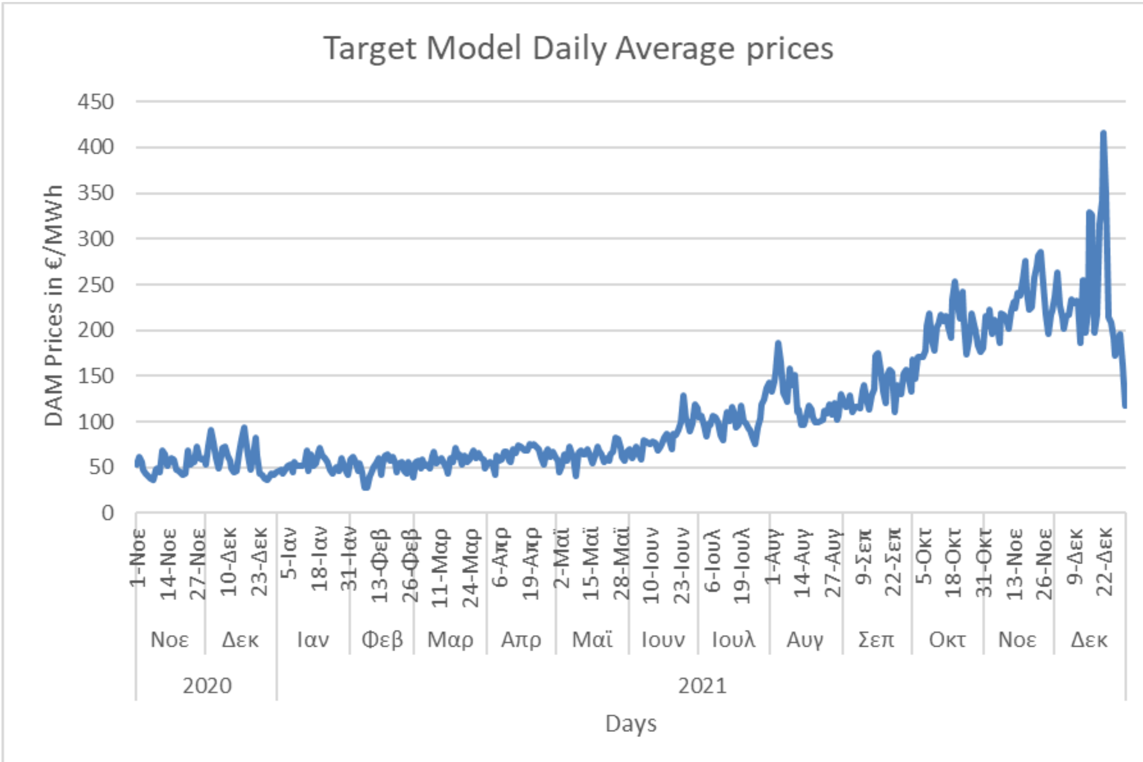
$$UPLIFT3p,t = NEUTRt * \frac{MQ_{p,t}}{\sum_p MQ_{p,t}} \text{ [3]}$$

Where

$NEUTRt$ is the amount ensuring the financial neutrality of the TSO expressed in € for the Imbalance Settlement Period t and
$MQ_{p,t}$ is the customer offtake of Balance responsible Party p for the Imbalance Settlement Period t

The implementation of the target model initially yielded similar outcomes regarding the DAM prices in comparison to the DAS system. DAM picked up at levels close to 55 €/MWh and generally remained low until the now widespread energy crisis that affects all European Energy markets began to evolve in July 2021. After that point, prices gradually moved upwards and broke one record after the other to reach an all-time high of 415€/MWh average daily price on December 22nd registering a staggering 542.5 €/MWh as a Market Clearing Price on 18:00 of that particular day (IPTO). This record would break again in 2022 on March 8th with an average daily price of 426.89€/ MWh with anall-time high of 600.07 €/MWh at 19:00 of that day.

Figure 9 Target Model DAM Prices Evolution

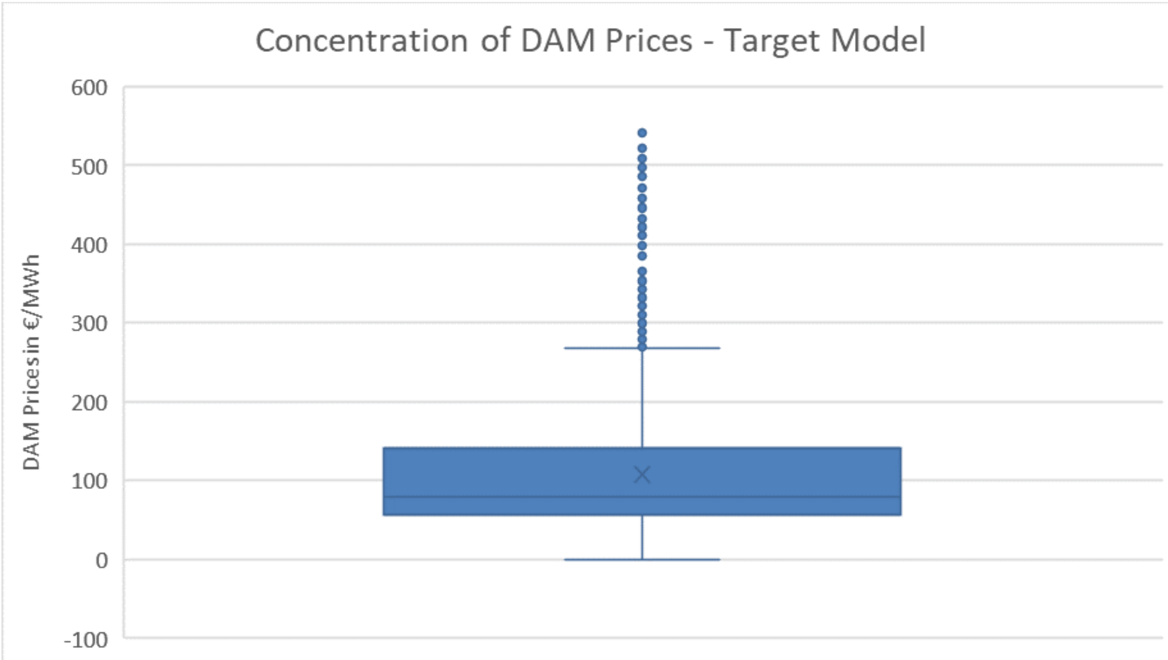


Source: IPTO

At this point, the high prices have indeed become the status quo in the market and estimations are that high prices may indeed become the new normal situation on the road to decarbonization (Popkostova, 2022) and definitely until 2025, although to a lesser degree than today.

As we can see regarding price concentration, the Lower Quartile (Q1) is at 56.4 €/MWh, and the Upper Quartile (Q3) is at 141.5 €/MWh with a Median of 107.76 €/MWh. It has to be noted that MCP reached 0 €/MWh or even marginally negative (-0.01€/MWh) on some occasions, but never on an average daily level.

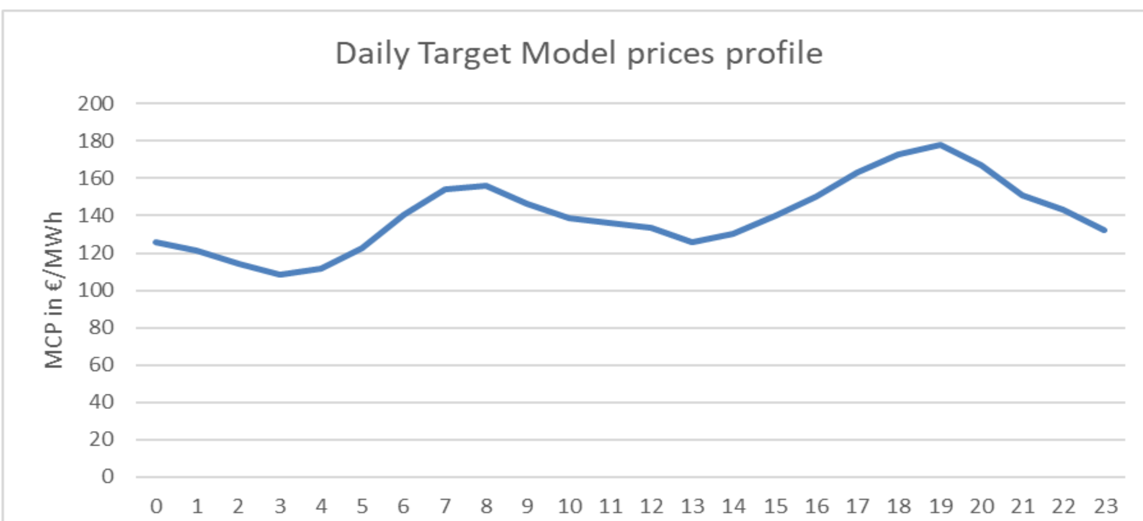
Figure 10 Concentration of DAM Prices Target Model



Source: IPTO

On an average daily profile within the target model, the effect of RES focused on Solar is evident with the lower prices captured in RES production times (typically 8:00-16:00).

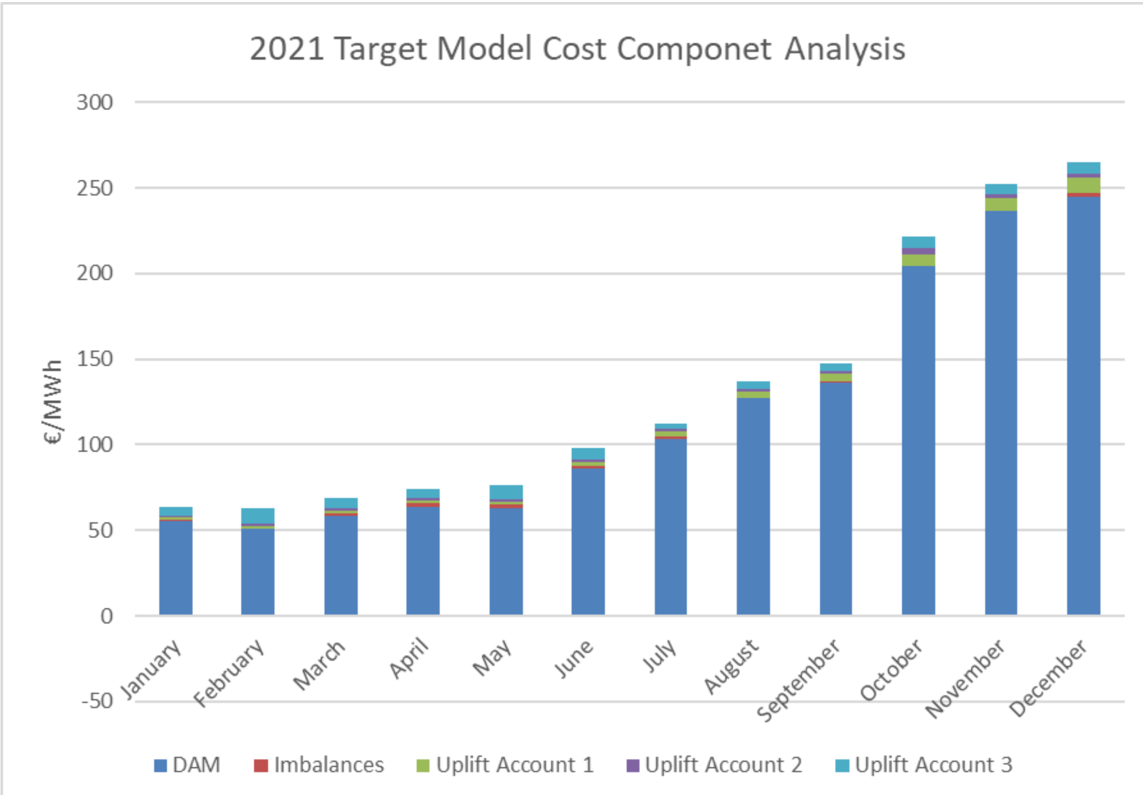
Figure 11 Daily Prices profile distribution



Source: IPTO

By examining the impact of each cost component, it is again evident that the Wholesale market prices are the primary cost component in the Target Model as well.

Figure 12 Target Model Cost Component Impact Analysis

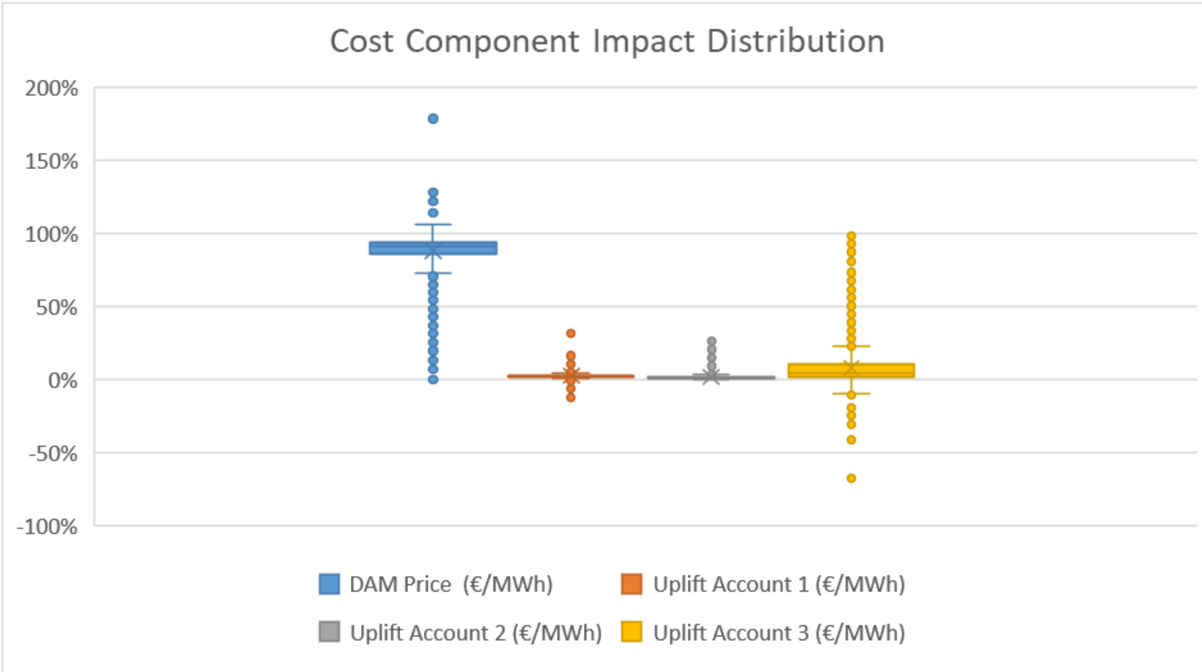


Source: IPTO

In fact, in the case of the Target Model, the DAM price is responsible for approximately 88% of the total cost with the Uplift Account 3 at about 8%. The rest of the uplifts, although rising since they are by nature linked to the DAM prices as explained above, remain at comparably insignificant levels of 3% and 2% respectively. Thus, within the Target Model, the emerging prices in the spot markets are the main driver of the cost that suppliers bear. In contrast, though to the DAS approach, the Target Model itself presents the opportunity to hedge against high spot market prices with the use of forwarding physical products in the Forward Market. In these first months of the new system, this opportunity was not explored by the participants. Even today when spot market prices remain at historical highs, as we can see in the Premarket data provided by EnEx (EnEx Group), the relative nominated quantities remain extremely low and adhere mostly to imports and exports from the System.

For a supplier to be able to differentiate from the rest of the competition, the exploitation of the Forward Market is of paramount importance.

Figure 13 Target Model Cost Component impact distribution

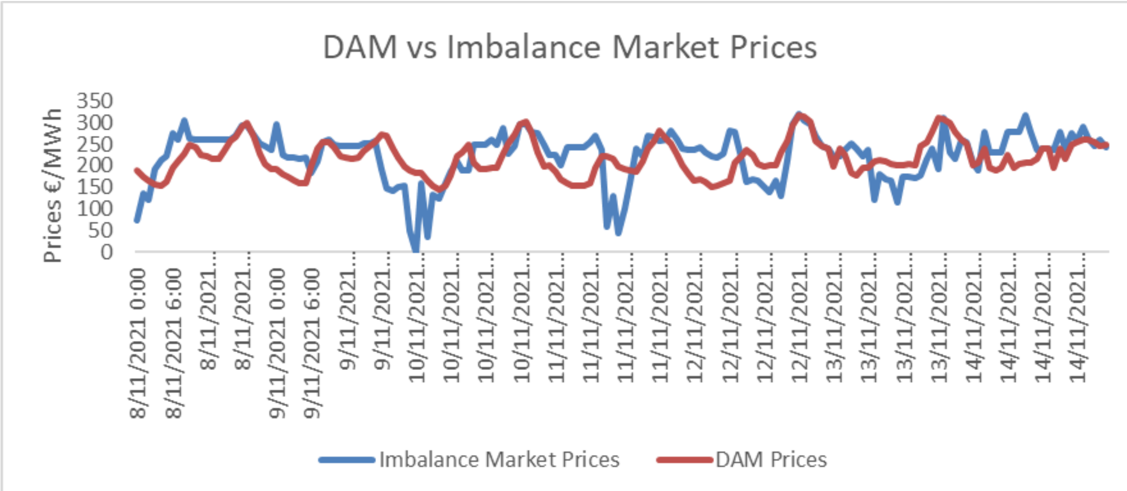


Source: IPTO

In the Forward Market (including Over-The-Counter bilateral transactions), the market participants can secure stable prices for their needs usually for long periods. Yet at the moment, according to data provided by EnEx, only one Market Maker was participating in the Forward Market and volumes remained relatively low (EnEx Group) .

Imbalance market Prices in general follow the trend of the DAM market. While spikes and valleys are much more common in the imbalance market, the general levels of prices remain close to each other.

Figure 14 DAM vs Imbalance Market Prices



Source: IPTO

Yet the Balancing Energy component is not that significant regarding the overall cost, since it refers to the Imbalance Quantities of each participant and not the whole energy transacted in the markets. This is evident by the aggregated data on monthly cost components provided by IPTO (IPTO), where Imbalances costs do not exceed 2,5 €/MWh while the relevant DAM prices are significantly higher.

Table 5 Wholesale Market Monthly Cost- 2021

Year	Month	MCP	Imbalances	Uplift Account 1	Uplift Account 2	Uplift Account 3	Total Uplifts
2021	January	55.441	0.830	1.413	0.869	5.357	6.770
2021	February	50.787	0.353	1.411	1.197	8.824	11.432
2021	March	58.614	1.181	1.400	1.773	6.251	9.424
2021	April	64.003	1.902	1.604	1.013	5.404	8.021
2021	May	63.172	1.996	1.591	1.158	8.408	11.157
2021	June	86.385	1.343	2.023	1.337	7.288	10.648
2021	July	103.446	1.500	2.684	1.324	3.526	7.534
2021	August	127.446	-0.087	3.337	2.008	4.077	9.422
2021	September	136.399	0.856	4.294	1.812	3.753	9.859
2021	October	204.052	-0.437	7.130	3.640	6.810	17.580
2021	November	236.376	0.072	7.885	2.087	5.581	15.553
2021	December	244.874	2.453	8.510	2.188	7.112	17.810

Source: IPTO

3. Large consumer Bills

Historically, large consumers are regarded as those that connect to the High and Medium Voltage Grid. Especially those in the High Voltage are regarded as baseload consumers equally responsible for the stability of the system in non-peak hours. Industries usually received a charge for the Power coefficient but since this is specific for each installation and registered and handled specifically, in the context of this work we will analyze the energy component (that is more than 80% of the eventual market-related cost).

