UNIVERSIDAD PONTIFICIA COMILLAS

ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

OFFICIAL MASTER'S DEGREE IN THE

ELECTRIC POWER INDUSTRY

Master's Thesis

TARIFF DESIGN AND METHODOLOGY FOR ALLOCATING NETWORK SYSTEM SERVICE COSTS

Author: María del Pilar López García

Supervisor: Manuel Martínez Benítez

Madrid, July 2026

Master’s Thesis Presentation Authorization

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Summary

The increasing relevance of ancillary service costs in the Spanish electricity system has increased the need to review the current methodology for allocating these costs. Under the current methodology, ancillary service costs may increase the final electricity price in hours where the day-ahead market price is low, especially during valley hours. This can create an inefficient price signal, since consumers may be discouraged from shifting demand towards periods where additional consumption could improve network utilization without requiring additional network investments.

The objective of this thesis is to assess whether ancillary service costs can be allocated in a more efficient, transparent, and cost-reflective way. Under the current Spanish methodology, these costs are treated as part of the cost of electricity production and are allocated to demand. For this purpose, data published by SO between 2020 and 2025 was collected and organized, including activated energy, prices, demand and costs related to technical restrictions in the PDBF and in real time, as well as secondary reserve, SRAD and other costs. Afterwards, several regression models were carried out to identify the main cost drivers. These models were applied under different scenarios: annual data, monthly disaggregation, CNMC tariff periods, month-period combinations, and hourly profiles for working and non-working days. This analysis aims to identify the most efficient cost allocation methodologies. In addition to this, a benchmark on European methodologies was performed to analyze how other countries recover these costs.

The results show that ancillary service costs increased significantly during the period analyzed. However, the analysis does not reveal a strong correlation with demand, suggesting that demand alone is not sufficient to support a direct allocation methodology. For upward restrictions, the cost is better explained by the amount of activated energy, although demand appears to be indirectly related to energy. Real-time models provide more robust results than PDBF models, as expected, because they reflect the actual balancing actions required to solve specific system constraints in each hour, rather than the initial scheduled dispatch. For downward restrictions, no clear relationship with demand was found, suggesting that these costs are more related to local constraints, renewable

curtailment, evacuation problems, or technical limitations. For the secondary band and SRAD, the results show a stronger relationship with demand uncertainty and variability than with the demand level itself. Therefore, demand uncertainty can be considered as a possible allocation parameter for these costs, instead of using demand directly.

Based on these findings, several tariff allocation methods were assessed, including cost causality, cost of service, short-term and long-term marginal cost, Ramsey pricing, postage stamp, peak pricing, average participation and an adaptation of the Circular 3/2020 network tariff methodology. The final proposal combines two methods. Upward technical restriction costs, secondary band, and SRAD are allocated using a covariance methodology, which assigns a higher share of costs to consumer groups and periods that contribute more to demand uncertainty. Downward restriction costs are recovered using a Ramsey pricing approach, since no clear cost driver related to the demand could be found.

The application of the proposed methodology to 2024 data shows that low-voltage groups bear a higher share of ancillary service costs, while high-voltage groups are allocated a lower share of costs. This is consistent with the covariance approach, as low-voltage demand profiles are generally more variable and less predictable. The elasticity analysis suggests that this change could also support a more efficient system price signal, encouraging consumption in hours where additional demand may be beneficial and discouraging it in periods where the system is more constrained. Therefore, the thesis concludes that the current allocation methodology is inefficient and that a combined covariance-Ramsey approach provides a more efficient and interpretable alternative for allocating ancillary service costs in Spain.

Agradecimientos

Quiero agradecer especialmente a mi tutor por toda la ayuda y el apoyo que me ha dado durante estos meses. Sus consejos y su orientación han sido fundamentales a lo largo de todo el proceso y, sin su ayuda, esta tesis no habría sido posible.

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Chapter 1. INTRODUCTION

This chapter consists of a brief introduction accompanied by the motivation of the project; it is followed by the main objectives of the thesis, and it concludes with the description of how the report is going to be structured.

1.1 MOTIVATION

Over the past 20 years, the Spanish electricity system has experienced significant structural, technological, and regulatory changes. Market dynamics and network operation requirements have been altered by the liberalization process, the integration of renewable energy sources, and the increasing electrification of demand. In the Iberian Electricity Market (MIBEL), Spain uses a marginal pricing model in which the day-ahead market sets hourly energy prices based on the merit-order principle. In this system, the price for every bid that is accepted during each hourly period is determined by the marginal generating unit.

Although the day-ahead market is crucial for energy scheduling and price formation, its outcome may need to be adjusted when it does not guarantee the technical feasibility, quality, and security of the electricity supply. For this reason, redispatching actions may be required both after the PDBF and in real time to ensure secure system operation. The system depends on several ancillary and balancing mechanisms outside of the wholesale market to guarantee frequency stability, voltage control, and network viability. As the use of renewable energy increases and the need for system flexibility increases, these ancillary service mechanisms become increasingly important.

The rising cost of system services in comparison to the average day-ahead market price has been a growing source of concern for the Spanish electricity industry over the last few years, as one of the effects of the energy transition is the increase of system services costs related to controlling network voltages and managing reactive power and network congestion.

The increasing share of system services costs in the electricity bill makes it necessary to review the current cost allocation methodologies to achieve cost-reflective and efficient tariffs.

This master's thesis aims to propose a tariff design and an alternative methodology for allocating network system services for the Spanish power system.

1.2 OBJECTIVES

The primary goals of this thesis are to examine the composition, development, and distribution of system service costs in the Spanish electricity market and to determine whether different tariff design approaches could improve cost effectiveness, transparency, and consistency to cost causality principles when applied to the demand.

First, using data released by SO in the e-sios web (esios, 2026), the study aims to gather all the information related to the cost and activation of technical and balancing services over several years. The identification of cost, volumes, activation patterns, and their relative significance in relation to wholesale market prices will be made possible by this quantitative evaluation.

Second, in order to find structural patterns and key cost drivers, the study will categorize technical constraints into various groups, such as upward and downward energy, case base contingencies, N-1 contingencies, distribution requirements, renewable evacuation restrictions, and voltage control actions.

Third, the analysis will contrast hourly day-ahead market prices with activated power volumes and related costs. Through this comparison, it will be possible to ascertain whether systematic over costs can be identified and whether balancing costs are concentrated during times of the day, such as times of high renewable output or peak or valley demand.

Fourth, the thesis assesses whether the cost causality principles are reflected in the current cost allocation mechanisms. It will focus on whether different time-based allocation strategies, such as differentiating expenses by time of day, could enhance economic efficiency and give market players more precise price signals.

Fifth, an international comparison of the methodologies for allocating these costs will be carried out. In some countries, several of these system services costs are recovered through volumetric charges.

Lastly, to propose a tariff design and a methodology for allocating system service costs for the Spanish electricity system that improves the efficiency price signal and cost reflectivity of their current allocation.

The thesis seeks to contribute to the continuing discussion on electricity tariff design in high-renewable systems by bridging regulatory analysis with empirical data through this organized set of goals.

1.3 STRUCTURE OF THE REPORT

This report is structured in three main blocks. The first one aims to gather all the information needed to have enough knowledge to carry out the research. It consists of a first chapter of the background needed to understand the basic concepts that are going to be treated in this thesis and a second chapter where similar work carried out by other entities is analyzed. This will contribute to extracting some conclusions from them and to identify possible gaps to overcome this thesis. The second block consists of the methodology chapter, where all the processes followed during the development of this thesis are going to be described. In addition to this, the analysis aims to obtain results that support the proposed allocation methodology, and finally, a third block with a chapter dedicated to expose the results extracted from the previous chapters and the conclusions obtained from them.

Chapter 2. BACKGROUND

This chapter contains the preliminary concepts needed to fully understand the problem tackled in the thesis.

2.1 THE STRUCTURE OF THE ELECTRICITY BILL IN SPAIN

There are several costs associated to the production and delivery of electricity in Spain. Some are regulated, and others are the result of competition in energy markets. In the beginning, the regulated costs were treated as a whole and charged in what was called access tariffs. The law 24/2013 (Ley 24/2013 del Sector eléctrico, 2013), introduced a differentiation in the access of tariffs, separating it in two: the system charges, established by the ministry; and the T&D costs, established by the CNMC through tariffs. These costs are unique for the whole territory, and they do not include taxes.

As an end consumer, you are going to be paying for all those costs. Nevertheless, the final bill will depend on whether you decide to sign a contract in the free market with a retailer, or on the other hand, if you have a contracted power of less than or equal to 10KW with voltage levels under 1kV, you can opt for the PVPC[1] tariff (a regulated tariff established by the government). The main components that you can find on your final bill are:

Retailer costs: Allowed revenues paid to the retailer for supplying electricity. It can be regulated or not depending on whether it is a reference retailer.

Transmission and distribution tariffs: Regulated grid retribution used to pay for the costs of the physical grid. It covers all the way from the generator stations to the meters of the end consumers.

[1] Precio voluntario al pequeño consumidor.

- Transport payments: Accepted payment for operating and maintaining the transmission grid.
- Distribution payments: Accepted payment for operating and maintaining the low/medium/high voltage grid.[2]

System charges: Regulated costs not directly related to the electricity supply itself but rather respond to energy and economic policy objectives.

- RECORE: Incentives to renewables, cogeneration, and residuals. Some of them cannot recover their investment since they are too cheap. For that reason, the system recognizes an additional payment to incentivize their participation.
- Non-mainland generation compensation: It is more expensive to generate electricity on the islands and Ceuta and Melilla. To avoid them paying a higher cost, the electric system compensates it by sharing the costs among the system.
- Deficit annuities due to past tariff deficits: Annual payment to pay for the accumulated debt from the past.
- Others: Payment to the Spanish regulator (CNMC[3]) and other small costs.

Cost of energy: This includes the costs associated with buying electricity in the markets and the cost of ensuring that the system operates safely. It includes:

a) Market operator (OMIE in Spain): It is the cost associated with operating the market where supply and demand bids are matched. It manages and supervises f.
b) System operator (REE in Spain): Payment to the system operator. It manages and supervises c, d and e.
c) Capacity payments: Payments made to generators for having capacity available in case it is needed. The payment is not for the power itself, but for its availability.

[2] Traditionally, voltages above 1 kV are classified as high voltage. However, in practice, levels up to 36 kV are usually considered medium voltage, while higher levels correspond to high voltage or transmission voltage levels.
[3] Comisión Nacional de Mercados y Competencias.

d) Interruptibility service: A mechanism through which certain large consumers make themselves available to reduce demand if the system requires it.

e) Ancillary service costs: These are the costs associated with operating the electricity system: security, balance, and technical constraints. They will be explained in detail in the following section.

f) Cost of the supplied energy.

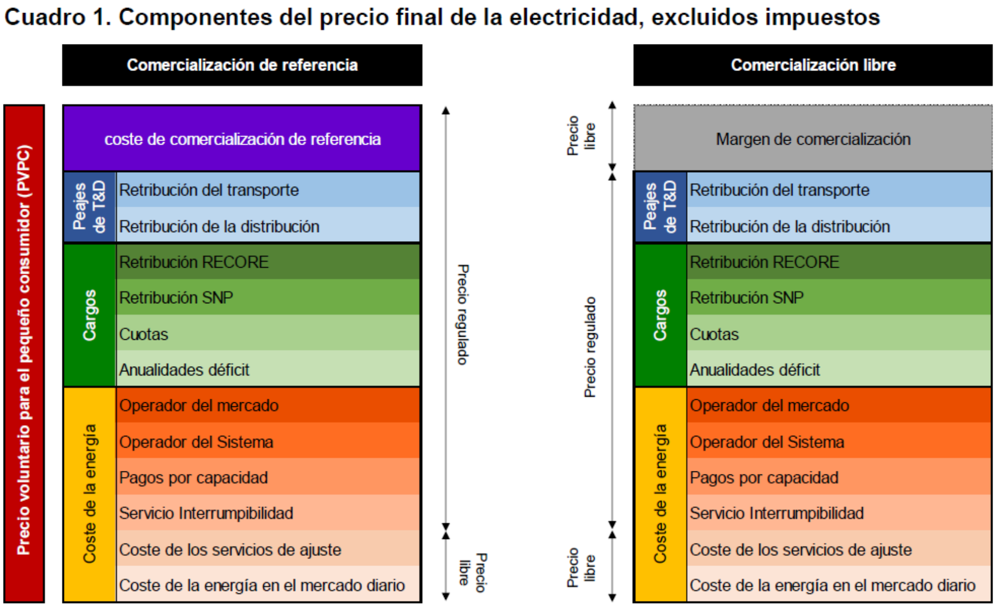


Figure 1: Depiction of costs in an electricity bill. Source: CNMC

2.2 *ANCILLARY SERVICES AND TECHNICAL CONSTRAINTS*

Ancillary services are a series of tools (including adjustment services, balancing services and SRAD) that are used for system operation to guarantee electrical supply and maintain a constant balance between energy and demand production, (Red Eléctrica, 2025). A technical constraint is any circumstance or incident arising from the state of the system that affects the security, quality and reliability of supply, including those arising from the non-compliance of security conditions in the distribution grid as communicated to the system operator by the relevant distribution grid manager. This adjustment service is aimed at resolving technical constraints within the system by limiting and, if necessary, modifying the production schedules of generation, demand, and storage units to resolve identified technical constraints at the lowest cost to the electrical system. (Red Eléctrica, 2025).

2.2.1 PREVIOUS CONSIDERATIONS

There are four operational states within the Spanish electrical system (Ministerio de Industria Energía y Turismo PO_1.1, 2016): **normal**, where all the control variables are within the margins and all the security constraints are met; **alert**, where the control variables are still within limits, but the system does not meet security constraints in the contingency analysis (N-1 criteria); **emergency**, where the variables are not within limits (voltage, frequency, or overload elements); and the **restitution**, where the system tries to recover the service after a zonal or national zero.

The control parameters considered are **frequency**, which normal range is among ±50mHz, its maximum accepted deviation after an incident in the transitory state is ±200mHz, and its maximum instantaneous deviation is ±800mHz (instantaneous peaks) (ENTSO-e, 2019); **voltage** in the system nodes (BOE PO_resol_30jul1998); and the elements of the system **load** (generators, transformers…) (Jefatura de estado BOE-A-2022-15354).

In addition to this, the security criteria and contingency analysis include:

- N-1: simple failure of a grid element (line, reactance, generator, transformer). In this case, voltages should be withing the presented limits:

Nivel	Mínimo	Máximo
400 kV	380 (95 por 100)	435 (108,7 por 100)
220 kV	205 (93 por 100)	245 (111 por 100)

Figure 2: Admissible voltages for the N-1 criteria. Source: SO, PO 1.3.

- Simultaneous failure of a double circuit if they share the same support towers for more than 30km in case of old lines and 50 km in case of new lines. The voltages should be within the presented limits:

Nivel	Mínimo	Máximo
400 kV 220 kV	375 (93,75 por 100) 200 (90 por 100)	435 (108,7 por 100) 245 (111 por 100)

Figure 3: Admissible voltage for double circuit failure. Source: SO. PO 1.3.

- Special situation: "Excessive correction time". The failure of the biggest generator of the zone and an interconnection line is considered with the rest of the system. This is a way of covering the risk of losing the highest local production and importation capacity.

Ancillary services are used to keep security constraints under control. When there is an imbalance on the grid or dispatch solutions that do not meet these criteria, the ancillary services are activated.

2.2.2 ANCILLARY SERVICES AND THE OPERATIONAL PROCEDURE

Service	***Description***	***Activation***	***Drivers***	***Settlement***
Adjustment services (Red eléctrica PO_3_2, 2025)	Adjustment of schedules for security, quality, and reliability	After PDBF and real-time when issues reappear.	Network constraints; outages; imbalances; voltage issues	Redispatch costs included in constraint price components
Primary control	Correction of instantaneous imbalances between production and consumption	Automatic in real time	Demand variability; renewable variability; outages; ramps	Not remunerated
Secondary control (aFRR)	Up/down reserve + automatic energy activated by AGC to	Automatic in real time; energy bids	Demand variability; renewable	Capacity paid at marginal price (€/MW); energy at marginal price;

(CNMC Resolución de 20 de octubre de 2025)	balance frequency-power	updateable up to T-25 min	variability; outages; ramps	penalties for non-delivery
Tertiary control	Upward activations to resolve imbalances and to restore the secondary reserve	Real-time. In a maximum of 15 minutes and can be maintained for two hours	Real demand changes; sudden outages; renewable variability	Through market mechanisms
Balancing Energy Non-Delivery	Provider fails to deliver activated balancing energy	During verification and settlement closure	Outages; failures; unforeseen constraints	Penalties/payment obligations
Imbalance Costs	Settlement of real imbalance	During balance settlement	Forecast errors; renewables; failures; demand deviations	€/MWh imbalance price component
Imbalance Settlement Residual	ex-ante vs real losses; corrected measurements;	Settlement closure	Loss differences; measurement corrections	Positive/negative adjustments in price components
Power Factor Control	Mandatory reactive power provision (cos φ) for voltage control	Continuous	Voltage deviations; network configuration; load	Regulated remuneration; penalties

PO 14.6 Balance (Interconnections)	Economic adjustment for international exchanges	Hourly with interconnections	Schedule-flow deviations; European balancing needs	Accounting adjustments linked to interconnections
SRAD (PO 7.5)	Fast demand reduction (≤12.5 min), up to 2h; allocated via auction	When upward mFRR is insufficient	Reserve depletion; incidents; high variability	Capacity: marginal auction price (€/MW); energy: max marginal upward mFRR price during activation
Voltage Control Service (CNMC Resolución de 12 de junio de 2025)	Remuneration for mandatory voltage control service	Continuous	Need for reactive power due to network/load	Penalties

Table 1: Summary of the ancillary services and related settlement components. Source: SO. PO 3.2; PO 3.3; PO 7.1; PO 7.2; PO 7.3; PO 7.4; PO 7.5.

They are activated after the day ahead market. The Market Operator (hereinafter MO) sends the PDBF, the schedule electricity program of generation and consumption. It includes the match of the day ahead market and the bilateral contracts before technical constraints are applied. Then, the System Operator (hereinafter SO) (REE in Spain) runs a security analysis to see if all the security constraints are met. The main causes that produce the need to activate the ancillary services are:

- Not complying with the security analysis in the steady state in the base case (hereinafter SCB) and/ or before a contingency restriction (N-1 analysis) (hereinafter SCA).
- Lack of power reserves for balance and frequency control, both upwards (hereinafter RIS), and downwards (hereinafter RIB).
- Lack of capacity for voltage control in the transmission grid (hereinafter SOT/COT).

- Non-compliance on the distribution grid communicated by the DSO (hereinafter RTD).

After the PDBF is published, the generators have a 30-minute period for submitting their offers to participate in the ancillary services. Once the 30 minutes are over, the SO analyses the scheduled dispatch and identifies whether the program fails to meet any technical operating criterion. This elaboration includes verifying the power flows resulting from the program; checking if physical limits are met, such as thermal constraints, voltage levels, reactive power requirements and stability conditions; assessing the availability of reserves; confirming compliance with N-1 security criteria; and considering any limitations communicated by distribution system operators. If any of these conditions are not fulfilled, the program is considered technically infeasible and SO activates the technical constraints resolution process established under Operating Procedure 3.2 (BOE PO 3.2, 2025). The redispatch process is then carried out by accepting or withdrawing offers to restore system security and ensure that the final dispatch is technically feasible. This process is structured in two phases:

Phase1: Modification of the PDBF based on security constraints

The system operator, using demand and generation forecasts, performs security analyses and determines a solution that resolves network constraints with an adequate security margin while minimizing overall system costs. In addition, SO establishes operational limitations to prevent the reappearance of constraints in the following market stages. The SO also incorporates modifications requested by Distribution System Operators (DSOs), provided that they demonstrate the existence of constraints within their networks due to external factors outside their capacities. The set of measures available to the SO in Phase 1 includes:

- Topological measures affecting active and reactive power flows, such as network reconfigurations, tap changer adjustments, switching of reactors and capacitors, and the use of power electronics devices.

- Pre-activation of load-shedding schemes, such as automatic or remote disconnection systems in facilities whose disconnection under contingency conditions contributes to maintaining system security.

- Upward energy adjustments relative to the PDBF through accepted bids including increasing generation or reducing localized demand.

- Downward energy adjustments relative to the PDBF, including limitations or curtailments to solve constraints. These may affect generation units, pumped storage, energy storage systems, localized demand, and even cross-border exports when no alternative measures are available or when supply security is at risk.

- Exceptional situations, in which the SO may request neighboring systems to modify their schedules in the absence of sufficient domestic resources or in the presence of a risk to supply security.

Phase 2: Rebalance of generation and demand

Once system security has been ensured, the SO proceeds to rebalance the system so that, in each quarter period, total generation equals total demand, while respecting the limitations established in Phase 1 and the available interconnection capacity.

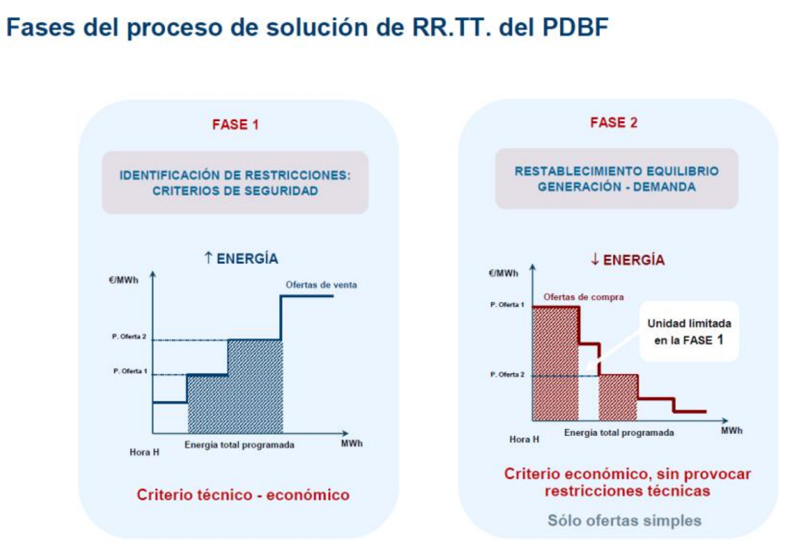


Figure 4: Phases of the process to solve the restrictions from the PDBF. Source: SO. PO 3.1; PO 3.2.

With that, the PDVP (programa diario viable provisional) is created and published not before 14:00, or two hours later of the publication of the PDBF in case of delay. Up to this point, two things can happen. If there is a lack of upward reserve, the SO can force thermal units to operate at their technical minimum, limit the maximum pumping, limit importations and if this is not enough, it can program additional start-ups. On the other hand, if there is a lack of downward reserve, SO can limit the pumping to avoid running out of this margin later. With all of this, the SO can designate some special units: GDO (groups that are obliged to be dispatched) GDL (groups with limited dispatch); GBR (groups that need to be keep at their minimum for security) and GSR (groups that have their upward capacity restricted to avoid surpassing their maximum for security).

At the same time, a Secondary Regulation Band Market is carried out. Every day, the SO establishes an estimation of the necessary available capacity for the next quarter-hour periods for the next day. These requirements are published before 14:45h on day D-1. Once they are published, it opens a period for bid submitting for the generators who want to provide this service, and it is closed at 16:00h. With this, before 16:30 it published the results for the assigned upward and downward reserve[4]. Finally, the assignation follows a minimum cost principle, and, in the end, two marginal prices are obtained (one for the upward reserve and another for the downward reserve).

Once all these markets are done (except the intraday markets), we enter in real time. There might be restrictions that occur very close to real time, mainly because changes on the predicted demand, renewables, unexpected failures, congestions… In this case, it does not exist a two-phase process to balance generation and demand (as in the day ahead) but instead, there exist real time mechanisms to solve these problems. After each session of the intraday market, and before the next session is open, the OS carries out the contingency analysis, removing some offers that may be causing these problems and adding some others. With

[4] In addition to this, all the generator units are obliged to submit offers with the available capacity that may have left, to participate in the tertiary regulation in case it is needed. These offers should be submitted before 23:00h of day D-1,

this, it produces the PHF that is published 15 minutes before the physical delivery of the energy.

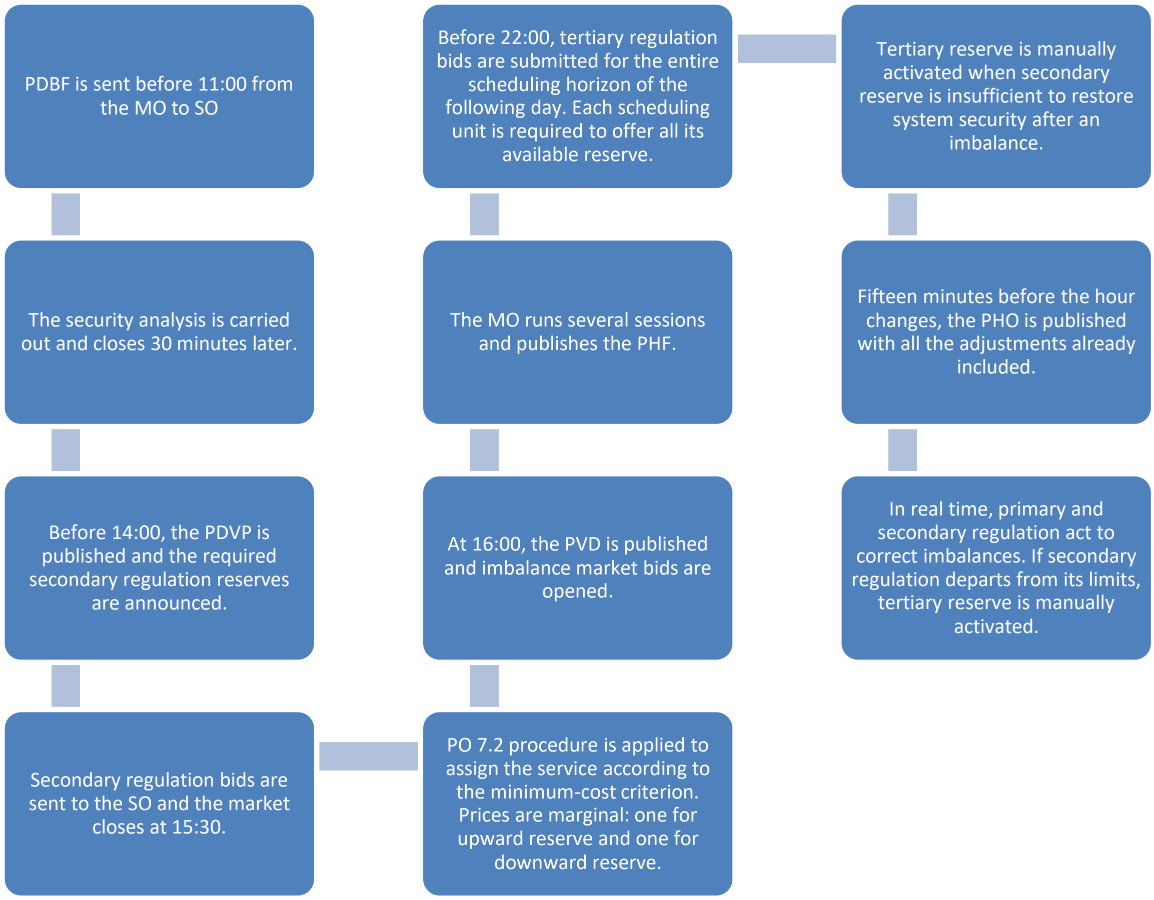


Figure 5: Process followed by SO to provide ancillary services. Source: Own elaboration.

To solve the problems, the first activated service is primary frequency control. This is an automatic response of the generators where they modify their speed to sustain frequency deviations and correct instantaneous disequilibrium. This is a compulsory and not remunerated service for all units. In case one unit cannot provide this service, it should acquire it from the other. The compulsory available capacity is ≥1.5% of Nominal Power per unit.

Then, the automatic frequency reserve restoration (Secondary frequency control) (BOE PO_resol_30jul1998) is activated. It is an automatic balance service to restore frequency levels to their optimal. It is activated in a few minutes. The SO makes a list of the units that can be eligible to provide this service and therefore participate in the secondary reserve market.

- Upward reserve ≈ $6 * \sqrt{Pmax\ of\ the\ system}$
- Downward reserve = (50-100) % of the upward reserve.

These estimations are used by SO to compute the secondary reserve that is needed.

These reserves are activated when the Ptarget established by the SO is reached. If Ptarget>0, it activates the upward reserve and if Ptarget<0, it activates the downward reserve. When the dispatch is closed, if a unit submitted an offer to provide a reserve and it can no longer do so, it could go to the IM to buy the energy. If it cannot obtain it, it should communicate it to the SO to run a redispatch and it will be penalized.

Finally, the manual frequence reserve restoration (tertiary reserve) (Ministerio de transición P.O.7.3, 2024) is a manual service to restore the secondary reserve. The needed reserve corresponds to the power of the biggest committed unit + 2% of the forecasted demand for that hour.

Other ancillary services include power factor control, a compulsory service for generators to maintain their reactive power within limits, to avoid excessive currents. And SRAD, a service provided by demand, to disconnect in hours where there is not enough generation or too much demand, that produces excessive voltages.

To have a first glance at the current situation, the next figures show the energy required for ancillary services and the associated cost of energy procurement, measured at generation level.

Necesidades de energías cubiertas en los servicios de ajuste

GWh	2023		2024		% 24/23	
	A subir	A bajar	A subir	A bajar	A subir	A bajar
Energía programada por seguridad	**13.828**	**2.689**	**19.018**	**2.418**	**37,5**	**-10,1**
Restricciones técnicas PDBF	9.502	1.513	13.588	1.717	43,0	13,5
Restricciones técnicas en tiempo real	4.326	1.176	5.429	701	25,5	-40,4
Energía utilizada por balances	**6.741**	**6.788**	**6.497**	**7.423**	**-3,6**	**9,3**
Reservas de sustitución (RR)	1.710	2.257	1.428	2.673	-16,5	18,4
Regulación secundaria	2.349	1.830	2.437	1.560	3,7	-14,8
Regulación terciaria	2.264	2.218	2.170	2.669	-4,2	20,4
IGCC[1]	417	483	462	520	10,9	7,6
Energía total gestionada	30.046		35.355		17,7	

Figure 6: Activated energy (GWh) for the ancillary services. Source: (Red Eléctrica, 2024)

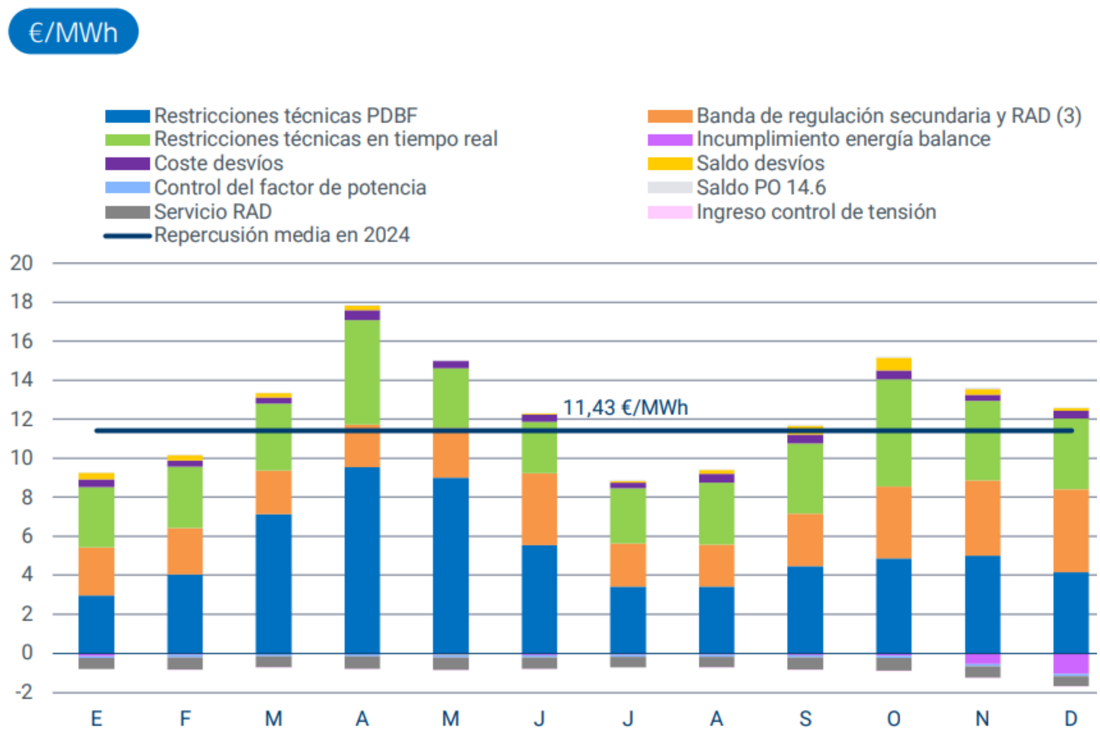


Figure 7: Ancillary service cost (€/MWh) of energy procurement at generation level. Source: (Red Eléctrica, 2024).

2.2.3 ANCILLARY SERVICE COSTS

As previously mentioned, the cost of the ancillary services has increased in recent years, with technical constraints representing the main components. Their costs are the result of the amount settled to the units participating in the technical constraints process and the value that the same energy would have had at the day-ahead market price. The CNMC methodology (CNMC_Normas_20251030, 2025) defines IMRRTT as the amount received by the units of aggregation k, in hour h and quarter-hour period q, for their participation in the technical constraints process. It also defines ENRRTT as the energy programmed for those units in the same process. Both concepts include not only generation units, but also pumping demand, demand units and storage when they participate in technical constraints.

Therefore, another relevant variable to account for is not only the energy activated in restrictions, but the economic settlement associated with that activation. IMRRTT represents the settled economic amount linked to the participation in technical constraints, while ENRRTT represents the energy programmed through that process. However, to understand the real impact of the restriction on the final cost of energy, it is necessary to compare this settlement amount with the value of that energy at the day-ahead market price. The process established by the CNMC includes this logic by subtracting the value of the programmed energy at the day-ahead price from the amount associated with the technical constraints process:

$$CRRTT = IMRRTT - ENRRTT \cdot PMD$$

Equation 1: Computation of the ancillary service costs. Over cost with respect to the market price. Source: (CNMC_Normas_20251030).

Where PMD is the day-ahead market price in hour h and quarter-hour period q. So, in the end, the cost of technical constraints is not only the amount paid in the restrictions process, but also the difference between the settlement of the restrictions and the reference value of that energy in the day-ahead market. This distinction is essential because the overcost with respect to the market price depends on three effects:

First, the volume effect. If more energy is programmed through technical constraints, the potential cost or overcost increases.

Second, the restriction price effect. If the units activated in the technical constraints process are settled at a higher price, the IMRRTT increases.

Third, the day-ahead market price effect. Since the overcost is calculated relative to the day-ahead price, a change in the day-ahead price can modify the overcost even if the technical constraint is the same. This effect is particularly important for the interpretation of the results. A higher day-ahead market price can reduce the overcost of a technical restriction, because the reference value ENRRTT·PMD becomes higher. On the other hand, a low or negative day-ahead price can make the overcost appear much larger, even if the activated resource itself has not become more expensive. This is why the cost of restrictions must be analyzed jointly with the day-ahead market price and not only with the activated energy or the settlement amount.

This is important in periods with high renewable production and low demand, where day-ahead prices can fall sharply while technical constraints may still be needed for security, voltage control, or network feasibility. In these hours, the final price signal can be counterintuitive: the day-ahead market price may be low, but the overcost of restrictions may increase because the difference between the technical constraints and the day-ahead reference price becomes larger.

Precisely, the need to revise the current cost allocation methodology that is analyzed in this thesis comes mainly from the increase in the need for adjustment services in the Spanish electricity system and the costs associated to it. As can be seen in figure 8, the amount of energy used for technical restrictions in the PDBF and real-time has increased rapidly over the years. For example, it can be observed that between 2020 and 2025, the upward energy required in the PDBF tripled, while the energy activated in real time increased by a factor of seven. Moreover, based on the available data, this trend appears likely to continue in 2026.

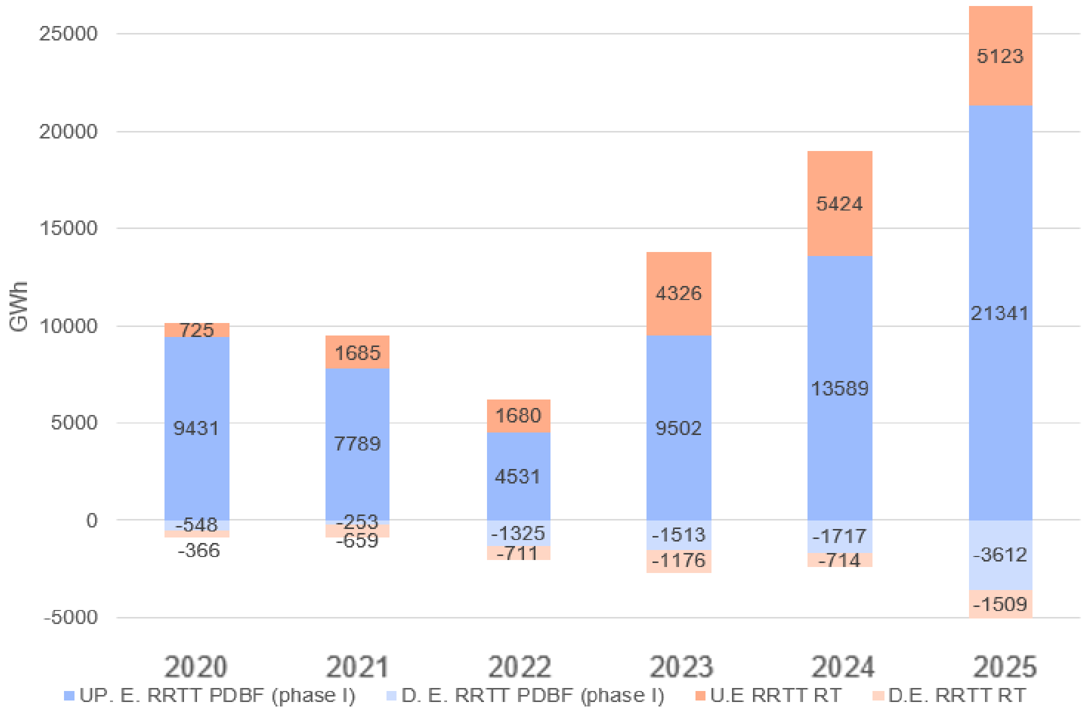


Figure 8: Energy from the restriction's evolution (GWh) from 2020 to 2025. Source: esios.

This increase in activated energy is also reflected in the prices of the service. The weighted average prices, especially for upward actions both in the PDBF and in real time, remain high. As a result, the total cost to recover from consumers also increases. This is especially important for retailers, since these costs represent an additional surcharge on top of the energy price. Therefore, an increase in these costs not only raises the final price paid by consumers, but also creates hedging difficulties for retailers, as they are exposed to a cost component that is harder to predict and manage in advance.

Precios medios ponderados por restricciones al pdbf y tiempo real (€/MWh) | Sistema eléctrico: Peninsular

Del 01/01/2020 al 01/01/2026

	2020	2021	2022	2023	2024	2025	2026
Precio PDBF a subir	75,3	135,8	235,4	170,9	134,5	162,4	166,4
Precio PDBF a bajar	30,7	82,8	144,9	76,1	44,8	52	48
Precio tiempo real a subir	146,6	269,2	499,2	290,2	238,8	248,5	225,8
Precio tiempo real a bajar	7,4	37,6	45,2	15,8	-4,2	-65	1,1

Figure 9: Evolution of the average price of the restrictions from 2020 to 2026. Source: esios.

In the case of the secondary reserve band, the cost mainly depends on the contracted capacity and the price at which that capacity is settled. Therefore, the total amount increases when a larger volume of capacity is procured or when the clearing price of the reserve band is higher. The final unitary overprice from the restrictions and the secondary band in the bill for the end consumer is depicted in figure 10.

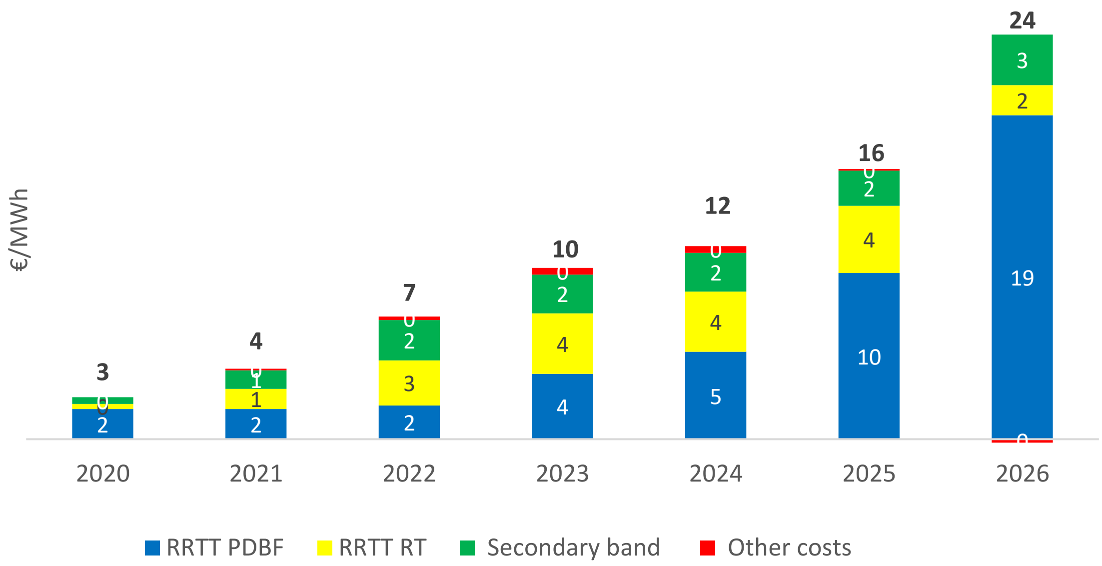
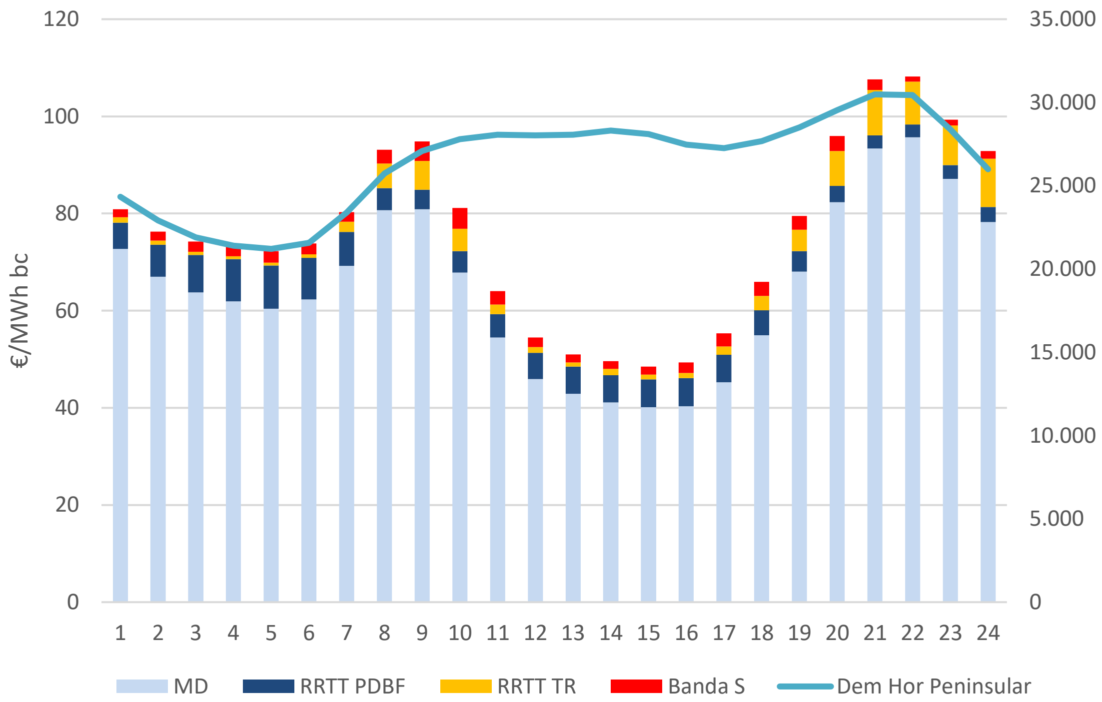


Figure 10: Evolution of the over cost from AASS at market price in €/MWh for the end consumer. Source: SO reports.

However, the main problem is not only that the total cost is increasing, but also how this cost is being assigned throughout the day. The hourly graphs for 2024 show that part of the unitary over costs (€/MWh) from ancillary services appear in hours where the market price would normally be lower. This is especially clear during hours with low demand, such as the night.



[5]*Figure 11: Average price of the ancillary services and day ahead market (€/MWh) for the 24 hours of 2024. Source: SO report.*

In these hours, the system may need more adjustment services to keep the system balanced. This could be due to the demand not being high enough in relation to the connected generation, or because the PDBF schedule is affected by technical constraint modifications linked to other hours. Therefore, although these periods usually record lower day-ahead market prices and lower regulated energy charges, the allocation of ancillary service costs increases the final price paid by consumers in those hours.

[5] Hereinafter hourly peninsular demand would be Dem Hor Peninsular.

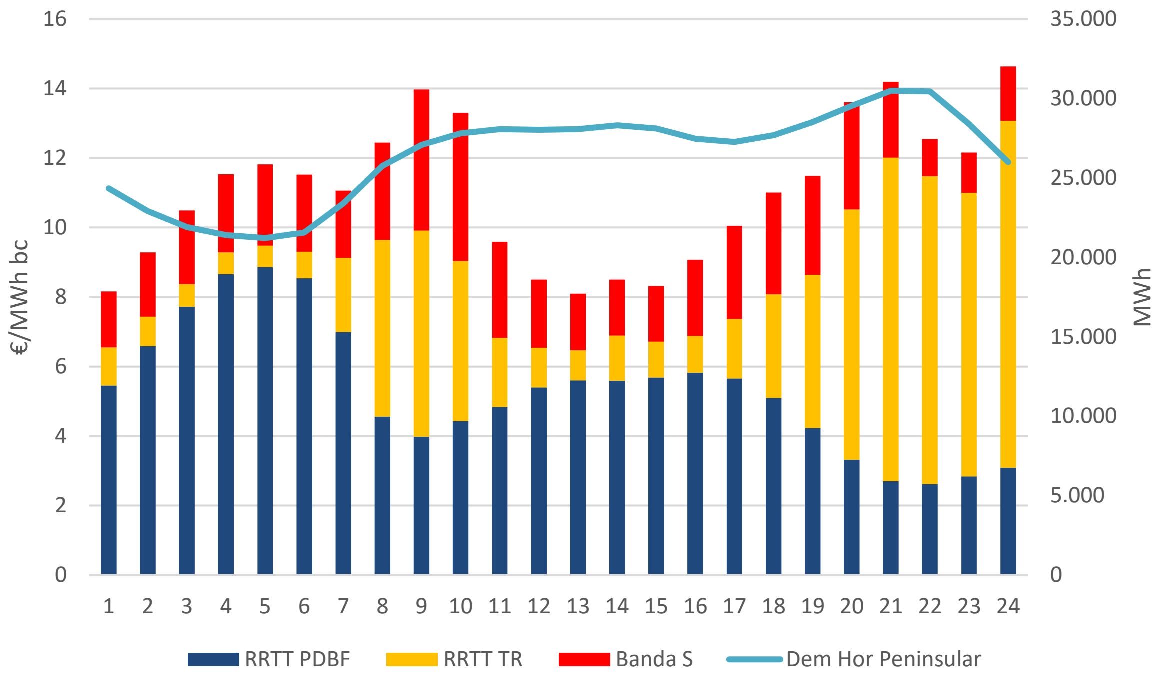


Figure 12: Average price of the ancillary services (€/MWh) for the 24 hours of 2024. Source: SO report.

This creates an inefficient price signal. If the hours with lower demand become more expensive because of these additional costs, consumers have less incentive to move their consumption to those hours. As a consequence, demand may decrease even more in the periods where the system already needs support, which can increase again the need for ancillary services and, therefore, their cost. In the end, this can create a spiral effect: lower demand increases the need for ancillary services, which in turn raises their cost and reinforces the inefficient price signal.

For this reason, the problem is not only the growing need for these services, but also the current way in which their costs are allocated. The present methodology may increase the price in hours where more demand could be useful for the system. This is the issue that this thesis aims to address, by looking for a cost allocation methodology that better reflects the origin of the service need and gives a more efficient signal to consumers.

Chapter 3. STATE OF THE ART

In the Iberian Electricity Market, as in most European markets, the day-ahead market determines hourly energy schedules and prices according to a marginal pricing mechanism. However, the economically efficient outcome of the day-ahead market is not necessarily technically feasible from a system operation perspective. After market clearing, the system operator must ensure that the resulting schedule complies with operational security criteria, including frequency stability, voltage limits, network constraints, N-1 security criteria and reserve requirements.

Recent reports (Davi-Arderius, 2025) have increasingly highlighted that the energy transition is changing the nature and relevance of these system operation needs. The large-scale integration of renewable energy sources modifies power flows, reduces the availability of synchronous generation, and increases the need for flexibility, balancing, and redispatching actions. Other reports (Davi-Arderius, 2023) show that, in Spain, redispatching costs increased sharply between 2019 and 2023, while the associated volumes doubled and costs multiplied by nine. In 2023, redispatching costs amounted to approximately €2 billion, with curtailment of around 3 TWh of wind and 0.9 TWh of photovoltaic generation. Their results also show that voltage-related constraints represented around half of redispatched volumes, while congestion and N-1 reliability constraints explained a smaller, although still relevant, share.

Therefore, the literature suggests that the cost of system services is not a transitory inefficiency of the electricity market, but a structural consequence of operating a secure power system with increasing renewable penetration. This is the starting point for the present thesis: if these costs are becoming more volatile and structurally linked to the energy transition, their allocation methodology must also be reviewed.

3.1 REDISPATCHING, TECHNICAL CONSTRAINTS AND COST DRIVERS

Earlier studies analyzed renewable curtailment, congestion management, and the environmental impact of redispatching in different systems. However, many of these contributions are either focused on specific technologies, such as wind or photovoltaic curtailment, or on specific consequences, such as emissions and balancing costs.

The report (Davi-Arderius, 2025) provides a particularly relevant contribution for the Spanish case because it disaggregates redispatching actions by operational constraint: voltage problems, congestion, reliability criteria and reserve adequacy. Their methodology combines hourly market and operational data from OMIE and SO and uses time-series estimators to identify how scheduled technologies contribute to different redispatching needs. Their results show that inverter-based resources aggravate voltage problems and congestion issues; while combining heat and power, wind and photovoltaic generation contribute to congestion problems, and thermosolar generation contributes to N-1 reliability issues.

This paper is useful for this thesis because it provides empirical evidence that system service costs should not be treated as a homogeneous category, and it serves as the starting point of the analysis developed in this thesis. Although the paper does not propose a specific cost allocation methodology, it analyses the technical drivers behind redispatching volumes in Spain and shows that different operational constraints are caused by different system conditions. In particular, it distinguishes between voltage problems, congestion, reliability issues and adequacy reserve needs. This initially supports the idea that system service costs should be analyzed separately before deciding how they should be recovered from consumers.

However, as the thesis progresses, it becomes evident that it is not possible to derive an efficient and marginal cost allocation based only on these distinctions, as no clear or stable patterns can be identified across years. As a result, the analysis ultimately suggests that a more uniform treatment of these costs may be more appropriate. Nevertheless, demand still appears to be indirectly related to part of these costs. Even if demand is not always the direct driver of redispatching costs, it affects system operating conditions, the need for reserves, network stress and the interaction between generation and consumption. Therefore, demand can still be considered relevant from a cost-causality perspective, but not strong enough to support a marginal allocation methodology.

3.2 EUROPEAN APPROACHES TO RECOVERING SYSTEM SERVICE COSTS

European countries apply very different approaches to recover system service costs. ACER's report on transmission tariff methodologies (ACER, 2019) shows that tariff structures vary significantly across jurisdictions, both in terms of which costs are included in transmission tariffs and in terms of whether charges are energy-based, power-based, time-differentiated or locational. ACER states that tariff design should balance cost recovery, cost reflectivity, transparency, non-discrimination, simplicity, stability, and predictability. It also explains that time and locational signals can improve efficiency when costs vary depending on when network use occurs. ACER also shows that ancillary services, balancing costs, and congestion management costs are treated differently across Europe. In many countries, some of these costs are included in the main transmission tariff. In others, they are recovered through separate charges.

Figure 29: Separate tariffs or tariff elements in transmission and distribution tariff structures

Tariffs / tariff elements	Transmission	Distribution
Building, upgrading, maintaining and operating the grid	6: AT, BE, HU, IS, PL, ES	5: AT, HU, MT, ES, (SE)
Grid losses	6: AT, HU, IS, PL, SK SE	5: AT, HU, IE, MT, (SE)
System services	9: AT, BE, CZ, HU, LT, NO, PL, RO, SK	4: AT, LT, MT, (SE)
Metering	6: AT, CY, FR, DE, IS, LU	12: AT, BE (Brussels and Wallonia regions), CY, DK, FR, DE, HU, IS, LU, MT, NL, (SE)
Reactive energy	14: AT, BE, BG, HR, FR, IT, LV, LT, NO, PL, PT, RO, SI, ES	18: BE, HR, CZ, EE, FI, FR, HU, IT, LV, LT, NL, NO, PL, PT, RO, SK, SI, ES

Figure 13: Tariff elements in transmission and distribution through different European countries. Source: (ACER, 2019).

This evidence can be complemented with the ENTSO-E report Overview of Transmission Tariffs in Europe: Synthesis 2023 (ENTSO-E, 2023), which illustrates both the composition and the evolution of transmission tariffs across Europe. In particular, figure 14 provides a breakdown of the TSO components of the Unit Transmission Tariff into infrastructure, system services and losses, showing that the relative importance of each component differs widely across countries. For example, in Spain the 2023 Unit Transmission Tariff is around €17.3/MWh, with system services representing the largest component (around €10.2/MWh), followed by infrastructure (around €5.3/MWh) and losses (around €1.9/MWh). In other countries, however, the weight of system services is either much smaller or much larger, which confirms that there is no common European approach to recovering these costs.

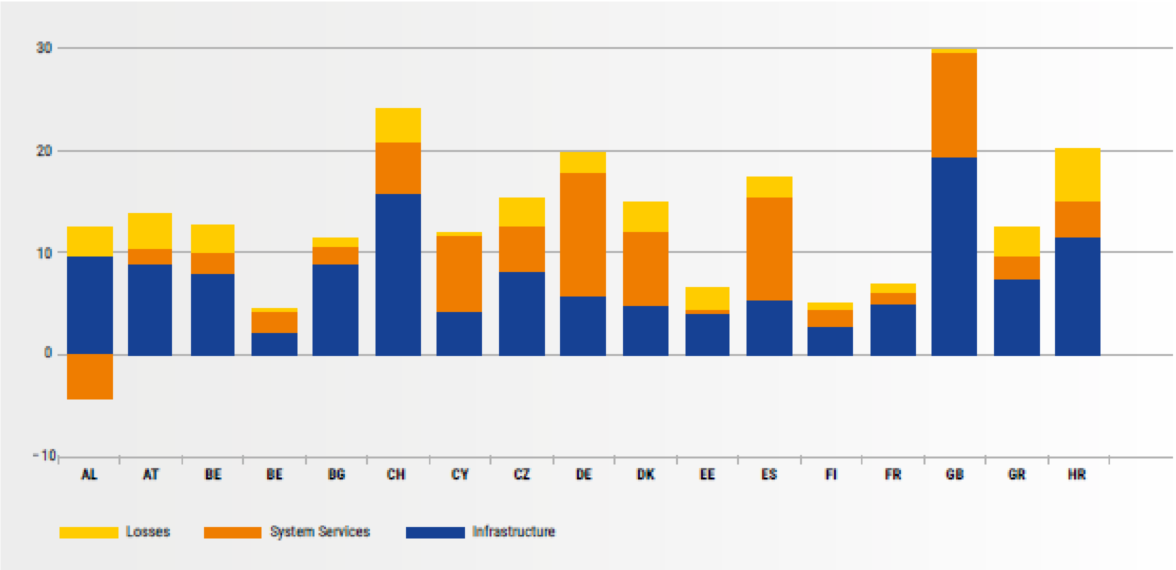


Figure 14: the split of the different TSO components (€/MWh) of the Unit Transmission Tariff. Source: (ENTSO-E, 2023).

Figure 15 further shows that transmission tariffs also change significantly over time. Between 2020 and 2023, Spain's Unit Transmission Tariff increased from around €9.8/MWh to €17.3/MWh, reflecting a substantial increase in TSO-related cost components. Similar variability can be observed in other countries, although with very different levels and trends

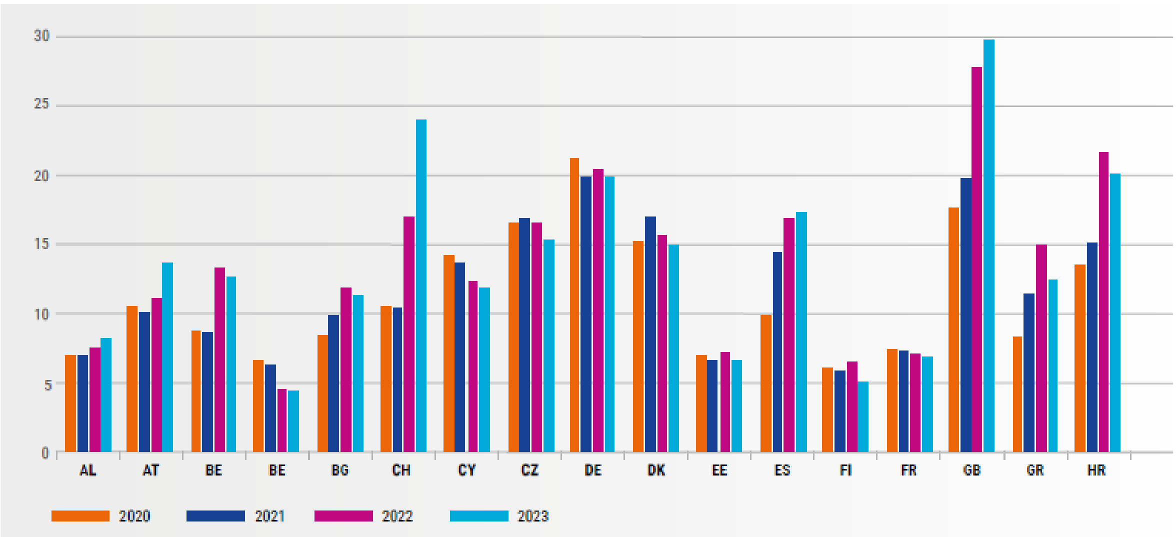


Figure 15: Evolution of TSO components of the Unit Transmission Tariffs (€/MWh). Source: (ENTSO-E, 2023).

This heterogeneity is important because it shows that there is no single European standard for allocating system service costs. However, the comparison also reveals a common weakness: in many cases, ancillary service costs are either bundled with network costs without a clear distinction or shared through simple volumetric charges. Both approaches may be inefficient in terms of cost allocation. If costs are bundled into network tariffs without identifying their drivers, the resulting tariff may be stable but not cost-reflective. If costs are recovered through hourly volumetric charges, the charge may reflect real-time costs but can become highly volatile and may distort demand behavior.

3.3 COST ALLOCATION THEORY AND TARIFF DESIGN

The economic theory of tariff design distinguishes between cost-reflective charges and residual charges. Cost-reflective charges should be linked to the marginal or forward-looking cost caused by users. Residual charges are needed to recover costs that cannot be efficiently attributed to a specific driver, but they should be designed to minimize distortions.

The paper (Chaves Ávila, 2025) is especially relevant because it addresses the allocation of system costs. The authors argue that system costs are increasing rapidly in Europe and that current allocation methodologies are often simplistic. They propose that balancing capacity costs should be partially embedded in the imbalance price, congestion management costs should be recovered through network tariffs, and costs that cannot be allocated according to cost causality should be recovered through residual charges.

This paper is the closest reference to the objective of the present thesis. Its main contribution is to establish a structured methodology: first, identify which system costs can be allocated according to cost causality; second, assign balancing-related costs through imbalance prices when possible; third, allocate congestion-related costs through network tariffs; and finally, recover the remaining residual costs through stable charges that avoid excessive volatility and inefficient price signals. The paper also identifies the problem of allocating residual system costs through hourly demand-based charges. When demand is low, the given cost must be divided by a smaller denominator, increasing the unit charge. This "denominator effect" can generate distorted price signals, especially overnight, when demand is low and the system may already be facing voltage-related operational problems. The authors therefore argue that residual charges should be stabilized rather than passed through hour by hour.

However, while the paper proposes a high-level methodology and tests its impact in a Spanish case study, it does not fully develop how the resulting charges should be distributed among final customer categories, tariff periods or voltage levels. It also does not fully analyze the impact on different types of consumers.

3.4 CONTRIBUTION OF THIS THESIS

The thesis contributes to an empirical elaboration using Spanish data. By comparing market prices, activated volumes, cost patterns, and demand profiles, it analyzes whether system service costs are concentrated in specific hours, periods, or operating conditions. This approach can help determine whether a time-differentiated allocation improves efficiency and cost reflectivity compared with the current methodology.

Overall, the state of the art suggests that the Spanish electricity system is facing a structural increase in system service costs driven by renewable integration, voltage control needs, balancing requirements and network constraints. Existing reports have identified the operational problem and have proposed general principles for cost allocation. However, there remains a need for a practical methodology that connects these principles with the actual distribution of costs among final consumers. This thesis addresses that gap by proposing a tariff design and cost allocation methodology for Spanish system services that aims to improve transparency, efficiency and cost reflectivity.

Chapter 4. DATA ANALYSIS AND METHODOLOGY

This chapter includes all the steps followed to tackle the main objectives and the main findings related to them. The purpose of this chapter is to give a clear explanation of the process that has been followed, the main reasons behind it, and the results obtained.

4.1 DATA COLLECTION

In order to provide an optimal tariff proposal, the main principles of tariffs must be followed. One of the most important is the causality principle. This principle refers to the fact that the cost should be allocated among those entities who are responsible for the need that ends up incurring that cost. So, after reviewing the regulatory framework for ancillary services, from both the CNMC and the Ministry, and the Operational procedures from REE, the next step in the process was to understand the reason behind the energy activations in the ancillary services from SO. To do so, we tried to understand the data related to the energy and cost that is published in its ancillary service reports. The information extracted included:

- Data related to the **activated energy to solve the restrictions** from both the PDBF and real time. SO classifies the restrictions in different labels to give information about the type of restriction the energy is contributing to solve. It is important to gain an insight into the reasons behind activation in order to determine the underlying nature of the cost. Among them, the most used are RSI, activated energy due to the lack of upward reserve; RTD, due to restrictions communicated by distributors; SOT, due to over voltages; SCB, due to overloads in the case base; SCA, due to overloads in case of contingencies; COT, due to voltage control. The energy collected included the upward and downward energy for the phases 1 and 2 of the PDBF[6] and the upward and downward energy needed in real time,

[6] The component that has increased most is the energy needed to solve the restrictions in the PDBF.

- Data related to the **marginal prices** for the upward and downward energy for both the PDBF and real time restrictions,
- The **average price** of the day ahead market,
- The **real time demand** measured at the busbars of the generators, as well as the hourly final demand per tariff group,
- The **ancillary service costs**.
- Annual tariff data by **tariff period** has also been extracted, as well as information on the **other cost components** included in the final electricity price.

The data was collected hourly, from 2020 to 2025. For the PDBF, the data was extracted from "seguridad del diario" on esios webpage and for the real time the data was gathered from "seguridad en tiempo real" on the same webpage.

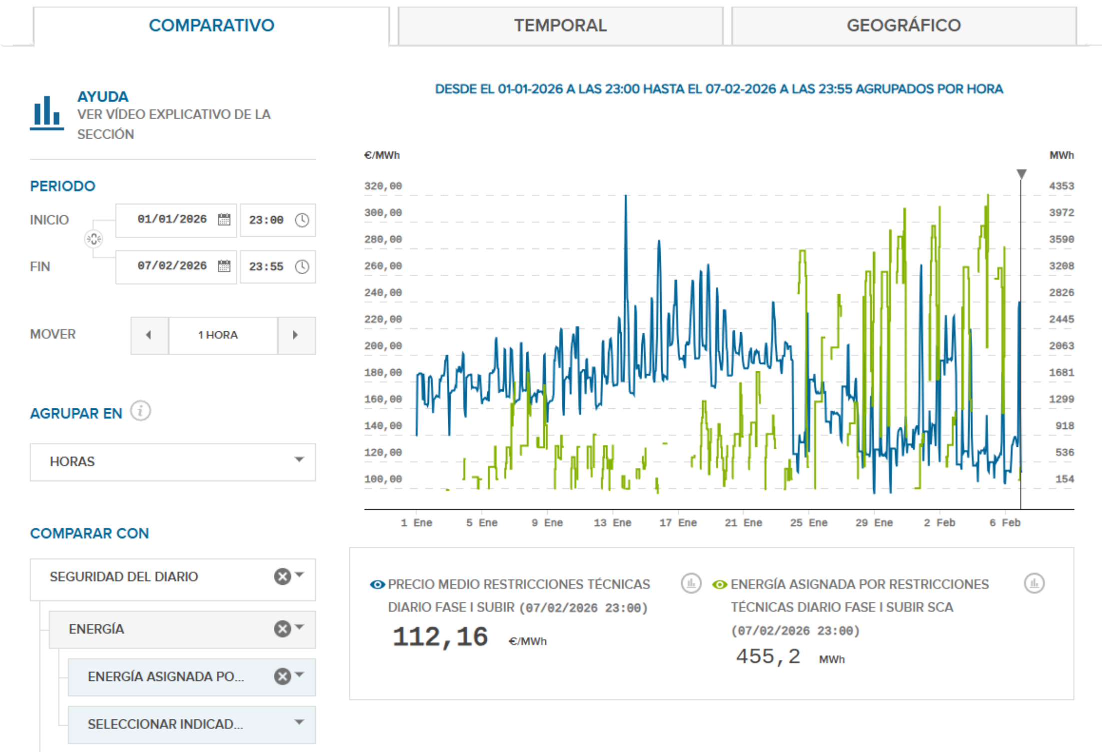


Figure 16: Example of data extracted from esios. Source: esios.

After collecting all the data, the values of the energy (GWh) average prices (€/MWh) and total cost (€) (when disaggregated by the labels and then summed up), were checked against the figures published in the official reports[7].

4.1.1 ENERGIES

	PDBF		*RT*	
	ERRTT F1S	*ERRTT F1B*	*EB*	*ES*
January	679.027	34.754	46.724	499.048
February	790.305	54.714	46.339	427.282
March	1.568.135	75.418	34.928	457.760
April	1.981.799	134.313	74.556	535.684
May	1.751.416	159.582	54.572	296.751
June	1.219.468	127.475	44.996	312.468
July	908.885	341.458	68.062	442.375
August	861.427	136.367	87.288	490.639
September	942.624	131.650	71.565	438.356
October	988.536	101.690	66.350	638.502
November	1.036.814	268.031	45.748	463.834
December	857.259	151.533	60.234	416.780
TOTAL MWh	**13.586**	**1.717**	**701.368**	**5.419.484**

Table 2: Monthly computation of the activated energy of the restrictions (MWh) in 2024. Source: Own elaboration and esios.

The results match the ones published in the SO report from 2024, presented in figure 6,

Once, I was able to understand how the energy was presented in the reports, it was also important to identify if there existed any temporal pattern related to their activation. To do so, they were represented in graphs, monthly and hourly disaggregated.

[7] The analysis was carried out using hourly data from 2020 to 2025. The 2024 graphs are included as an illustrative example of the methodology followed, while the same process was applied to the full period of analysis. A glossary of the abbreviations used throughout the section is also provided.

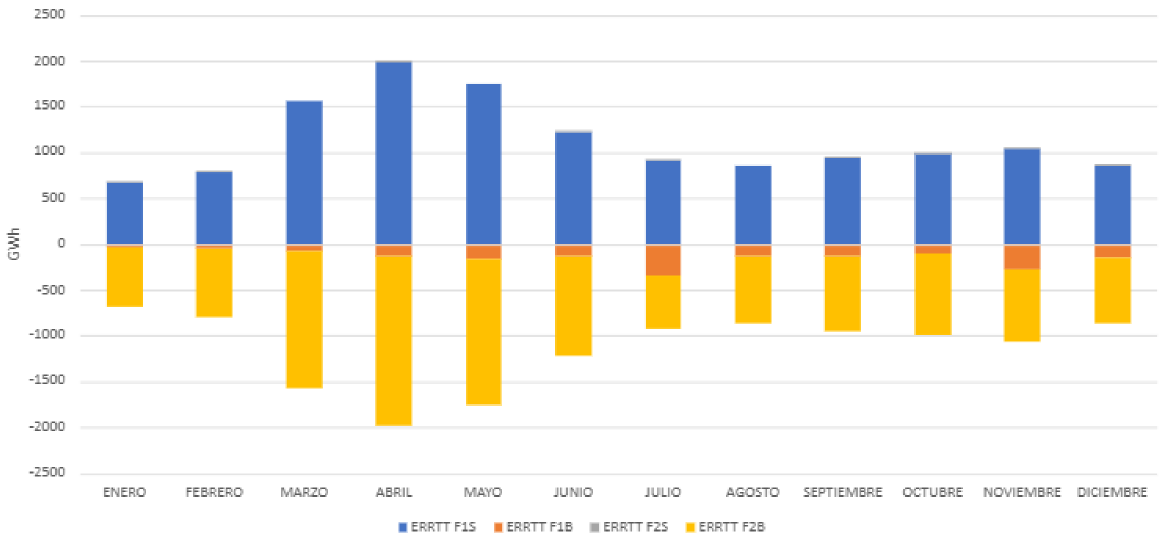


Figure 17: Monthly representation of the activated energy (GWh) for the restrictions in the PDBF in 2024. Source: Own elaboration.

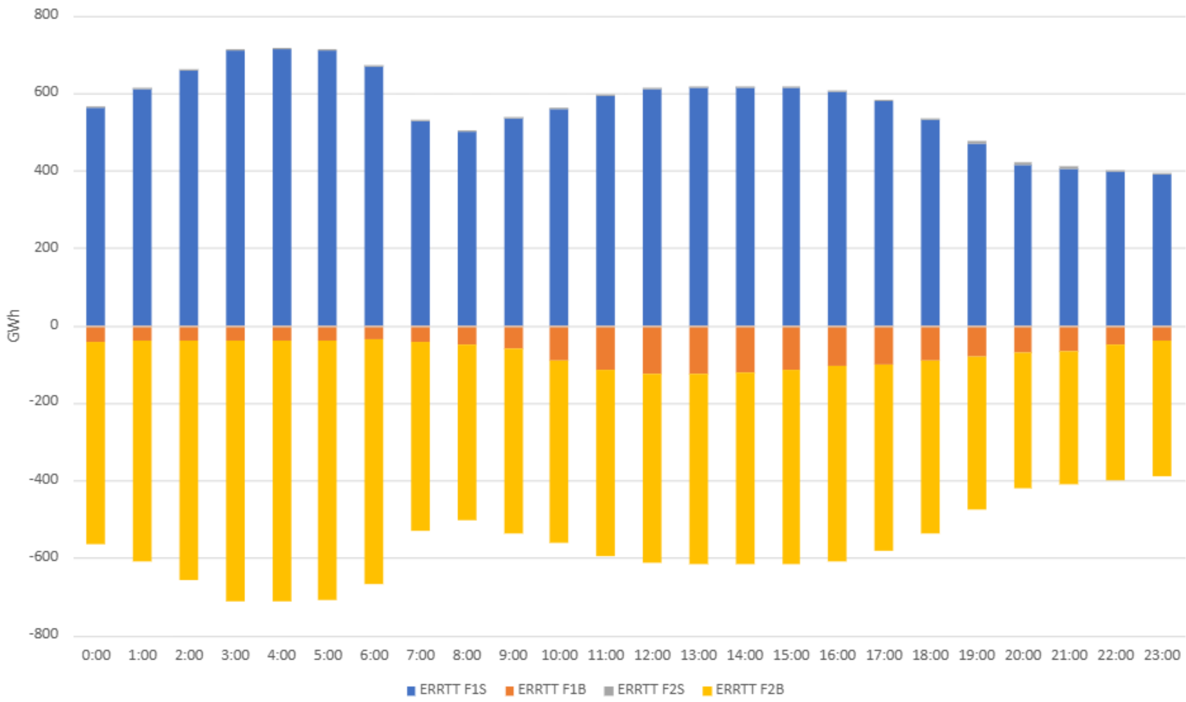


Figure 18: Hourly representation of the activated energy (GWh) for the restrictions in the PDBF in 2024. Source: Own elaboration.

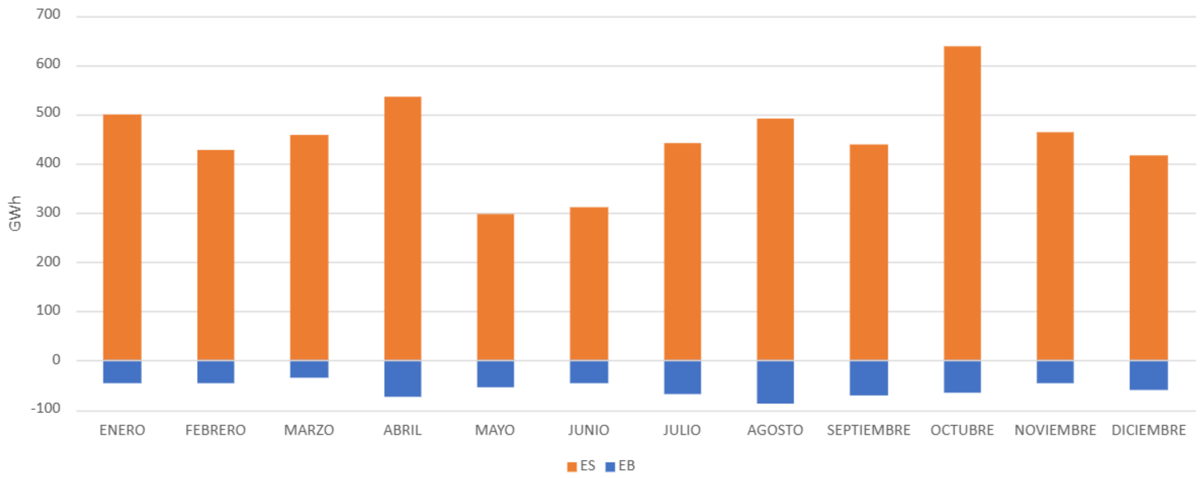


Figure 19: Monthly representation of the activated energy (GWh) for the restrictions in real time in 2024. Source: Own elaboration.

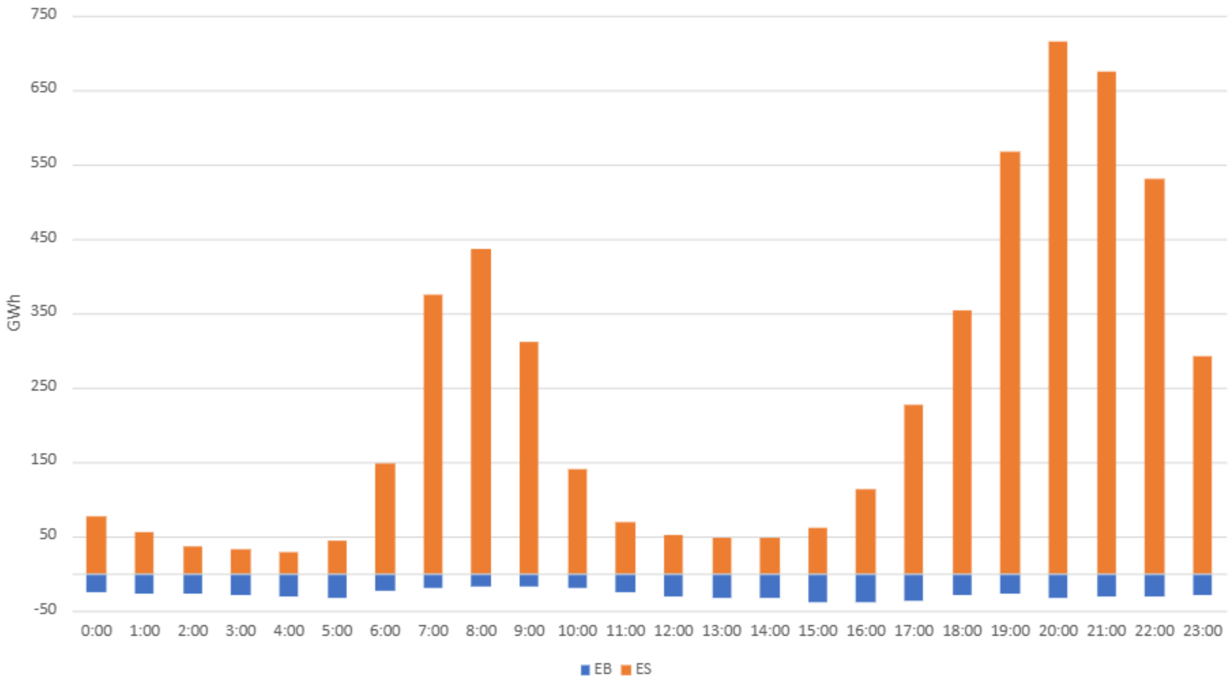


Figure 20: Hourly representation of the activated energy (GWh) for the restrictions in real time in 2024. Source: Own elaboration.

The next step on the analysis consisted of disaggregating the restrictions with the information provided by the SO. The disaggregation is only made in phase 1 for the PDBF because phase

2 is used to adjust the positions to avoid imbalances. Real time disaggregation was also made. On top of that, it was disaggregated also by month and hour to try to identify any possible pattern.

PDBF	BSCA	SSCA	BSCB	SSCB	BRTD	SRTD	BSOT	SSOT	BPEV	SCOT	SDAN	SPCB
Jan.	31	42	2	0	0	152	0	482	2	0	2	0
Febr.	29	137	6	21	20	179	0	442	0	0	5	6
Mar.	34	808	0	0	32	164	0	502	9	93	0	1
April	53	967	50	0	18	191	0	532	14	284	0	7
May	29	581	77	11	52	201	0	522	2	434	2	0
June	43	398	53	0	28	118	0	386	4	317	0	0
July	33	301	266	1	29	166	0	238	14	197	0	6
Aug.	48	328	62	0	22	167	0	183	5	183	0	0
Sept.	42	264	77	0	10	251	0	216	3	212	0	0
Oct.	26	170	36	7	29	220	0	331	11	261	0	0
Nov.	253	201	0	0	13	129	0	462	2	239	0	6
Dec.	119	133	12	0	18	113	0	427	2	183	0	1
Tot.	740	**4330**	641	40	271	**2051**	0	**4723**	68	**2403**	9	27

Table 3: Monthly disaggregated data from activated energy of phase 1 from PDBF in 2024. Source: Own elaboration and data from esios.