3.1. High Voltage

High Voltage consumers are about 270 and require approximately 600 GWh monthly overall. High Voltage installations are mainly heavy Industries (such as metallurgy) or ancillary load from lignite plants and other heavy industrial activity (plastics, oil extraction, natural gas storage etc) (IPTO, 2020). As such, the final bills for the industry are extremely confidential. Until very recently PPC was the sole supplier that maintained High Voltage consumers. Since 2014, PPC offered a range of seven (7) typical bills for the high voltage that specified different zones within the day or week and thus different charges.

Three typical High Voltage bills are presented as follows[5]:

Table 6 High Voltage prices

	HV No 5 (€/MWh)	HV No7 (€/MWh)	HV No2 (€/MWh)
Peak	56.5	62	57.4
Low	44	43.5	57.4
Intermediate	49.5	51	57.4
Weekends	44	43.5	57.4

Source: PPC, Web Archive

The Peak, Low and intermediate zones are defined as follows:

[5] Bills for High Voltage were initially publicly available. As individual agreements took place over the years and especially after 2017, no information was available in PPCs website. The presented bills were extracted through WayBack Machine (https://web.archive.org/)

Table 7 High Voltage Zonal Pricing

Zone	Winter Time (October to April)	Summer Time (May to September)	Weekends and Holidays
Peak	10:00-14:00 & 18:00-21:00	10:00-14:00	N/A
Low	23:00-08:00	23:00-8:00	00:00-24:00
Intermediate	08:00-10:00 &14:00-18:00 & 21:00-23:00	08:00-10:00 &14:00-23:00	N/A

Source: PPC, Web Archive

High Voltage bills also included a Power charge, meaning surges of power that would be requested by the customer while operational and are charged against the contract agreed power.

3.2. Medium Voltage

Medium Voltage consumers are about 11.500 and require approximately 840 GWh monthly overall (Regulatory Authority for Energy, 2021). Medium Voltage clients include industries of various capacity, as well as big buildings (offices or supermarkets), data centers, Greenhouse plantations etc. As such the diversity between the various consumption profiles makes it more difficult to categorize. PPC maintained the dominant position in the MV market sector, yet it is in the Medium Voltage that customer mobility began early in the past decade. As in the High Voltage approach, PPC had standard bill plans for some broad categories of Medium Voltage Consumers.

The most typical, generic categories were the following:

Table 8 Medium Voltage Prices

	ΒΓ Commercial/ Industrial (€/MWh)	BX Low-Capacity factor (€/MWh)	BY High-Capacity factor (€/MWh)	BA Agricultural (€/MWh)
Peak	64.28	71.24	59.03	59.33
Low	50.62	56.57	46.14	59.33
Weekends	50.62	56.57	46.14	59.33

Source: PPC, Web Archive

Medium Voltage time zones are relatively less complex and are defined as follows[6]:

[6] Bills for Medium Voltage offered by PPC were publicly available until 2020. PPC removed the information form the publicly available website and now offers more customized billing schemes to individual consumers. No data were ever available for alternative suppliers. The presented bills were extracted through WayBack Machine (https://web.archive.org/)

Table 9 Medium Voltage zonal Pricing

Zone	Yearly zones
Peak	07:00-23:00
Low	23:00-07:00
Weekends	00:00-24:00

Source: PPC, Web Archive

Medium Voltage bills also usually included a Power charge, meaning surges of power that would be requested by the customer while operational and are charged against the contract agreed power.

3.3. CO2 clauses

An additional clause present in the majority of contracts is the CO_2 clause.

The CO_2 clause (in €/MWh) works as follows:

$$CO2_{Charge} = \frac{P(n-1)-Q(n-1)}{E(n-1)} \text{ [4]}$$

Where:

n: The relevant charge month

P(n-1): Average CO_2 Futures EUA as formed on ICE with maturity month December of month n-1 calendar year

E(n-1): Energy provided by PPC into the interconnected Grid during month n-1

M (n-1): Total CO_2 emissions by PPC into the interconnected Grid during month n-1

According to PPC calculations of the CO_2 charges made publicly available by the RAE Price Comparison tool, the Clauses can be found in Appendix 1.

4. Overall Supply Prices Evolution

The final energy supply cost, is always the driver that formulates the final consumer prices. This principle applies to both household and non-household final prices alike.

In general, it is usually more apparent in household consumer bills, since due to nature household consumers lack the negotiating power of Large Commercial or Industrial installations. This is implied even in the provisions of the Electricity Supply Code, where it is stated that for large Consumers that are not included in some special category, it is possible for special charges to be provided, adjusted in the specific characteristics and offered services agreed between Supplier and Consumer, adhering the principles of free market competition, avoidance of cross-subsidies and after meaningful negotiations between the parties involved (Regulatory Authority for Energy, 2013).

In any case, bills to consumers should always reflect the wholesale market costs, the administrative cost for managing each consumer and a reasonable margin in favor of the supplier.

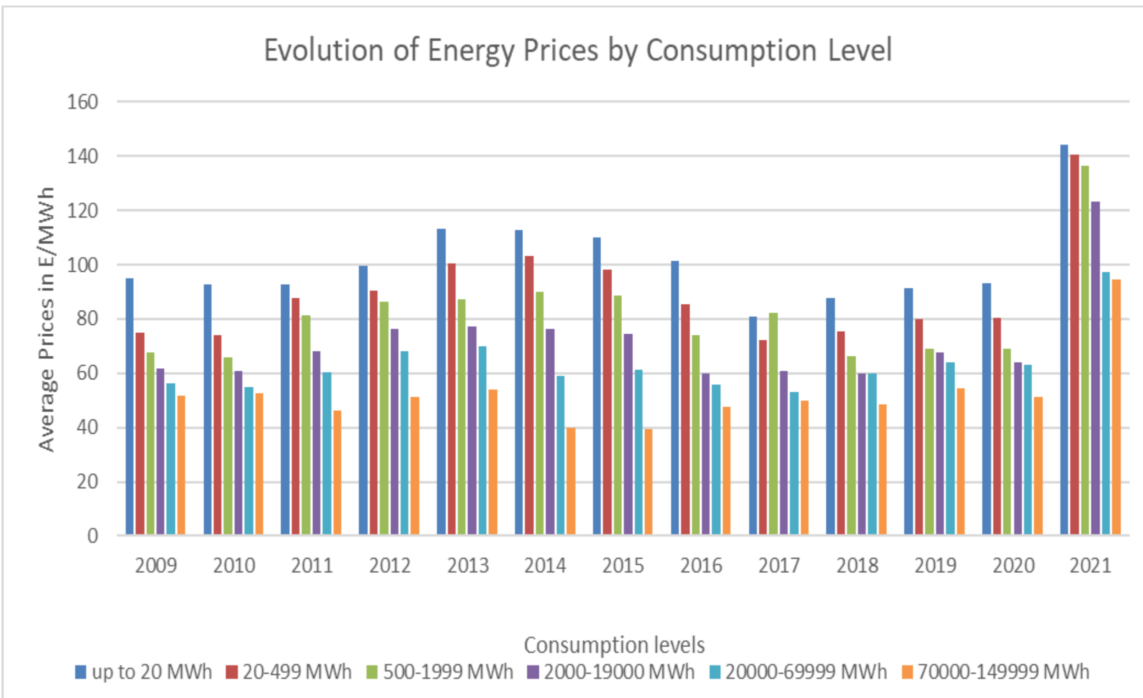
Table 10 - Level of Energy and Supply prices according to consumption levels for non-household consumers

Consumption Levels (annual) / Years	Up to 19 MWh	20- 499 MWh	500- 1999 MWh	2000-19999 MWh	20000-69999 MWh	70000-149999 MWh
2009	95.0	74.8	67.6	61.7	56.3	51.7
2010	92.7	74.1	66.0	60.7	54.9	52.4
2011	92.9	87.8	81.3	68.0	60.3	46.4
2012	99.5	90.4	86.2	76.2	68.1	51.1
2013	113.1	100.4	87.1	77	69.7	53.9
2014	112.7	103.0	89.9	76.1	58.9	39.8
2015	110.0	98.3	88.6	74.3	61.3	39.3
2016	101.2	85.6	73.8	59.7	55.6	47.5
2017	81.0	72.0	82.0	61.0	53.0	49.7
2018	87.6	75.2	66.3	60.1	59.9	48.7
2019	91.2	79.9	68.9	67.6	64.1	54.4
2020	93.3	80.3	69.1	63.9	63.3	51.1
2021	144.4	140.6	136.6	123.1	97.1	94.7

Source: Eurostat

Eurostat provides data on electricity prices for both household and non-household consumers (Eurostat, Last assesed April 2022). Data provided by Eurostat are in a modular form so that the energy component (or supply cost) can be differentiated from the overall cost of electricity, which naturally included taxes, levies as well as Network and System fees that can be different in both nature and impact in various EU countries. Especially for non-household consumers the second kind of clustering takes place that has to do with annual consumption levels. In the case of Greece, as we can see from the publicly available information, there is a scarcity of data that involves the highest tier of consumption level (over 150.000 MWh/ year) and only for the years between 2009 and 2011. That is why in this analysis we are going to focus more on the consumption categories for which data are provided.

Figure 15 Evolution of Energy prices by Consumption level



Source: Eurostat

Additionally, it has to be noted that for the second largest consumption level (70.000-149.999 MWh/ year), data after the year 2017 are classified as confidential and thus not publicly provided by Eurostat. Yet, the level of prices for that category can be derived by applying the least squares methodology, where the prices of the smaller magnitude categories are treated as the known independent variables (x) and the large consumption category has retreated as the dependent in question variable y. By applying the said methodology, the overall evolution of the average annual prices by consumption level and the supply charges can be estimated for the years 2017-2021.

Table 11Wholesale prices and prices offered to non-household consumers

Consumption Levels (annual) / Years	Up to 19 MWh	20- 499 MWh	500- 1999 MWh	2000-19999 MWh	20000-69999 MWh	70000-149999 MWh	Average annual wholesale prices
2017	81.0	72.0	82.0	61.0	53.0	49.7	56.50
2018	87.6	75.2	66.3	60.1	59.9	48.7	61.52
2019	91.2	79.9	68.9	67.6	64.1	54.4	64.08
2020	93.3	80.3	69.1	63.9	63.3	51.1	45.91
2021	144.4	140.6	136.6	123.1	97.1	94.7	119.25

Source: Eurostat

By examining the period in question (2017-2021) we can observe that prices finally offered to consumers are strongly positive correlated, with the large consumption category bearing the highest positive correlation index (0.97) with the wholesale (DAM) prices.

Table 12 Correlation Matrix of Wholesale prices and prices offered to consumers

Consumption Levels (annual) / Years	Up to 19 MWh	20- 499 MWh	500- 1999 MWh	2000-19999 MWh	20000-69999 MWh	70000-149999 MWh	Average annual wholesale prices
Up to 19 MWh	1.000						
20- 499 MWh	0.997	1.000					
500- 1999 MWh	0.932	0.954	1.000				
2000-19999 MWh	0.990	0.997	0.967	1.000			
20000-69999 MWh	0.996	0.989	0.901	0.981	1.000		
70000-149999 MWh	0.988	0.996	0.968	1.000	0.978	1.000	
Average annual wholesale prices	0.942	0.957	0.943	0.968	0.936	0.970	1.000

As it is evident, large consumers, enjoyed prices even lower than the average wholesale market prices. This is since large consumers, especially industrial serve as baseload for the majority of the suppliers and play their part in the stability of the system in general. Furthermore, it should be noted that most large consumers, enjoyed closed contracts with at least a yearly duration and except for the CO_2 clauses in the Medium Voltage bills, no other market-derived component or clause was taken into account in the pricing mechanism. This made in turn large consumer contracts very difficult to change mid-term. On top of that, the intensification of supplier competition, along with the capabilities that the Forward Electricity Products[7] offered and several Arbitrages performed by RAE - such as the widely debated ALUMINION SA arbitrage[8] that regulated a benchmark price for High Voltage of 36.7 €/MWh- retained prices for large consumers at a low level.

The situation in this particular market segment is radically changing, along with the Electricity Prices skyrocketing due to the EU energy crisis, that emerged in the second half of 2021.

[7] NOME products
[8] https://www.dei.gr/el/dei-omilos/ependytikes-sxeseis/anakoinoseis/xrimatistiriakes-anakoinoseis/xrimatistiriakes-anakoinwseis-2013/apofasi-rae-gia-timi-ie-stin-alouminion-ae/

5. Current Industry bills

By late 2021, suppliers, under the pressure of the wholesale market's extremely high prices, have begun adjusting the bills offered to large consumers, especially towards the medium Voltage grid.

What made the difference was either offer that included a stable (not market-linked) price significantly higher than the previous period or offers that incorporated the wholesale cost in what is commonly known as the Wholesale Market Clause (WMC).

The Wholesale Market Clause in general operates as follows, according to RAEs 409/2020 Decision, titled “Guidelines for the transparency and validity of charges on the competitive part of Low Voltage[9] Consumers” (Regulatory Authority for Energy, 2020):

$$WMC(x) = \begin{cases} a * (x - L_l) + b, & x < L_l \\ 0, & L_l \leq x \leq L_u \\ a * (x - L_u) + b, & x \geq L_u \end{cases} \quad [5]$$

Where:

$WMC(x)$ = Cost of Clause expressed in €/MWh triggered by values of Market Index x

x = Market index that triggers the clause (DAM Price, Market Clearing Price, Total Wholesale Market price etc

L_u = Upper limit of market index x above which the clause is triggered

L_l = Lower limit of market index x below which the clause is triggered

a= factor freely chosen by the supplier. Must be a number >0

a= factor freely chosen by the supplier. Must be a number >0

b = factor freely chosen by the supplier. Must be a number ≥0

Whatever the case might have been, the energy crisis instigated a new era in large consumer bills, with strong references to the wholesale market.

[9] At that point such charges only applied to Low Voltage Consumers and not Industrial or Commercial Large Consumers.

Offers collected, during January 2022 by suppliers for Medium Voltage installations of various levels of consumption present a large diversification even when being provided by the same supplier.

The offers in this section, are provided anonymized towards suppliers.

5.1. Supplier 1 offers

Supplier no 1 provided the following offers:

Fixed Pricing

A fixed price of 326.90 €/MWh

Indexed Pricing

A simplistic Market clause with the following structure:

$WMC(MCP) =$ 46.62€/MWh + Average Monthly DAM Market Clearing Price (in €/MWh) [6]

Wholesale Market Clause Pricing

A full Market Clause with the following structure:

$WMC(MCP) =$ 21.09€/MWh + 1.038[10] * (Average Monthly DAM Market Clearing Price + Uplift Accounts) (in €/MWh) [7]

5.2. Supplier 2 offer

Wholesale Market Clause Pricing

A full Market Clause with the following structure:

$WMC(MCP) =$ 10€/MWh + 1.038 * (Average Monthly DAM Market Clearing Price + Imbalances +Uplift Accounts) (in €/MWh) [8]

[10] 1.038 is derived from the relevant percentage of losses in the Grid (3.77%), as calculated and approved by relevant RAE yearly decisions

5.3. Supplier 3 offer

Wholesale Market Clause Pricing

A full Market Clause with the following structure:

$WMC(MCP) =$ 2€/MWh + 1.038 * (Average Monthly DAM Market Clearing Price + Imbalances +Uplift Accounts) (in €/MWh) [9]

5.4. Supplier 4 offer

Wholesale Market Clause Pricing

A full Market Clause with the following structure:

$WMC(MCP) =$ 2€/MWh + 1.038 * (Hourly DAM Market Clearing Price + Special RES Account Irregular charge[11] + Uplift Accounts + Losses Normalization Cost[12]) (in €/MWh) [10]

5.5. Supplier 5 offers

Wholesale Market Clause Pricing A[13]

A full Market Clause with the following structure:

$WMC(MCP) =$ 5€/MWh + 1.038 * (Hourly DAM Market Clearing Price + Monthly Uplift Accounts + Imbalances) (in €/MWh) [11]

Wholesale Market Clause Pricing B[14]

A full Market Clause with the following structure:

[11] Irregular Supplier Charge towards Special RES Account. Calculated and approved by RAE at 2 €/MWh. It is a transitory charge and it applies in the pricing for as long as it is passed through to the suppliers
[12] Normalization cost charged by HEDNO (DSO) to suppliers. It varies for each supplier according to his load portfolio. For this particular case it is calculated by the supplier at 0.5€/MWh
[13] Was publicly available until 10/05/2022
[14] At the moment it is the only publicly available offer for Medium Voltage

$WMC(MCP) =$ 98€/MWh +/- (Average Monthly DAM Market Clearing Price + Monthly Uplift Accounts + Any potential charges) (in €/MWh) [12]

L_u = 77 €/MWh

L_l = 72 €/MWh

Upper and Lower limits apply to the sum of: Monthly DAM Market Clearing Price + Monthly Uplift Accounts + Any potential charges.

Indexed Various Markets Clause Pricing

A Pricing structure that incorporates EUAs and Natural Gas spot markets in the relevant pricing module:

$Final\ Price(TTF, EUA, MCP) =$ 2,0785*TTF price + 0.3815*EUAs price+21.50 + Hourly DAM MCP *γ €/MWh [13]

Where,

TTF (Title Transfer Facility): is the weighted average price for every forward product with physical delivery month the month under consideration as provided by ICIS[15]

EUAs: The average price of every forward product with physical delivery month the last month of the current year as closed within the relevant month as provided by European Energy Exchange[16]

γ: factor that incorporates system losses and other Wholesale market costs. Current value calculated by the supplier = 0.09483

5.6. Supplier 6 offer

Wholesale Market Clause Pricing

A full Market Clause with the following structure:

$WMC(MCP) =$ 75€/MWh +/- 1.038*(Hourly DAM Market Clearing Price + Average Monthly Uplift Accounts) (in €/MWh) [14]

[15] https://www.icis.com/compliance/reports/european-spot-gas-market/
[16] https://www.eex.com/en/market-data/environmental-markets/derivatives-market

L_u = 68.5 €/MWh

L_l = 65.5 €/MWh

Upper and Lower limits apply to the sum of: Monthly DAM Market Clearing Price + Average Monthly Uplift Accounts augmented by the losses factor.

Supplier offers are summarized in the following table:

Supplier	Pricing Offers	Formula	Inputs
Supplier 1	Fixed	326.9 €/MWh	N/A
	Indexed	MCP + 46.62 €/MWh	MCP
	Clause	(1+losses factor) *(MCP+ Uplifts) + 21.09 €/MWh	MCP, Losses factor, Uplift Accounts
Supplier 2	Clause	(1+losses factor) *(MCP+ Uplifts+ Imbalances) + 10 €/MWh	MCP, Losses factor, Uplift Accounts, Imbalances
Supplier 3	Clause	(1+losses factor) *(MCP+ Uplifts+ Imbalances) + 2 €/MWh	MCP, Losses factor, Uplift Accounts, Imbalances
Supplier 4	Clause	(1+losses factor) *(MCP+ Uplifts+ RES Charges+ Losses normalization cost) + 2 €/MWh	MCP, Losses factor, Uplift Accounts, RES Charges (currently 0€/MWh), Losses normalization cost (estimated at 0.5€/MWh)
Supplier 5	Clause A	(1+losses factor) *(MCP+ Uplifts+ Imbalances) + 5 €/MWh	MCP, Losses factor, Uplift Accounts, Imbalances
	Clause B	$Price(TC) = \begin{cases} 98 + (TC - 72), & TC < 72 \\ 98, & 72 \leq x \leq 77 \\ 98 + (TC - 77), & x > 77 \end{cases}$ TC= MCP+ Uplifts+ Potential Charges	MCP, Uplift Accounts, Potential Charges (currently 0€/MWh)
	Various Markets Clause	2.0785* TTF + 0.3815*EUAs + MCP* 0.09483 +21.50 €/MWh	TTF, EUAs, MCP
Supplier 6	Clause	$Price(TC) = \begin{cases} 75 + (TC - 65.5), & TC < 65.5 \\ 75, & 65.5 \leq x \leq 68.5 \\ 75 + (TC - 68.5), & x > 68.5 \end{cases}$ TC= (1+losses factor) *(MCP+ Uplifts)	MCP, Uplift Accounts

Table 13 Supplier offers for 2022

In general, as we can observe, the majority of suppliers rely on similar concepts of approaching their wholesale market costs. MCP and the Uplift Accounts seem the most persistent components, while most suppliers incorporate the losses factor and the Imbalances into their billing structures. Supplier no 5 is the only supplier so far that provided a clause that incorporates inputs of cost besides the electricity market, namely Natural Gas prices and EUAs prices, in an attempt to partially disengage from the Greek Electricity Market framework and address the European and International status of electricity cost dependencies.

5.7. Overall proposal assessment

To attempt a generic assessment of the proposals for 2022, the relevant average prices provided by IPTO and the European Energy Exchange for EUAs as well as the TTF prices, should be taken into account.

Monthly prices for all of these components are as follows:

Table 14 Monthly Billing Components

Year	Month	MCP	Imbalances	Uplift Account 1	Uplift Account 2	Uplift Account 3	TTF	EUAs
2022	January	231.968	2.887	6.659	2.241	7.381	84.67	98.24
2022	February	214.7	1.425	5.804	1.959	5.985	98.595	82.21
2022	March	274.251	4.726	8.14	2.701	8.123	125.905	76.48
2022	April	248.51	1.319	6.819	0.991	9.33	99.45	84.45

By performing a simulation of a billing process (on a market level detail) and by applying the weighted average prices by month from IPTO and EEX, we can obtain the following outcome:

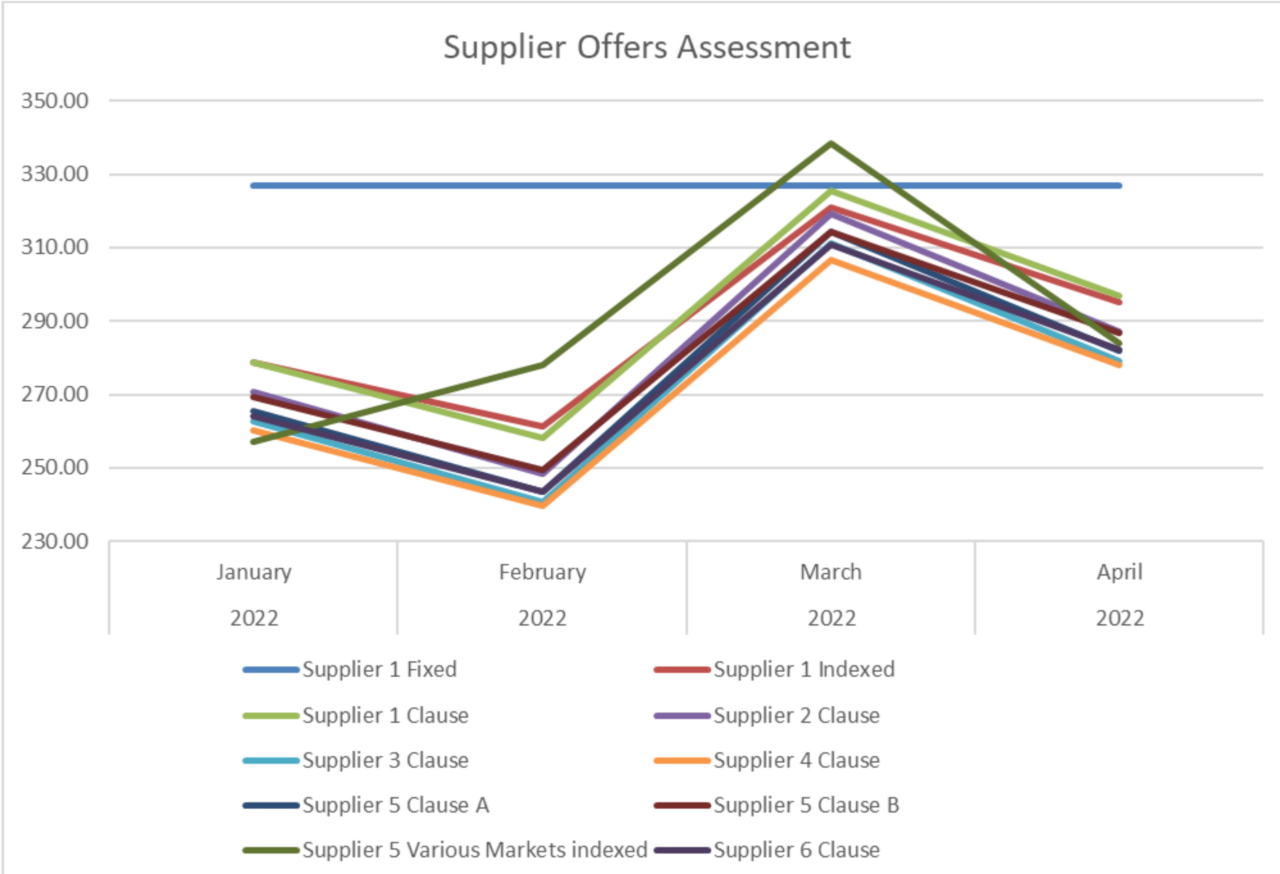
Table 15 Billing simulation for January- April 2022

Supplier	Pricing Offers	January 2022	February 2022	March 2022	April 2022
Supplier 1	Fixed	326.9	326.9	326.9	326.9
	Indexed	278.59	261.32	320.87	295.13
	Clause	278.7	258.15	325.36	296.76
Supplier 2	Clause	270.60	248.54	319.17	311.17

Supplier 3	Clause	262.60	240.54	311.17	279.03
Supplier 4	Clause	260.13	239.58	306.79	278.18
Supplier 5	Clause A	265.60	243.54	314.17	282.03
	Clause B	269.25	249.45	314.22	286.65
	Various Markets Clause	256.96	278.15	338.38	283.99
Supplier 6	Clause	264.11	243.56	310.77	282.17

As we can deduct from both the above numbers, as well as their graphical representation, 2 proposals stand out in terms of cost, The fixed offer by Supplier 1 and the Various Market Clause offer by Supplier 5 in February and march 2022. The rest proposals revolve around similar prices for each month. Differentiation evidently has to do with the risk that each supplier is willing to bear regarding mostly Uplift Accounts and the relevant margins that are formed as parts of the proposals. This can be seen more clearly, by comparing the offers by Supplier 2, Supplier 3, Supplier 4 and the Clause A offer by Supplier 5. These proposals essentially carry the same cost components, that are nominally identical and the fixed part (serving as the desired margin in these cases) varies between 2,5 and 10 €/MWh.

Figure 16 Supplier offers assessment



Furthermore, it should be also noted that while these are the proposals from the supplier side, the only cost component upon which hedging and alternatives can be found is the principal cost component of the MCP.

Whatever the case may be, large consumers are called to bear an electricity energy cost significantly higher than in the previous years. This rise is almost 5 times higher for the high consumption level category, from about 50 €/MWh to almost 250 €/MWh on average.

In this situation, forward contracting of energy and disengaging to the fullest extend from the wholesale markets becomes a necessity for both suppliers who want to remain competitive and ahead of the competition, as well as large energy consumers to ensure they can continue production or procurement of services in a sustainable manner, from an energy cost point of view.

One of the answers -and certainly the most sustainable one- resides within the exploitation of RES and their relatively low cost, as we will explain in the following chapters. RES are themselves in a transition period as well, as we transit from the relatively High Feed-in-Tariff schemes of the past to Feed-in-Premium schemes and eventually full Market obligations and participation. In this context, the application of RES within the market but removed from Government supported subsidy schemes can provide a meaningful solution to the high wholesale market cost.

6. RES Prices

6.1. Feed-in-Tariff and Feed-in-Premium mechanisms

Since 2006 a Feed-in-Tariff support model for RES was established (Hellenic Republic, 2006) .This Feed-in-Tariff scheme, facilitated and accelerated Solar technology as it compensated producers with significantly high prices. Specifically for Solar projects installed on the Interconnected System the compensation was set to 400€/MWh. Wind farms on the other hand received a lower compensation in the area of 90-100 €/MWh (Hellenic Republic, 2009) with a contract for the sale of the energy of 20 years with some extensions up to 25 years.

In 2014, for reasons related to the financial crisis of the Greek Economy, and the steadily increasing deficit of the RES Special Account the government halted for a period of almost 3 years (2012-2014) the installation of new solar parks and retroactively diminished the Feed-in-Tariffs for all RES (Solar, Wind, Small Hydro units and CHP) (Hellenic Republic, 2014). This retroactive arrangement (commonly known as the New Deal) and the pause of new PV installations caused great uncertainty to the market. After various changes in Law and Ministerial decisions, the prices for the dominant technologies of Solar parks and Wind farms with the Feed-in-Tariff subsidies support were:

Table 16 Feed-in-Tariffs for Wind Farms

Technology (Wind)	Tariff for the Interconnected System (€/MWh)	Tariff for the Non-Interconnected System (€/MWh)
< 5MW	105	110
>5 MW	105	110

Source: RAE

Table 17 Feed-in-Tariffs for Solar Parks

Technology (Solar)	Tariff for the Interconnected System (€/MWh)	Tariff for the Non-Interconnected System (€/MWh)
From August 2014 < 100 kW	115	95
From August 2014 >100 kW	90	95

From 2015 < 100 kW	1.2x $AMSP_{v-1}$[17]	1.1x $AMSP_{v-1}$
From 2015 >100 kW	1.1x $AMSP_{v-1}$	1.1x $AMSP_{v-1}$

Source: RAE

Finally, the Feed-in-Tariff regime was suspended by the end of 2015 and replaced with the Feed-in-Premium mechanism from 01.01.2016 (Hellenic Republic, 2016). The Feed-in-Premium (or FiP) support mechanism is even itself a transitory approach, that aims to bring the RES and their revenues closer to the market and also binds them with obligations for market participation and (in due time) balancing costs.

The FiP allows payments to be performed based on the relevant Spot Market Prices. For each technology, a Reference Price is set. If the Market Prices in the spot market are above the said Reference Price, then the RES producer is obliged to return the difference to the RES Special Account. If the market price is below the said Reference Price, then the producer receives the difference form the RES special account. Naturally, the stability of the Reference Price resembles in the long run a FiT mechanism, but in the Greek case, Technologies such as Solar and Wind (that are regarded mature technologies) are subjected to participate and compete against each other in descending price auctions (tenders) that determine the Reference Price. In addition to the above support mechanism changes, RES assets are now required to actively participate in the spot market[18].

The Reference Prices in €/MWh for the basic RES technologies are:

Table 18 RES Auction Reference Prices

Technology	2016	2020
CHP (Biomass)	184	176
Hydro (R-o-R)	100	90
PV- Commercial (above 400 kW)	Tender procedure	Tender procedure

[17] $AMSP_{v-1}$ is the Average Marginal System Price of the previous year

[18] To accommodate the need for market participation, the Role of the Aggregator was introduced. The RES aggregator assembles an energy portfolio form various RES assets and participates with that portfolio in the markets. The Aggregator bears the full responsibility for balancing and compliance issues.

Wind Onshore	98	60

Source: RAE

The Auction System is run by the Regulatory Authority for Energy (RAE) and has the approval of the European Commission[19]. The auctions are taking place in an online environment and each auction has a specific set of rules that differentiate on the starting price and the guarantees and specific licenses that have to be procured by the interested producer to participate.

Since it is a "lowest bidder" mechanism, a lot of projects under development that take place in the auctions do not get awarded with a Premium. Projects that cannot take that premium are often abandoned or postponed as the Premium subsidy is a major factor in project financing. Without a long-term contract, that ensures the bankability of the project and the lack of any alternatives, the question of reaching the NECP plan on the subject of RES production arises. An additional point is that so far, there is no specific framework for non-mature projects, meaning that auction participation is limited to projects that have received Connection Terms for the relevant Network or Grid Operator and have a COD[20] up to 3 years (for big projects).

6.2. Evolution of RES auction prices.

The first auction was held in July 2018 and was Technology and Capacity specific, as it was split in to 3 categories. Category I involved Solar parks of less than 1 MW installed capacity, Category II involved Solar parks of more than 1 MW capacity and Category III involved Wind farms. 106 MW were awarded to Solar farms and 170.93 MW to wind farms. A total of 77 solar projects and 7 Wind projects that eventually participated in the procedure were not awarded a premium.

The second auction, took place in December of 2018. This second procedure was notorious for the cancelation of the Category II procedure. Eventually a total of 61.94 MW for Solar and 159.65 MW for wind projects were awarded a reference price.

The third auction took place in April 2019 and involved Solar projects above 20 MWs installed capacity and Wind projects above 50 MWs installed capacity as well as smaller projects with common connection points to the system. This auction was technology

[19] SA 48143 (2017/N),C(2017) 9102 final/4.1.2018
[20] Commercial Operations Date

neutral and signaled the much lower prices that Solar technology requires. 7 out of 8 projects that participated were selected, but only one of them was of Wind Technology

The fourth auction took place in July 2019 and the fifth on December 2019. Both were technology specific. In these auctions some capacity caps were enforced. Solar projects should be less than 20 MWs and Wind projects less than 50 MWs. Prices dropped even further for both technologies, but it has to be noted that Wind technology seemed to be reaching a threshold below which offers did not take place.

Table 19 RES Auction results

Auction	Month/ Year	Technology	Average Price (€/MWh)	Maximum Price (€/MWh)	Minimum Price (€/MWh)	Allocated MWs	Number of projects
1	July 18	Solar	77,31 €	80,00 €	62,97 €	106,00	91
		Wind	69,66 €	71,93 €	68,18 €	170,93	7
2	December 18	Solar	66,87 €	68,99 €	63,00 €	61,94	95
		Wind	60,09 €	65,37 €	55,00 €	159,65	9
3	April 19	Solar	61,86 €	139,25 €	24,23 €	371,18	6
		Wind	60,00 €	60,00 €	60,00 €	66,60	1
4	July 19	Solar	63,21 €	67,7	61,95	142,88	23
		Wind	67,78 €	69,18	59,09	179,55	9
5	December 19	Solar	61,13 €	65,99	53,82	105,09	27
		Wind	57,90 €	61,94	55,77	224,00	7
6	April 20	Solar	53,66 €	54,82	49,11	502,94	12
		Wind	- €	0,00	0,00	0,00	
7	July 20	Solar	52,19 €	62,45	45,84	141,93	39
		Wind	55,74 €	57,7	53,86	471,83	15
8	May 21	Solar	37,60 €	51,20	32,97	349,91	49
		Wind	- €	0	0	0,00	0

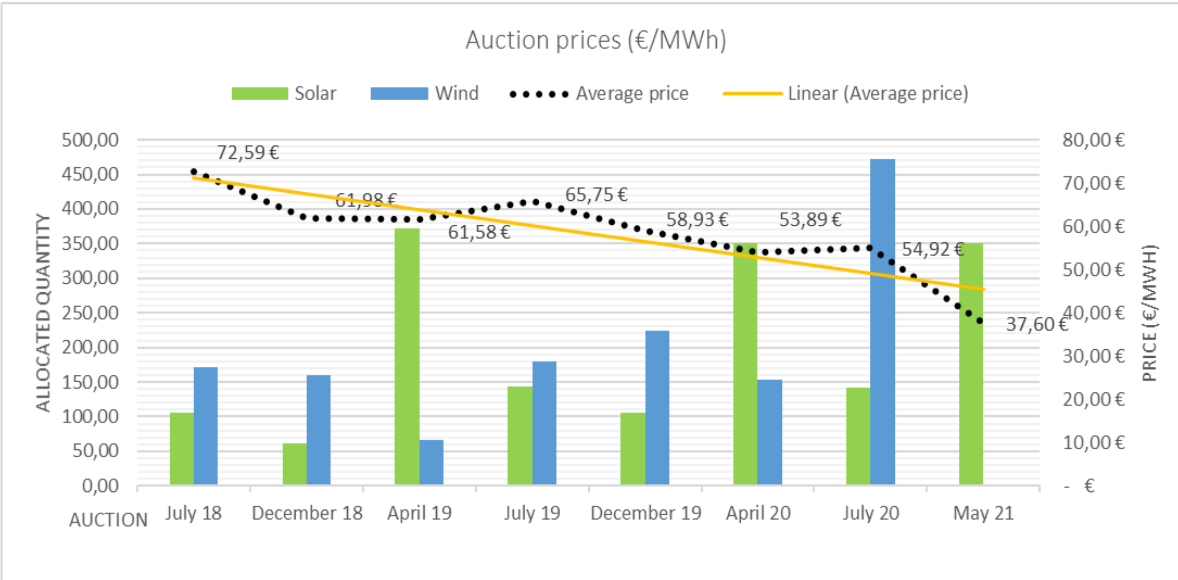
Source: RAE

The sixth auction took place in April 2020. It was a neutral technology auction were Solar technology dominated once more. 11 Solar projects were awarded a premium in contrast to 1 Wind project. A historic low was awarded to a 200 MW solar project (PPC Renewables) at 49.11 €/MWh.

The seventh Auction took place in July 2020 that was technology specific. Average prices dropped further, but there was some recovery on the minimum price of Solar.

Finally, the eighth auction took place in May 2021 (Regulatory Authority for Energy, 2020). Although the auction was a technology neutral procedure, no Wind farms managed to get awarded with a premium. Solar technology dominated and a new benchmark historical low was reached at 32.97 €/MWh with an average of 37.60 €/MWh.

Figure 17 Evolution of RES auction prices



Source: RAE

Prices as low as the ones formulated at the last auction as well as the fact that the auction itself was dominated by one of the major participants in the Greek market, led to a lasting debate on whether the auctions and the relevant Governmental subsidies are in fact the best available option for developers or other, market oriented solutions have to be sought.

6.3. Levelized Cost of Energy.

The levelized cost of Energy is a metric used to compare the actual cost of producing energy between different technologies. In another approach, LCOE represents the minimum price the the power generated must be sold at, in order for the project to be able to break even at the end of the expected lifetime. Essentially, it can be calculated as the NPV of all costs over the lifetime of an energy producing asset divided by the energy (discounted) produced over the same period (Lai & McCulloch, 2017).

The formula for calculating LCOE for any project stands as follows:

$$LCOE = \frac{Sum\ of\ costs}{Sum\ of\ produced\ electrical\ energy} = \frac{\sum_{t=1}^{n}\frac{I_t+O\&M_t+FC_t}{(1+r)^t}}{\sum_{t=1}^{n}\frac{E_t}{(1+r)^t}} \ [15]$$

Where:

I_t : CAPEX of year t

$O\&M_t$: Operations and Maintenance cost of year t

FC_t : Fuel cost in year t

r: discount rate

n : Expected lifetime of project

According to RAE (Regulatory Authority for Energy, 2021), the relevant parameters for RES assets are:

Table 20 Renewables Cost components

Technology	Capital Cost (k€/MW)	Annual Maintenance Cost (k€/MW)	Fuel Cost (k€/MW)	Annual Full Load hours	Economic lifetime (Years)
CHP (Biomass)	2500	74	25	4140	30
Hydro (R-o-R)	1200	30	-	3490	40
PV- rooftop	550	13.8	-	1510	22
PV-Commercial	400	10	-	1510	22
Wind Onshore	1000	25	-	2350	22
Wind Offshore	3100	77.5	-	3400	20

Source: RAE

Annual Full load Hours imply the MWh produced per installed MW in each technology type. By utilizing the above numbers and a discount factor of 8% for both the costs and the energy produced yields:

Table 21 RES Levelised Cost of Energy

Technology	LCOE (€/MWh)
CHP (Biomass)	82.36
Hydro (R-o-R)	39.86
PV- rooftop	48.41
PV- Commercial	35.18
Wind Onshore	56.52
Wind Offshore	105.66

As it is evident, RES auctions, have dropped to a point where until a technological breakthrough is implemented, resulting auction prices cannot incite further development of RES projects.