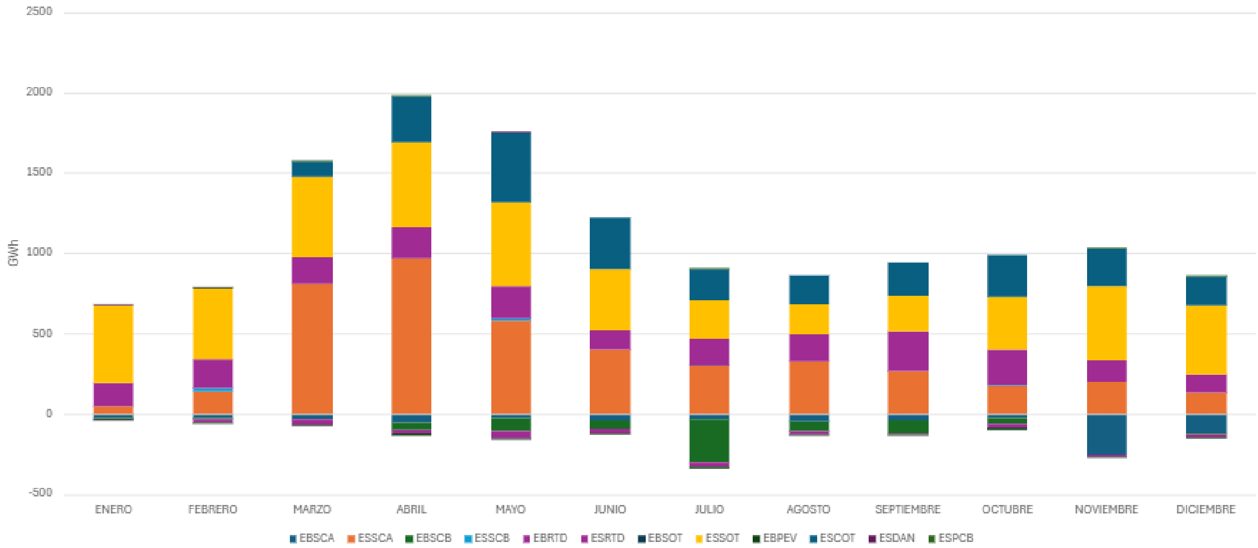


Figure 21: Monthly representation from disaggregated energy (GWh) on phase 1 on PDBF in 2024. Source: Own elaboration.

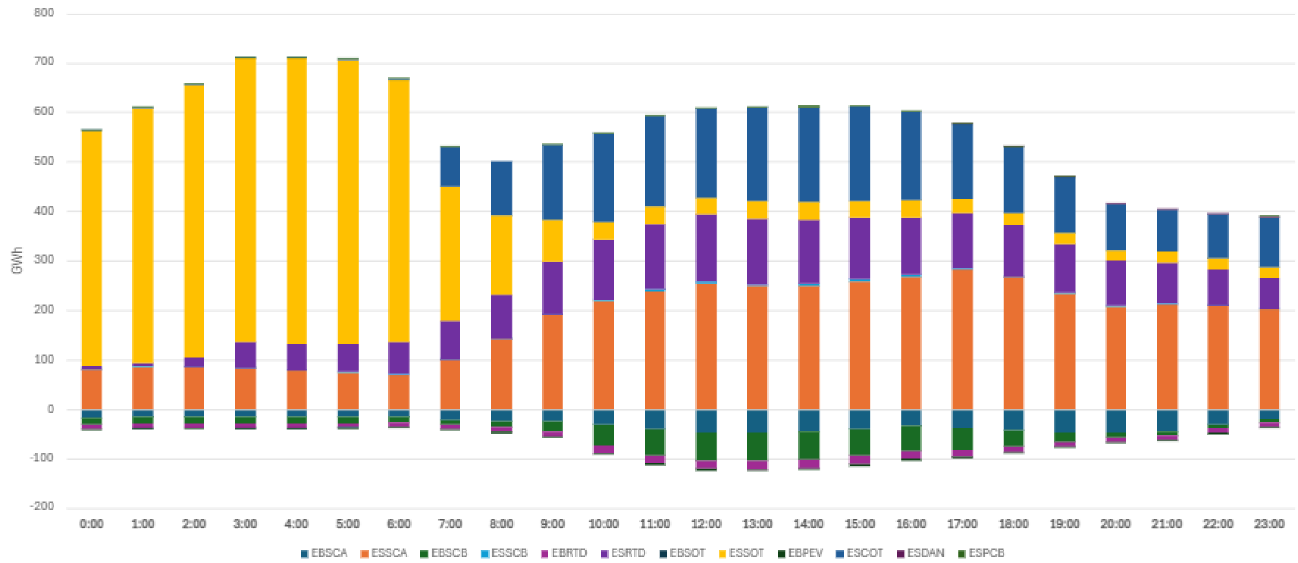


Figure 22: Hourly representation from disaggregated energy (GWh) on phase 1 on PDBF in 2024. Source: Own elaboration.

And in real time:

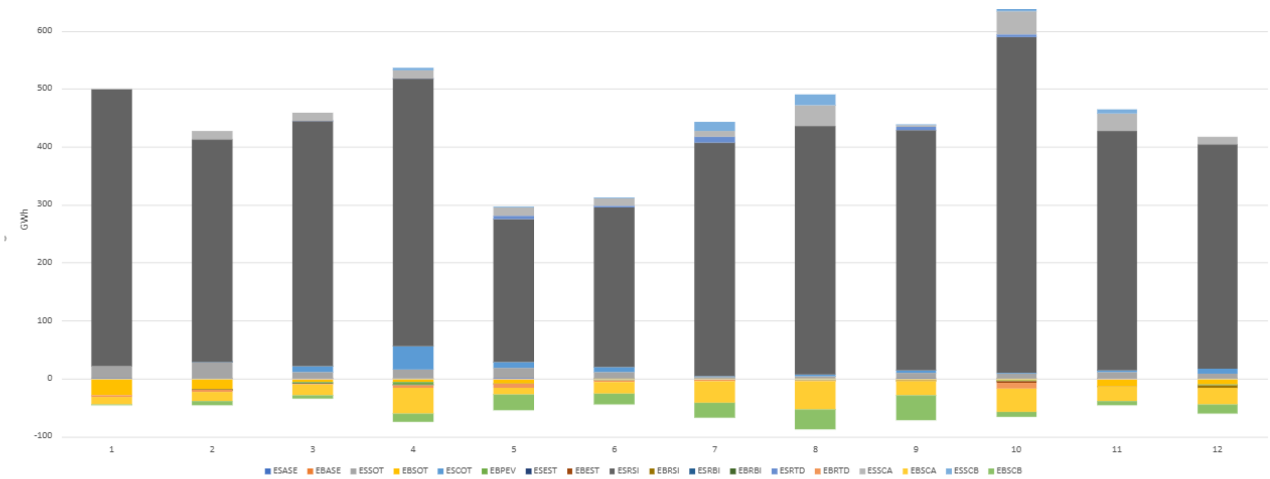


Figure 23: Monthly representation from disaggregated energy (GWh) in real time in 2024. Source: Own elaboration.

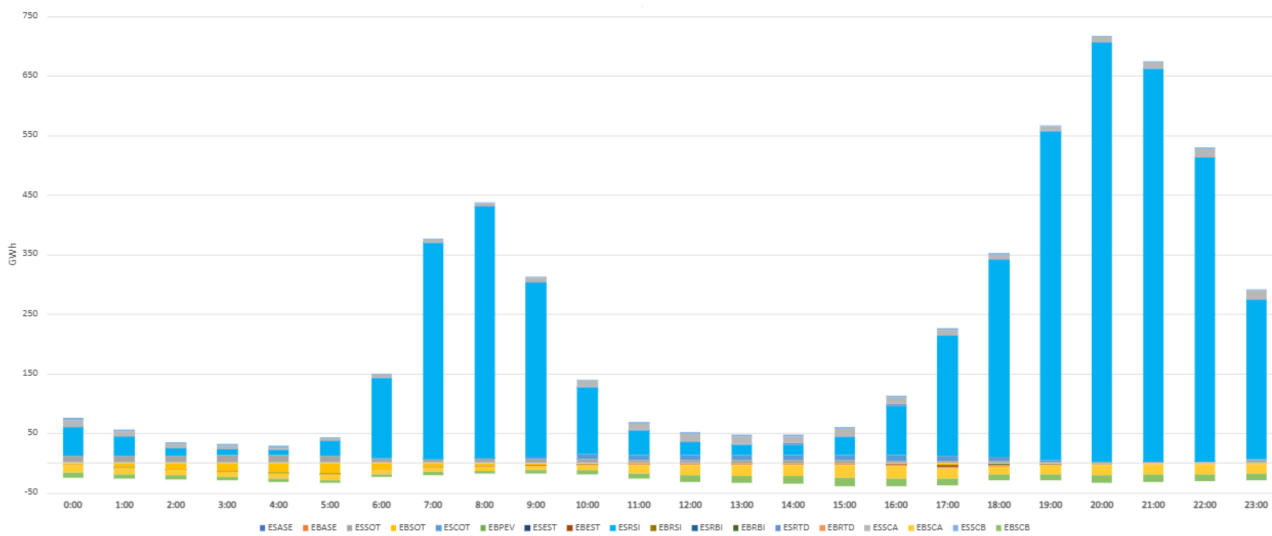


Figure 24: Hourly representation from disaggregated energy (GWh) in real time in 2024. Source: Own elaboration.

Once the activated energy values had been identified and classified, the same process was repeated for average prices.

4.1.2 PRICES

As with energy, the first step is to replicate the data from the report published by SO. The average price of the energy is computed for both real time and the PDBF.

PRRTT (€/MWh)	***Upwards Phase 1***	***Down. Phase 1***	***Upwards Phase 2***	***Down. Phase 2***
PDBF	134.58	55.87	110.49	43.17
RT[8]	-4.68[9]	238.87		

Table 4: Upward and downward average energy prices from 2024. Source: Own elaboration with data from esios.

It is compared to the average prices published on the Ancillary services report of 2024:

Precios medios ponderados de energías de los servicios de ajuste del sistema peninsular

	2023		2024		% 24/23	
	A subir	A bajar	A subir	A bajar	A subir	A bajar
Restricciones técnicas PDBF fase I	171,7	73,2	134,6	55,9	-21,6	-23,7
Restricciones técnicas PDBF fase II	100,8	76,7	110,5	43,2	9,6	-43,7
Restricciones técnicas en tiempo real	289,9	15,8	238,4	0,8	-17,7	-94,8
Regulación secundaria	98,6	60,0	69,9	22,3	-29,1	-62,9
Regulación terciaria	116,1	31,4	91,1	9,8	-21,5	-68,7
Reservas de sustitución[1]	113,8	37,8	92,1	20,7	-19,1	-45,3

Figure 25: Average energy prices for restrictions from 2024. Source: (Red Eléctrica, 2024)

[8] It does not exist phase 1 and phase 2 since it is a real time operation to correct final imbalances and deviations
[9] It does not match the one published by red Eléctrica. It may be due to the time between liquidations and published data.

After having both the prices and the energies properly identified, the next step was to compute the IMRRTT and the CRRTT. Following equation 1, to compute the CRRTT, the IMRRTT needs to be computed first:

$$IMRRTT = ERRTT * PRRTT$$

Equation 3: Computation of IMRRTT. Source: (CNMC_Normas_20251030, 2025).

It was computed monthly and hourly for both the PDBF and the real time restrictions.

MONTH/IMRRT (M€)	*IMRRTT F1S*	*IMRRTT F1B*	*IMRRTT F2S*	*IMRRTT F2B*
January	105	-2	0	-41
February	104	-1	0	-25
March	157	-1	0	-15
April	185	-1	0	-9
May	201	-3	0	-31
June	146	-4	0	-39
July	131	-16	1	-42
August	146	-10	0	-65
September	147	-8	0	-56
October	155	-6	0	-56
November	188	-28	3	-70
December	163	-16	2	-66

Table 5: IMRRTT computation for the PDBF. Source: Own elaboration.

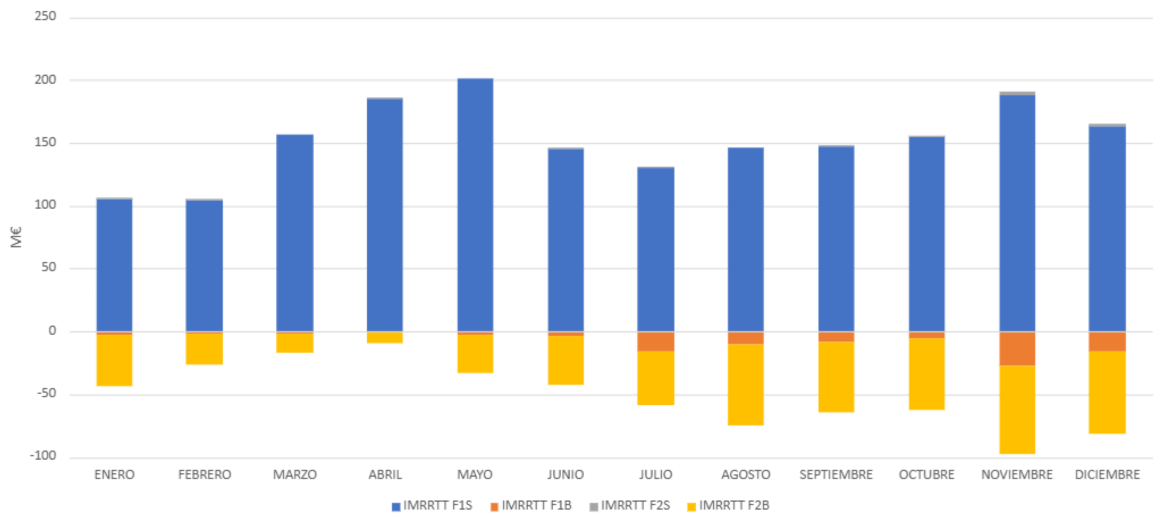


Figure 26: Monthly IMRRTT (M€) for the PDBF in 2024. Source: Own elaboration.

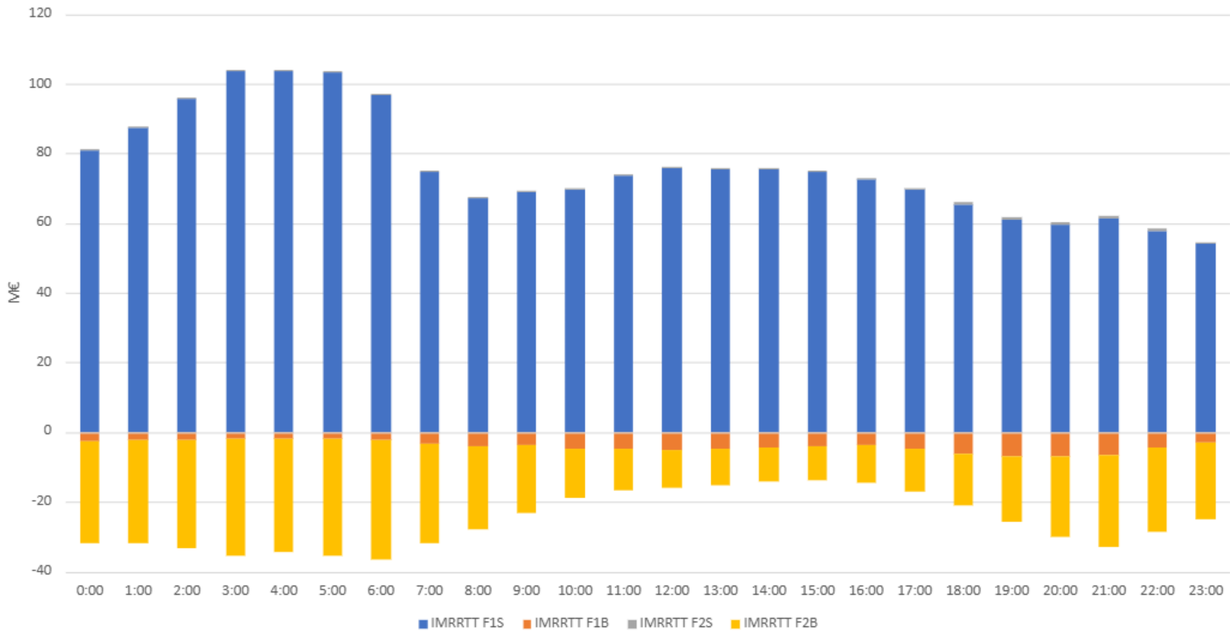


Figure 27:Hourly IMRRTT (M€) for PDBF in 2024. Source: Own elaboration.

And for real time:

MONTH/IMRRT (M€)	*IMRRTT B*	*IMRRTTS*
January	-2	112
February	0	86
March	0	90
April	1	112
May	0	72
June	0	77
July	1	100
August	1	116
September	1	110
October	0	164
November	0	131
December	0	127

Table 6: IMRRTT computation for real time. Source: Own elaboration.

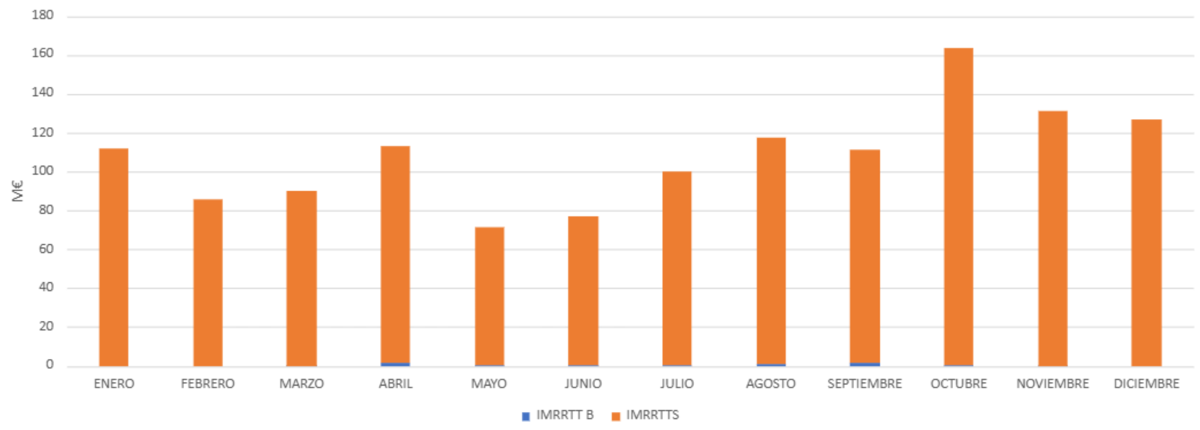


Figure 28: Monthly IMRRTT (M€) RT in 2024. Source: Own elaboration.

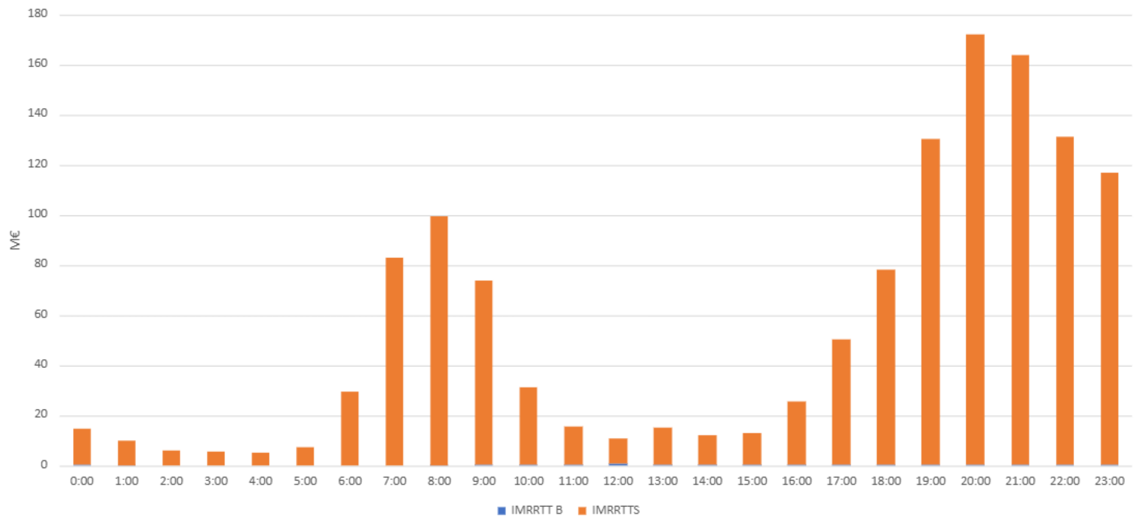


Figure 29: Hourly IMRRTT (M€) RT in 2024. Source: Own elaboration.

Lastly, the final cost of the restrictions was computed.

MONTH/IMRRT (M€)	*IMRRTT F1S*	*IMRRTT F1B*	*IMRRTT F2S*	*IMRRTT F2B*
January	60	0	0	2
February	76	0	0	2
March	135	0	0	5
April	167	0	0	8
May	161	0	0	7
June	98	0	0	4
July	71	0	0	2
August	69	0	0	2
September	81	0	0	3

October	90	0	0	2
November	90	0	0	3
December	81	0	0	2
TOTAL	**1223**			

Table 7: CRRTT computation for the PDBF. Source: Own elaboration.

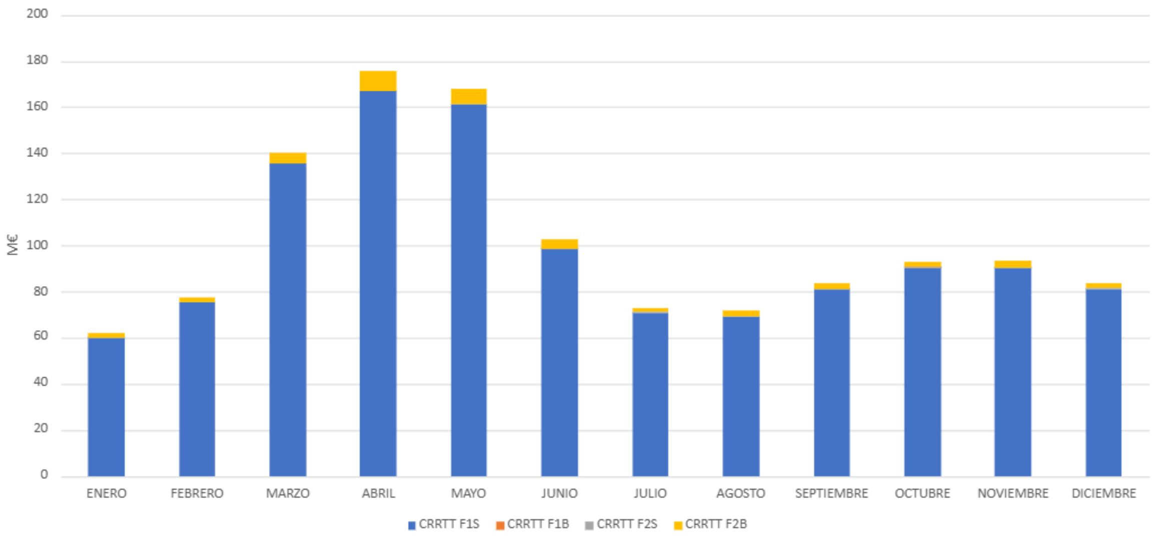


Figure 30:Monthly CRRTT (M€) for PDBF in 2024. Source: Own elaboration

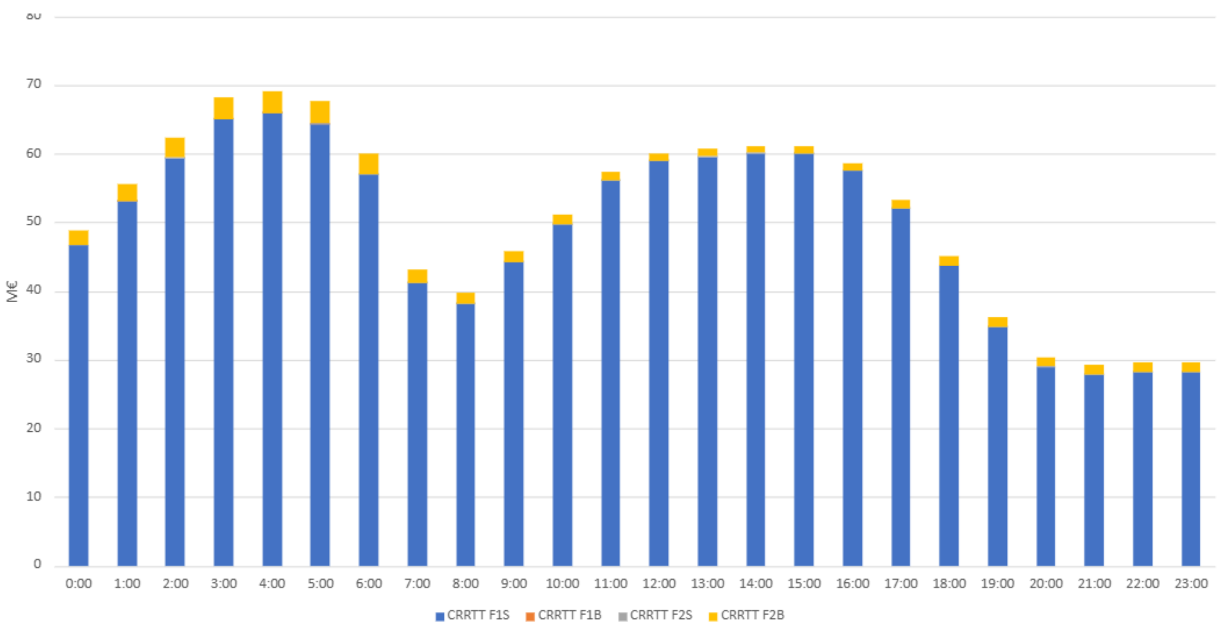


Figure 31: Hourly CRRTT (M€) for PDBF in 2024. Source: Own elaboration.

And for real time:

MONTH	*CRRTTS*	*CRRTTB*
January	64	1
February	61	1
March	67	1
April	97	2
May	56	1
June	47	1
July	55	3
August	59	5
September	62	3
October	100	3
November	72	3
December	67	0
TOTAL M€	806	25
TOTAL M€	**831**	

Figure 32: CRRTT computation for real time. Source: Own elaboration.

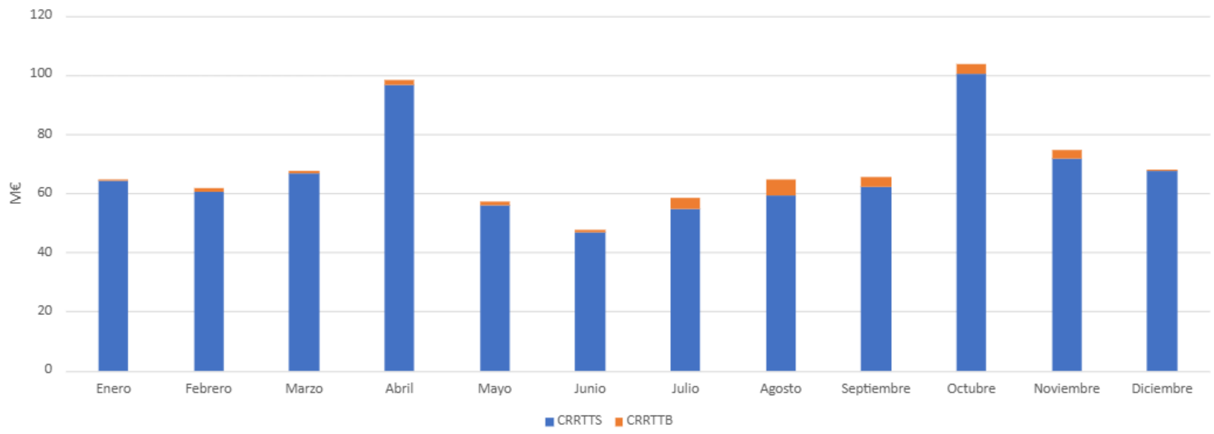


Figure 33: Monthly CRRTT (M€) for RT in 2024. Source: Own elaboration.

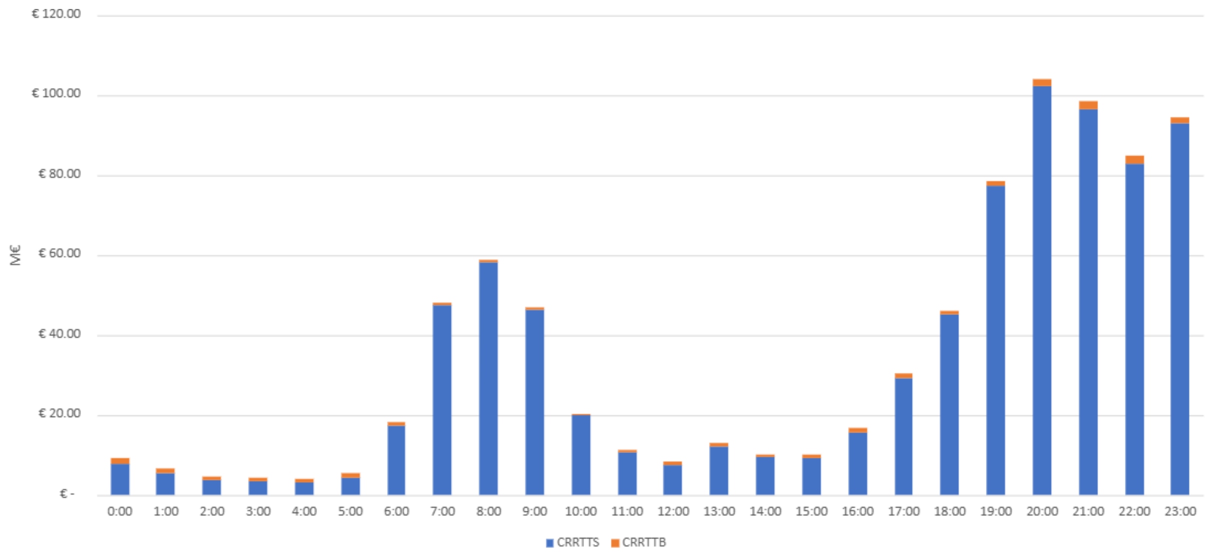


Figure 34: Hourly CRRTT (M€) for RT in 2024. Source: Own elaboration.

Coste servicios ajustes en M€

€/MWh€

	2023	2024
Restricciones PDBF	1.054	1.217
Restricciones tiempo real	844	842
Restricciones técnicas	1.898	2.059
Banda y RAD	604	666
Desvíos	103	89
Otros*	-103	-120
Control de factor de potencia	-19	-26

Figure 35: CRRTT published by SO. Source: (Red Eléctrica, 2024)

The calculation allowed the final cost of technical restrictions to be replicated, so now we have a better understanding of the main components of those costs. The main components are the demand, the activated energy and the price associated with it, and the price on the day ahead market. Further on this chapter, it will be analyzed which of the four components is the main driver of the final costs.

After all this process, some restriction labels associated with different restriction causes were identified as the most needed ones to solve the problems. As can be seen in figure 30, when talking about the PDBF, the restrictions that were responsible for most of the activations were ESSOT, ESCOT, ESSCA and ESRTD.

PDBF Phase 1 (GW)	EBSCA	ESSCA	EBSCB	ESSCB	EBRTD	ESRTD	EBSOT	ESSOT	EBPEV	ESCOT	ESDAN	ESPCB
January	31	42	2	0	0	152	0	482	2	0	2	0
February	29	137	6	21	20	179	0	442	0	0	5	6
March	34	808	0	0	32	164	0	502	9	93	0	1
April	53	967	50	0	18	191	0	532	14	284	0	7
May	29	581	77	11	52	201	0	522	2	434	2	0
June	43	398	53	0	28	118	0	386	4	317	0	0
July	33	301	266	1	29	166	0	238	14	197	0	6
August	48	328	62	0	22	167	0	183	5	183	0	0
September	42	264	77	0	10	251	0	216	3	212	0	0
October	26	170	36	7	29	220	0	331	11	261	0	0
November	253	201	0	0	13	129	0	462	2	239	0	6
December	119	133	12	0	18	113	0	427	2	183	0	1

Figure 36: Monthly energy disaggregation of the PDBF (GW) in 2024. Source: Own elaboration.

	EBSCA	ESSCA	EBSCB	ESSCB	EBRTD	ESRTD	EBSOT	ESSOT	EBPEV	ESCOT	ESDAN	ESPCB
0:00	18	79	13	0	9	6	0	477	2	1	0	0
1:00	16	85	13	0	8	8	0	515	2	1	0	1
2:00	16	85	13	0	8	20	0	551	2	0	0	1
3:00	16	81	14	0	8	54	0	574	2	1	0	1
4:00	16	77	13	0	8	54	0	578	2	1	0	1
5:00	17	74	13	0	8	57	0	575	2	1	0	1
6:00	16	70	11	0	7	66	0	530	2	1	0	0
7:00	23	99	9	0	7	77	0	273	2	79	0	0
8:00	26	143	10	1	10	89	0	158	3	110	0	0
9:00	24	190	21	1	11	108	0	84	3	151	0	0
10:00	32	218	43	2	14	122	0	36	3	178	0	2
11:00	40	239	54	5	16	131	0	35	3	182	0	2
12:00	46	253	58	4	17	136	0	34	4	180	0	3
13:00	47	248	58	4	17	133	0	35	4	189	0	3
14:00	45	249	57	4	17	130	0	35	4	193	0	2
15:00	41	258	54	5	17	124	0	35	4	190	0	2
16:00	34	267	52	5	15	117	0	34	3	179	0	2
17:00	37	283	46	2	14	111	0	30	3	152	0	2
18:00	42	266	34	1	11	104	0	25	2	134	0	2
19:00	46	235	20	1	10	99	0	22	2	113	1	0
20:00	46	208	11	1	10	91	0	21	3	93	2	0
21:00	45	212	8	1	9	83	0	22	3	86	2	0
22:00	31	209	8	0	9	72	0	22	3	90	3	0
23:00	19	203	8	0	9	62	0	23	3	100	1	1

Figure 37: Hourly energy disaggregation of the PDBF (GW) in 2024. Source: Own elaboration.

And in real time the main responsible is ESRSI. Nevertheless, we will keep analyzing SSOT, SCOT and SCA to compare them to the ones on the PDBF.

GW	ESASE	EBASE	ESSOT	EBSOT	ESCOT	EBPEV	ESEST	EBEST	ESRSI	EBRSI	ESRBI	EBRBI	ESRTD	EBRTD	ESSCA	EBSCA	ESSCB	EBSCB
January	1	1	21	29	0	0	0	0	477	0	0	0	0	2	0	13	0	2
February	0	1	29	18	0	1	0	0	384	0	0	0	0	4	15	15	0	8
March	0	1	10	5	11	1	0	0	423	0	0	2	0	1	14	19	0	5
April	0	0	15	6	41	4	0	0	463	0	0	1	0	5	13	43	4	14
May	1	1	17	8	10	0	0	0	247	0	0	0	6	8	14	11	2	27
June	0	0	11	1	9	2	0	0	275	0	0	0	3	3	13	20	1	19
July	0	0	2	1	1	1	0	0	403	0	0	0	10	3	11	37	14	27
August	0	0	3	2	3	1	0	0	429	0	0	0	0	2	37	49	18	34
September	1	0	9	2	4	0	0	0	415	0	0	0	6	2	3	24	1	43
October	0	0	9	3	1	0	0	4	579	0	0	0	5	9	40	40	4	9
November	0	1	12	11	3	1	0	0	412	0	0	0	0	0	31	25	6	7
December	0	0	8	10	9	2	0	0	388	4	0	0	0	0	12	28	0	16

Figure 38:Monthly energy disaggregation of the RT (GW) in 2024. Source: Own elaboration.

	ESASE	EBASE	ESSOT	EBSOT	ESCOT	EBPEV	ESEST	EBEST	ESRSI	EBRSI	ESRBI	EBRBI	ESRTD	EBRTD	ESSCA	EBSCA	ESSCB	EBSCB
0:00	0	0	11	2	0	0	0	0	49	0	0	0	0	1	11	14	4	9
1:00	0	0	12	7	0	0	0	0	32	0	0	0	0	1	8	11	3	7
2:00	0	0	12	11	0	0	0	0	12	0	0	0	0	0	8	9	3	7
3:00	0	0	13	14	0	0	0	0	10	0	0	0	1	1	5	9	2	6
4:00	0	0	13	17	0	0	0	0	9	0	0	0	1	1	4	9	2	5
5:00	0	0	11	18	0	0	0	0	26	0	0	0	1	1	3	10	2	5
6:00	0	0	8	10	0	0	0	0	135	0	0	0	1	1	4	9	1	4
7:00	0	0	6	7	0	0	0	0	363	0	0	0	1	1	4	8	0	4
8:00	0	0	7	4	1	0	0	0	422	0	0	0	1	1	4	7	0	4
9:00	0	2	6	2	4	0	0	0	293	0	0	0	1	2	7	7	1	6
10:00	0	1	6	1	8	0	0	0	112	0	0	0	2	2	9	9	1	7
11:00	0	0	4	0	9	0	0	0	40	1	0	0	2	2	10	14	3	8
12:00	0	0	4	0	9	0	0	0	21	0	0	0	2	3	12	18	3	11
13:00	0	0	4	0	9	0	0	0	17	1	0	0	2	3	12	18	3	12
14:00	0	0	4	0	9	0	0	0	17	1	0	1	2	2	12	18	3	13
15:00	1	0	4	0	10	0	0	0	29	0	0	1	2	3	13	22	3	14
16:00	0	1	3	1	9	1	0	0	83	0	0	1	2	3	11	21	3	13
17:00	0	0	4	3	8	0	0	2	201	0	0	1	2	3	8	17	4	12
18:00	0	0	3	0	8	1	0	1	330	0	0	0	2	3	6	14	3	9
19:00	0	1	2	0	3	2	0	0	551	0	0	0	2	2	7	15	1	10
20:00	0	0	1	0	1	2	0	0	704	0	0	0	2	2	7	18	1	11
21:00	0	0	1	0	1	1	0	0	660	0	0	0	1	1	11	17	1	12
22:00	0	0	1	0	1	1	0	0	510	0	0	0	1	1	14	17	3	12
23:00	0	0	4	0	2	1	0	0	268	0	0	0	1	1	15	15	2	12

Figure 39: Hourly energy disaggregation of the PDBF (GW) in 2024. Source: Own elaboration.

One of the issues addressed in this thesis is that, during certain hours, final consumers may face a higher effective unitary electricity cost (€/MWh) even when day-ahead market prices are relatively low. This situation is mainly explained by the additional costs associated with technical restrictions and balancing actions. To identify critical hours where this effect is more relevant, some graphs have been depicted. For that, the average price of the CRRTT has also been computed:

$$PMC = \frac{CRRTT}{ERRTT}$$

Equation 2: Average price of the overcost of the restrictions. Source: Own elaboration.

where CRRTT represents the total cost associated with technical restrictions and ERRTT represents the energy activated to solve them. This indicator can be interpreted as the average cost per unit of activated energy.

This calculation makes it possible to compare the amount of energy required, the day-ahead market price and the average unit cost of the activated restrictions. Therefore, it helps to identify whether the additional cost is mainly driven by a high volume of activated energy, by a high unit cost, or by the combination of both effects.

For the PDBF, the graphs of the main needed resources have been plotted:

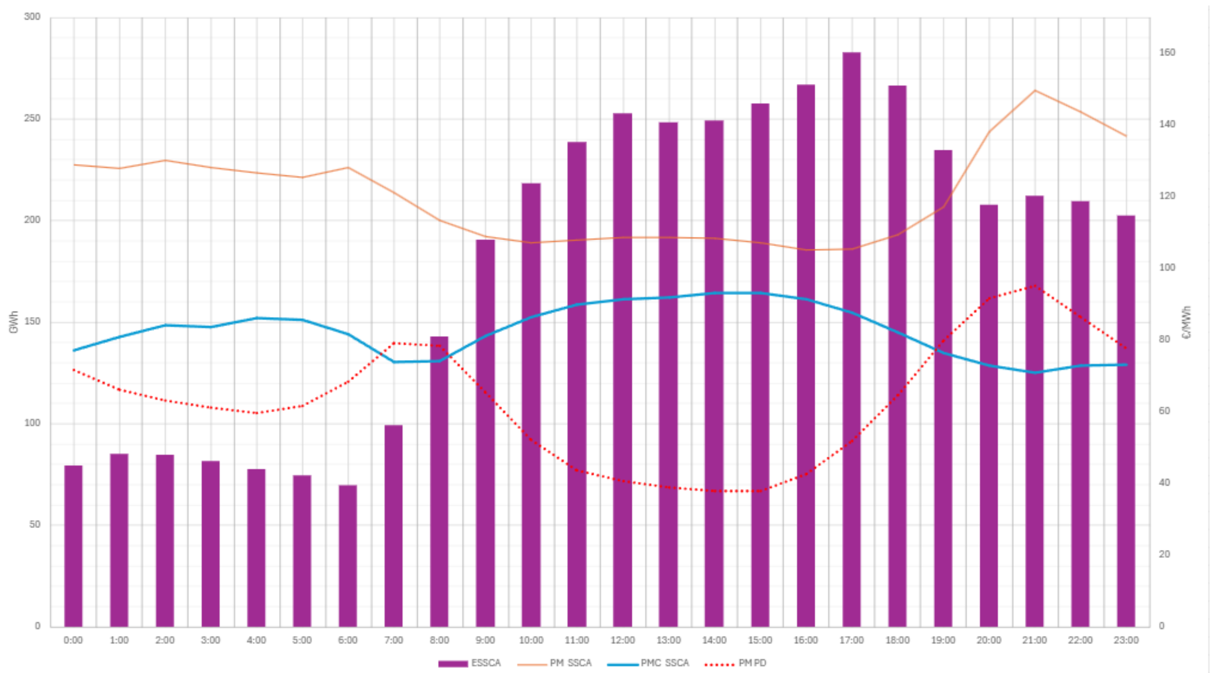


Figure 40: Hourly PMD vs PMC (€/MWh) for the ENSSCA (GWh) on the PDBF in 2024. Source: Own elaboration.

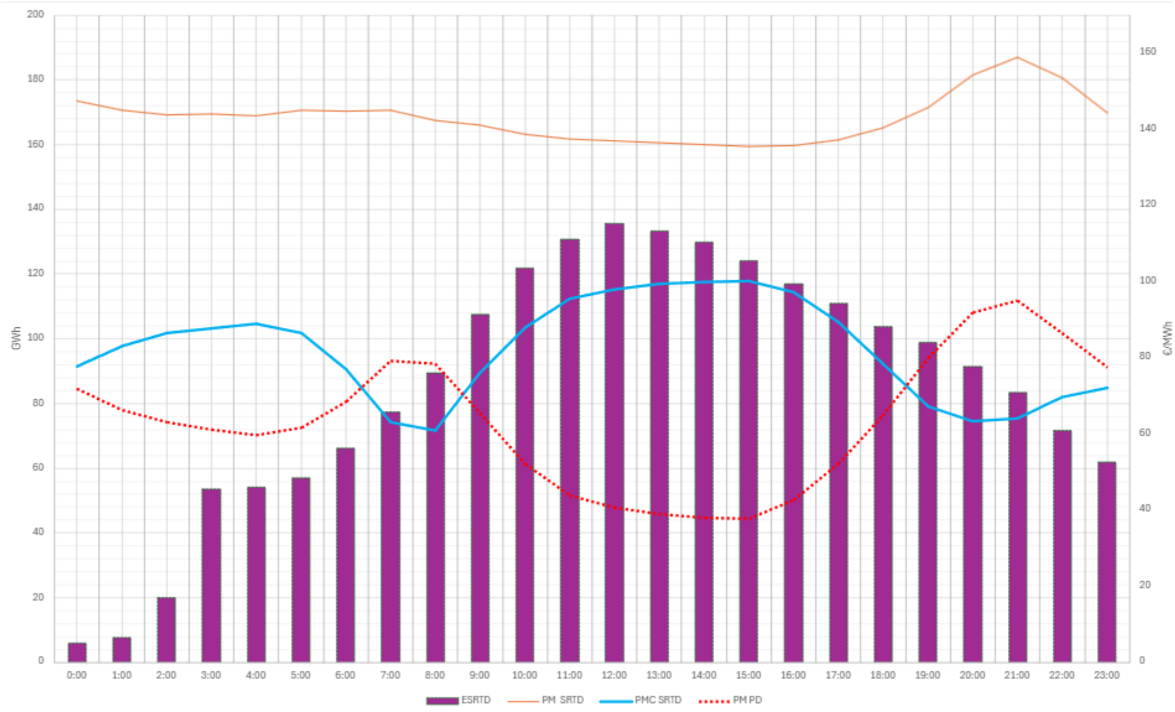


Figure 41: Hourly PMD vs PMC (€/MWh) for the ENSRTD (GWh) on the PDBF in 2024. Source: Own elaboration.

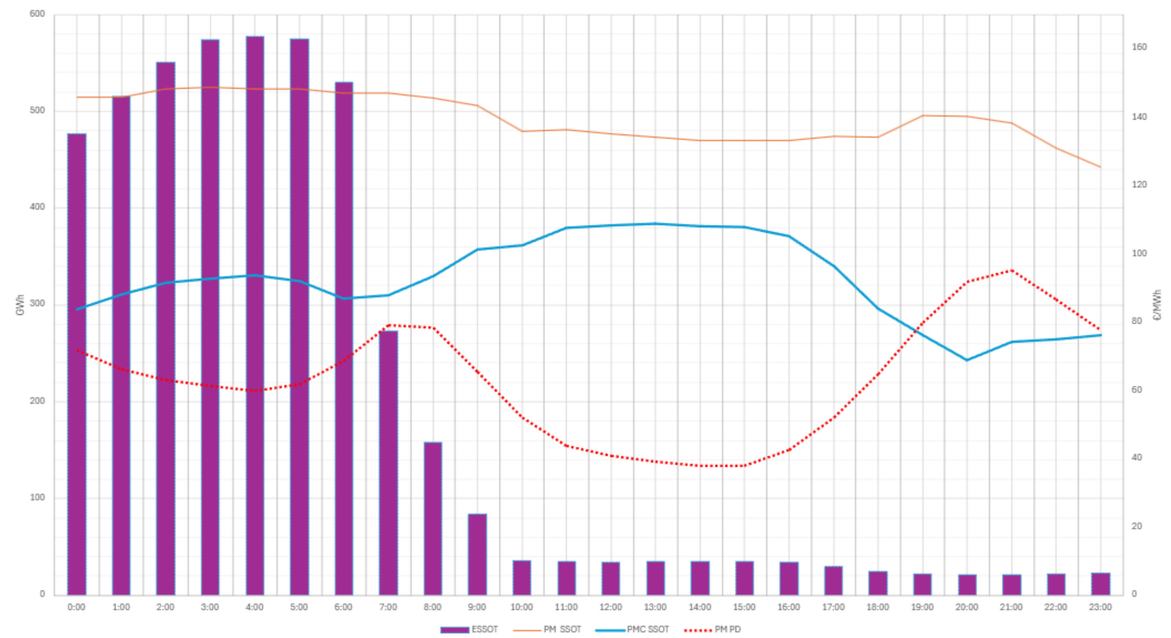


Figure 42: Hourly PMD vs PMC (€/MWh) for the ENSSOT (GWh) on the PDBF in 2024. Source: Own elaboration.

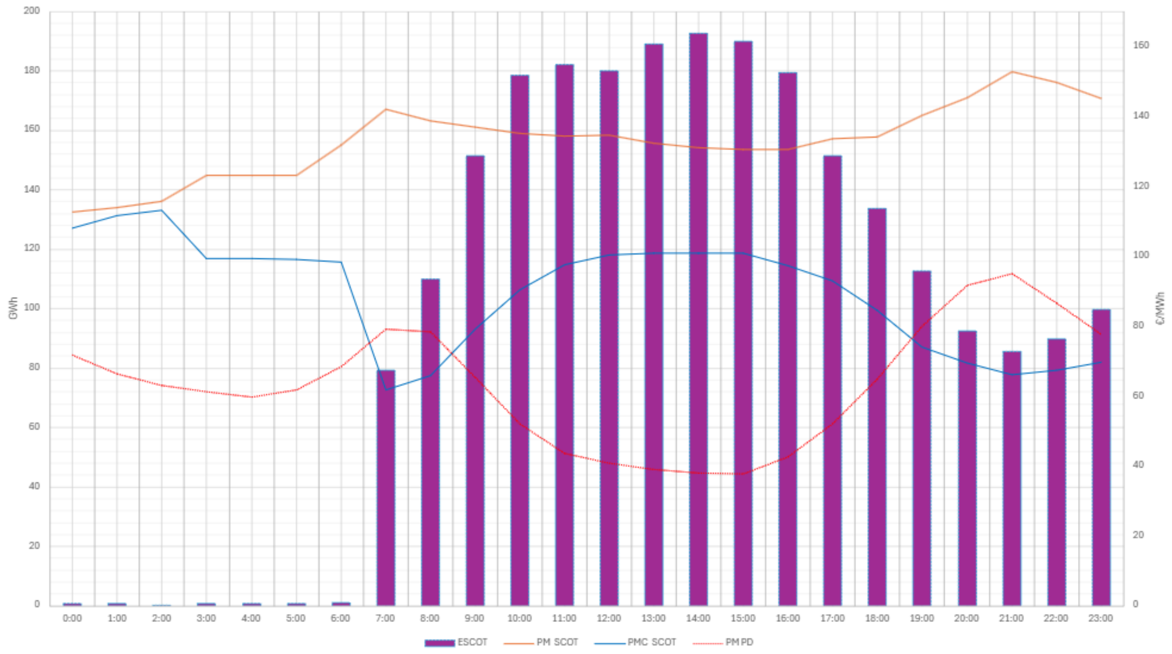


Figure 43: Hourly PMD vs PMC (€/MWh) for the ENSCOT (GWh) on the PDBF in 2024. Source: Own elaboration.

In the PDBF, the overcost associated with technical restrictions can be driven by both a volume effect and a price effect. The volume effect occurs when the system needs to activate a large amount of energy to solve a technical constraint. In that case, the total cost may be high even if the average unit cost of the activated energy is moderate. The price effect, on the other hand, appears when the energy activated to solve the restriction has a high unit cost. In this case, even a relatively small activation volume may generate a relevant overcost.

The comparison with the day-ahead market price is particularly important. Certain hours may present low or moderate PMD values, giving the impression that the electricity cost should be low. However, if technical restrictions require additional energy activation, the final effective cost borne by consumers may be significantly higher due to the difference between the cost for providing the service and the PMD. Therefore, the PDBF analysis shows that the day-ahead price alone does not fully capture the cost of ensuring the technical feasibility of the system.

And for real time:

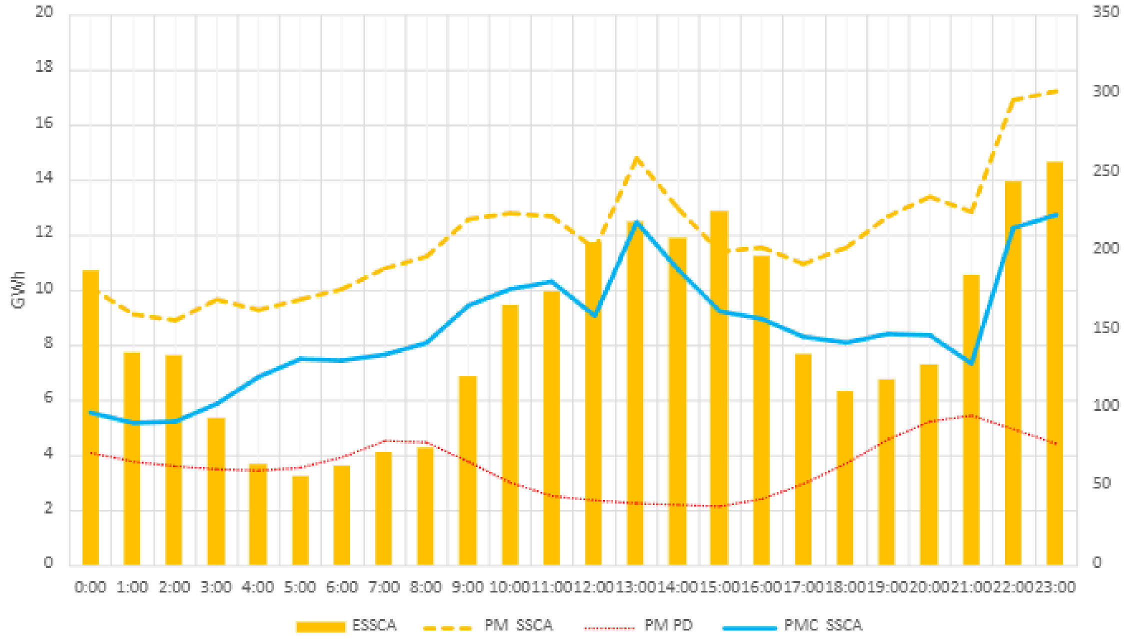


Figure 44: Hourly PMD vs PMC (€/MWh) for the ENSSCA (GWh) in RT in 2024. Source: Own elaboration.

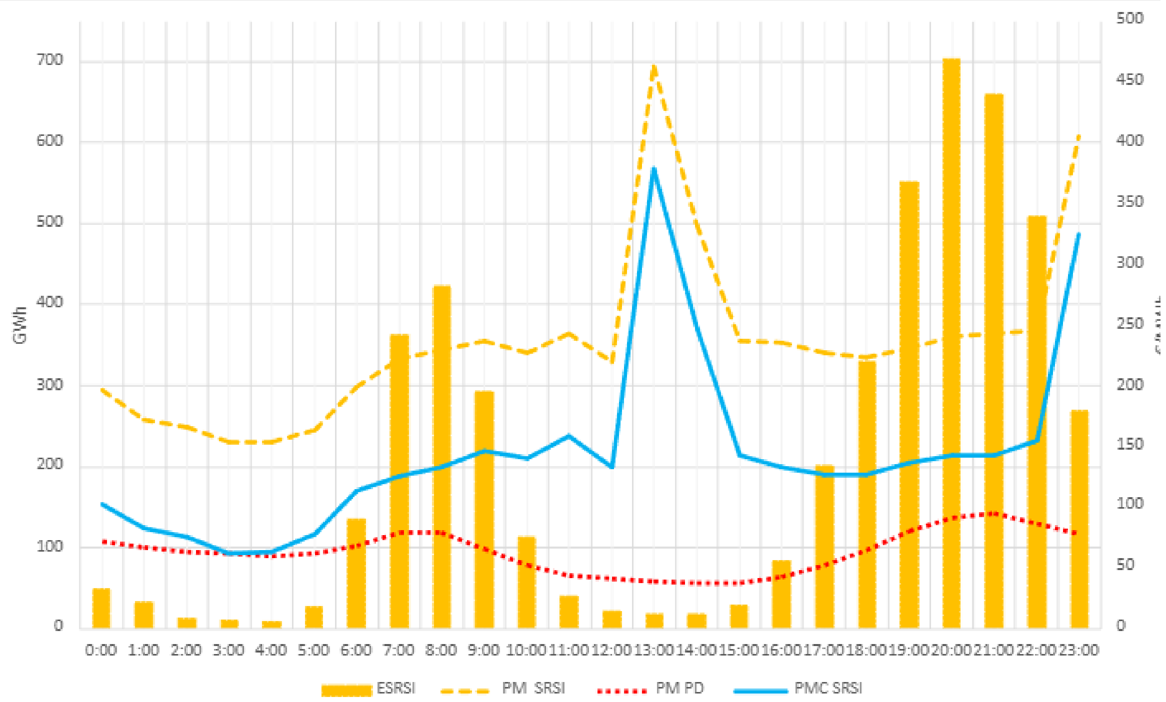


Figure 45: Hourly PMD vs PMC (€/MWh) for the ENSRSI (GWh) in RT in 2024. Source: Own elaboration.

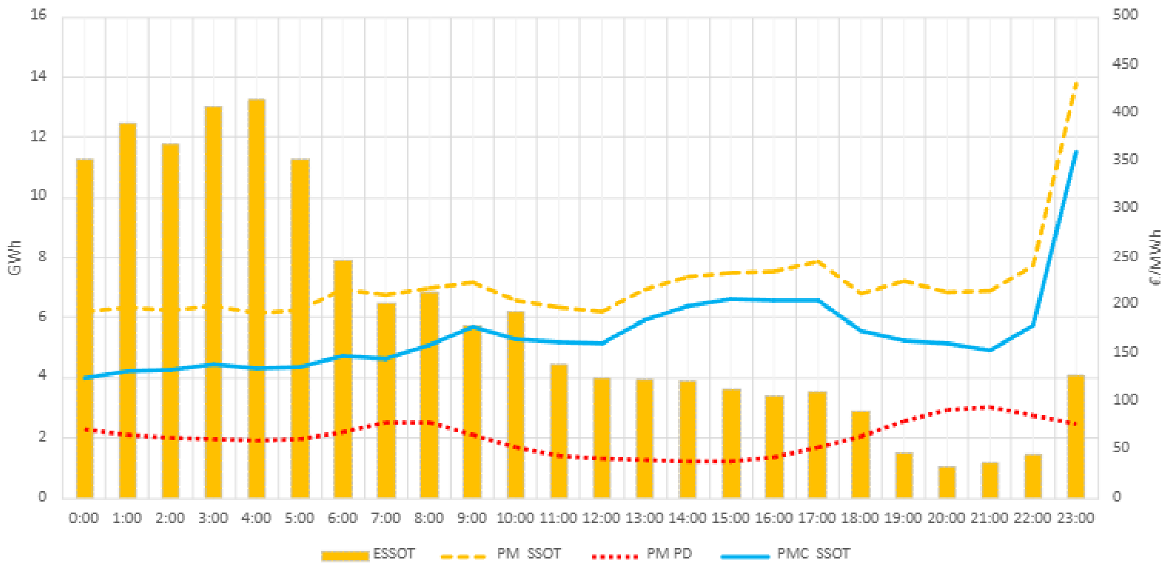


Figure 46: Hourly PMD vs PMC (€/MWh) for the ENSSOT (GWh) in RT in 2024. Source: Own elaboration.

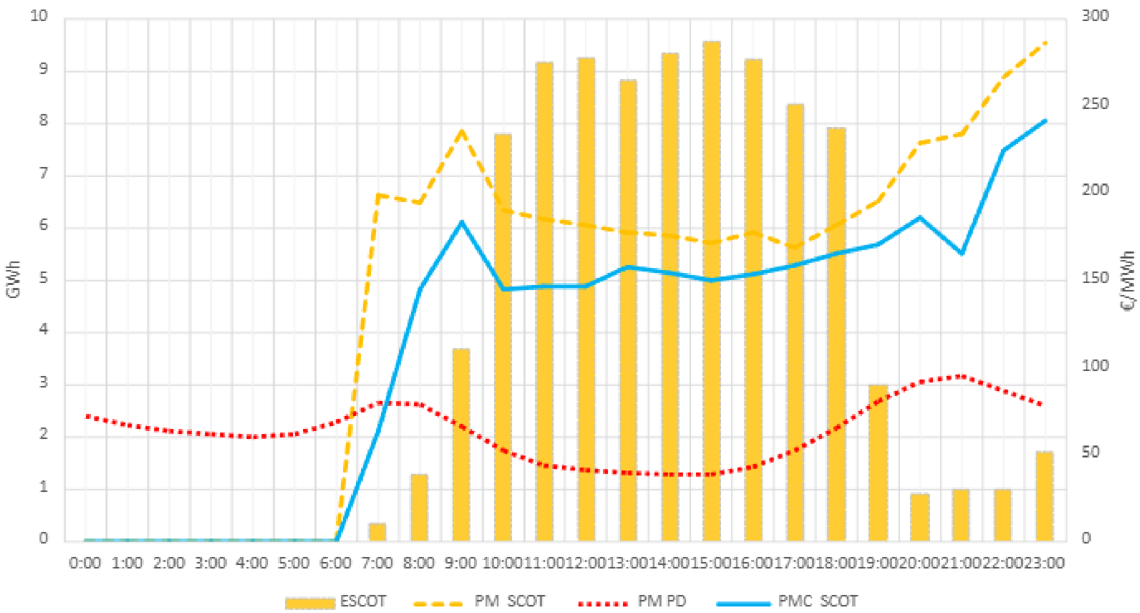


Figure 47: Hourly PMD vs PMC (€/MWh) for the ENSCOT (GWh) in RT in 2024. Source: Own elaboration.

As in the PDBF, real-time costs show that the final price faced by consumers may differ from the day-ahead market signal. Even if the PMD is low or moderate, the need to activate energy in real time can generate additional costs that increase the effective final price. This reinforces the idea that the PMD alone is not responsible for the hours in which consumers bear higher system costs.

We also tried to identify any possible seasonal pattern that could explain better the origin of these costs. For that, heat maps of the activated energy were computed and analyzed.

ESSCA (GWh)	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	24	14	1	3	9	13	9	4	1	1
1	0	0	27	14	1	3	9	14	10	4	1	1
2	0	1	25	14	1	3	9	15	10	4	1	1
3	0	1	26	14	1	1	7	15	12	4	1	0
4	0	1	26	14	1	1	6	13	11	4	1	0
5	0	1	26	14	1	1	6	11	10	3	1	0
6	0	1	21	14	1	1	6	10	9	3	3	1
7	0	4	25	26	5	4	4	7	5	6	6	6
8	1	7	29	45	19	5	4	6	5	6	8	7
9	1	9	41	54	30	16	5	4	5	7	12	6
10	2	10	43	57	35	23	8	7	8	7	13	5
11	2	9	45	59	40	29	12	8	9	8	14	6
12	2	10	46	61	42	29	15	8	9	9	15	8
13	2	10	47	55	41	29	17	8	9	8	15	8
14	2	10	47	54	41	29	18	8	9	9	15	8
15	2	10	46	57	45	33	19	8	10	8	13	7
16	2	9	46	57	52	38	21	9	10	8	10	5
17	2	10	43	61	63	40	22	9	10	9	8	7
18	2	8	34	62	62	36	16	9	8	9	11	10
19	5	7	30	59	47	24	12	9	8	9	13	11
20	5	6	26	44	20	15	13	25	19	11	12	10
21	5	6	28	39	12	12	21	36	22	10	11	10
22	3	5	30	41	11	12	20	37	24	11	8	8
23	1	4	27	40	12	11	23	41	24	9	6	5

Figure 48: Heat map of the ENSSCA on the PDBF in 2024. Source: Own elaboration.

ESSCA shows a seasonal pattern, with the highest activation levels in March, April and May. The activation is also mainly located during daylight hours. The activation appears to be linked to ramping hours, when the system moves from one operating condition to another and the scheduled dispatch has to be adjusted to remain technically feasible. This is especially relevant in spring, when the net demand profile may change significantly during the day due to the increasing contribution of solar generation.

ESRTD	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	1	0	0	0	0	1	2	2	0	0
1	0	1	1	0	0	0	0	1	3	2	0	0
2	1	2	2	2	1	1	1	1	4	3	1	1
3	3	6	4	6	6	2	4	3	8	7	3	2
4	3	6	4	6	6	2	4	3	8	7	3	2
5	3	6	4	6	6	3	4	3	8	8	4	2
6	5	7	5	7	6	4	5	3	9	8	4	3
7	6	7	6	8	7	4	6	7	11	9	4	4
8	6	8	7	9	9	5	7	8	12	10	5	4
9	8	9	9	10	9	6	8	10	13	11	7	6
10	10	11	10	11	12	7	10	11	14	12	8	7
11	10	11	11	12	13	8	10	11	14	13	9	8
12	11	12	12	13	13	9	10	11	14	13	9	9
13	10	11	11	12	13	9	10	11	14	13	9	9
14	10	11	11	12	13	8	10	11	14	13	9	9
15	9	10	10	11	13	8	10	11	14	13	8	8
16	8	9	10	10	12	8	10	10	14	12	7	7
17	8	9	9	9	11	7	10	10	14	12	7	6
18	8	8	8	8	10	7	9	9	13	11	7	6
19	9	8	8	9	10	6	8	9	12	10	7	5
20	8	7	7	9	10	4	7	8	11	9	6	5
21	7	7	7	8	8	4	7	7	10	9	5	4
22	5	7	6	8	7	2	7	5	9	8	4	4
23	3	6	4	7	7	2	7	3	9	8	3	3

Figure 49: Heat map of the ENSRTD on the PDBF in 2024. Source: Own elaboration.

ESRTD shows a concentration of activation during daylight hours, especially between 10:00 and 17:00. This hourly profile is consistent with solar production hours, suggesting that the service may be linked to technical conditions created by high renewable generation and the resulting changes in network flows.

ESSOT	1	2	3	4	5	6	7	8	9	10	11	12
0	36	38	43	64	63	43	26	14	19	37	51	42
1	42	41	44	66	66	46	28	17	24	39	56	45
2	43	41	44	68	68	48	30	18	26	44	63	54
3	44	42	46	69	68	51	33	26	30	42	65	56
4	44	42	46	69	69	52	33	26	30	42	65	56
5	44	42	46	69	69	51	32	26	30	43	65	56
6	42	39	43	67	66	47	31	26	29	40	51	46
7	26	24	30	35	28	22	11	15	12	18	26	27
8	17	15	17	15	15	14	4	7	8	12	17	16
9	15	12	14	4	7	5	2	2	5	6	3	9
10	11	9	11	1	0	1	1	0	0	1	0	1
11	10	9	11	0	0	1	1	1	0	1	0	1
12	10	9	11	0	0	1	1	1	0	1	0	0
13	10	9	11	0	0	1	1	1	0	1	0	0
14	10	9	11	0	0	1	1	1	0	1	0	0
15	10	9	11	0	0	1	1	1	0	1	0	0
16	10	9	11	1	0	1	1	1	0	1	0	0
17	10	7	9	1	0	1	1	1	0	1	0	0
18	8	6	8	1	0	1	0	0	0	0	0	0
19	8	6	6	1	0	0	0	0	0	0	0	0
20	8	6	6	0	0	0	0	0	0	0	0	0
21	8	6	6	0	0	0	0	0	0	0	0	0
22	8	6	7	0	0	0	0	0	0	0	0	0
23	8	6	7	0	0	0	0	0	0	0	0	0

Figure 50: Heat map of the ENSSOT on the PDBF in 2024. Source: Own elaboration.

ESCOT	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	1	0	0	0	0	0	0	0	0	0
1	0	0	1	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	1	0	0	0	0	0	0	0	0	0
4	0	0	1	0	0	0	0	0	0	0	0	0
5	0	0	1	0	0	0	0	0	0	0	0	0
6	0	0	1	0	0	0	0	0	0	0	0	0
7	0	0	2	5	18	12	8	4	9	10	8	3
8	0	0	6	10	22	16	10	7	11	11	10	8
9	0	0	6	17	29	19	12	13	13	15	17	11
10	0	0	6	20	35	20	14	15	16	19	18	16
11	0	0	6	21	34	22	14	15	16	19	18	16
12	0	0	6	22	32	22	15	15	16	19	18	16
13	0	0	6	27	34	24	15	15	16	19	18	15
14	0	0	6	27	35	25	15	15	16	19	19	15
15	0	0	6	26	33	26	15	15	16	19	18	15
16	0	0	6	26	29	24	15	15	16	19	16	13
17	0	0	5	21	21	19	14	14	16	18	14	9
18	0	0	5	16	21	17	15	14	15	15	9	6
19	0	0	4	8	23	15	12	11	11	13	9	6
20	0	0	4	11	19	14	8	4	6	10	9	6
21	0	0	4	8	17	13	5	4	6	10	10	6
22	0	0	4	9	17	13	5	4	6	11	12	7
23	0	0	4	10	18	14	6	4	6	12	16	8

Figure 51: Heat map of the ENSCOT on the PDBF in 2024. Source: Own elaboration.

For SSOT and SCOT there is no clear pattern, it is just the way SO labels the restrictions. Analysis from previous years have shown that they used to be considered as the same restriction. It was in 2023[10] when SO started to label them separately.

And in real time:

ESSCA	1	2	3	4	5	6	7	8	9	10	11	12
0	0	1	0	1	0	1	1	5	0	1	1	0
1	0	0	0	0	0	0	1	4	0	1	0	0
2	0	0	0	1	0	1	1	4	0	1	0	0
3	0	0	0	0	0	0	1	3	0	1	0	0
4	0	0	0	0	0	0	0	2	0	1	0	0
5	0	0	0	0	0	0	0	2	0	1	0	0
6	0	0	0	0	0	0	0	2	0	1	0	0
7	0	0	0	0	0	0	0	2	0	1	0	0
8	0	0	0	0	1	0	0	1	0	2	0	0
9	0	1	1	0	0	1	0	1	0	1	1	0
10	0	1	1	1	1	1	0	0	0	2	2	1
11	0	1	1	1	1	1	0	0	0	2	2	0
12	0	1	1	1	1	1	0	0	0	3	3	0
13	0	0	1	1	1	1	0	0	0	3	4	1
14	0	0	1	1	1	1	0	0	0	2	4	1
15	0	1	1	1	1	1	0	0	1	2	4	1
16	0	0	1	1	1	1	1	0	0	2	3	1
17	0	0	1	1	1	1	1	0	0	2	1	0
18	0	1	1	0	1	0	0	0	0	2	0	0
19	0	0	1	0	1	0	0	0	0	2	1	1
20	0	0	0	0	1	0	0	0	0	2	1	1
21	0	1	1	0	0	0	0	2	0	2	2	2
22	0	1	1	0	0	1	0	3	0	3	1	2
23	0	1	1	0	0	1	1	4	0	3	1	2

Figure 52: Heat map of the ENSSCA in RT in 2024. Source: Own elaboration.

[10] See heat map from Annex.

ESSCA has no clear activation pattern.

ESRSI 2024	1	2	3	4	5	6	7	8	9	10	11	12
0	0	1	6	5	1	3	11	14	4	6	0	1
1	0	0	4	3	0	3	8	8	2	4	0	0
2	0	0	1	1	0	1	4	3	1	1	0	0
3	0	0	1	1	0	1	3	2	0	1	0	0
4	0	0	1	1	0	1	2	2	0	1	0	0
5	0	0	4	3	0	3	5	6	2	3	0	0
6	2	5	15	14	8	15	20	17	12	16	7	3
7	23	25	26	40	24	30	34	31	38	40	30	22
8	29	33	29	47	29	31	38	37	42	46	32	31
9	31	30	14	30	8	10	14	20	29	48	27	31
10	22	11	4	5	2	2	5	5	8	26	9	13
11	11	4	1	2	0	0	2	1	4	8	2	5
12	6	1	0	0	0	0	1	0	1	5	1	3
13	6	1	0	0	0	0	1	0	1	3	1	4
14	7	2	0	0	0	0	1	0	0	2	1	4
15	10	2	1	0	0	0	0	0	0	2	6	6
16	23	6	3	0	0	0	1	0	0	5	24	22
17	48	23	16	1	0	0	1	1	3	19	48	41
18	55	43	45	6	0	1	5	10	15	56	52	41
19	56	51	58	48	19	19	30	46	59	75	50	41
20	53	52	63	74	47	46	66	76	67	73	46	42
21	50	47	59	76	46	44	61	63	63	68	41	41
22	31	32	44	63	41	42	59	55	42	46	25	29
23	15	16	27	41	20	24	34	31	19	23	9	10

Figure 53: Heat map of the ENSRSI in RT in 2024. Source: Own elaboration.

ESRSI is activated mainly during ramping hours. In the morning, the system has to adjust to the increase in demand and changing generation patterns. In the evening, the reduction of solar generation and the increase in net demand may require additional real-time actions.

ESSOT (GWh)	1	2	3	4	5	6	7	8	9	10	11	12
0	1	2	1	2	2	1	0	0	1	1	1	0
1	2	1	0	2	2	2	0	0	1	1	1	1
2	1	2	0	2	2	1	0	0	1	1	1	0
3	1	2	0	2	2	2	0	0	1	1	2	0
4	1	2	0	2	2	1	0	0	1	1	1	0
5	1	2	0	2	2	1	0	0	1	1	1	0
6	1	1	0	1	1	1	0	0	1	1	1	1
7	2	1	0	1	1	0	0	0	0	0	1	0
8	2	1	0	1	0	0	0	0	0	0	1	0
9	1	1	0	1	1	0	0	1	0	0	0	0
10	1	2	1	0	0	0	0	0	0	0	0	1
11	1	2	1	0	0	0	0	0	0	0	0	0
12	1	2	1	0	0	0	0	0	0	0	0	0
13	1	1	1	0	0	0	0	0	0	0	0	0
14	1	1	1	0	0	0	0	0	0	0	0	0
15	1	1	1	0	0	0	0	0	0	0	0	0
16	0	1	1	0	0	0	0	0	0	0	0	0
17	0	2	1	0	0	0	0	0	0	0	0	0
18	0	1	1	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0
23	1	1	0	1	0	0	0	0	0	0	0	0

Figure 54: Heat map of the ENSSOT in RT in 2024. Source: Own elaboration.

ESCOT	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	0	0	0	0	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	1	1	1	0	0	0	0	0	0	1
10	0	0	1	3	1	1	0	0	0	0	0	1
11	0	0	0	4	1	1	0	0	1	0	0	2
12	0	0	0	4	1	1	0	0	1	0	0	2
13	0	0	1	4	1	1	0	0	0	0	0	1
14	0	0	1	4	1	1	0	0	0	0	1	1
15	0	0	1	4	1	1	0	0	0	0	1	1
16	0	0	1	4	1	1	0	0	0	0	0	1
17	0	0	1	4	1	1	0	0	0	0	0	0
18	0	0	1	4	1	1	0	0	0	0	0	0
19	0	0	0	2	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	1	0	0	0	0	0	0	0	0

Figure 55: Heat map of the ENSCOT in RT in 2024. Source: Own elaboration.

As with the PDBF, For SSOT and SCOT there is no clear pattern, it is just the way SO labels the restrictions.

In addition to this, the same process was repeated from 2020 to 2025 to check if there was any replicable pattern. The results showed that the allocation patterns identified in 2024 were not consistent across the other years. The main issue here is the classification method changing over time[11]. The reason behind it is not mainly because of a physical cause, rather than the way SO decides to label the resources. The SO may follow an internal classification procedure that has evolved over time. For example, in the case of SOT and COT, we could not find a clear explanation on why the SO decided to assign each one to different hours in the recent years, while in the past it was treated as the same resource. Distinguishing between two different labels may in itself be positive, as it can provide more detailed information. However, the questionable aspect is that the labels seem to be assigned in hourly blocks for the system as a whole. This suggests that a generic or predefined allocation criterion may be applied, rather than a classification based strictly on the actual cause of each activation. What

[11] Examples of this evolution are provided in annex II.

we found is that there was a change in the way of labeling the cost from 2023 onwards, so for further analysis we will consider the years 2023, 2024 and 2025. In addition to this, the "label" effect has increased since the blackout, so when analyzing 2025, we will consider only until March. Nevertheless, since we could not find a pattern in the way SO labels the resources, for further analysis, it was decided to consider all the energies together, instead of disaggregating them. Differentiations will be made by PDBF and real time, and whether the energy was used to modify the program upwards or downwards.

For the rest of the ancillary services, the costs published in esios were computed and compared to the ones that SO published in its reports.

Once we had all the needed information, the next step was to identify which one of the parameters forming the costs was the main driver. But, before entering into the models, it was important to understand what methodologies have been followed in other countries. For that, a benchmark was carried out.

4.2 BENCHMARK

The objective of this benchmark is to compare how some reference European countries allocate, recover and regulate the costs associated with ancillary services, balancing, redispatch, congestion management and other activities related to the operation of the system. In some countries, these costs are embedded within the regulated network tariff. In others, they are recovered through a separate system charge or directly through imbalance settlement. ACER states that network tariff methodologies should remain cost reflective, transparent and non-discriminatory, and that users should contribute to the cost of the network they use. This is particularly relevant in the current European context, where higher renewable penetration, network congestion, electrification and flexibility needs are increasing the importance of tariff design. The benchmark covers six representative countries: Spain, France, Portugal, Italy, Germany and UK.

4.2.1 SPAIN

In Spain, the transmission system operator and system operator is SO, while distribution is performed by several distribution system operators. The economic regulator responsible for the methodology of access tariffs is the CNMC. The Spanish system distinguishes between regulated network access tariffs and system-operation or adjustment costs.

The regulated network tariffs recover the recognized remuneration of transmission and distribution networks, including adjustments from previous years and other regulated items. These payments are set ex ante, on an annual basis, within a broader regulatory period. The methodology is based on the principles of cost causality and additivity. The starting point is not the amount of energy consumed, but the network capacity required to satisfy peak demand under security and quality criteria, mainly following the N-1 criteria. Once the reference network has been identified, expected energy flows, losses and quality of supply indicators are incorporated. The remuneration assigned to each voltage level is then divided between a power term and an energy term and allocated across tariff periods according to each period's contribution to the peak demand of the relevant voltage level (CNMC Actualizacion circular 3/2020, 2021).

This means that the Spanish network tariff is not a purely volumetric charge. It is built around the idea that network costs are driven by the capacity that must be available at any time (especially critical hours). Consequently, the power component reflects the cost of dimensioning the network, while the energy component captures the use of that network and other energy related elements. In addition, the tariff structure differentiates by voltage level, contracted power and time period.

However, the costs of ancillary services, technical restrictions and deviations are not embedded into the network tariffs. Spain is a clear example of a dual structure: network tariffs are set ex ante, while adjustment costs are settled through system operation mechanisms that are closer to actual hourly system conditions. REE, as system operator, procures and activates the relevant mechanisms, such as the balancing energy, technical restrictions and other adjustment services.

4.2.2 PORTUGAL

Portugal combines a regulated tariff structure with a separate operational settlement for balancing, deviations and technical restrictions. The transmission system operator and system operator is REN, the main distribution system operator is E-Redes, and the regulator is ERSE.

The Portuguese tariff system is built around the principle of additivity. The access tariff is the sum of several regulated components. It includes the *Tarifa de Uso Global do Sistema* (UGS), the *Tarifa de Uso da Rede de Transporte*, and the *Tarifa de Uso da Rede de Distribuição.* The UGS includes a Parcel I, associated with system management costs, and a Parcel II, associated with energy-policy, environmental or general economic-interest costs. The Portuguese tariff regulation defines regulated activities and the revenues to be recovered by each activity. ERSE's tariff documentation states that tariffs should reflect the costs of the relevant activities (ERSE, 2022).