Hence, a new alternative must be found that can substitute Government subsidies for commercial RES assets, linked to the spot market and still be able to provide project financing. (Pexapark, 2021)

7. Private Green Power Purchase Agreements

7.1. What are Green PPAs

Power Purchase Agreements in general are long-term contracts between producers (or developers of electricity production projects) and buyers of energy (typically called off-takers). During the Agreement period, the producer is liable for all costs that revolve around energy generation and the buyers procures energy at a specified rate (fixed or indexed). PPA terms usually range between 5-20 years.

Green PPAs are agreements where the energy is produced by a RES asset (dispatchable or not). In order for the agreement to make sense for both parties, the price of the PPA contract, is typically lower than the one the buyer can obtain via a standard supplier contract (based on the wholesale market cost), but at the same time, higher than the one that can be gained from a producer in government RES auction and higher than the LCOE implies, for the investment to take place. The off-taker disengages almost completely from fluctuating prices for energy, that depend heavily on prices of CO_2 emission allowances and Natural Gas prices (the standard fuel for electricity generation in the post lignite era). (Huneke, Göß, Österreicher, & Dahroug, 2018).

Green PPAs are characterized from a number of parameters, with the most important the duration of the contract, the pricing mechanism, the PPA profile and the overall amount of electricity procured. Different technology (e.g solar or wind) also implies different profiling for the contract. Additionally, there is a variety of contracts that apply in each market, depending on the regulatory framework in place (Huneke & Claußner, POWER PURCHASE AGREEMENTS: MARKET ANALYSIS, PRICING AND HEDGING STRATEGIES, 2019).

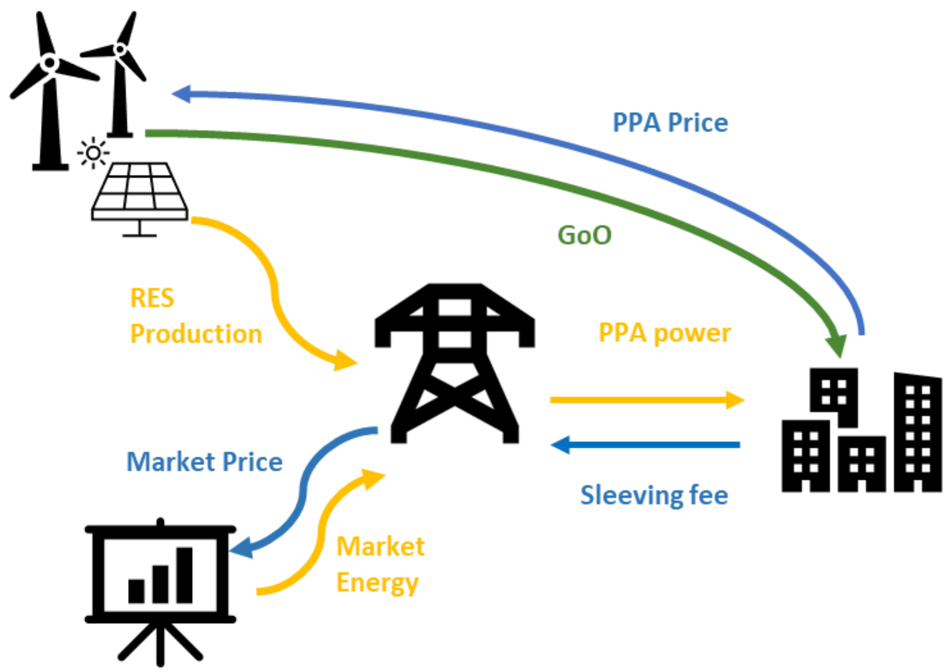
7.2. Physical vs Virtual PPA

Power Purchase Agreements can be distinguished to two broad categories. Physical and Financial PPAs.

Physical PPAs demand that the RES asset and the final off-taker are on the same Grid (or the same Bidding zone in market terms) and are further divided to On-site and Off-site (usually called Sleeved) PPAs.

An **On-site PPA**, requires that the RES asset and the consumption are physically connected and the RES asset is also positioned behind the metering point of the power grid. This means that the RES asset exists only to exclusively provide energy to the linked off-taker installation and does not inject energy to the Grid. It can be combined with a storage system to better accommodate the load profile needs, but this also increases the relevant cost of the asset and thus the final PPA price. The benefit of an on-site PPA lies with the fact that Grid charges as well as the involvement of a Balance Responsible Party (BRP) can be avoided. The downside is that alterations in profile of the off-taker, the locality is a constraint and the project essentially has to be co-developed between the RES producer and the Off-taker. Off-takers in such contracts are also limited to direct consumers (industries) and not other market participants such as suppliers (Deutche Energie Agentur GmbH, 2019).

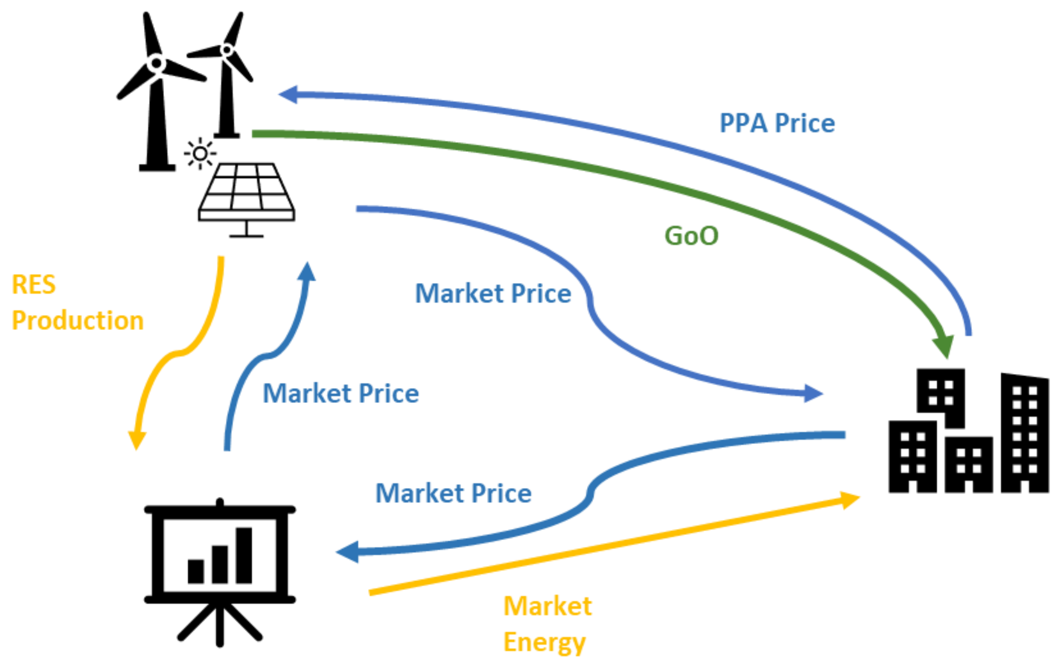
Figure 18 Physical PPA conceptual architecture



In the cost common case of a physical PPA, the **Off-site** approach is selected. This happens since large scale Wind or Solar projects cannot be located close to the off-taker consumption or the off-taker (for example a large industry) can have multiple locations to serve (multiple plants, offices, divisions etc) with the PPA contract. Additionally, the Off-site allows for other market participants (as suppliers) to benefit from such a long-term agreement and the producer is less reliant on the one exclusive buyer in comparison to the On-site approach. These contracts are called **Sleeved PPAs**. In Sleeved PPAs, the off-taker procures energy from the RES producer via a BRP. The BRP, performs as the agent of the off-taker in the market and manages the aggregated portfolio of the energy involved in order to provide the agreed energy profile. BRPs can be Aggregators or

Suppliers that manages production surpluses or shortages as well as balancing market mechanisms and settlement and receive the sleeving fee for the facilitation of the contract. In the case of the Sleeved PPA the involvement of a third party in the agreement (basically a trilateral contract) increases the cost in comparison to the On-site approach, but the delivery of energy in a balance by the BRP is of paramount importance (Deutche Energie Agentur GmbH, 2019).

Figure 19 Virtual PPA conceptual architecture



Virtual PPAs (a.k.a. Synthetic PPAs), are an alternative where the off-taker and the RES producer agree on a Contract for Difference (CfD) based on the Wholesale Electricity markets. The RES producer, trades directly the electricity produced on the spot market (usually via an Aggregator who is also the BRP involved). The off-taker, procures energy from the same market as well in spot market prices. The parties are thus required to make differential payments to each other according to the Wholesale market Settlement price and the PPA strike price. If the PPA price is below the Wholesale market price then the producer has to compensate the buyer for the difference of Spot Market Price- PPA price. If the PPA strike price is above the market price, then the off-taker compensates the producer for the PPA price- Spot Market Price difference. These agreements are bilateral arrangements between the participants and the Wholesale market price is the index upon the PPA is based and both parties reach the stability and security provided by the PPA agreement (Deutche Energie Agentur GmbH, 2019).

7.3. PPA pricing structures

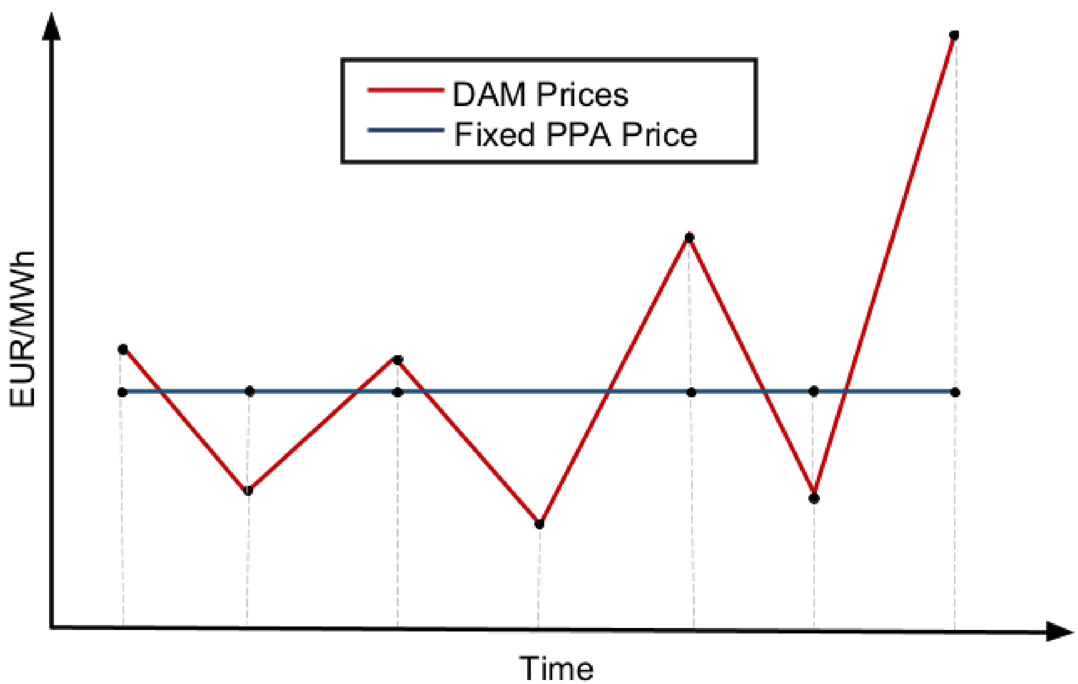
PPA pricing schemes depend on a number of parameters. The agreements itself, reflects the risk (or risk aversion) of either party involved, the current to the contract spot market status as well as the market expectations or beliefs for future trends.

Whatever the case, there are 3 main categories that the pricing schemes can be allocated to. “Fixed Price”, “Floor and Ceiling” and “Floor and Collar” that provide various combinations of risk and reward for both the producer and the off-taker.

7.3.1. Fixed Price

In “Fixed Price” agreements, the producer receives a fixed -stable- compensation expressed usually in €/MWh either produced (in a Pay-as-Produced or PaP) or according to the agreed profile of energy that has to be covered.

Figure 20 Fixed Price PPA

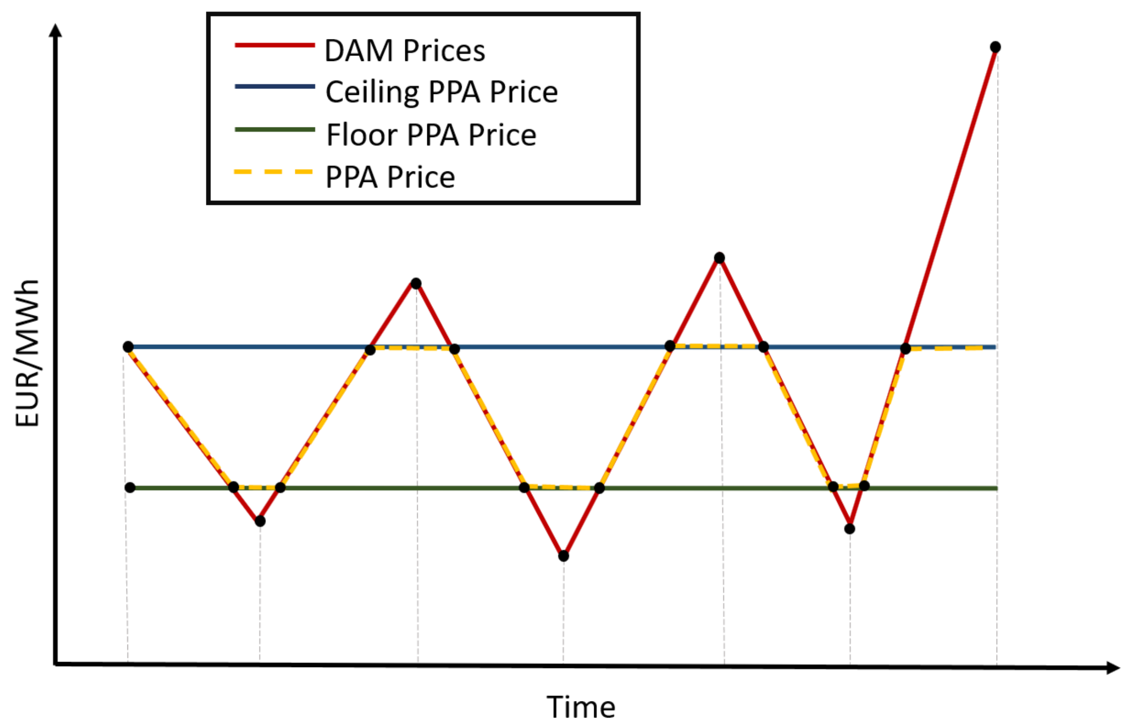


This mechanism resembles the Feed-in-Tariff Governmental support scheme more than anything else. With a Fixed contract, the producer ensures steady revenues regardless of potential spot market prices drops and on the other hand the off-taker ensures a stable cost for the electricity procured. In such agreements the opportunities and risks from Market exposure are totally negated.

7.3.2. Floor and Ceiling

In “Floor and Ceiling Price” agreements, the producer receives a compensation equal to the Spot Market price, as long as the latter is between the Floor and Ceiling limits. When the spot market drops below the Floor price, the producer receives the said Floor price. When the Spot Market prices rise above the Ceiling Price, the producer receives the said ceiling. Any differences between the spot market price and the floor (ceiling) is what the off-taker has to pay (receive from) the producer.

Figure 21 Floor and Ceiling conceptual graph



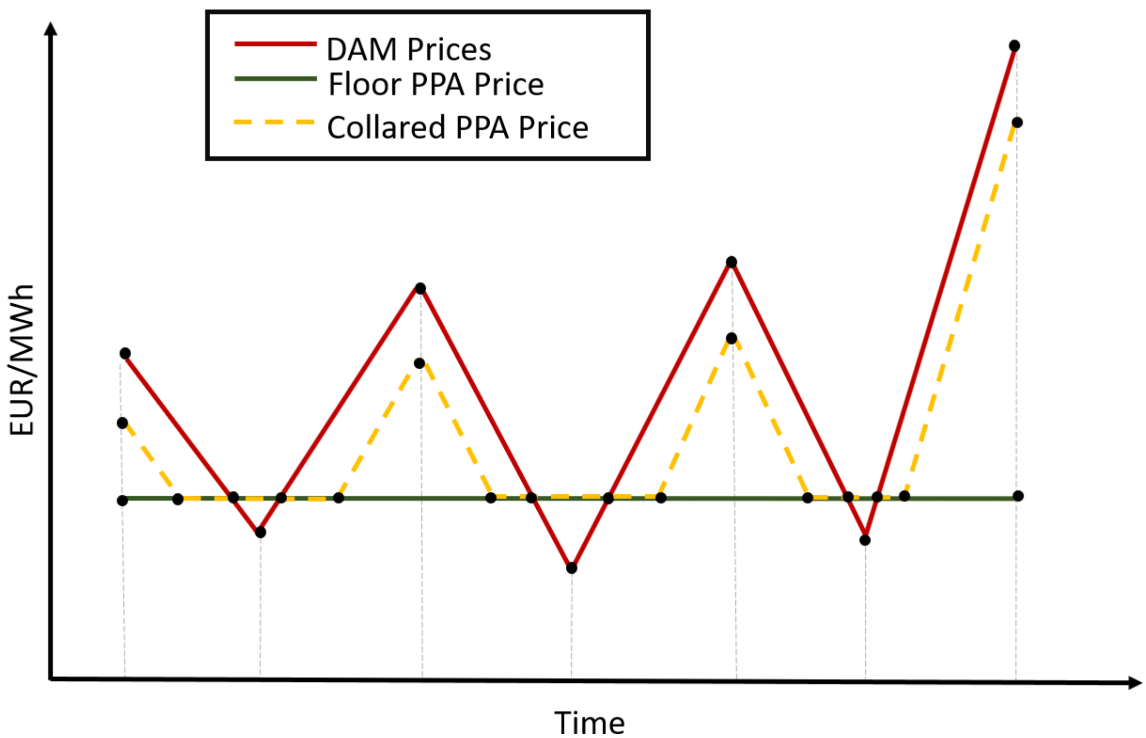
Floor and Ceiling agreements, allow increased revenues for the RES asset -in comparison to the fixed price arrangements, but allows some liquidity based on the Spot Market prices. The floor is typically set to a level that will ensure project financing, and at the same time the ceiling to a reasonable span to provide incentives for market exposure.

Usually, the Floor price is placed lower than the Fixed price equivalent and the Ceiling significantly lower than market expectations for the duration of the PPA.

7.3.3. Floor and Collar (or Share)

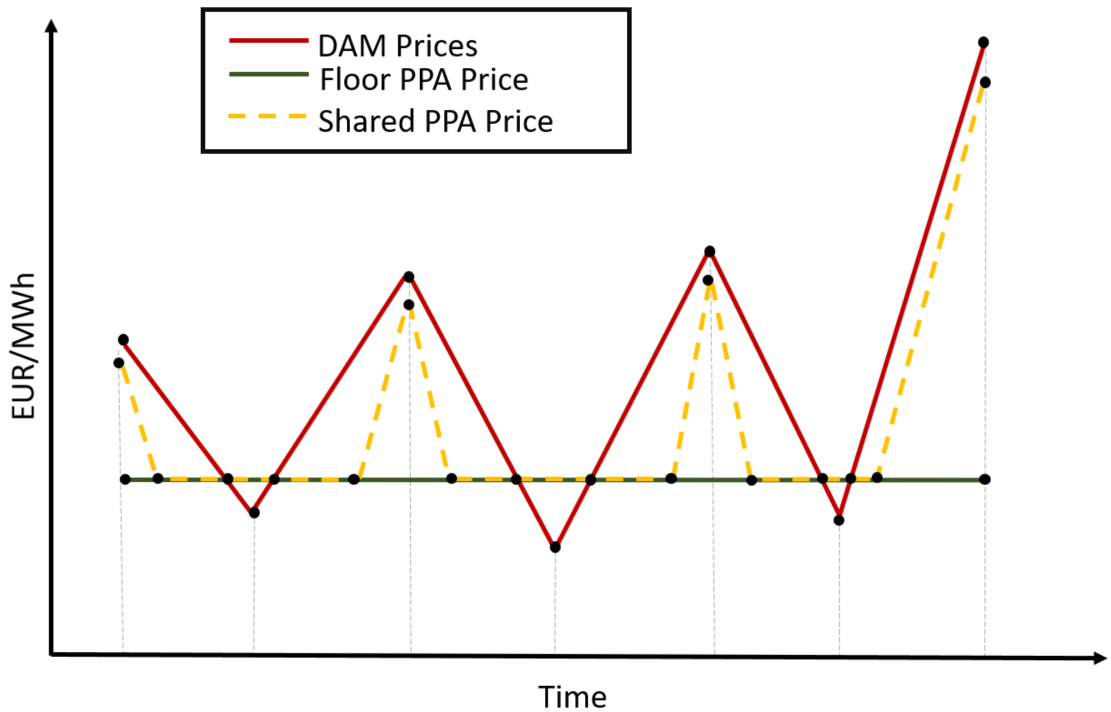
The Floor and Collar and the Floor and Share mechanisms are variations of the Floor and Ceiling price that include a volatile Ceiling price. Floor prices in both cases are typically lower than the ones found in the concrete Floor and Ceiling mechanisms. The Floor and Collar includes a discount imposed on the Spot Market price by a fixed amount expressed in €/MWh. On the other hand, the Floor and Share, expresses the volatility of the Ceiling with a percentile factor (%) imposed on the Spot Market Price.

Figure 22 Floor and Collar conceptual graph



The Floor and Collar defines the best- and worst-case scenarios for the off-taker in the same concept. The ever-present project financing issues dictate the level of the minimum price for the producer but on the other hand, exposure to spot prices when they are deemed high -as in the present situation in a European level- is not per se a bad scenario. The off-taker, by claiming the Collar can ensure that he will be in a position where he is hedged against rising prices and always maintains a competitive advantage against competition fully exposed to the Wholesale market.

Figure 23 Floor and Share conceptual graph



A Floor and Share mechanism resemble a partnership between the producer and the off-taker in a PPA contract. The Floor is present for the same reasons as in other mechanisms (mainly financing), but market revenues achieved above the said Floor price are split between the partners. The split of revenues can be in equal shares or asymmetrical between the partners and is usually expressed in percentages. This mechanism is essentially a project co-development. Minimum (floor) prices are established, to finance the project but revenues from the market (especially if market projections yield high prices) are split as benefits among the PPA contract prices.

7.4. PPA fair value

Any possible combination of the previous mentioned pricing structures may apply in a PPA contract. For example, a 10-year PPA may begin with 3 or 4 years with a fixed price and revert to a Floor and Share for the rest of the period, or an agreement can be reached that provides 40% of production to be on a fixed price and 60% to follow a floor and ceiling price etc.

Regardless of the mechanism, one of the most essential parts of a PPA price (of any format) is based on market predictions and expectations. As such, the longer the PPA tenor, the bigger the insecurity for the off-taker, regarding market prices predictions and estimations and thus the lower is the relevant price (a fixed price or a floor price) for which the off-taker is willing to commit.

To adequately asses and determine a fair PPA Price, extensive analysis with fundamental parameters has to take place for each occasion. The essential inputs of a long-term forecasting system can be non-exhaustively listed as the following:

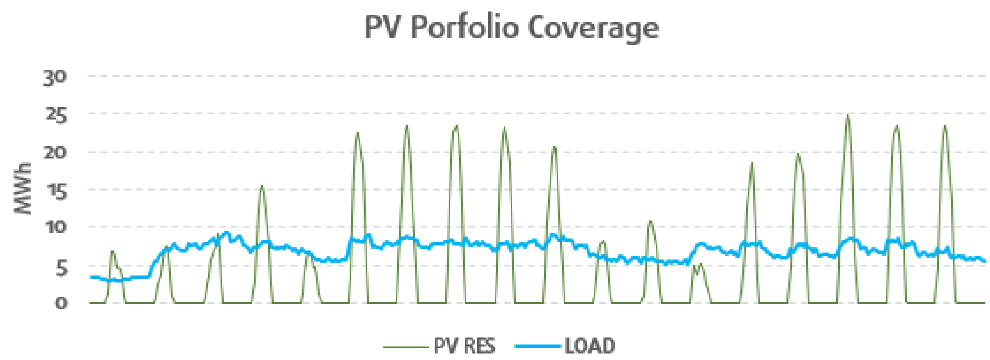
- National targets for RES penetration
- Electricity demand forecasts
- Natural Gas and EUA prices
- Impact of Energy Efficiency measures
- Penetration of EVs, HVAC electrification and Storage
- Cross border interconnections

This non exhaustive list of parameters leads to a fundamental modelling of the market on an hourly level with some assumptions and relevant scenarios. RES penetration is extremely important in this procedure, as cannibalization[21] of RES prices is a key factor when assessing the market-based value of the energy produced (Hamburg Commercial Bank, 2019).

The RES production profile, location and expected yield -as well as equipment degradation issues- are taken into account and are expressed as a discount on the expected market prices. Balancing costs that occur either by RES stochastic nature or load and RES profile mismatches are also a factor bearing into the final PPA strike price. This initial - mostly market derived- analysis brings to the front the RES Energy Value.

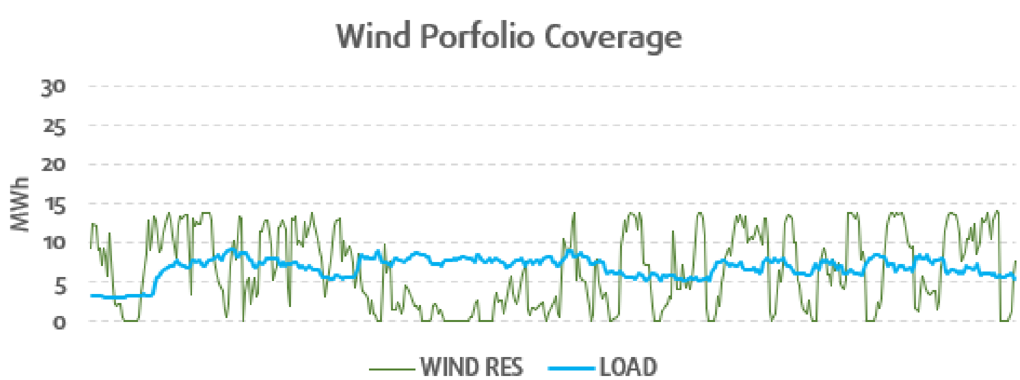
[21] Price cannibalization occurs when RES assets of the same technology produce at the same time and drive the market to lower prices at the moment they produce. Essentially the more RES operate at the same time the lower is the value of the energy they produce.

Figure 24 Solar Production and Load needs



Energy produced from RES assets comes along with Guarantees of Origin (GoOs) or as they are comonly named “Green Certificates”. GoOs add value to the energy produced by the RES asset, since off-takers may be interested in them for a number of reasons, such as Corporate Social Responsibility constraints, subsidies or CO_2 footprint calculations. GoOs are part of a Physical PPA structure, but can also be separately traded in any kind of arrangement (even outside the scope of a PPA. Whatever the approach, the cost of GoO procurement adds up to the overall value of the energy produced by the RES asset. (Koulouvari -DAPEEP, 2019)

Figure 25 Wind production and Load needs



Finally, a risk factor has to be incorporated into the strike price, that has to do with Quantity or Price exposure of the contract. In the case of Quantity exposure, production cannot cover the agreed demand and thus the energy has to be procured on spot market prices. Quantity excesses have to be sold on spot market prices as well to flatten the difference but relevant transactions may not be able to financially cover the gap. This is one component of the price exposure and has to do with the producer. Another component of price exposure (that has to do with the off-taker) is a scenario where production can cover demand at a specific time unit, but spot market prices are lower than the agreed PPA strike price, due to cannibalization. Overall, some Capital is always at risk -as in any venture and long-term agreement- and has to be taken into account during negotiations.

Whatever the individual mechanics may be, the PPA contract should be able to reach a balance between the needs and expectations of the RES producer and the off-taker. Any shortcoming for either party jeopardizes the PPA viability in the long run (Claußner, 2020).

As such, an individual assessment has to take place to properly evaluate and construct each PPA. Different load characteristics dictate for different portfolio needs and different and a different RES portfolio can service a different kind of consumer.

8. Case study benefit on large consumers

In order to properly evaluate the financial impact of a PPA proposal, a thorough analysis of large consumer load profiles has to take place. Depending on the baseload a peak load needs of each consumer, a relevant portfolio of RES has to be utilized to maximize the impact, according to those specific requirements.

For this case study, (i) a large Commercial, (ii) a medium sized industrial and (iii) a large industrial comprised of three installations were selected. After the analysis of the consumer profiles, the relevant RES production hourly production profiles have to be correspondingly matched. Finally, the actual pricing of each PPA has to take place for assessing the economic impact.

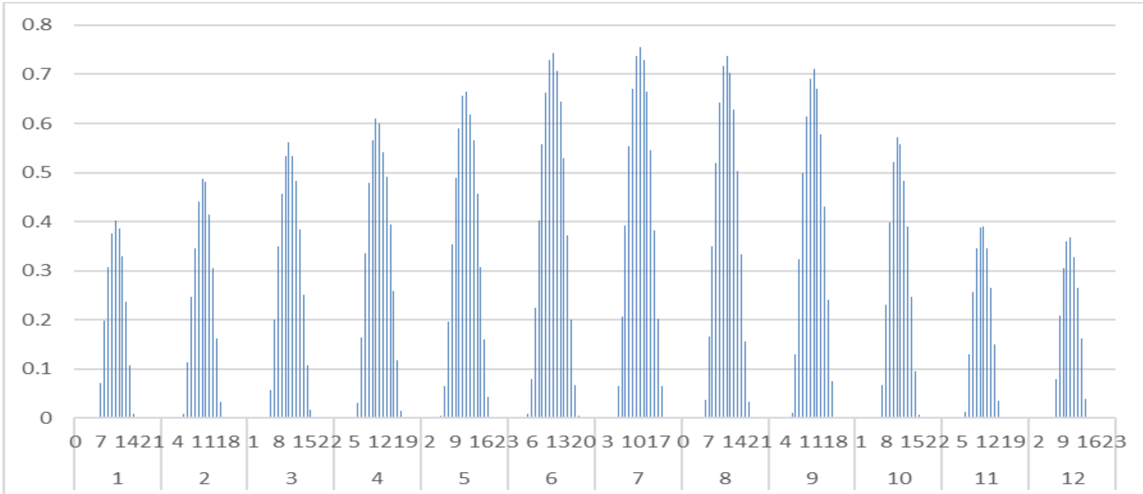
8.1. RES production Profiles

8.1.1. Solar Plants

For the purposes of this analysis, the overall annual production figures per technology as provided by RAE (Regulatory Authority for Energy, 2021), will be used. As such, for Solar production an average of 1510 MWh/ annum per installed MW will be used. The actual production profile may vary significantly according to location. For example, a solar plant in the southern edge of the Peloponnese can indeed produce more than 1600 MWh/MW/annum, while a technologically similar asset in Central Macedonia can be found to produce around 1400 MWh/MW/annum.

Whatever the case, real production profiles were aggregated in various regions of mainland Greece and adjusted accordingly to provide the desired 1510 MWh/MW basic production profile. The hourly distribution per month can be observed in the graph below:

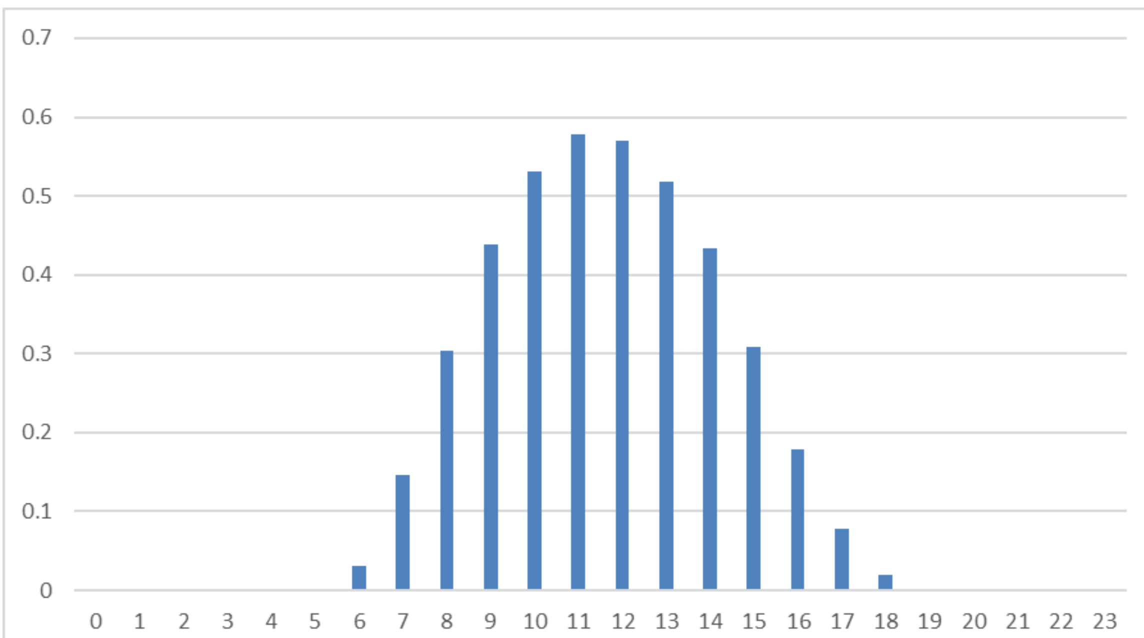
Figure 26 Hourly production per month - Solar 1 MW installed capacity



Source: VERD

On an average hourly basis, the equivalent production can be show as follows:

Figure 27 Average daily production- Solar 1 MW installed capacity



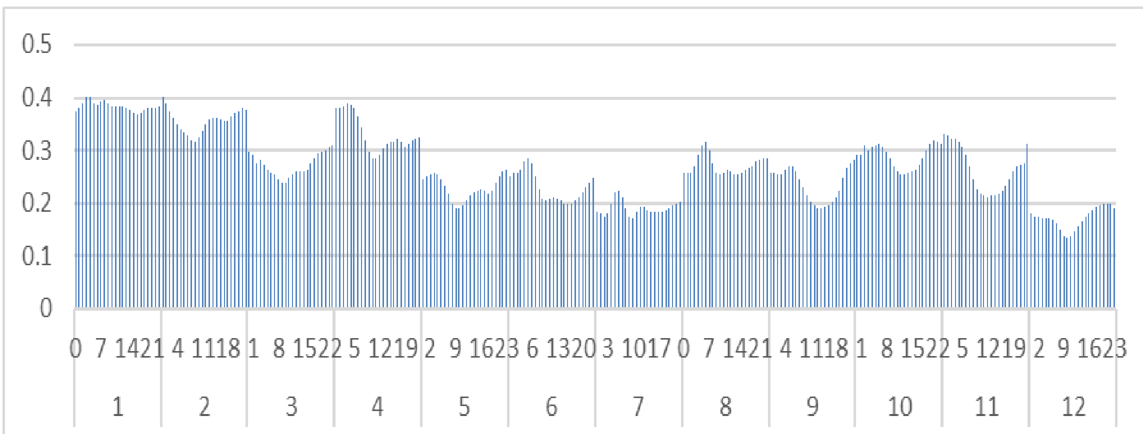
Source: VERD

As expected, solar production can be fairly reliable in terms of energy output profile throughout the year with the magnitude of the production varying between months.

8.1.2. Wind Farms

With a similar methodology, and using again RAE figures (Regulatory Authority for Energy, 2021), a reference profile for wind farms was also created with a target production value of 2350 MWh/MW/annum. Again, locality plays a factor, but in the case of wind assets prediction is significantly harder since bursts and gusts of wind are a lot more volatile in nature than in the case of Solar energy, where basic parameters (such as sun elevation and azimuth angle) are relatively stable in nature. By aggregating wind assets in various locations within mainland Greece[22] and adjusting them accordingly to provide the desired 2350 MWh/MW basic production profile, the hourly distribution per month can be observed in the graph below:

Figure 28 Hourly production per month - Wind 1 MW installed capacity

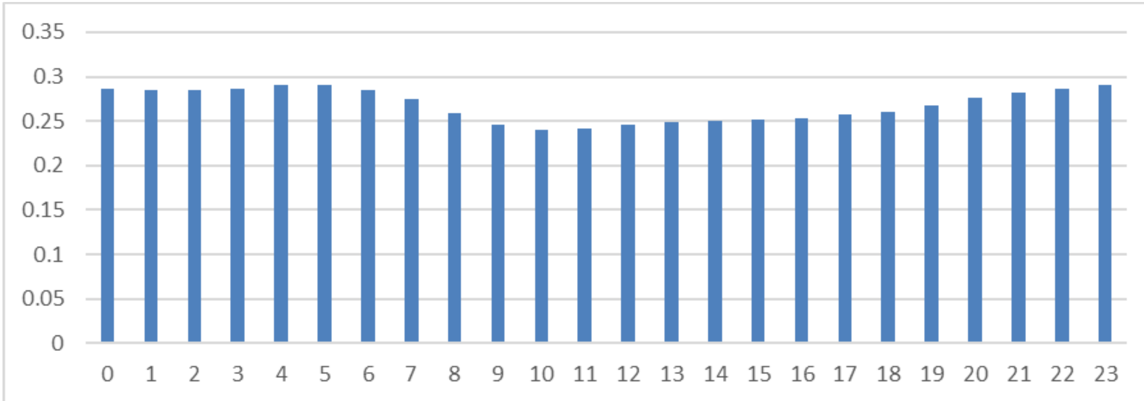


Source: VERD

On an average hourly basis, the equivalent production can be show as follows:

[22] no offshore wind is installed so far in the country and Wind farms in non-interconnected islands do not play a part in the Wholesale market as they do not belong in IPTO's bidding zones.