Portugal also has a detailed operational framework for system services, balancing, deviations and technical restrictions, governed by the Manual de Procedimentos da Gestão Global do Sistema. This manual establishes the rules for system security criteria, system service markets, cost recovery associated with system service procurement, and settlement and billing procedures (ERSE, 2025).

In tariff terms, Portugal uses a combination of power, energy and reactive-energy components, depending on the voltage level and tariff block. UGS Parcel I is mainly energy-based and is not strongly time-differentiated, while the transmission and distribution tariffs may include contracted power, power in peak hours, active energy and reactive energy. The methodology also includes cost cascading: users connected at lower voltage levels bear the cost of the upstream network levels they use. This is important because it means that the final access tariff reflects both the user's own voltage level and the cost of the upstream system. Regulated tariffs are set ex ante on an annual basis, within a multi-year regulatory framework. However, the tariff formula includes adjustments from previous years, such as t-2 corrections, so that forecast errors are later incorporated into allowed revenues.

Operational balancing, deviations and technical restrictions, as in Spain, are settled separately and closer to real system operation.

4.2.3 ITALY

Italy is one of the clearest examples of separation between pure ex-ante network tariffs and dispatching or balancing charges. The transmission system operator is Terna, distribution is performed by several DSOs, and the regulator is ARERA. The Italian framework distinguishes between the regulated network tariff side and the dispatching side.

The regulated network side includes transmission, distribution and metering related costs. By contrast, dispatching, balancing, redispatch and ancillary services are stablished in the TIDE (Testo Integrato del Dispacciamento Elettrico). It states that its purpose is to promote efficient and sustainable use of available resources, support liquid and competitive electricity markets, and ensure impartiality, neutrality and transparency towards system users. It also assigns Terna responsibility for dispatching services, security constraints and the procurement of national ancillary services according to economic merit order where possible. So, in the end, system-operation costs are recovered through corrispettivi di dispacciamento, especially the uplift component. It is set for three month periods (ARERA, 2025). Terna publishes the estimated uplift before the period, applies it as a unit charge, and later calculates whether it over-recovered or under-recovered relative to actual dispatching costs. The difference is then recovered subsequent uplift values.

The payment chain is therefore: Terna organizes and activates dispatching and balancing resources; Terna pays providers or settles with market participants; the costs are recovered through dispatching charges applied to withdrawal users or BRPs; and the final economic burden reaches consumers through the electricity bill.

4.2.4 UK

Great Britain is the clearest example in this benchmark of a separate system-operation charge. The system operator is NESO, the regulator is Ofgem, and distribution is performed by regional distribution network operators.

Great Britain distinguishes between connection charges, transmission network use-of-system charges and BSUoS. BSUoS is designed to recover the costs associated with balancing the electricity transmission system and related system-operation activities. It is not a network capacity tariff. It is a specific system charge applied to Final Demand.

The BSUoS framework has changed significantly in recent years. It has been introduced an ex ante fixed volumetric BSUoS tariff (NESO, 2025). The objective was to reduce volatility, improve transparency and give suppliers more certainty when pricing final customer offers. NESO explains that balancing costs are influenced by wholesale market prices, weather conditions and network outages, making them difficult to predict, and that the fixed BSUoS tariff was introduced in 2023 to reduce this volatility (Birkner, 2021).

Under the current methodology, NESO forecasts balancing costs and other relevant non-balancing cost items. These are added to obtain total BSUoS costs, which are then divided by forecast BSUoS chargeable volumes to obtain the fixed tariff for the relevant period. Since April 2023, BSUoS has been charged to Final Demand only, following (OFGEM, 2013). NESO defines chargeable volume as electricity consumed other than for generation or export to the electricity network.

The final NESO tariffs for 2026/27 have been confirmed at £13.74/MWh for the first half of the year and £12.49/MWh for the second. Although determined annually and ex-ante, the pricing structure is segmented seasonally (NESO, 2025).

The treatment of over recovery and under recovery is explicit. NESO incurs in balancing and system operation costs, while the tariff is fixed in advance. If actual costs and recovered revenues do not match, the difference is carried forward into future BSUoS tariffs. The final payer is final demand. The charge is energy-based only, expressed in £/MWh, and it is not differentiated by voltage level, contracted capacity or individual network peak contribution. This makes Great Britain very different from France, Portugal or Germany, where power and voltage level differentiation play a much stronger role in the network-tariff methodology.

4.2.5 FRANCE

France is one of the clearest examples of a system in which the cost of operating the electricity system is incorporated into the regulated network tariff itself. The transmission system operator is RTE, the main distribution system operator is Enedis, and the regulator is the Commission de Régulation de l'Énergie (CRE). The tariff framework is built around the TURPE (Tarif d'Utilisation des Réseaux Publics d'Électricité) with TURPE 6 HTB applying to the high-voltage transmission network and TURPE 6 HTA-BT applying to distribution. CRE states that TURPE 6 HTB entered into force on 1 August 2021 (CRE, 2021) for a period of approximately four years and was designed after several public consultations on the regulatory framework, tariff structure and pricing signals. The tariff is designed to cover the costs of an efficient transmission operator

RTE's net operating expenses include purchases related to electricity system operation. These include the cost of compensating losses, constituting and reconstituting balancing reserves, voltage ancillary services and congestion costs. CRE's tariff decision also explains that grid costs borne by transmission and distribution operators include management and metering costs, infrastructure costs, loss compensation costs, reserve costs, voltage control and other centrally managed costs. These costs are then passed on to network users through tariff components differentiated by voltage level. This makes France very different from countries such as Italy or Great Britain.

The French tariff methodology is also highly developed. It is based on cost causality and aims to allocate costs to users in a way that reflects the network costs they generate. The methodology moves from total cost to cost drivers, from cost drivers to marginal costs, and from marginal costs to tariff coefficients. For HTB and HTA networks, CRE uses a network-design logic that reflects the fact that these grids are meshed and redundant. The relevant peak is not simply the single maximum annual demand, but a sustained high-load reference. For low-voltage networks, where redundancy is lower, the sizing logic is more local and more directly related to shorter high-load periods.

The tariff is charged through several components. The withdrawal component includes coefficients applied to subscribed capacity, expressed in €/kW/year, which reflect the contribution of users' maximum demand to infrastructure costs. It also includes coefficients applied to energy, expressed in €/kWh, which reflect the duration of use of subscribed power and the contribution of withdrawn energy to loss compensation costs. France therefore does not apply a simple flat volumetric tariff. It combines power and energy, with differentiation by voltage level, time category and, for some users, duration of use.

The treatment of temporary differences between forecast and actual costs is handled through CRCP. RTE initially incurs the recognized costs. If actual costs or revenues differ from forecasts, the difference is recorded in the CRCP and later incorporated into the tariff path through annual updates. In other words, the TSO bears the mismatch initially, but the regulatory framework is designed to recover or return the difference through future tariff adjustments.

The charging chain also differs from that of Spain or Great Britain. In France, a distributor connected to the transmission network can be treated as a user of the upstream transmission grid. Therefore, a DSO may pay the transmission-use tariff to RTE at the transmission-distribution boundary, and that cost is then included in the DSO's regulated economics and ultimately passed on to final users. A large industrial consumer connected directly to the transmission grid pays as an HTB user; a generator pays the relevant injection component; and a distributor pays for its use of the transmission network at the boundary point. The final payer is therefore the network user.

4.2.6 GERMANY

Germany has one of the most differentiated models in the benchmark. The four transmission system operators are 50Hertz, Amprion, TenneT and TransnetBW. The regulator is the Bundesnetzagentur. The German system must be understood through a distinction between two categories: balancing and imbalance settlement, and redispatch or congestion management.

Balancing energy and deviations are settled separately through the reBAP, the uniform cross-control-area imbalance price. The reBAP is calculated for each quarter-hour. The German reBAP methodology states that the calculation is carried out in a 15-minute time frame and is based on the aggregate balance of the four German control areas. The methodology also explains that if the system is under-supplied, the NRV balance is positive, while if it is over-supplied, the balance is negative. The sign of the imbalance price determines the direction of payment between the balance responsible party and the TSO (50Hertz, 2022).

Redispatch and congestion management are treated as regulated costs included in the network tariffs German network tariffs follow an average-cost allocation logic. Recognized network costs are used to determine a revenue cap. These costs are allocated across network and transformation levels and then translated into power and energy charges, with differentiation according to annual utilization hours, especially the 2,500-hour threshold. Costs are cascaded from higher to lower voltage levels, so downstream users also pay for the upstream network they use. This has an important implication for the TSO–DSO relationship. In the network-tariff chain, the DSO does pay for upstream network use, and those costs are passed down to final customers through distribution tariffs (Tennet, 2022). As congestion-management and other transmission-related costs increase, this mechanism can place significant upward pressure on final network tariffs. The relevance of this issue is illustrated by Germany's decision to provide a €6.5 billion public subsidy in 2026 to partially finance transmission network costs. The amount must be deducted when calculating the national transmission tariff, with the explicit objective of reducing the network charges ultimately borne by consumers (Bundesministerium der Justiz und für Verbraucherschutz, 2025).

From this analysis, the first conclusion that can be made is that there is no single European model. What is more, the analyzed countries can be grouped into three families: France and Germany place a significant part of system-operation and network-related costs within the same regulated network tariff. Great Britain maintains a more explicit separation between network-use tariffs and system-operation or dispatching charges. Spain and Portugal occupy an intermediate position: part of system-management costs is recovered through regulated frameworks, but balancing, deviations and technical restrictions remain linked to system settlements and operational mechanisms whose price are settled ex-post. This confirms ACER's observation that European tariff comparisons are difficult because the perimeter of what is included in transmission tariffs varies significantly between countries (ACER, 2025).

After reviewing the cost-recovery methodologies applied in different European countries, the analysis focuses on the Spanish case in order to assess which allocation approach could provide a more efficient and cost-reflective signal.

How do ancillary services work in the main European countries?

1	Generic network charge or specific charge for ancillary services?	Specific	Specific	Specific	Specific	Generic	Generic
2	Cost/payment	Over costs(2) SSAA	Sobrecustos(2) Encargos de Regulaçao	Corrispettivo di dispacciamento	BSUoS charge	TURPE	reBAP y Netzentgelte(3)
3	Charge included in the energy price or in the network charge?[1]	E	E	E	P	P	P
4	Who pays for it: demand or generation?	D	D	D	D	D	D
5	Who settles the cost: Agent(s)	Cx / Direct consumer	BRP	BRP	Cx / Direct consumer.	Red user (Dx/ Cons)	Red user (Dx/ Cons)
6	Who computes the ancillary services payments?	REE	REN	TERNA / ARERA	NESO	RTE	TSOs
7	Who bears the time mismatches in costs?	-	-	TERNA	Agents	RTE	TSOs

8	Charge structure? [1]	€/kWh bc	€/kWh bc	€/kWh bc	€/kWh bc	€/kW €/kWh	€/kW €/kWh
9	Time discrimination	CH	CH	Ex – ante trimestral price	Ex – ante seasonal price	Ex – ante annual period-price	Ex – ante annual price
10	Price update frequency	CH	CH	T	A	A[2]	A
11	Discrimination by consumer size?	✗	✗	✗	✗	Power usage[4]	Power usage[5]
12	Discounts?	✗	✗	✗	✗	Big consumers[3]	Big consumers[6] Tx subsidies2026 [7]
13	Recent prices	23.4 €/MWh 26Q1(1)	21.15 €/MWh 26Q1	10.65 €/MWh	13.74 £/MWh A26-S26 12.49 £/MWh O26-M27	1.09 €/MWh [8]	7,86 €/MWh [9]
14	Source:	https://www.sistemaelectrico-ree.es/es/informe-del-sistema-electrico/mercados/servicios-ajuste/energia-precios-por-seguridad	SISTEMA DE INFORMAÇÃO DE MERCADOS DE ENERGIA	Tarifas del mercado eléctrico | Datos de Terna Driving Energy	https://www.neso.energy/industry-information/charging/balancing-services-use-system-bsuos-charges	https://www.cre.fr/documents/deliberations/tarif-dutilisation-des-reseaux-publics-de-transport-delectricite-turpe-7-htb-1.html	Netztransparenz > Sobre nosotros > Tarifas de la red

Figure 56: European benchmark summary. Source: Own elaboration.

4.3 REGRESSION ANALYSIS

The analysis was carried out by estimating several regression models to identify potential relationships between the variables that determine the cost: demand, ENRRTT, PMRRTT and PMD. The main objective was to find a direct relation between the demand and the cost, to justify a possible allocation methodology in a marginal way. The analysis was carried out through several scenarios for both the PDBF and real time:

- A model considered the total of hours from the year, without any discrimination.
- A model disaggregating the data into months.
- A model disaggregating the data by the periods established in the Circular 3/2020 of the CNMC (CNMC Actualizacion circular 3/2020, 2021).
- A model disaggregated by months and periods.
- A model disaggregated by hours of a working day and a non-working day.
- A model disaggregated by hours and months.

This process was repeated for 2023 and 2025 and then it was applied to 2023, 2024 and 2025[12].

In addition to this, for the monthly scenario, simple regression models were computed to try to find better relationships between the variables. This was done for the PDBF and the real time.

- Y: CRRTT; X: ERRTT.
- Y: CRRTT; X: Demand.
- Y: CRRTT; X: PMD.
- Y: CRRTT; X: PRRTT.
- Y: ERRTT; X: Demand.
- Y: PRRTT; X: ERRTT.

[12] Only the months before the black out was taken into account for the jointly analysis (January, February and march).

- Y: PRRTT; X: PMD.
- Y: PRRTT; X: Demand.

Also, an additional model consisting of Y: CRRTT and X1: ERRTT; X2: Demand was carried out to understand better the relationship among these variables.

The previous models were also repeated for 2023, 2025 and for all years.

For the downward energy, models were computed in real time, as this energy is more related to the real time operation of the system rather than to the day ahead market schedule. Downward activations are often driven by deviations, excess generation, technical restrictions or balancing needs that become visible closer to real time.

For PRSS, instead of trying to find a direct relationship with costs using regression models, a covariance-based model was applied. This approach was chosen because PRSS costs are linked to the uncertainty and variability that the system operator must manage, rather than to the absolute demand level of each group.

Type	***Scenarios analyzed***	***Objective***
Multiple regression models	Annual, monthly, CNMC periods, month-period, hourly working/non-working days, and hourly-monthly models	To assess whether technical restriction costs show a stable relationship with demand, activated energy or prices.
Simple monthly regressions	CRRTT vs ENRRTT, Demand, PMD and PMRTT; ENRRTT vs Demand; PMRTT vs ENRRTT, PMD and Demand	To identify which individual variable better explains the costs.

Multiple regression model	CRRTT explained by ENRRTT and Demand	To determine whether demand adds explanatory information beyond the effect captured by activated energy.

Table 8: Summary of analyzed scenarios. Source: Own elaboration.

4.3.1 PDBF MULTIPLE REGRESSION MODELS FOR 2024 USING ENSRRTT

Since the objective was to allocate the cost based on the causality principle, the models aimed at finding a direct relationship between the costs and the demand. Regression models follow the structure:

$$Y = a * X_1 + b * X_2 + \cdots$$

Equation 3: Regression models equation.

For our analysis, the first regression models to be analyzed include the following explanatory variables: the energy from the restrictions, the demand and both the prices from the restrictions and the day ahead market. A model is considered to be suitable when the obtained values of R2 are between 0,5 and 0,7 (IONOS, 2024). And the explanatory variables are considered to be representative when the p-value associated with them is lower than 0,05. For the purpose of this analysis, we will only analyze those models where the R-squared is above 0,5 and all the variables have p-values lower than 0,05. In addition to this, special attention will be paid to the demand coefficient, to see the degree of correlation between it and the cost. The graphs contribute to help to illustrate this, since the obtained R-squared value of the model and the coefficient of the demand is displayed. The first model was carried out using the data from all the hours of the year:

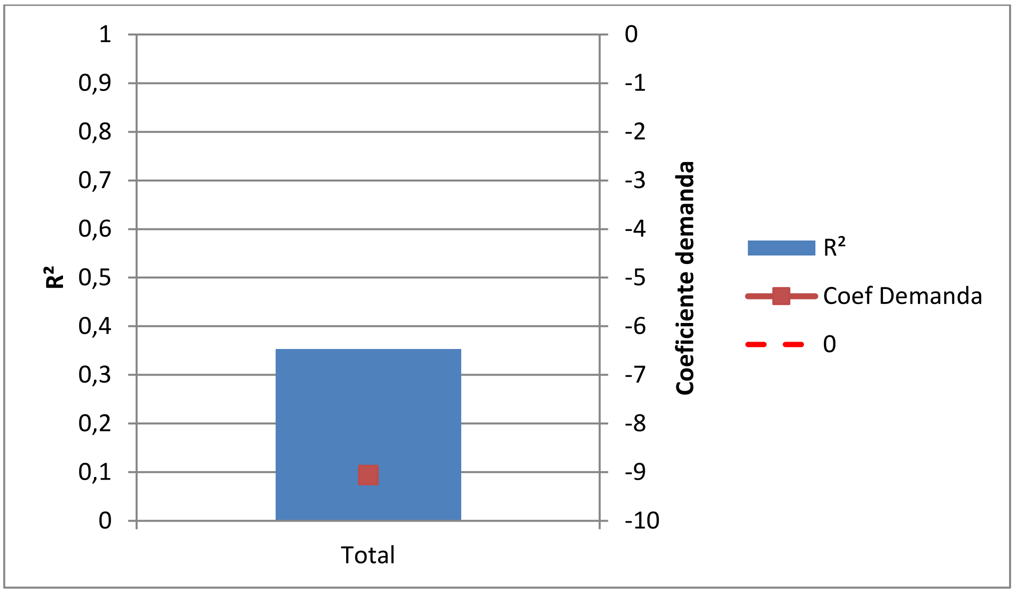


Figure 57: Multiple regression model for upward energy activated in PDBF in 2024 annually computed. Source: Own elaboration.

The obtained model was not acceptable since the R2 obtained was equal to 0,33. For this reason, the next step was to disaggregate the analysis by month.

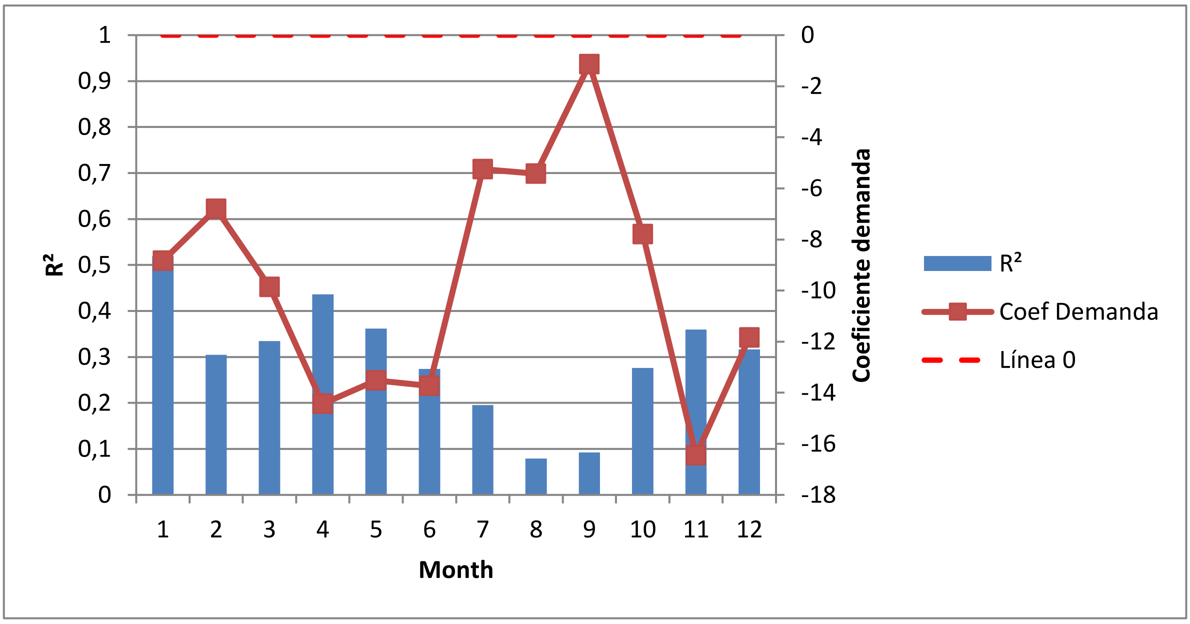


Figure 58: Multiple regression model for upward energy activated in PDBF in 2024 monthly computed. Source: Own elaboration.

The obtained model was not robust. Only in January was a certain degree of correlation observed, as it was the only month with an R-squared higher than 0,5. It was decided to move to the next scenario. A disaggregation by periods established in the CNMC methodology. In this approach, P1 P2 P3 P4 P5 were jointly considered. 1 means the model is considering P6 hours and 0 that it considers the rest.

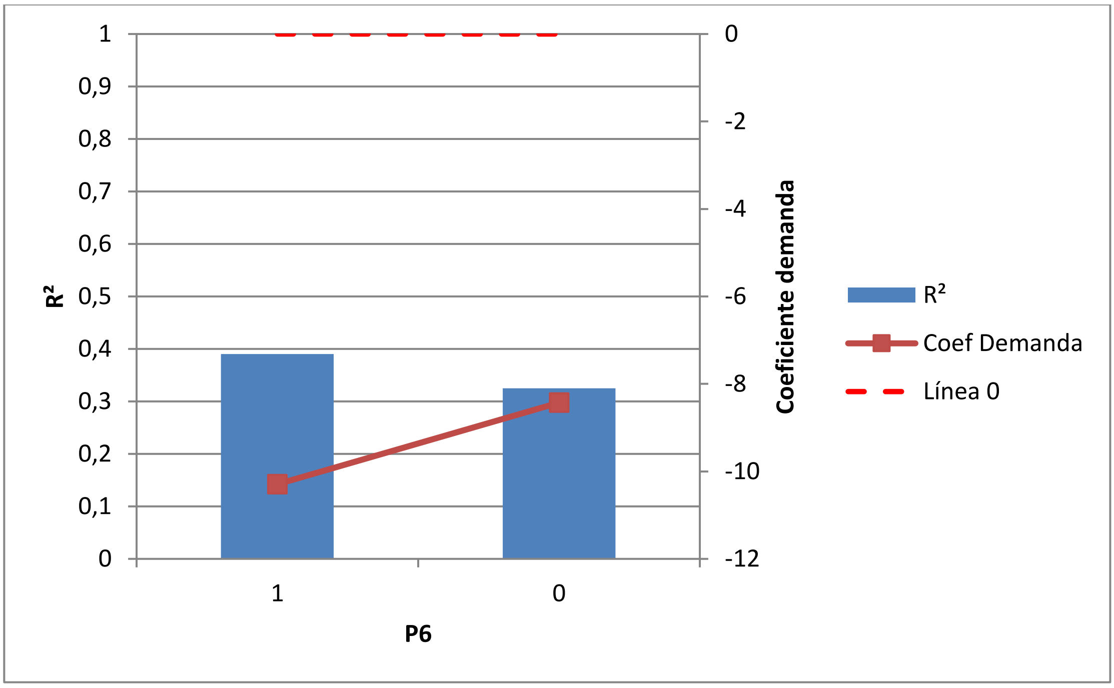


Figure 59:Multiple regression model for upward energy activated in PDBF in 2024 by period. Source: Own elaboration.

Once again, the model obtained is not robust enough, so it has been decided to make another model, disaggregating by month and grid tariff period[13].

[13] For further information, review Circular 3/2020 from the CNMC.

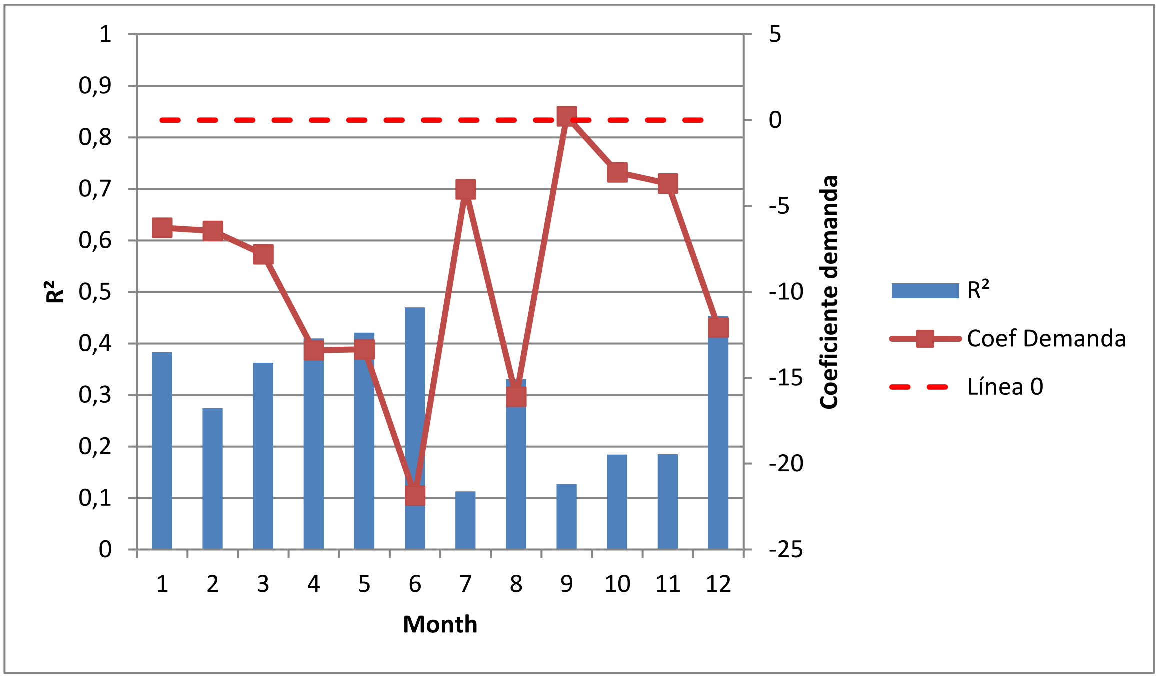


Figure 60: Multiple regression model for upward energy activated in PDBF in 2024 by month outside P6. Source: Own elaboration.

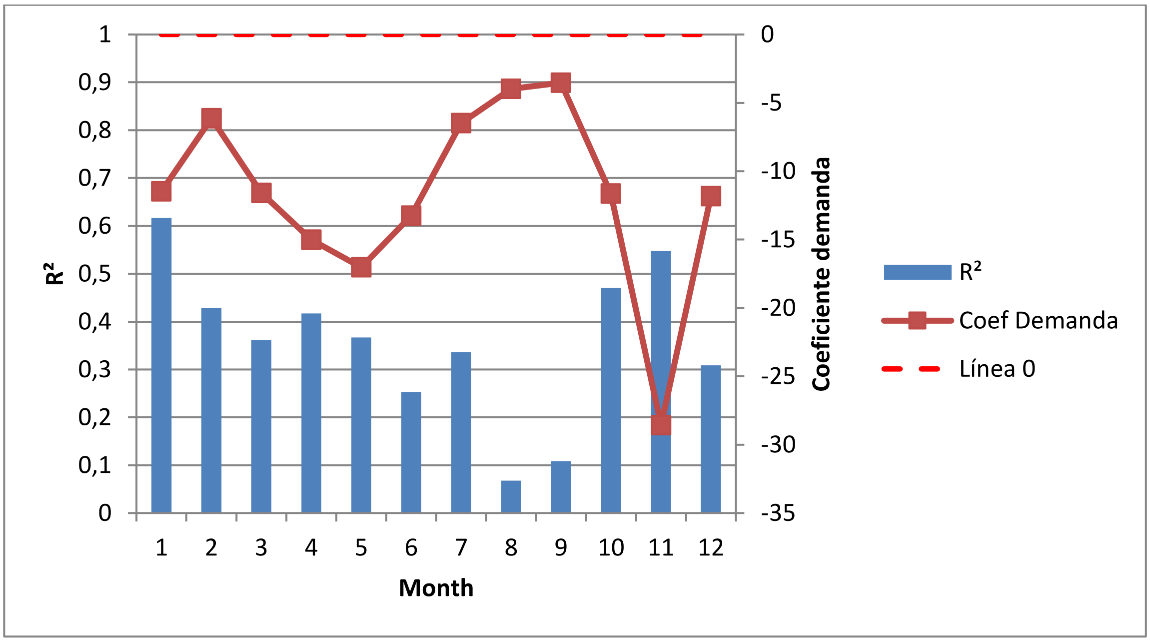


Figure 61: Multiple regression model for upward energy activated in PDBF in 2024 by month and P6. Source: Own elaboration.

The R-squared values obtained in this scenario are more robust than in the previous analysis, although this improvement is not observed consistently across all months. Nevertheless, one relevant result can be identified in period P6[14], where an inverse relationship between demand and costs is observed. This suggests that, during these hours, an increase in demand may be associated with a reduction in restriction costs.

This result is particularly relevant to the objective of this thesis. One of the main issues identified in the analysis is that technical-constraint costs increase final prices during certain hours. However, the hourly adjustments made in the PDBF do not necessarily imply that all the costs allocated to a given hour originate from a restriction occurring in that same period. Due to complex bids and intertemporal operating constraints, the reprogramming of a unit in one hour may be required to solve or anticipate a technical restriction in another hour. Therefore, part of the cost assigned to a specific period may be a collateral effect of reprogramming decisions driven by system needs in different hours.

This is important from an efficiency perspective. Although tariff design should avoid indiscriminate cost socialization and, in principle, allocate costs to the periods that cause them, the current hourly allocation may not fully reflect the true temporal origin of the restriction. If the resulting higher prices discourage consumers from shifting their demand towards those hours, the price signal may be inefficient. Instead of encouraging consumption, when it could help reduce system costs, the current allocation may move demand away from those periods, potentially increasing operational stress, the need for further restrictions and, consequently, final prices.

Therefore, the results shown in the graph support the idea that the current cost-allocation methodology may not provide an efficient economic signal. A more efficient approach should recognize that, in some periods, such as P6, higher demand may contribute to reducing restriction costs. In these cases, the price signal should not penalize consumption in those hours but rather encourage demand to shift towards them when doing so helps reduce the overall cost of the system.

[14] P6 corresponds to valley hours of a working day, weekends and bank holidays.

More robust results were obtained in these scenarios, especially during non-working days and during night hours on working days. Once again, an inverse relationship between demand and cost can be observed in several hours. This means that, in those cases, higher demand is associated with lower restriction costs. This result is particularly relevant because it suggests that, during certain low-demand hours, an increase in consumption could contribute to reducing the need for restrictions and, consequently, the associated costs.

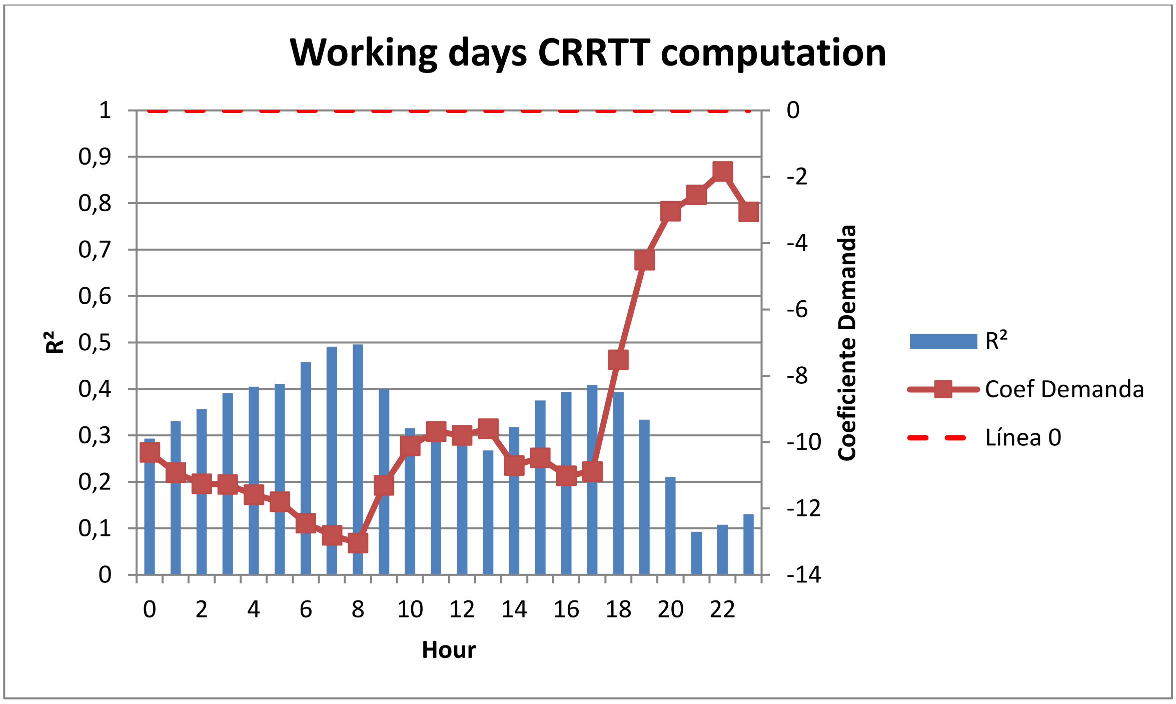


Figure 62: Multiple regression model for upward energy activated in PDBF in 2024 by hours of labor days. Source: Own elaboration.

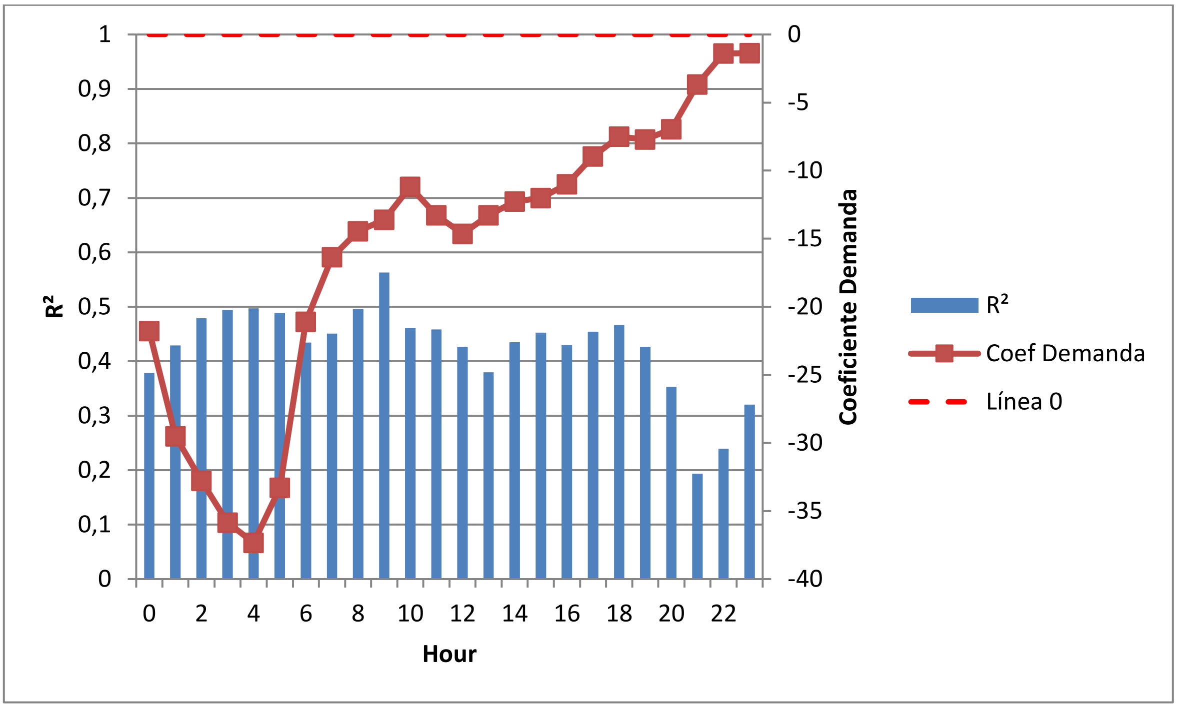


Figure 63: Multiple regression model for upward energy activated in PDBF in 2024 by hours in non-labor days. Source: Own elaboration.

4.3.2 REAL TIME MULTIPLE REGRESSION MODELS FOR ENSRRTT TR

In the real-time analysis, the models generally present higher R^2 values than in the previous scenarios. This is consistent with the nature of real-time restriction costs, since these costs are more closely linked to the actual operating conditions of the system. Real-time models capture deviations, technical constraints and balancing needs that appear closer to the physical operation of the system. Therefore, a higher explanatory capacity is expected when real-time variables are used.

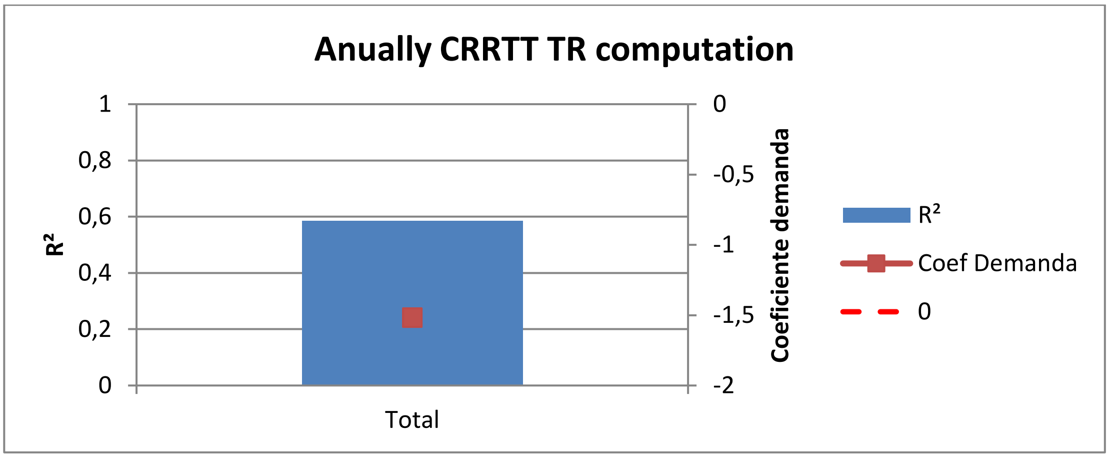


Figure 64: Multiple regression model for upward energy activated in RT in 2024 annually computed. Source: Own elaboration.

The annual real-time model shows a higher degree of robustness than the previous analyses, with an R-squared value close to 0,6. This result suggests, as expected, that real time variables are more suitable to explain the costs, which is consistent with the fact that these costs are linked to the actual operation of the system.

The next step was to disaggregate by month to see if we were able to find a direct relationship between the cost and the demand. When the model is disaggregated by month, the R-squared values remain above 0,5 in most of the central months of the year. This confirms that the real time approach improves the robustness of the models compared with previous scenarios.

Nevertheless, the demand coefficient does not show a stable pattern across the months. In some months, the coefficient is positive, while in others it becomes negative. This indicates that the relationship between demand and cost is not homogeneous throughout the year. The behavior of CRRTT costs in real time may be affected by other operational factors, such as renewable generation patterns, network constraints, deviations or specific technical restrictions. Therefore, although the model is more robust in terms of R-squared, the demand coefficient cannot be interpreted as a stable allocation signal at the monthly level.

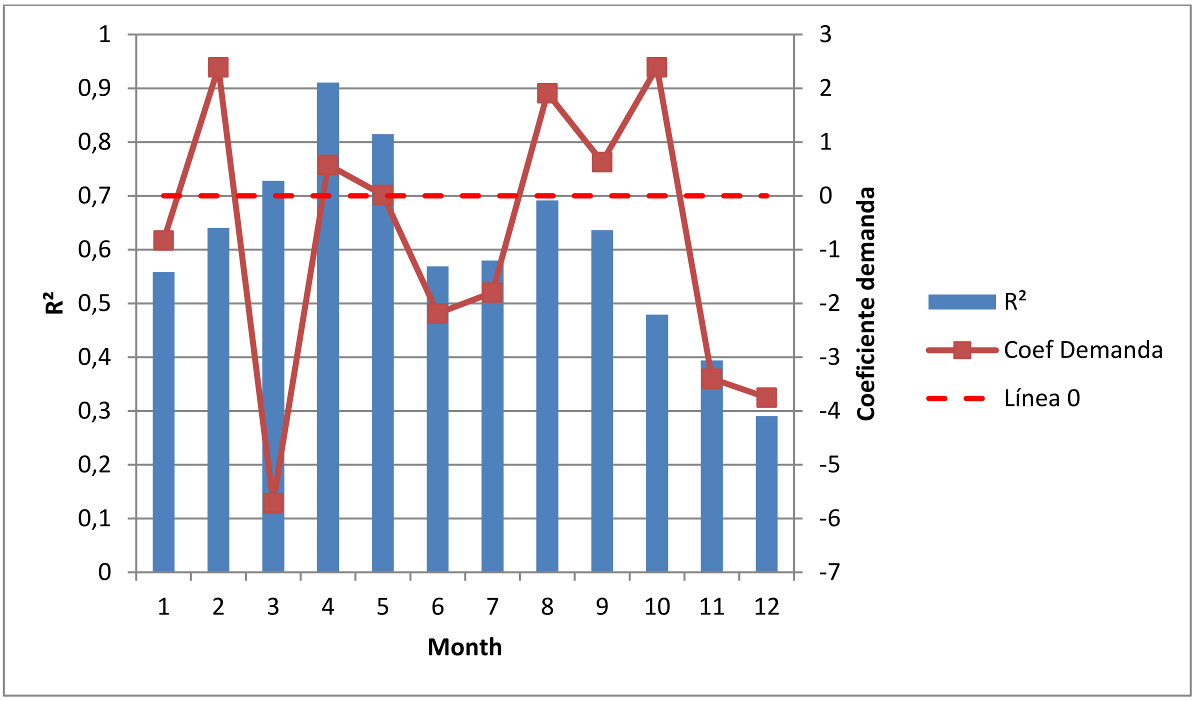


Figure 65: Multiple regression model for upward energy activated in RT in 2024 by month: Source: Own elaboration.

The disaggregation according to P6 and non P6 periods also provides robust R-squared values. The demand coefficient is negative in both cases, but the inverse relationship appears to be stronger outside P6. This effect was expected to be found during P6 hours, but not outside them. To analyze this in depth, a disaggregation by month and period was made.

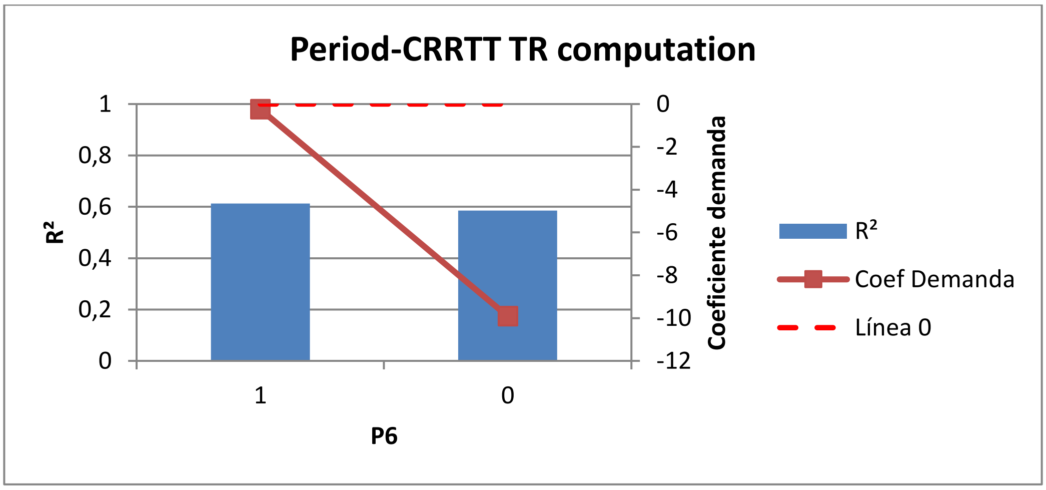


Figure 66: Multiple regression model for upward energy activated in RT in 2024 by period. Source: Own elaboration.

When this disaggregation is made, the demand coefficient is highly unstable across the year. In particular, a strong negative peak is observed in June, while other months show much weaker or even positive coefficients.

This suggests that the apparent inverse relationship between demand and cost may be driven by specific monthly events rather than by a stable structural relationship. The peak observed in June may reflect exceptional operating conditions, such as specific network constraints, renewable generation variability, deviations or technical restrictions concentrated in that period. Without additional operational information, it is not possible to attribute this behavior directly to demand. In P6, the monthly disaggregation also presents high R-squared values in several months. However, the demand coefficient does not follow a clear or stable pattern. In some months, the coefficient is positive, in others it is negative, and in several cases, it remains close to zero. In addition to this, variations were also observed across different years for the same month[15]. Therefore, the P6 obtained model should be interpreted with caution.

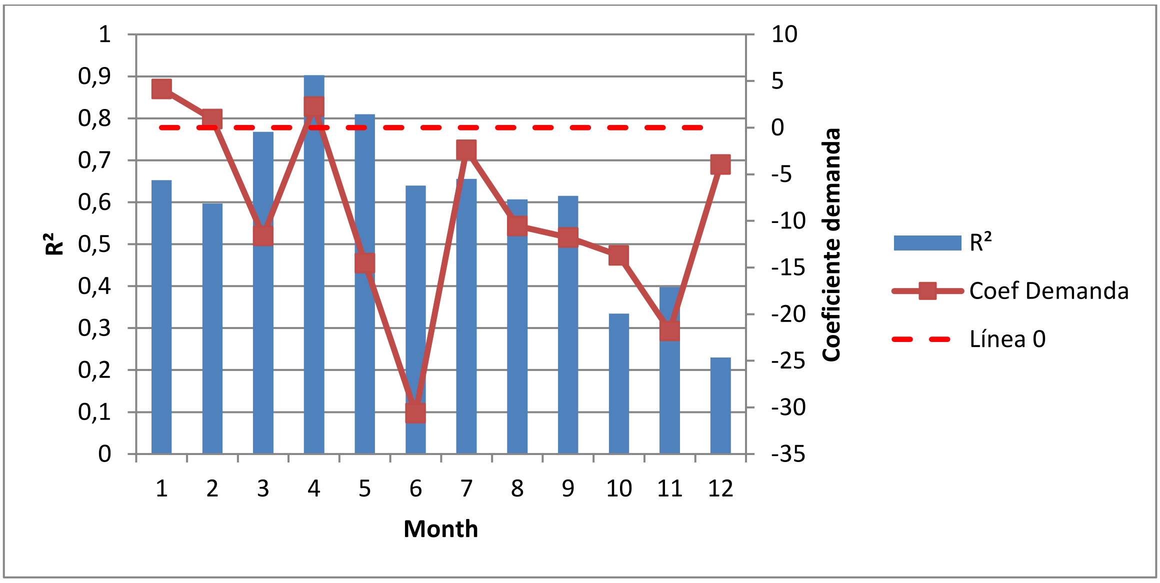


Figure 67: Multiple regression model for upward energy activated in RT in 2024 by month outside P6. Source: Own elaboration.

[15] Go to annex II for more information.

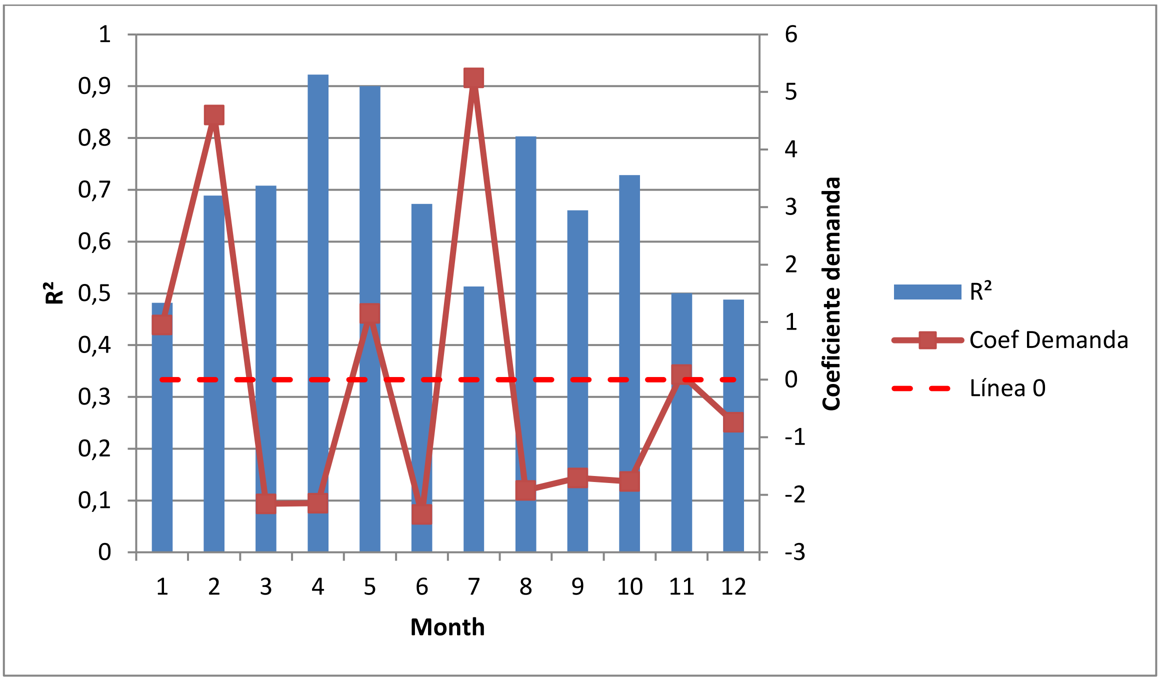


Figure 68: Multiple regression model for upward energy activated in RT in 2024 by month in P6. Source: Own elaboration.

The hourly disaggregation for working days shows high R-squared values in many hours, especially during the night and daytime hours. However, the demand coefficient remains close to zero or slightly positive in many hours, which suggests that changes in demand do not have a strong effect on costs during most of the day. Negative coefficients are mainly observed in the final hours of the day, where higher demand appears to be associated with lower costs. Nevertheless, this pattern is not consistent enough across all hours to support a general conclusion.

For non-working days, the hourly model also presents high R-squared values in several hours, especially during the first part of the day and in some afternoon periods. However, as it happened before, the demand coefficient does not show a stable relationship with costs. In most hours, the coefficient remains close to zero, while some negative peaks are observed, particularly at the end of the day. These peaks may reflect specific operating conditions rather than a relationship between cost and demand.

Overall, the real-time models provide more robust results than the previous scenarios, which is consistent with the operational nature of CRRTT costs. However, the relationship between demand and cost is not stable across the different disaggregation levels. Some results appear to be influenced by specific peaks, such as those observed in June and July or in the final hours of the day. These peaks may be related to exceptional operating conditions and may distort the interpretation of the demand coefficient. Therefore, although the real-time models are useful to understand the behavior of the costs, they are not sufficiently stable to be used as a direct allocation methodology.

As no clear relationship using the previous models was found, the next approach was to try to find relationship among pairs of variables using simple regression models.

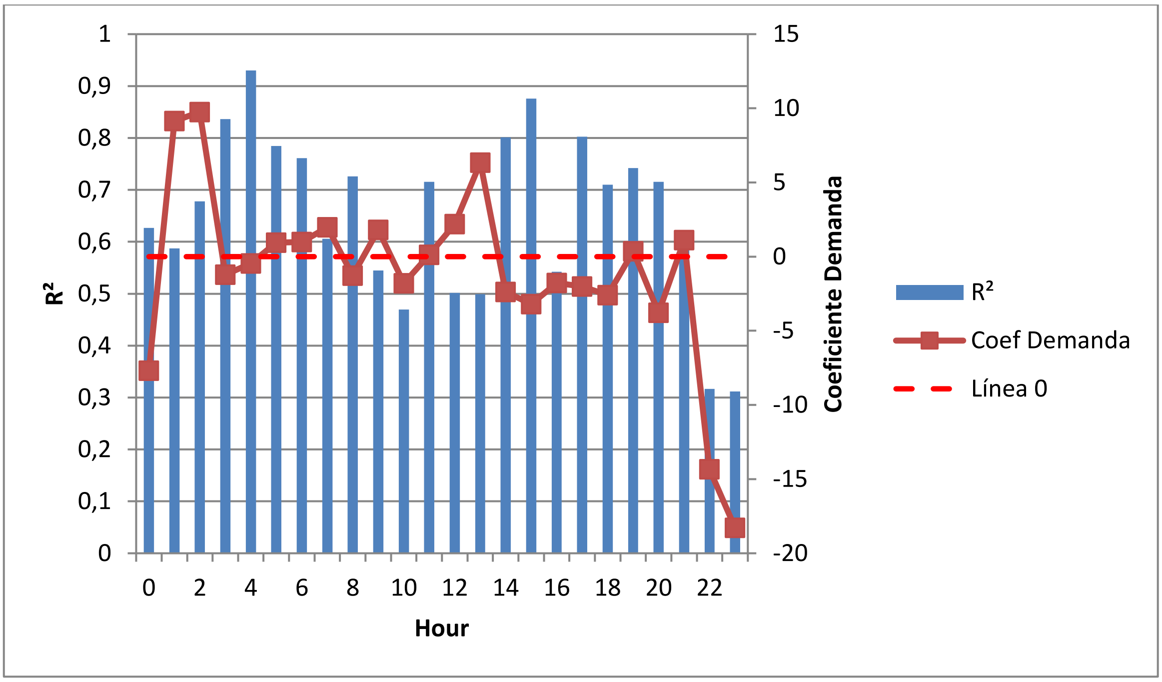


Figure 69: Multiple regression model for upward energy activated in RT in 2024 in working days. Source: Own elaboration.

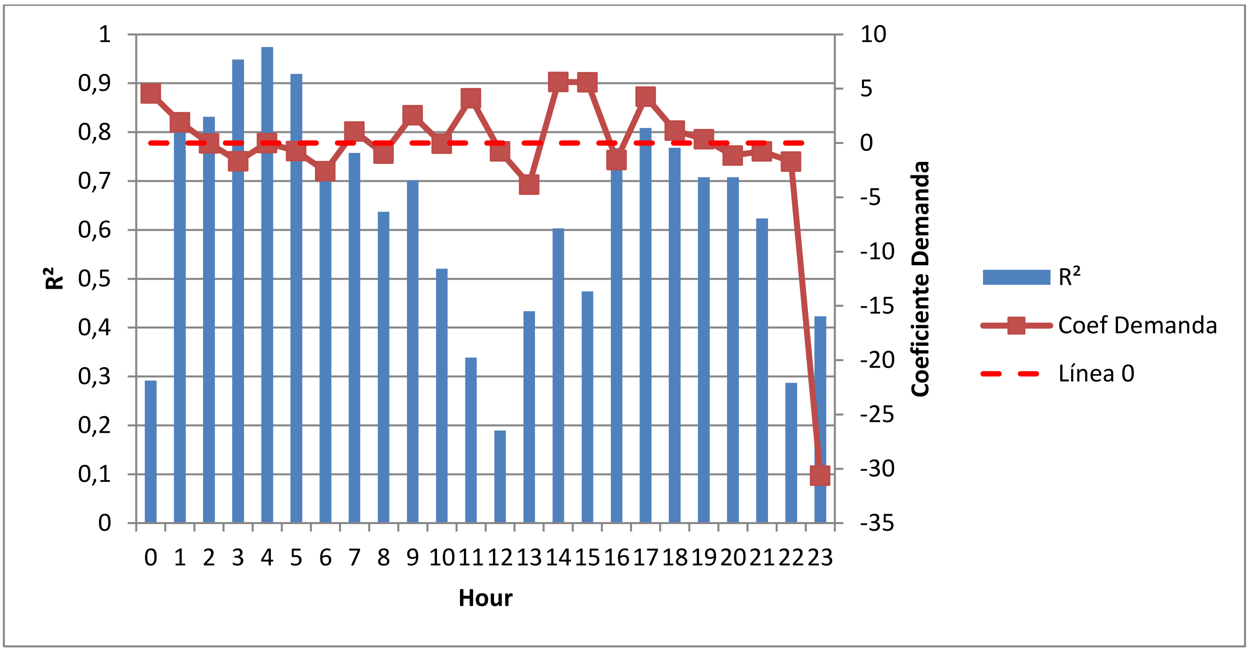


Figure 70: Multiple regression model for upward energy activated in RT in 2024 in non-working days. Source: Own elaboration.

4.3.3 PDBF SIMPLE REGRESSION MODELS

As with the complex regression models, the first analysis was carried out using the data from all the hours of the year:

PDBF	*R2*	*X Coefficient*
ENSRRTTvsD	0,10	-0,071
PRTvsENSRRTT	0,20	-0,018
PRTvsD	0,0094	0,000907
PRTvsPMD	0,29	0,44
CRRTTvsENSRRTT	0,20	48,34
CRRTTvsD	0,22	-11,42

CRRTTvsPRT	0,085	-751,75
CRRTTvsPMD	0,17	-881,90

Table 1: R2 and X coefficient for annual regression models in PDBF for 2024. Source: Own elaboration.

No robust models were obtained in the initial analysis. For this reason, a monthly disaggregation was carried out for each of the analyzed variables, in order to assess whether the relationship became clearer when seasonal or monthly effects were considered. However, the results remained weak. Among the different models, the highest R-squared values were obtained in the models relating CRRTT to demand and CRRTT to ENRRT. This suggested that both variables could contain some explanatory. Therefore, a final multiple regression model was estimated, including both demand and ENRRT as explanatory variables.

Nevertheless, this combined model did not provide robust results either. The explanatory capacity remained insufficient. For this reason, the analysis was redirected towards upward real time restrictions, where a more direct relationship was expected.

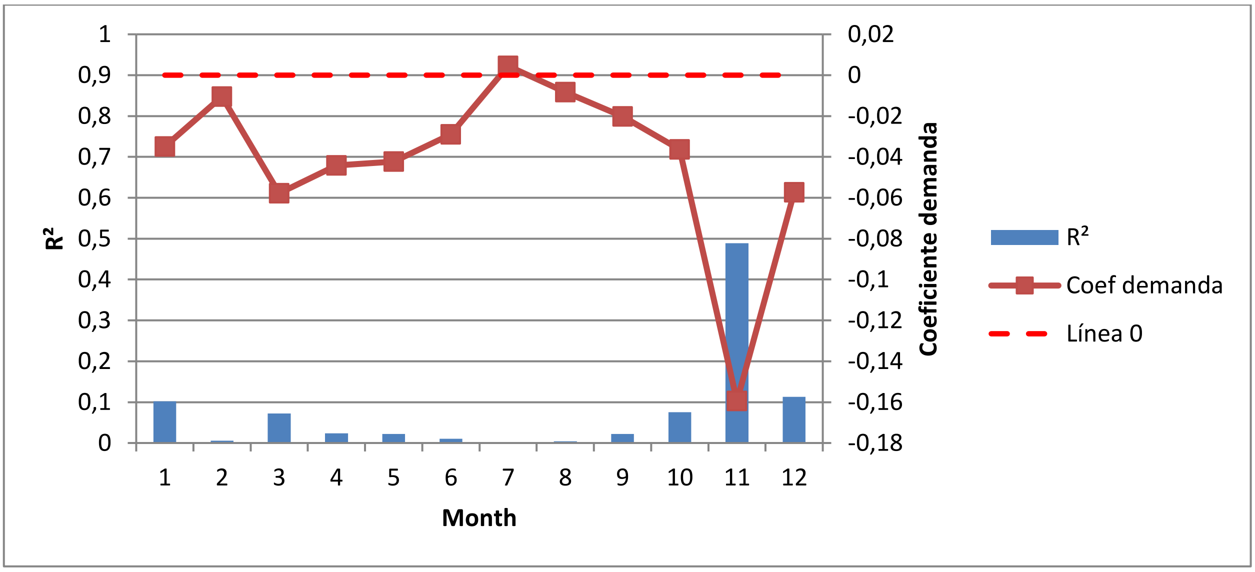


Figure 71: Simple regression models for 2024 in PDBF. Energy vs Demand. Source: Own elaboration.

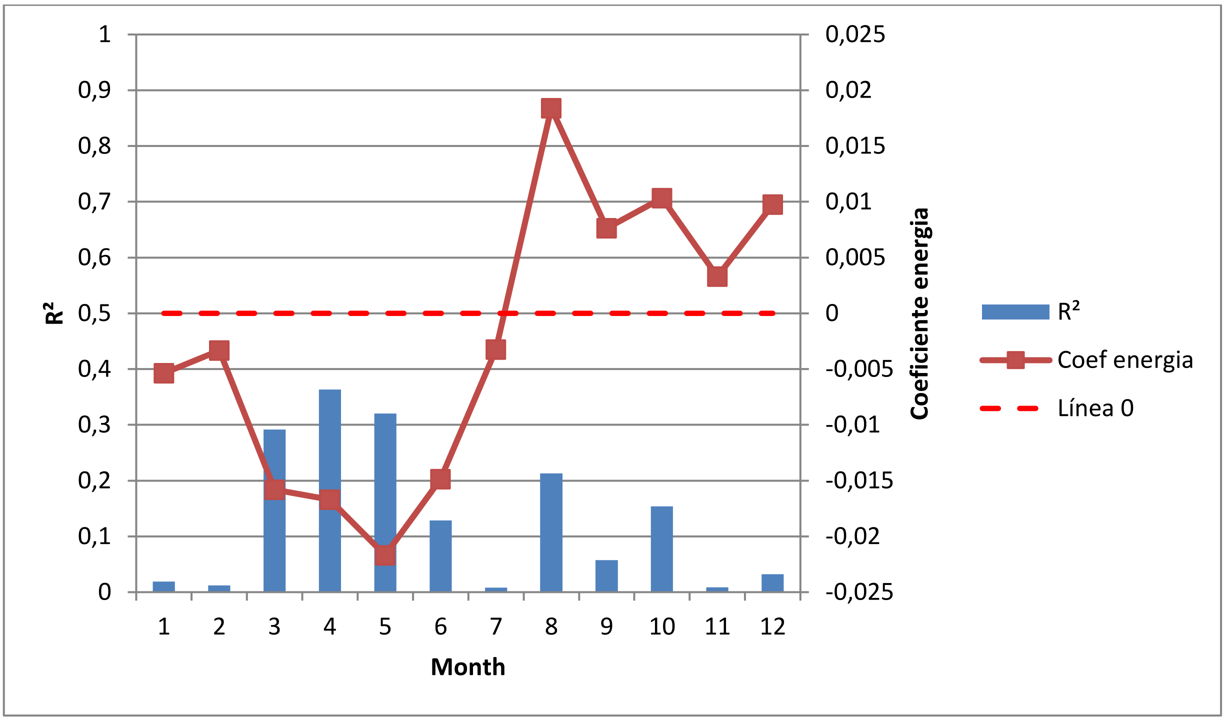


Figure 72: Simple regression models for 2024 in PDBF. PRRTT vs ENRRTT. Source: Own elaboration.

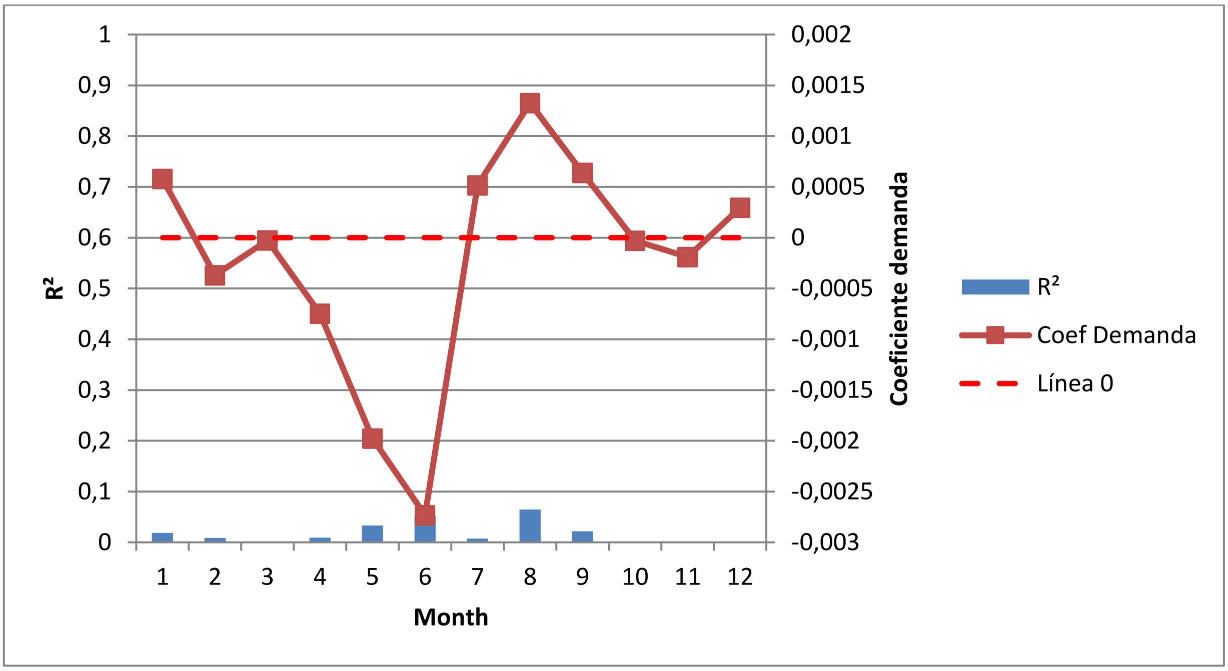


Figure 73: Simple regression models for 2024 in PDBF. PRRTT vs Demand. Source: Own elaboration.

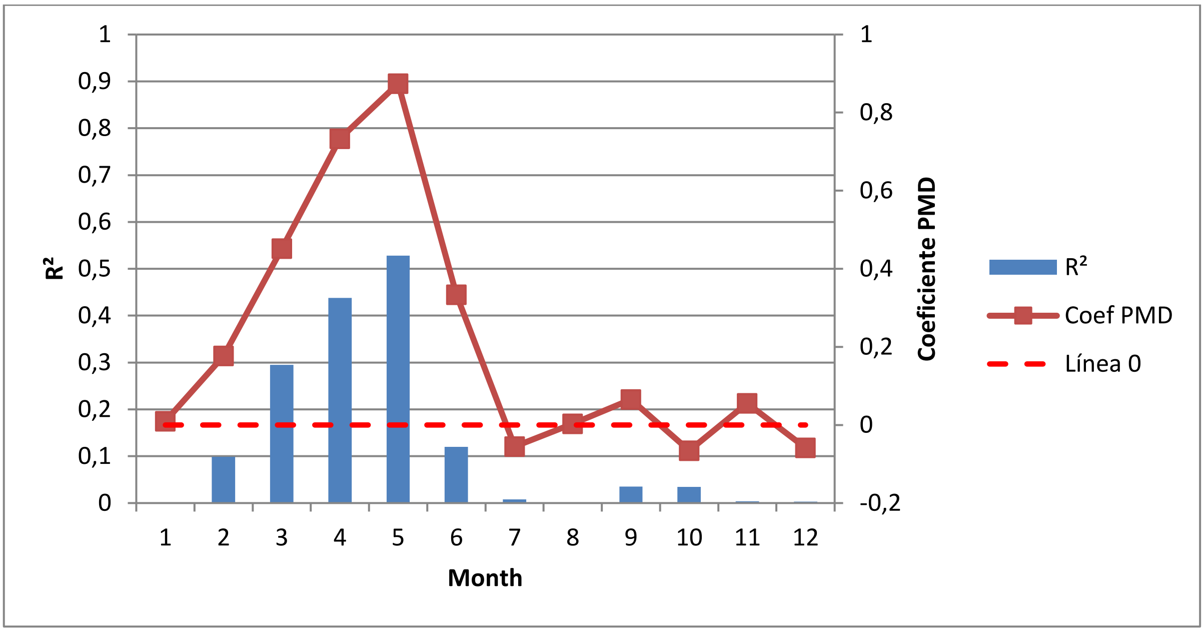


Figure 74: Simple regression models for 2024 in PDBF. PRRTT vs PMD. Source: Own elaboration.

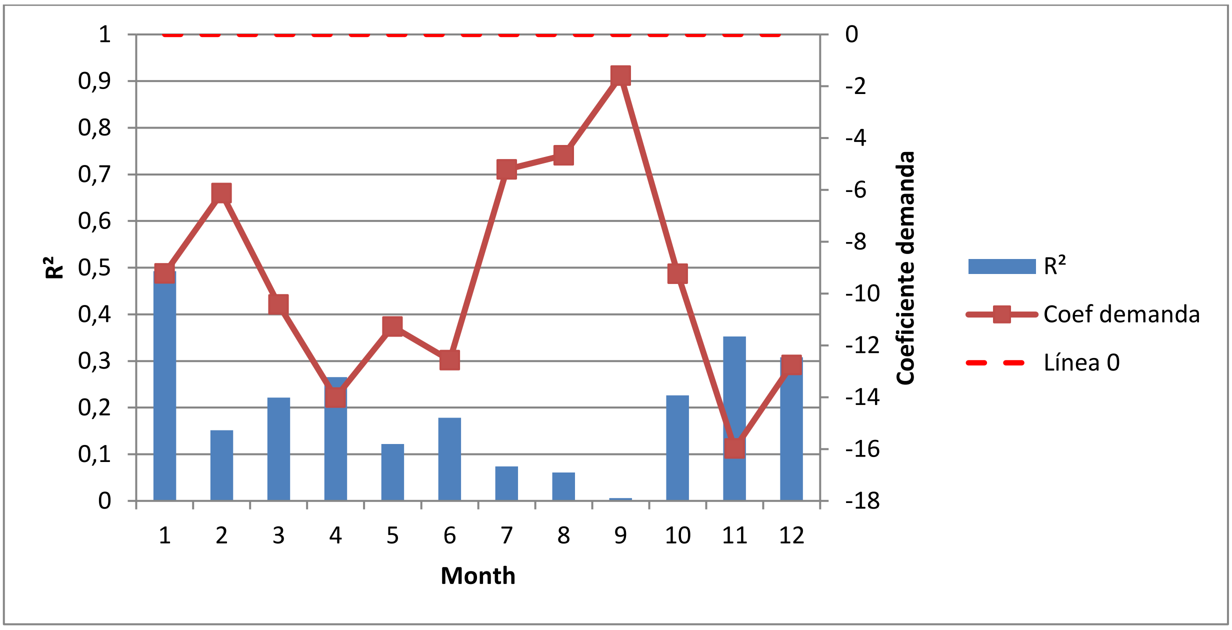


Figure 75: Simple regression models for 2024 in PDBF. CRRTT vs Demand. Source: Own elaboration.

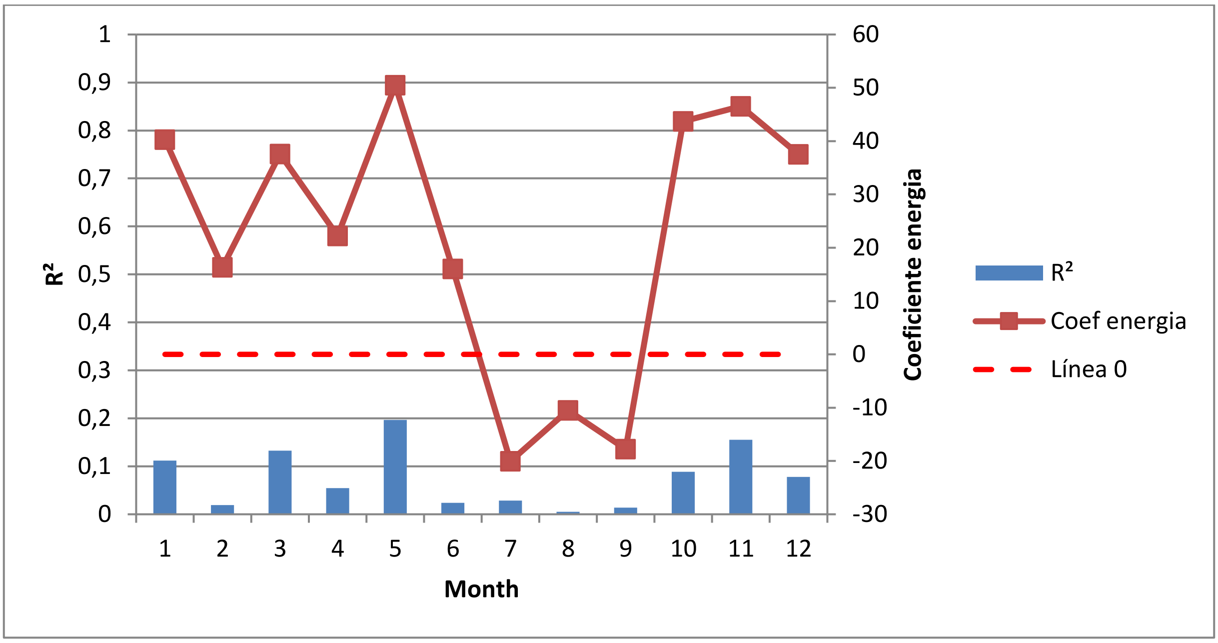


Figure 76: Simple regression models for 2024 in PDBF. CRRTT vs Energy. Source: Own elaboration.

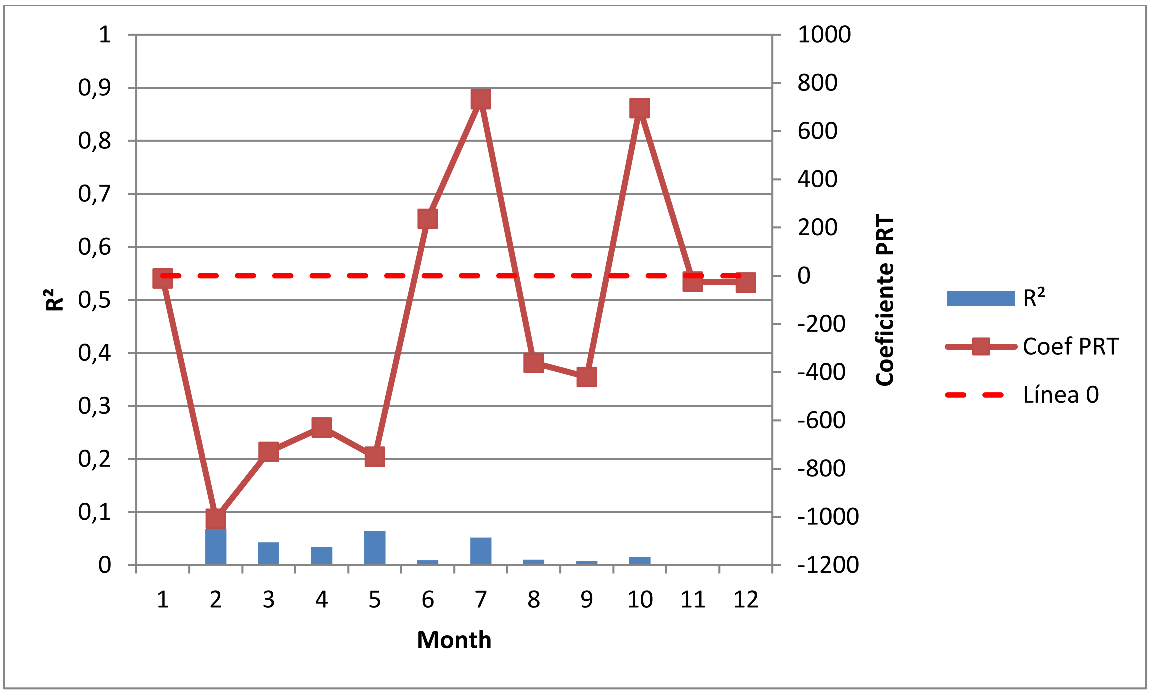


Figure 77: Simple regression models for 2024 in PDBF. CRRTT vs PRRTT. Source: Own elaboration.

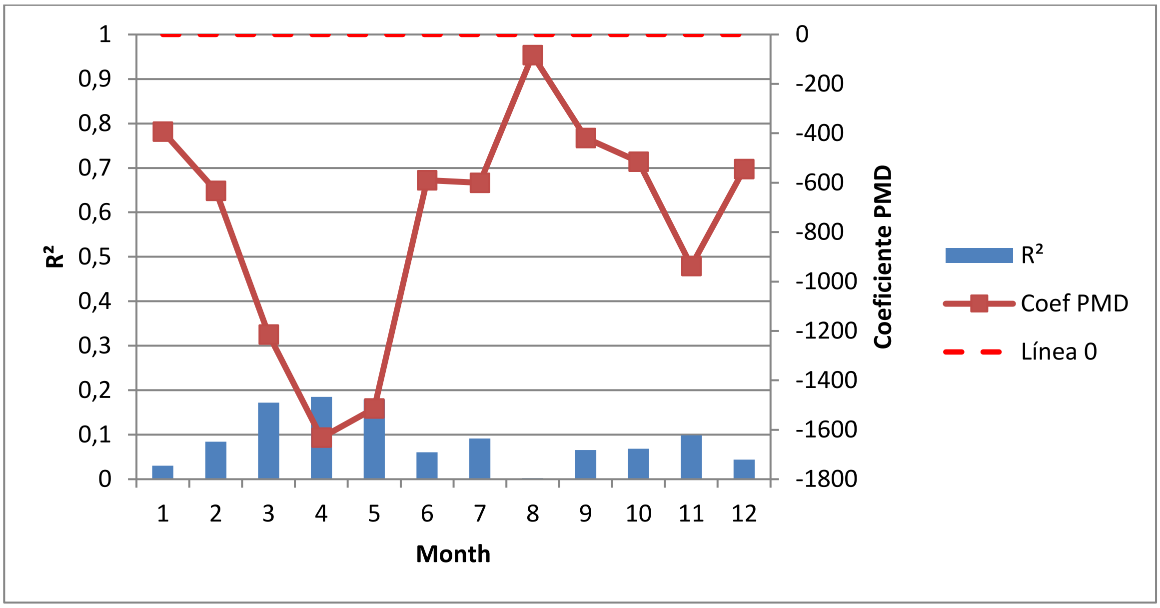


Figure 78: Simple regression models for 2024 in PDBF. CRRTT vs PMD. Source: Own elaboration.