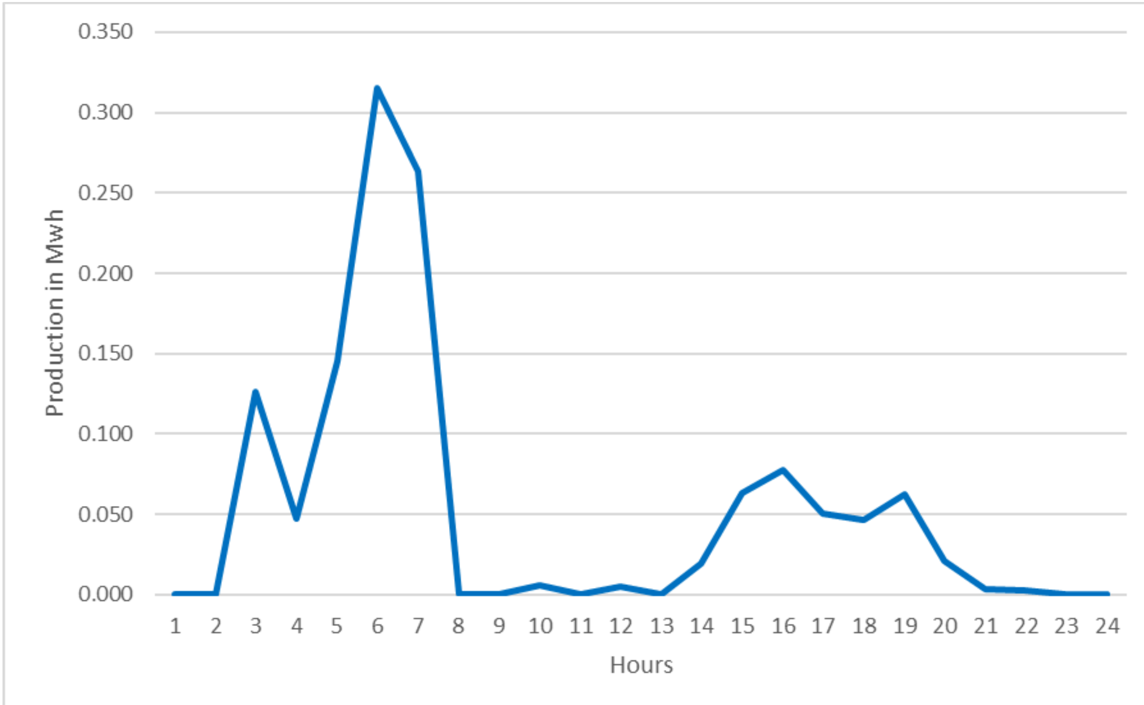
Figure 29 Average daily production- Wind 1 MW installed capacity



Source: VERD

Wind assets, provide a more stable distribution of production within a day in general. But besides a pattern that can be extracted and has to do with the fact that this technology is generally favored during the night time instead of mid-day in contrast to Solar, it can be observed that various outages take place in a highly unpredictable manner.

Figure 30 Highly volatile Wind Production Day (summer)



Source: VERD

This can be better shown by examining particular days within the time series as the one presented above.

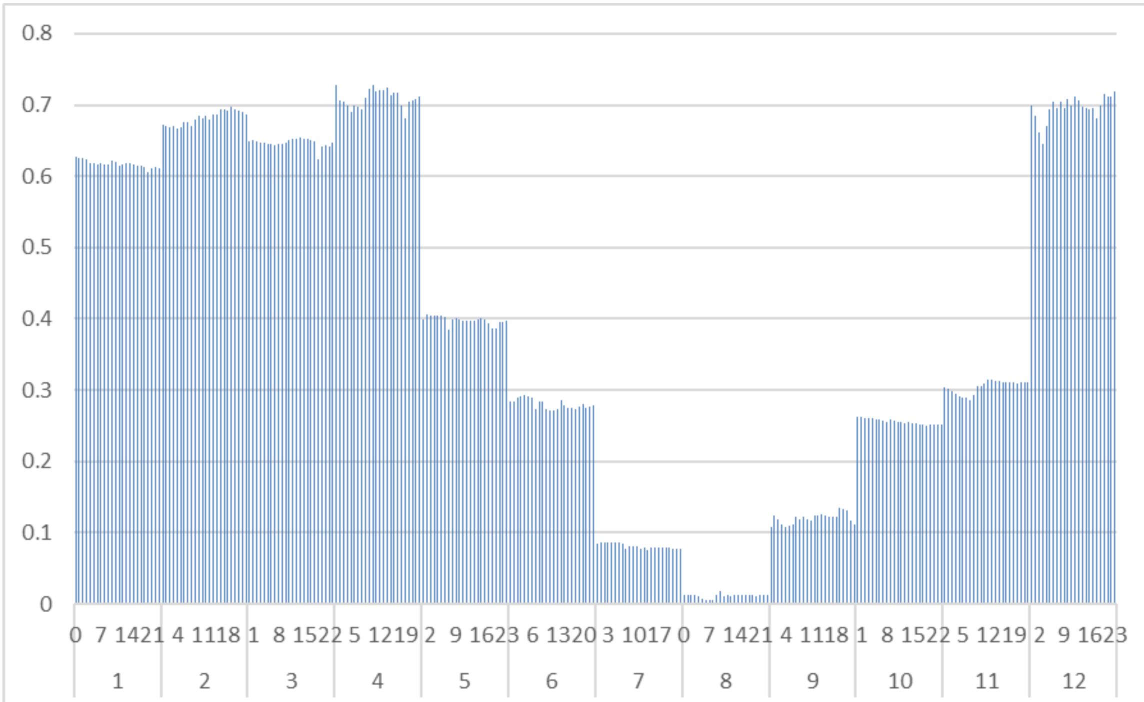
8.1.3. Run -of- River Hydro Stations

Run of River (ROR) Hydro plants are another adequately mature RES technology that can be utilized for PPA contracts, yet to a lesser extent. In the case of ROR Hydro installations, there is no presence of a dam or reservoir to store and control water flow. As such, running water is diverted from a stream and guided to the generator. Diverted water is returned to the river at a point downstream. Since there is no reservoir, in periods of drought, water extraction for agricultural or other purposes the flow becomes marginally zero and as such no production of energy is possible (Walczak, 2018).

According to RAE (Regulatory Authority for Energy, 2021), ROR plants have a reference production of 3490 MWh/MW/annum. Besides locality, precipitation in a season is of paramount importance. As such production between even adjacent years can vary significantly due to differences in rain levels, but for the purposes of this analysis, we are utilizing various production curves from calendar year

2021. By adjusting them accordingly to provide the desired 3490 MWh/MW basic production profile, the hourly distribution per month can be observed in the graph below:

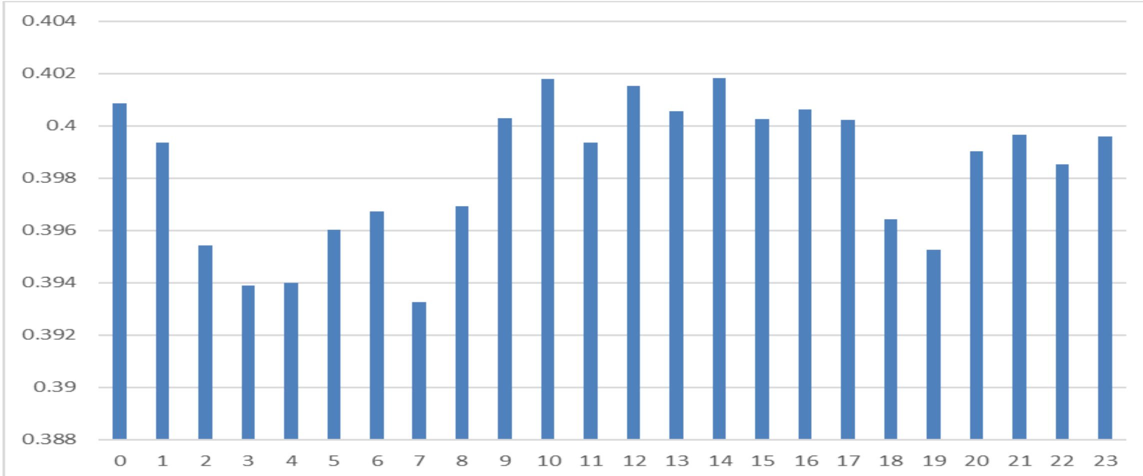
Figure 31 Hourly production per month - Hydro 1 MW installed capacity



Source: VERD

On an average hourly basis, the equivalent production can be show as follows:

Figure 32 Average daily production- Hydro 1 MW installed capacity



Source: VERD

Finally, when estimating production of the asset within its lifetime – or the lifetime of the PPA contract- an additional degradation factor has to be also incorporated. For Solar plants it is set to 0.5% production losses due to degradation per year (Aghaei, et al., 2022), for Wind assets it is set to 1.57% (Byrne, Astolfi, Castellani, & Hewitt, 2020) and for Hydro plants to 1% (Abgottspon, Staubil, & Felix, 2016).

8.2. Industrial consumer profiles

Large consumers present a variety in both consumption profiles as well as magnitude or seasonality. Although similar solutions may eventually apply in terms of RES assets that are going to be deployed within a PPA contract, these differences play a significant role in determining the portfolio in question.

8.2.1. Large Industrial Consumer – 3 distinct installations

The first consumer under consideration is a large industry with 3 distinct installations, all in Medium Voltage.

Some basic characteristics can be found in the table below:

Table 22 Basic characteristics of Load profile

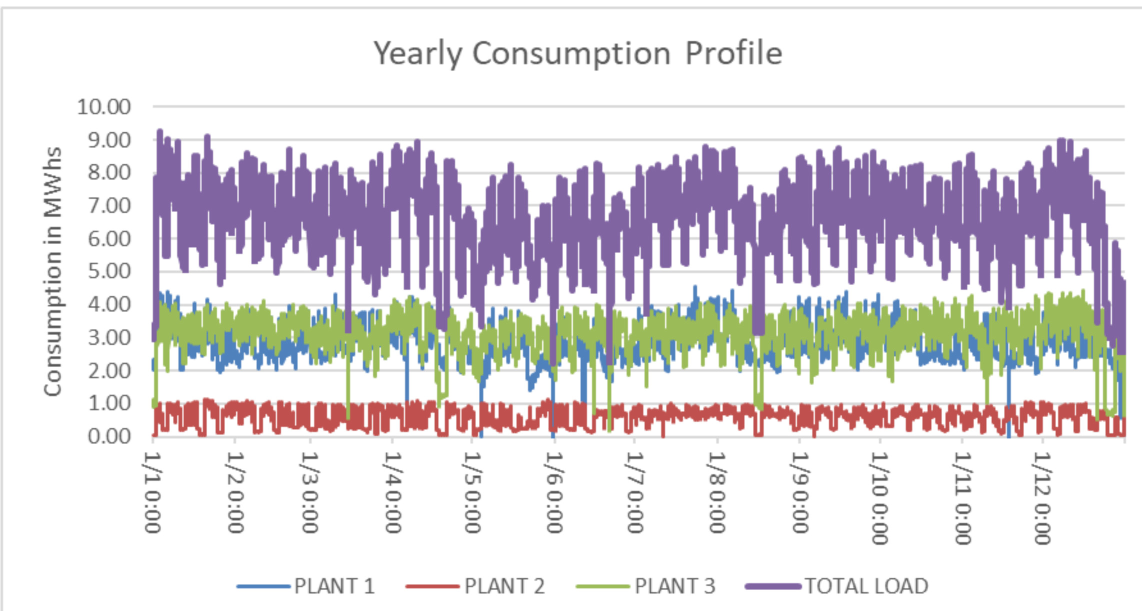
Characteristic	Plant 1 (MWh)	Plant 2 (MWh)	Plant 3 (MWh)	Total Load (MWh)

Minimum Load	0.01	0.01	0.19	2.20
Maximum Load	4.55	1.12	4.14	9.24
Baseload Equivalent	2.86	0.58	3.12	6.56
Yearly load	25072.68	5113.27	27302.88	57494.84

Source: VERD

As we can observe, while specific plants may stop operations for some hours -or even whole days- most likely due to maintenance, this situation does not take place simultaneously across all installations. This effectively means that this industrial consumer is always in need of energy with a minimum hourly consumption of 2.2 MWh/h. This can also be verified from a graphical representation of load fluctuations across the year, when the total load never drops below the said value.

Figure 33 Yearly Consumption Profile



Source: VERD

On an average 24-hour basis, the average load profile for a full year can be calculated and serve as a baseline for further analysis.

Table 23 Average 24 hour profiles

Hours	Plant 1 (MWh)	Plant 2 (MWh)	Plant 3 (MWh)	Total Load (MWh)
0	2.715	0.530	3.148	6.393
1	2.717	0.529	3.159	6.404
2	2.706	0.523	3.162	6.391
3	2.667	0.520	3.156	6.343
4	2.694	0.513	3.146	6.353
5	2.678	0.493	3.156	6.326
6	2.593	0.456	3.024	6.073
7	2.660	0.561	2.982	6.204
8	2.942	0.631	3.152	6.724
9	3.012	0.655	3.151	6.819
10	3.052	0.670	3.148	6.869
11	3.006	0.647	3.157	6.810
12	3.061	0.658	3.162	6.882
13	3.085	0.666	3.175	6.926
14	3.072	0.609	3.102	6.782
15	3.036	0.616	2.992	6.644
16	3.058	0.629	3.092	6.780
17	3.031	0.632	3.143	6.806
18	2.925	0.601	3.133	6.659
19	2.820	0.598	3.092	6.510
20	2.854	0.612	3.144	6.610
21	2.858	0.596	3.149	6.603
22	2.761	0.538	3.056	6.355
23	2.689	0.530	3.033	6.260

Source: VERD

8.2.2. Medium Sized Industrial Consumer

The second consumer under consideration is a small to medium industrial installation operating in the Medium Voltage. The basic characteristics, are:

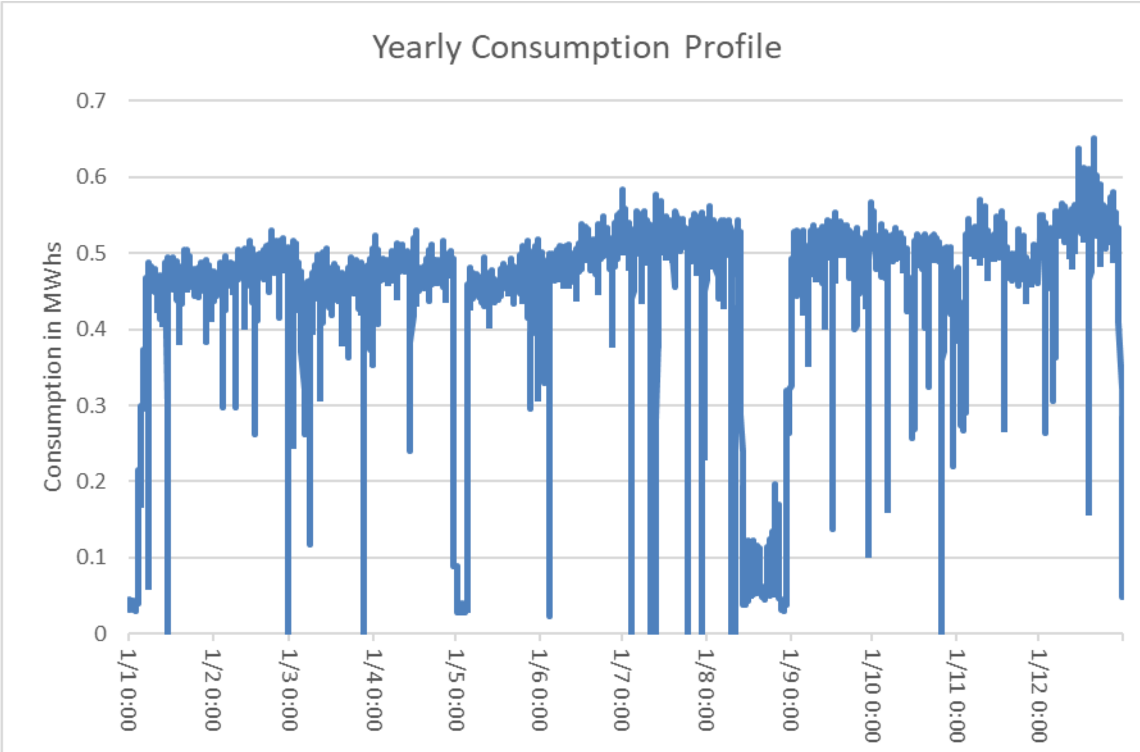
Table 24 Basic characteristics of the medium Voltage installation

Characteristic	Medium Industrial Load (MWh)
Minimum Load	0.01
Maximum Load	0.651
Baseload Equivalent	0.445
Yearly load	3901.97

Source: VERD

What can be observed by the analysis of this particular profile, is the fact that the plant seems to almost totally shut down, usually around national and religious holidays as well as the presumed summer leaves of the personnel as well as some weekends. Thus, there are actually frequent periods where consumption reaches an absolute minimum, with maintenance systems running.

Figure 34 Yearly Consumption Profile



Source:VERD

What is more interesting though in this particular profile is the hourly average distribution within the day.

Table 25 Average 24 hour consumption profile

Hours	Medium Industrial Load (MWh)
0	0.453
1	0.452
2	0.450
3	0.450
4	0.448
5	0.447
6	0.444
7	0.439
8	0.433

9	0.434
10	0.434
11	0.435
12	0.439
13	0.442
14	0.444
15	0.448
16	0.449
17	0.449
18	0.449
19	0.448
20	0.448
21	0.451
22	0.452
23	0.453

Source: VERD

With differences in essentially in a few kWh, we can safely demise that the consumption profile of this industrial consumer is relatively stable. Even more stable in terms on actual energy needs differences than the large industry discussed above.

8.2.3. Large Commercial Consumer

The final consumer under study, is a large commercial consumer. It is a Medium Voltage installation that operates within public hours mostly, yet as we will see there are some significant persisting loads. The basic characteristics of the commercial consumer are the following:

Table 26 Basic characteristics of the Commercial installation

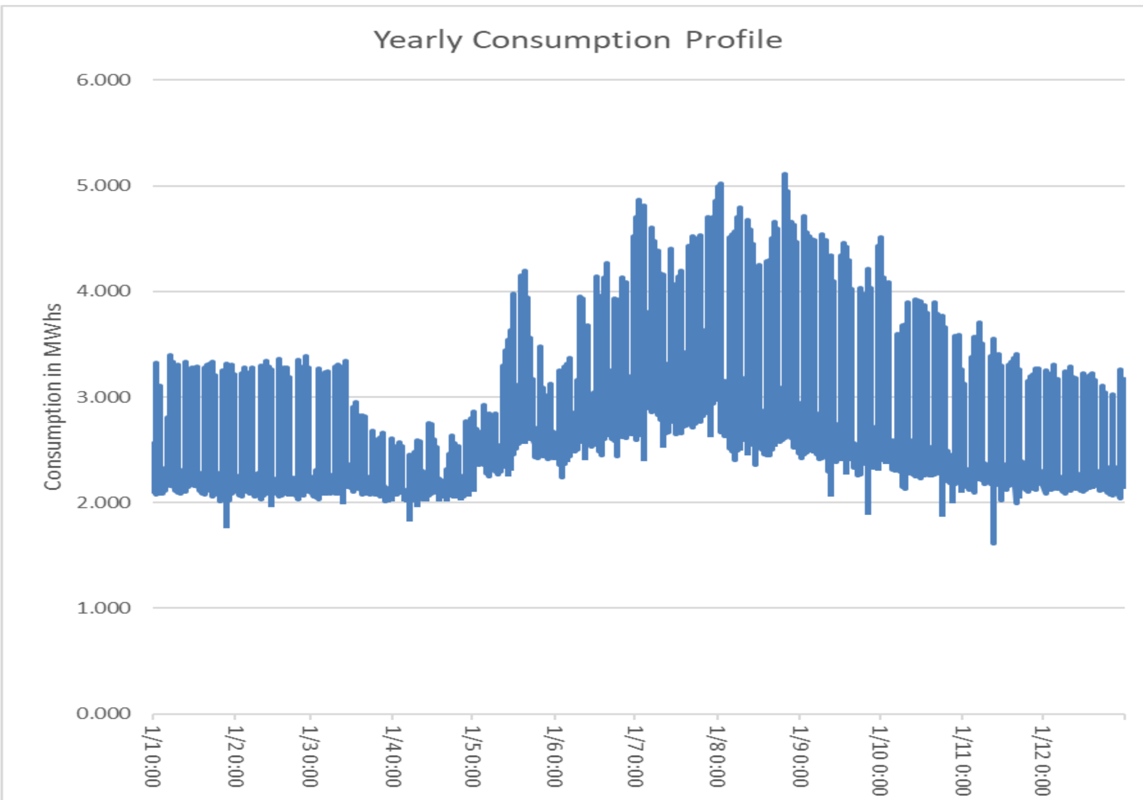
Characteristic	Commercial consumer (MWh)
Minimum Load	1.620

Maximum Load	5.107
Baseload Equivalent	2.752
Yearly load	24109.35

Source: VERD

As we have mentioned before, there is a significant presence of a persisting baseload, with an absolute minimum of 1,62 MWh. The high end of consumption is in the area of 5,1 MWh. This is a serious difference that goes along with the operation hours.

Figure 35 Yearly consumption profile



Source: VERD

An additional point of interest is that there is no operation in weekends and there is a recurring profile during seasons. Summer time presents the highest needs for energy, due to the use of air conditioning and HVAC systems.

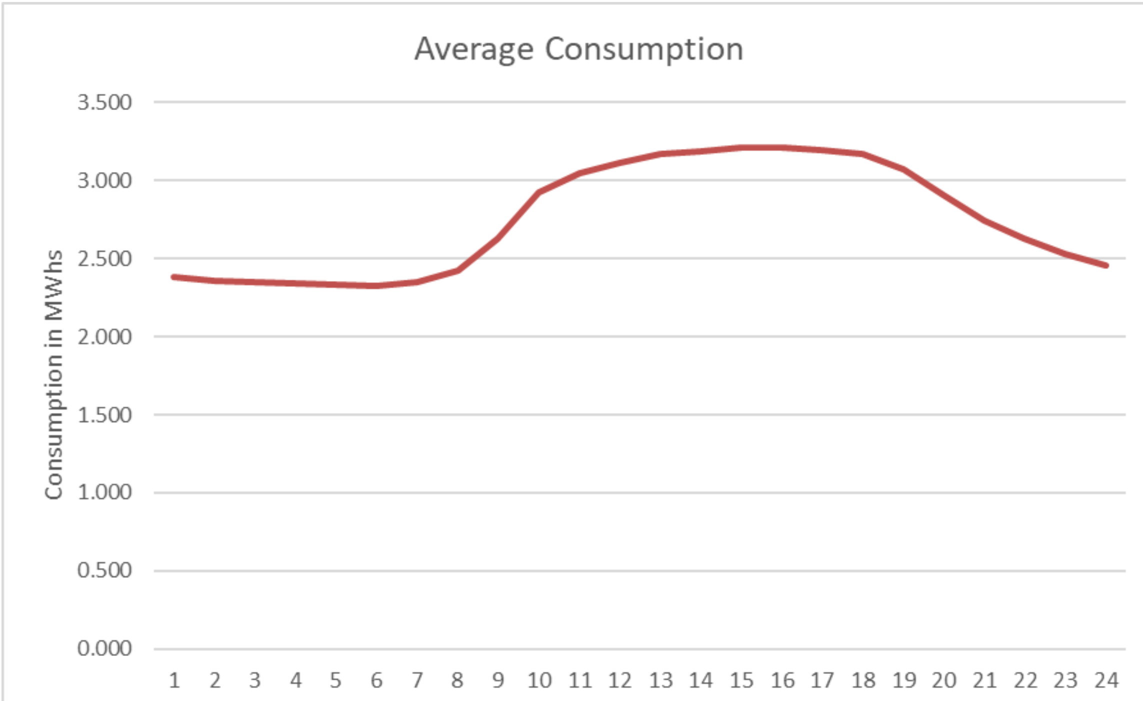
Table 27 Average 24-hour consumption profile

Hours	Commercial Load (MWh)
0	2.383
1	2.359
2	2.349
3	2.341
4	2.334
5	2.328
6	2.353
7	2.425
8	2.629
9	2.924
10	3.044
11	3.112
12	3.166
13	3.190
14	3.207
15	3.207
16	3.198
17	3.168
18	3.074
19	2.911
20	2.740
21	2.625
22	2.530
23	2.455

Source: VERD

The 24-hour average profile of the consumer also has significant value. There is a steep rise during operational hours and an equally steep drop at shut down. This is extremely important as it resembles as we can see with the average Solar production portfolio and thus can exploit these features.

Figure 36 Average 24-hour consumption profile



Source: VERD

8.3. PPA proposals

As discussed, prices for producers for a PPA contract, vary according to RES technology, duration and of course the target market situation – in both wholesale market as well as RES specific market. Due to the nature of production profile, as seen above in the reference profiles, wind assets tend to favor fixed prices, as they are able to produce relatively stable (on average) quantities of energy in a 24-hour basis. Also, seasonality - while present to some extend- does not affect the overall capacity factor of the assets. In general terms the same applies to Run of River Hydro installations in terms of hourly profile, but the later are heavily affected by seasonality, where summer production is practically marginally zero. Solar plants on the other hand, are unable to produce during night time, are heavily affected by seasonality issues – much lower capacity factor in winter than in summer time.

These features heavily affect the final formulation of robust contracts, with a tendency towards market indexed ones.

In general, RES producers regardless of technology begun to step away for the Physical structure and turn to Virtual (or Synthetic) PPAs, since the later allow such contracts to be executed in different bidding zones and markets, without the physical limitations on Grid or System constraints. Additionally, the settlement standard remains the pay-as-produced hourly settlement, although some more risk-averse off-takers might be willing to turn towards daily or weekly average pricing, closer to the relatively stable consumption profiles of corporate buyers, against the volatile production profiles of the RES (World Business Council for Sustainable Development, 2021).

For this study of impact of a PPA contract on the specific consumer profiles analyzed in the previous chapter, a series of PPA structures are being deployed and considered:

8.3.1. Offer 1

Product: Financially settled Pay-as-Produced product at a Fixed Contract price (expressed in €/MWh) applicable to each generated and metered unit of electricity (in MWhs) per Market Time Unit.

Settlement: Off-taker compensates RES producer as follows:

$$Cost\ of\ Electricity = \sum_{i=0}^{n} MQ_i * (Contract\ Price - MCP_i) \quad [16]$$

Where:

MQi = Metered generation in hour i

MCPi = Market Clearing Price in hour i

Contract Price = PPA strike price, set in case of Offer 1 at 52 €/MWh for Solar Energy and 59 €/MWh for Wind Energy

8.3.2. Offer 2

Product: Financially settled Pay-as-Produced product at an indexed Contract Price (expressed in €/MWh) with an additional floor price, applicable to each generated and metered unit of electricity (in MWhs) per Market Time Unit.

Settlement: Off-taker compensates RES producer as follows:

$$Cost\ of\ Electricity = \sum_{i=0}^{n} MQ_i * \max_{MQ,MCP,Floor\ Price} \{MCP_i(1 - df); Floor\ Price\} \text{ [17]}$$

Where:

MQi = Metered generation in hour i

MCPi = Market Clearing Price in hour i

Floor Price = PPA floor price, set in case of Offer 2 at 35 €/MWh for Solar Energy and 42 €/MWh for Wind Energy

df= Discount Factor applied on the Market Clearing Price, set in case of Offer 2 at 8%

8.3.3. Offer 3

Product: Financially settled Pay-as-Produced product at a Fixed Contract price (expressed in €/MWh) applicable to weighted monthly average Day Ahead Market Clearing Price for each generated and metered unit of electricity (in MWhs) per Market Time Unit.

Settlement: Off-taker compensates RES producer as follows:

$$Cost\ of\ Electricity = \sum_{m=0}^{m=12} MQ_m * (Contract\ Price - MCP_m) \text{ [18]}$$

Where:

MQm = Metered generation in month m

MCPm = Weighted Average Market Clearing Price in month m

$$MCP_m = \frac{\sum_{i=0}^{n} MQ_i * MCP_i}{\sum_{i=0}^{n} MQ_i} \text{ [19]}$$

MQi = Metered generation in hour i

MCPi = Market Clearing Price in hour i

Contract Price = PPA strike price, set in case of Offer 3 at 55 €/MWh for Solar Energy and 60 €/MWh for Wind Energy

8.3.4. Offer 4

Product: Financially settled Pay-as-Produced product at an indexed Contract Price (expressed in €/MWh) that is comprised by a floor price, a cap price and an extra floating compensation, applicable to each generated and metered unit of electricity (in MWhs) per Market Time Unit.

Settlement: Off-taker compensates RES producer as follows:

$$Cost\ of\ Electricity = Floor\ Price + \min_{Cap\ Price, Floating\ fee}(Cap\ Price; Floating\ fee) \qquad [20]$$

Where:

Floor Price = PPA floor price, set in case of Offer 4 at 35€/MWh for Solar energy and 42 €/MWh for Wind Energy

Cap Price = The maximum applicable extra compensation above the floor price, in this offer at 25 €/MWh

Floating fee = The extra compensation above the floor price and below the Cap price defined as

$$Floating\ fee = \max_{MQ,MCP,Floor\ Price}\{Average\ (Floor\ Price; MCP_i)\ ; 0\} \quad [21]$$

8.3.5. Offer 5

Product: Financially settled Pay-as-Produced product at an indexed Contract Price (expressed in €/MWh) that is comprised by a floor price, a cap price and a floating compensation in between, applicable to each generated and metered unit of electricity (in MWhs) per Market Time Unit.

Settlement: Off-taker compensates RES producer as follows:

$$Cost\ of\ Electricity = \begin{cases} Floor\ Price, & MCP_i \leq Floor\ Trigger \\ MCP_i - DP, & Floor\ Trigger < MCP_i < Cap\ Trigger \\ Cap\ Price, & MCP_i \geq Cap\ Trigger \end{cases} \quad [22]$$

Where:

MCPi = Market Clearing Price in hour i

DP = Discount Price, in offer 5 at 15€/MWh

Floor Trigger = MCP value for which the Floor price is triggered at 57 €/MWh

Cap Trigger = MCP value for which the Cap price is triggered at 90 €/MWh

Floor Price = PPA floor price, set in case of Offer 5 at 42 €/MWh

Cap Price = PPA cap price, set in case of Offer 5 at 75 €/MWh

Offer is technology neutral.

PPA offers are summarized in the following table:

Table 28 PPA offers overview

PPA Offer	Structure	Formula	Clearing
Offer 1	Fixed	$Cost\ of\ Electricity = \sum_{i=0}^{n} MQ_i * (Contract\ Price - MCP_i)$	Hourly
Offer 2	Indexed with floor	$Cost\ of\ Electricity = \sum_{i=0}^{n} \max_{MQ,MCP,Floor\ Price} \{MQ_i * MCP_i(1-df); Floor\ Price\}$	Hourly
Offer 3	Fixed	$Cost\ of\ Electricity = \sum_{m=0}^{m=12} MQ_m * (Contract\ Price - MCP_m)$	Monthly
Offer 4	Indexed Floor and Collar	$Cost\ of\ Electricity = Floor\ Price + \min_{Cap\ Price,Floating\ fee}(Cap\ Price; Floating\ fee)$	Monthly
Offer 5	Indexed Floor and Ceiling	$Cost\ of\ Electricity = \begin{cases} Floor\ Price, & MCP_i \leq Floor\ Trigger \\ MCP_i - DP, & Floor\ Trigger < MCP_i < Cap\ Trigger \\ Cap\ Price, & MCP_i \geq Cap\ Trigger \end{cases}$	Hourly

8.4. RES portfolio selection

Selecting a proper portfolio of RES assets to cover the load in each instance, relies on one fundamental principle. As it is expected, there can be no RES portfolio that can guarantee the absolute cover of the load profile in a daily cycle all over a full calendar year of the PPA contract. The methodology for selecting the appropriate portfolio is described as follows.

In each operational hour, the difference between the actual load and the energy production by the RES assets can be defined as the exposure of the load to Wholesale market prices. Exposure can indeed receive also negative values, that indicate an overhead production - unnecessary to cover the load in that particular Market Time Unit – itself subject to Wholesale market prices.

The overall exposure can be then defined as follows:

$$Total\ Exposure = \sum_{i=0}^{n} Exposure_i \text{ [23]}$$

Where:

n = hours of the contract

Exposurei = The exposure in hour i

$$Exposure_i = Load_i - a * PV_i - b * WI_i - c * HY_i$$

Where

Loadi = Load demand in hour i

PVi = Solar production of 1 MW installed capacity in hour i

WIi = Wind production of 1 MW installed capacity in hour i

HYi = Hydro production of 1 MW installed capacity in hour i

a,b,c = coefficients representing MWs of installed capacity per RES technology.

Thus, what should be selected is a portfolio that can cover the load, but not exceed in in overall terms relies in calculating the a, b and c capacity coefficients that will result in a Total Exposure of zero.

This approach can take a number of variants, depending on the years that should be covered, constraints regarding technology capacity or technology preference, but the principle remains the same. Another feature, is that the solution of a, b and c coefficients usually results in physically not applicable installed capacities and as such, approximations are usually made up to a degree of 0.5 MW of installed capacity.

A second approach, requires also that at all hours:

$$Load_i \geq a * PV_i + b * WI_i + c * HY_i \text{ [24]}$$

And in that case the requirement for the Total Exposure is to be minimum instead of zero. This constraint, ensures that no excess energy is procured at all times, but also is certain to leave a significant quantity uncovered by the PPA and exposed to the market. In the load profiles under study, the full calendar year coverage has been selected.

Any of these combinations is eligible to cover the relevant load in a full calendar year. Yet, the final decision on the selected technology, is also affected from the final cost of procuring the energy (according to the PPA structures) as well as the market capture price of each technology (Lion, 2013).

The Market Capture Price can be defined as follows:

$$Market\ Capture\ Price_y = \frac{\sum_{i=0}^{n} MCP_i * (\, PV_i + WI_i + HY_i)}{\sum_{i=0}^{n} (PV_i + WI_i + HY_i)} \text{ [25]}$$

Where:

n = hours of calendar year y

PVi = Solar production in hour i

WIi = Wind production in hour i

HYi = Hydro production in hour i

To evaluate the Market capture price for each Technology, the hourly MCP of calendar year 2021 are going to be used. 2021 was a year fully under the Target Model and can adequately represent a situation between normal electricity prices and the skyrocketing that took place as part of the EU energy crisis in the later half of the year. The market capture price, represents the value of the electricity pre-obtained by the PPA contract in the market itself.

A series of results and combinations, as well as the Market Capture Price for each can be summarized in the following table:

Table 29 RES Combinations to cover case study load Profiles

Load Profiles	Annual consumption (MWhs)	PV (MW)	Wind (MW)	Hydro (MW)	Market Capture Price (€/MWh)
Large Industrial	57,494.84	38.08	0	0	107.21
Large Industrial	57,494.84	0	24.47	0	108.10
Large Industrial	57,494.84	0	0	16.47	107.72
Large Industrial	57,494.84	11.13	17.32	0	107.84
Large Industrial	57,494.84	6.00	0	13.88	107.64
Large Industrial	57,494.84	0	7.63	11.33	107.84
Large Industrial	57,494.84	4.34	6.76	10.04	107.76
Medium Industrial	3,901.97	2.58	0	0	107.21
Medium Industrial	3,901.97	0	0.52	0.77	107.84
Medium Industrial	3,901.97	0	1.66	0	108.10
Medium Industrial	3,901.97	0	0	1.12	107.72
Large Commercial Load	24,109.35	15.97	0	0	107.21
Large Commercial Load	24,109.35	0	10.26	0	108.10
Large Commercial Load	24,109.35	0	0	6.91	107.72
Large Commercial Load	24,109.35	4.67	7.26	0	107.84
Large Commercial Load	24,109.35	2.52	0	5.82	107.64
Large Commercial Load	24,109.35	0	3.20	4.75	107.84
Large Commercial Load	24,109.35	1.82	2.84	4.21	107.77

The second criterion is the cost of the PPA according to the Offers, as described above. Essentially, this is the cost of procuring the energy and will be compared to the Market capture Price. As we can observe, RES tend to capture lower prices than the average wholesale market prices, due to their unstable production. Solar captures the lowest price alone, as expected due to cannibalization phenomena, but in general the capture prices are relatively close. This can also be verified by the monthly data provided by DAPEEP[23] that present the aggregated capture prices per technology countrywide.

The evaluation of the offers according to potential RES portfolio allocations is the following (in €/MWh):

Table 30 Cost of PPA procurement in €/MWh

Offers	PV	Wind	Hydro	PV and Wind	PV and Hydro	Wind and Hydro	PV, Wind and Hydro
Offer 1	52	59	N/A	56.26	N/A	N/A	N/A
Offer 2	99.12	100	N/A	99.74	N/A	N/A	N/A
Offer 3	55	60	N/A	58.04	N/A	N/A	N/A
Offer 4	59.97	66.99	N/A	64.94	N/A	N/A	N/A
Offer 5	62.69	60.42	56.79	61.08	57.72	57.92	58.47

As it is evident, offer 2 -that is essentially an uncapped indexed price- yields the biggest benefit for the RES producer as prices in the market remain high. As such, a potential off-taker will revert from PPA strictures such as these, as the effective benefit in comparison to the market value for the procured is relatively low. Capped proposals are better from the off-taker perspective as they always ensure competitive final prices in comparison to the wholesale market costs. Fixed prices on the other hand provide a stability in terms of cost for the off-taker and are preferable as they can serve both hedging against high Wholesale market costs as well as benefits by exploiting the energy in the market itself in case the off-taker is an electricity supplier. Fixed prices, contain a risk that has to do with wholesale market prices dropping below the fixed, stable cost through the PPA, but so far stable PPA prices tend to remain relatively low.

[23] https://www.dapeep.gr/eta/#1613031411987-b5402821-49b6

8.5. Impact on Final Energy Cost

Regardless of the PPA financial structure, the actual effect on the reduction of the overall cost is different for each consumer even when the exact same mix of RES production is utilized to cover the annual needs. Specific characteristics of the load profile itself, mean different costs even for the same billing schemes by the suppliers and different benefits form the PPA.

To assess the Green PPA impact on each consumer, a thorough hourly billing according to supplier offers took place. Assessment results take into account the overall cost in € per year, the cost in €/MWh according to each consumer load profile and the discount achieved by the relevant PPA proposals.

For the Large Industrial Consumer, we have the following results:

Table 31 Cost of Energy 2021- Large Industrial Consumer

Billing proposal	Pricing Offers	Annual Cost in €	Annual cost in €/MWh
Supplier 1	Fixed	18,795,063.98 €	326.90
	Indexed	9,407,780.17 €	163.63
	Clause	8,893,201.62 €	154.68
Supplier 2	Clause	8,314,345.95 €	144.61
Supplier 3	Clause	7,854,387.21 €	136.61
Supplier 4	Clause	7,825,456.28 €	136.11
Supplier 5	Clause A	8,026,871.74 €	139.61
	Clause B	8,695,409.56 €	151.24
	Various Markets Clause	8,630,887.37 €	150.12
Supplier 6	Clause	8,084,281.53 €	140.61

For the same consumer, the PPA proposals evaluation yields the following results:

Table 32 PPA proposal evaluation - Large Industrial Consumer

PPA proposal	Portfolio	Annual Benefit in €	Annual benefit in €/MWh
Proposal 1	PV	-3,174,630.77 €	-55.22
	Wind	-2,854,337.82 €	-49.65
	PV and Wind	-2,926,146.44 €	-50.89
Proposal 2	PV	-465,150.95 €	-8.09
	Wind	-470,605.83 €	-8.19
	PV and Wind	-465,416.17 €	-8.09
Proposal 3	PV	-3,002,128.37 €	-52.22
	Wind	-2,796,198.82 €	-48.63
	PV and Wind	-2,835,025.54 €	-49.31
Proposal 4	PV	-2,716,581.07 €	-47.25
	Wind	-2,389,756.63 €	-41.56
	PV and Wind	-2,467,023.55 €	-42.91
Proposal 5	PV	-2,559,855.35 €	-44.52
	Wind	-2,772,053.44 €	-48.21
	Hydro	-2,927,359.25 €	-50.92
	PV and Wind	-2,688,854.52 €	-46.77
	PV and Hydro	-2,870,354.12 €	-49.92
	Wind and Hydro	-2,868,703.34 €	-49.89
	PV, Wind and Hydro	-2,833,687.15 €	-49.29

Based on the lowest average Cost of energy - 136.11€/MWh- we can see that the benefits form the PPA proposals range between 5.94% and 40.57%. In average the calculated benefit is 30.99% and if the low benefit proposal -proposal 2 - is omitted, then the average benefit is 35.69%.