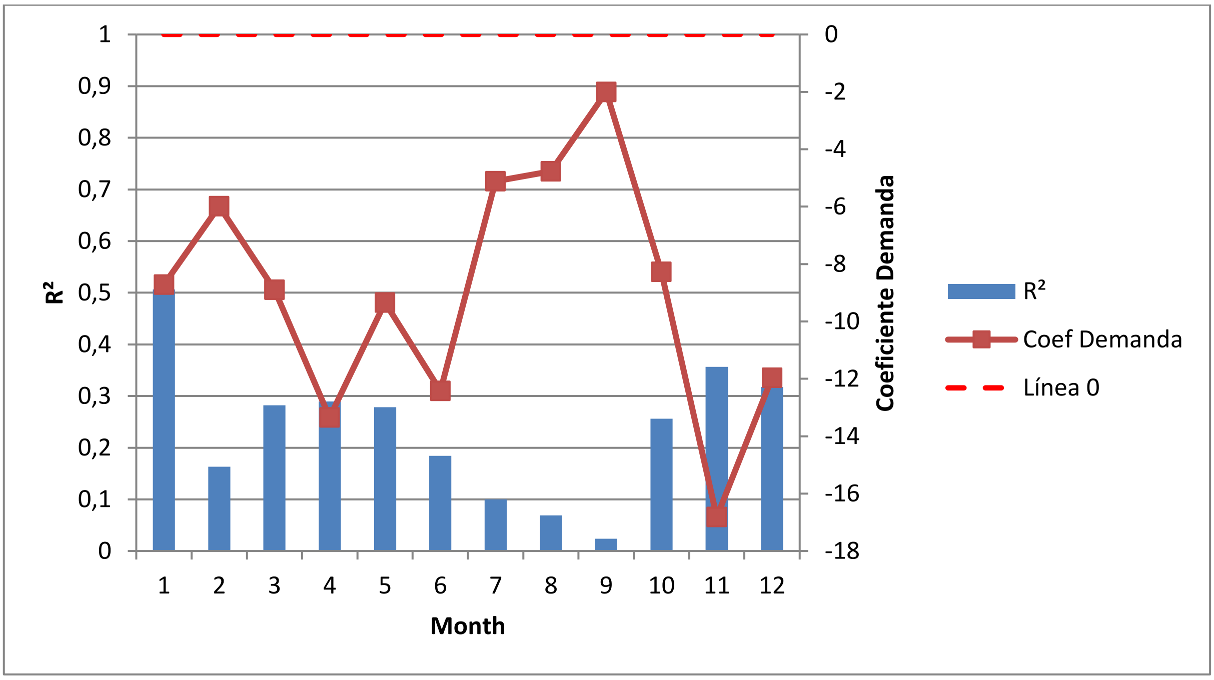


Figure 79: Simple regression models for 2024 in PDBF. CRRTT vs ENRRTT and Demand. Source: Own elaboration.

4.3.4 REAL TIME SIMPLE REGRESSION MODELS FOR THE YEAR 2024

As in the PDBF analysis, the first step was to estimate simple regression models for each explanatory variable individually. The results suggest that real time restriction costs may be explained **by the need of the resource** (amount of energy activated), since the most robust model was obtained for the relationship between CRRTT and ENRRTT.

In addition, relatively higher R-squared values were also obtained when analyzing the relationship between ENRRTT and demand, and between CRRTT and ENRRTT. Although these values are not high enough to consider the models fully acceptable, they should still be considered. This is because the difference between these results and the remaining models, whose R-squared values are close to zero, is significant. This suggests that there could be an intrinsic relationship among these variables, whose effect could be hindered due to price effects.

RT	***R2***	***X coefficient***
ENRRTTvsDemand	*0,23*	*0,1*
PRRTTvsENRRTT	0,00013	0,045
PRRTTvsDemand	1,9E-05	0,0026
PRRTTvsPMD	0,0017	2,27
CRRTTvsENRRTT	**0,71**	**136,43**
CRRTTvsDemand	*0,15*	*13,37*
CRRTTvsPRRTT	0,0014	2,18
CRRTTvsPMD	0,032	529,62

Table 2: Annual simple regression models in 2024 for Real Time. Source: Own elaboration.

The next step in finding a relationship among these variables was to disaggregate them by month. In the first model, real time energy was regressed against demand. The obtained R-squared values are not high enough for the model to be considered robust. However, the demand coefficient is positive throughout the year, which suggests that higher demand is associated with a higher need for activated energy. This indicates that demand may be related to the need for the resource, even if the relationship is not strong enough to be used as a direct explanatory model.

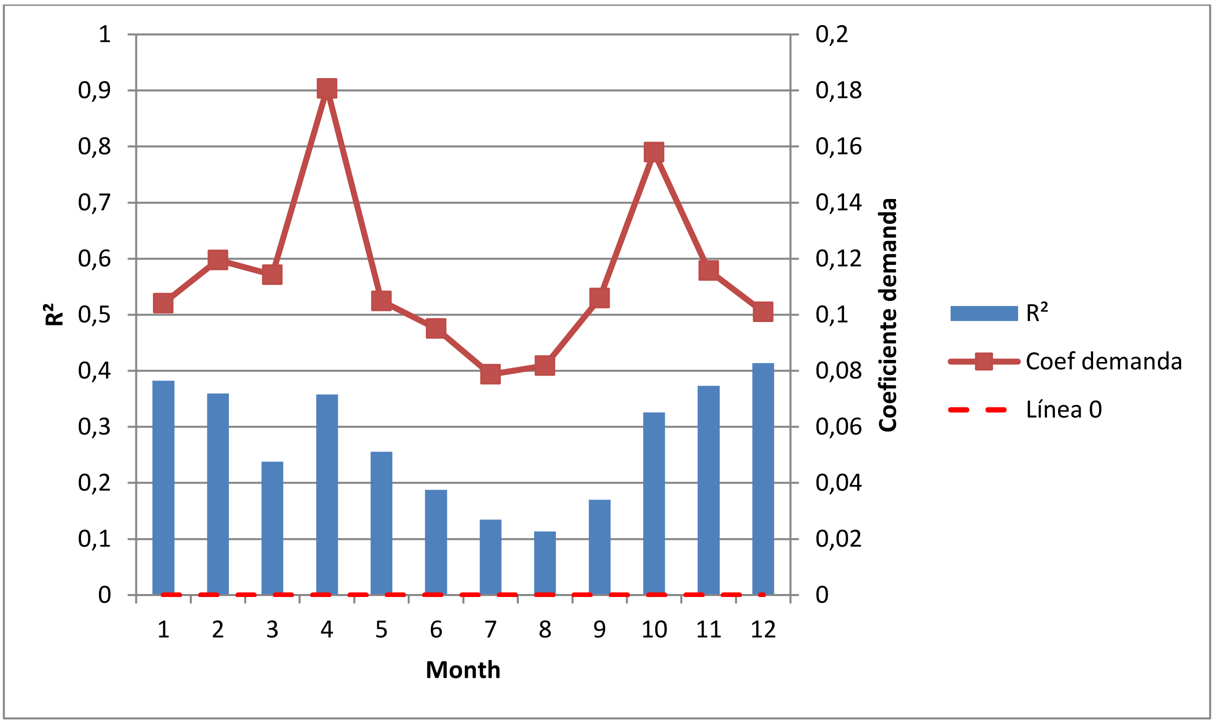


Figure 80: Simple regression models in 2024 for Real Time ENRRTT vs Demand. Source: Own elaboration. Source: Own elaboration.

The next model analyses PRRTT against demand. In this case, the R-squared values are almost zero.

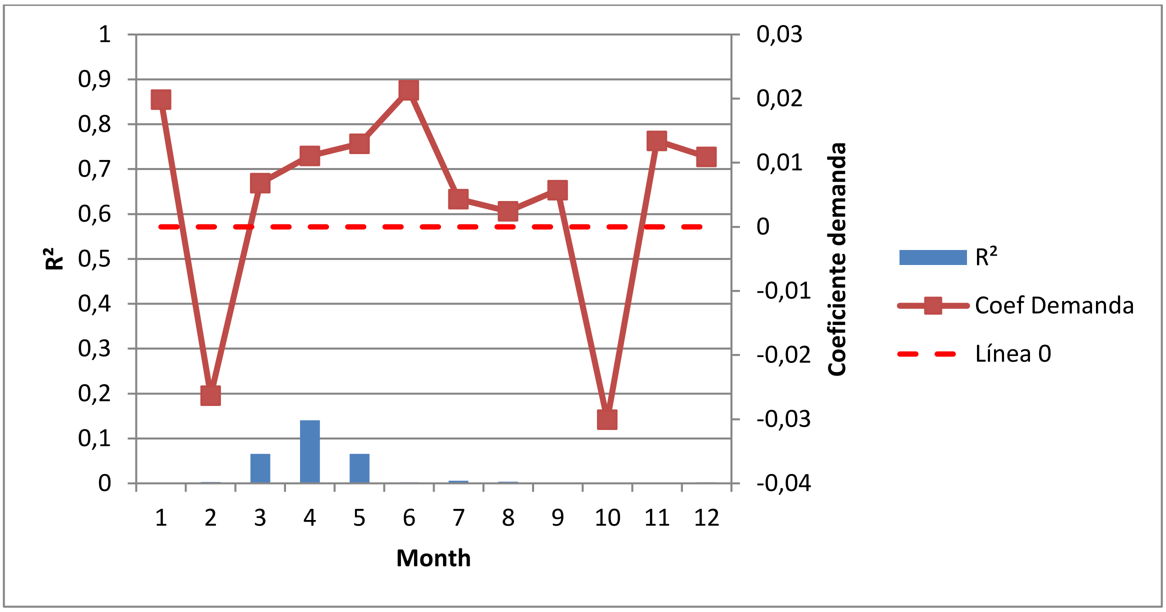


Figure 81:Simple regression models in 2024 for Real Time PRRTT vs Demand. Source: Own elaboration.

The model between PRTT and energy also presents very low R-squared values. Therefore, the price component of the cost appears to introduce additional variability that is not captured either by demand or by energy alone.

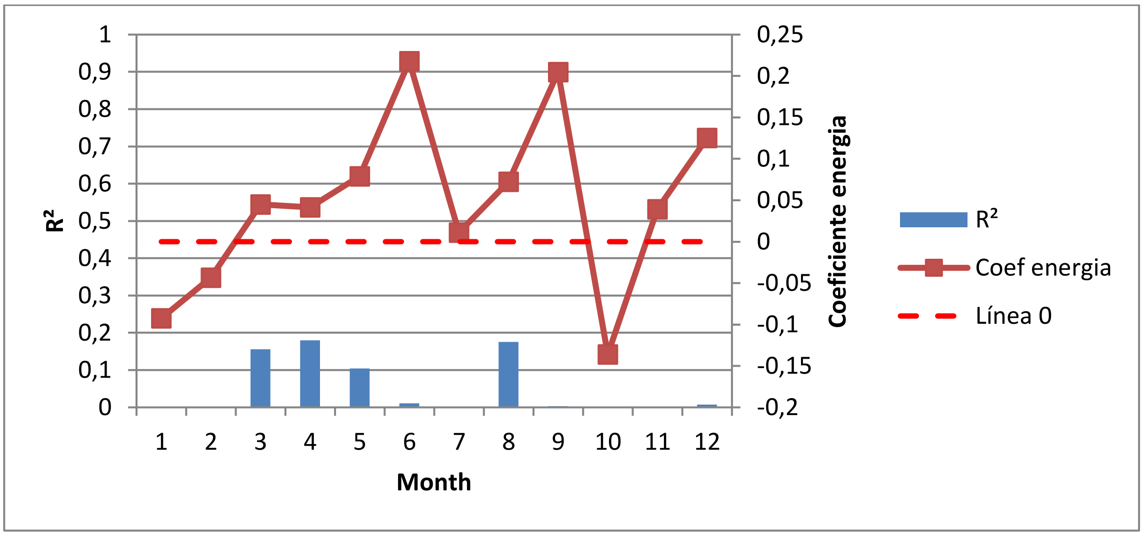


Figure 82: Simple regression models in 2024 for Real Time PRRTT vs ENRRTT. Source: Own elaboration.

The models based on price variables present low explanatory capacity, despite showing high coefficients. This is reasonable, since an increase in price directly increases the final cost.

However, the low R-squared values suggest that price alone does not capture the variability of the cost.

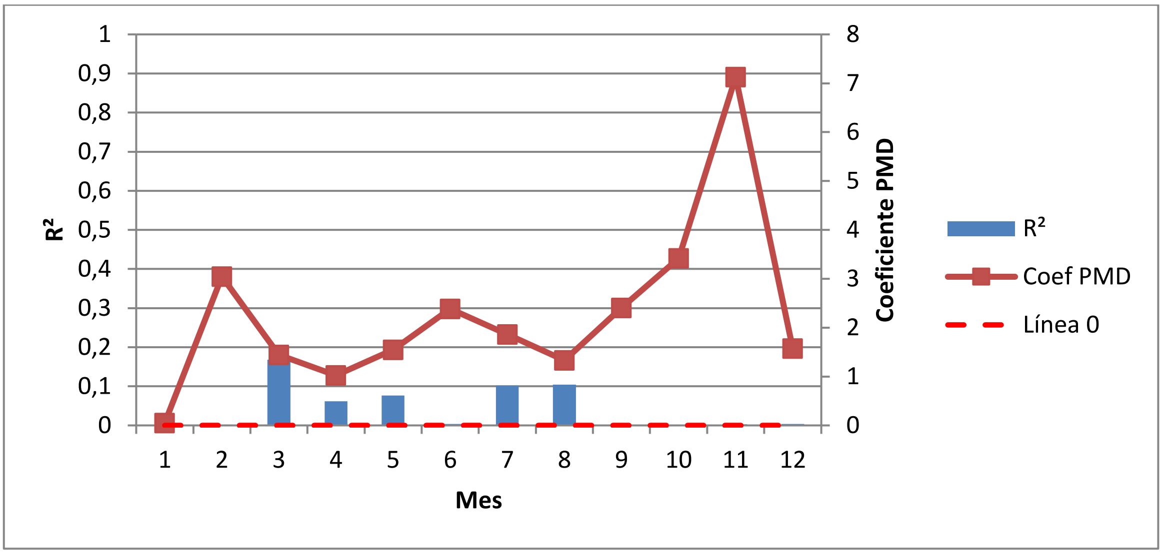


Figure 83: Simple regression models in 2024 for Real Time PRRTT vs PMD. Source: Own elaboration.

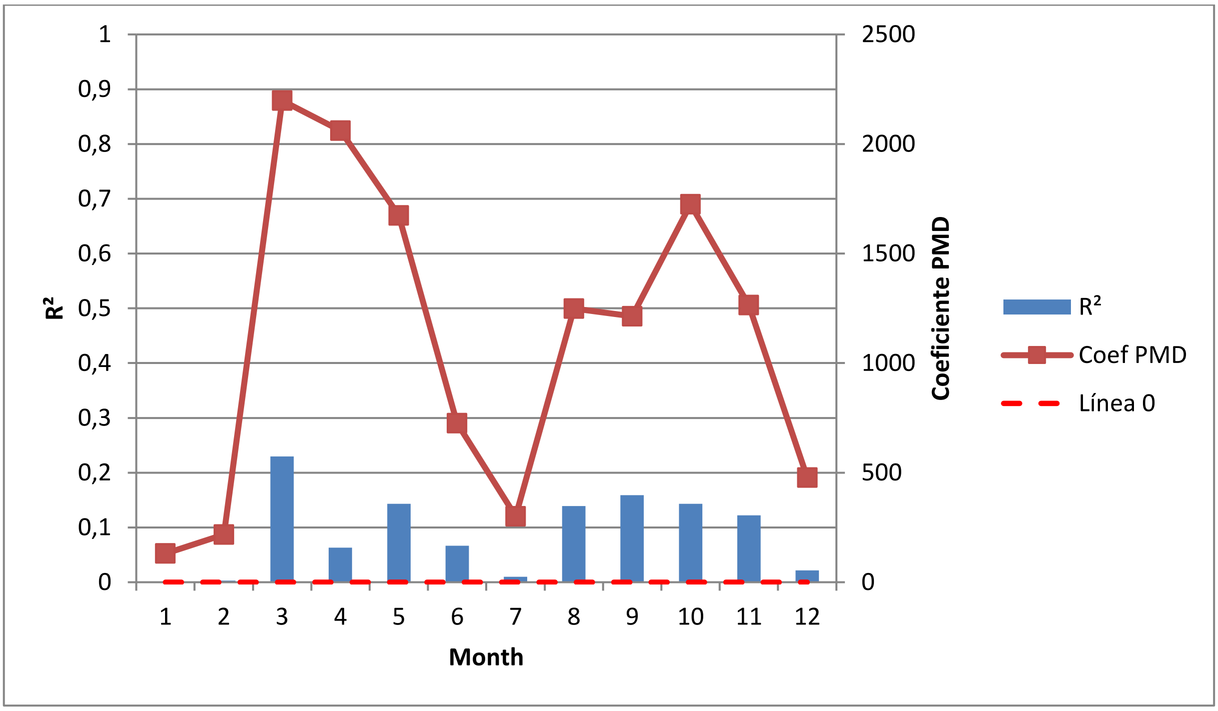


Figure 84: Simple regression models in 2024 for Real Time CRRTT vs PMD. Source: Own elaboration.

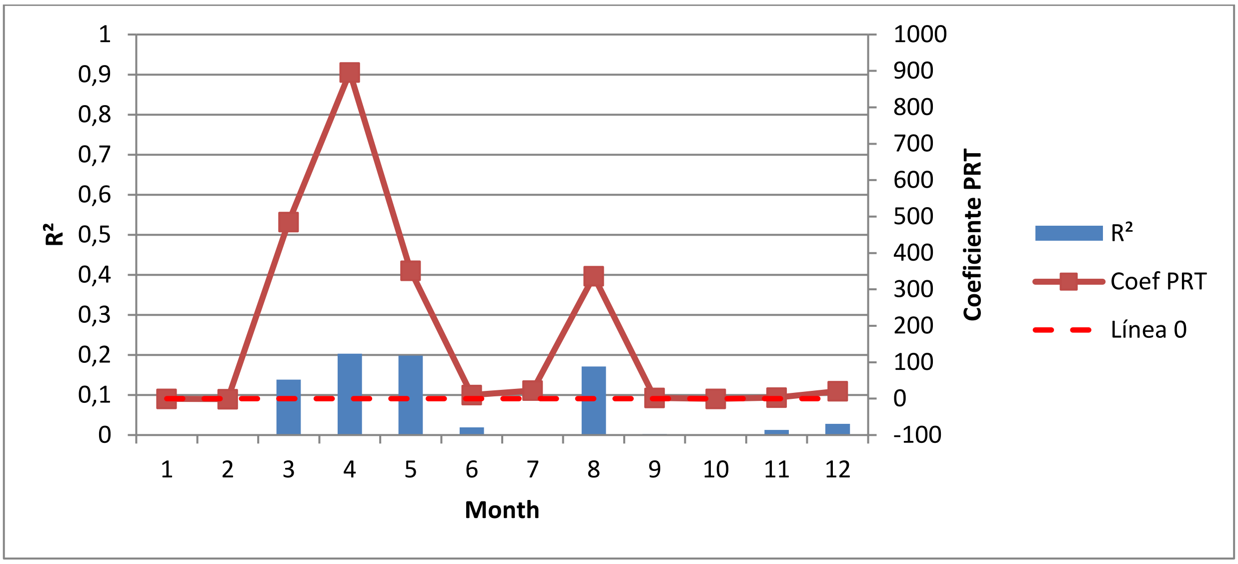


Figure 85 : Simple regression models in 2024 for Real Time CRRTT vs PRRTT. Source: Own elaboration.

A clearer result is obtained in the model between CRRTT and energy. In this case, the R-squared values are significantly higher and much more stable across the year. This indicates that activated energy is the variable with the strongest explanatory capacity. The energy coefficient is positive, meaning that higher activated energy is associated with costs. This result is consistent with the nature of these costs, since the final cost is directly linked to the amount of energy that needs to be activated.

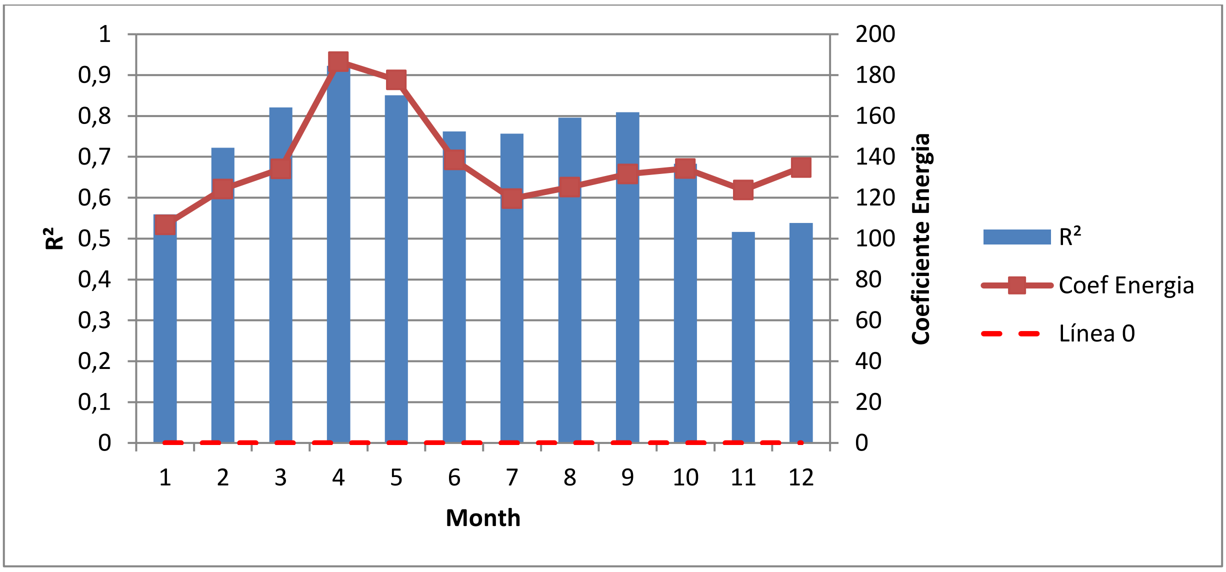


Figure 86: Simple regression models in 2024 for Real Time CRRTT vs ENRRTT. Source: Own elaboration.

The model between CRRTT and demand presents weaker results than the model based on energy. The R-squared values are not high enough to consider the model robust, although they are higher than those obtained for the price variables. This suggests that demand may contain some relevant information, but it is not the direct driver of the cost.

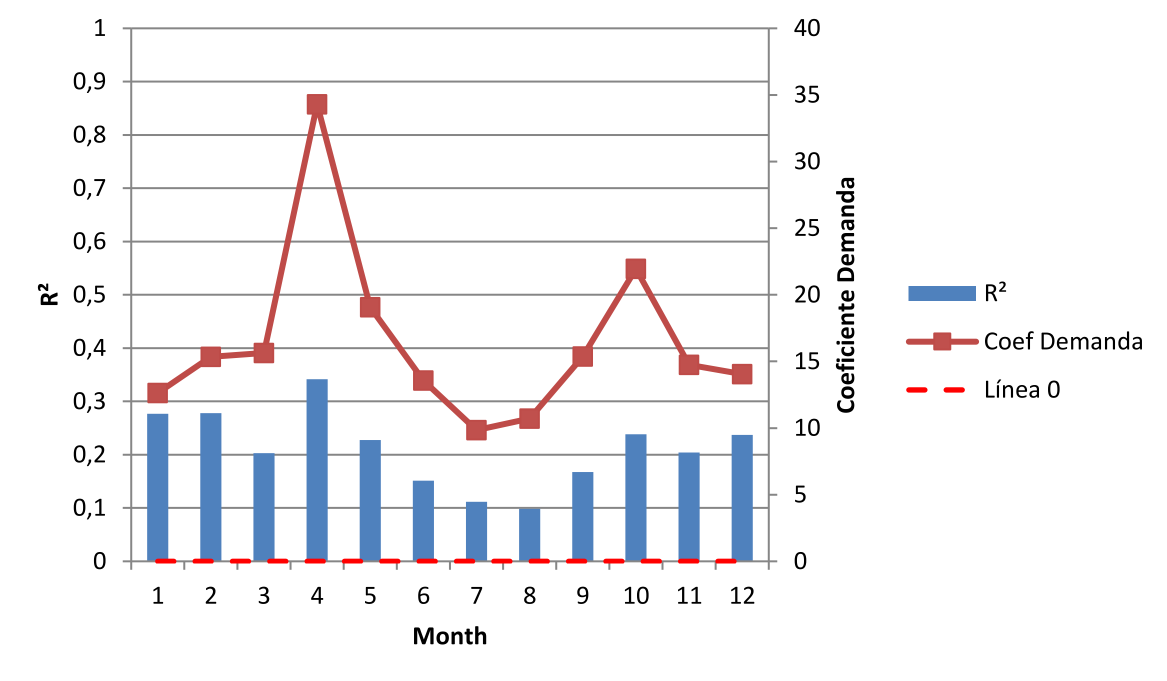


Figure 87: Simple regression models in 2024 for Real Time CRRTT vs Demand. Source: Own elaboration.

To test whether demand provided additional information beyond activated energy, a multiple regression model was estimated, including both variables as explanatory variables. The results show that the R-squared values remain very close to those obtained in the model based only on activated energy. Therefore, the inclusion of demand does not improve the explanatory capacity of the model. This suggests that demand and activated energy are closely related variables. Since activated energy is the variable that best explains the cost, and demand does not add relevant information once energy is included, part of the demand effect may already be captured through the activated energy variable. Therefore, the relationship between demand and cost appears to be indirect. Demand is related to the need for the resource, while the activated energy represents the need that produces the cost.

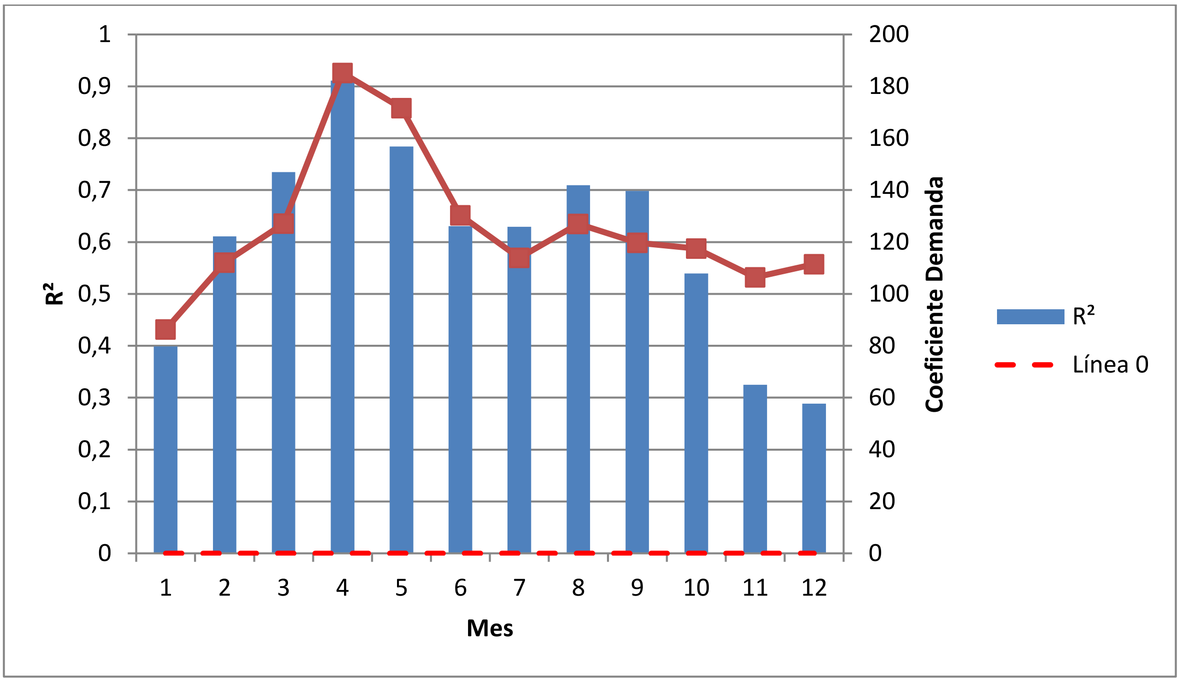


Figure 88: Simple regression models in 2024 for Real Time CRRTT vs Energy and demand. Source: Own elaboration.

Finally, two additional multiple regression models were estimated by differentiating between working and non-working days. The objective was to assess whether the indirect relationship between demand and cost became clearer when the hourly behavior of demand was analyzed separately for each type of day.

In the case of working days, the model presents high R-squared values, which confirms that the combination of activated energy and demand provides a reasonable explanation of the costs. However, the demand coefficient stays close to zero in most hours. This indicates that the cost is mainly explained by the amount of activated energy, while demand does not have a significant independent effect once energy is included in the model. A similar pattern is observed for non-working days.

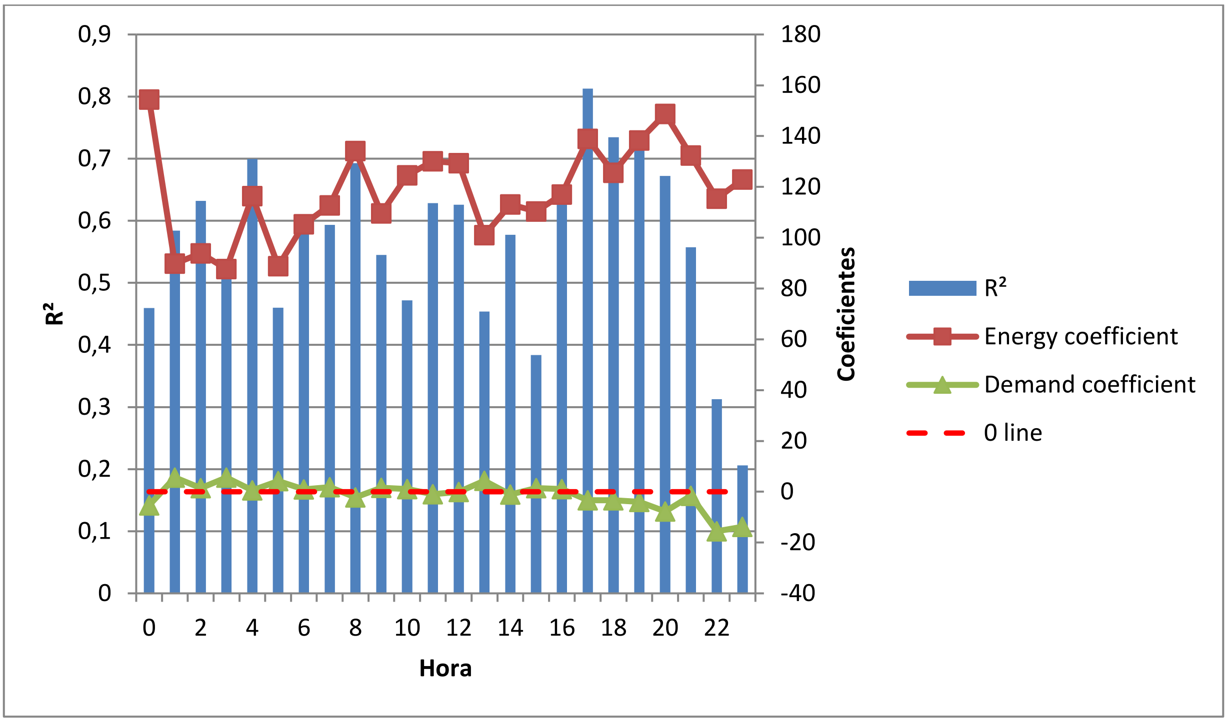


Figure 89: Simple regression model in real time for 2024 by hours of a working day CRRTT vs Energy and Demand. Source: Own elaboration.

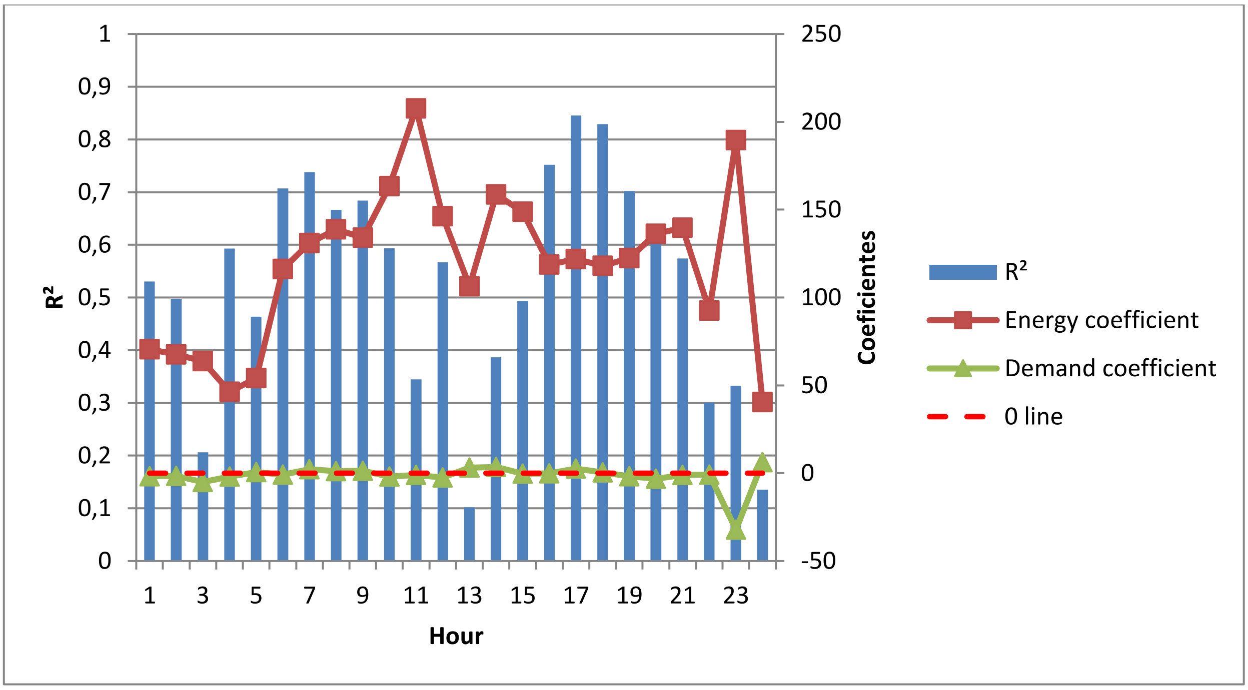


Figure 90: Simple regression model in real time for 2024 by hours of a non-working day CRRTT vs Energy and demand. Source: Own elaboration.

Overall, the results show that the need for the resource represented by the activated energy, is the variable that best explains the costs. However, demand should not be disregarded. The analysis suggests that demand and activated energy are intrinsically related, since changes in demand may contribute to the system conditions that require the activation of the resource. Nevertheless, this effect is not clearly captured when demand is analyzed directly against the cost, partly because the final cost also depends on the price component. Therefore, the impact of demand may be partially hidden by price effects, while being indirectly reflected through the activated energy variable.

4.3.5 PDBF DOWNWARD MULTIPLE REGRESSION MODELS

Since a clear pattern has not been found in the PDBF for the upward energy models, it is decided to compute the downward energy directly as a whole for the PDBF. The years 2023, 2024 and 2025 until the blackout were considered. The first model included the total number of hours for the different years.

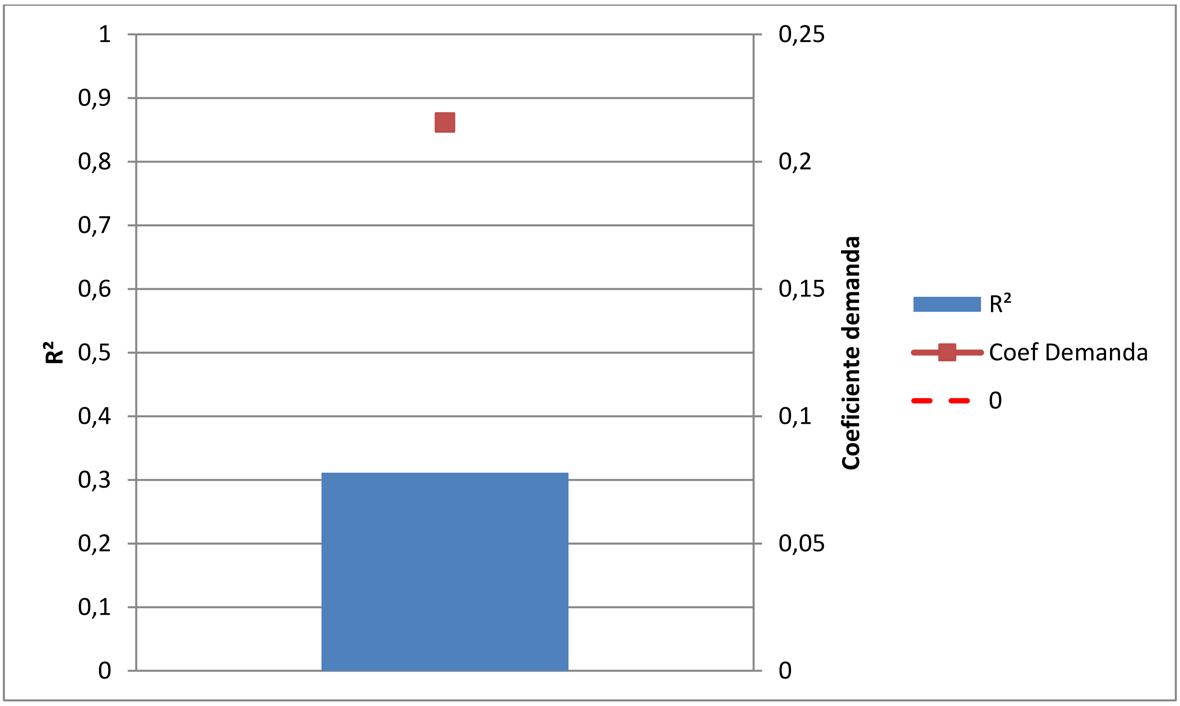


Figure 91: Downward multiple regression model for the total of years in PDBF. Source: Own elaboration.

The obtained R-squared value is low, around 0.3, which indicates that the model does not have enough explanatory capacity to be considered robust. For this reason, the analysis was further disaggregated by month.

When the model is disaggregated by month, the R-squared values improve significantly. However, the demand coefficient does not show a stable pattern. In most months, the coefficient remains close to zero, which suggests that variations in demand are not strongly associated with variations in the cost. In addition, a positive peak is observed in July. This peak may be related to specific operating conditions during that month, such as seasonal demand patterns, renewable generation conditions, network constraints or particular technical restrictions. Therefore, although the monthly models are more robust in terms of R^2, they do not provide a stable relationship between demand and downward restriction costs.

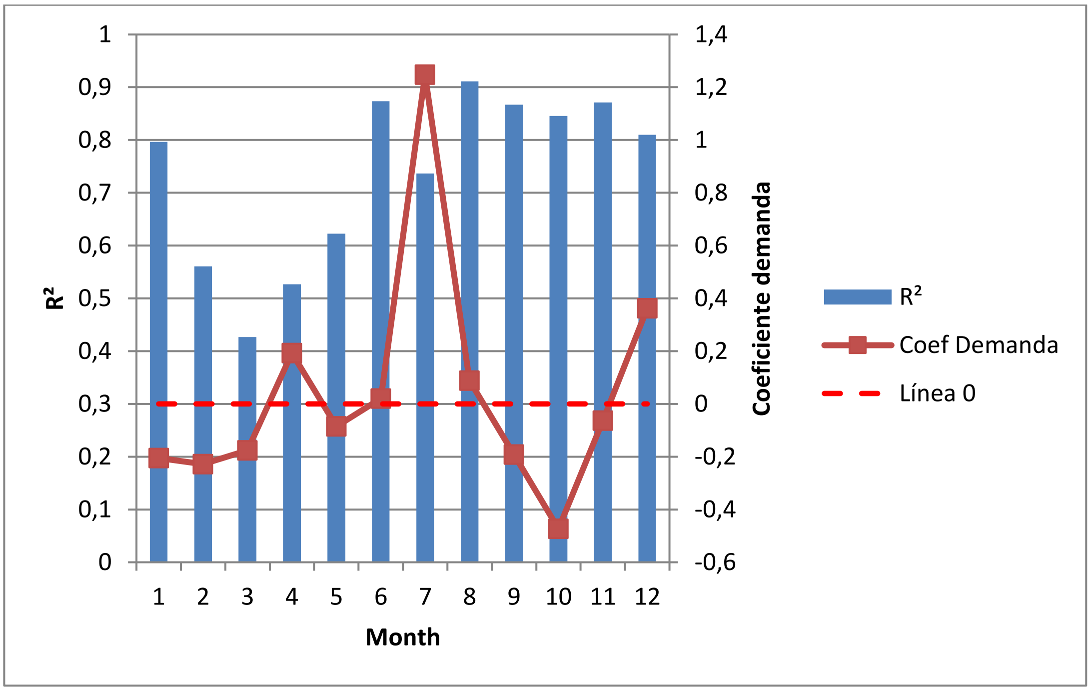


Figure 92: Downward multiple regression model for of years in PDBF by month. Source: Own elaboration.

The disaggregation between P6 and non P6 periods provides a more relevant result. In this case, the models show robust R-squared values. On top of that, the demand coefficient is negative in P6, whereas is positive outside P6. This suggests that, during P6 hours, higher demand may result in lower costs. This result is important because P6 corresponds to low-demand hours. If additional demand during these hours helps reduce the need for downward restrictions, allocating higher costs to these hours may send an inefficient economic signal.

Under the current allocation methodology, adjustment service costs increase final prices in the hours in which they occur. As a result, consumers may be discouraged from consuming during P6, even though higher demand in those hours could contribute to reducing the need for downward activation. This may create a reinforcing effect: higher costs increase prices, higher prices reduce demand in those hours, lower demand increases the need for downward restrictions, and this leads to higher costs again.

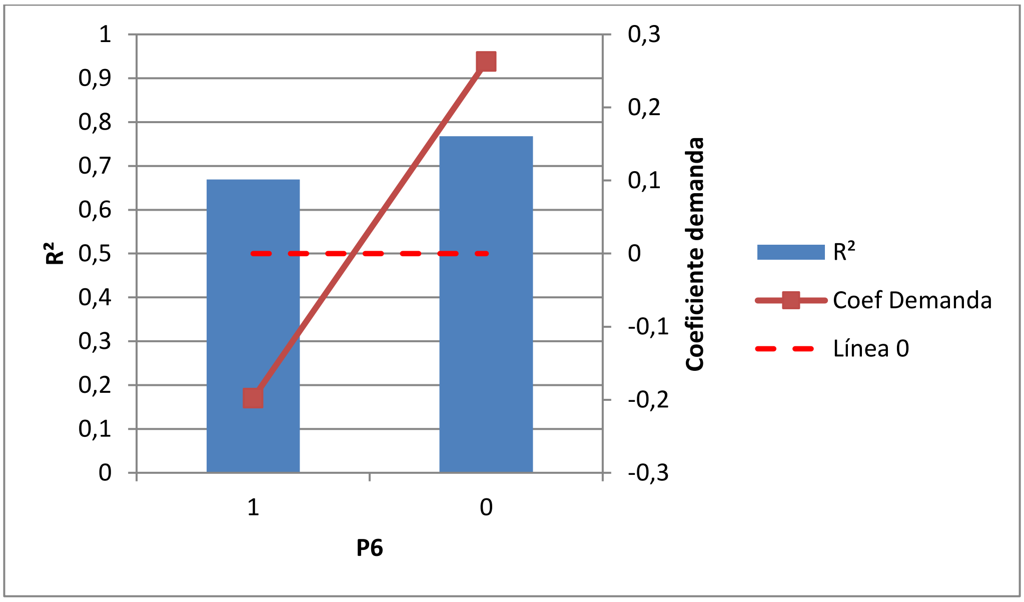


Figure 93: Downward multiple regression model for the total of years in PDBF by period. Source: Own elaboration.

To further analyze the effect observed in P6, the model was disaggregated by month, however no further conclusions can be extracted since the demand coefficient is not stable across the year. In some months it is negative, in others it is close to zero, and in the final months it becomes positive.

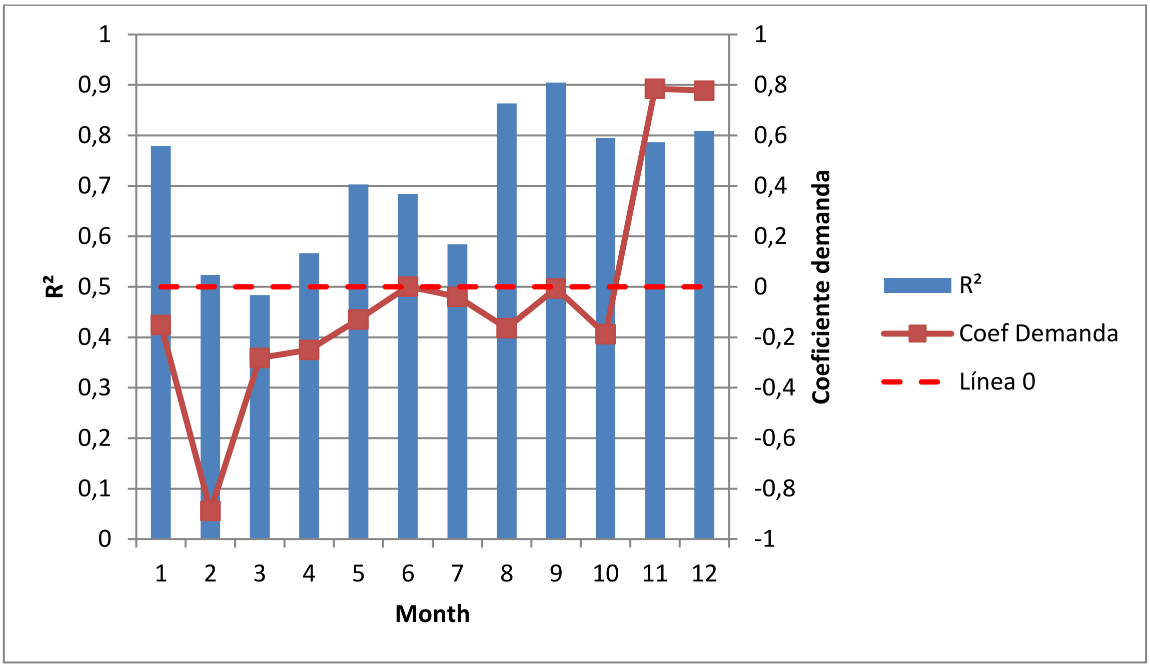


Figure 94: Downward multiple regression model for the total of years in PDBF by month in P6. Source: Own elaboration.

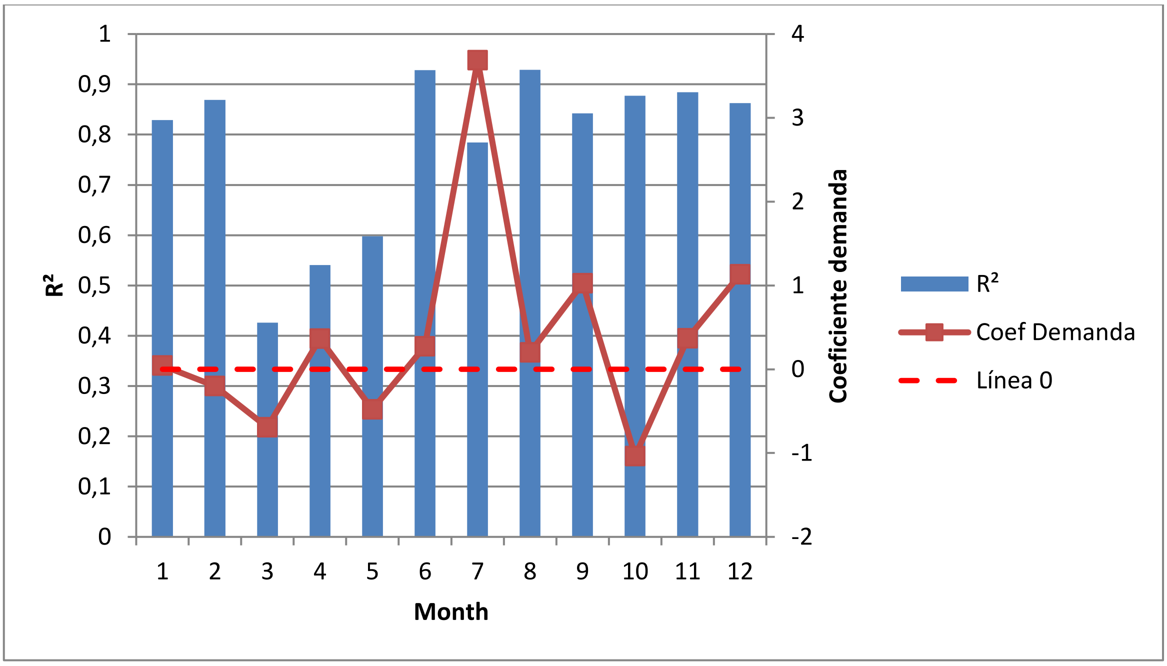


Figure 95: Downward multiple regression model for the total of years in PDBF by month outside P6. Source: Own elaboration.

4.3.6 REAL TIME DOWNWARD MULTIPLE REGRESSION MODELS

For downward restrictions in real time, the models generally present higher R-squared values than those obtained in PDBF. This result is expected, since real time models are closer to the actual operation of the system and therefore better capture the conditions under which restrictions are activated. In the Anex III downward real time computations for each year

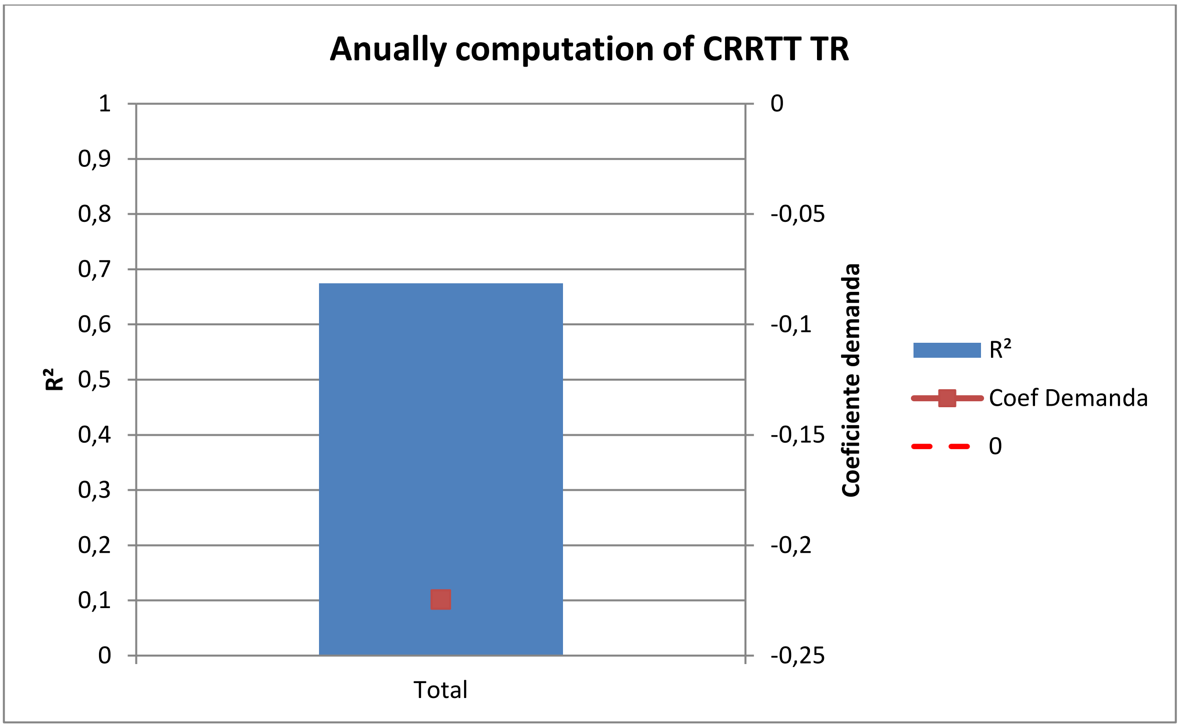


Figure 96: Downward multiple regression model for 2024 in real time. Source: Own elaboration.

When the model is disaggregated by month, the R-squared values improve in several months, especially in the central part of the year. However, the demand coefficient does not present a stable pattern. It changes across the months and remains close to zero. Therefore, although the models are more robust, the relationship between demand and cost is not found.

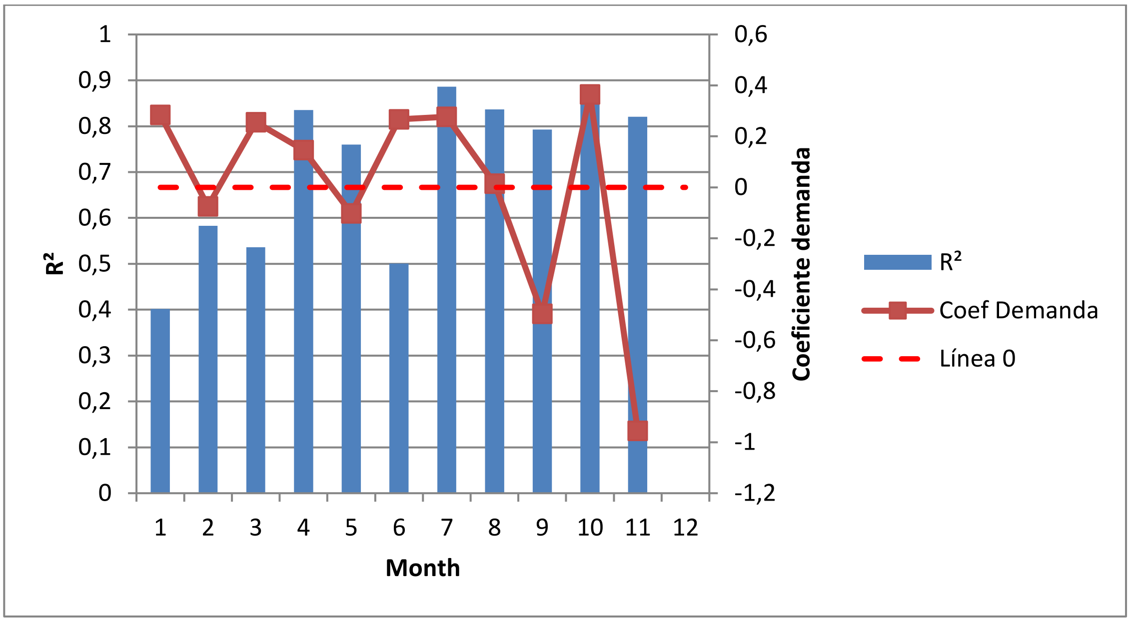


Figure 97: Downward multiple regression model for 2024 in real time by month. Source: Own elaboration. Source: Own elaboration.

The disaggregation between P6 and non P6 periods also provides robust R-squared values. However, the demand coefficient remains very close to zero in both cases. Although the sign differs between P6 and non-P6 periods, these values are too small, meaning that changes in demand do not produce changes on the final cost.

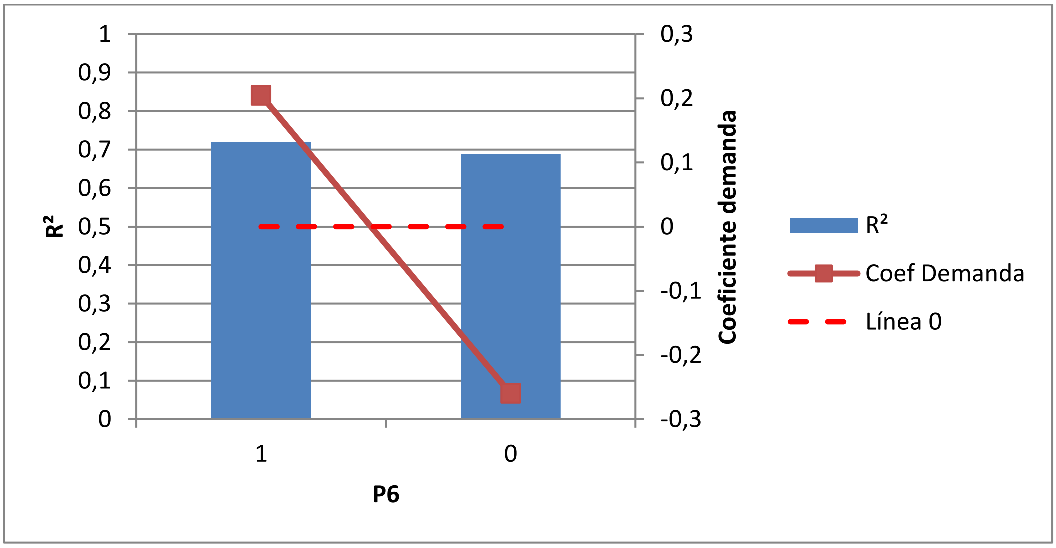


Figure 98: Downward multiple regression model for 2024 in real time in P6. Source: Own elaboration.

When P6 is analyzed by month, some months show robust R-squared values. However, the demand coefficient remains unstable, with values closed to zero and isolated peaks, particularly in August. As a result, the P6 monthly model does not provide a stable relationship with the cost.

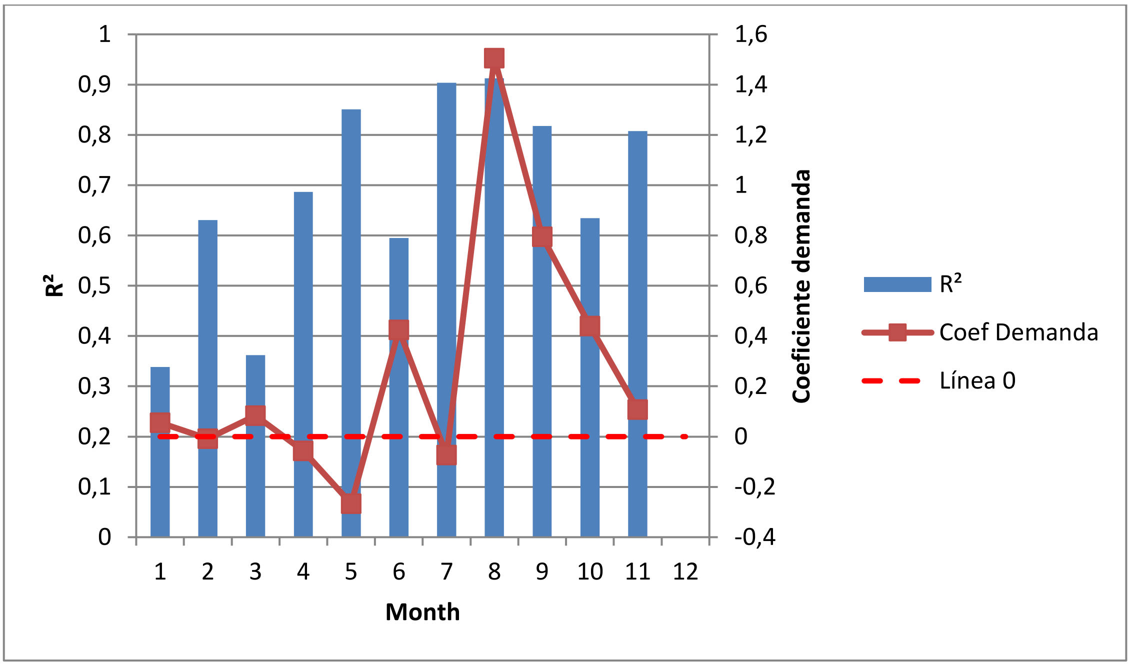


Figure 99:Downward multiple regression model for 2024 in real time by month in P6. Source: Own elaboration.

Outside P6, the monthly models also show high R-squared values in several months. Nevertheless, the demand coefficient remains unstable and close to zero. Therefore, the relationship between demand and cost cannot be considered stable outside P6 either.

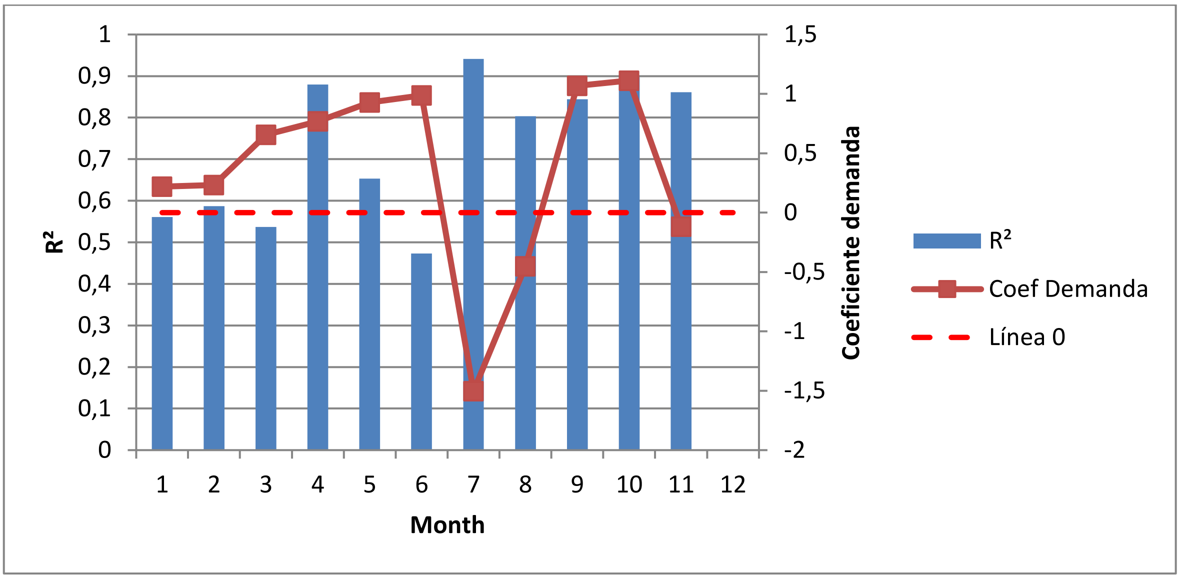


Figure 100: Downward multiple regression model for 2024 in real time by month outside P6. Source: Own elaboration.

Overall, the real time models for downward restrictions are more robust than the PDBF models, as expected due to their closer link with actual system operation. However, the demand coefficient does not show a stable or consistent behavior. It remains close to zero, and in some months presents unexpected peaks. Therefore, although real time modelling improves the explanatory capacity of the regressions, the results do not provide enough evidence to conclude that demand directly explains downward restriction costs. This is going to be important when allocating the costs. Since there is no direct relationship between the demand and the restrictions, the costs would need to be assigned in a way that does not distort the efficient economic signal.

4.3.7 SECONDARY BAND

For the secondary band, a different approach is followed. First, some regression models were estimated following the same structure applied to technical restrictions, in order to test whether the cost of these services could be directly explained by the level of demand. However, this approach was discarded because the results were not robust. The regressions did not show a clear and stable relationship between demand and the cost of the secondary band.

After this, an alternative approach was considered. The reason is that the secondary band is not only related to the level of demand, but the uncertainty it introduces to the system. The unexpected and unpredictable variations in the level of the demand, is what makes SO have balancing resources available. For this purpose, a new explanatory variable was created, defined as demand uncertainty. This variable was calculated as the absolute difference between the hourly demand of each group and its average demand. It measured how much the demand of each group deviated from its usual level in each hour.

$$Demand\ uncertainty_{hour} = ABS(Demand_{hour} - Average\ group\ demand)\ \forall group$$

Equation 4: Demand uncertainty variable computation

The objective of this variable was to see whether higher deviations from the average demand could be associated with a greater need for secondary band and, therefore, with a higher cost. So, the analysis did not only consider how much each group consumes, but also the level of stability of its demand profile. The results obtained with this new variable were still not fully robust, and therefore they cannot be used directly as an allocation methodology. However, they improved considerably compared to the initial regression models based only on demand. This suggests that the relevant driver of these costs may be more closely related to uncertainty and variability than to the absolute level of demand. Therefore, the following approaches continue in this direction and are based on the idea that these costs should be recovered considering the uncertainty generated by the demand that each group presents.

Chapter 5. TARIFF DESIGN ASSESSMENT

Once all the relevant information was gathered, the next step was to review the literature in order to understand the different cost allocation methods available and to identify which of them could be more efficient for the model. For each method that can be considered appropriate for our thesis, an allocation approach is designed to distribute the different ancillary service costs across tariff periods and consumer groups.

Before applying these methodologies, it was necessary to define which cost should be used in the analysis. The costs considered in this section correspond to technical restrictions in the PDBF and in real time and are summarized in Table 8; and the costs from the secondary band and SRAD, collected in Table 9.

When analyzing the information published by ESIOS (Esios, 2026) and comparing it with the reports from SO, it was observed that the values published in ESIOS correspond to IMRRTT, while the values reported by SO correspond to CRRTT. For the purpose of this study, CRRTT values are used, since the objective is not to allocate the total cost of technical restrictions, but the overcost generated by them.

CRRTT (€)	*Downward ENRRTT*	*Upward ENRRTT*	*TOTAL U+D*
CPDBF	43,126,406.61	1,180,901,435.00	1,224,027,026.35
CRT	24,540,512.49	806,056,569.36	830,597,081.85
CTOT	67,666,103.84	1,986,958,004.36	2,054,624,108.20

Table 9: Ancillary service costs (€) from 2024. Source: Own computation with data from esios.

And for the secondary band and SRAD:

Total cost for the secondary band and SRAD (€)	*670,155,293.51*

Table 10: Costs from the secondary band and SRAD (€) from 2024. Source: Own computation with data from esios.

Once the costs to be recovered have been clearly identified, the next step is to determine the most appropriate allocation method.

5.1 *ALLOCATION METHODOLOGY ANALYSIS*

5.1.1 COST CAUSALITY

It consists of allocating the price not only according to the total consumption of an agent, but to those responsible for the need for the service. Applied to ancillary services, this implies that costs should be assigned according to each group's contribution to the need for balancing, redispatching or reserve activation (Sunkyo Kim, 2024). This approach is particularly relevant when the observed cost includes price effects that may obscure the physical relationship between demand and system needs.

The main advantages of this method are that it provides the possibility to allocate the costs not only according to the total consumption, but also to attribute it to the responsible for the need for the service. This is especially relevant when trying to prevent the allocation of the costs to consumers at hours where their demand is not actually causing the need for the service. Nevertheless, this method requires the identification of the cost driver, and the causality of the costs are not always directly observable, especially regarding ancillary services where the final cost is not easily interpretable due to price signal effects interacting with the demand and energy activation.

That said, this method is considered as a possibility since it aligns with the main principle of tariff design that is cost causality. It allows us to allocate the cost of the ancillary services according to the contribution of each group to the need for that service. From previous sections, we concluded that no direct relationship between the cost and the demand level could be found in the analyzed period. Instead, the main driver of the cost was the activated energy for the restrictions[16]. For our analysis, the main cost driver can be interpreted as the

[16] When talking about restrictions, only upward energy activated for the restrictions is considered. Downward energy is considered in a separated way since no relationship was found among the different variables.

activated energy for the ancillary services in each period, because it represents the physical magnitude of the necessities of the system. A proposal is going to be made based on this assumption.

On the other hand, even though a direct relationship between the cost and the demand was not found, there existed an intrinsic relationship between the energy and the demand. This could mean that the demand level was not that significant, but instead the uncertainty the system operator has to face when deciding to activate the resource. For that reason, based on the analysis carried out for the secondary band, it seems reasonable to consider a second driver: the **uncertainty of demand**, estimated by the covariance of each tariff group with the total demand, because the activated energy and the needed reserves do not only depend on the level of the demand but also on its uncertainty and variability. This possibility will be also considered.

5.1.1.1 Demand uncertainty

Since no direct relationship with the level of consumption was found, another possibility is to assign the costs based on the level of uncertainty of the demand. The logic behind this approach is simple: those groups with a more stable load through the hours are going to be more predictable and therefore SO is going to be able to program the resources more efficiently. On the other hand, groups with more variable load levels are going to be less predictable. Therefore, SO is going to be more conservative (since the demand must be covered under all circumstances) and is going to need to program more resources, making the ancillary services cost increase. So, these groups should be responsible for a higher share of those costs.

First, to see the level of uncertainty of each group, the covariance between the demand of each group and the total demand is computed. It is assumed that groups connected to higher voltage levels are going to have a similar behavior, so they are going to be analyzed together. Once the covariances are obtained, the costs are going to be assigned according to the relative weights of the covariances from each group:

$$A.C_{group} = \frac{Covariance_{group}}{\sum Covariance_{group}} \; \forall \; group$$

Equation 5: Allocation coefficient applying the covariances method proposal.

Group	*Allocation coefficient*
2.0	47%
3.0	24%
AT	29%

Table 11: Weights per group obtained with the covariance method proposal. Source: Own elaboration.

In addition to this, to provide a more efficient signal, this allocation percentage could be obtained by differentiating by the periods established by the CNMC. To do so, the covariance of each group on each period with the demand is calculated. The following percentages are obtained:

$$A.C_{group,period} = \frac{Covariance_{group,period}}{\sum Covariance_{group,period}} \; \forall group, period$$

Equation 6: Allocation coefficient obtained from applying the covariances method proposal and the CNMC period differentiation.

	Demand BC 2.0TD	*Demanda BC 3.0TD y 3.0TDVE*	*AT*
P1	12%	6%	7%
P2	8%	5%	7%
P3	3%	3%	6%
P4	3%	2%	5%
P5	1%	2%	5%
P6	12%	6%	6%
TOTAL	40%	24%	36%

Table 12: Weights per group obtained with the covariance method proposal and the CNMC period differentiation. Source: Own elaboration.

And finally, the unitary cost per group and period is computed as well:

$$U.C_{group,period} = \frac{A.C_{group,period} * Total\ cost}{Demand_{group,period}}$$

Equation 7: Unitary cost computation.

	Demand BC 2.0TD	Demand BC 3.0TD y 3.0TDVE	AT
P1	26.77	29.39	12.56
P2	14.76	19.92	10.71
P3	6.71	12.79	8.96
P4	5.83	9.04	6.22
P5	7.32	21.16	15.25
P6	6.52	7.40	2.10
TOTAL	**9.98**	**13.41**	**6.13**

Table 13: Unitary cost (€/MWh) per group and period in 2024 obtained with the covariance proposed methodology and the CNCMC periods. Source: Own elaboration.

The method provides a differentiated and efficient signal per group and period. The highest values correspond to P1 and P2, whereas P6 presents the lowest. On top of that, the low voltage groups also present higher costs. This is coherent with the rationale behind the method that is assigning higher costs to the groups responsible for the need for the service due to their variability in load levels.

Although the covariance allocation provides a differentiated signal by tariff group and time period, the results show a singular behavior in P5. In some cases, the allocation obtained for P5 is too high. This is because it corresponds to a low number of hours concentrated in specific months. Therefore, the value obtained for this period may be strongly affected by the reduced number of observations and by the particular characteristics of those hours, rather than by a causal relationship with the demand. For this reason, the methodology is considered to be optimal, but with a correction for P5. This correction is consistent with the logic followed in the regulated access tariff methodology of the CNMC, where similar inconsistencies between P5 and P6 are corrected to avoid sending an inefficient price signal. In particular, when P6 results in a higher value than P5, both periods are assigned the same price, since P6 should not provide a stronger cost signal than P5 (CNMC Circular 3/2020, 2020). To support our findings, the same process was repeated for 2023 and for both years together.

2023	*Demand BC 2.0TD*	*Demand BC 3.0TD y 3.0TDVE*	*AT*
P1	*8%*	*1%*	*5%*
P2	*8%*	*3%*	*5%*
P3	*8%*	*4%*	*4%*
P4	*10%*	*3%*	*4%*
P5	*4%*	*3%*	*6%*
P6	*15%*	*4%*	*5%*
TOTAL	*52%*	*19%*	*29%*

Table 14: Weights per group obtained with the covariance method proposal and the CNMC period differentiation for 2023. Source: Own elaboration.

2023	Demand BC 2.0TD	Demand BC 3.0TD y 3.0TDVE	AT
P1	21,00	7,63	10,85
P2	14,97	11,78	7,07
P3	16,37	16,88	5,90
P4	15,28	9,35	4,40
P5	12,55	22,82	12,66
P6	7,01	4,29	1,47
TOTAL	**11,72**	**9,24**	**4,42**

Table 15: Unitary cost per group and period (€/MWh) obtained with the covariance proposed methodology and the CNCMC period for 2023. Source: Own elaboration.

total 2023 y 2024	*Demand BC 2.0TD*	*Demand BC 3.0TD y 3.0TDVE*	*AT*
P1	14%	7%	8%
P2	7%	4%	6%
P3	4%	3%	5%
P4	4%	2%	4%
P5	2%	2%	5%
P6	11%	5%	5%
TOTAL	43%	24%	34%

Table 16: Weights per group obtained with the covariance method proposal and the CNMC period differentiation for 2023 and 2024. Source: Own elaboration.

The results obtained for 2023, 2024 and the joint period show a consistent pattern. The method provides an efficient signal by allocating higher unitary costs to the periods and groups that contribute more to system uncertainty. However, a singularity appears in P5, mainly due to the reduced number of hours and their concentration in specific months. Therefore, the methodology is proposed with a correction for P5, following the same logic used in the CNMC tariff methodology to avoid inefficient signals between P5 and P6.

For further analysis, a P5 correction will be made, assigning both P5 and P6 the same pondered value obtained as:

$$Ponderated\ value = \frac{PM_{\ p5} * Demand_{p5} + PM_{\ p6} * Demand_{p6}}{Demand_{p5} + Demand_{p6}}$$

Equation 8: Correction for P5 in the covariances method proposal.

In addition, for the 2.0 tariff group, the weighted value is also calculated including P4. This is because, in this group, the value obtained for P4 is lower than the values obtained for the higher periods. Therefore, P4 is also corrected together with P5 and P6 in order to maintain a more coherent tariff structure and avoid assigning an excessively low value to an intermediate period.

2024 (€/MWh)	Demand BC 2.0TD	Demand BC 3.0TD y 3.0TDVE	AT
P1	26,77	29,39	12,56
P2	14,76	19,92	10,71
P3	6,71	12,79	8,96
P4	6,45	9,04	6,22
P5	6,45	8,96	3,45
P6	6,45	8,96	3,45
TOTAL	**9.98**	**13.41**	**6.13**

Table 17: Final unitary prices (€/MWh) per group and period in 2024 with the covariance methodology and the corrections for the upward energy. Source: Own elaboration.

The same methodology can be followed to recover the cost from the secondary band. Using the percentages from table 11 to allocate the costs from table 9, the following unitary prices were obtained:

€/MWh	Demand BC 2.0TD	Demand BC 3.0TD y 3.0TDVE	AT
P1	9,03	9,91	4,24
P2	4,98	6,72	3,61
P3	2,26	4,32	3,02
P4	1,97	3,05	2,10
P5	2,47	7,14	5,14
P6	2,20	2,50	0,71
TOTAL	**3,37**	**4,52**	**2,07**

Table 18: Final unitary prices (€/MWh) per group and period in 2024 with the covariance method and for the secondary band and SRAD. Source: Own elaboration.

And the unitary prices after applying the same correction process:

€/MWh	Demand BC 2.0TD	Demand BC 3.0TD y 3.0TDVE	AT
P1	9,03	9,91	4,24
P2	4,98	6,72	3,61
P3	2,26	4,32	3,02
P4	2,18	3,05	2,10
P5	2,18	2,93	1,16
P6	2,18	2,93	1,16
TOTAL	**3,37**	**4,52**	**2,07**

Table 19: Final unitary prices (€/MWh) per group and period with the covariance method in 2024 and the corrections for the secondary band and SRAD. Source: Own elaboration.

Overall, the covariance method can be considered a suitable allocation methodology, since it reflects differences in demand predictability across groups and periods, while the P5 correction ensures that the final signal remains coherent and economically interpretable.

The calculation is carried out using the six-period time-of-use structure. It can then be converted into the three periods applicable to the 2.0TD tariff in order to align it with the current CNMC structure.

5.1.1.2 Activated energy

The cost can be assigned due to the need of the resource, meaning the cost associated with the activated energy in each period. As has been discussed, a direct relationship between the cost and the demand was observed. Instead, it was explained by the activated energy itself. So, the first approach is to try to assign the cost in proportion to the percentage of activated upward reserve on each period. It must be said that, since the relationship was more robust in real time, the coefficient is going to be obtained based on the energy activated in that case[17]. An allocation coefficient (AC) is computed for each period:

[17] When studying this method is important to consider that from 2025 onwards, a singularity exists since Red Eléctrica starts to assign the real time necessities to the PDBF. So, this method should be studied using historical and robust data.

$$A.C_{period} = \frac{Upward\ activated\ energy\ in\ real\ time_{period}}{\sum Upward\ activated\ energy\ in\ real\ time_{period}}\ \forall period$$

Equation 9: Proposed allocation coefficient from the activated energy method.

The following values are obtained:

Period	*Allocation coefficient*
P1	15%
P2	16%
P3	14%
P4	18%
P5	7%
P6	30%

Table 20: Allocation coefficient obtained from the activated energy method proposal for 2024. Source: Own elaboration.

With this approach, we would assign the same volumetric charge to all the groups. In order to provide a more efficient signal, it is proposed to combine this method with the covariances method. By doing so, we can allocate the costs to each group based on the level of the demand of each one of them. Therefore, the allocation coefficient for each group and period would be allocated as follows:

$$A.C_{group,period} = Covariance\ percentage_{group} * Energy\ percentage_{period}$$

Equation 10: Allocation coefficient per group and period with the activated energy method proposal.

	Demand BC 2.0TD Real	*Deman BC 3.0TD y 3.0TDVE Real*	*AT*
P1	7%	4%	4%
P2	8%	4%	5%
P3	7%	3%	4%
P4	8%	4%	5%
P5	3%	2%	2%
P6	14%	7%	9%
	47%	24%	29%

Equation 11: Allocation coefficients obtained from the activated energy proposal. Source: Own elaboration.

And the unitary cost per group and period, obtained from multiplying the percentages times the total cost and diving it by the demand oof each group on each period:

	Demand BC 2.0TD	Demand BC 3.0TD y 3.0TDVE	AT
P1	15.13	16.41	7.61
P2	13.88	15.83	6.65
P3	16.06	15.76	6.51
P4	17.60	17.28	6.87
P5	16.22	17.03	6.10
P6	7.47	9.35	2.99
TOTAL	**11,79**	**13,38**	**4,92**

Table 21: Unitary costs (€/MWh) from activated energy allocation methodology in 2024. Source: Own elaboration.

This methodology provides a highly balanced result. It allocates costs to the periods in which the activated energy due to restrictions was actually needed, directly reflecting the operational needs of the system. On top of that, the allocation between groups is based on their covariances, which preserves the principle that groups with a larger uncertainty should bear a greater part of the cost. This method is a combination of actual operational activation and demand responsibility.

5.1.2 COST OF SERVICE

With this method, each group should pay an amount that reflects the cost of providing the service. First, costs are separated by functions such as generation, transmission, distribution, ancillary services... then each cost is classified according to the provided service and finally, a unitary price is computed and allocated to each consumer group (Schmalensee, 2024). allocation criteria.

This method can be attractive because of its simplicity and replicability. However, for ancillary service costs, the cost of service allocation may not be sufficient on its own. The reason is that the relationship between demand and ancillary service costs is not always positive. In some hours, additional demand may help reduce the costs. In those cases, allocating a high cost to consumers simply because they consumed energy in that hour could send the wrong signal. This method is the one that is currently in place, and it is not contributing to the efficiency of the system.

5.1.3 SHORT TERM MARGINAL COST

It is the most common method to set prices. It can be defined as the change on the total cost when modifying by one unit the studied variable. Using the example from (Jose-Fernando Forero-Quintero, 2022) when talking about the short term in an energy system, the capacity of the system is fixed, so the marginal cost of the infrastructure only includes its operating costs, not any additional investments. This method is used in the wholesale electricity market to set the price.

This method is the most theoretically efficient. It reflects the incremental cost caused by one additional unit of demand. So, it sends a direct economic signal by capturing different effects depending on the hour, period or system condition. Nevertheless, the method only works if the marginal effect of the demand on the cost can be properly estimated. In our previous analysis, the regressions did not show a stable relationship between demand and cost. They did show a strong relationship between the activated energy and the cost, and an intrinsic relationship between the demand and energy. But since we were not able to estimate a robust model that explains the variations in the cost by changes in demand, we discarded this method as the main one to allocate the costs.

5.1.4 LONG RUN MARGINAL COST (FORWARD LOOKING CHARGES)

This method is similar to short term marginal cost, but it focuses on future possible scenarios. Using the same example as before (Jose-Fernando Forero-Quintero, 2022), it would be the cost of the same demand increase but having the possibility to invest in new infrastructure in order to adapt to new demand levels in the long term. So, the cost is not allocated according to total consumption alone, but according to the user's contribution to future network stress.

As in (Tomás Gómez, 2020) the authors explain that, in the long term, the objective is to reduce incremental network costs by allocating them to the users that stress the network during periods of maximum utilization.

This could be a good approach since this method provides long term signals that could encourage consumers to modify their behavior in a way that reduces future system costs. It is especially appropriate when demand growth creates future investment need, supporting efficient planning and system development. This should be one of the most optimal and efficient ways to allocate the costs. Nevertheless, there is a high uncertainty regarding the evolution of the ancillary services, and they will strongly depend on many scenarios. It will need assumptions on electrification, renewable penetration, storage and flexibility. And since we were not even able to find models that allow us to see a stable marginal cost in the short term, this method that applies to the long term is also discarded due to the uncertainty of the future evolution of ancillary service needs and the lack of robust and stable models in the short term.

5.1.5 RAMSEY PRICING

This method assumes that any deviation from marginal cost pricing produces a change in the consumption patterns of demand that are not efficient. If prices were marginal, consumers would consume the optimal amount of energy. By setting prices inversely proportional to price elasticity, this method allows them to recover the residual costs without distorting the optimal consumption patterns (Toby Brown, 2014).

This method is especially relevant to recovering costs that cannot be assigned through a clear driver. It tries to recover the costs while minimizing distortions and consumption patterns. It can be used as a complement to other allocation methods. For the purpose of this thesis, since no relationship with the downward energy cost and the demand was found, this method will be chosen to allocate those costs.

5.1.6 POSTAGE STAMP

This method is based on allocating the same fixed tariff to all system users, independent of the distance, the localization or any other relevant parameter. This is the most simple and replicable tariff method. Nevertheless, this method lacks efficiency since it does not reflect the actual cost that each user causes on the system (Kamh & Alhaddad, 2024).

Some advantages of this method are that it is very easy to calculate and apply, the consumers can understand the tariff, it does not require detailed information, and it produces predictable and stable charges. On the other hand, it does not follow the cost causality principle since it does not reflect which group contributes to the need for the service. Therefore, groups that do not cause the cost will have to pay the same as those who do. So, although it is simple and easy method to implement, it would not provide an efficient signal, and it is decided to be discarded.

5.1.7 PEAK PRICING

Peak Pricing (PP) is a dynamic way of allocating higher prices during critical periods. These periods correspond to moments when the electricity system or distribution network is more likely to be constrained. The main objective of PP is to send a strong price signal to consumers so that they reduce their electricity consumption during high consumption hours. Therefore, PP encourages demand response only during specific high stress periods, but it does not create incentives to reduce consumption during normal hours. It can be applied through either capacity-based or volumetric charges, depending on the metered variable used (CEER, 2020).

Some advantages of this method are the fact that it does not need to identify a direct marginal relationship with the demand, it dimensions the system for situations of maximum stress. It provides the opportunity to differentiate between the periods, differentiating those that are close to the peak situations, and it gives an efficient signal to reduce consumption during moments close to the possible peak situations. Nevertheless, it assumes that the peak demand is the main driver, and it is not always true for ancillary services, since many activations occur outside the peak periods.

If the cost-causality approach does not provide sufficiently robust results, an alternative allocation criterion can be based on an extended peak pricing methodology. In this case, peak pricing is not interpreted as a simple distinction between peak and off-peak hours, but as an allocation mechanism based on the distance between the average demand on each period and the maximum demand of the peninsular system. The rationale behind this approach is that the electricity system must be dimensioned to withstand the most demanding operating conditions. Therefore, periods whose average demand is closer to the system peak can be considered to contribute more to the need for system security, reserve requirements and operational flexibility. Consequently, these periods should bear a higher share of the cost.

Since this method assigns higher costs to the periods that are closer to the maximum demand of the peninsular system, the distance between the average demand of each tariff period and the overall system peak is calculated. The smaller this distance, the closer the period is to system saturation, and therefore the higher the share of costs allocated to it.

$$Complementary\ area_{period} = D_{max} * h_{period} - D_{period}\ \forall period$$

Equation 12: Computation of the complementary area.

Figure 98 illustrates the Dmax method with the complementary area. The blue area represents the average demand of each period, while the grey area represents the distance between that average demand and the maximum demand of the peninsular system. The scale is tried to be maintained to represent the hours of each period as well.

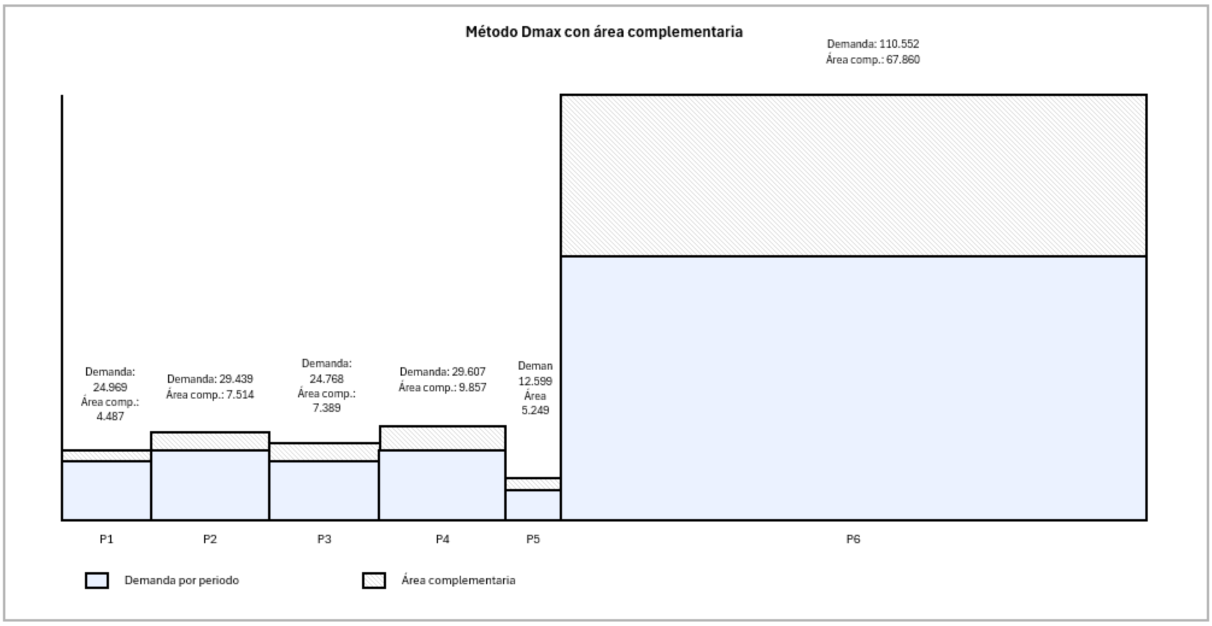


Figure 101: Visual representation of the Dmax method. Source: Own elaboration.

Then, in order to standardize the process and make the allocation comparable across periods, a factor is calculated for each tariff period. This factor relates the demand of each period to its complementary area and compares this ratio with the equivalent ratio for the total system.

$$Factor_{period} = \frac{\frac{Demand_{period}}{Complementary\ area_{period}}}{\frac{Demand_{total}}{Complementary\ area_{total}}} \ \forall period$$

Equation 13: Dmax factor.

Once this factor has been obtained for all tariff periods, the relative weight of each period is calculated. These weights are then used to allocate the total cost among periods.

Period	*Allocation coefficient*
P1	22%
P2	18%
P3	13%
P4	14%
P5	5%
P6	28%

Table 22: Allocation coefficient obtained from the Dmax method proposal. Source: Own elaboration.

The results obtained are similar to those of the activated energy method. However, the objective of this proposal is not only to recover the total cost, but also to provide an efficient economic signal for the system. For this reason, applying the same volumetric charge to all tariff groups would not be the most appropriate solution, since it would not differentiate between groups.

Given this limitation, a possible alternative is to combine this method with the covariances method. This makes it possible to differentiate costs across tariff groups. In this way, lower costs are assigned to periods where the system is less saturated, such as P6, while higher unitary costs are assigned to the groups whose demand is more related to the need for ancillary services.

$$A.C_{group,period} = Covariance\ percentage_{group} * Max.demand\ percentage_{period}$$

$$\forall group, period$$

Equation 14: Allocation coefficient obtained from the Dmax and covariances method proposal.

	Demand BC 2.0TD Real	*Demand BC 3.0TD y 3.0TDVE Real*	*AT*
P1	10%	5%	6%
P2	9%	4%	5%
P3	6%	3%	4%
P4	7%	3%	4%
P5	2%	1%	1%
P6	13%	7%	8%
	47%	24%	29%

Table 23: Final allocation coefficient obtained from the Dmax and covariances method proposal. Source: Own elaboration.

And the unitary cost per group and period, obtained applying equation 6:

	Demand BC 2.0TD	Demand BC 3.0TD y 3.0TDVE	AT
P1	22.02	23.88	11.08
P2	15.72	17.93	7.53
P3	14.96	14.69	6.06
P4	13.66	13.41	5.33
P5	11.01	11.56	4.14
P6	7.05	8.82	2.82
TOTAL	**11,79**	**13,38**	**4,92**

Table 24: Final unitary prices (€/MWh) from the Dmax method proposal for 2024. Source: Own elaboration.

The results obtained with the extended peak pricing methodology show a coherent allocation pattern. The highest unitary charges are assigned to P1, while the lowest values are obtained in P6. The methodology also provides a differentiated signal across tariff groups. The highest values are obtained for the 3.0TD and 3.0TDVE demand group, followed by the 2.0TD demand group, while high-voltage demand receives lower unitary charges. This suggests that the method is able to reflect not only the temporal contribution to system stress, but also the different contribution of each demand group.

This method does not prove direct cost causality, but it provides a good approximation of the contribution of each group and period to system stress.

5.1.8 AVERAGE PARTICIPATION METHOD

This method assigns network costs to users according to their estimated participation in the use of the system. The assumption is that, at each network node, incoming flows are distributed proportionally among outgoing flows. The method requires detailed network data, including nodal generation, nodal demand, transmission lines, technical constraints and flow results. The method is useful as a reference because it is based on the idea that users should pay according to their participation in the system conditions that create costs, not simply according to total consumption (international, 2009).

It underlies a very useful conceptual reference, since it supports the idea that costs should not be allocated by total consumption but instead, they should be allocated according to the participation of each agent in the network flows. So, users pay according to their contribution to the system use. Nevertheless, we will need to count on an amount of information that is not easy to obtain. Especially, for distribution related requests, it would be necessary to know how those requests are made and whether the cause lies at the customer frontier, the generation frontier or the network itself. So, this method is also discarded.

5.1.9 ALLOCATION BASED ON CIRCULAR 3/2020 NETWORK TARIFF METHODOLOGY

This approach is relevant because Circular 3/2020 provides an existing accepted regulatory methodology for allocating network costs. One of the main advantages of this methodology is that it differentiates costs by time periods. In this way, it sends a more efficient economic signal, assigning a higher share of costs to those periods that are more likely to be stressed due to their proximity to peak demand hours. In addition, the methodology also differentiates costs according to the voltage level at which consumers are connected, reflecting the fact that different tariff groups use the transmission and distribution networks in different ways.

However, this is also the main reason why Circular 3/2020 cannot be directly applied to ancillary service costs. Network tariffs are based on the use of transmission and distribution infrastructures, where the allocation by voltage level is justified by the physical flows across the different network levels. In contrast, ancillary service costs are related to operational needs of the system, such as balancing, redispatching, reserve activation and technical restrictions. These costs do not necessarily follow the same physical flow logic by voltage level. To support these previous ideas, a further analysis has been carried out:

In case the methodology of the CNMC were decided to be the one implemented to allocate the ancillary service costs, several issues should be considered. First, it should be decided which part of the costs should be assigned to transmission and which ones to distribution. The first problem is the way SO labels the restrictions when it describes the nature of the necessity. The classification made by SO, depending on the nature of the restriction, is the following:

Label	*Meaning*	*Location*
RSI	Lack of upward capacity reserve	Not defined
RBI	Lack of downward capacity reserve	Not defined
RTD	Technical restriction in the distribution network	Not defined
SOT	Over voltages	Transmission network
COT	Voltage control	Transmission network
SCA	Overload in contingency scenarios	Transmission network
SCB	Overload in case base	Transmission network
DAN	Angular phase deviation	Transmission network
PEV	Evacuation impossibility	Transmission network
PCB	Loss of pumping capacity	Transmission network

Table 25: Summary of Red Eléctica network constraints labels. Source: SO I3dia reports.

It can be seen that several restrictions are already assigned by SO to the transport network, but some of them have not been clearly defined. On the one hand, RSI and RBI are restrictions that do not correspond to a specific network or a physical limitation of the grid. These labels refer to an insufficiency of upward or downward reserve capacity in the system. Therefore, their nature is mainly operational. They are related to the need of the system operator to ensure enough flexibility to maintain the balance between generation and demand and to respond to deviations, forecast errors, renewable variability, outages or other system security requirements. For this reason, these costs cannot be clearly attributed to distribution networks. The fact that a reserve need may arise in a given area, or may be influenced by demand conditions, does not provide enough evidence to conclude that it is caused by consumers connected to distribution grids

On the other hand, a more critical discussion arises in the case of RTD. Some could argue that this should be attributed to the distribution part. Nevertheless, the restriction may be associated not only to the demand, but also with generation connected at distribution level. Therefore, the fact that a restriction could be identified in a distribution area does not provide enough certainty to allocate the corresponding cost directly to distribution consumers. For this reason, and in order to avoid introducing an unjustified cost-causality assumption, the most prudent approach is not to allocate these costs specifically to distribution unless there is clear evidence that they are caused by the demand connected to distribution networks. In the absence of such evidence, the costs should be treated as general system operation costs and, for the purpose of adapting the CNMC methodology, assigned to the transmission level rather than to distribution.

Once the costs are assumed to be assigned to transmission, the second question is whether they should be recovered through the capacity term, through the energy term or through both. Costs associated with network capacity, peak demand or the need to reinforce infrastructure should be recovered through a capacity term. Costs associated with the formal use of the network should be assigned to the energy term. In the case of ancillary service costs, a discussion can arise in some restriction labels, such as overloads in the base case or overloads under contingency conditions. On the one hand, overloads in case of contingency could be argued to arise from the lack of capacity of the grid, since they are activations that follow the N-1 criteria. Nevertheless, with the available information it cannot be assured that the overload is due to network constraints or, on the contrary, the generators in the area are the ones causing possible overload. The P.O. 1.1 (Ministerio de Industria Energía y Turismo PO_1.1, 2016) explains that there exists a special situation labelled as "excessive correction time" that considers the failure of the largest generator in the area and an interconnection line with the rest of the system. For this reason, assigning this kind of contingencies to the power term cannot be fully justified. Finally, an overload in the case base can mean that the network may not have enough capacity. So, the costs of this restriction could be justified in being assigned to the power term. Nevertheless, the costs associated with this restriction represent roughly 1% of the total costs so it makes no sense making this differentiation.

	UPWARD ENERGY	*SSCB*
CRRTT PDBF (€)	1.180.901.435,00	4.157.068,73
CRRTT RT (€)	806.056.569,36	5.938.677,63
CRRTT TOTAL (€)	1.986.958.004,36	10.095.746,36

Table 26: Upward energy restriction costs and SSCB restriction cost for 2024. Source: Own elaboration.

The resulting average final price obtained when applying the CNMC methodology and separating the recovery between a capacity term and an energy term is shown in Figure 103[18].

[18] These computations are made with the demand measured at the end consumer, following the methodology of the CNMC.

Grupo tarifario	Facturación media (€/MWh)		
	Término de potencia	Término de energía	Total
2.0 TD	0,10	10,25	10,35
3.0 TD	0,03	10,77	10,80
6.1 TD	0,04	9,21	9,25
6.2 TD	0,03	6,86	6,89
6.3 TD	0,03	6,72	6,75
6.4 TD	0,03	8,99	9,03
Total	**0,06**	**9,40**	**9,45**

Figure 102: Average final price obtained by applying the CNMC methodology and considering a power term and an energy term for 2024. Source: Own elaboration.

As can be observed, the average price associated with the capacity term is very low, around 0,06. Moreover, since the capacity term is billed on a monthly basis, this value would have to be divided by 31 billing periods. As a result, the final monthly charge would be almost negligible and would not provide a meaningful economic signal to consumers.

For this reason, although this specific restriction could theoretically be linked to the capacity term, its limited weight in total costs does not justify creating a separate capacity charge. Introducing this distinction would increase the complexity of the methodology while having a negligible effect on the final tariff. Therefore, these costs are finally recovered through the energy term, following the approach observed in France, where ancillary service and balancing reserve costs are included within the electricity system operation costs recovered through TURPE and are not treated as a separate capacity charge for each specific restriction.

	Retribución provisional CRRTT de la energía a subir 2024
Retribución de la actividad de transporte que se recupera a través de peajes (miles €)	*1.986.958*
Retribución del transporte	**1.986.958**
± TSO	**-**
± Desvios de ejercicios anteriores	**-**

Figure 103: Classification of the upward energy restriction costs for 2024. Source: Own elaboration.

Finally, figure 105 presents the final unit price obtained for each tariff period after applying the CNMC methodology.

Grupo tarifario	Periodo 1	Periodo 2	Periodo 3	Periodo 4	Periodo 5	Periodo 6
2.0 TD	0,052268	0,022712	0,007932	0,003892	0,000194	0,000023
3.0 TD	0,051071	0,021643	0,007584	0,003947	0,000207	0,000022
6.1 TD	0,040917	0,017462	0,006183	0,003208	0,000165	0,000017
6.2 TD	0,045032	0,019052	0,006846	0,003642	0,000190	0,000020
6.3 TD	0,061938	0,027690	0,009879	0,005218	0,000277	0,000027
6.4 TD	0,061938	0,027690	0,009879	0,005218	0,000277	0,000027

Figure 104: Unit cost to be recovered through the energy term of network tariffs in each hourly period (€/kWh) for 2024. Source: Own elaboration.

The following table provides a comparative assessment of the main cost-allocation methodologies considered for ancillary services. For each alternative, it summarizes the allocation criterion, its main advantages and limitations, and its relevance to the problem analyzed. This comparison helps identify which approaches can provide an efficient and cost-reflective signal and which are less suitable given the available data and the uncertain causality behind ancillary service costs

Method	*Allocation of costs*	*Pros*	*Cons*	*Justification*
Cost causality	To the groups that contribute to the need of the system	Reflects the origin of the costs; efficient signal	Causality may be difficult to observe	It links ASS costs to the activated energy need and/or demand uncertainty
Cost of service	Incurred costs to provide the service to each group	Simple and replicable	May send the wrong signals	Insufficient for system efficiency. Demand not always increase ASS costs

Short term marginal cost	Based on the change an extra unit produces on the final cost	Theoretically efficient; direct price signal	Need for robust models that justify the relationship among variables	Robust models that showed a stable relationship between demand and costs could not be found
Long term marginal cost	Based on user`s marginal contribution to the future system stress	Forward-looking; long-term efficiency	Highly scenario dependent; uncertainty for ancillary services	Future ancillary service needs are too uncertain and short-term robust models were not even found
Ramsey pricing	Based on elasticity of the consumers	Minimize distortions	Not causality identification	Useful to recover residual costs
Postage stamp	Same charge for all users	Simple; transparent	Not cost-reflective; no efficient signals	It does not reflect each groups contribution to ASS needs
Peak pricing	Higher prices to periods close to critical conditions	Simpler; reflect proximity to system peaks	May miss non-peak restrictions. Assumes peak demand to be relevant.	Useful if causality approach is not robust enough. Charging more to periods closer to stress the system
Average participation method	Based on user's participation in network flows	Consistent with system use allocation	Difficult to translate into tariff groups; need for clearer information from the distribution side	Conceptually useful but not applicable with tariff groups and actual data.

Circular 3/2020. Network tariff methodology	Different groups, periods and voltage levels	Regulatory reference; structured by groups and periods; replicable and transparent	Network based costs due to physical flows; once this issue is solved, it fails to provide a sufficient signal in P6	Useful since it has a recognized regulatory structure

Table 27: Summary of possible allocation method. Source: Own elaboration.

In the end the chosen method for the optimal allocation of the costs must follow the main principles of tariff design that are cost recovery while sending efficient economic signals. For this reason, some of the methods considered to be optimal could be the cost causality allocation method, an adaptation of the peak pricing method or the CNMC methodology, along with Ramsey pricing for residual costs.

Chapter 6. ANALYSIS OF POSSIBLE EFFICIENT ALLOCATION METHODS

Based on the analyses and allocation methods previously assessed, it is proposed that restriction costs be allocated by dividing them into different groups:

- A clear relationship between the downward energy of the restrictions and the demand was not found. This is mainly because they are not directly linked to the demand but because of evacuation problems and renewables curtailment. For that reason, they are prposed to be recovered through Ramsey, following the methodology from RD 148/21 (BOE-Real Decreto 148/2021).
- The upward activated energy showed to have a direct relationship with the demand and with the costs. This relationship can be also found in the secondary band, so they are going to be recovered following the same methodology.

	What is included	*Comments*
Group 1	Activated upward energy and secondary band	Observable indirect relationship with the demand. Cost will be recovered following the same methodology
Group 2	Activated downward energy	No relationship with the considered variables. Cost will be recovered through Ramsey.

Table 28: Aggrupation of resources for cost recovery. Source: Own elaboration.

Once the costs that need to be recovered are known and classified, the next step is to decide which method is optimal for that purpose. In light of the information gathered from the previous chapter, the following alternatives are going to be considered:

Method	*What is included (€)*	*Where is the demand considered*	*Tariff allocation method*	*Period allocation method*[19]
CNMC	ESPDBF+ESRT	Consumption[20]	Circular 3/2020	Circular 3/2020
Max. Demand	ESPDBF+ESRT	Demand consumption + grid losses[21]	Covariance	Max. demand
Activated energy in real time	ESRT+ESPDBF	Demand on supply point.	Covariance	Activated energy
Demand uncertainty (covariances)	ESPDBF+ESRT	Demand on supply point.	Covariance	Covariance
Ramsey (charges)	EBPDBF+EBRT	Demand on supply point.	RD 148/21	RD 148/21
		End consumer	RD 148/21	RD 148/21

Table 29: Summary of possible alternatives for cost allocation. Source: Own elaboration.

The objective of this work is not only to recover ancillary service costs, but also to allocate them in a way that provides an efficient signal to consumers. Therefore, the selected methodology should be simple, transparent, economically interpretable and related to the

[19] Price per hour following the periods stablished by the CNMC.
[20] Demand considered at the end consumer point.
[21] Demand considered at the generation supply point. This is equal to the demand measured in the end consumer pls the grid losses.

factors that increase the need for system operation services. Four alternatives have been considered: an allocation based on the logic of Circular 3/2020, the covariance method, the activated energy method (both following the cost causality principle) and the extended peak pricing method. Each of them captures a different dimension of the problem.

The first alternative is based on adapting the methodology established in **Circular 3/2020** for network tariffs. Its main advantage is that it relies on a regulatory framework that is already well established and widely accepted for the allocation of transmission and distribution network costs. The methodology differentiates costs according to voltage level and time period, providing a tariff structure that is familiar from a regulatory perspective and designed to encourage consumption in periods with lower network congestion. However, applying this approach to ancillary service costs presents some limitations. P6 receives a very small share of the costs because it corresponds to periods with lower expected network congestion. The need for ancillary services does not depend only on network loading conditions. It is also influenced by factors such as balancing requirements, reserve procurement, renewable generation variability, voltage control needs, technical restrictions and overall system security. As a result, assigning almost no cost recovery responsibility to P6 may fail to capture the actual operational requirements of the system and increases in excess the signal that is sending to avoid peak hours. For this reason, the Circular 3/2020-based approach is useful as a regulatory benchmark, but it is not selected as the preferred methodology.

The second alternative is the **activated energy method**. This methodology allocates costs according to the percentage of upward activated energy in real time in each period. Its main advantage is that it is directly linked to the actual use of the service. Therefore, it reflects the periods in which the system actually needed additional resources. This makes the method transparent and easy to justify from an operational point of view. However, the activated energy method also presents relevant limitations. First, it identifies when the service was activated, but not necessarily which demand groups caused the need for that activation. assigning the same volumetric charge to all groups. Therefore, it fails to provide an optimal and efficient signal to the system. To achieve this objective, an alternative was proposed. Combine this method with the covariances weight of each group to assign the responsibility based on the uncertainty of the demand. This improves the result, but it also means that the method depends on the covariance approach to provide an efficient signal by group.

Therefore, the activated energy methodology is useful as a complementary reference, but it is not the best option as the main allocation criterion. In addition to this, a change in 2025 has been observed. SO is changing the way it labels the need for the resources, and it is moving all the requirements to the PDBF. So, in order to apply this method, one should be very careful and rely on historic and robust data rather than the current information available.

The third alternative is the **extended peak pricing method**. This approach assigns higher costs to the groups and periods whose demand is closer to the maximum demand of the system (system saturation). Its main advantage is that it is simple, intuitive and economically interpretable. The electricity system must be able to operate under the most demanding conditions, so it is reasonable to assign a higher cost to the periods that are closer to system peak demand. In this sense, the method provides a clear incentive to reduce consumption in periods where the system is more saturated. The results obtained with this methodology are coherent from a tariff design perspective. P1 receives the highest unitary charge, while P6 receives the lowest one. This sends a clear signal to shift consumption away from periods close to the system peak and towards valley periods. In addition, when this method is combined with covariance weights, it also allows us to differentiate between demand groups providing a more efficient signal.

Nevertheless, this method does not seem to be the most appropriate one for ancillary service cost allocation. The main reason is that ancillary services are not required only during peak demand hours. Many activations and technical restrictions that are happening in recent years, may occur outside peak periods due to renewable generation, voltage control, congestion, outages or other operational security constraints. On top of this, it seems that this tendency is going to be maintained in the medium term. Therefore, peak demand is not always the main driver of ancillary service costs. The extended peak pricing method provides a good signal for system saturation, but it does not reflect the actual need for ancillary services. For this reason, it is considered a useful alternative scenario, but it is not selected as the preferred allocation methodology.

The fourth alternative is the **covariance method**. This methodology allocates costs according to the variation of the demand of each group and the relationship it has with the total demand of the system. The logic behind this approach is that groups with more variable and less predictable load patterns create more uncertainty for the system operator. As a consequence, SO may need to schedule more resources or operate the system more conservatively in order to guarantee system security. For this reason, the groups and periods that contribute more to demand uncertainty should bear a higher share of the ancillary service costs.

The results obtained with the covariance method show a generally coherent pattern. The methodology differentiates between tariff groups and time periods, and low voltage groups receive higher unitary costs than the high voltage ones. This is consistent with the idea that these groups are generally less stable and less predictable. However, the method also presents one limitation. A singular behavior appears in P5, where the allocation can be higher than expected in some cases. This is mainly due to the limited number of hours included in P5 and to the fact that these hours are concentrated in specific months. As a result, the value obtained for this period may be affected by the low representativeness of the observations, rather than by a stable cost signal. For this reason, the methodology should be applied with a correction for P5.

In the end, the method that is going to be proposed to allocate the ancillary service costs is going to consist of the addition of the unitary costs resulting from:

- Ramsey methodology following the RD 148/41 for the downward activated energy for the restrictions, as it does not have a clear relationship with the demand, but instead they are mainly due to evacuation problems and renewable curtailments.
- The covariances methodology for the upward activated energy for the restrictions and the secondary band, as it was concluded that the main reason behind the need of these services is the uncertainty of the demand.

6.1 CASE STUDY: PROPOSED METHODOLOGY

From previous analysis, it was concluded that the optimal methodology was to combine the covariances method for the upward energy restrictions and secondary band, and a Ramsey pricing for the downward energy restrictions. The objective of this section is to compute the final cost of supplying energy to the final consumer and compare the variation of the distribution of the costs within groups.

6.1.1 UNITARY COSTS FOR THE AASS

On the one hand, since no direct relationship was found between the costs related to the **downward energy and the demand**, it was decided to allocate these costs according to the Ramsey pricing principle. As the charges, these costs must be allocated to each consumer in a way that does not distort the efficient economic signal as they are not related to the usage of the grid, nor the grid itself. So, following the RD 148/21, first the TAC is calculated. For the analysis, the power term is going to be neglected as all the costs are going to be recovered through the energy term. (54.268.383) (the energy term is the only one considered)

$$TAC = \sum_{i=1}^{i=6} \sum_{s=1}^{s=6} \frac{E_{si}}{Ce_{si}} + \frac{P_{si}}{Cp_{si}}$$

Figure 105: TAC equation. Source: RD 148/21.

The next step of this methodology is to obtain the TAU using the costs of the downward energy from table 30:

EN BAJAR (€)	
CPDBF	24.540.512,49
CRT	67.666.103,84
CTOT	43.126.406,61

Table 30: Total cost (€) for the downward energy restrictions for 2024. Source: Own elaboration.

Following the RD 148/21, we computed the final unitary price for the downward energy restrictions.

$$TAU = \frac{Cargos\ totales}{TAC}$$

Figure 106: TAU equation. Source: RD 148/21.

And finally, the unitary price for each period and group is obtained by dividing the TAU between the coefficients from the RD. The final unitary price (U.P) for the downward energy restrictions is:

$$U.P_{downaward\ energy\ restrictions} = \frac{TAU}{Ce_{si}}$$

Equation 15: Final unitary price for the downward energy restrictions.

Energy term (€/MWh b.c.)	P1	P2	P3	P4	P5	P6	TOTAL
2.0TD	2,570032	0,514006	0,128502				0,383305
3.0TD	1,432719	1,060822	0,573088	0,286544	0,183682	0,114618	0,486008
6.1TD	0,779041	0,577067	0,311616	0,155808	0,099877	0,062323	0,243268
6.2TD	0,365532	0,270735	0,146213	0,073106	0,046863	0,029243	0,108574
6.3TD	0,299631	0,221949	0,119852	0,059926	0,038414	0,023970	0,081870
6.4TD	0,113832	0,084317	0,045533	0,022766	0,014594	0,009107	0,030829
							0,291744

Table 31: Unitary price (€/MWh) for the downward energy restrictions for 2024. Source: Own elaboration.

On the other hand, it was decided that the covariances method was going to be used to recover the costs from the upward energy restrictions, the secondary band and the SRAD. Therefore, the unitary costs per group and period are going to be the ones in tables 17 and 19.

The final unitary price for the restrictions will be the sum of the upward and downward unitary prices.

6.1.2 Final cost allocation

With the actual methodology, the allocation among each group of **the current costs for 2024** are the ones in figure 108:

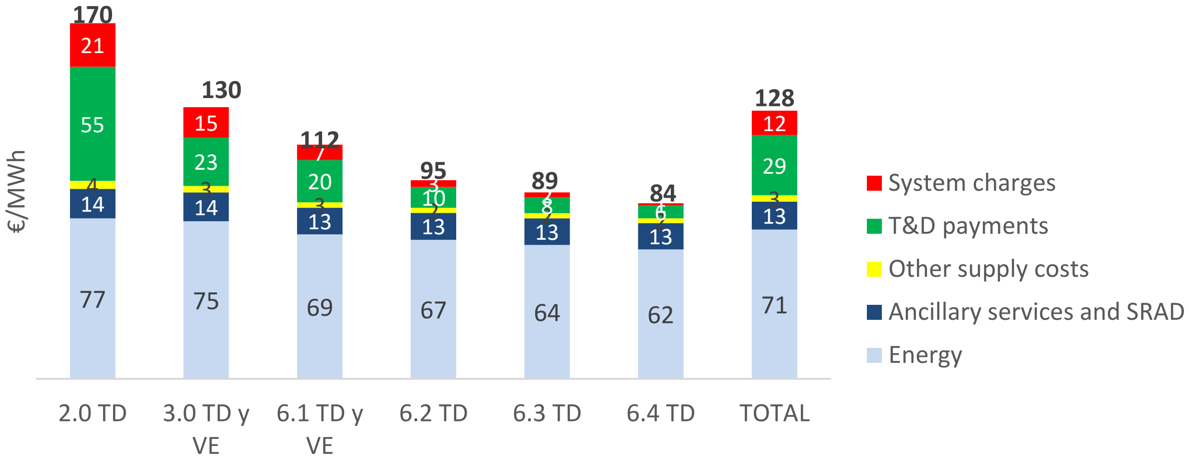


Figure 107: Graph of the current costs (€/MWh) from 2024 for the end consumer. Source: CNMC and SO 2024 report.

With **the proposed methodology**, the allocation among each group of the costs for 2024 would be the ones in figure 109:

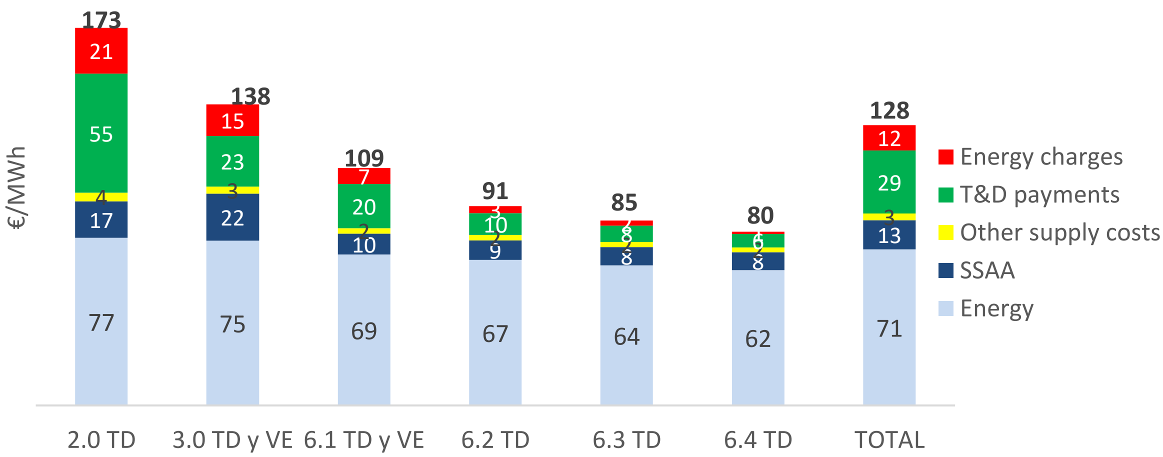


Figure 108: Graph of the allocation of the costs (€/MWh) with the proposed methodology for 2024 for the end consumer. Source: Own elaboration.

A variation among groups is observed in the AASS term, the rest of the components remain the same. Table 32 shows the variation in the total cost and AASS per group.

	Total AASS current	*Total AASS proposed*	*VARIATION*
2.0 TD	***14,0***	***16,7***	***18,79%***
3.0 TD y VE	***13,9***	***21,6***	***55,26%***
6.1 TD y VE	***12,9***	***9,6***	***-25,48%***
6.2 TD	***12,8***	***9,0***	***-29,51%***
6.3 TD	***12,8***	***8,4***	***-34,42%***
6.4 TD	***12,5***	***8,2***	***-34,82%***
TOTAL	***13,4***	***13,4***	

Table 32: Liquidated €/MWh of the AASS vs proposed allocation in €/MWh of the AASS and the variation for 2024. Source: Own elaboration.

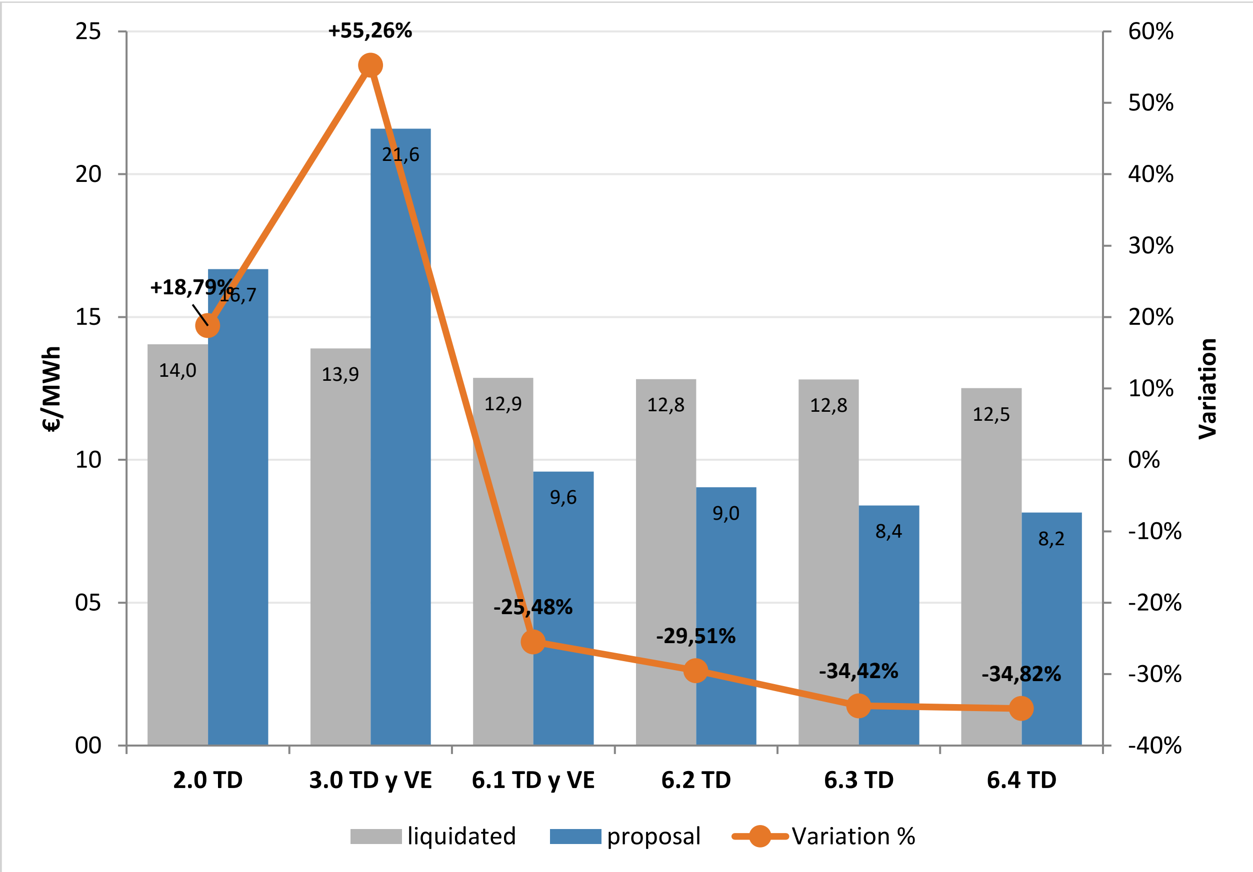


Figure 109: Evolution of the AASS costs (€/MWh) with the proposed methodology. Source: Own elaboration.

	Total current without taxes	*Total proposed without taxes*	*VARIATION*
2.0 TD	*170,3*	*173,0*	*1,56%*
3.0 TD y VE	*130,1*	*138,0*	*6,02%*
6.1 TD y VE	*112,1*	*108,8*	*-2,95%*
6.2 TD	*95,2*	*91,3*	*-4,04%*
6.3 TD	*89,3*	*84,8*	*-5,06%*
6.4 TD	*84,1*	*79,7*	*-5,28%*
TOTAL	*128,4*	*128,4*	*0,00%*

Table 33:Liquidated €/MWh of the total vs proposed allocation in €/MWh of the total and the variation for 2024. Source: Own elaboration.

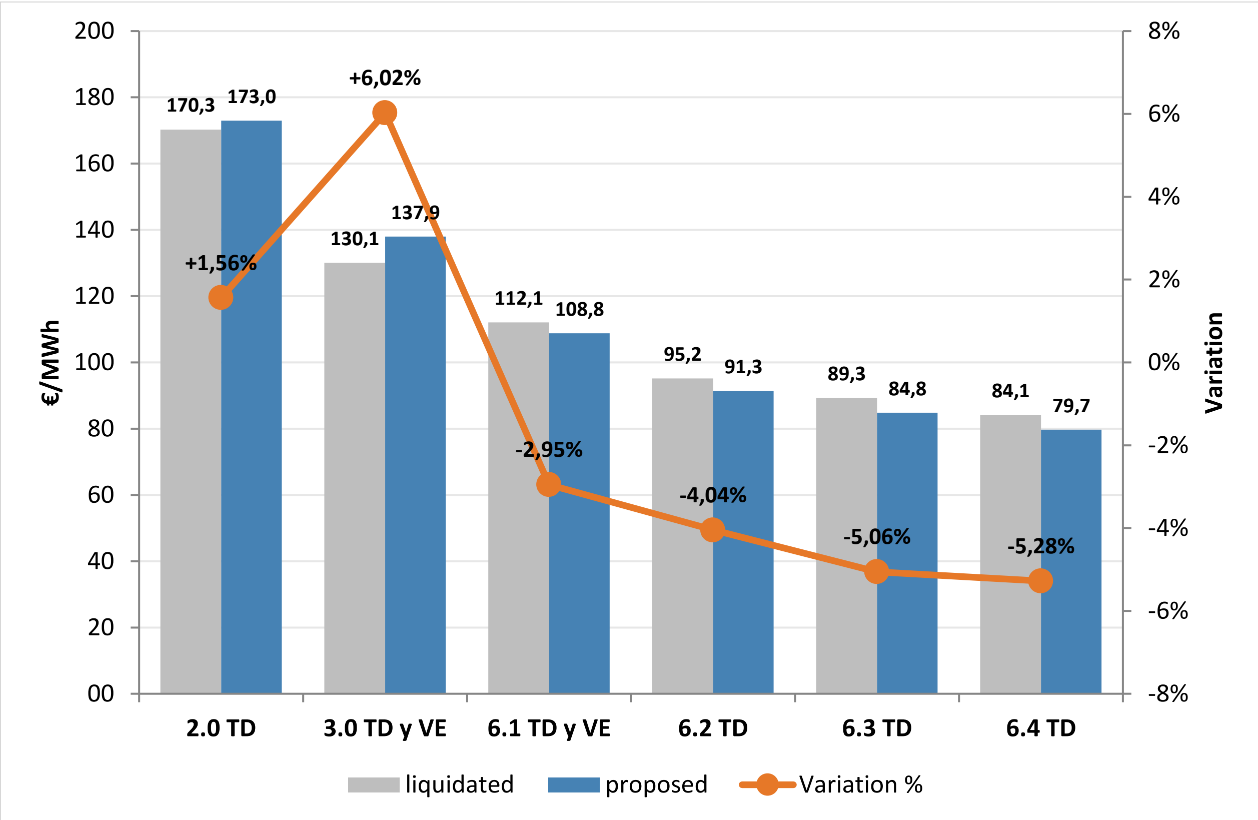


Figure 110: Evolution of the supply costs (€/MWh) with the proposed methodology. Source: Own elaboration.

The results show that with the proposed methodology, the costs assigned to 2.0 and 3.0 increases, whereas the costs assigned to the higher voltage groups decrease. This is coherent with the proposed allocation methodology since these groups have a demand profile that contributes more to the variation and uncertainty of total demand. If some groups generate a more variable or less predictable demand profile, it makes sense that they bear a higher share of these costs.

Nevertheless, the ultimate objective of this methodology was to send an optimal economic signal, lowering the prices during off-peak hours and increasing them during the hours that the system is more stressed. The following figures show how the ancillary service costs are redistributed across the different hours of the day before and after applying the proposed allocation methodology.

INCURRED PRICES IN 2024

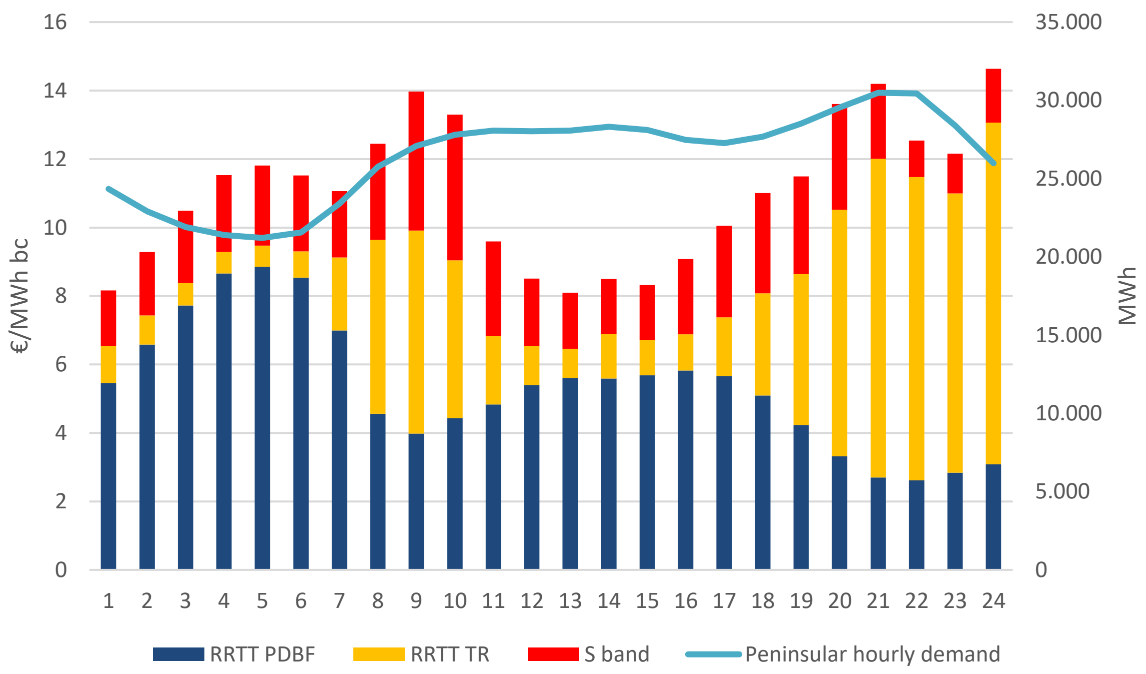


Figure 111: Hourly average energy cost (€/MWh) of the current AASS for 2024. Source: SO.

PROPOSED

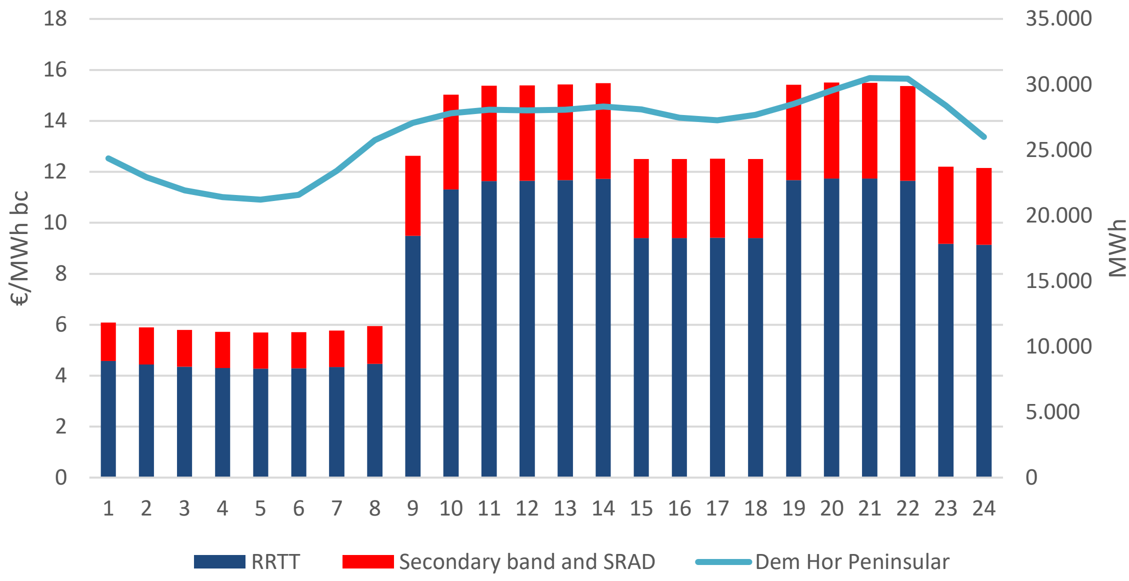


Figure 112: Hourly average energy cost (€/MWh) of the proposed AASS allocation cost for 2024. Source: Own elaboration.

INCURRED PRICES IN 2024

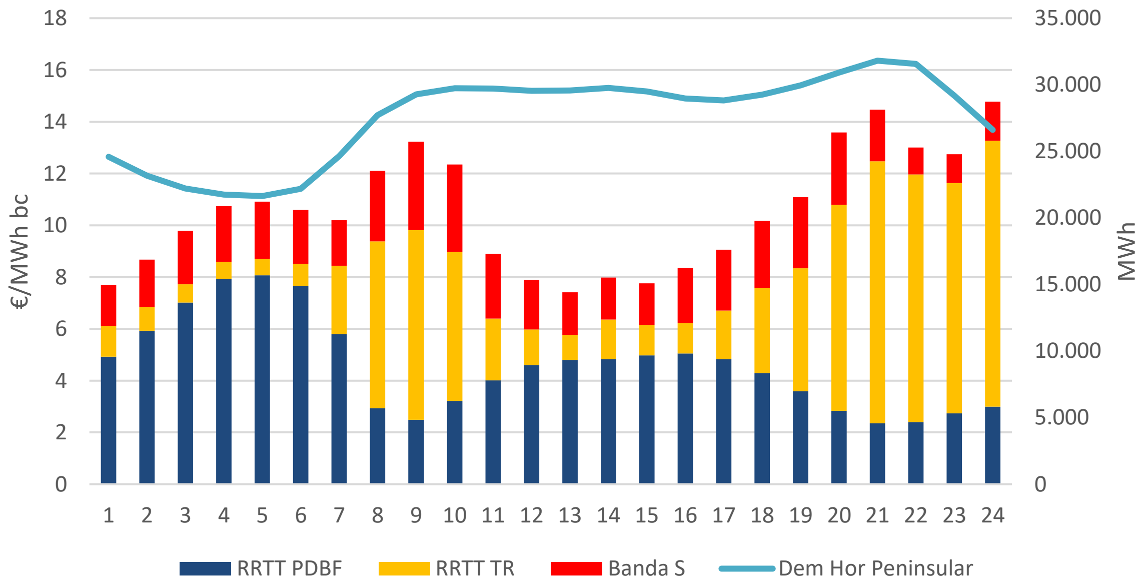


Figure 113: Hourly average energy cost (€/MWh) of the current AASS on a working day for 2024. Source: SO.

PROPOSED

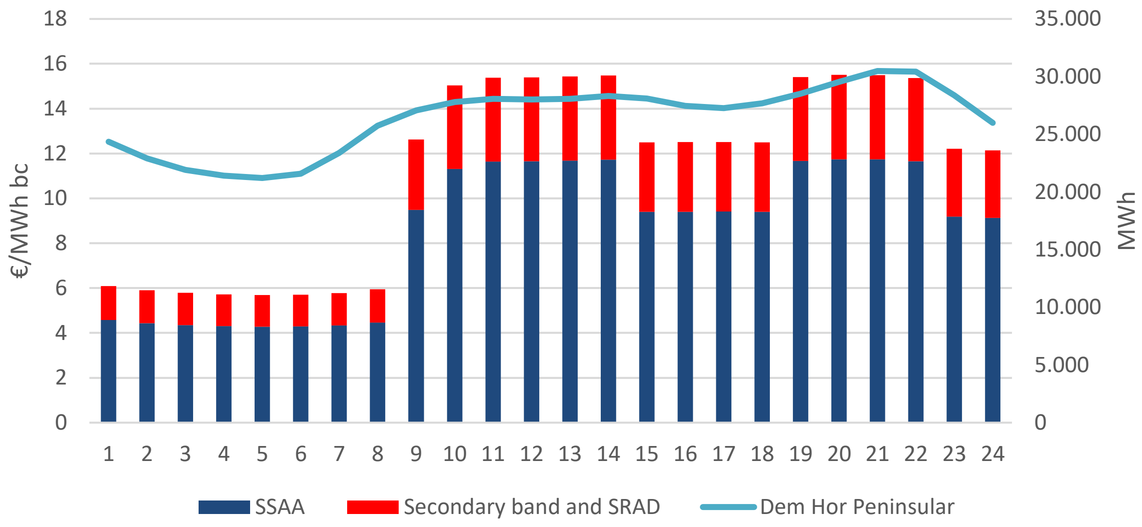


Figure 114: Hourly average energy cost (€/MWh) of the proposed AASS allocation cost on a working day for 2024. Source: Own elaboration.

INCURRED PRICES IN 2024

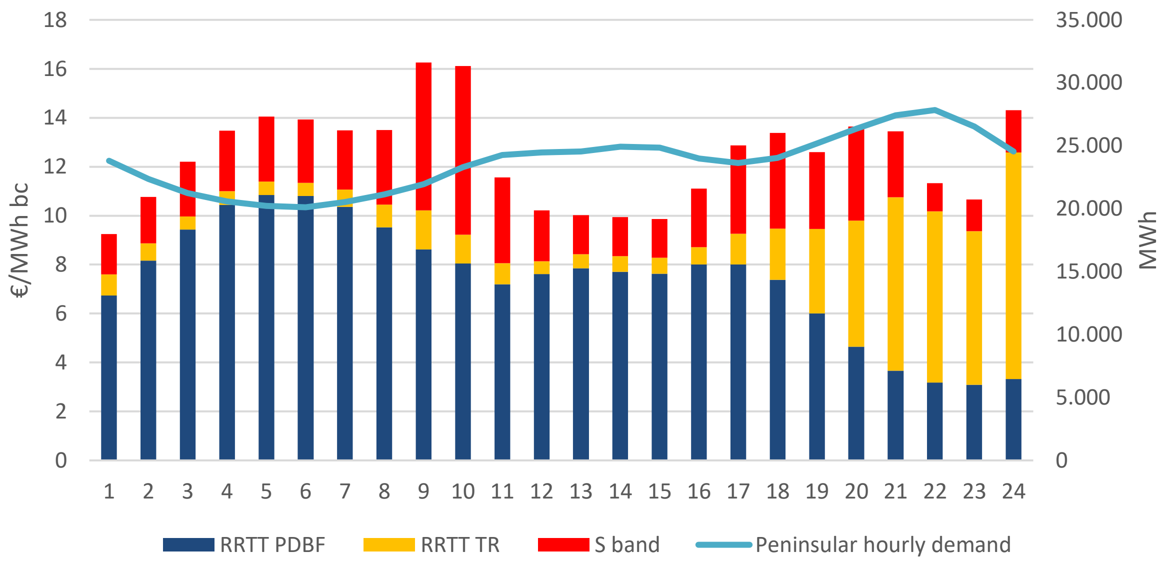


Figure 115: Hourly average energy cost (€/MWh) of the current AASS on a non-working day for 2024. Source: SO.

PROPOSED

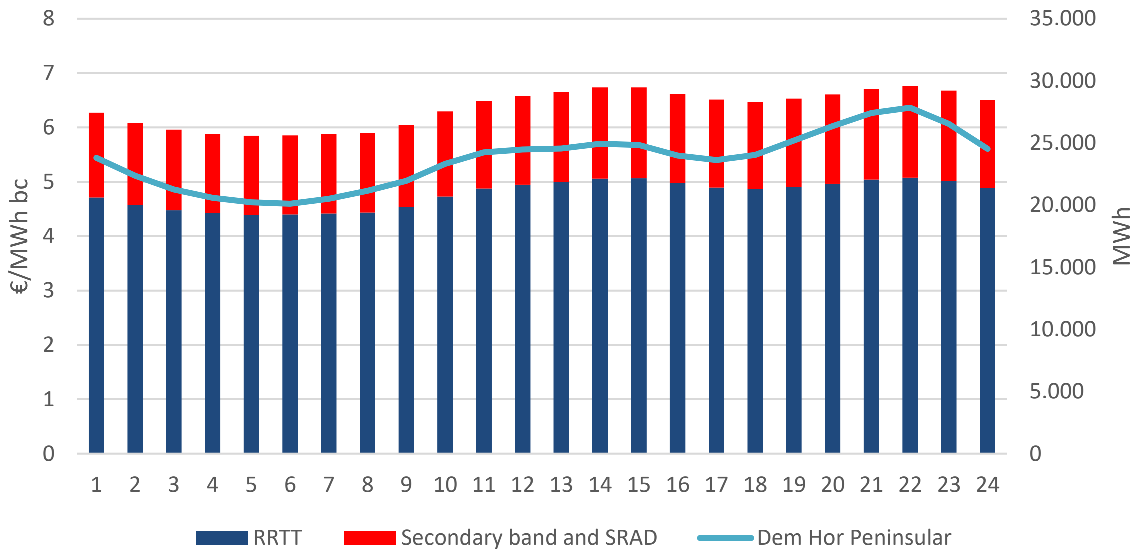


Figure 116: Hourly average energy cost (€/MWh) of the proposed AASS allocation cost on a non-working day for 2024. Source: Own elaboration.

The comparison between graphs shows that the proposed methodology significantly changes the hourly profile of the ancillary service cost. Before applying the methodology, the costs of RRTT and secondary band were more dispersed throughout the day and, in some cases, higher costs appeared during hours with relatively low demand. This made the price signal less consistent with the stress of the system, since consumers could face high ancillary service costs in hours that were not necessarily associated with higher demand or higher operational needs.

After applying the proposed methodology, the allocation of the costs becomes more concentrated in the hours in which demand is higher, and it decreases during the first hours of the day. The same pattern can be observed in the graph for working days. With the actual allocation methodology, relevant costs appeared during early morning hours. With the proposed methodology, the cost is shifted towards the hours with higher demand, especially between hours 9 and 14 and again during the evening peak. This produces a clearer and more efficient signal, since the consumer faces a higher cost in the hours where their demand is more likely to contribute to system stress. In the case of non-working days, the difference is even clearer. With the current methodology, the cost profile was irregular, with significant costs in several hours that did not follow the demand curve. With the proposed methodology, the hourly allocation becomes much more stable and better aligned with the demand profile.

As always, there are some losers and some winners with this methodology. However, the proposed methodology achieves its main purpose: it reinforces the price signal in the hours with higher system stress and reduces it in the hours in which the need for ancillary services is lower.

Finally, to complete the previous analysis, the method is applied to obtain the expected results for 2026. As inputs, the expected costs from SO for the ancillary services have been used.

Services	***M€***		
	2023	**2024**	**2025p**
Restrictions PDBF	*1.054*	*1.217*	*2.383*
Restrictions in real time	*844*	*842*	*960*
Technical restrictions	**1.898**	**2.059**	**3.343**
Secondary band	526	523	512
SRAD	79	143	283
Deviations	103	89	107
Others*	-103	-120	-48
Power factor control	-19	-26	-21
Total AASS	**2.483**	**2.668**	**4.176**
Annual variation %		**7,5**	**56,5**

Table 34: Provisional data from January 2025. Source: www.ree.es

In addition, an estimation of the market price has been included in the analysis. For this purpose, the expected market price for 2027 was obtained from the OMIP webpage. The data was collected on 15 June, and the expected annual day-ahead market price was 62.50 €/MWh (OMIP, 2026). However, since the expected price for the first quarter of 2027 was around 76 €/MWh, a reference value of 70 €/MWh was finally selected for the analysis. This value is considered a reasonable intermediate assumption between the annual average and the higher prices expected at the beginning of the year.

$$Expected\ 2026\ day\ ahead\ market\ price_{group} = \frac{70 * Market\ price_{group}}{Average\ market\ price}$$

Equation 16: Expected market price for 2026.

Finally, the costs have been allocated using the percentages that resulted from the proposed covariance method on table 16.

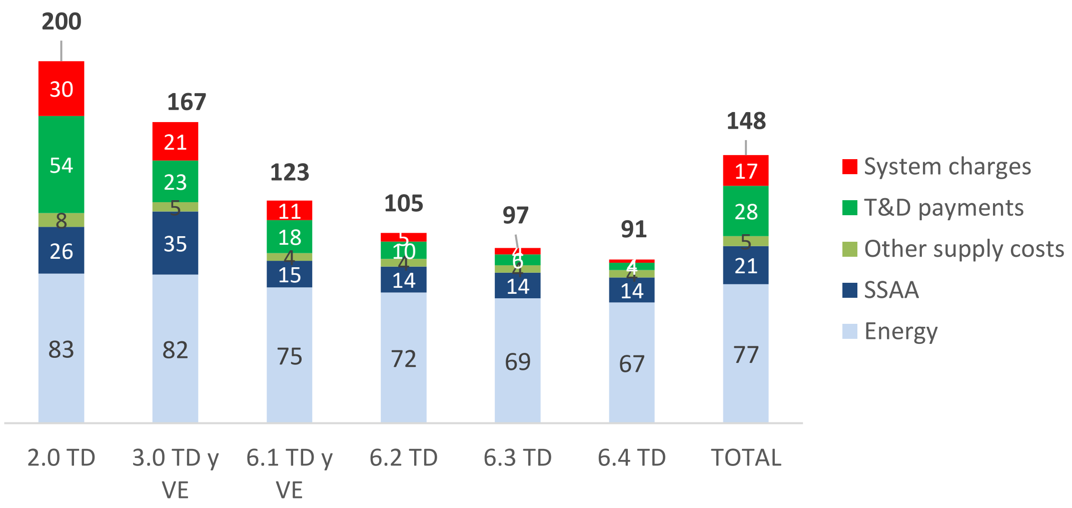


Figure 117: Forecast of the supply cost (€/MWh) per group for 2026. Source: Own elaboration.

6.1.3 ELASTICITY ANALYSIS

As discussed throughout the thesis, under the current allocation methodology, some valley hours are facing a higher ancillary services cost than expected. This creates an inefficient economic signal, as it discourages consumption precisely in the hours where additional demand could be useful for the system. This effect is especially relevant for higher-voltage consumers, since they are usually more sensitive to price signals and have more capacity to adjust their production schedules by shifting consumption towards lower-cost hours. With the proposed methodology, the cost assigned to valley hours is reduced, while a larger share of the cost is concentrated in peak periods. Although this may lead some consumers to reduce their consumption during peak hours, the objective is to obtain a positive net effect for the system. Our proposal aims to encourage demand in the hours when it is more beneficial and reduce it when the system is already under higher stress. To evaluate this effect, an elasticity analysis is carried out to estimate how demand may change depending on the variation in final prices:

$$\Delta Q = \varepsilon * \Delta P$$

Equation 17: Elasticity computation.

The first step was to obtain the elasticities from a residential consumer and an industrial consumer. Several reports have been consulted, and in the end, the data was extracted from (Csereklyei, 2020). This author (as well as other) distinguishes between two types of elasticity prices: the elasticity in the short run, that is the annual price elasticity; and the long run elasticity. The long run is not an exact number of years but instead is defined as the time that the demand needs to adapt to changes in the steady state. In addition to this, since the residential consumers are more inelastic, the elasticity coefficient is lower in absolute terms than the residential ones, as they have a more elastic profile. Table 35 summarizes the elasticities from the report. To have a more complete analysis, three scenarios are going to be considered: a low elasticity scenario, a medium and a high elasticity one:

Short run	***Low***	***Medium***	***High***
Residential consumer	-0,07	-0,075	-0,08
Industrial consumer	-0,08	-0,09	-0,1
Long run			
Residential consumer	-0,53	-0,545	-0,56
Industrial consumer	-0,75	-0,88	-1,01

Table 35: Elasticities for residential and industrial consumers in different scenarios. Source: (Csereklyei, 2020).

The elasticities represent the percentage of variation in the demand when increasing by 1% the price.

Once having the elasticities set, the next step was to estimate the variation in the price. For that, the difference between the current final average price and the proposed final average price was computed. This was made for the 24 hours of a working and non-working day.

$$\Delta P_h = \frac{P_{proposed\ h} - P_{liquidated\ h}}{P_{liquidated\ h}} \ \forall h$$

Equation 18: Price variation computation

Finally, using the elasticities from table 35 and following equation 15, the variation of the demand on each scenario was obtained.

In the short term:

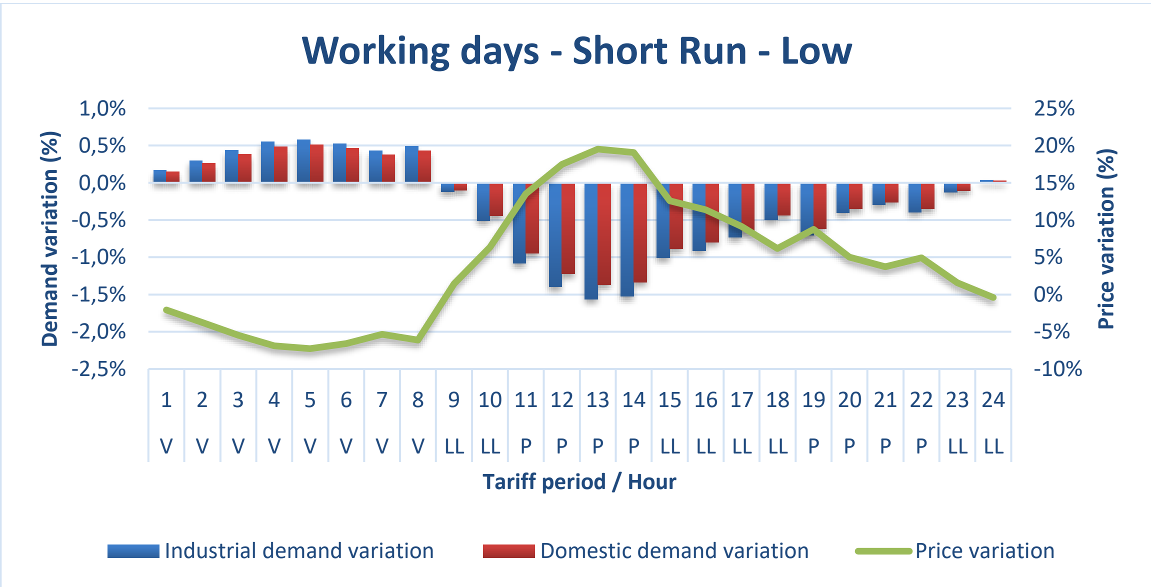


Figure 118: Demand variation in the short run for a working day on a low elasticity scenario. Source: Own elaboration.

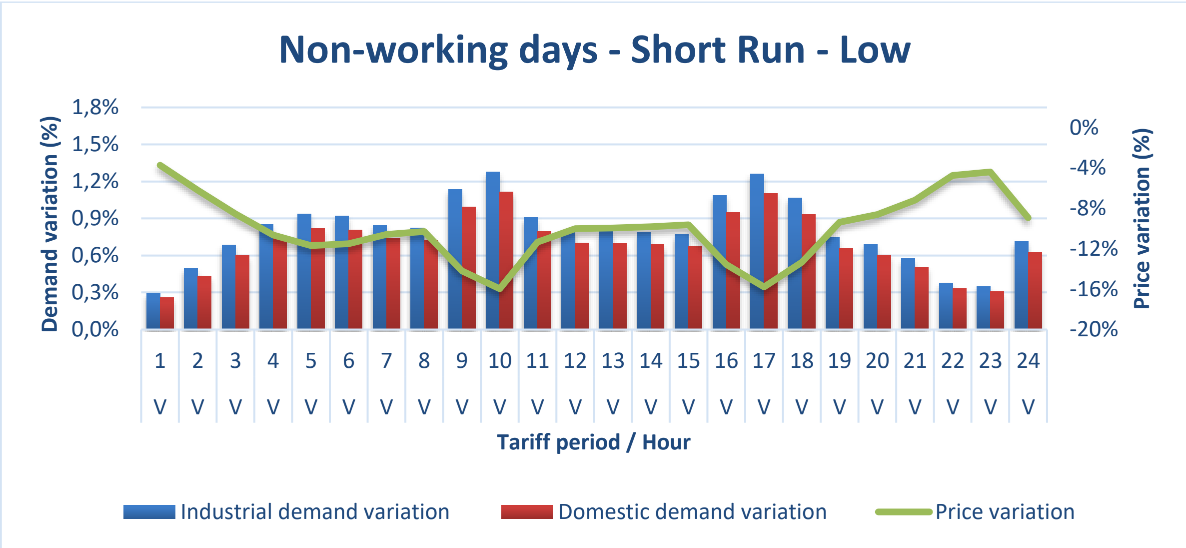


Figure 119: Demand variation in the short run for a non-working day on a low elasticity scenario. Source: Own elaboration.

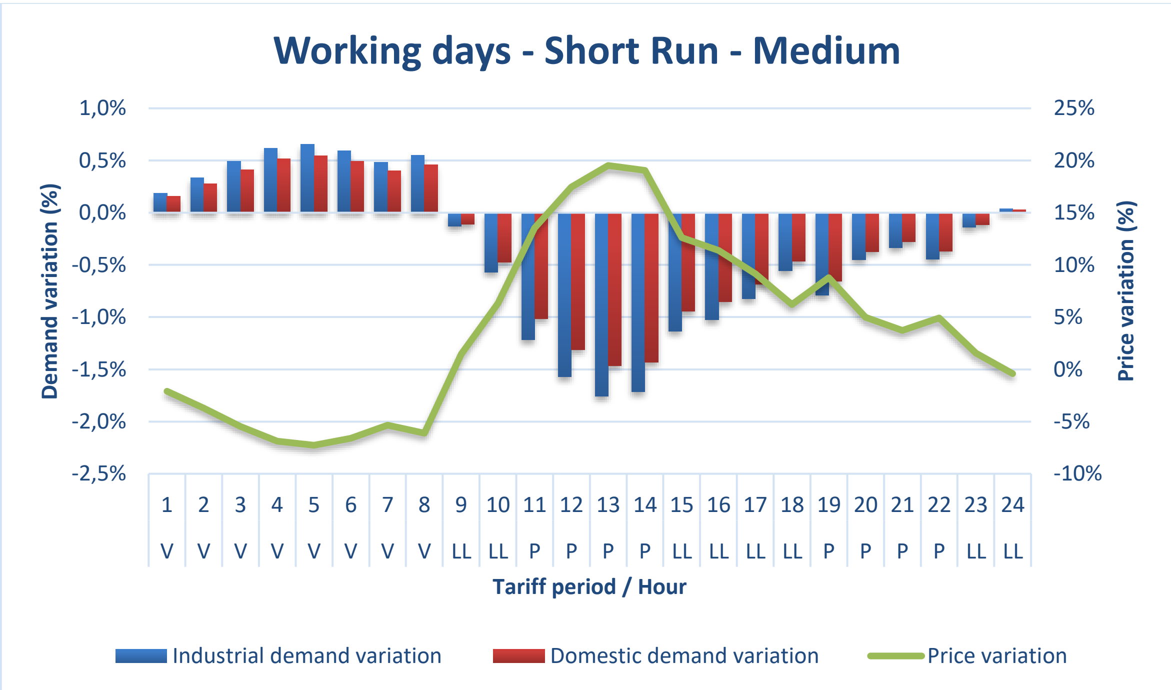


Figure 120: Demand variation in the short run for a working day on a medium elasticity scenario. Source: Own elaboration.

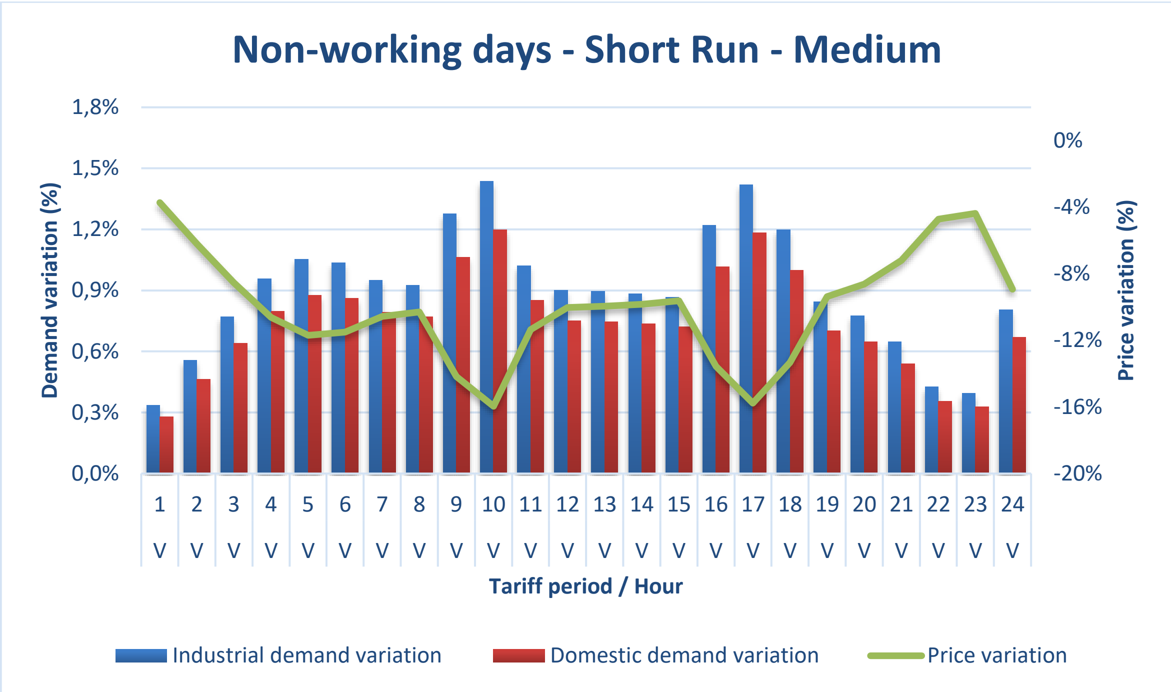


Figure 121: Demand variation in the short run for a non-working day on a medium elasticity scenario. Source: Own elaboration.

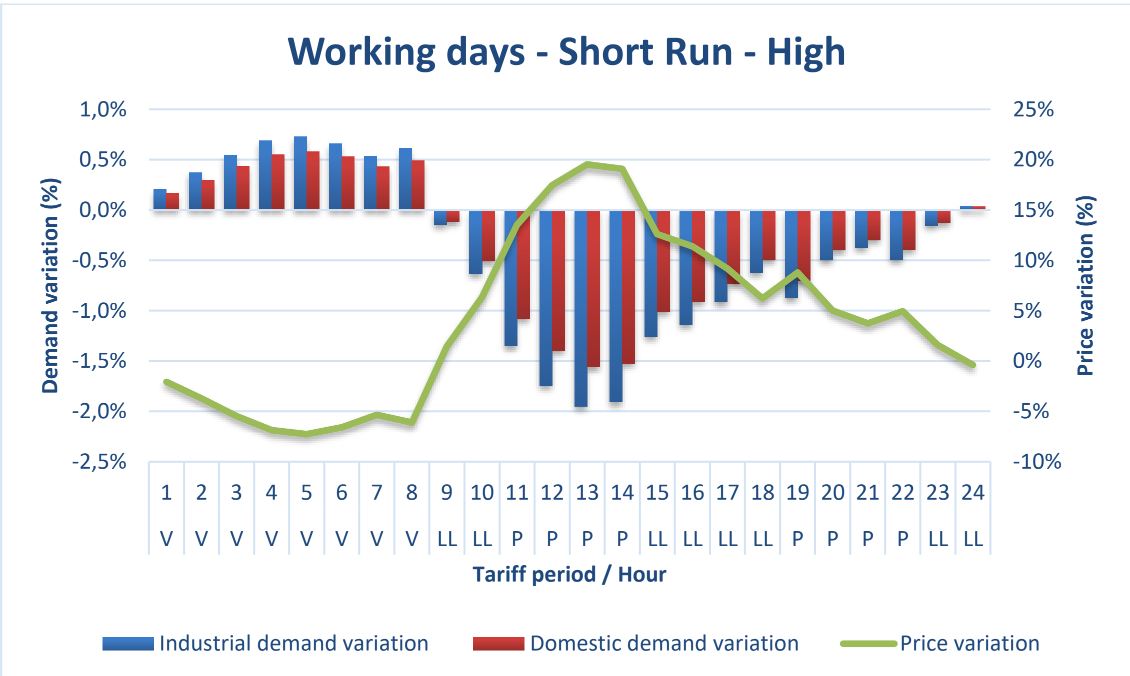


Figure 122: Demand variation in the short run for a working day on a high elasticity scenario. Source: Own elaboration.