For the Medium Industrial Consumer, we have the following results:

Table 33 Cost of Energy 2021- Medium Industrial Consumer

Billing proposal	Pricing Offers	Annual Cost in €	Annual cost in €/MWh
Supplier 1	Fixed	1,275,554.16 €	326.90
	Indexed	649,948.89 €	166.57
	Clause	616,323.32 €	157.95
Supplier 2	Clause	577,300.03 €	147.95
Supplier 3	Clause	546,084.26 €	139.95
Supplier 4	Clause	543,859.24 €	139.38
Supplier 5	Clause A	557,790.17 €	142.95
	Clause B	602,185.60 €	154.33
	Various Markets Clause	595,495.30 €	152.61
Supplier 6	Clause	561,289.04 €	143.85

For the same consumer, the PPA proposals evaluation yields the following results:

Table 34 PPA proposal evaluation - Medium Industrial Consumer

PPA proposal	Portfolio	Annual Benefit in €	Annual benefit in €/MWh
Proposal 1	PV	-215,087.90 €	-55.12

	Wind	-191,519.84 €	-49.08
Proposal 2	PV	-31,514.95 €	-8.08
	Wind	-31,576.62 €	-8.09
Proposal 3	PV	-203,400.50 €	-52.13
	Wind	-187,618.84 €	-48.08
Proposal 4	PV	-184,054.07 €	-47.17
	Wind	-160,347.45 €	-41.09
Proposal 5	PV	-173,435.58 €	-44.45
	Wind	-195,123.60 €	-50.01
	Hydro	-185,998.74 €	-47.67
	Wind and Hydro	-199,067.54 €	-51.02

Based on the lowest average Cost of energy – 139.38 €/MWh- we can see that the benefits form the PPA proposals range between 5.80% and 39.55%. In average the calculated benefit is 30.01% and if the low benefit proposal -proposal 2 - is omitted, then the average benefit is 34.86%.

Finally, for the Large Commercial Consumer, we have the following results:

Table 35 Cost of Energy 2021- Large Industrial Consumer

Billing proposal	Pricing Offers	Annual Cost in €	Annual cost in €/MWh
Supplier 1	Fixed	7,881,345.96 €	326.90
	Indexed	3,958,034.75 €	164.17
	Clause	3,741,069.18 €	155.17
Supplier 2	Clause	3,498,107.05 €	145.09
Supplier 3	Clause	3,305,232.26 €	137.09

Supplier 4	Clause	3,293,330.86 €	136.60
Supplier 5	Clause A	3,377,560.31 €	140.09
	Clause B	3,654,163.63 €	151.57
	Various Markets Clause	3,665,240.70 €	152.03
Supplier 6	Clause	3,400,421.15 €	141.04

For the same consumer, the PPA proposals evaluation yields the following results:

Table 36 PPA proposal evaluation - Large Industrial Consumer

PPA proposal	Portfolio	Annual Benefit in €	Annual benefit in €/MWh
Proposal 1	PV	-1,331,377.45 €	-55.22
	Wind	-1,183,731.04 €	-49.10
	PV and Wind	-1,226,936.64 €	-50.89
Proposal 2	PV	-195,075.12 €	-8.09
	Wind	-195,166.36 €	-8.10
	PV and Wind	-195,144.68 €	-8.09
Proposal 3	PV	-1,259,033.35 €	-52.22
	Wind	-1,159,620.04 €	-48.10
	PV and Wind	-1,188,720.54 €	-49.31
Proposal 4	PV	-1,139,280.46 €	-47.25
	Wind	-991,063.18 €	-41.11
	PV and Wind	-1,034,430.77 €	-42.91
Proposal 5	PV	-1,073,552.78 €	-44.53

	Wind	-1,149,606.64 €	-47.68
	Hydro	-1,228,175.62 €	-50.94
	PV and Wind	-1,034,430.77 €	-42.91
	PV and Hydro	-1,203,842.44 €	-49.93
	Wind and Hydro	-1,202,811.43 €	-49.89
	PV, Wind and Hydro	-1,188,841.39 €	-49.31

Based on the lowest average Cost of energy - 136.60€/MWh- we can see that the benefits form the PPA proposals range between 5.92% and 40.42%. In average the calculated benefit is 30.65% and if the low benefit proposal -proposal 2 - is omitted, then the average benefit is 35.29%.

9. Organized Wholesale RES PPA Marketplace in the Greek Market Reform Plan

The effectiveness of Green PPA deals, is also highlighted in the Greek Market Reform Plan. The necessity of introduction of PPAs in the Greek Market in order to lower costs and hedge against market prices volatility through private bilateral RES PPAs, urged the Greek Government to provide assurances and governmental guarantees for the successful and timely implementation of these contracts (either financial as the ones explored in the previous chapters or physical. Private Green PPAs that will fall under the governmental auspices will have to incorporate only new RES assets that are not in any kind of public support mechanisms. This way the provision of the NECP regarding new RES can be supported. As it is clearly stated, the producers, require a PPA contract in case there is no support mechanism in order to be able to raise the required funds for the project from investors or banking institutions, yet the market surrounding PPAs is characterized by high uncertainty from the offtakes to conclude Green PPAs and this results in a stalling of new projects and a general investment stalemate.

Therefore, the Greek State is planning a legal and market framework to create a (non- mandatory) PPA market platform for private bilateral PPA agreements with the aim to create a safe environment with positive externalities for the further development of RES and the stability of electricity cost towards energy intensive economic activities but also the wholesale market in general.

The greatest uncertainty regarding the PPAs is the fact that an extra cost of matching the exact profile for each interested consumer has to be undertaken for aggregated volumes. This framework under consideration, is a concept of a Green Pool. The Green Pool is essentially a virtual aggregator for all the energy produced by the RES PPAs that undertakes all the profiling and shaping required to deliver a matched to the load profile outtake. With this process the relevant risks and costs are reduced by diversification of the hedging activities in large volumes across all available tools (financial hedging, physical delivery hedging, options etc).

The cost of these matching activities will be under the assurances and guarantee of the State. The end goal is for the State to initially play the part of a “Market Maker” to achieve a substantial quantity of bilateral contracts that will allow the PPA market to operate freely after that. The Green Pool will co-exist with the bilateral free market and the products will be primarily Contracts for Differences (CfDs) with physical delivery as an additional option. The energy traded through the Green Pool will also be accompanied by the relevant Guarantees of Origin, further promoting the decarbonization targets and objectives.

The exact configuration of the mechanism is not yet fully created and is subject to European Union approval (DG Energy), but is expected to be formatted in the second half of 2022 (Hellenic Rebublic, 2021).

10. Conclusions

For the better part of the past 2 decades after the Greek Electricity market liberalization, energy intensive consumers, both large industries as well as commercial energy consumers, enjoyed relatively low prices regarding their electricity costs. This was due to the fact that the Greek Energy mix relied heavily on the systematic exploitation of the lignite reserves in Western Macedonia and the Peloponnese that allowed low and stable prices, especially considering that access to these valuable resources was practically limited to the state owned incumbent PPC SA and the low EUA prices.

Gradually, Natural Gas production units began to emerge from both by IPPs and PPC and EU policy moved heavily towards decarbonization and the admission of more renewables into the EU energy mix. This resulted in the gradual decommissioning of lignite fired plants and the setup for a 'greener' mix with the Natural Gas as a transitory fuel until 2030, as is it described in the National Energy and Climate Plan. At the same time, the full unbundling of the electricity market took place and a new status emerged in the markets especially after 2016 and the ownership separation of the Greek TSO from PPC. Nevertheless -and despite gradual EUA prices rising- final cost for the energy intensive consumers remained at manageable levels.

Yet, after 2017 it became apparent that Natural Gas, as a commodity traded in international markets and without any kind of domestic production is subject to big fluctuations that directly reflect on the wholesale market at least. Natural Gas price crises occurred in both the beginning of 2017 and 2019, but were short in duration and did not eventually manage to fully reflect on the final consumer prices. This is not the case though in the current crisis- which initiated in the second half of 2021- that includes both economical as well as geopolitical parameters.

In any case, the upwards trend in final prices - as described in Chapter 5- was already evident (with the exception of the COVID affected 2020). In comparison to 2017, in 2021 energy intensive consumers had to withstand an increase between 67-91% depending on their consumption level. This situation in 2022, is even worse were increases in comparison to 2017 are even reaching a staggering 170%. Wholesale market prices are now linked to the final cost of energy directly through clauses. The high Wholesale market prices, after breaking one record after the other are also estimated to remain in significantly high levels for at least the following 3-5 years according to EU estimations.

At the same time, during the past decade Renewables quickly developed in the Greek Market mix, supported by governmental subsidies in the form of Feed-in-Tariff schemes. As the RES technology matured, the Levelized Cost of Energy, meaning the cost per MWh produced over the lifecycle of a RES asset steadily dropped. Since 2016, the Feed-in-Tariff schemes were abolished and a new status formed around Renewables with obligations for market participation and Feed-in-Premium support mechanisms through auctions. Prices in auctions have resulted in marginal prices towards LCOE and as such further development of RES projects under the circumstances is uncertain, jeopardizing the targets set in the NECP.

However, competitive market derived energy portfolios will heavily depend in the very near future on the access to Renewable Energy. Suppliers and large consumers are thus propelled to establish a new status with the deployment of private Green Power Purchase Agreements (PPAs). The development of storage installations will also encourage these endeavors.

In this work, we have delved in to the PPA specifics, their nature, structure and effect on the off-taking consumer. Three different consumer profiles were analyzed and five PPA proposals were formed in terms of RES portfolio and evaluated in market terms (based on the market prices of 2021).

The Greek State has also identified the need to promote Green Power Purchase Agreements and facilitate both the further deployment of RES as well as shaving insecurities and concerns from the final off-takers by the setting up of a Green Pool mechanism.

Results are extremely encouraging, since benefits and reduction of costs for these cases spans up to approximately 40% in comparison to what would have been the case without the green PPA. In general, costs and benefits heavily depend on the wholesale market and billing structure and the actual numbers may vary at the end, but still, green PPAs are a tool for the future of the Greek Market.

In order for the fast deployment of Green PPAs in the Greek Market, some policy initiatives have to take place. The Green Pool, as it is ordained in the Market Reform Plan and described in Chapter 9, is a step in the right direction, but it is found wanting in a number of sectors. Namely, the Green Pool will guarantee the trading activities that are required for profiling Renewable energy, but will not serve as an effective marketplace for all interested parties, but only some very energy intensive industries. This means that medium industries and commercial consumers will not be eligible to participate, at least in the initial phases. Taking into account that the Greek economy is not an industrial economy, this implies that the majority of potential offtakers is excluded.

At the same time, due to Network constraints, a relevant Ministerial Decision (YPEN/GDE/84014/7123) attempts to prioritize new Renewables projects for the next decade. Unfortunately, Renewables with potential Green PPAs that involve households are ranking low in priority measures and that in turn affects suppliers that have a significant proportion of residential consumers, from becoming offtakers. In addition -according to the same Decision- Renewables combined with Storage facilities – the actual paragon of RES technology- ranks even lower. Capacity constraints can be resolved by either enhancing the existing infrastructure or deploying greater interconnection capacity with neighboring countries, especially those that operate under the EU Target Model regime.

At the moment, while RES open market participation instead of subsidies is provisioned in the basic legislation, the relevant Ministerial Decisions have not yet been issued. This means that all the relevant policy issues have to be addressed prior to the Commercial Operations Date of an asset under a PPA contract. For the Renewables to also be able to participate in the market, the Target Model transitory period has to come to an end. Renewables should be allowed to trade freely in the market and undertake full responsibilities in the Balancing Market. Renewables with Storage could also undertake Balancing Services in a much lower cost than conventional units. The end of the transitory period is directly linked to the initiation of Cross Border Continuous Intraday Trading -commonly known as XBID- that has not been materialized after almost 2 full calendar years into the new market. XBID is expected to begin in December 2022, but not with full deployment until mid-2023, according to the Hellenic Energy Exchange. On top of that, due to the energy crisis, the Government has imposed a cap on Wholesale Market revenues from all kinds of energy producing sources, including Renewables. The presence of a cap, has hindered -and practically halted- all Green PPA discussions and negotiations, since the market value of the energy component of the PPA is heavily distorted.

In order to further explore the potential of Green PPAs in the Greek Market, a thorough analysis of future wholesale market prices has to take place. Given the fact that the energy crisis experienced by the EU is a new phenomenon, relevant technological, policy and geopolitical factors have to be taken into account, that were not present in the previous decades. The persistence of the crisis and a potential re-evaluation of EU policies in response to the war in Ukraine and whichever aftermath, is crucial to explore the momentum and potential of Renewables to play a pivotal part in the energy transition. In addition, all the recently introduced legislation (such as connection priorities or wholesale market caps), has to be inserted into the analysis, to further quantify potential impacts. Finally, the inclusion of all consumers (industrial, commercial and residential) to the benefits of green electricity through bilateral PPAs, has to become a priority in further analysis on a market level.

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11. Appendix 1 CO_2 Clauses

Year	Month	CO2 Clause (€/MWh)
2017	January	3.83
2017	February	3.83
2017	March	3.83
2017	April	2.95
2017	May	2.95
2017	June	2.95
2017	July	2.95
2017	August	3.50
2017	September	3.50
2017	October	4.31
2017	November	4.31
2017	December	6.07
2018	January	6.07
2018	February	5.86
2018	March	6.27
2018	April	5.42
2018	May	5.19
2018	June	9.17
2018	July	9.17
2018	August	11.91
2018	September	13.51
2018	October	13.93
2018	November	13.93
2018	December	14.00
2019	January	23.90
2019	February	23.13
2019	March	22.82
2019	April	27.43
2019	May	25.45
2019	June	27.50
2019	July	29.38
2019	August	27.37
2019	September	25.76
2019	October	26.35
2019	November	25.94
2019	December	25.18
2020	January	25.44
2020	February	24.50
2020	March	24.18
2020	April	19.89
2020	May	20.18
2020	June	20.04
2020	July	23.55
2020	August	27.53
2020	September	26.87
2020	October	27.82
2020	November	25.18
2020	December	26.56
2021	January	30.77

2021	February	33.54
2021	March	37.96
2021	April	40.96
2021	May	45.34
2021	June	52.26
2021	July	52.92
2021	August	53.39
2021	September	56.66
2021	October	61.31
2021	November	59.48
2021	December	80.33
2022	January	80.33
2022	February	80.33

12. Appendix 2 Historical DAS/DAM Market Data

Year	Month	DAS	Imbalances	Uplift Accounts	RES Floor	FRM	PXEFEL	Annual Clearing
2017	January	78.177	0.648	7.154	0.233	2.711	10.541	0.030
2017	February	58.346	-0.293	3.771	0.215	3.005	8.825	0.030
2017	March	47.043	-0.233	2.380	0.923	3.352	6.792	0.030
2017	April	44.859	0.296	2.898	1.067	3.661	6.147	0.030
2017	May	46.832	-0.583	2.896	0.999		7.533	0.030
2017	June	52.540	-0.760	1.796	0.089		6.006	0.030
2017	July	54.787	-1.666	2.269	0.235		7.204	0.030
2017	August	51.773	-0.812	2.216	0.317		7.952	0.030
2017	September	54.635	-1.288	2.339	0.126		6.033	0.030
2017	October	56.498	-0.950	2.645	0.519		8.032	0.030
2017	November	74.359	-1.144	3.397	0.153		9.439	0.030
2017	December	58.201	-1.217	2.254	0.513		10.221	0.030

Year	Month	DAS	Imbalances	Uplift Accounts	RES Floor	FRM	PXEFEL	Annual Clearing
2018	January	54.572	-0.597	2.321	0.485		2.363	0.35
2018	February	52.881	-0.719	2.771	0.797		2.912	0.35
2018	March	45.150	-0.214	4.288	3.530		4.425	0.35
2018	April	51.490	-0.766	3.582	2.944		2.133	0.35
2018	May	57.201	-0.678	3.036	1.336		2.305	0.35
2018	June	62.219	-1.185	2.285	0.640		2.315	0.35
2018	July	66.599	-1.954	3.067	0.350		1.713	0.35
2018	August	65.185	-1.043	3.313	0.946		2.209	0.35
2018	September	68.562	-0.971	3.666	0.715		2.390	0.35
2018	October	72.114	-0.354	3.088	0.608	3.184	2.324	0.35
2018	November	70.015	-0.032	3.466	0.703	2.861	2.401	0.35
2018	December	72.292	-0.054	3.408	0.549	2.499	1.845	0.35

Year	Month	DAS	Imbalances	Uplift Accounts	RES Floor	FRM	PXEFEL	Annual Clearing
2019	January	77.128	-0.621	3.122	0.639	2.711		0.073
2019	February	69.076	0.555	3.004	1.518	2.868		0.073
2019	March	59.952	0.954	4.015	3.148	3.251		0.073
2019	April	62.365	0.925	4.287	2.474			0.073
2019	May	65.734	0.725	3.948	2.372			0.073
2019	June	67.738	0.661	3.126	1.230			0.073
2019	July	63.137	-0.332	3.016	1.158			0.073
2019	August	63.489	1.234	3.173	1.144			0.073
2019	September	60.826	0.848	4.196	1.697			0.073
2019	October	63.229	1.185	5.157	1.841			0.073
2019	November	55.225	1.418	4.631	2.887			0.073
2019	December	61.071	0.809	6.627	3.139			0.073

Year	Month	DAS	Imbalances	Uplift Accounts	RES Floor	FRM	PXEFEL	Annual Clearing
2020	January	60.539	0.940	3.756	2.091			
2020	February	48.206	2.175	3.866	3.485			

2020	March	42.410	3.208	6.704	4.630			
2020	April	27.710	1.832	5.905	5.640			
2020	May	33.637	1.433	4.270	2.451			
2020	June	33.636	0.988	3.005	1.048			
2020	July	41.679	0.376	3.494	0.406			
2020	August	47.114	-0.389	4.328	0.790	1.648		
2020	September	48.444	-0.299	5.330	1.592	3.287		
2020	October	48.282	-0.226	6.727	2.649	3.746		
2020	November*	55.421	0.894	16.937	5.515	2.597		
2020	December*	63.830	-0.381	15.945	7.336	2.338		

*DAS Equivalents as ordained ty RAE

Year	Month	DAM & IDM	Imbalances	Uplift Account 1	Uplift Account 2	Uplift Account 3	Total Uplifts
2021	January	55.441	0.830	1.413	0.869	5.357	6.770
2021	February	50.787	0.353	1.411	1.197	8.824	11.432
2021	March	58.614	1.181	1.400	1.773	6.251	9.424
2021	April	64.003	1.902	1.604	1.013	5.404	8.021
2021	May	63.172	1.996	1.591	1.158	8.408	11.157
2021	June	86.385	1.343	2.023	1.337	7.288	10.648
2021	July	103.446	1.500	2.684	1.324	3.526	7.534
2021	August	127.446	-0.087	3.337	2.008	4.077	9.422
2021	September	136.399	0.856	4.294	1.812	3.753	9.859
2021	October	204.052	-0.437	7.130	3.640	6.810	17.580
2021	November	236.376	0.072	7.885	2.087	5.581	15.553
2021	December	244.874	2.453	8.510	2.188	7.112	17.810