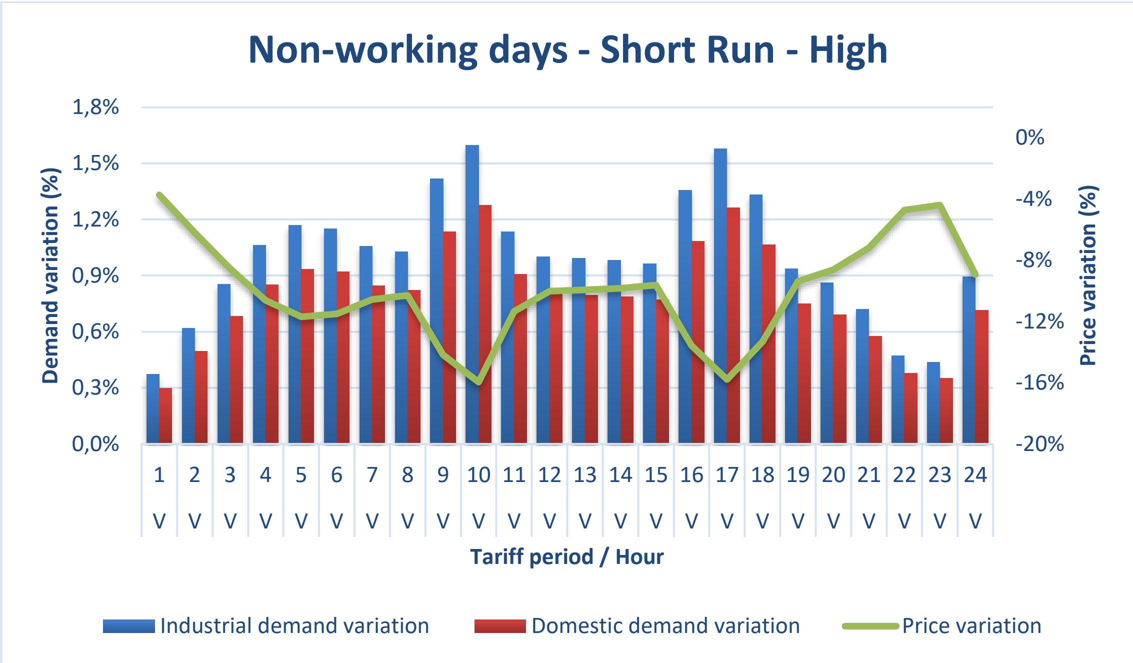


Figure 123: Demand variation in the short run for a non-working day on a high elasticity scenario. Source: Own elaboration.

And in the long term:

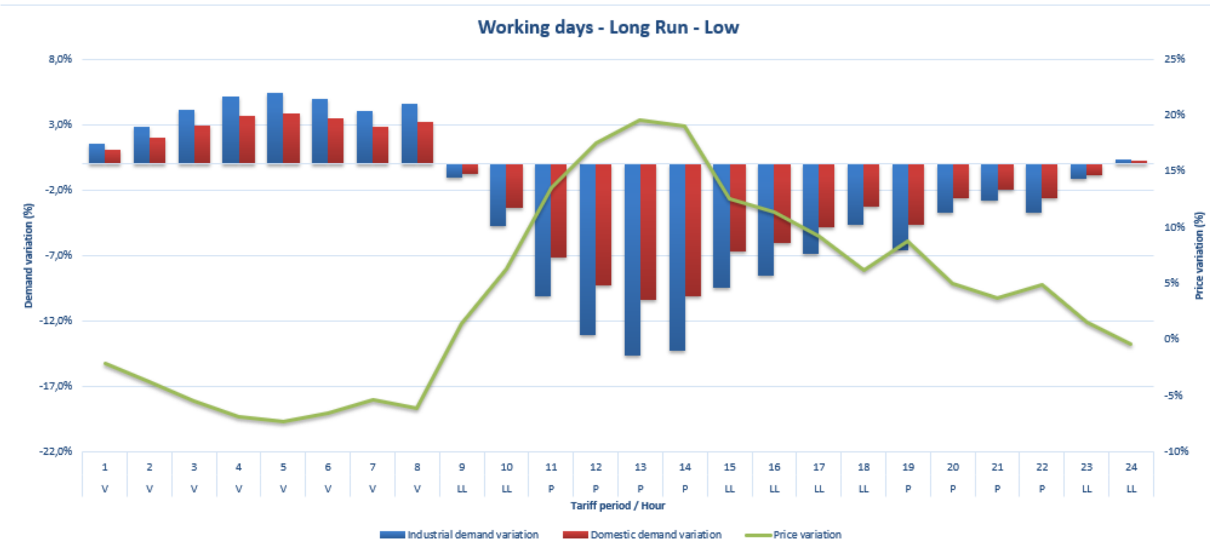


Figure 124: Demand variation in the long run for a working day on a low elasticity scenario. Source: Own elaboration.

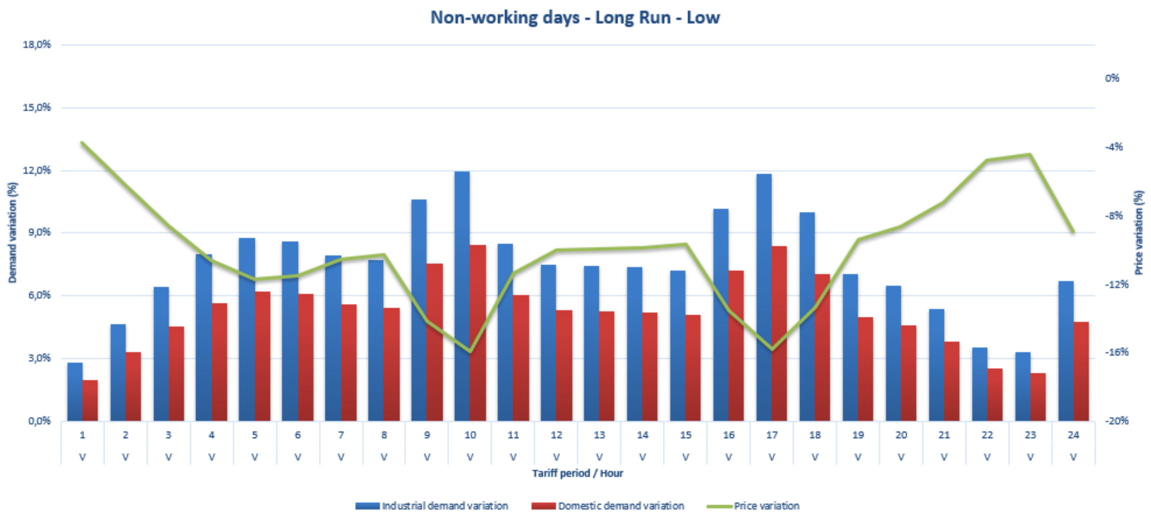


Figure 125: Demand variation in the long run for a non-working day on a low elasticity scenario. Source: Own elaboration.

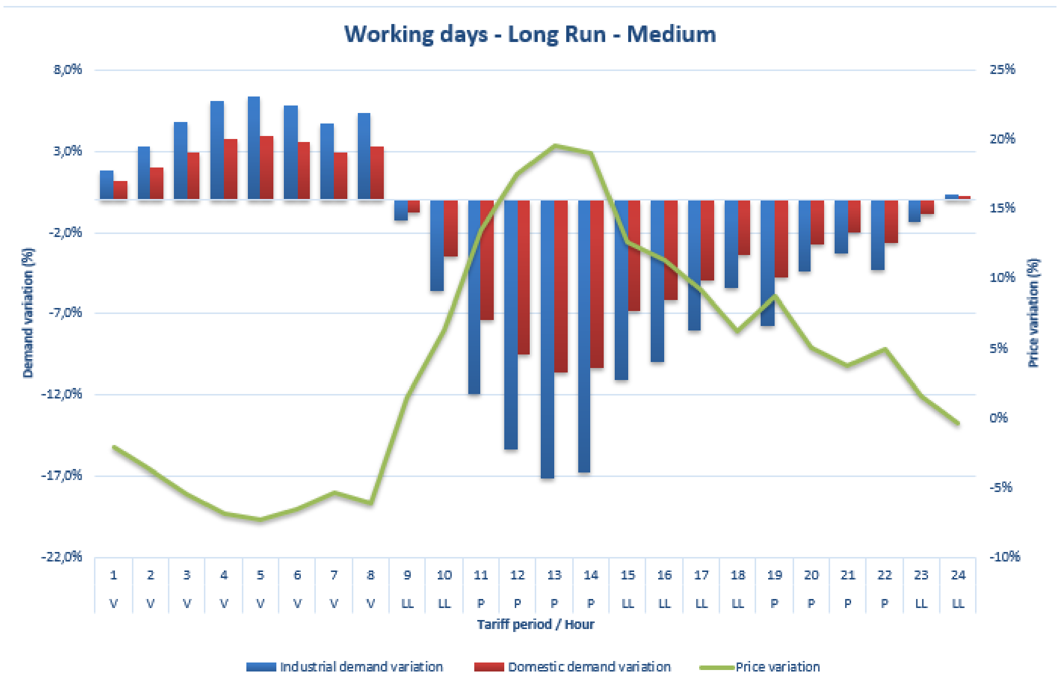


Figure 126: Demand variation in the long run for a working day on a medium elasticity scenario. Source: Own elaboration.

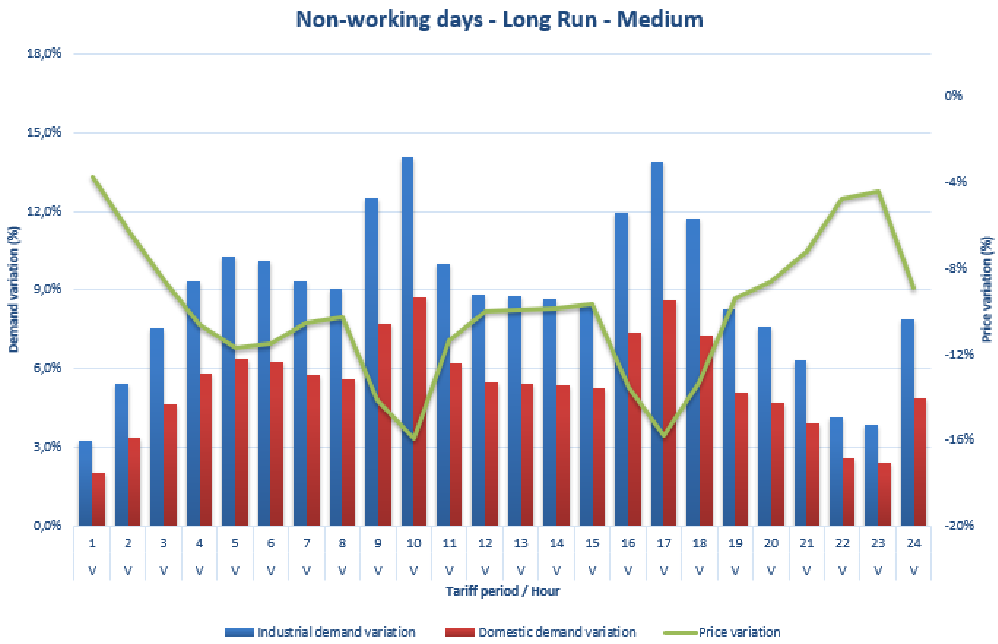


Figure 127: Demand variation in the long run for a non-working day on a medium elasticity scenario. Source: Own elaboration.

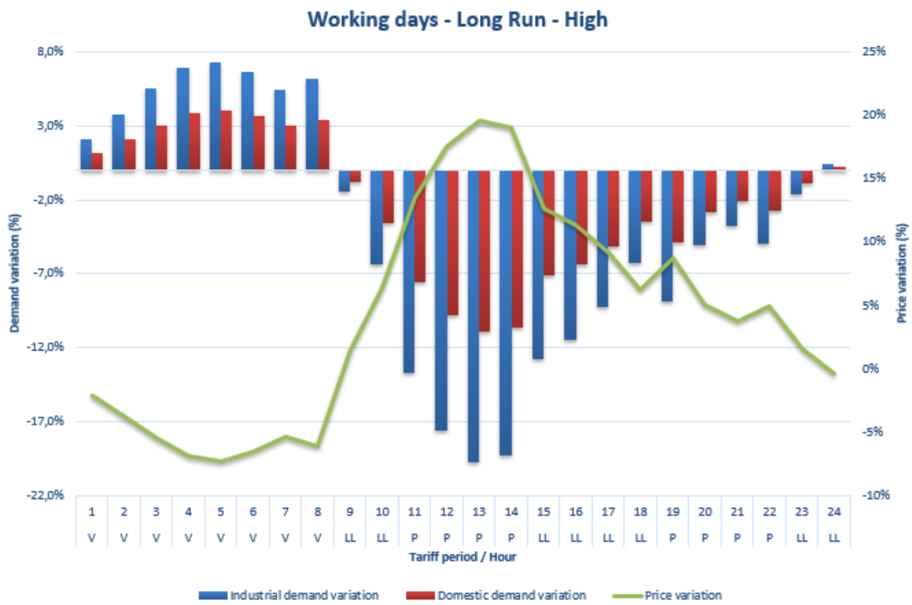


Figure 128: Demand variation in the long run for a working day on a high elasticity scenario. Source: Own elaboration.

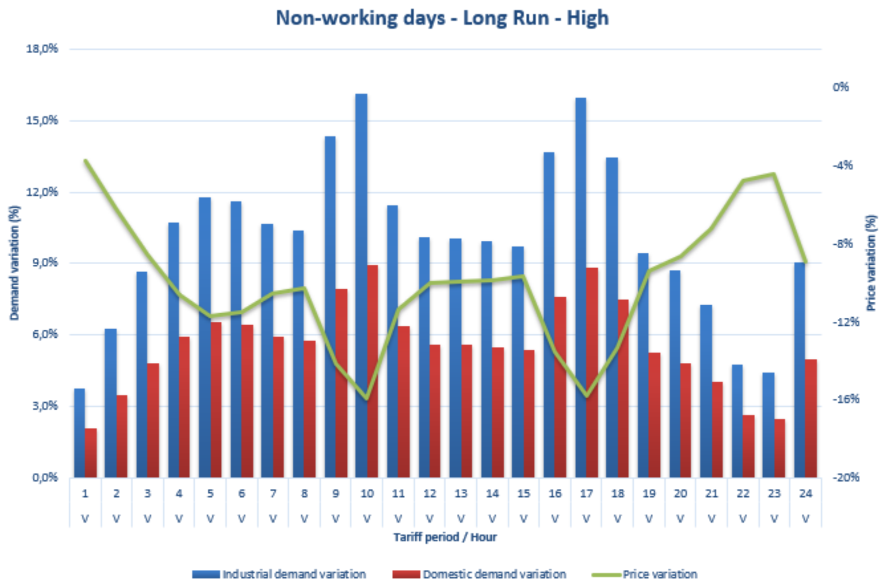


Figure 129: Demand variation in the long run for a non-working day on a high elasticity scenario. Source: Own elaboration.

Finally, the average demand variation for each scenario has been computed and summarized in the following tables.

SR WORKING DAYS AVERAGE DEMAND VARIATION		*Valley*	*Flat*	*Peak*
LOW	Industrial	0,44%	-0,48%	-0,92%
	Domestic	0,38%	-0,42%	-0,81%
MEDIUM	Industrial	0,49%	-0,54%	-1,04%
	Domestic	0,41%	-0,45%	-0,86%
HIGH	Industrial	0,54%	-0,60%	-1,15%
	Domestic	0,44%	-0,48%	-0,92%

Table 36: Average demand variation in the short run of a working day. Source: Own elaboration.

SR NON- WORKING DAYS AVERAGE DEMAND VARIATION		*Valley*
LOW	Industrial	0,80%
	Domestic	0,70%
MEDIUM	Industrial	0,90%
	Domestic	0,75%
HIGH	Industrial	1,00%
	Domestic	0,80%

Table 37: Average demand variation in the short run of a non-working day. Source: Own elaboration.

LR WORKING DAYS AVERAGE DEMAND VARIATION		*Valley*	*Flat*	*Peak*
LOW	Industrial	4,08%	-4,53%	-8,63%
	Domestic	2,88%	-3,20%	-6,10%
MEDIUM	Industrial	4,79%	-5,31%	-10,12%
	Domestic	2,96%	-3,29%	-6,27%
HIGH	Industrial	5,49%	-6,10%	-11,62%
	Domestic	3,05%	-3,38%	-6,44%

Table 38: Average demand variation in the long run term of a working day. Source: Own elaboration.

LR NON- WORKING DAYS AVERAGE DEMAND VARIATION		*Valley*
LOW	Industrial	7,50%
	Domestic	5,30%
MEDIUM	Industrial	8,80%
	Domestic	5,45%
HIGH	Industrial	10,10%
	Domestic	5,60%

Table 39: Average demand variation in the long run of a non-working day. Source: Own elaboration.

Overall, the elasticity analysis shows that the proposed methodology provides a more efficient price signal than the current allocation approach. The results indicate that, when ancillary service costs are reallocated according to the proposed method, demand tends to increase in valley hours and decrease in flat and peak hours. This effect is observed in both working and non-working days, although it is more significant in the long run, as consumers have more time to adapt their consumption patterns.

The degree of the estimated demand response depends on the elasticity scenario considered. In the short run, the effect is moderate, which is expected because consumers have limited ability to immediately change their consumption. However, in the long run, the response becomes more relevant, especially for industrial consumers, whose demand is more elastic. This suggests that the proposed methodology could support a progressive adaptation of consumption patterns over time.

Therefore, the analysis supports the idea that the proposed allocation methodology is not only more consistent with cost-reflectivity principles, but also more efficient from a system perspective. By shifting part of the consumption towards hours where additional demand is more useful, the methodology may reduce the risk of reinforcing inefficient price signals and contribute to a better alignment between consumer behavior and system needs.

Chapter 7. CONCLUSIONS

This chapter summarizes the main conclusions obtained throughout the thesis. The main problem identified the way in which these costs are allocated across hours. The current allocation methodology has shown some inefficiencies, as it can increase the final price in hours when the day-ahead market price is low and is efficient to consume from the system perspective as there is too much available capacity in the grid. This is particularly relevant because these hours are precisely the periods in which additional consumption could help the system. However, if the allocation of ancillary service costs makes these hours more expensive, consumers may have fewer incentives to shift their demand towards them. As a result, demand may decrease even further in periods where the system already needs more support, increasing again the need for ancillary services and reinforcing the same effect. For this reason, the development of an alternative allocation proposal is justified.

The main findings obtained throughout the thesis, which support this conclusion and justify the proposed methodology, are summarized in this chapter.

7.1 DATA COLLECTION

The first part of the methodology consisted of collecting and organizing the information published by SO related to the activation, price and cost of ancillary services. Some conclusions that can be extracted for this section are:

1. The overcost of restrictions must be understood as the difference between the settlement of the activated energy and the value that this same energy would have had in the day-ahead market.
2. This is especially relevant in hours with low demand and high renewable production, where the market price may be low, but the system may still require technical restrictions, voltage control or balancing actions.
3. The ancillary service costs are associated mainly with the upward energy activations.

4. There is a "label" effect. The way SO registers the necessity of these energies, does not allow the underlying cause to be clearly identified and does not follow a consistent pattern.
5. The way SO label energy changed from 2023 onwards.
6. The label effect was intensified after the blackout.
7. Since there was no clear pattern, for further analysis it is more appropriate to aggregate energy restrictions into groups, distinguishing between upward and downward actions, and between PDBF and real-time restrictions.
8. In addition to this, the benchmark showed that there is no single European methodology for recovering adjustment service and system operation costs.

7.2 REGRESSION ANALYSIS

The regression analysis was carried out to see whether demand could be used as a robust driver for allocating ancillary service costs. Considering the previous results, some clear insights can be extracted:

1. **Demand provides a clearer signal when the analysis is segmented:** If the total number of hours of the year are analyzed together, the relationship between cost and demand is weak. However, if the analysis is disaggregated by months or tariff periods (P6 and not P6), the models considerably improve, but still there does not exist a clear pattern. The relationship in real time is stronger but still unclear.
2. **Downward CRRTT cannot be justified by demand**: Downward technical constraints (both on the PDBF and real time) do not show a relationship with the demand. Some peaks, such as the ones in summer, can be explained by the coincidence of high demand and generation, but since it is a downward constraint, increasing the demand would not solve the problem. Therefore, it seems to be a more local problem (related to curtailments), not directly attributable to demand.
3. **Upward CRRTT is better explained by activated energy that directly by demand**: For upward constraints, the overcost is mainly explained by activated energy. This indicates that demand is not the most direct variable to justify this cost,

although it is intrinsically related to energy. Nevertheless, it reveals one of the main allocation problems: in periods where the demand is low, especially in P6, an increase on the demand side leads to a reduction in the total cost.

4. **The current PDBF allocation may be distorting the economic signal**: The current methodology might be "masking" the relationship between cost, demand and activated energy. There may be a reduction in demand in high-cost hours, but still the cost keeps rising due to technical reasons, so there must be a price effect that does not allow us to clearly see said relationship.
5. **The strong growth of the energy needed for adjustments makes them not adequate to be used as an allocation method**. These energies capture the physical needs of the system, but not the causal contribution of the demand to it.
6. **The need for secondary band is more related to uncertainty** than to the absolute level of demand. Therefore, a covariance approach was considered more appropriate, since it captures how each group contributes to the variability that the system operator has to manage.

It can be concluded that there exists an actual allocation problem. In some hours, the restriction cost is high due to high generation, congestion, curtailments and local problems. In these situations, increasing the demand could reduce the problem. Nevertheless, a marginal allocation method based on the demand consumption is not possible since a direct relationship with the cost of the restrictions or a common and stable pattern has not been found in the analyzed years.

7.3 TARIFF DESIGN ASSESSMENT

This section reviewed the different tariff design methodologies that could be applied to allocate ancillary service costs. The objective was to identify which ones provide an efficient and cost-reflective signal. For this reason, several alternatives were assessed, including cost causality, cost of service, short-term marginal cost, long-term marginal cost, Ramsey pricing, postage stamp, peak pricing, average participation and an adaptation of the Circular 3/2020 network tariff methodology. The main conclusions obtained were:

1. **The cost causality principle is the most efficient methodology,** since ancillary service costs should be allocated to the users that contribute more to the need for the service. However, the causality behind these costs is not always directly observable.
2. **The regression analysis did not provide a robust model** that showed a strong relationship between demand and cost to justify a short-term marginal cost methodology.
3. **Cost of service and postage stamp methodologies were discarded** because, although they are simple and transparent, they do not provide an efficient economic signal.
4. **Long-run marginal cost was also discarded** because future ancillary service needs are highly uncertain and depend on renewable penetration, electrification, storage, flexibility and future network operation conditions. If robust short-term models could not be obtained, applying a forward-looking marginal methodology would be even less reliable.
5. **Ramsey pricing was chosen only for recovering downward energy restriction costs.** It does not identify the origin of the cost, but it is useful when a clear cost driver cannot be found, because it allows cost recovery while minimizing distortions in consumption patterns.
6. **An adaptation of the peak pricing and the Circular 3/2020 methodology were considered**, but neither of them was selected as the final solution. Peak pricing provides a good signal for system stress, but ancillary services are not only needed during peak demand hours. Circular 3/2020 provides a recognized regulatory structure, but it was designed for network costs and cannot be directly applied to ancillary services.
7. **The covariance method was selected as the main methodology** for upward energy restrictions and secondary band because it reflects the uncertainty and variability that each demand group introduces into the system.

7.4 FINAL PROPOSAL

This section applied the proposed methodology to the 2024 data in order to evaluate how ancillary service costs would be redistributed across consumer groups and time periods. The proposed approach combines the covariance method for upward activated energy, secondary band and SRAD, with the Ramsey methodology for downward activated energy.

1. **The proposal ensures cost recovery but changes how costs are distributed.** The allocation between tariff groups and periods changes in order to better reflect the contribution of each group to the need for adjustment services.
2. **The methodology increases the AASS cost assigned to low-voltage groups and reduces it for higher-voltage groups**. The cost assigned to 2.0 TD and 3.0 TD increases, while the cost assigned to 6.1 TD, 6.2 TD, 6.3 TD and 6.4 TD decreases. This is consistent with the covariance approach, since low-voltage groups show more variable and less predictable demand profiles. The tables below summarize the variations in €/MWh per group.

Tariff	*Market price*	*Market price*	*AASS liquidated*	*AASS proposed*	*Other costs liquidated*	*Other costs proposed*	*T&D*	*Charges*
2.0 TD	76,9	76,9	14,0	16,7	3,9	3,9	54,6	20,9
3.0 TD	75,5	75,5	13,9	21,6	3,1	3,2	23,2	14,6
6.1 TD	69,1	69,1	12,9	9,6	2,5	2,5	20,3	7,3
6.2 TD	66,7	66,7	12,8	9,0	2,5	2,4	10,0	3,3
6.3 TD	64,1	64,1	12,8	8,4	2,4	2,3	7,5	2,4
6.4 TD	62,0	62,0	12,5	8,2	2,3	2,3	6,1	1,1
Total	**71,5**	**71,5**	**13,4**	**13,4**	**3,0**	**3,0**	**28,9**	**11,6**

Table 40: Unitary cost comparison (€/MWh) liquidated and proposed for 2024 per tariff group. Source: Own elaboration.

Tariff	*Total liquidated*	*Total proposed*	*Variation*	*Variation (%)*
2.0 TD	170,3	173,0	**+2,7**	**+1,6 %**
3.0 TD y VE	130,1	137,9	**+7,8**	**+6,0 %**
6.1 TD y VE	112,1	108,8	**−3,3**	**−2,9 %**
6.2 TD	95,2	91,3	**−3,9**	**−4,1 %**

6.3 TD	89,3	84,8	**−4,5**	**−5,0 %**
6.4 TD	84,1	79,7	**−4,4**	**−5,2 %**
Total	**128,4**	**128,4**	**0,0**	**0,0 %**

Table 41: Continuation of the unitary cost comparison (€/MWh) liquidated and proposed for 2024 per tariff group. Source: Own elaboration.

Tariff	***RRTT liquidated***	***RRTT proposed***	***Variation***	***Secondary band and SRAD liquidated***	***Secondary band and SRAD proposed***	***Variation***
2.0 TD	10,2	12,2	+2,0	3,3	3,9	+0,6
3.0 TD	10,0	15,9	+5,9	3,4	5,2	+1,8
6.1 TD	9,3	6,9	−2,4	3,1	2,3	−0,8
6.2 TD	9,3	6,4	−2,9	3,1	2,1	−1,0
6.3 TD	9,4	6,0	−3,4	3,0	2,0	−1,0
6.4 TD	9,2	5,8	−3,4	3,0	1,9	−1,1
Total	**9,7**	**9,7**	**0,0**	**3,2**	**3,2**	**0,0**

Table 42: Breakdown of the liquidated and proposed AASS costs (€/MWh) for 2024. Source: Own elaboration.

3. **The proposal may improve the hourly price signal by reducing costs in valley hours.** Under the current methodology, some ancillary service costs appear in hours with relatively low demand, especially during early morning or valley periods. With the proposed methodology, the cost is shifted towards hours with higher demand, making the final price signal more consistent with system stress.
4. **The flexibility analysis shows that the proposal can support a more efficient demand response**. It suggests that reducing prices in valley hours and increasing them in peak periods can encourage demand to move towards hours where additional consumption is more beneficial for the system. In the long run, the response becomes more relevant, especially for industrial consumers, whose demand is more elastic.

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ANEX I: GLOSSARY

AASS: Ancillary services.

COT: Energy activated for voltage control.

CRRTT: Over cost of the restrictions computed as the difference between the IMRRTT and the activated energy times the day ahead price (CRRTTT = ERRTT*(PMRRTT-PMD).

DAN: Phase imbalance.

EB: Downward activated energy.

ES: Upward activated energy.

ENRRTT: Energy activated for the ancillary services in the PDBF.

ENRRTT F1S: Upwards energy activated for the ancillary services in phase 1.

ENRRTT F1B: Downwards energy activated for the ancillary services in phase 1.

ENRRTT F2S: Upwards energy activated for the ancillary services in phase 2.

ENRRTT F2B Downwards energy activated for the ancillary services in phase 2.

IMRRTT: Ancillary service cost computed as the energy activated (ERRTT) time the average price of the restriction (PMRRTT).

PCB: Loss of pumping capacity.

PEV: Impossibility of energy evacuation.

PMD: Average day ahead price.

PMRRTT F1S: Average price for the upwards activated energy in phase 1.

PMRRTT F1B: Average Price for the upwards activated energy in phase 1.

PMRRTT F2S: Average Price for the upwards activated energy in phase 1.

PMRRTT F2B: Average Price for the upwards activated energy in phase 1.

PRSS: Upward capacity reserve.

RBI: Scarcity of downward power reserve.

RTD: Technical restriction on the distribution grid.

RSI: Scarcity of upward power reserve.

SCA: Activated energy due to contingencies.

SCB: Energy activated in the case base.

SOT: Energy activated due to over voltages.

RT: Real time.

ANEX II: GRAPHS ON ENERGY, PRICES AND COSTS FROM THE AASS OVER THE YEARS

2020 PDBF

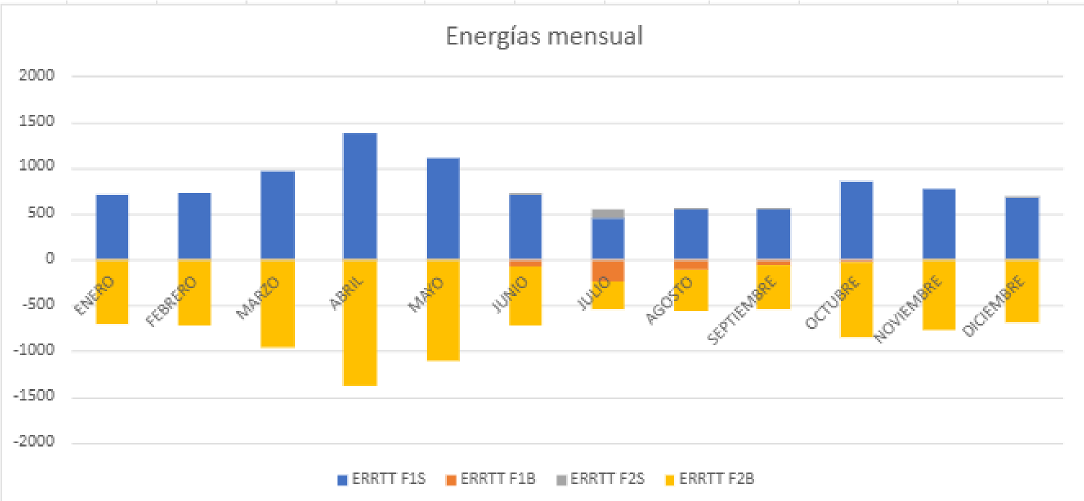


Figure 130: Monthly desegregated energies from the PDBF in 2020. Source: Own elaboration.

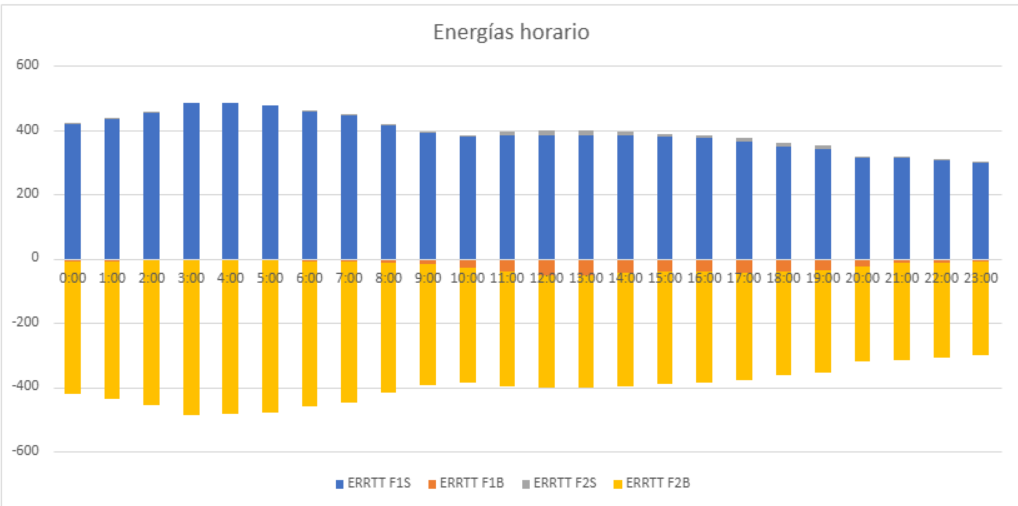


Figure 131: Hourly desegregated energies from the PDBF in 2020. Source: Own elaboration.

MES/ENEI	EBSCA	ESSCA	EBSCB	ESSCB	EBRTD	ESRTD	EBSOT	ESSOT	EBPEV	ESCOT
ENERO	0	90	0	0	1	145	0	465	3	0
FEBRERO	0	28	0	0	0	164	0	535	5	0
MARZO	0	4	0	0	3	159	0	795	0	3
ABRIL	0	22	0	0	0	69	0	1288	0	0
MAYO	0	27	0	19	1	104	0	929	0	30
JUNIO	74	42	2	3	3	176	0	491	3	0
JULIO	223	12	1	0	15	201	0	232	8	0
AGOSTO	104	22	0	0	1	188	0	339	3	0
SEPTIEMB	37	42	0	0	8	151	0	348	10	0
OCTUBRE	16	213	0	0	15	141	0	501	1	0
NOVIEMB	0	2	0	0	7	165	0	607	0	0
DICIEMBR	1	18	0	0	4	116	0	551	0	0

Figure 132: Heat map of the monthly desegregated energies from the PDBF by labels in 2020. Source: Own elaboration.

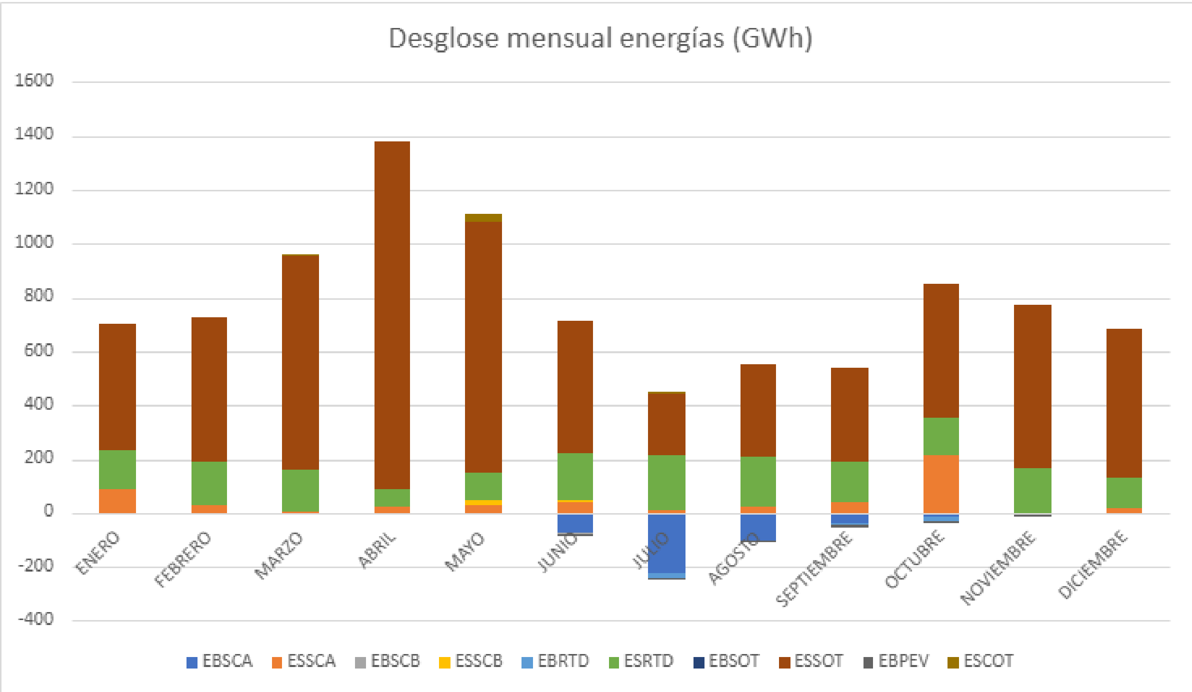


Figure 133: Monthly desegregated energies from the PDBF by labels in 2020. Source: Own elaboration.

HORA/EN	EBSCA	ESSCA	EBSCB	ESSCB	EBRTD	ESRTD	EBSOT	ESSOT	EBPEV	ESCOT
0:00	5	6	0	1	2	3	0	409	1	1
1:00	4	7	0	1	2	3	0	423	1	1
2:00	4	7	0	1	2	14	0	430	1	1
3:00	3	5	0	1	2	42	0	436	1	1
4:00	2	5	0	1	2	42	0	435	1	1
5:00	3	5	0	1	2	43	0	428	1	1
6:00	5	6	0	1	2	50	0	399	1	1
7:00	6	12	0	1	2	63	0	370	1	1
8:00	8	25	0	1	3	76	0	313	2	2
9:00	12	28	0	1	3	89	0	270	2	2
10:00	22	29	0	1	3	102	0	248	2	2
11:00	35	27	0	1	3	115	0	242	2	2
12:00	44	26	0	1	3	118	0	240	2	2
13:00	44	25	0	1	3	119	0	239	2	2
14:00	40	26	0	1	3	114	0	240	1	1
15:00	36	28	0	1	3	109	0	241	1	1
16:00	35	28	0	1	3	104	0	241	1	1
17:00	38	28	0	1	3	94	0	240	1	1
18:00	33	30	0	1	2	84	0	233	2	1
19:00	32	35	0	1	2	82	0	223	2	1
20:00	20	36	0	1	2	84	0	192	2	2
21:00	10	35	0	1	2	84	0	193	2	2
22:00	8	33	0	1	2	76	0	195	1	2
23:00	7	26	0	1	2	68	0	200	1	2

Figure 134: Heat map of the hourly desegregated energies from the PDBF by labels in 2020. Source: Own elaboration.

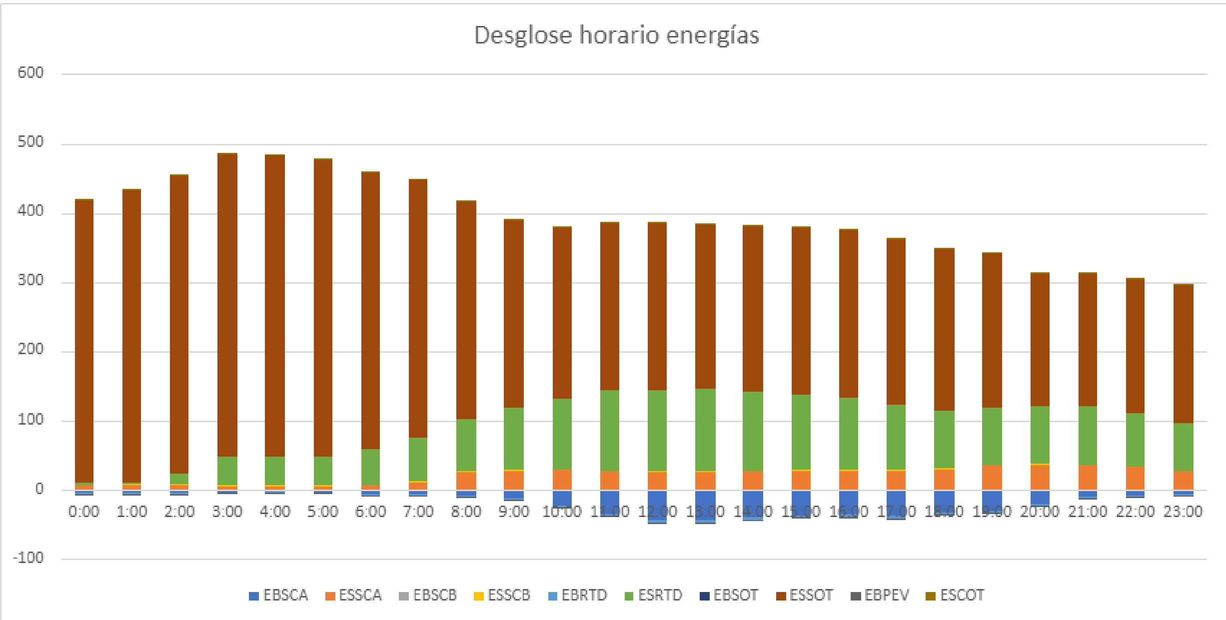


Figure 135: Hourly desegregated energies from the PDBF by labels in 2020. Source: Own elaboration.

Hora/mes ESSCA (GWh)	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	1	2	1	0	0	2	0	0
1	0	0	0	0	1	2	1	0	0	2	0	0
2	0	0	0	0	1	2	1	0	0	3	0	0
3	0	0	0	0	1	1	1	0	0	2	0	0
4	0	0	0	0	1	1	0	0	0	2	0	0
5	0	0	0	0	1	1	0	0	0	2	0	0
6	0	1	0	0	1	1	0	0	0	3	0	0
7	1	1	0	0	1	1	0	0	0	8	0	1
8	5	1	0	1	0	1	0	1	2	13	0	1
9	5	1	0	1	1	1	0	1	3	14	0	1
10	5	1	0	1	1	1	0	1	3	15	0	1
11	4	1	0	1	1	1	0	1	3	14	0	1
12	2	1	0	1	1	2	0	1	3	14	0	1
13	2	1	0	1	1	2	0	1	3	14	0	1
14	2	1	0	1	1	2	0	1	3	15	0	1
15	2	1	0	1	1	2	0	1	3	16	0	1
16	2	1	0	1	1	2	0	1	3	16	0	1
17	2	1	0	1	1	2	0	2	3	16	0	1
18	7	1	0	1	1	2	0	2	3	12	0	1
19	12	2	0	1	1	2	0	2	3	11	0	1
20	12	3	1	3	3	2	0	1	2	7	0	1
21	12	3	1	3	3	3	1	2	2	5	0	1
22	10	3	1	3	3	3	1	1	2	5	0	1
23	5	3	1	3	2	3	0	1	2	5	0	1

Figure 136: Heat map of the ESSCA of the PDBF by hours and months in 2020. Source: Own elaboration.

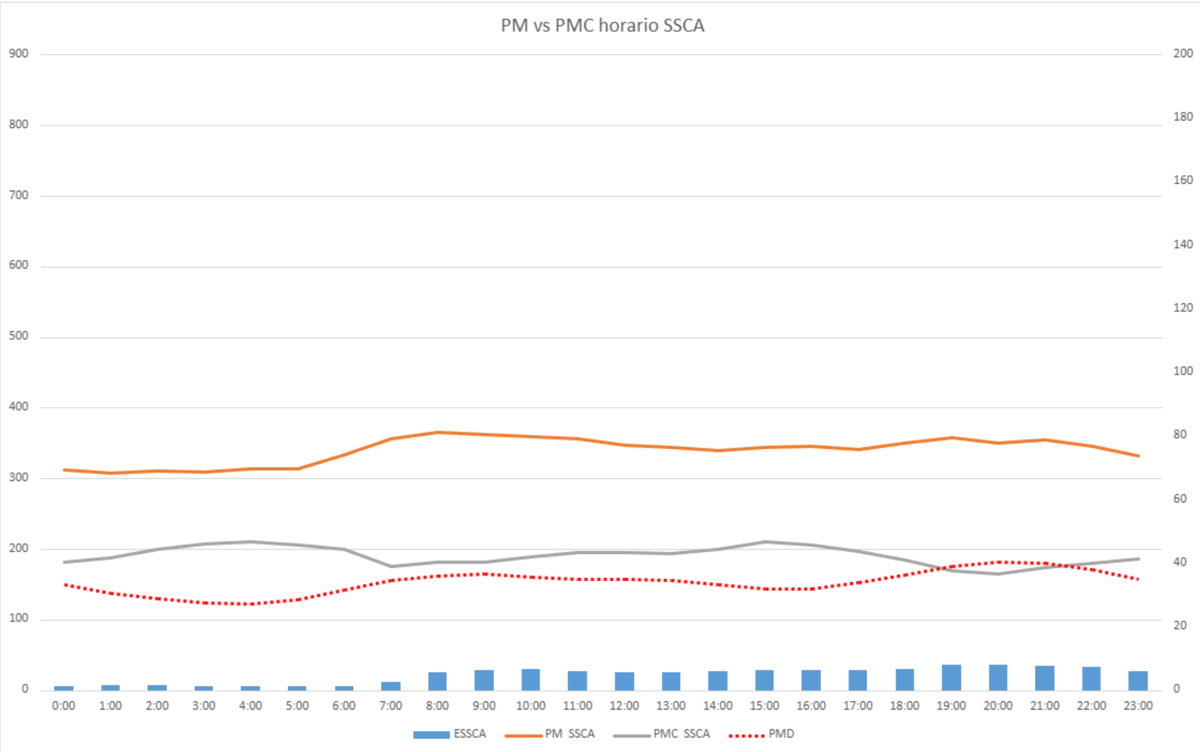


Figure 137: ESSCA, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2020. Source: Own elaboration.

Hora/mes ESRTD	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	1	0	0	1	0	0	0
1	0	0	0	0	0	1	0	0	0	0	0	0
2	1	2	1	0	1	2	2	2	2	1	1	0
3	1	5	3	0	2	6	7	6	5	3	3	2
4	1	5	3	0	2	6	7	5	5	3	2	2
5	1	6	3	0	2	6	7	5	5	4	2	2
6	3	6	3	0	4	6	7	6	5	4	4	2
7	6	7	6	1	4	7	7	6	6	5	5	3
8	7	7	7	2	6	7	9	7	7	6	7	5
9	7	7	8	4	6	8	11	10	7	7	9	6
10	8	8	9	5	6	9	11	11	8	8	10	8
11	9	10	10	7	7	10	12	11	9	9	12	9
12	9	10	10	7	7	10	12	12	9	9	12	9
13	9	10	11	7	7	10	12	13	9	9	12	9
14	9	10	10	7	7	11	12	11	9	9	11	8
15	9	9	10	7	7	10	11	11	9	9	10	7
16	9	9	10	5	7	10	10	10	8	9	10	7
17	8	8	10	4	5	9	10	10	8	8	8	6
18	8	7	8	3	4	9	9	9	7	7	7	6
19	8	8	8	3	4	8	9	9	7	5	7	5
20	9	8	9	1	4	8	9	9	7	6	8	6
21	8	8	8	2	5	8	8	9	7	7	8	6
22	7	7	7	2	3	8	8	9	7	6	8	5
23	7	7	6	1	3	7	8	8	6	5	7	4

Figure 138: Heat map of the ESRTD of the PDBF by hours and months in 2020. Source: Own elaboration.

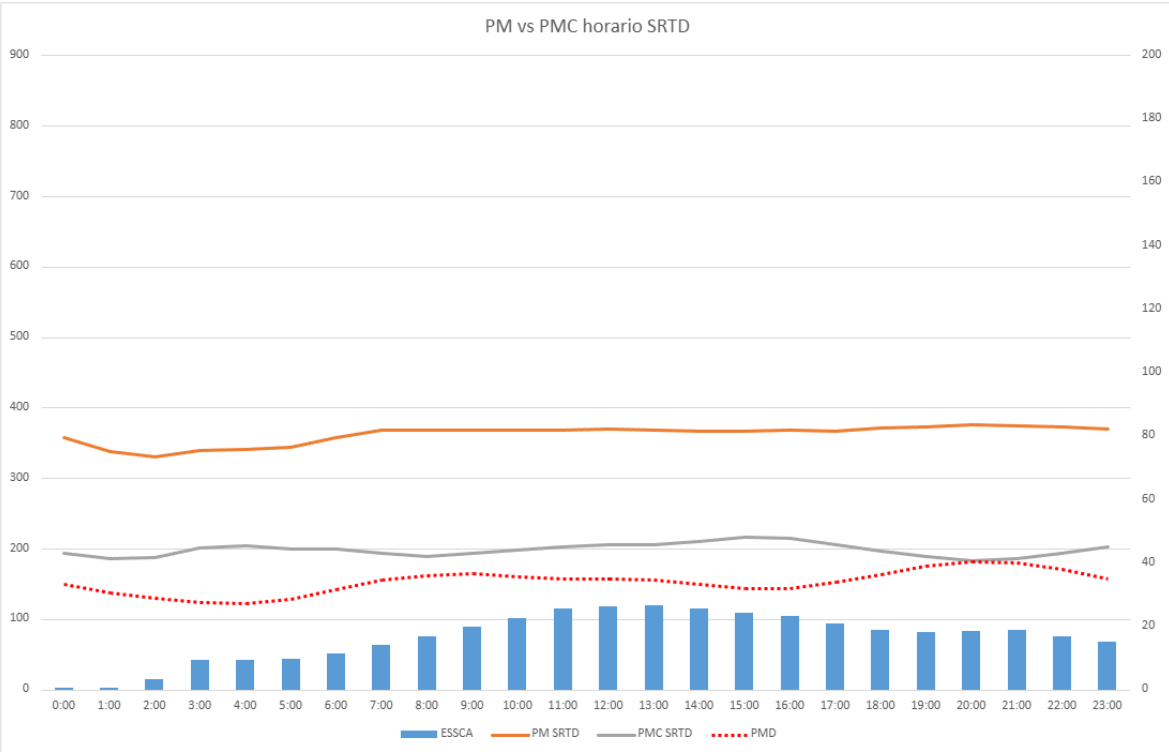


Figure 139: ESRTD, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2020. Source: Own elaboration.

Hora/mes ESSOT	1	2	3	4	5	6	7	8	9	10	11	12
0	27	31	41	65	53	31	11	17	23	34	40	35
1	30	31	41	66	54	33	13	19	24	35	41	36
2	30	31	40	67	54	34	16	20	24	36	42	36
3	30	31	42	70	54	35	16	21	24	35	42	36
4	30	31	42	70	54	35	16	21	24	35	42	36
5	30	31	42	70	53	35	15	20	22	34	41	35
6	27	27	42	70	52	30	13	18	18	32	38	34
7	23	25	41	69	51	24	11	16	17	28	34	31
8	19	21	36	66	46	19	9	14	14	19	24	24
9	17	20	32	59	37	17	8	12	12	15	20	21
10	16	18	31	52	33	15	8	12	11	15	18	19
11	16	19	30	50	33	15	8	12	10	14	18	18
12	16	19	30	49	33	15	8	11	10	14	18	18
13	16	19	30	48	33	15	7	12	10	14	18	18
14	16	19	30	49	33	15	7	11	10	14	18	18
15	16	19	30	49	32	16	7	12	10	14	19	18
16	16	19	30	49	32	16	7	12	10	14	19	18
17	16	19	30	49	32	15	7	12	10	14	19	18
18	13	19	30	49	32	15	7	12	10	15	17	15
19	12	18	27	48	32	14	7	12	10	14	16	14
20	11	17	25	31	24	13	7	11	11	13	15	13
21	12	17	25	31	23	12	7	11	11	14	16	14
22	13	17	25	31	24	12	8	11	11	14	16	14
23	14	18	25	31	24	12	8	11	11	14	16	16

Figure 140: Heat map of the ESSOT of the PDBF by hours and months in 2020. Source: Own elaboration.

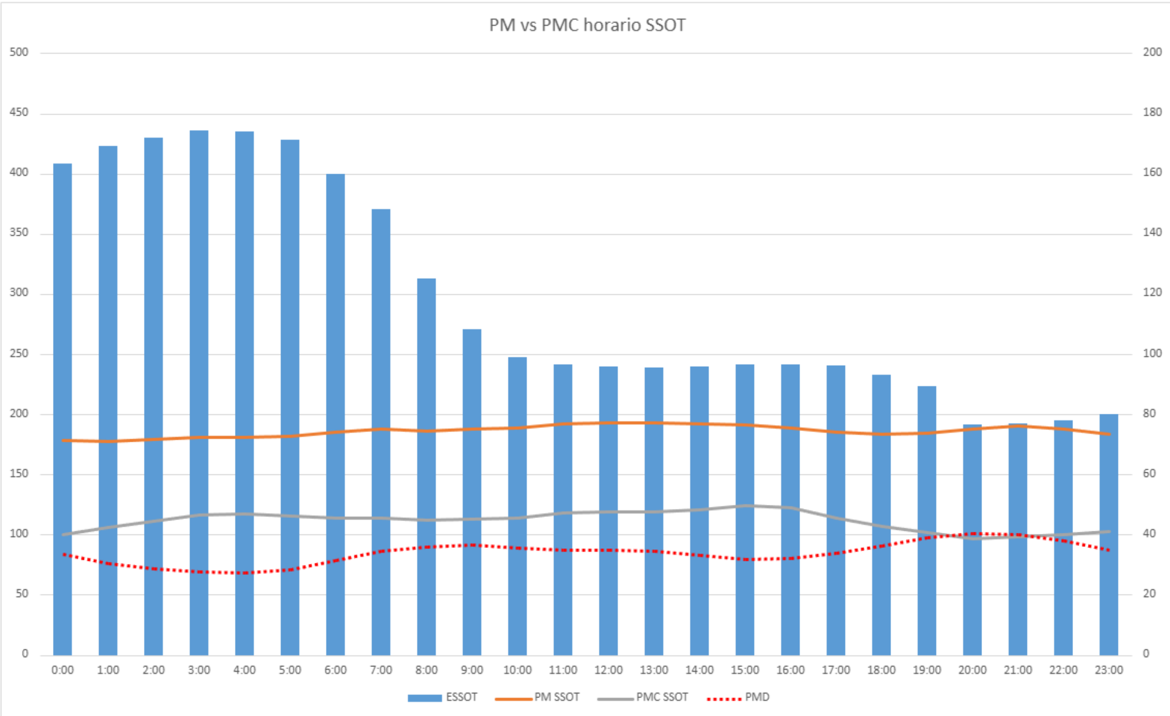


Figure 141: ESSOT, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2020. Source: Own elaboration.

Hora/mes ESCOT	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	1	0	0	0	0	0	0	0
1	0	0	0	0	1	0	0	0	0	0	0	0
2	0	0	0	0	1	0	0	0	0	0	0	0
3	0	0	0	0	1	0	0	0	0	0	0	0
4	0	0	0	0	1	0	0	0	0	0	0	0
5	0	0	0	0	1	0	0	0	0	0	0	0
6	0	0	0	0	1	0	0	0	0	0	0	0
7	0	0	0	0	1	0	0	0	0	0	0	0
8	0	0	0	0	2	0	0	0	0	0	0	0
9	0	0	0	0	2	0	0	0	0	0	0	0
10	0	0	0	0	2	0	0	0	0	0	0	0
11	0	0	0	0	2	0	0	0	0	0	0	0
12	0	0	0	0	2	0	0	0	0	0	0	0
13	0	0	0	0	2	0	0	0	0	0	0	0
14	0	0	0	0	1	0	0	0	0	0	0	0
15	0	0	0	0	1	0	0	0	0	0	0	0
16	0	0	0	0	1	0	0	0	0	0	0	0
17	0	0	0	0	1	0	0	0	0	0	0	0
18	0	0	0	0	1	0	0	0	0	0	0	0
19	0	0	0	0	1	0	0	0	0	0	0	0
20	0	0	0	0	2	0	0	0	0	0	0	0
21	0	0	0	0	2	0	0	0	0	0	0	0
22	0	0	0	0	2	0	0	0	0	0	0	0
23	0	0	0	0	2	0	0	0	0	0	0	0

Figure 142: Heat map of the ESCOT of the PDBF by hours and months in 2020. Source: Own elaboration.

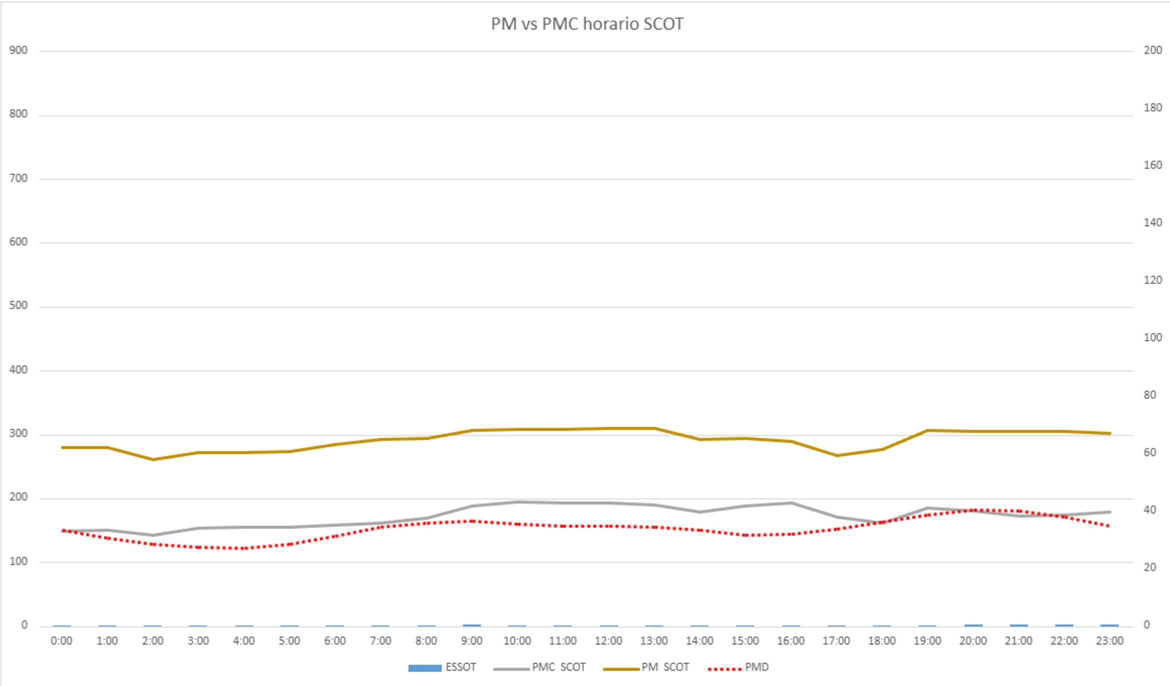


Figure 143: ESCOT, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2020. Source: Own elaboration.

MES/ENERGIAS GW	ESASE	EBASE	ESSOT	EBSOT	ESCOT	EBPEV	ESEST	EBEST	ESRSI	EBRSI	ESRBI	EBRBI	ESRTD	EBRTD	ESSCA	EBSCA	ESSCB	EBSCB
ENERO	0	2	14	10	0	1	0	0	25	0	0	0	1	0	0	0	0	1
FEBRERO	0	2	3	10	0	0	0	0	8	0	0	0	0	0	0	0	0	0
MARZO	0	1	21	11	0	1	0	0	10	0	0	0	2	1	0	3	0	1
ABRIL	0	1	7	6	0	0	0	0	3	0	0	0	0	0	2	0	0	0
MAYO	0	1	6	3	0	1	0	0	1	0	0	0	5	0	3	9	0	4
JUNIO	0	0	12	2	0	0	0	0	2	0	0	0	0	0	5	27	2	13
JULIO	0	0	0	1	0	0	0	0	14	0	0	0	0	0	2	33	0	8
AGOSTO	0	0	0	7	0	0	0	0	63	0	0	0	0	0	2	36	2	9
SEPTIEMBRE	0	0	10	5	0	5	0	0	122	0	0	0	7	0	0	39	0	2
OCTUBRE	0	0	7	30	0	0	0	0	83	0	0	0	0	0	22	39	0	2
NOVIEMBRE	0	0	1	23	0	0	0	0	114	0	0	0	2	0	0	0	0	1
DICIEMBRE	0	1	4	6	0	0	0	0	122	0	0	0	0	1	3	6	0	1

Figure 144: Heat map of the monthly desegregated energies from the RT by labels in 2020. Source: Own elaboration.

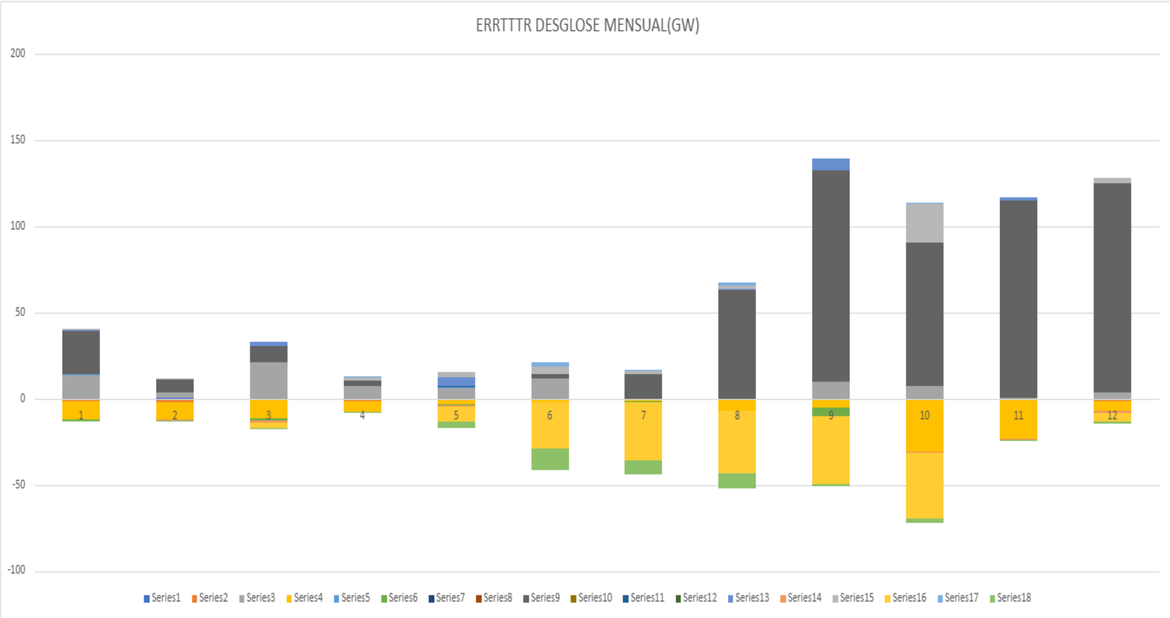


Figure 145: Monthly desegregated energies from the RT by labels in 2020. Source: Own elaboration.

HORA/ENERGIAS GW	ESASE	EBASE	ESSOT	EBSOT	ESCOT	EBPEV	ESEST	EBEST	ESRSI	EBRSI	ESRBI	EBRBI	ESRTD	EBRTD	ESSCA	EBSCA	ESSCB	EBSCB
0:00	0	0	3	4	0	0	0	0	0	0	0	0	1	0	2	7	0	2
1:00	0	0	4	8	0	0	0	0	0	0	0	0	0	0	1	7	0	2
2:00	0	0	5	11	0	0	0	0	0	0	0	0	0	0	1	6	1	2
3:00	0	0	5	12	0	0	0	0	0	0	0	0	1	0	1	6	0	2
4:00	0	0	5	14	0	0	0	0	0	0	0	0	0	0	1	5	0	2
5:00	0	1	5	18	0	0	0	0	0	0	0	0	0	0	0	5	0	2
6:00	0	1	4	13	0	0	0	0	3	0	0	0	1	0	0	4	0	1
7:00	0	1	4	12	0	0	0	0	19	0	0	0	1	0	0	4	0	1
8:00	0	1	3	7	0	0	0	0	42	0	0	0	1	0	0	4	0	1
9:00	0	0	3	4	0	0	0	0	46	0	0	0	1	0	0	5	0	1
10:00	0	0	4	1	0	0	0	0	31	0	0	0	1	0	1	6	0	1
11:00	0	0	4	0	0	0	0	0	19	0	0	0	1	0	1	9	0	2
12:00	0	0	4	0	0	0	0	0	12	0	0	0	1	0	2	10	0	2
13:00	0	0	4	0	0	1	0	0	7	0	0	0	1	0	2	11	0	2
14:00	0	0	4	0	0	1	0	0	3	0	0	0	1	0	2	11	0	2
15:00	0	0	4	1	0	1	0	0	1	0	0	0	1	0	3	12	1	1
16:00	0	0	3	2	0	1	0	0	3	0	0	0	1	0	3	13	0	2
17:00	0	1	3	2	0	0	0	0	24	0	0	0	1	0	2	13	1	1
18:00	1	1	3	1	0	0	0	0	62	0	0	0	1	0	2	12	1	1
19:00	0	1	3	2	0	0	0	0	93	0	0	0	1	0	3	11	0	2
20:00	0	0	3	0	0	1	0	0	111	0	0	0	1	0	3	7	0	2
21:00	0	0	2	0	0	1	0	0	77	0	0	0	1	0	2	7	0	2
22:00	0	0	2	0	0	1	0	0	14	0	0	0	1	0	3	7	0	1
23:00	0	0	2	0	0	0	0	0	0	0	0	0	1	0	3	7	0	1

Figure 146: Heat map of the hourly desegregated energies from the RT by labels in 2020. Source: Own elaboration.

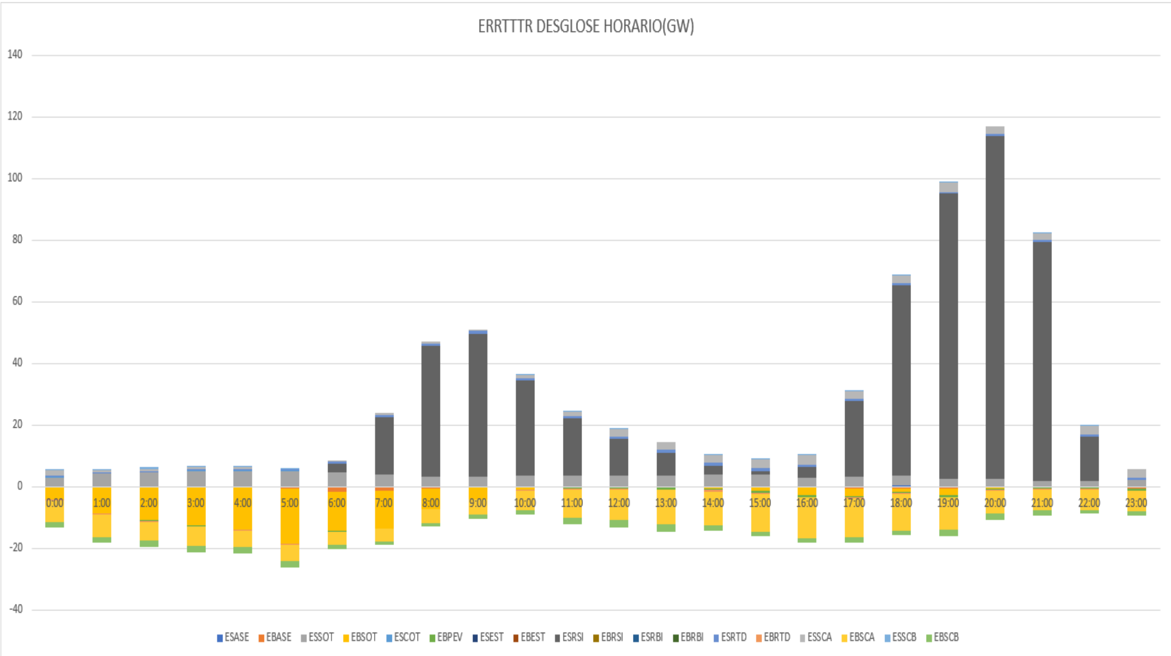


Figure 147: Hourly desegregated energies from the RT by labels in 2020. Source: Own elaboration.

HORA/ MES ESSOT (GWh)	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	1	0	1	0	0	0	0	0	0	1
1	0	0	1	0	1	1	0	0	0	0	0	1
2	0	0	0	0	1	1	0	0	0	1	0	0
3	1	0	1	0	1	1	0	0	0	1	0	0
4	1	0	1	0	1	1	0	0	0	1	0	0
5	1	0	1	0	1	0	0	0	0	1	0	0
6	1	0	1	0	0	0	0	0	0	1	0	0
7	1	0	1	0	0	0	0	0	0	1	0	0
8	1	0	1	0	0	0	0	0	1	0	0	0
9	1	0	1	0	0	0	0	0	1	0	0	0
10	1	0	1	0	0	1	0	0	0	0	0	0
11	1	0	1	0	0	0	0	0	0	0	0	0
12	1	0	1	0	0	0	0	0	0	0	0	0
13	1	0	2	0	0	0	0	0	0	0	0	0
14	1	0	2	0	0	0	0	0	0	0	0	0
15	1	0	2	0	0	0	0	0	0	0	0	0
16	1	0	1	0	0	0	0	0	0	0	0	0
17	1	0	1	0	0	0	0	0	0	0	0	0
18	1	0	1	1	0	1	0	0	0	0	0	0
19	1	0	1	1	0	0	0	0	0	0	0	0
20	1	0	1	1	0	0	0	0	0	0	0	0
21	1	0	1	0	0	0	0	0	0	0	0	0
22	1	0	1	0	0	0	0	0	0	0	0	0
23	1	0	1	0	0	0	0	0	0	0	0	0

Figure 148: Heat map of the ESSOT of the RT by hours and months in 2020. Source: Own elaboration.

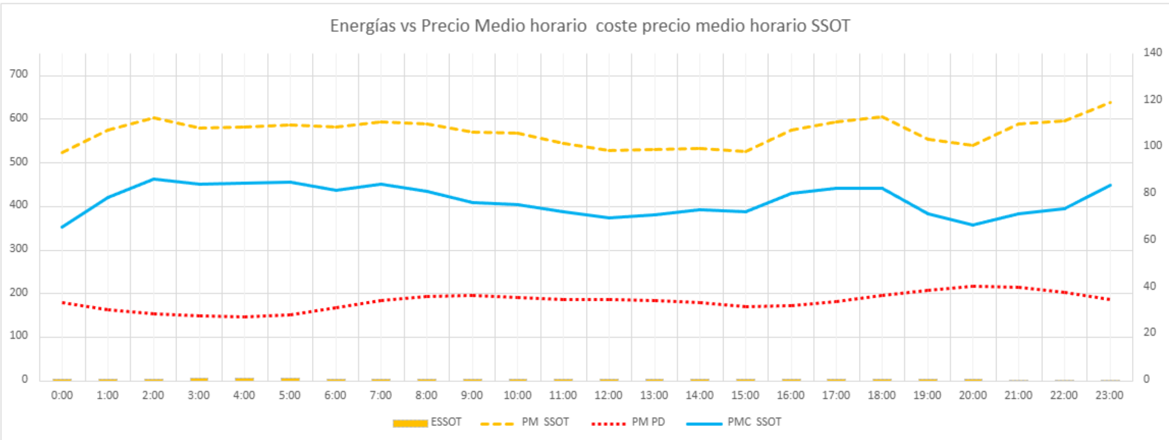


Figure 149: ESSOT, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2020. Source: Own elaboration.

HORA/ MES ESCOT	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	0	0	0	0	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0

Figure 150: Heat map of the ESCOT of the RT by hours and months in 2020. Source: Own elaboration.

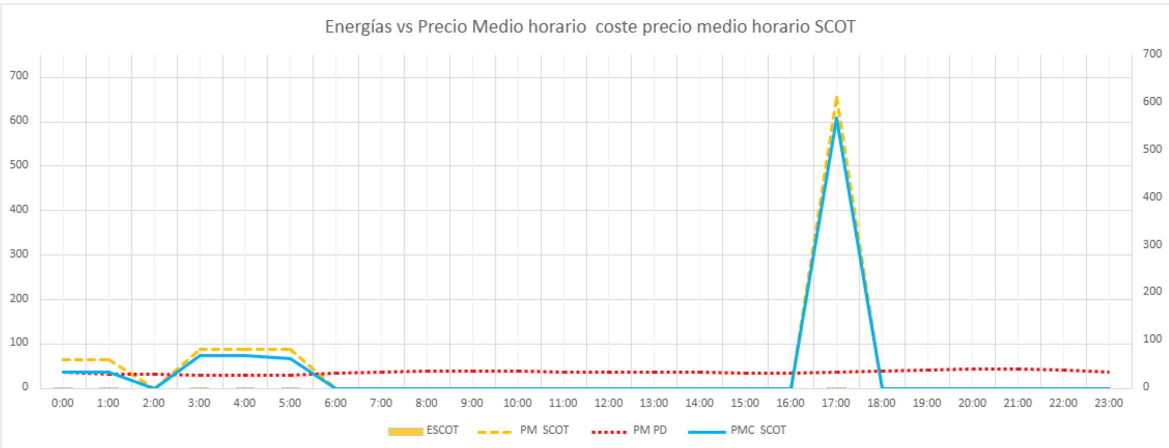


Figure 151: ESCOT, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2020. Source: Own elaboration.

HORA/ MES ESRSI 2020	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	0	0	0	0	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	3	0	0	0
7	0	0	0	0	0	0	0	2	9	3	2	3
8	2	0	0	0	0	0	0	4	12	6	8	9
9	2	0	0	0	0	0	0	5	12	7	8	11
10	2	0	0	0	0	0	1	3	7	3	5	10
11	2	0	0	0	0	0	1	4	5	1	2	5
12	1	0	0	0	0	0	1	3	3	0	0	3
13	0	0	0	0	0	0	1	2	3	0	0	1
14	0	0	0	0	0	0	1	0	1	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	1	1
17	1	0	0	0	0	0	0	1	2	0	11	9
18	5	0	0	0	0	0	2	2	4	4	26	19
19	5	3	3	0	0	1	2	5	9	19	26	20
20	4	3	4	1	0	1	2	12	27	23	16	19
21	1	1	2	1	0	0	1	14	24	15	7	11
22	0	0	0	1	0	0	1	5	4	2	0	1
23	0	0	0	0	0	0	0	0	0	0	0	0

Figure 152: Heat map of the ESRSI of the RT by hours and months in 2020. Source: Own elaboration.

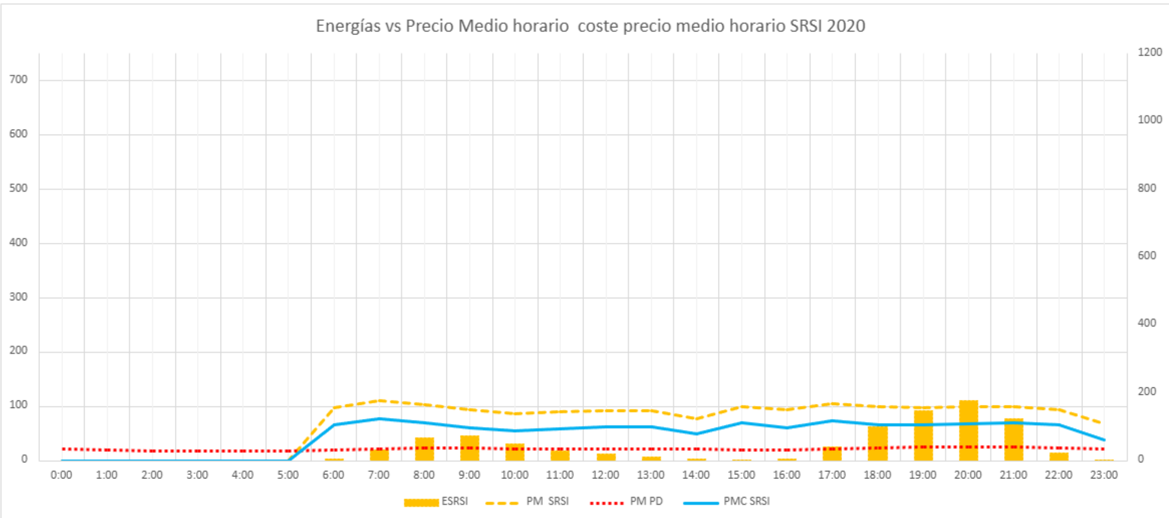


Figure 153: ESRSI, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2020. Source: Own elaboration.

HORA/ MES ESSCA	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	0	0	0	0	0	0	0
1	0	0	0	0	1	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	1	0	0	0	0
3	0	0	0	0	0	0	0	1	0	0	0	0
4	0	0	0	0	0	0	0	1	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	1	0	0
12	0	0	0	0	0	0	0	0	0	2	0	0
13	0	0	0	0	0	0	0	0	0	2	0	0
14	0	0	0	0	0	0	0	0	0	2	0	0
15	0	0	0	0	0	0	0	0	0	2	0	0
16	0	0	0	0	1	0	0	0	0	2	0	0
17	0	0	0	0	0	0	0	0	0	2	0	0
18	0	0	0	0	0	0	0	0	0	2	0	0
19	0	0	0	0	0	0	1	0	0	2	0	0
20	0	0	0	0	0	0	0	0	0	2	0	0
21	0	0	0	0	0	0	0	0	0	1	0	0
22	0	0	0	1	1	0	0	0	0	1	0	0
23	0	0	0	1	1	0	0	0	0	1	0	0

Figure 154: Heat map of the ESSCA of the RT by hours and months in 2020. Source: Own elaboration.

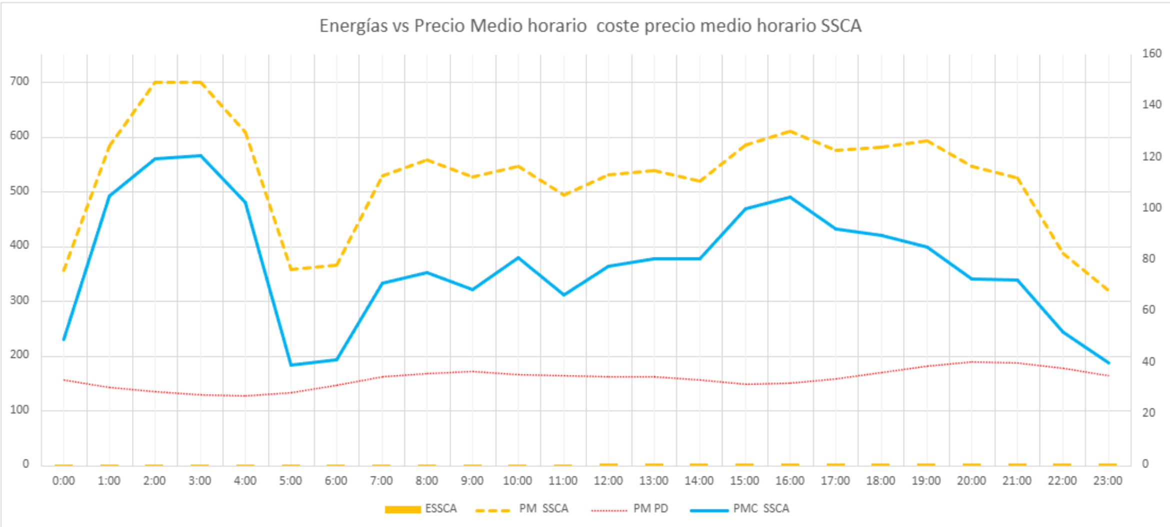


Figure 155: ESSCA, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2020. Source: Own elaboration.

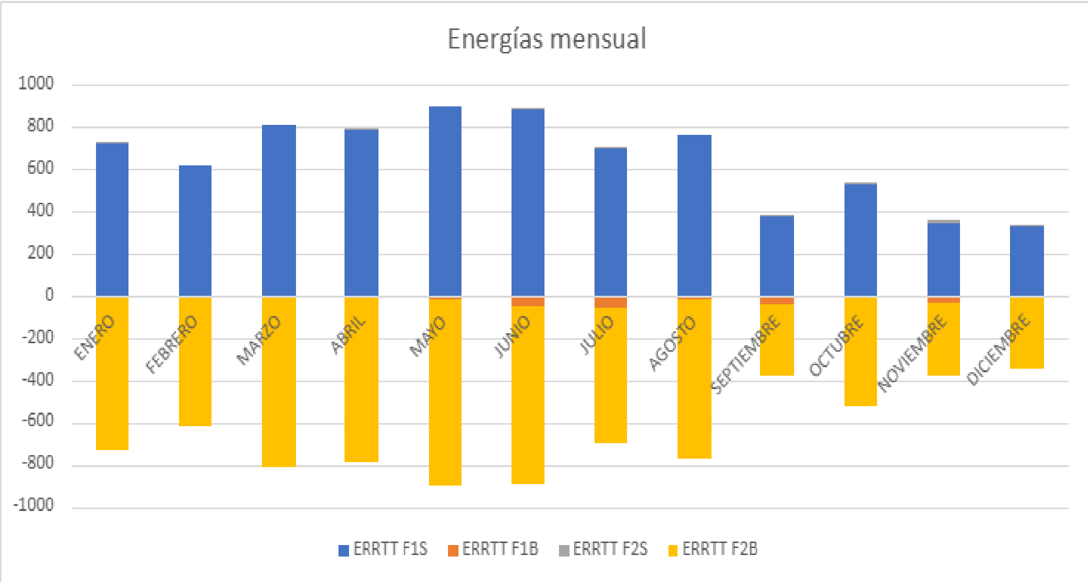


Figure 156: Monthly desegregated energies from the PDBF in 2021. Source: Own elaboration.

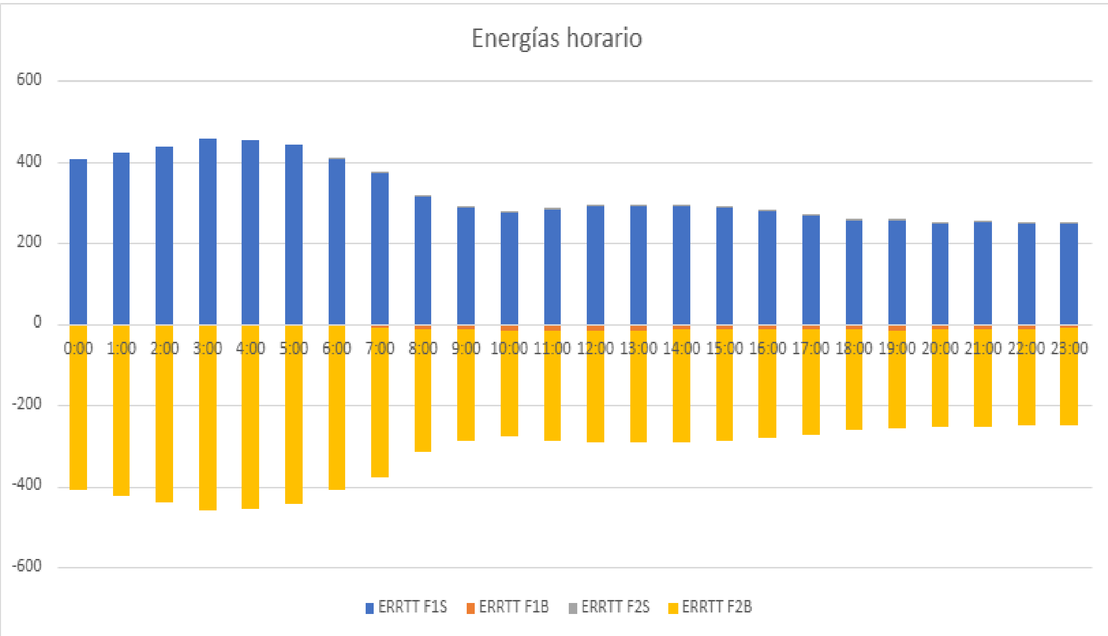


Figure 157: Hourly desegregated energies from the PDBF in 2021. Source: Own elaboration.

MES/ENEI	EBSCA	ESSCA	EBSCB	ESSCB	EBRTD	ESRTD	EBSOT	ESSOT	EBPEV	ESCOT
ENERO	0	51	0	0	6	49	0	626	0	0
FEBRERO	0	7	0	0	1	104	0	504	1	0
MARZO	0	16	0	0	10	183	0	612	0	0
ABRIL	7	30	0	0	3	238	0	521	0	0
MAYO	6	33	2	0	3	204	0	660	6	0
JUNIO	35	71	0	0	2	294	0	512	13	12
JULIO	43	95	0	0	7	202	0	396	7	0
AGOSTO	2	236	0	0	9	99	0	435	3	0
SEPTIEMB	9	36	0	0	10	3	0	336	16	0
OCTUBRE	8	60	0	0	0	14	0	449	1	0
NOVIEMB	34	52	0	1	0	11	0	296	0	0
DICIEMBR	4	17	0	0	0	4	0	318	2	0

Figure 158: Heat map of the monthly desegregated energies from the PDBF by labels in 2021. Source: Own elaboration.

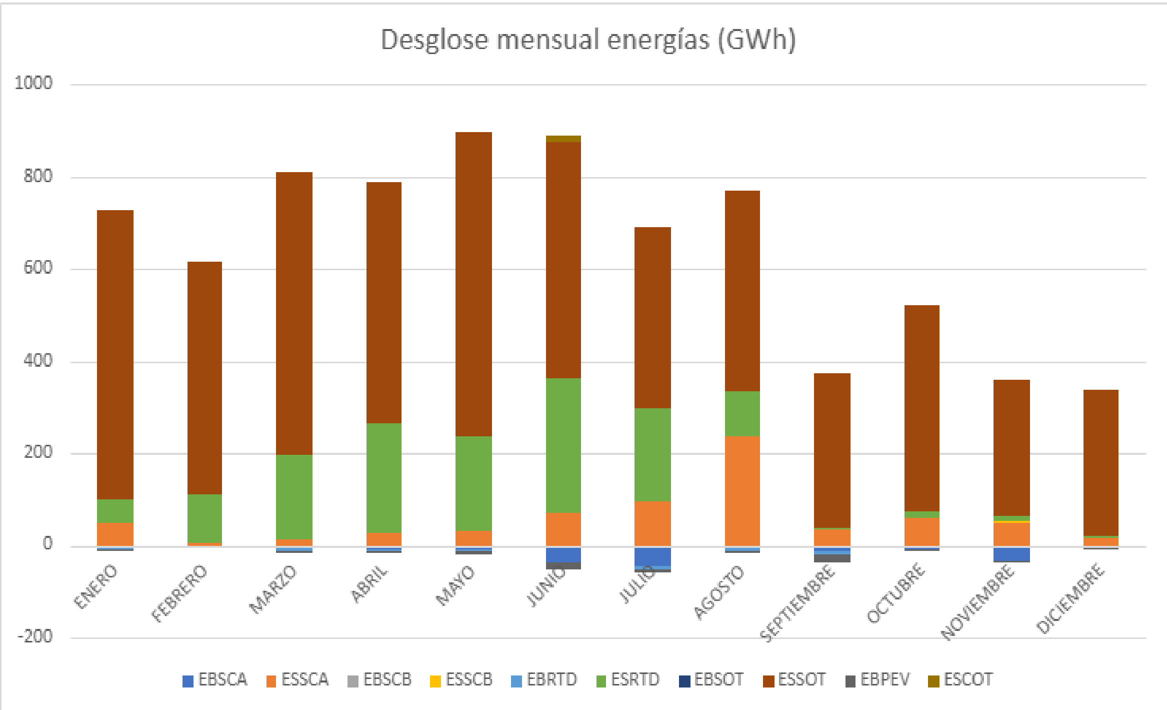


Figure 159: Monthly desegregated energies from the PDBF by labels in 2021. Source: Own elaboration.

HORA/EN	EBSCA	ESSCA	EBSCB	ESSCB	EBRTD	ESRTD	EBSOT	ESSOT	EBPEV	ESCOT
0:00	1	33	0	0	2	6	0	369	2	1
1:00	1	34	0	0	2	5	0	383	2	1
2:00	1	35	0	0	2	14	0	388	2	1
3:00	1	24	0	0	2	39	0	394	2	1
4:00	0	21	0	0	2	39	0	394	2	1
5:00	0	19	0	0	2	38	0	385	1	1
6:00	2	17	0	0	2	43	0	349	2	1
7:00	5	17	0	0	2	46	0	311	2	1
8:00	9	20	0	0	2	61	0	232	2	0
9:00	9	20	0	0	2	71	0	196	2	0
10:00	11	19	0	0	3	82	0	174	2	0
11:00	11	21	0	0	3	90	0	174	2	0
12:00	11	22	0	0	3	94	0	174	2	0
13:00	9	22	0	0	3	93	0	175	2	0
14:00	8	22	0	0	3	91	0	177	2	0
15:00	6	22	0	0	3	88	0	178	2	0
16:00	6	22	0	0	3	80	0	177	3	0
17:00	8	22	0	0	3	73	0	174	3	0
18:00	10	25	0	0	2	65	0	168	2	0
19:00	11	34	0	0	2	63	0	159	2	0
20:00	9	53	0	0	2	60	0	136	2	0
21:00	8	60	0	0	2	59	0	130	3	1
22:00	8	60	0	0	2	56	0	131	2	2
23:00	5	58	0	0	2	52	0	139	2	2

Figure 160: Heat map of the hourly desegregated energies from the PDBF by labels in 2021. Source: Own elaboration.

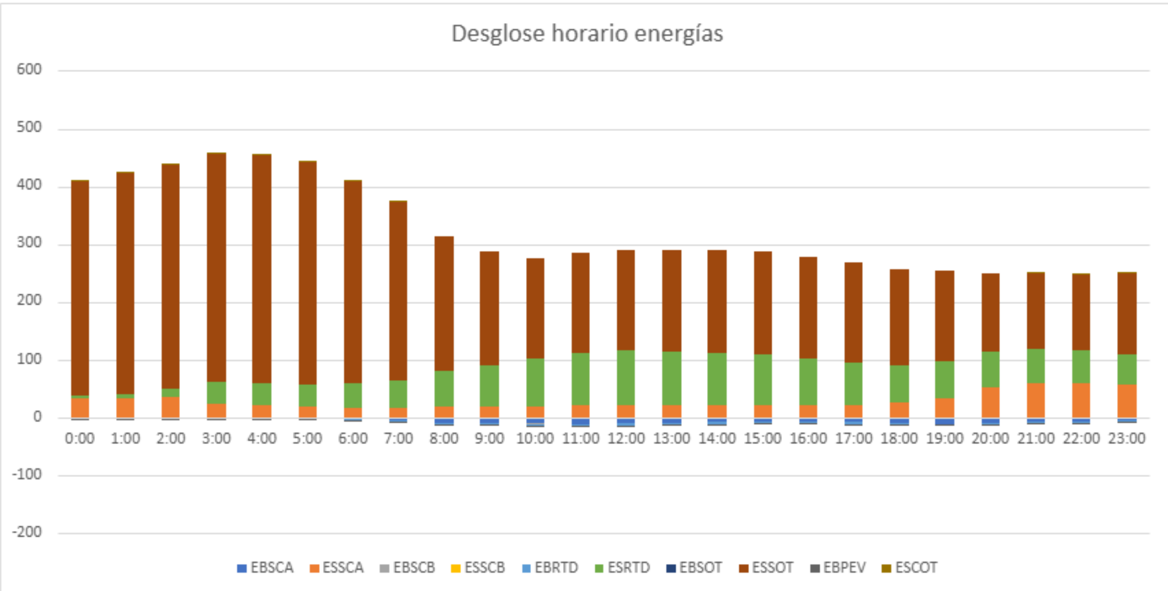


Figure 161: Hourly desegregated energies from the PDBF by labels in 2021. Source: Own elaboration.

Hora/mes ESSCA (GWh)	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	1	0	3	6	17	2	4	1	0
1	0	0	0	1	0	3	6	17	2	4	1	0
2	0	0	0	1	0	3	6	18	2	4	1	0
3	0	0	0	1	0	2	2	13	1	3	1	0
4	0	0	0	1	0	2	1	12	1	2	1	0
5	0	0	0	0	0	2	1	11	1	2	1	0
6	0	0	0	1	0	2	1	10	1	1	0	0
7	0	0	0	1	0	2	1	10	1	0	1	0
8	1	0	0	1	1	3	2	6	1	1	2	1
9	2	0	0	1	2	2	2	5	1	1	3	1
10	2	0	0	1	2	2	3	3	0	1	3	1
11	2	0	0	1	2	2	4	3	1	1	4	2
12	2	0	0	1	2	2	4	3	1	2	4	2
13	1	0	0	1	2	2	4	3	1	2	4	2
14	1	0	0	1	2	2	4	3	1	2	4	2
15	1	0	0	1	2	2	4	3	1	2	3	1
16	1	0	0	1	2	2	4	3	1	1	3	1
17	2	0	0	1	2	3	4	3	1	1	3	1
18	4	0	0	1	2	3	4	4	1	1	3	1
19	6	1	1	2	2	3	4	8	1	2	3	1
20	6	1	2	3	2	7	3	18	3	5	3	1
21	6	1	2	4	2	5	8	21	4	6	2	1
22	6	1	2	3	2	5	8	22	4	6	1	0
23	4	1	2	2	2	5	8	22	4	6	1	0

Figure 162: Heat map of the ESSCA of the PDBF by hours and months in 2021. Source: Own elaboration.

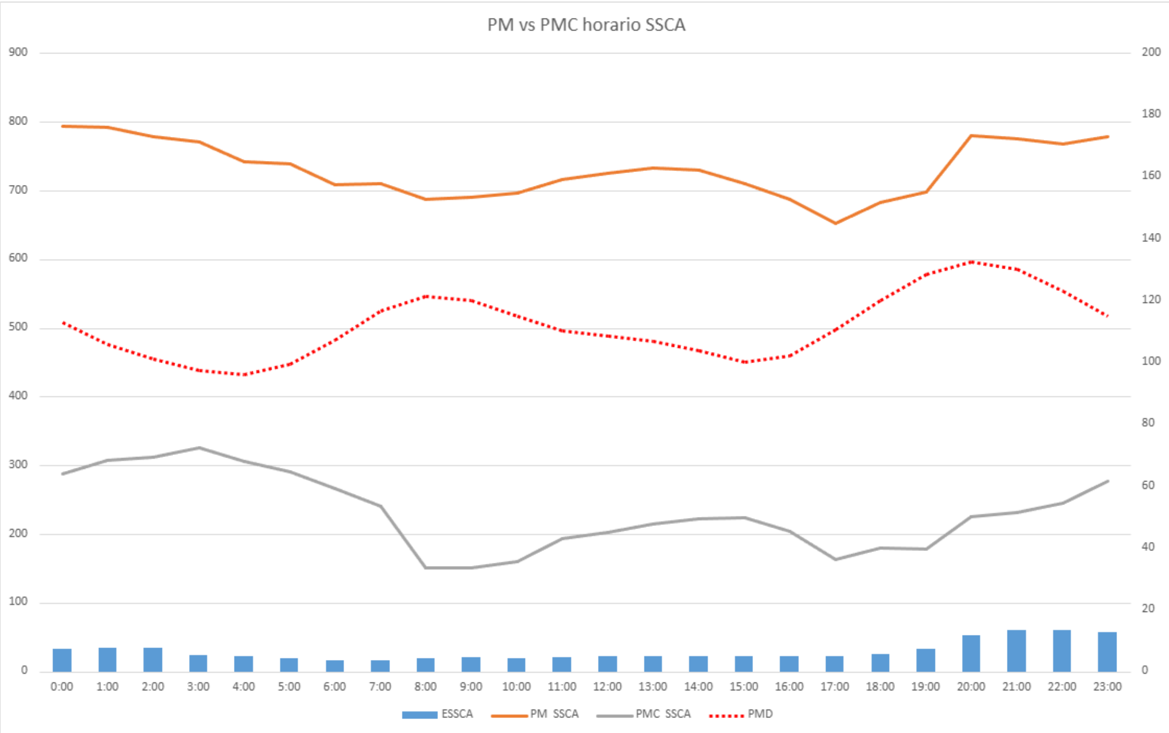


Figure 163: ESSCA, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2021. Source: Own elaboration.

Hora/mes ESRTD	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	1	1	0	2	0	0	0	0	0	0
1	0	0	1	1	0	2	0	0	0	0	0	0
2	0	0	1	3	2	4	2	1	0	0	0	0
3	1	0	3	7	6	10	7	4	0	0	0	0
4	1	1	5	7	6	9	6	3	0	0	0	0
5	1	1	4	8	4	10	6	3	0	0	0	0
6	2	2	5	8	6	11	6	3	0	0	0	0
7	2	2	5	8	7	12	6	3	0	0	0	0
8	2	5	8	10	8	13	8	5	0	0	0	0
9	3	6	10	11	10	14	10	5	0	1	0	0
10	3	7	11	13	12	16	12	6	0	1	1	1
11	4	8	12	15	13	17	12	6	0	1	1	0
12	4	9	13	15	14	17	12	6	0	1	1	1
13	4	9	12	15	15	17	12	6	0	1	1	1
14	4	8	12	15	14	16	13	6	0	1	1	1
15	4	8	11	15	13	16	12	6	0	1	1	0
16	3	7	11	14	12	15	11	6	0	1	1	0
17	2	5	10	13	11	14	10	5	0	1	0	0
18	1	5	8	11	10	14	10	5	0	0	0	0
19	2	6	8	10	9	14	10	4	0	0	0	0
20	2	5	9	9	8	14	10	4	0	0	0	0
21	2	5	9	10	8	13	9	4	0	0	0	0
22	1	2	8	10	8	13	8	4	0	0	0	0
23	1	2	7	9	8	12	8	4	0	0	0	0

Figure 164: Heat map of the ESRTD of the PDBF by hours and months in 2021. Source: Own elaboration.

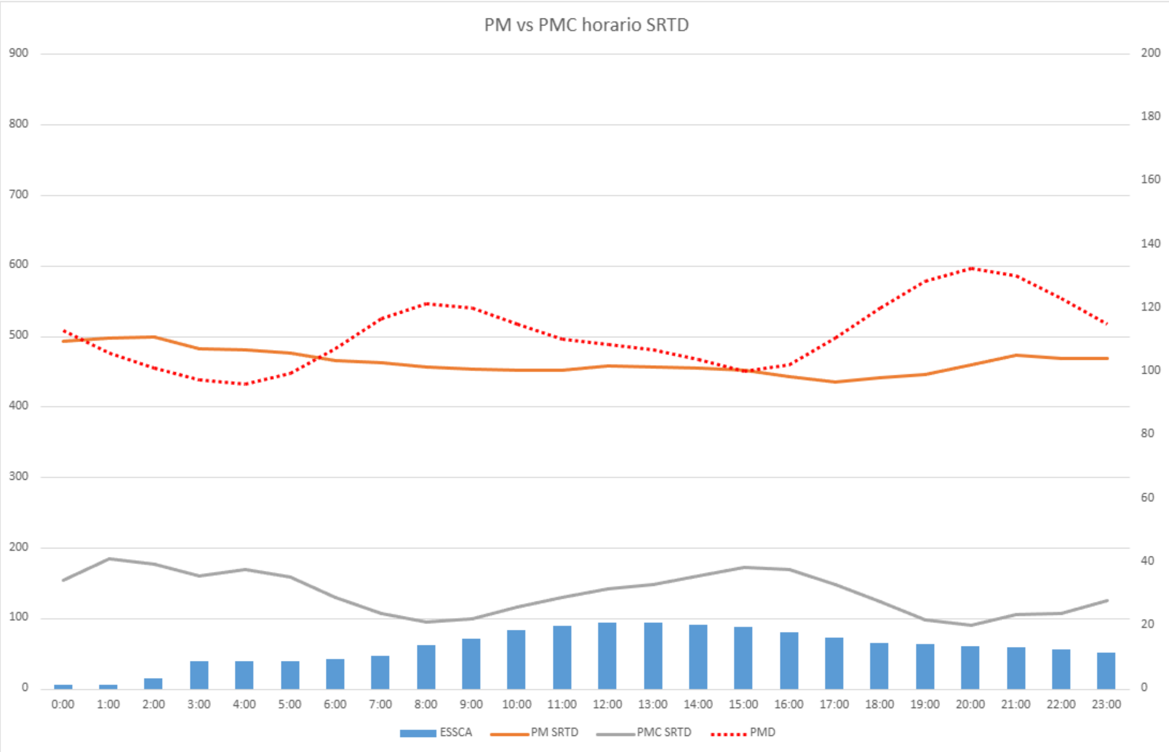


Figure 165: ESRTD, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2021. Source: Own elaboration.

Hora/mes ESSOT	1	2	3	4	5	6	7	8	9	10	11	12
0	39	30	38	36	41	31	25	25	19	32	28	25
1	41	30	38	37	42	31	26	27	22	32	30	25
2	41	30	37	38	42	32	26	27	24	34	31	26
3	41	30	38	38	42	32	29	29	25	33	31	26
4	41	30	38	38	42	32	29	29	26	32	31	26
5	41	30	38	35	41	31	29	29	25	31	29	25
6	38	30	35	30	39	29	27	28	22	29	21	21
7	35	29	33	26	35	27	23	27	17	26	15	18
8	28	22	26	22	27	21	16	17	13	19	10	12
9	23	19	23	19	22	19	12	14	12	15	8	10
10	19	18	21	16	20	17	11	14	10	13	5	9
11	19	17	21	16	21	17	11	15	10	13	5	9
12	19	17	21	16	22	17	11	15	11	13	5	9
13	19	17	20	17	22	17	12	15	11	13	5	9
14	19	17	20	17	22	18	12	15	11	13	5	9
15	19	17	20	17	22	19	12	15	11	13	5	9
16	19	17	20	16	22	19	12	15	11	13	5	8
17	19	17	20	16	22	19	12	15	11	12	4	7
18	18	17	20	16	22	18	11	14	10	12	4	6
19	18	16	20	14	21	16	11	13	9	11	4	6
20	17	14	17	11	18	13	10	11	6	9	4	6
21	17	14	17	10	17	13	9	9	6	9	3	6
22	17	13	16	10	17	13	9	9	6	10	4	6
23	18	14	16	12	18	14	10	11	7	10	4	6

Figure 166: Heat map of the ESSOT of the PDBF by hours and months in 2021. Source: Own elaboration.

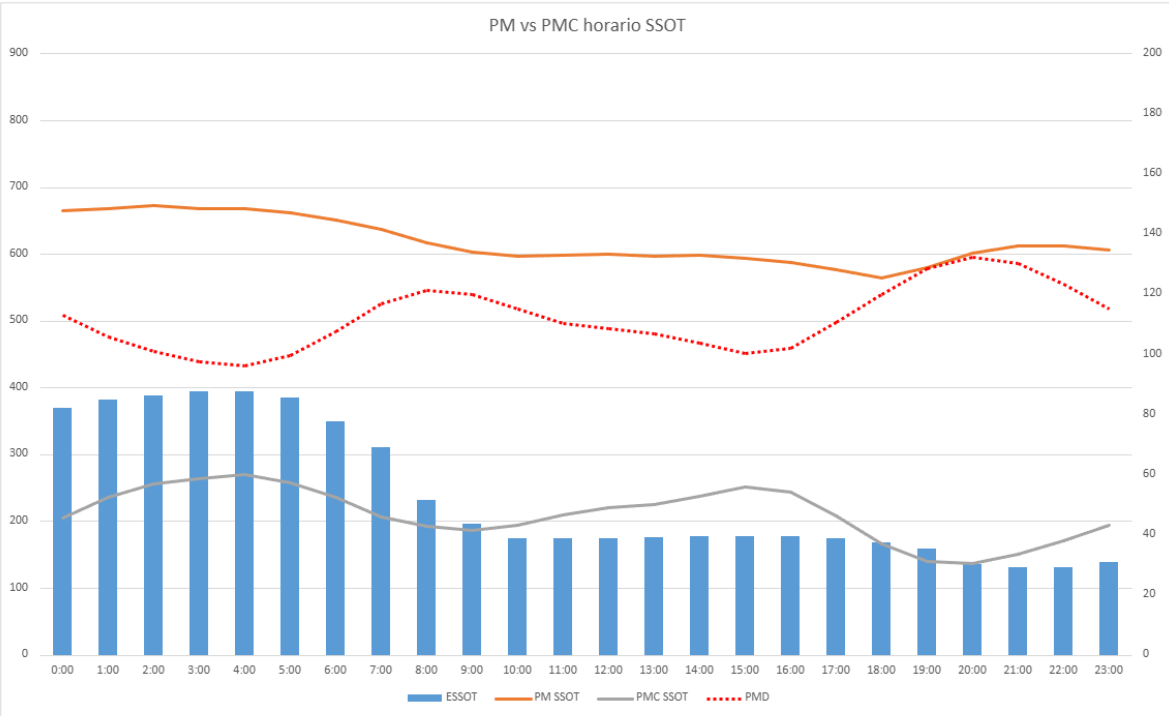


Figure 167: ESSOT, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2021. Source: Own elaboration.

Hora/mes ESCOT	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	1	0	0	0	0	0	0
1	0	0	0	0	0	1	0	0	0	0	0	0
2	0	0	0	0	0	1	0	0	0	0	0	0
3	0	0	0	0	0	1	0	0	0	0	0	0
4	0	0	0	0	0	1	0	0	0	0	0	0
5	0	0	0	0	0	1	0	0	0	0	0	0
6	0	0	0	0	0	1	0	0	0	0	0	0
7	0	0	0	0	0	1	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	1	0	0	0	0	0	0
22	0	0	0	0	0	2	0	0	0	0	0	0
23	0	0	0	0	0	2	0	0	0	0	0	0

Figure 168: Heat map of the ESCOT of the PDBF by hours and months in 2021. Source: Own elaboration.

Figure 169: ESCOT, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2021. Source: Own elaboration.

MES/ENERGIAS GW	ESASE	EBASE	ESSOT	EBSOT	ESCOT	EBPEV	ESEST	EBEST	ESRSI	EBRSI	ESRBI	EBRBI	ESRTD	EBRTD	ESSCA	EBSCA	ESSCB	EBSCB
ENERO	0	1	8	12	1	1	0	0	197	0	0	0	0	2	4	14	0	1
FEBRERO	0	4	10	5	0	0	0	0	152	0	0	0	4	3	0	2	0	1
MARZO	0	1	4	23	0	0	0	0	113	0	0	0	0	1	1	8	0	1
ABRIL	0	1	8	47	0	1	0	0	75	0	0	0	0	0	6	45	1	7
MAYO	0	0	10	19	0	1	0	0	52	0	0	0	0	1	0	8	0	11
JUNIO	0	0	2	9	0	1	0	0	33	1	0	0	0	1	2	10	2	4
JULIO	0	0	1	8	0	1	0	0	171	0	0	0	5	1	15	65	0	1
AGOSTO	1	0	1	3	0	0	0	0	184	0	0	0	0	1	42	69	7	1
SEPTIEMBRE	0	0	1	11	0	0	0	0	205	0	0	0	0	0	6	10	0	0
OCTUBRE	0	0	3	35	0	0	0	0	148	0	0	0	0	0	7	18	0	10
NOVIEMBRE	0	0	4	67	0	0	0	0	111	0	0	0	0	0	0	50	0	1
DICIEMBRE	0	0	18	48	0	3	0	0	62	0	0	0	0	0	1	4	0	2

Figure 170: Heat map of the monthly desegregated energies from the RT by labels in 2021. Source: Own elaboration.

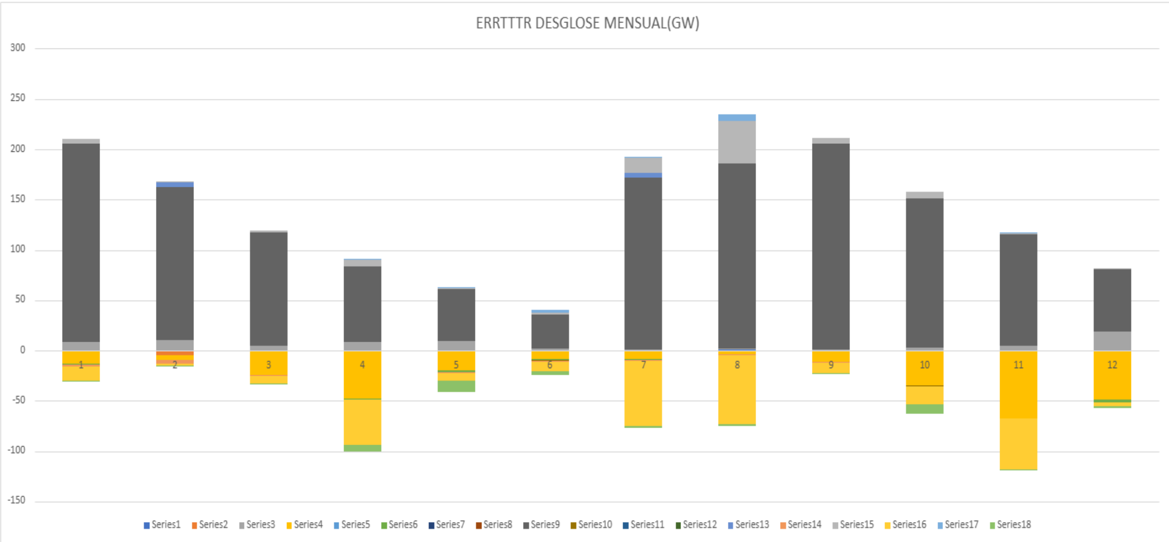


Figure 171: Monthly desegregated energies from the RT by labels in 2021. Source: Own elaboration.

HORA/ENERGIAS GW	ESASE	EBASE	ESSOT	EBSOT	ESCOT	EBPEV	ESEST	EBEST	ESRSI	EBRSI	ESRBI	EBRBI	ESRTD	EBRTD	ESSCA	EBSCA	ESSCB	EBSCB
0:00	0	0	3	10	0	0	0	0	6	0	0	0	0	0	12	17	0	1
1:00	0	0	6	25	0	1	0	0	6	0	0	0	0	0	11	16	0	1
2:00	0	0	6	34	0	0	0	0	4	0	0	0	0	0	7	15	0	1
3:00	0	0	5	37	0	0	0	0	2	0	0	0	0	0	5	13	0	1
4:00	0	0	6	39	0	0	0	0	2	0	0	0	0	0	3	12	0	1
5:00	0	0	6	45	0	0	0	0	2	0	0	0	0	0	2	11	0	1
6:00	0	1	4	29	0	0	0	0	22	0	0	0	0	0	1	8	0	0
7:00	0	0	3	19	0	0	0	0	88	0	0	0	0	0	1	7	0	0
8:00	0	0	1	12	0	0	0	0	123	0	0	0	0	0	3	7	0	0
9:00	0	0	3	6	0	0	0	0	114	0	0	0	1	1	3	7	0	0
10:00	0	1	4	3	0	0	0	0	76	0	0	0	1	0	2	8	0	1
11:00	0	0	2	3	0	0	0	0	47	0	0	0	1	0	1	10	0	2
12:00	0	0	2	3	0	0	0	0	36	0	0	0	1	0	1	12	0	3
13:00	0	0	2	2	0	0	0	0	28	0	0	0	1	1	1	13	0	2
14:00	0	0	2	3	0	1	0	0	23	0	0	0	1	1	1	14	0	3
15:00	0	0	3	3	0	1	0	0	21	0	0	0	1	0	1	15	0	4
16:00	0	0	2	4	0	1	0	0	27	0	0	0	1	1	1	15	0	4
17:00	0	0	2	5	0	1	0	0	50	0	0	0	1	0	1	15	0	4
18:00	1	1	2	3	0	1	0	0	114	0	0	0	0	0	1	15	1	3
19:00	0	1	1	2	0	1	0	0	189	0	0	0	0	1	2	15	0	2
20:00	0	0	1	0	0	0	0	0	229	0	0	0	1	1	3	14	0	2
21:00	0	0	1	0	0	0	0	0	187	0	0	0	1	1	4	14	1	2
22:00	0	0	1	0	0	0	0	0	83	0	0	0	0	1	9	13	2	1
23:00	0	1	1	1	0	0	0	0	24	0	0	0	0	1	12	16	2	1

Figure 172: Heat map of the hourly desegregated energies from the RT by labels in 2021. Source: Own elaboration.

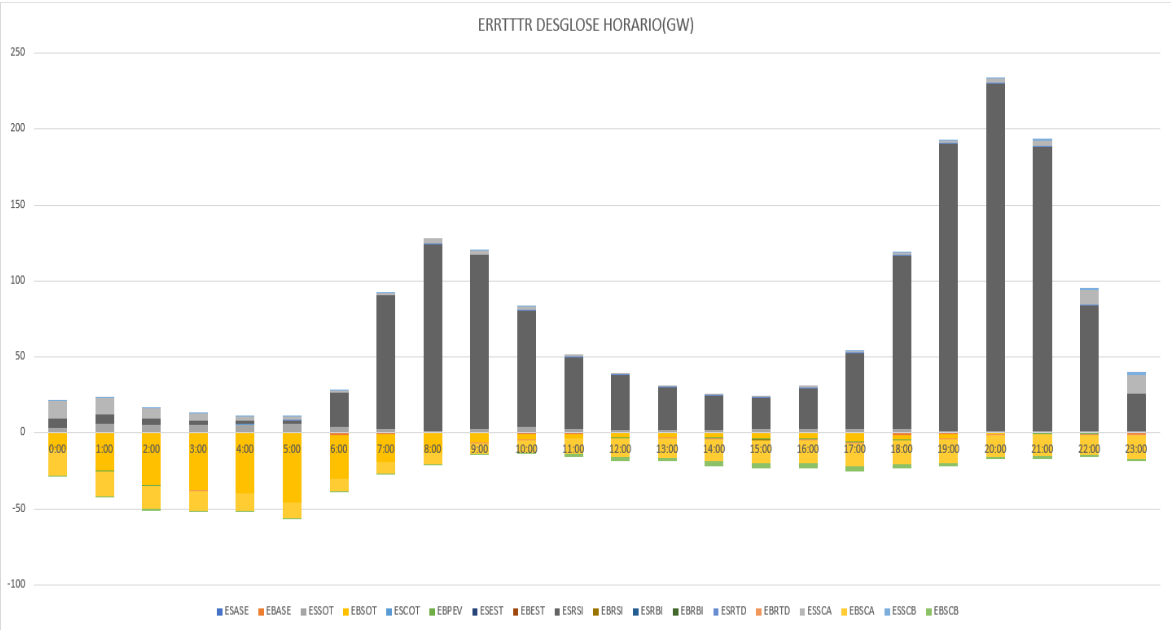


Figure 173: Hourly desegregated energies from the RT by labels in 2021. Source: Own elaboration.

HORA/ MES ESSOT (GWh)	1	2	3	4	5	6	7	8	9	10	11	12
0	1	1	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	0	0	0	0	0	0	1
2	1	1	0	1	1	0	0	0	0	0	0	1
3	1	1	0	1	1	0	0	0	0	0	0	1
4	1	1	0	1	1	0	0	0	0	0	0	1
5	1	1	0	1	1	0	0	0	0	0	0	1
6	1	0	0	1	1	0	0	0	0	0	0	1
7	0	0	0	1	0	0	0	0	0	0	0	1
8	0	0	0	0	0	0	0	0	0	0	0	1
9	0	0	0	0	0	0	0	0	0	0	0	1
10	0	1	0	0	1	0	0	0	0	1	0	1
11	0	0	0	0	0	0	0	0	0	0	0	1
12	0	1	0	0	0	0	0	0	0	0	0	1
13	0	1	0	0	0	0	0	0	0	0	0	1
14	0	0	0	0	0	0	0	0	0	0	0	1
15	0	1	0	0	0	0	0	0	0	0	0	1
16	0	0	0	0	0	0	0	0	0	0	0	1
17	0	0	0	0	0	0	0	0	0	0	0	1
18	0	0	0	0	1	0	0	0	0	0	0	1
19	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	1
23	0	0	0	0	0	0	0	0	0	0	0	1

Figure 174: Heat map of the ESSOT of the RT by hours and months in 2021. Source: Own elaboration.

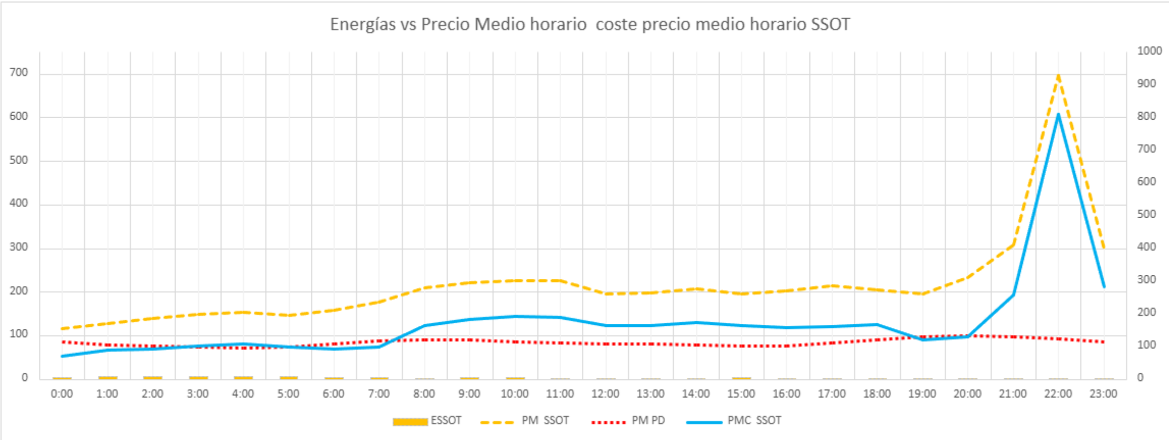


Figure 175: ESSOT, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2021. Source: Own elaboration.

HORA/ MES ESCOT	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	0	0	0	0	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0

Figure 176: Heat map of the ESCOT of the RT by hours and months in 2021. Source: Own elaboration.

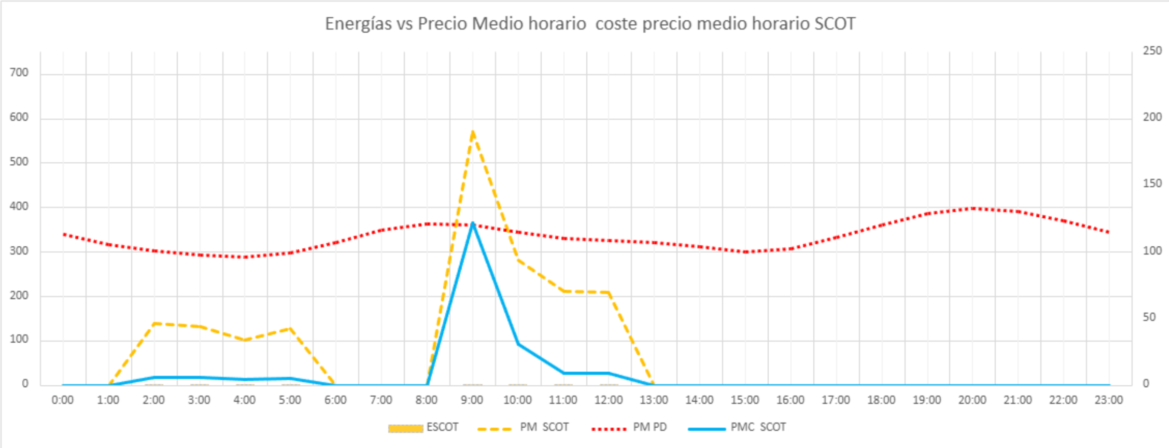


Figure 177: ESSOT, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2021. Source: Own elaboration.

HORA/ MES ESRSI 2021	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	0	2	1	2	1	0	0
1	0	0	0	0	0	0	2	2	2	1	0	0
2	0	0	0	0	0	0	1	1	1	1	0	0
3	0	0	0	0	0	0	0	0	1	1	0	0
4	0	0	0	0	0	0	0	0	1	1	0	0
5	0	0	0	0	0	0	0	1	1	1	0	0
6	0	0	1	1	0	0	5	6	5	3	0	0
7	3	4	8	8	4	3	13	9	16	12	7	1
8	12	11	13	10	6	3	14	12	15	16	8	3
9	17	11	12	9	3	2	13	11	16	13	5	3
10	14	8	6	6	0	1	10	8	10	8	2	2
11	12	4	2	2	0	1	8	6	6	4	1	1
12	9	4	1	0	0	1	6	6	4	3	1	1
13	8	4	0	0	1	0	3	6	3	2	1	1
14	6	3	0	0	0	0	3	6	2	1	1	0
15	6	3	0	0	0	0	1	5	2	2	1	1
16	7	4	1	0	0	0	1	4	2	2	3	3
17	11	5	2	0	0	0	1	4	6	4	9	5
18	21	17	8	0	1	3	5	5	13	9	20	11
19	24	24	19	6	4	6	16	12	24	21	21	12
20	23	23	23	15	13	8	24	23	28	22	17	11
21	16	18	16	14	13	5	21	26	24	18	10	6
22	6	7	2	3	5	1	16	19	15	4	3	1
23	2	2	0	0	0	0	5	8	6	1	0	0

Figure 178: Heat map of the ESRSI of the RT by hours and months in 2021. Source: Own elaboration.

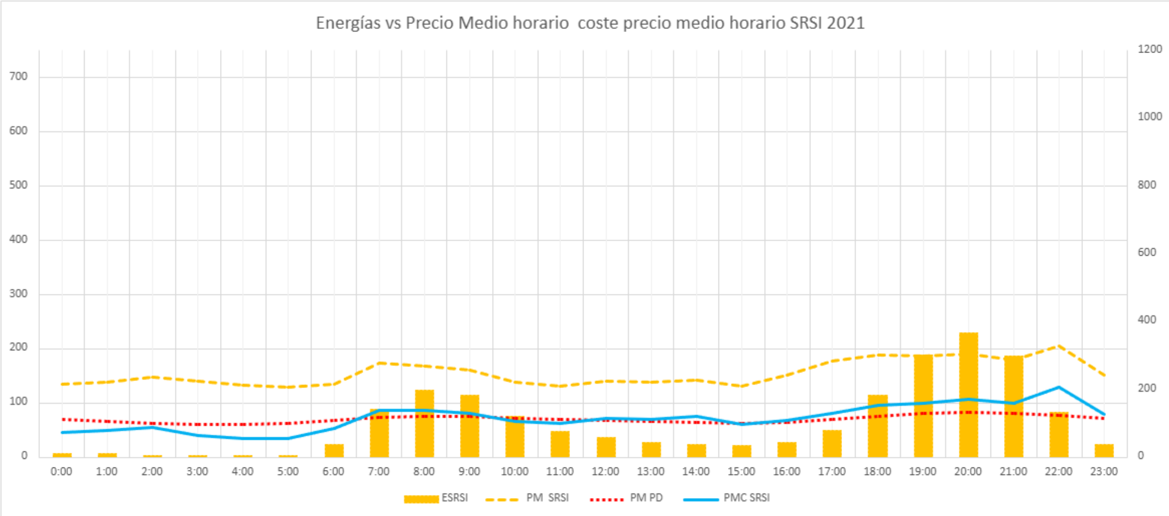


Figure 179: ESRSI, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2021. Source: Own elaboration.

HORA/ MES ESSCA	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	1	0	0	2	7	0	1	0	0
1	0	0	0	0	0	0	2	8	0	0	0	0
2	0	0	0	0	0	0	1	4	0	0	0	0
3	0	0	0	0	0	0	1	3	0	0	0	0
4	0	0	0	0	0	0	0	2	0	0	0	0
5	0	0	0	0	0	0	0	1	0	0	0	0
6	0	0	0	0	0	0	0	1	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	2	0	0	0	0
9	0	0	0	0	0	0	0	2	0	0	0	0
10	0	0	0	0	0	0	0	2	0	0	0	0
11	0	0	0	0	0	0	0	1	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	1	0	0	0	0
20	0	0	0	0	0	0	0	1	0	0	0	0
21	0	0	0	0	0	0	1	1	0	1	0	0
22	1	0	0	1	0	0	2	2	1	2	0	0
23	1	0	0	1	0	0	3	5	0	1	0	0

Figure 180: Heat map of the ESSCA of the RT by hours and months in 2021. Source: Own elaboration.

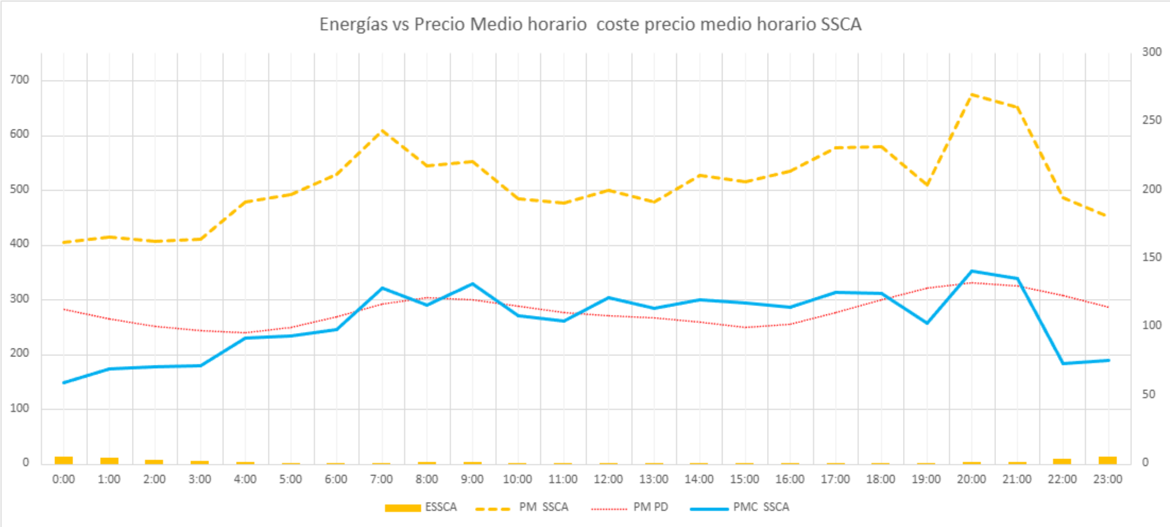


Figure 181: ESSCA, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2021. Source: Own elaboration.

2022 PDBF

MES/ENEI	ERRTT F1S	ERRTT F1B	ERRTT F2S	ERRTT F2B
ENERO	565	7	3	284
FEBRERO	589	18	4	286
MARZO	675	20	3	331
ABRIL	1142	125	14	533
MAYO	1264	95	4	664
JUNIO	450	353	208	151
JULIO	257	369	267	84
AGOSTO	252	188	126	86
SEPTIEMB	338	87	49	143
OCTUBRE	498	30	14	311
NOVIEMB	770	13	0	451
DICIEMBR	1066	17	3	576

Figure 182: Heat map of the monthly desegregated energies from the PDBF in 2022. Source: Own elaboration.

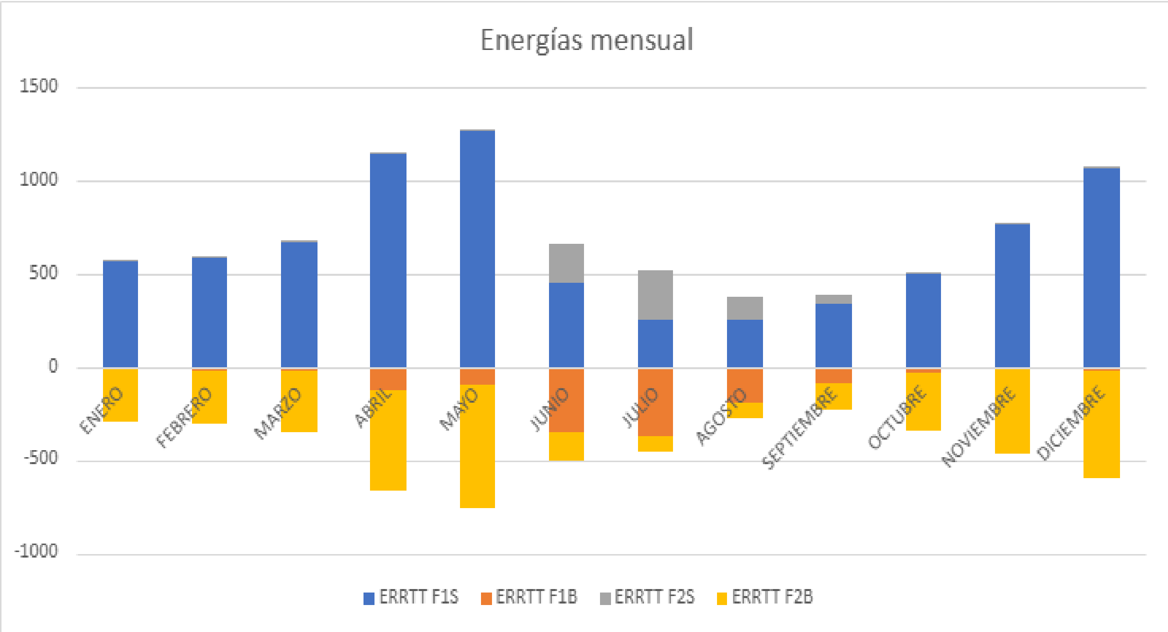


Figure 183: Monthly desegregated energies from the PDBF in 2022. Source: Own elaboration.

HORA/EN	ERRTT F1S	ERRTT F1B	ERRTT F2S	ERRTT F2B
0:00	505	26	8	239
1:00	537	24	7	257
2:00	556	24	7	268
3:00	573	23	6	282
4:00	571	23	6	281
5:00	549	22	6	272
6:00	489	19	6	244
7:00	435	18	5	220
8:00	317	17	6	171
9:00	273	24	10	150
10:00	244	67	35	124
11:00	255	105	64	124
12:00	262	134	86	123
13:00	263	140	89	123
14:00	266	133	83	124
15:00	264	130	80	123
16:00	256	120	71	118
17:00	240	94	52	112
18:00	209	56	27	102
19:00	184	30	10	98
20:00	162	24	7	90
21:00	158	25	9	87
22:00	154	24	9	83
23:00	158	22	8	85

Figure 184: Heat map of the hourly desegregated energies from the PDBF by labels in 2022. Source: Own elaboration.

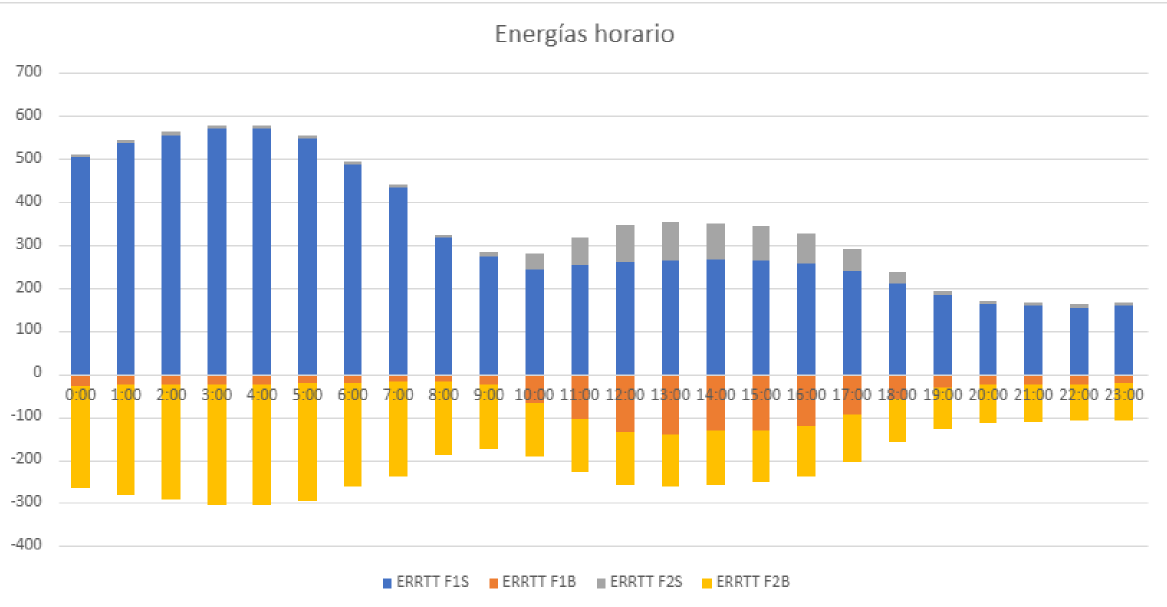


Figure 185: Hourly desegregated energies from the PDBF by labels in 2022. Source: Own elaboration.

MES/ENEI	EBSCA	ESSCA	EBSCB	ESSCB	EBRTD	ESRTD	EBSOT	ESSOT	EBPEV	ESCOT
ENERO	6	5	0	0	1	5	0	277	0	0
FEBRERO	17	5	0	0	1	5	0	289	0	1
MARZO	19	7	0	0	0	12	0	325	0	2
ABRIL	124	74	0	2	2	79	0	491	1	0
MAYO	94	54	0	0	1	183	0	519	0	0
JUNIO	337	62	9	5	5	66	0	158	1	4
JULIO	352	111	11	2	2	13	0	62	5	0
AGOSTO	184	32	0	0	0	2	0	113	4	0
SEPTIEMB	78	36	0	0	11	4	0	144	0	0
OCTUBRE	23	95	0	1	6	65	0	166	0	0
NOVIEMB	9	54	0	0	3	94	0	314	0	0
DICIEMBR	12	36	0	0	0	70	0	485	5	0

Figure 186: Heat map of the monthly desegregated energies from the PDBF by labels in 2022. Source: Own elaboration.

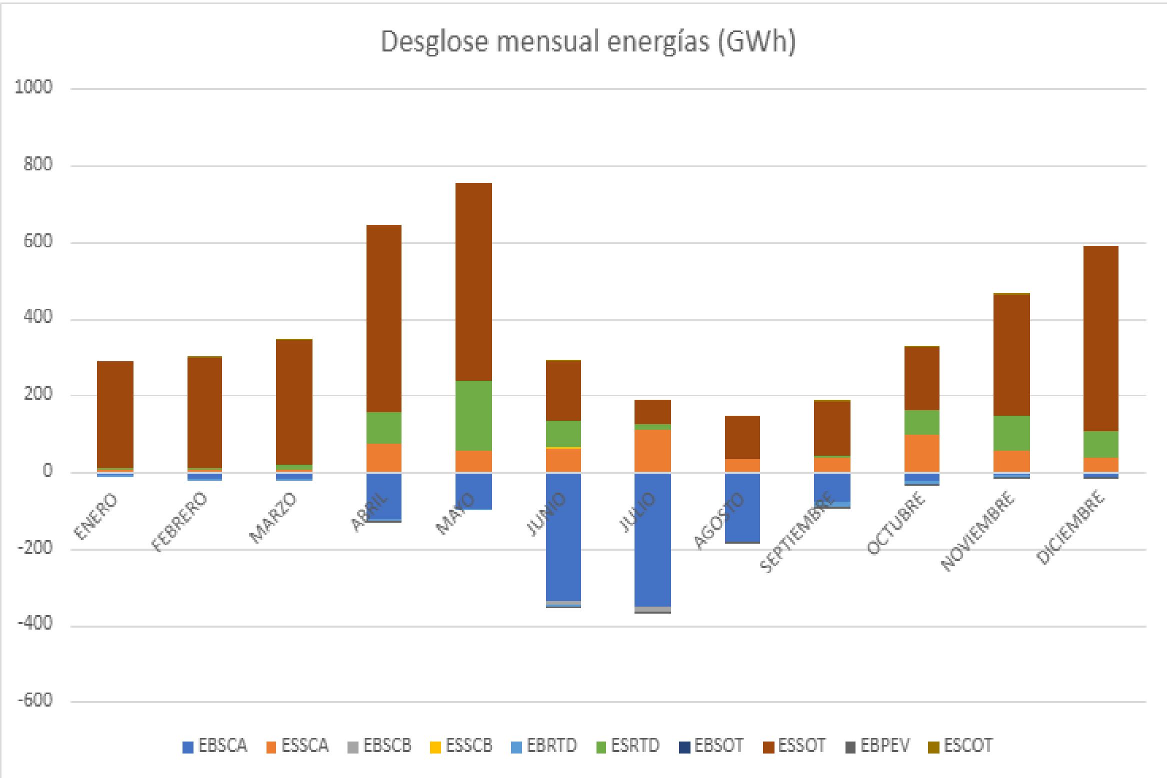


Figure 187: Monthly desegregated energies from the PDBF by labels in 2022. Source: Own elaboration.

HORA/EN	EBSCA	ESSCA	EBSCB	ESSCB	EBRTD	ESRTD	EBSOT	ESSOT	EBPEV	ESCOT
0:00	23	8	1	0	1	2	0	247	1	0
1:00	21	10	1	0	1	2	0	262	1	0
2:00	21	9	1	0	1	4	0	271	1	0
3:00	20	8	1	0	1	16	0	274	1	0
4:00	21	8	1	0	1	18	0	272	1	0
5:00	20	8	1	0	1	20	0	260	1	0
6:00	17	5	1	0	1	20	0	232	1	0
7:00	15	6	1	0	1	24	0	203	1	0
8:00	14	21	1	0	2	28	0	134	1	0
9:00	21	24	1	0	1	31	0	109	1	0
10:00	64	32	1	0	1	35	0	88	1	0
11:00	102	37	1	0	2	39	0	89	1	0
12:00	132	41	1	1	2	41	0	89	1	0
13:00	137	42	1	1	2	41	0	90	1	0
14:00	130	42	1	1	2	40	0	91	1	1
15:00	127	42	1	1	2	38	0	91	1	1
16:00	116	41	1	1	2	35	0	89	1	1
17:00	90	35	1	1	2	33	0	85	1	1
18:00	54	27	1	1	1	25	0	78	1	1
19:00	27	27	1	1	1	23	0	66	1	1
20:00	20	28	1	0	2	23	0	55	1	1
21:00	22	27	1	0	1	22	0	54	1	0
22:00	21	23	1	0	1	19	0	55	1	0
23:00	18	21	1	0	1	18	0	59	1	0

Figure 188: Heat map of the hourly desegregated energies from the PDBF by labels in 2022. Source: Own elaboration.

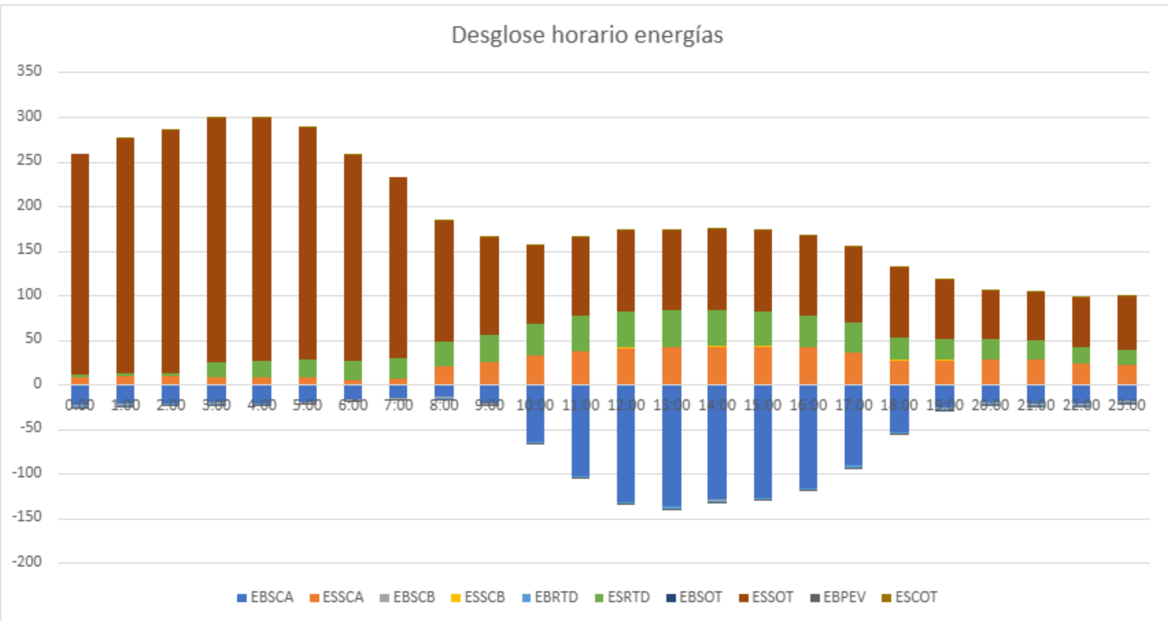


Figure 189: Hourly desegregated energies from the PDBF by labels in 2022. Source: Own elaboration.

Hora/mes ESSCA (GWh)	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	4	0	0	1	0	1	1	0	0
1	0	0	0	4	0	0	2	0	1	2	0	0
2	0	0	0	4	0	0	1	0	1	2	0	0
3	0	0	0	4	0	0	1	0	1	2	0	0
4	0	0	0	4	0	0	1	0	1	2	0	0
5	0	0	0	3	0	0	1	0	1	2	0	0
6	0	0	0	1	0	0	1	0	1	1	0	0
7	0	0	0	2	0	0	1	0	0	2	0	0
8	0	0	0	3	2	3	4	0	1	3	3	2
9	0	0	0	3	2	2	5	1	1	4	4	2
10	0	0	0	3	3	4	7	2	1	5	5	3
11	0	0	0	3	4	4	7	3	2	6	5	3
12	0	0	0	3	4	4	7	3	3	7	5	3
13	0	0	0	3	4	4	7	3	3	8	5	3
14	0	0	0	3	4	4	7	3	4	8	5	3
15	0	0	0	3	4	4	7	4	3	9	5	3
16	0	0	0	3	4	4	7	4	3	9	4	3
17	0	0	0	3	3	4	8	3	3	7	3	2
18	0	0	0	2	3	4	7	2	2	3	2	2
19	1	1	0	2	2	4	7	1	1	3	2	2
20	1	1	1	3	3	4	6	1	1	4	1	2
21	1	1	1	4	3	4	6	1	1	3	1	1
22	1	1	1	4	3	4	4	0	1	2	1	1
23	1	1	1	4	2	5	3	0	1	2	1	0

Figure 190: Heat map of the ESSCA of the PDBF by hours and months in 2022. Source: Own elaboration.

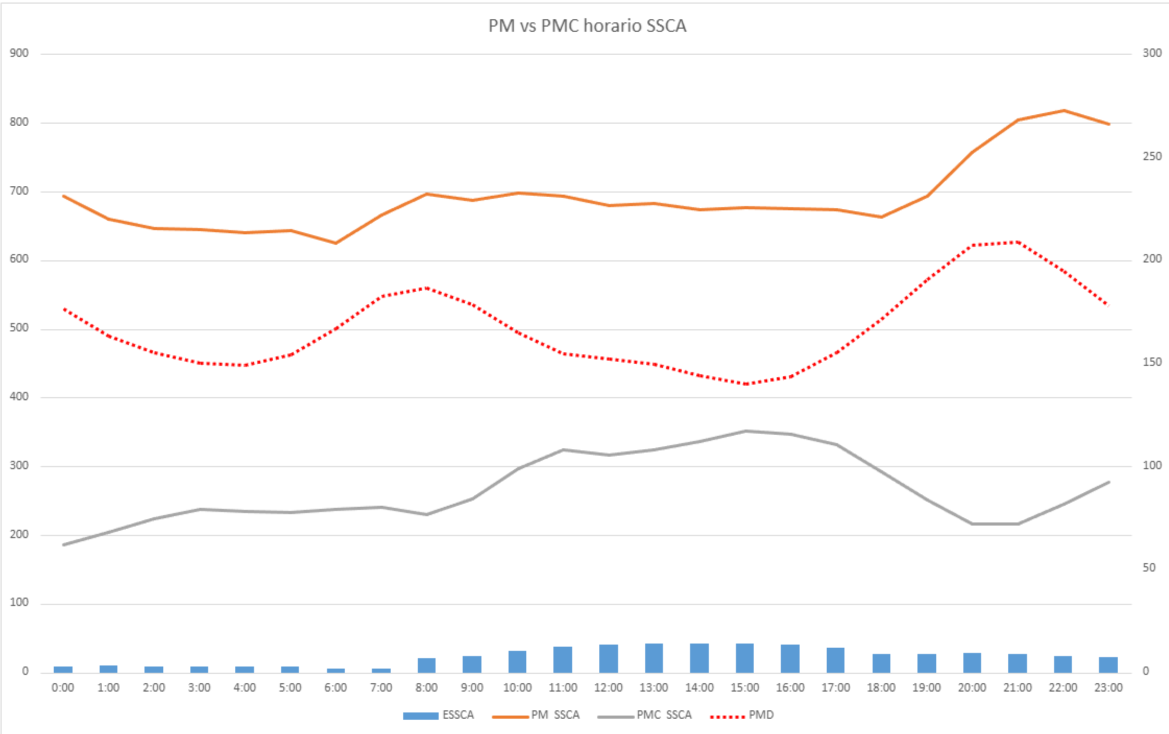


Figure 191: ESSCA, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2022. Source: Own elaboration.

Hora/mes ESRTD	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	1	0	0	0	0	0	0	0	0
1	0	0	0	1	0	0	0	0	0	0	0	0
2	0	0	0	1	0	0	0	0	0	0	0	1
3	0	0	0	3	7	2	0	0	0	1	1	2
4	0	0	0	3	7	2	0	0	0	1	3	2
5	0	0	0	3	7	2	0	0	0	1	4	2
6	0	0	0	3	7	2	0	0	0	1	4	2
7	0	0	0	3	7	3	0	0	0	3	4	3
8	0	0	1	3	8	3	1	0	0	4	5	3
9	0	0	1	3	8	3	1	0	0	4	6	4
10	0	0	1	3	10	4	1	0	0	4	7	4
11	0	0	1	4	11	4	1	0	0	4	7	5
12	0	1	1	5	12	4	1	0	0	4	7	5
13	0	1	1	5	12	4	1	0	0	4	7	5
14	0	1	1	5	12	4	1	0	0	4	8	4
15	0	0	1	5	11	4	1	0	0	4	7	4
16	0	0	1	4	10	4	1	0	0	4	6	4
17	0	0	1	4	10	4	1	0	0	4	5	3
18	0	0	0	4	9	3	0	0	0	3	2	3
19	0	0	0	4	8	3	0	0	0	3	3	3
20	0	0	0	4	7	3	0	0	0	3	3	3
21	0	0	0	3	7	2	0	0	0	3	3	3
22	0	0	0	3	7	2	0	0	0	2	1	3
23	0	0	0	3	7	2	0	0	0	1	1	3

Figure 192: Heat map of the ESRTD of the PDBF by hours and months in 2022. Source: Own elaboration.

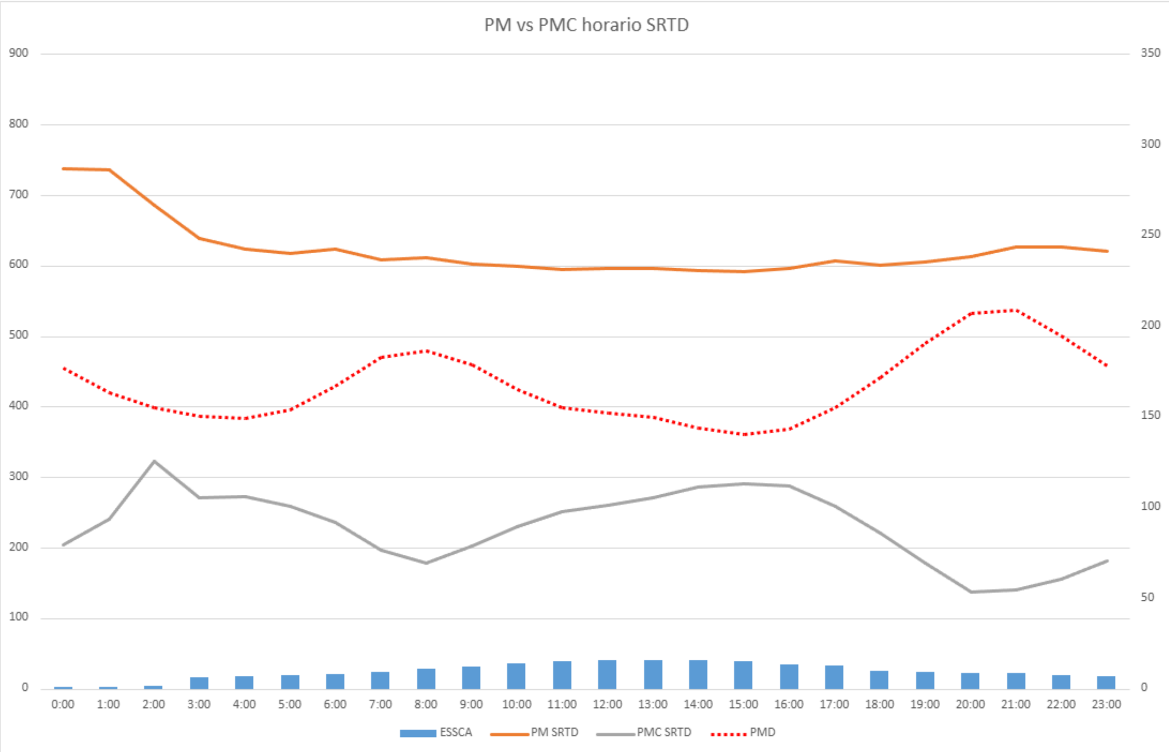


Figure 193: ESRTD, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2022. Source: Own elaboration.

Hora/mes ESSOT	1	2	3	4	5	6	7	8	9	10	11	12
0	23	22	29	32	34	11	5	8	9	14	24	34
1	26	24	30	34	38	13	6	8	9	15	25	34
2	27	25	30	36	40	13	6	8	9	16	26	35
3	26	25	31	36	41	13	6	9	9	15	26	35
4	26	24	31	36	41	14	6	8	10	15	26	35
5	26	22	29	34	39	13	6	8	10	14	25	35
6	20	19	25	33	34	10	6	8	9	13	23	33
7	14	16	20	31	30	9	5	7	8	10	22	30
8	9	11	11	22	20	7	3	4	6	7	13	20
9	7	8	8	18	17	6	2	4	6	5	11	18
10	7	7	6	14	14	4	1	3	5	3	9	15
11	6	7	6	14	15	4	1	3	5	4	9	15
12	6	7	6	14	15	4	1	3	5	4	9	15
13	6	7	6	14	15	4	1	3	5	4	9	15
14	6	8	6	14	16	5	1	3	5	4	9	15
15	6	7	6	15	16	5	1	3	5	4	9	15
16	6	8	6	15	16	5	1	3	5	4	7	14
17	5	7	6	15	16	5	1	3	5	3	6	13
18	5	6	6	14	15	4	1	3	4	3	5	11
19	4	6	5	13	12	4	1	3	3	2	4	9
20	4	6	5	9	9	2	0	2	3	2	4	9
21	4	6	5	9	9	2	0	2	3	2	4	9
22	4	6	5	9	9	2	0	2	3	2	4	11
23	4	6	6	9	9	2	0	2	3	2	4	11

Figure 194: Heat map of the ESSOT of the PDBF by hours and months in 2022. Source: Own elaboration.

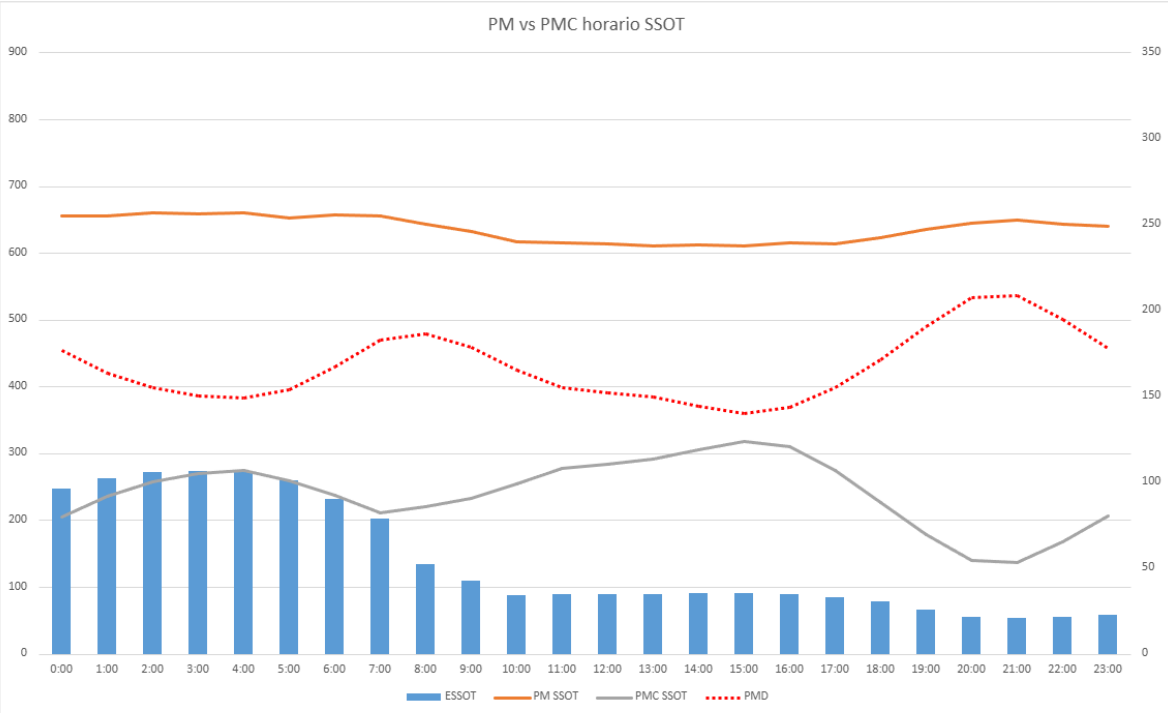


Figure 195: ESSOT, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2022. Source: Own elaboration.

Hora/mes ESCOT	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	0	0	0	0	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	1	0	0	0	0	0	0
17	0	0	0	0	0	1	0	0	0	0	0	0
18	0	0	0	0	0	1	0	0	0	0	0	0
19	0	0	0	0	0	1	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0

Figure 196: Heat map of the ESCOT of the PDBF by hours and months in 2022. Source: Own elaboration.

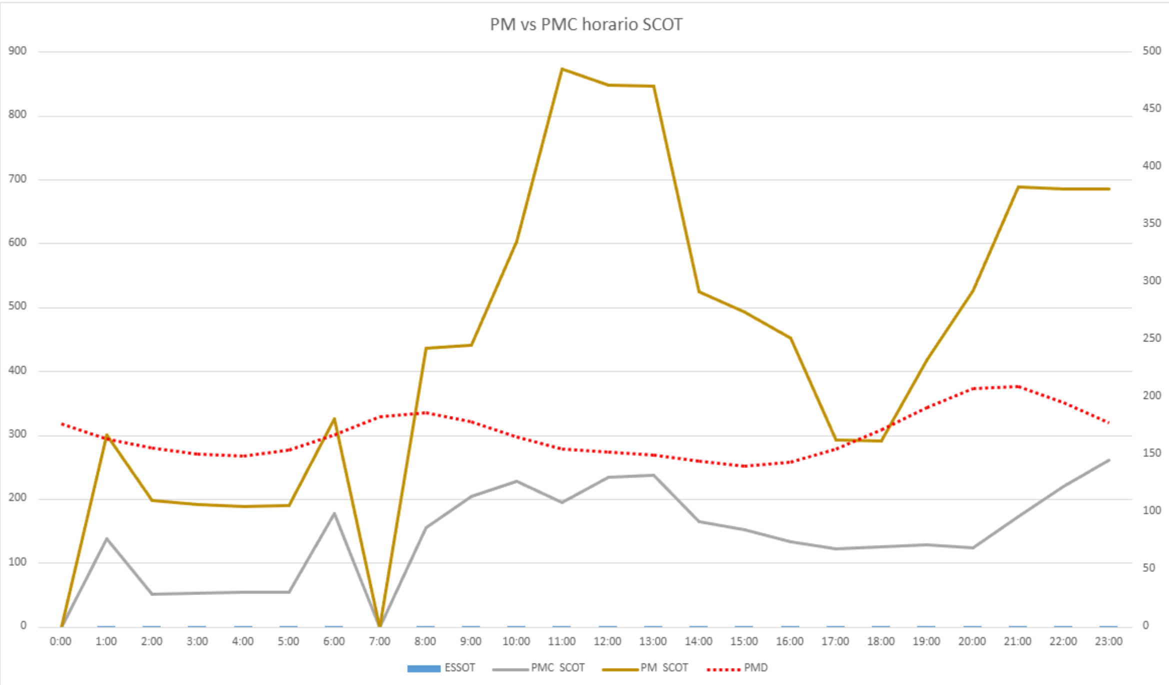


Figure 197: ESCOT, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2022. Source: Own elaboration.

MES/ENERGIAS GW	ESASE	EBASE	ESSOT	EBSOT	ESCOT	EBPEV	ESEST	EBEST	ESRSI	EBRSI	ESRBI	EBRBI	ESRTD	EBRTD	ESSCA	EBSCA	ESSCB	EBSCB
ENERO	0	1	5	34	0	0	0	0	19	0	0	0	0	1	0	28	0	0
FEBRERO	0	0	10	17	0	0	0	0	15	0	0	0	0	0	0	44	0	1
MARZO	0	1	14	33	0	0	0	0	47	0	0	0	0	0	0	33	0	2
ABRIL	1	1	13	37	1	1	0	0	38	0	0	0	0	1	9	25	0	22
MAYO	1	0	10	29	0	0	0	0	41	0	0	0	3	2	3	25	0	6
JUNIO	2	1	8	12	2	1	0	0	41	21	0	0	0	1	5	22	10	26
JULIO	0	0	2	3	0	1	0	0	192	8	0	0	0	0	18	12	11	43
AGOSTO	0	0	9	9	0	0	0	0	146	5	0	0	0	4	9	2	2	22
SEPTIEMBRE	0	1	2	11	1	0	0	0	225	7	0	0	0	0	6	3	1	21
OCTUBRE	0	0	5	27	4	0	0	0	220	27	0	0	0	1	7	0	5	11
NOVIEMBRE	0	0	11	15	1	0	0	0	163	0	0	0	1	3	2	5	0	6
DICIEMBRE	0	0	5	21	0	2	0	0	337	3	0	5	0	0	0	4	0	3

Figure 198: Heat map of the monthly desegregated energies from the RT by labels in 2022. Source: Own elaboration.

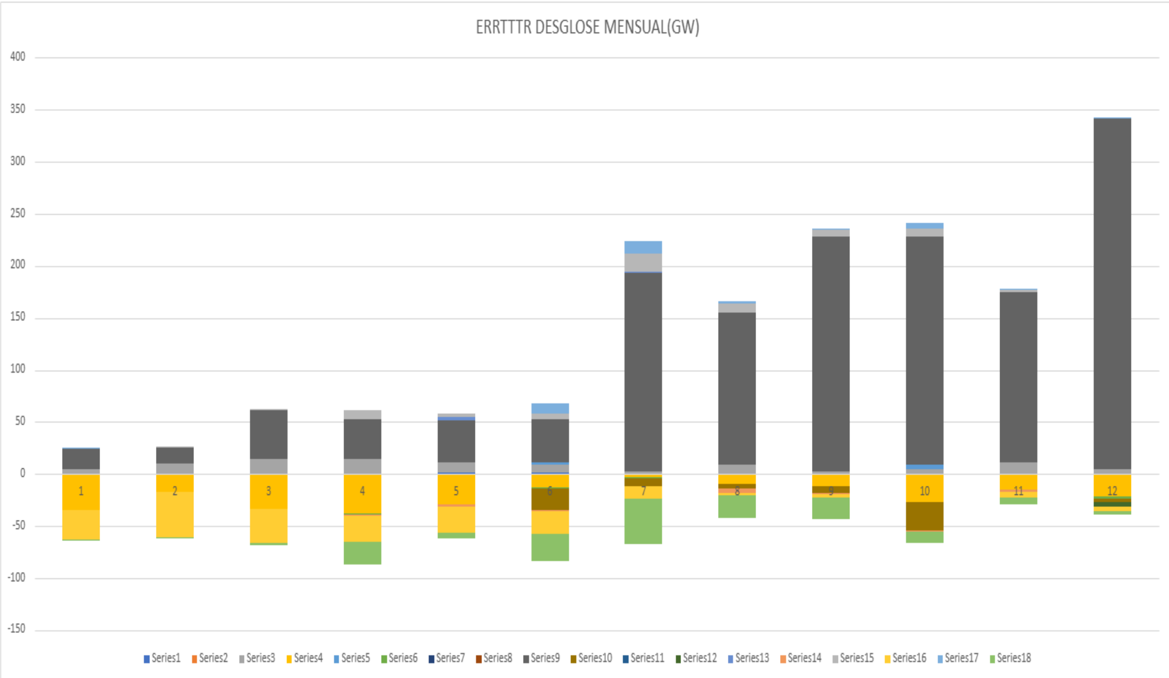


Figure 199: Monthly desegregated energies from the RT by labels in 2022. Source: Own elaboration.

HORA/ENERGIAS GW	ESASE	EBASE	ESSOT	EBSOT	ESCOT	EBPEV	ESEST	EBEST	ESRSI	EBRSI	ESRBI	EBRBI	ESRTD	EBRTD	ESSCA	EBSCA	ESSCB	EBSCB
0:00	1	1	4	4	0	0	0	0	15	2	0	0	0	0	2	11	0	6
1:00	0	0	5	14	0	0	0	0	12	5	0	0	0	0	2	11	0	4
2:00	0	0	6	25	0	0	0	0	6	6	0	0	0	1	2	9	0	3
3:00	0	0	7	32	0	0	0	0	4	6	0	0	0	1	1	8	0	3
4:00	0	0	7	37	0	0	0	0	3	7	0	0	0	1	1	7	0	3
5:00	0	0	7	40	0	0	0	0	4	9	0	0	0	0	1	7	0	2
6:00	0	0	5	32	0	0	0	0	21	7	0	0	0	0	1	5	0	2
7:00	0	0	5	23	0	0	0	0	64	3	0	0	0	0	1	5	0	3
8:00	0	0	3	14	0	0	0	0	86	2	0	1	0	0	1	5	0	2
9:00	0	0	5	8	0	0	0	0	73	1	0	0	0	0	1	4	0	3
10:00	1	0	5	2	0	1	0	0	47	1	0	0	0	0	2	4	1	6
11:00	0	0	3	0	0	1	0	0	29	1	0	0	0	1	2	5	1	7
12:00	0	0	4	0	1	0	0	0	25	2	0	0	0	1	3	7	1	8
13:00	0	0	4	0	1	0	0	0	21	2	0	1	0	1	4	8	1	12
14:00	0	0	4	1	1	0	0	0	21	3	0	1	0	1	5	9	2	13
15:00	0	0	4	1	0	0	0	0	24	3	0	1	0	1	5	10	3	15
16:00	0	0	4	2	1	0	0	0	39	4	0	1	0	1	5	11	3	15
17:00	0	0	3	4	1	0	0	0	68	3	0	0	0	1	4	11	3	13
18:00	0	1	3	4	0	0	0	0	111	2	0	0	0	1	3	12	3	10
19:00	0	0	2	3	1	0	0	0	176	1	0	0	0	0	3	12	3	8
20:00	0	0	1	1	0	0	0	0	238	0	0	0	0	0	3	10	2	6
21:00	1	0	1	0	1	0	0	0	223	0	0	0	0	0	3	10	2	5
22:00	0	0	2	0	0	0	0	0	132	1	0	0	0	1	3	11	2	6
23:00	0	0	2	1	0	0	0	0	42	1	0	0	0	0	2	11	2	7

Figure 200: Heat map of the hourly desegregated energies from the RT by labels in 2022. Source: Own elaboration.

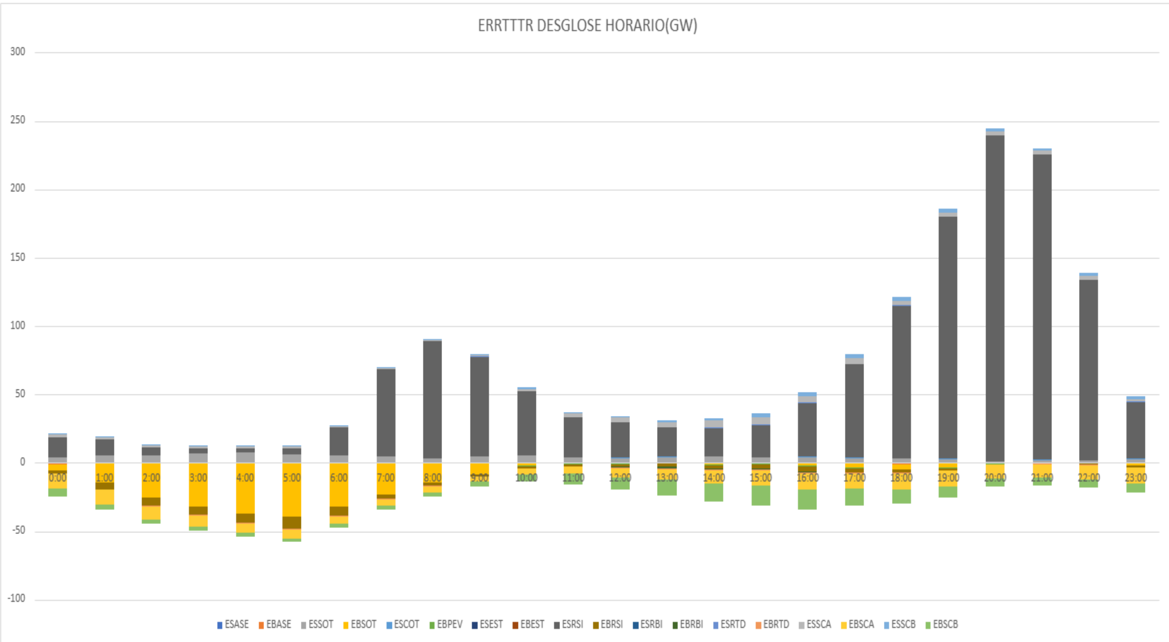


Figure 201: Hourly desegregated energies from the RT by labels in 2022. Source: Own elaboration.

HORA/ MES ESSOT (GWh)	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	1	0	0	0	0	0	0	1	0
1	0	0	1	1	0	0	0	0	0	0	1	0
2	1	1	1	1	0	1	0	0	0	0	1	0
3	1	1	2	1	0	0	0	0	0	1	1	0
4	1	1	2	1	0	1	0	0	0	1	0	0
5	1	0	1	1	0	1	0	0	0	1	0	0
6	1	0	1	1	0	1	0	0	0	0	0	0
7	0	0	1	1	0	1	0	0	0	0	0	0
8	0	0	1	0	0	0	0	0	0	0	0	0
9	0	0	1	0	1	1	0	0	0	0	0	0
10	0	1	1	0	1	1	0	1	0	0	0	0
11	0	0	0	0	1	0	0	0	0	0	0	0
12	0	0	0	0	1	0	0	1	0	0	1	0
13	0	0	0	0	1	0	0	1	0	0	0	0
14	0	0	0	0	1	0	0	1	0	0	1	0
15	0	0	0	0	1	0	0	1	0	0	1	0
16	0	0	0	0	0	0	0	1	0	0	1	1
17	0	0	0	0	0	0	0	0	0	0	1	0
18	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	1	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	1	0	0	0	0	0	0	0	0

Figure 202: Heat map of the ESSOT of the RT by hours and months in 2022. Source: Own elaboration.

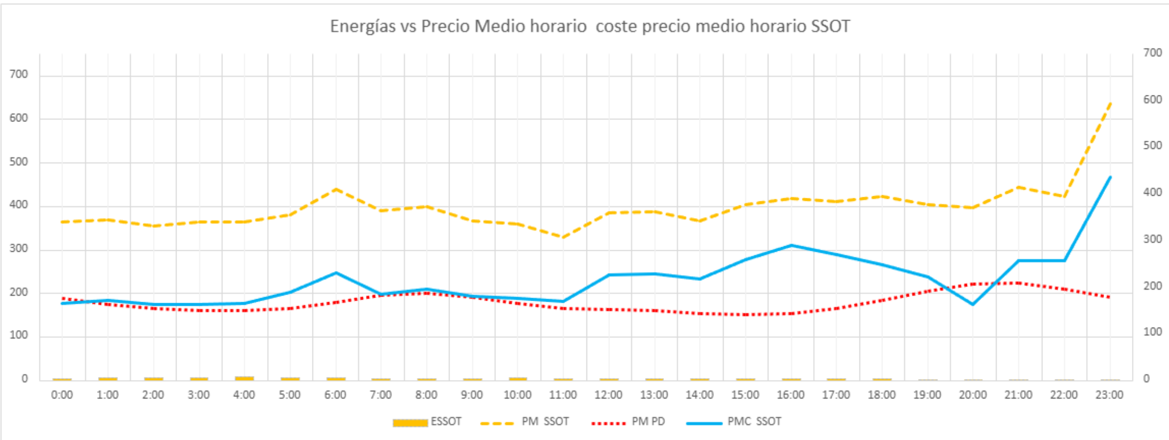


Figure 203: ESSOT, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2022. Source: Own elaboration.

HORA/ MES ESCOT	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	0	0	0	0	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	1	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	1	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0

Figure 204: Heat map of the ESCOT of the RT by hours and months in 2022. Source: Own elaboration.

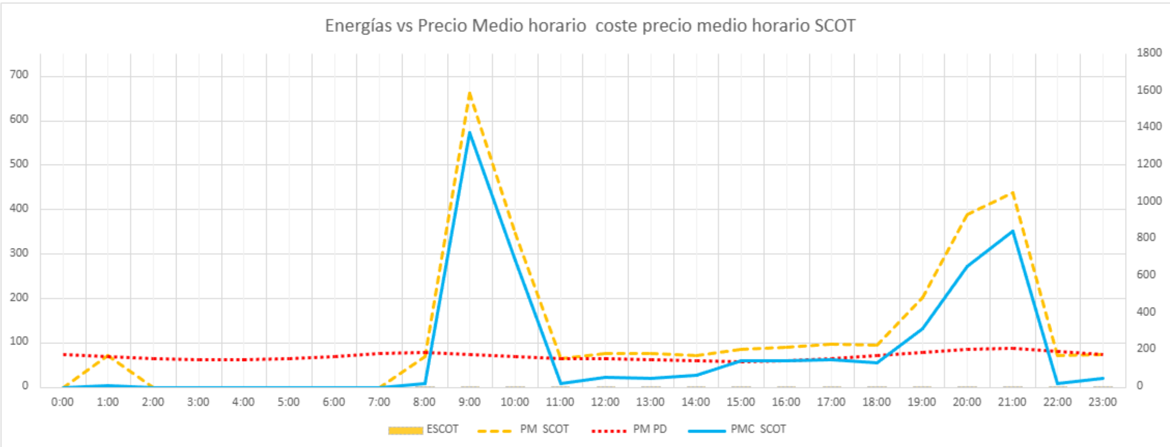


Figure 205: ESCOT, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2022. Source: Own elaboration.

HORA/ MES ESRSI 2022	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	0	4	2	4	2	0	2
1	0	0	0	0	1	0	3	1	4	2	0	1
2	0	0	0	0	0	0	2	0	2	1	0	0
3	0	0	0	0	0	0	1	0	2	1	0	0
4	0	0	0	0	0	0	1	0	1	0	0	0
5	0	0	0	0	0	0	2	0	2	0	0	0
6	0	0	0	1	0	1	6	2	8	2	1	0
7	0	0	3	1	3	2	10	5	15	10	7	8
8	0	1	4	2	4	2	9	5	15	16	10	17
9	0	0	2	3	1	2	8	4	12	15	9	18
10	0	0	1	2	1	2	6	3	4	9	5	15
11	0	0	1	1	0	1	5	2	3	4	2	9
12	0	0	1	1	0	1	6	3	3	3	1	7
13	0	0	0	0	0	1	6	3	2	1	1	7
14	0	0	0	0	0	1	6	3	1	2	1	7
15	0	0	0	0	0	1	4	3	1	2	1	11
16	0	0	0	0	0	1	5	2	1	3	5	22
17	0	0	1	0	0	1	5	1	3	8	16	33
18	5	1	6	0	1	1	5	3	7	20	25	38
19	7	5	11	3	2	2	13	9	25	33	25	42
20	5	5	11	11	10	5	25	29	37	33	25	41
21	2	2	5	11	12	6	26	33	38	30	21	38
22	0	0	1	2	5	6	25	25	25	16	9	17
23	0	0	1	0	0	2	9	7	11	6	1	5

Figure 206: Heat map of the ESRSI of the RT by hours and months in 2022. Source: Own elaboration.

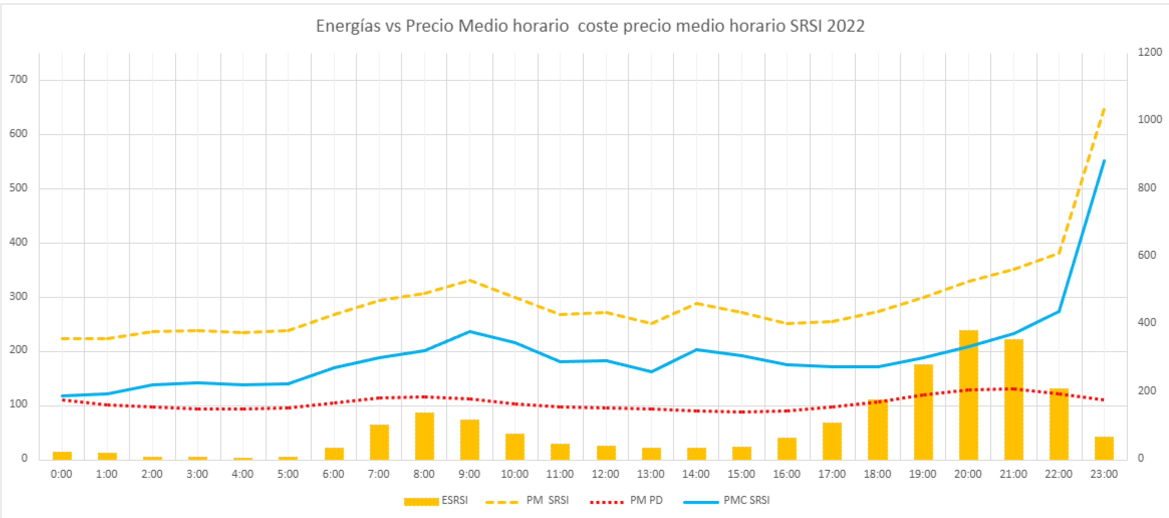


Figure 207: ESRSI, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2022. Source: Own elaboration.

HORA/ MES ESSCA	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	1	1	0	0	0	0	0
1	0	0	0	1	0	0	1	0	0	0	0	0
2	0	0	0	1	0	0	1	0	0	0	0	0
3	0	0	0	1	0	0	1	0	0	0	0	0
4	0	0	0	1	0	0	0	0	0	0	0	0
5	0	0	0	1	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	1	0	0	0	0	0
10	0	0	0	0	0	0	1	0	1	0	0	0
11	0	0	0	0	0	0	1	0	0	0	0	0
12	0	0	0	0	0	0	1	1	1	1	0	0
13	0	0	0	0	0	0	1	1	1	1	1	0
14	0	0	0	0	0	1	1	1	1	1	0	0
15	0	0	0	0	0	1	2	1	1	1	0	0
16	0	0	0	0	0	0	2	1	1	1	0	0
17	0	0	0	0	0	1	1	1	0	1	0	0
18	0	0	0	0	0	1	1	1	0	0	0	0
19	0	0	0	0	0	0	1	1	0	0	0	0
20	0	0	0	0	0	0	1	1	0	0	0	0
21	0	0	0	0	0	0	0	1	0	0	0	0
22	0	0	0	1	0	0	0	1	0	0	0	0
23	0	0	0	1	0	0	0	0	0	0	0	0

Figure 208: Heat map of the ESSCA of the RT by hours and months in 2022. Source: Own elaboration.

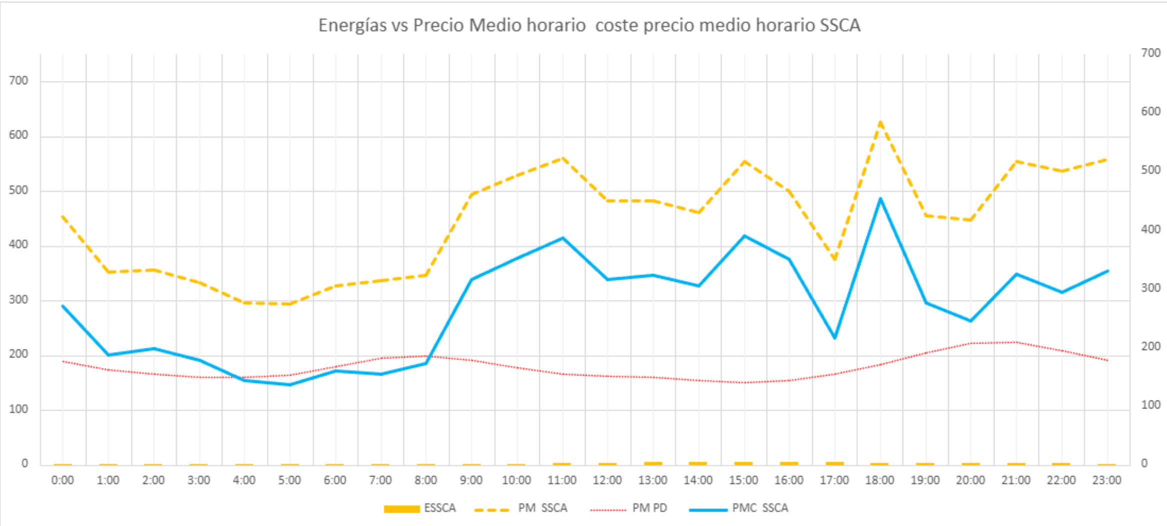


Figure 209: ESSCA, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2022. Source: Own elaboration.

MES/ENEI	ERRTT F1S	ERRTT F1B	ERRTT F2S	ERRTT F2B
ENERO	1477	62	0	809
FEBRERO	981	45	1	565
MARZO	1022	91	1	548
ABRIL	1192	113	1	637
MAYO	1288	180	1	674
JUNIO	1162	172	13	627
JULIO	1073	295	38	539
AGOSTO	1002	198	17	526
SEPTIEMB	1093	72	5	656
OCTUBRE	1419	121	27	803
NOVIEMB	1556	58	0	937
DICIEMBR	1453	103	13	783

Figure 210: Heat map of the monthly desegregated energies from the PDBF in 2023. Source: Own elaboration.

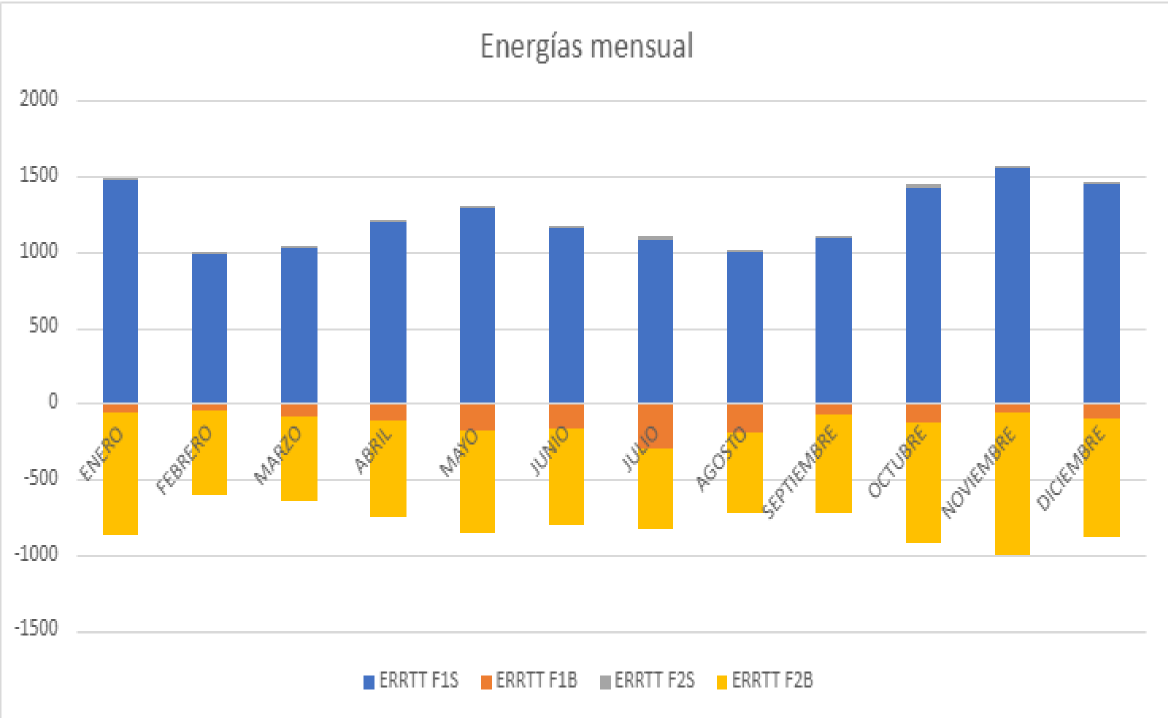


Figure 211: Monthly desegregated energies from the PDBF in 2023. Source: Own elaboration.

HORA/EN	ERRTT F1S	ERRTT F1B	ERRTT F2S	ERRTT F2B
0:00	794	36	1	380
1:00	864	36	1	416
2:00	902	35	1	444
3:00	950	35	1	487
4:00	953	34	1	488
5:00	944	33	1	485
6:00	885	31	1	459
7:00	768	32	1	412
8:00	588	40	4	340
9:00	555	56	6	328
10:00	544	85	7	311
11:00	556	111	11	304
12:00	559	123	13	300
13:00	559	126	13	298
14:00	556	124	11	295
15:00	555	119	10	299
16:00	543	107	8	302
17:00	516	85	5	301
18:00	443	64	4	273
19:00	378	50	3	250
20:00	331	39	3	233
21:00	334	37	3	241
22:00	334	37	3	235
23:00	332	35	3	223

Figure 212: Heat map of the hourly desegregated energies from the PDBF in 2023. Source: Own elaboration.

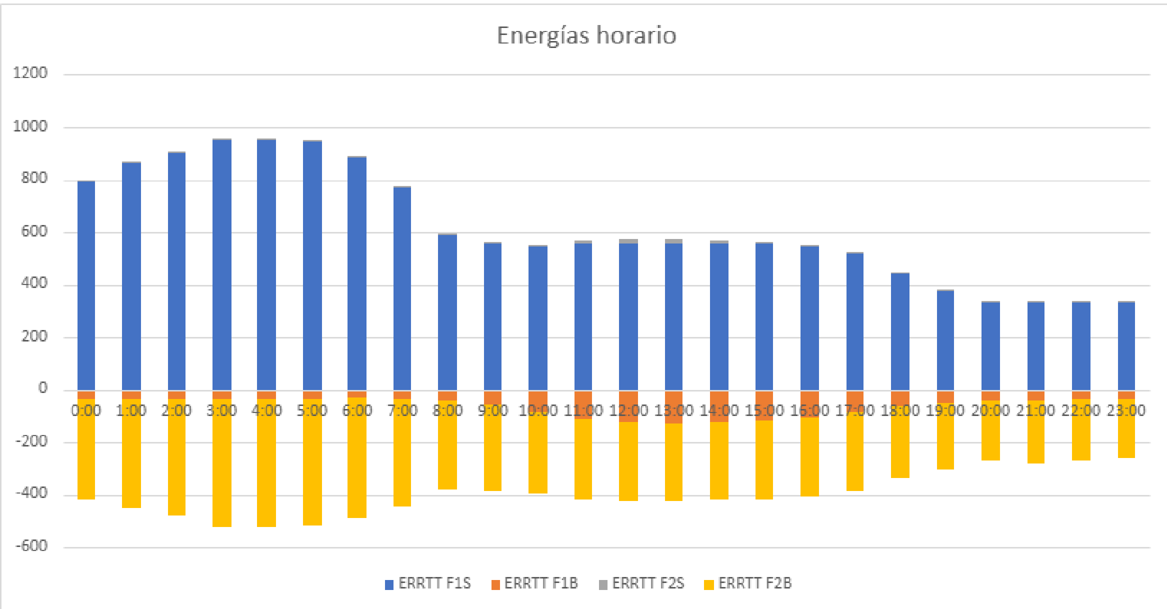


Figure 213: Hourly desegregated energies from the PDBF in 2023. Source: Own elaboration.

MES/ENEI	EBSCA	ESSCA	EBSCB	ESSCB	EBRTD	ESRTD	EBSOT	ESSOT	EBPEV	ESCOT
ENERO	45	74	0	0	17	189	0	607	0	0
FEBRERO	38	72	0	0	6	162	0	374	0	0
MARZO	90	50	0	0	2	210	0	381	0	0
ABRIL	98	131	13	0	0	180	0	439	0	0
MAYO	161	218	16	0	2	195	0	441	3	0
JUNIO	130	160	34	0	1	243	0	378	2	0
JULIO	123	316	172	37	2	176	0	274	5	0
AGOSTO	69	249	125	7	3	154	0	298	1	0
SEPTIEMB	32	172	36	0	1	190	0	360	3	0
OCTUBRE	47	185	14	19	1	179	0	514	60	0
NOVIEMB	33	254	10	1	6	173	0	553	10	15
DICIEMBR	63	108	35	0	1	158	0	604	4	3

Figure 214: Heat map of the monthly desegregated energies from the PDBF by labels in 2023. Source: Own elaboration.

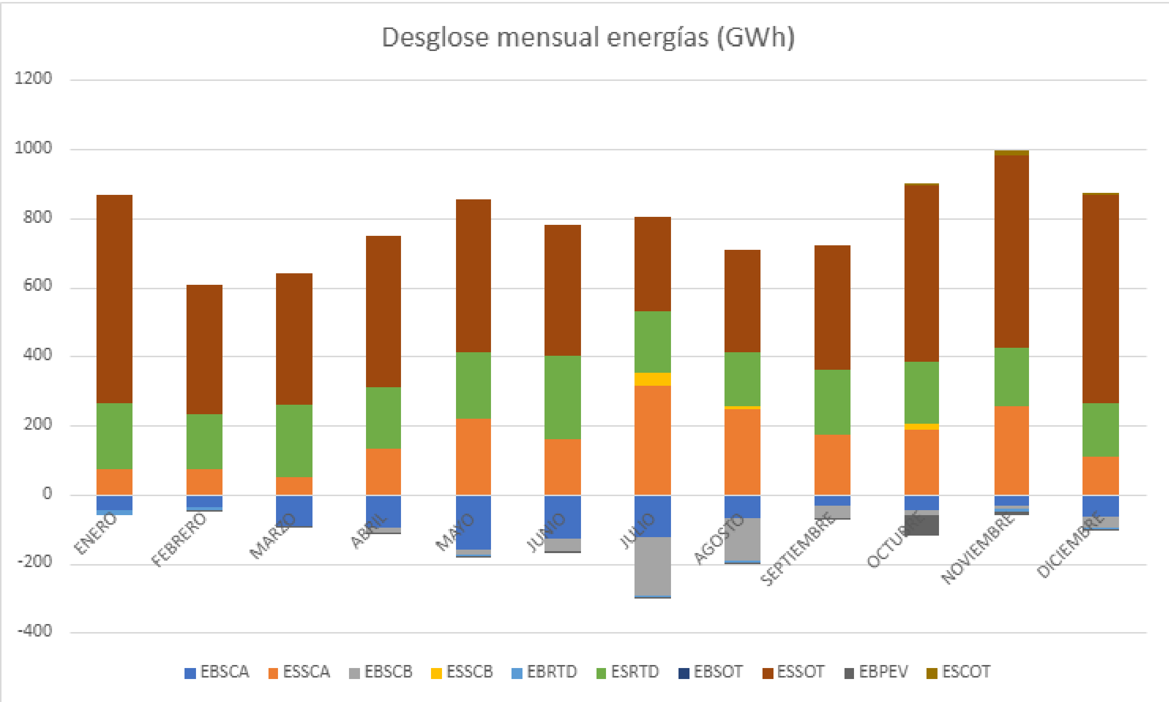


Figure 215: Monthly desegregated energies from the PDBF by labels in 2023. Source: Own elaboration.

HORA/EN	EBSCA	ESSCA	EBSCB	ESSCB	EBRTD	ESRTD	EBSOT	ESSOT	EBPEV	ESCOT
0:00	24	30	9	3	1	4	0	379	2	1
1:00	24	34	9	1	1	4	0	411	2	2
2:00	23	33	9	1	1	21	0	423	2	2
3:00	22	25	10	1	1	67	0	427	2	2
4:00	22	22	10	1	1	68	0	430	2	2
5:00	21	20	9	1	1	69	0	425	2	2
6:00	20	19	8	1	1	74	0	395	2	0
7:00	20	34	8	1	1	83	0	325	3	0
8:00	24	64	10	1	1	101	0	212	5	0
9:00	37	83	14	0	1	118	0	177	4	0
10:00	53	99	25	0	2	133	0	154	5	1
11:00	64	109	40	2	3	140	0	150	5	1
12:00	68	111	47	5	3	144	0	148	5	1
13:00	70	113	48	5	3	142	0	148	5	1
14:00	70	115	46	6	3	138	0	146	5	1
15:00	69	124	42	8	3	131	0	145	5	1
16:00	64	129	35	8	3	121	0	143	5	0
17:00	56	131	22	7	2	110	0	136	5	0
18:00	47	122	12	5	2	100	0	111	3	0
19:00	35	121	10	1	2	95	0	80	3	0
20:00	25	112	9	1	1	93	0	62	4	1
21:00	25	123	7	1	1	89	0	58	4	1
22:00	25	115	7	3	1	85	0	65	4	1
23:00	23	100	8	3	1	78	0	74	3	0

Figure 216: Heat map of the hourly desegregated energies from the PDBF by labels in 2023. Source: Own elaboration.

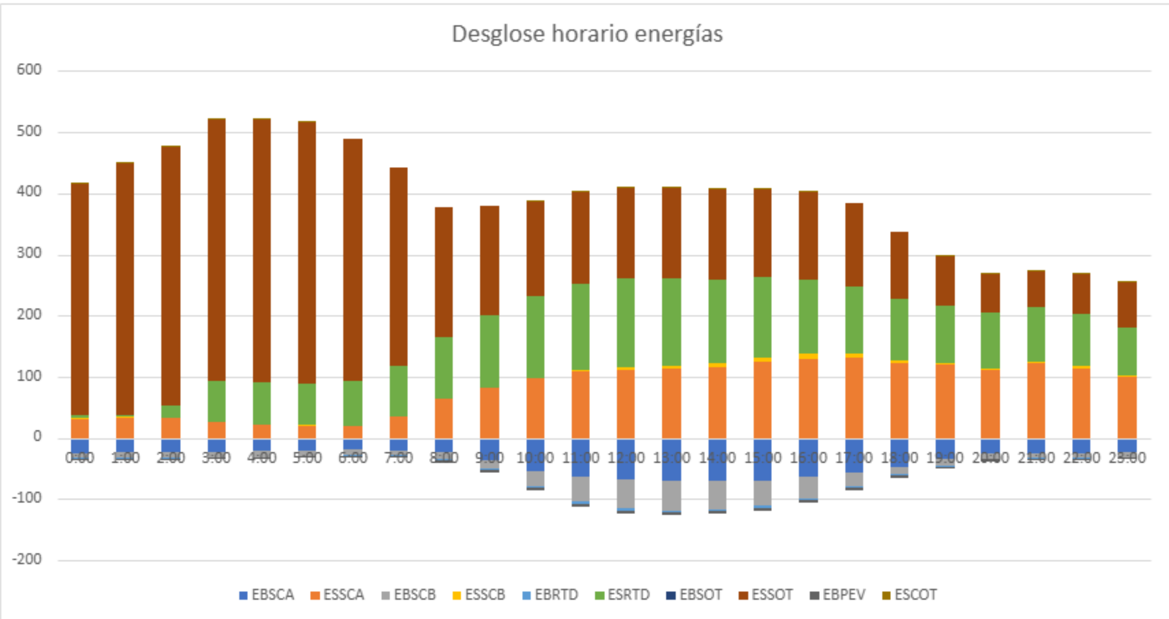


Figure 217: Hourly desegregated energies from the PDBF by labels in 2023. Source: Own elaboration.

Hora/mes ESSCA (GWh)	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	3	0	13	4	5	1	2	0
1	0	0	0	0	3	0	15	5	5	1	2	0
2	0	0	0	0	3	0	15	5	5	2	2	0
3	0	0	0	0	3	0	11	3	5	1	1	0
4	0	0	0	0	2	0	9	3	4	1	1	0
5	0	0	0	0	2	0	8	3	4	1	1	0
6	0	0	0	0	2	0	6	3	4	1	1	0
7	2	1	1	0	2	2	5	3	2	6	7	3
8	4	3	3	3	8	6	5	5	4	8	12	5
9	4	4	3	6	12	8	8	9	4	9	14	5
10	3	3	3	10	15	10	10	11	6	9	15	4
11	3	4	4	13	16	11	10	12	6	11	15	4
12	3	4	4	13	16	11	11	13	6	11	15	4
13	3	4	4	14	15	12	11	13	6	11	16	4
14	3	4	4	14	15	13	12	13	6	11	16	4
15	3	4	4	14	17	14	14	16	8	12	15	4
16	2	3	4	14	16	15	15	17	11	11	15	4
17	2	3	4	13	16	14	18	21	11	10	14	6
18	5	3	3	8	14	12	18	18	8	8	15	9
19	8	5	2	4	11	11	17	14	8	12	18	11
20	8	6	2	2	7	9	16	11	9	13	17	12
21	8	6	1	1	7	4	24	16	15	12	16	12
22	8	7	1	1	7	4	22	16	15	11	13	10
23	6	4	1	1	7	3	22	16	15	9	10	7

Figure 218: Heat map of the ESSCA of the PDBF by hours and months in 2023. Source: Own elaboration.

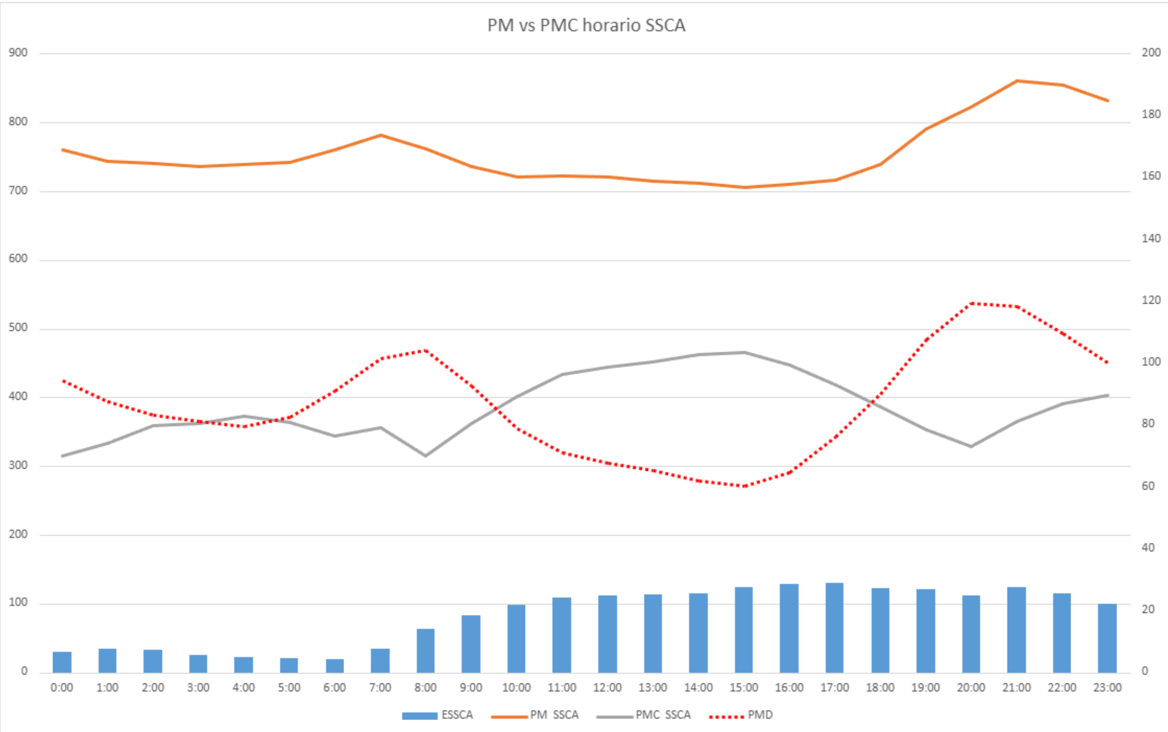


Figure 219: ESSCA, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2023. Source: Own elaboration.

Hora/mes ESRTD	1	2	3	4	5	6	7	8	9	10	11	12
0	1	0	0	0	0	1	0	0	0	0	1	1
1	1	0	0	0	0	1	0	0	0	0	1	1
2	2	1	2	1	2	3	2	1	2	1	2	2
3	6	5	6	4	7	9	6	3	5	5	5	5
4	6	5	6	6	7	9	6	3	5	5	5	5
5	6	5	7	6	7	9	6	3	5	5	5	5
6	7	6	7	6	7	10	6	3	6	5	5	5
7	7	7	8	7	7	10	7	4	8	6	5	6
8	9	8	10	8	9	11	8	8	9	8	8	7
9	10	9	11	10	11	13	9	9	11	10	9	8
10	11	10	12	11	12	14	11	10	12	11	10	9
11	12	10	13	11	12	14	11	10	13	12	11	10
12	12	11	13	12	12	15	12	10	13	12	11	10
13	12	11	13	11	12	14	11	10	13	12	12	10
14	12	11	13	11	12	14	11	10	12	12	11	10
15	11	10	13	11	11	13	10	10	12	11	10	9
16	10	9	12	10	10	12	10	9	11	10	10	9
17	9	8	11	9	9	11	9	8	10	9	9	8
18	9	7	10	8	8	10	8	8	9	8	8	7
19	8	7	9	8	8	10	7	7	8	8	8	7
20	8	7	9	7	8	10	7	7	8	7	8	7
21	7	6	8	7	8	10	7	7	8	7	7	7
22	7	5	7	7	8	10	7	7	6	7	7	7
23	7	5	7	5	8	10	7	6	6	7	5	5

Figure 220: Heat map of the ESRTD of the PDBF by hours and months in 2023. Source: Own elaboration.

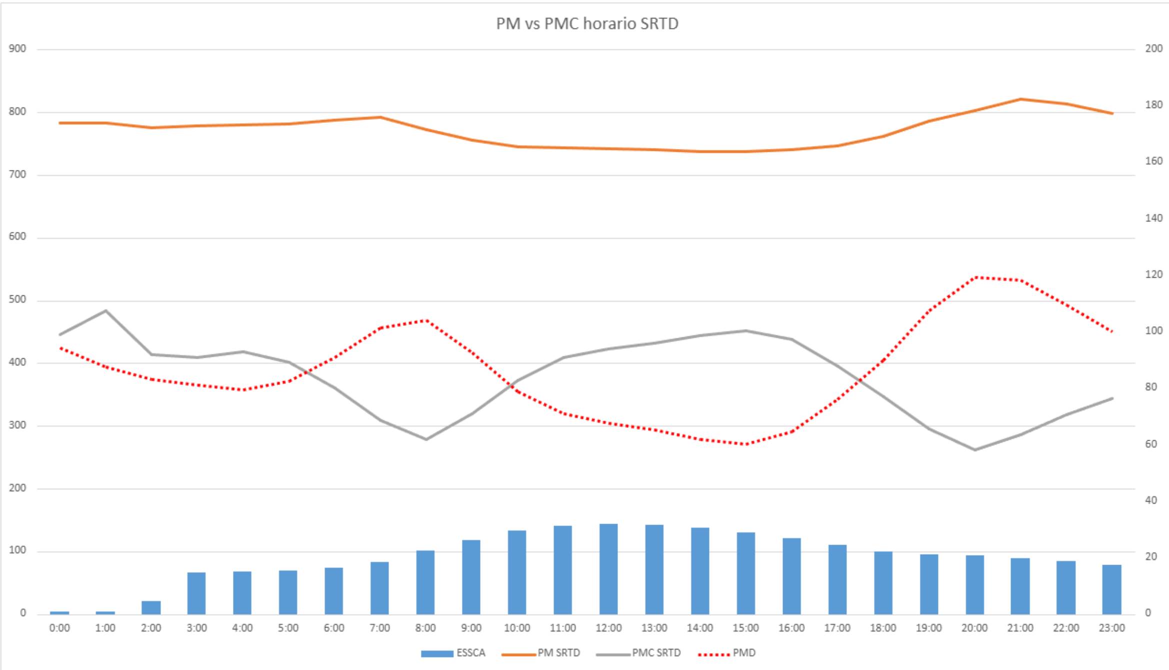


Figure 221: ESRTD, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2023. Source: Own elaboration.

Hora/mes ESSOT	1	2	3	4	5	6	7	8	9	10	11	12
0	40	30	29	31	33	27	14	15	24	41	48	47
1	42	32	31	33	36	31	19	18	28	43	49	50
2	43	33	31	33	37	32	20	20	30	46	48	51
3	43	33	32	33	37	32	22	21	31	44	48	51
4	43	33	32	33	37	33	23	21	31	45	48	51
5	43	32	31	32	37	32	22	20	32	45	48	51
6	42	29	27	31	34	29	19	17	28	42	48	50
7	37	23	26	29	32	27	17	17	24	30	31	34
8	26	13	15	20	19	16	12	13	14	18	20	25
9	23	11	13	17	15	13	10	12	11	15	16	19
10	20	10	12	14	13	10	10	12	11	14	12	15
11	19	11	11	13	12	10	10	12	12	14	12	15
12	19	11	11	13	12	10	9	12	11	14	12	15
13	19	11	11	13	12	10	9	13	11	14	12	14
14	19	11	10	13	11	10	9	13	11	14	12	14
15	19	11	10	13	11	10	9	12	11	14	12	14
16	18	10	10	12	11	9	9	12	11	14	11	14
17	17	9	10	12	11	9	8	11	10	13	11	13
18	13	5	8	12	11	9	8	10	7	9	9	11
19	12	3	4	10	9	5	6	5	2	6	8	9
20	12	3	4	5	4	3	3	3	2	5	8	10
21	12	3	4	5	2	3	2	2	2	5	9	10
22	14	4	5	5	2	3	2	2	2	6	10	10
23	15	5	5	6	4	3	2	3	3	6	11	11

Figure 222: Heat map of the ESSOT of the PDBF by hours and months in 2023. Source: Own elaboration.

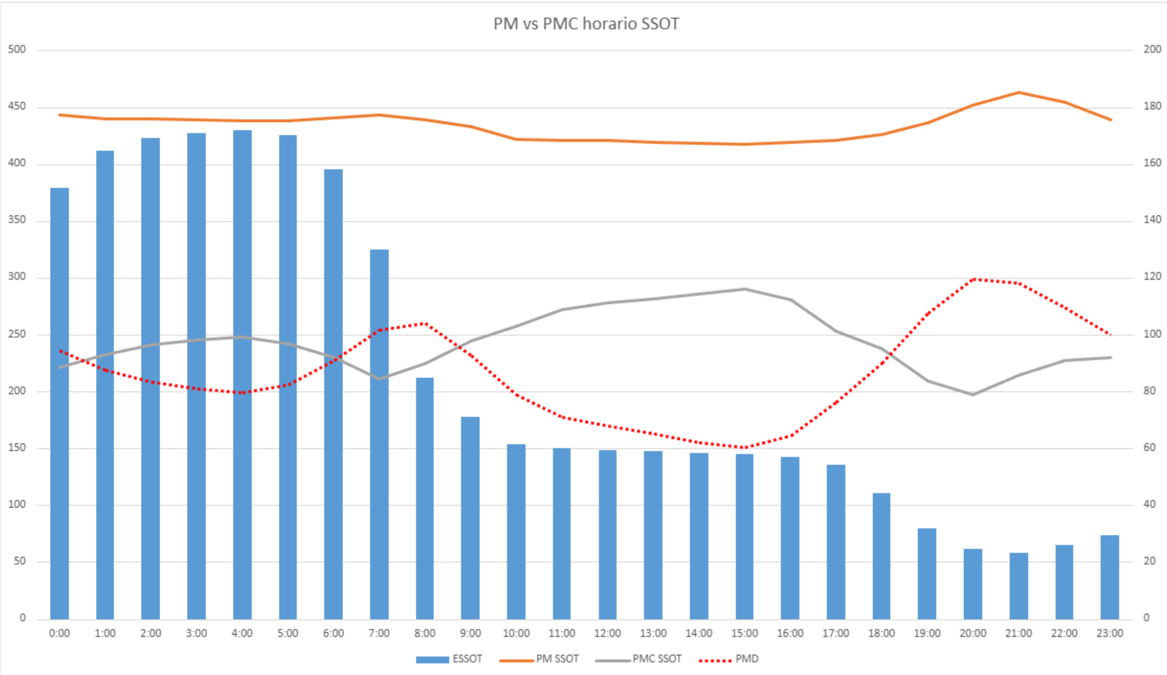


Figure 223: ESSOT, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2023. Source: Own elaboration.

Hora/mes ESCOT	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	0	0	0	0	0	1	0
1	0	0	0	0	0	0	0	0	0	0	2	0
2	0	0	0	0	0	0	0	0	0	0	2	0
3	0	0	0	0	0	0	0	0	0	0	2	0
4	0	0	0	0	0	0	0	0	0	0	2	0
5	0	0	0	0	0	0	0	0	0	0	2	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	1	0
11	0	0	0	0	0	0	0	0	0	0	1	0
12	0	0	0	0	0	0	0	0	0	0	1	0
13	0	0	0	0	0	0	0	0	0	0	1	0
14	0	0	0	0	0	0	0	0	0	0	1	0
15	0	0	0	0	0	0	0	0	0	0	1	0
16	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	1
21	0	0	0	0	0	0	0	0	0	0	0	1
22	0	0	0	0	0	0	0	0	0	0	0	1
23	0	0	0	0	0	0	0	0	0	0	0	0

Figure 224: Heat map of the ESCOT of the PDBF by hours and months in 2023. Source: Own elaboration.

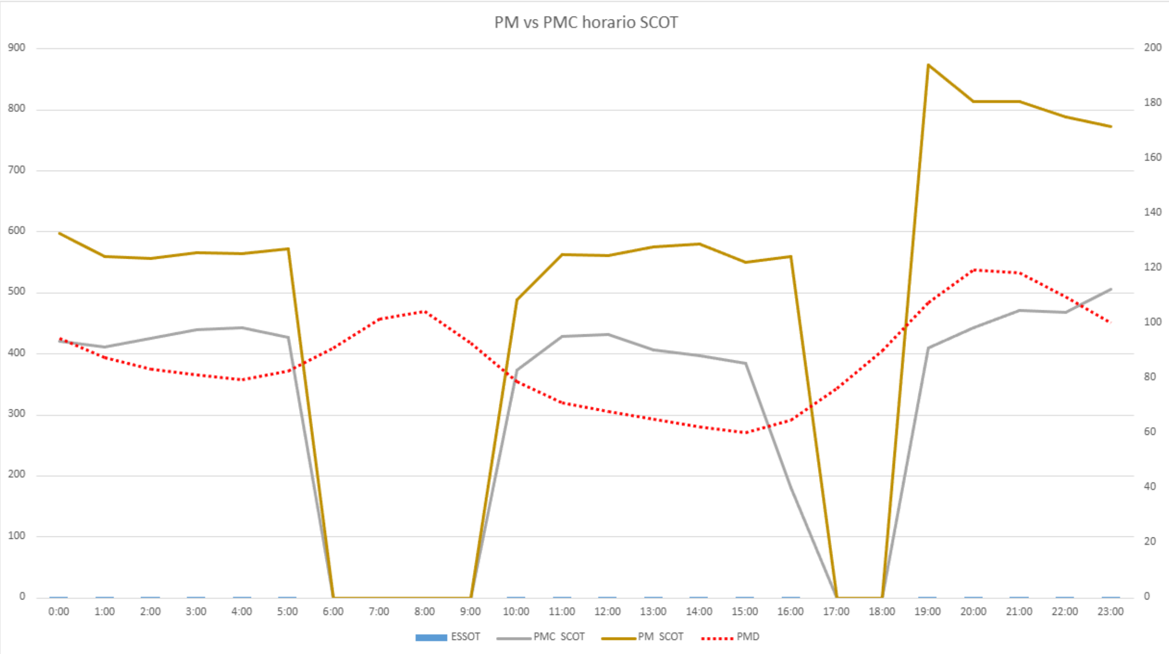


Figure 225: ESCOT, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2023. Source: Own elaboration.

Hora/mes ESSCB	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	0	0	1	0	0	0	0
1	0	0	0	0	0	0	0	1	0	0	0	0
2	0	0	0	0	0	0	0	1	0	0	0	0
3	0	0	0	0	0	0	0	1	0	0	0	0
4	0	0	0	0	0	0	0	1	0	0	0	0
5	0	0	0	0	0	0	0	1	0	0	0	0
6	0	0	0	0	0	0	0	1	0	0	0	0
7	0	0	0	0	0	0	0	1	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	2	0	0	0	0	0
11	0	0	0	0	0	0	4	0	0	1	0	0
12	0	0	0	0	0	0	4	0	0	2	0	0
13	0	0	0	0	0	0	4	0	0	2	0	0
14	0	0	0	0	0	0	5	0	0	2	0	0
15	0	0	0	0	0	0	6	0	0	2	0	0
16	0	0	0	0	0	0	5	0	0	2	0	0
17	0	0	0	0	0	0	4	0	0	1	0	0
18	0	0	0	0	0	0	0	0	0	1	0	0
19	0	0	0	0	0	0	0	0	0	1	0	0
20	0	0	0	0	0	0	0	0	0	1	0	0
21	0	0	0	0	0	0	1	1	0	1	0	0
22	0	0	0	0	0	0	1	1	0	1	0	0
23	0	0	0	0	0	0	1	1	0	1	0	0

Figure 226: Heat map of the ESSCB of the PDBF by hours and months in 2023. Source: Own elaboration.

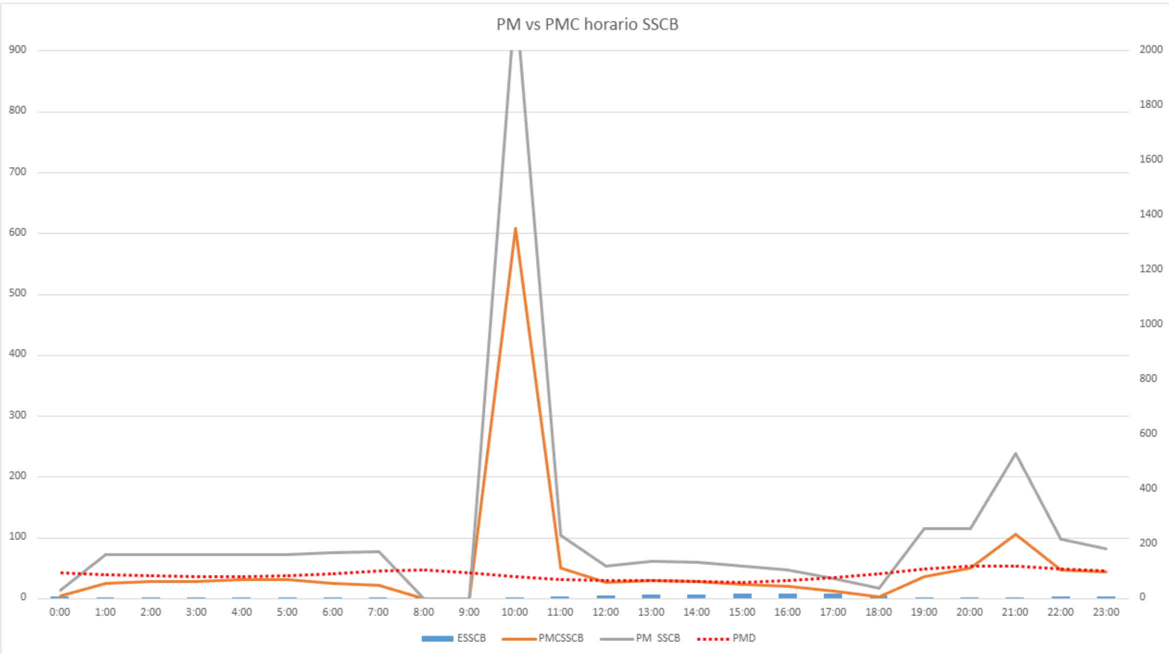


Figure 227: ESSCB, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2023. Source: Own elaboration.

MES/ENERGIAS GW	ESASE	EBASE	ESSOT	EBSOT	ESCOT	EBPEV	ESEST	EBEST	ESRSI	EBRSI	ESRBI	EBRBI	ESRTD	EBRTD	ESSCA	EBSCA	ESSCB	EBSCB
ENERO	0	0	11	11	0	0	0	0	384	0	0	0	0	6	5	5	0	15
FEBRERO	0	1	44	31	0	0	0	0	280	0	0	0	0	1	4	2	3	13
MARZO	0	1	150	35	0	0	0	0	210	0	0	5	2	1	1	17	0	17
ABRIL	1	0	60	20	0	0	0	0	103	0	0	1	0	0	15	24	5	45
MAYO	0	1	113	17	0	0	0	0	113	0	0	0	0	0	26	22	2	28
JUNIO	1	1	86	38	0	0	0	0	217	0	0	1	0	0	16	22	9	60
JULIO	2	0	79	12	4	1	0	0	157	9	0	0	0	1	17	25	14	134
AGOSTO	0	1	2	10	0	0	0	0	193	6	0	0	0	0	22	45	20	139
SEPTIEMBRE	0	0	14	27	0	0	0	0	297	0	0	0	0	0	10	11	12	41
OCTUBRE	1	0	8	40	0	67	0	0	346	0	0	0	1	0	51	18	11	15
NOVIEMBRE	0	1	32	19	12	7	0	0	524	0	0	0	2	1	18	9	1	22
DICIEMBRE	0	0	50	22	1	1	0	0	545	0	0	0	1	2	11	32	6	14

Figure 228: Heat map of the monthly desegregated energies from the RT by labels in 2023. Source: Own elaboration.

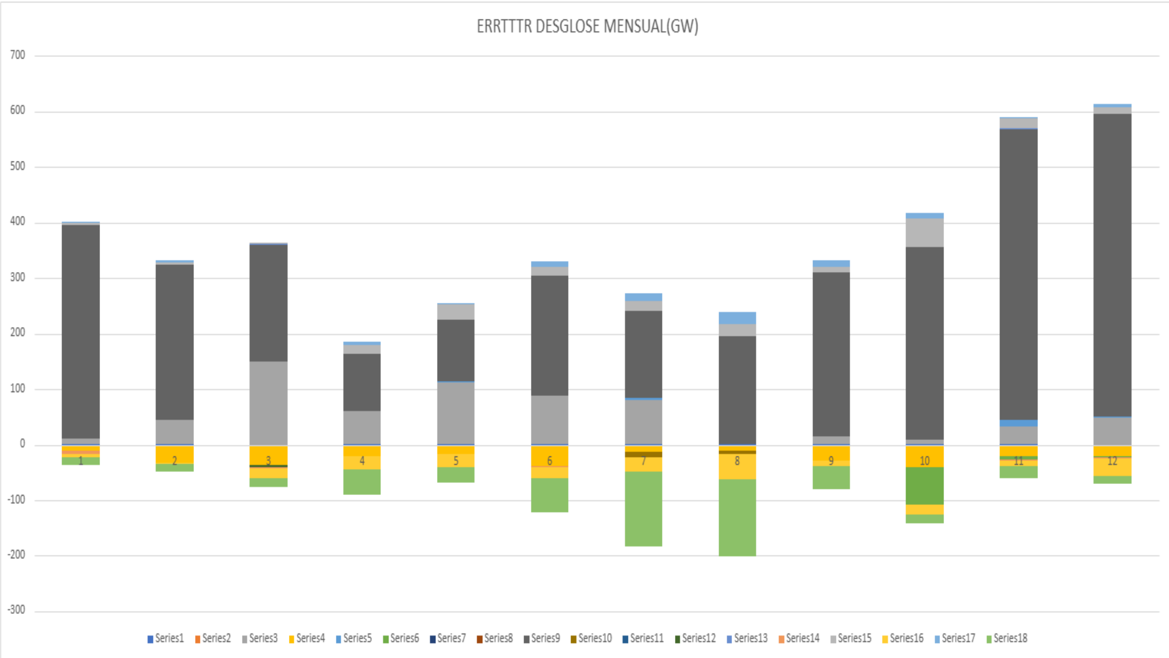


Figure 229: Monthly desegregated energies from the RT by labels in 2023. Source: Own elaboration.

HORA/ENERGIAS GW	ESASE	EBASE	ESSOT	EBSOT	ESCOT	EBPEV	ESEST	EBEST	ESRSI	EBRSI	ESRBI	EBRBI	ESRTD	EBRTD	ESSCA	EBSCA	ESSCB	EBSCB
0:00	0	0	29	9	1	2	0	0	13	0	0	0	0	0	9	7	3	11
1:00	0	0	31	24	1	2	0	0	7	1	0	0	0	0	7	7	2	9
2:00	0	0	31	35	1	2	0	0	2	2	0	0	0	0	5	6	2	7
3:00	0	0	33	44	0	3	0	0	0	2	0	0	0	0	4	6	1	6
4:00	0	0	33	47	0	3	0	0	0	2	0	0	0	0	4	6	1	6
5:00	0	0	32	51	0	3	0	0	2	2	0	0	0	0	4	5	0	7
6:00	0	0	31	33	1	4	0	0	40	2	0	0	0	0	3	5	0	6
7:00	0	0	28	19	0	3	0	0	177	1	0	0	0	0	2	4	0	5
8:00	0	0	25	10	0	3	0	0	239	0	0	0	0	0	4	4	0	5
9:00	2	1	29	4	0	2	0	0	180	0	0	0	0	0	7	4	2	8
10:00	0	1	30	1	1	2	0	0	84	0	0	1	0	0	9	5	3	18
11:00	0	1	30	0	1	2	0	0	44	0	0	0	0	0	8	9	3	33
12:00	0	1	30	0	1	2	0	0	29	0	0	0	0	1	9	15	5	49
13:00	0	0	30	0	1	2	0	0	26	0	0	0	1	1	9	18	6	53
14:00	0	0	31	0	1	3	0	0	25	0	0	0	1	1	9	18	8	54
15:00	1	0	31	0	1	3	0	0	35	1	0	0	0	1	11	19	8	56
16:00	0	1	29	3	3	4	0	0	91	0	0	1	0	1	12	19	8	55
17:00	0	0	28	1	1	4	0	0	174	0	0	1	0	1	13	18	6	48
18:00	0	1	23	1	0	5	0	0	277	0	0	2	0	1	14	14	5	34
19:00	0	1	18	0	0	5	0	0	429	0	0	1	0	1	14	11	4	22
20:00	0	0	15	0	0	6	0	0	544	0	0	0	0	1	10	8	4	14
21:00	0	0	16	0	0	5	0	0	492	0	0	0	0	1	9	8	5	13
22:00	1	0	16	0	0	4	0	0	327	0	0	0	0	1	11	9	5	12
23:00	0	0	17	1	1	4	0	0	133	0	0	0	0	0	10	9	3	12

Figure 230: Heat map of the hourly desegregated energies from the RT by labels in 2023. Source: Own elaboration.

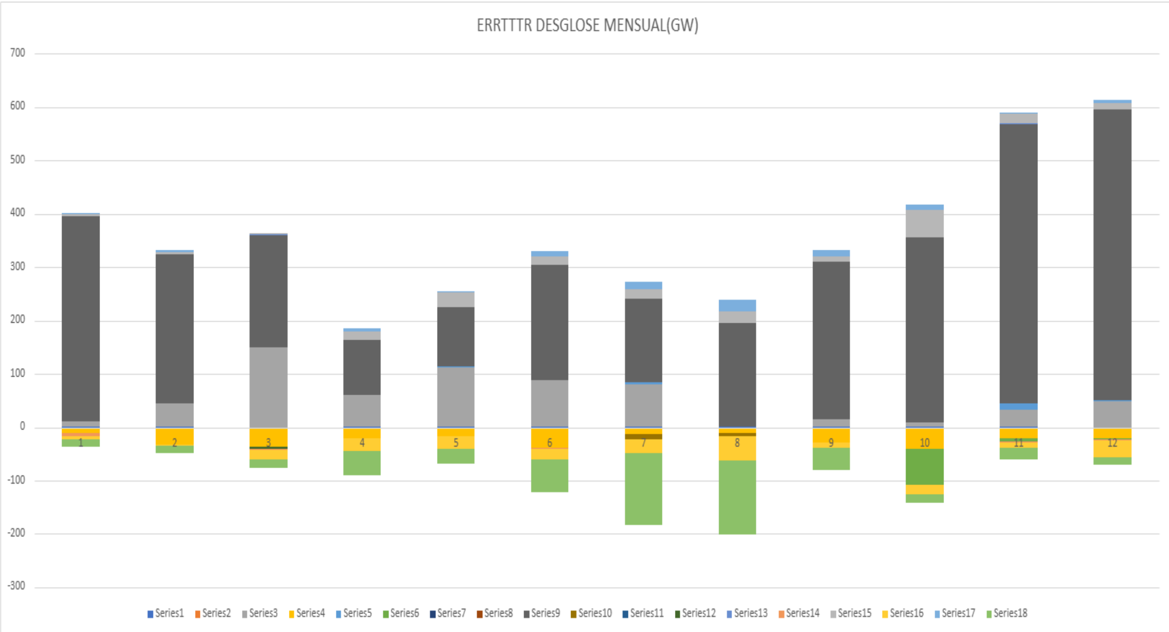


Figure 231: Hourly desegregated energies from the RT by labels in 2023. Source: Own elaboration.

HORA/ MES ESSOT (GWh)	1	2	3	4	5	6	7	8	9	10	11	12
0	1	2	7	2	6	4	3	0	0	0	2	2
1	1	3	7	3	6	4	3	0	0	0	2	3
2	1	3	6	3	6	4	3	0	0	0	2	3
3	0	2	7	4	6	4	4	0	0	0	2	3
4	0	2	7	4	6	5	4	0	0	0	2	3
5	0	2	7	3	6	5	4	0	1	0	2	3
6	0	2	7	3	6	4	3	0	0	0	1	3
7	0	1	7	2	6	4	3	0	0	0	1	2
8	0	1	6	3	4	4	4	0	0	0	1	1
9	0	2	6	3	5	5	4	0	0	1	2	2
10	0	2	6	2	5	4	4	0	1	1	2	3
11	1	2	6	2	5	4	3	0	1	0	2	3
12	1	2	6	2	5	4	4	0	1	0	2	3
13	1	2	6	2	5	4	4	0	1	0	2	3
14	1	2	6	2	5	4	4	0	1	1	2	3
15	1	2	6	2	5	4	4	0	1	1	2	3
16	0	2	6	3	5	4	4	0	1	1	1	2
17	0	2	6	3	5	4	4	0	1	1	1	1
18	0	2	6	2	4	3	3	0	1	0	0	1
19	0	1	6	2	3	2	2	0	0	0	0	0
20	0	1	5	2	2	1	2	0	0	0	1	1
21	0	2	6	2	2	1	2	0	0	0	1	1
22	0	2	6	2	2	1	2	0	0	0	0	1
23	0	2	6	2	2	1	2	0	0	0	1	1

Figure 232: Heat map of the ESSOT of the RT by hours and months in 2023. Source: Own elaboration.

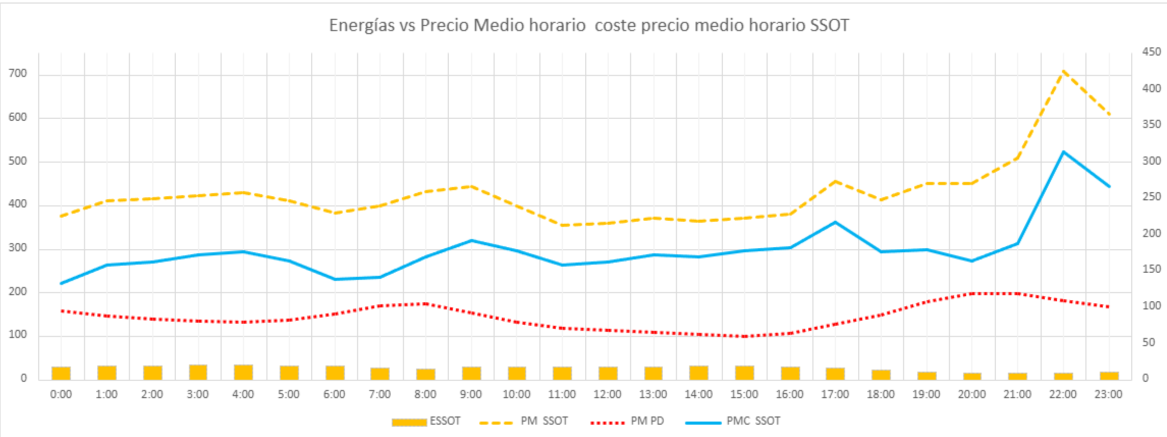


Figure 233: ESSOT, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2023. Source: Own elaboration.

HORA/ MES ESCOT	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	0	0	0	0	0	1	0
1	0	0	0	0	0	0	0	0	0	0	1	0
2	0	0	0	0	0	0	0	0	0	0	1	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	1	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	1	0
11	0	0	0	0	0	0	0	0	0	0	1	0
12	0	0	0	0	0	0	0	0	0	0	1	0
13	0	0	0	0	0	0	0	0	0	0	1	1
14	0	0	0	0	0	0	0	0	0	0	1	0
15	0	0	0	0	0	0	1	0	0	0	1	0
16	0	0	0	0	0	0	1	0	0	0	2	0
17	0	0	0	0	0	0	1	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0

Figure 234: Heat map of the ESCOT of the RT by hours and months in 2023. Source: Own elaboration.

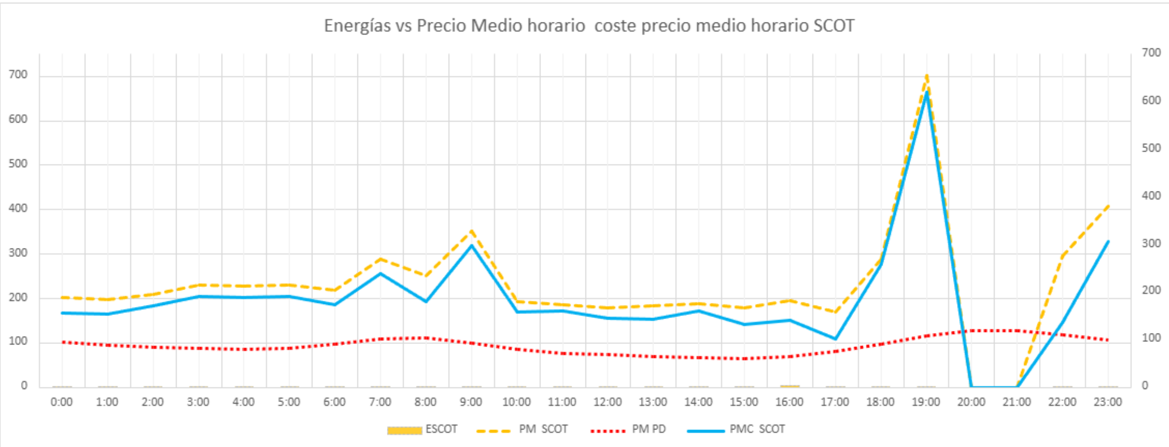


Figure 235: ESCOT, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2023. Source: Own elaboration.

HORA/ MES ESRSI 2023	1	2	3	4	5	6	7	8	9	10	11	12
0	0	1	0	0	0	0	2	6	1	0	2	1
1	0	1	0	0	0	0	0	3	0	0	1	1
2	0	0	0	0	0	0	0	1	0	0	0	1
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	1	0	0	0
6	1	2	1	1	1	5	3	4	4	5	9	5
7	15	16	14	6	5	12	10	7	18	19	32	22
8	25	20	20	9	9	18	12	8	23	27	36	31
9	26	21	10	3	5	8	4	1	15	21	32	34
10	21	12	0	0	1	2	0	1	1	9	13	23
11	13	4	0	0	1	1	0	1	0	6	6	12
12	8	2	0	0	0	0	0	0	0	5	4	9
13	7	2	0	0	0	0	0	0	0	5	3	9
14	6	2	0	0	0	0	0	0	0	5	3	9
15	6	2	0	0	0	0	0	0	0	5	8	13
16	15	7	0	0	0	0	0	0	0	6	29	34
17	30	18	2	0	0	0	1	0	2	9	56	55
18	42	34	20	0	0	5	1	3	21	33	61	58
19	48	40	40	7	10	22	13	23	55	52	60	59
20	48	39	45	30	29	42	35	48	58	54	57	57
21	41	34	37	29	28	44	32	42	52	48	52	54
22	22	18	17	16	19	38	29	33	32	27	38	39
23	8	5	4	1	5	18	15	12	14	10	21	19

Figure 236: Heat map of the ESRSI of the RT by hours and months in 2023. Source: Own elaboration.

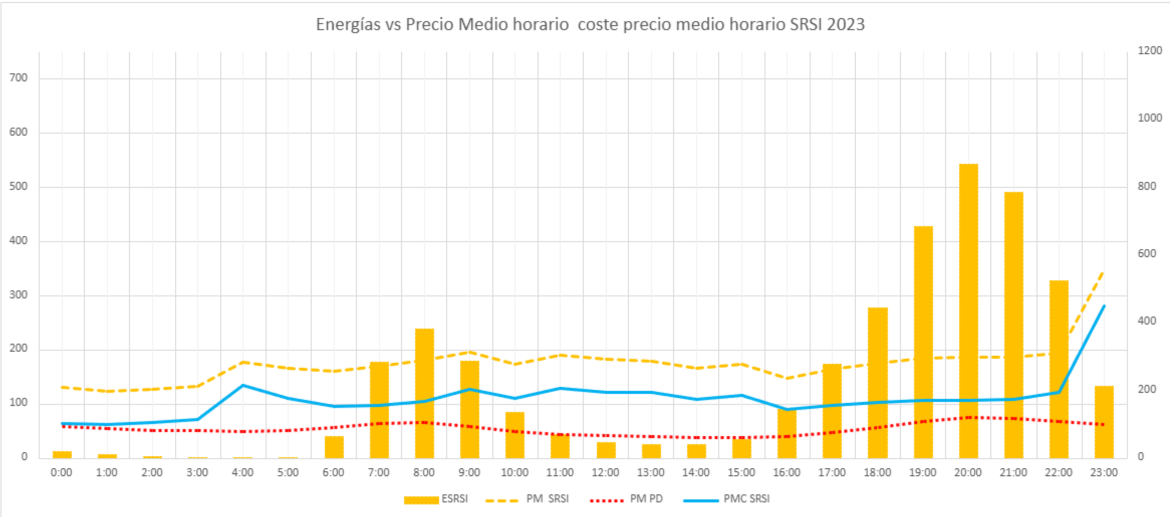


Figure 237: ESRSI, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2023. Source: Own elaboration.

HORA/ MES ESSCA	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	1	1	1	2	3	0	1	0	0
1	0	0	0	1	1	1	1	2	0	1	0	0
2	0	0	0	1	1	0	1	2	0	0	0	0
3	0	0	0	1	1	0	0	1	0	0	0	0
4	0	0	0	1	2	0	0	1	0	0	0	0
5	0	0	0	1	1	0	0	1	0	0	0	0
6	0	0	0	0	1	0	0	1	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	1	2	1	0
9	0	0	0	1	0	0	1	0	1	2	1	0
10	0	0	0	1	1	0	0	1	0	3	1	0
11	0	0	0	0	1	0	0	1	0	3	1	0
12	0	1	0	0	1	0	0	1	0	3	1	1
13	0	1	0	0	1	1	0	0	1	3	1	1
14	0	0	0	0	2	1	0	0	1	3	1	1
15	0	0	0	1	2	1	0	0	1	3	2	1
16	0	0	0	1	2	1	1	1	1	3	1	1
17	0	1	0	1	2	1	1	1	1	4	1	1
18	0	0	0	1	3	1	2	1	1	4	0	1
19	0	0	0	0	2	2	3	1	1	4	1	1
20	1	0	0	0	1	1	1	1	0	3	0	1
21	1	0	0	0	0	1	1	1	0	3	1	1
22	1	0	0	2	1	1	1	2	0	2	1	0
23	0	0	0	1	0	1	1	1	0	3	0	0

Figure 238: Heat map of the ESSCA of the RT by hours and months in 2023. Source: Own elaboration.

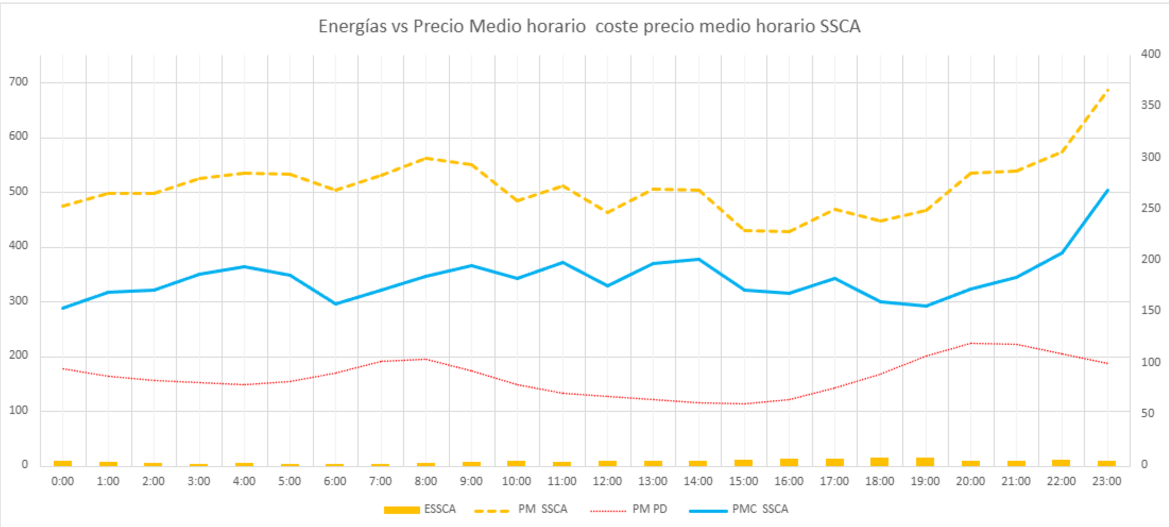


Figure 239: ESSCA, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2023. Source: Own elaboration.

MES/ENEI	ERRTT F1S	ERRTT F1B	ERRTT F2S	ERRTT F2B
ENERO	1384	152	6	673
FEBRERO	1372	38	3	796
MARZO	2007	78	4	1159
ABRIL	2886	48	0	1530
MAYO	5005	143	0	2548
JUNIO	3483	209	0	1708
JULIO	2575	1178	350	832
AGOSTO	2735	719	116	1114
SEPTIEMB	2914	482	14	1287
OCTUBRE	3455	331	2	1772
NOVIEMB	4082	162	0	2303
DICIEMBR	3765	56	0	2500

Figure 240: Heat map of the monthly desegregated energies from the PDBF in 2025. Source: Own elaboration.

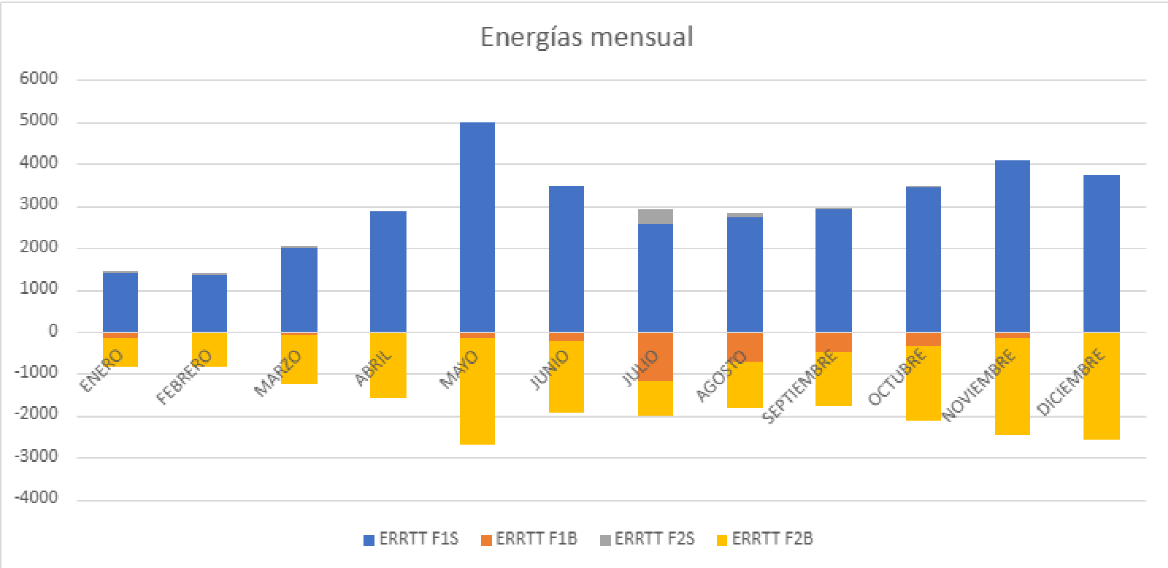


Figure 241: Monthly desegregated energies from the PDBF in 2025. Source: Own elaboration.

HORA/EN	ERRTT F1S	ERRTT F1B	ERRTT F2S	ERRTT F2B
0:00	1581	28	0	823
1:00	1640	27	0	854
2:00	1693	26	0	884
3:00	1735	24	0	890
4:00	1741	23	0	893
5:00	1735	23	0	890
6:00	1641	21	0	848
7:00	1479	22	0	800
8:00	1490	30	0	855
9:00	1527	91	3	845
10:00	1543	249	25	737
11:00	1560	361	49	669
12:00	1561	418	73	638
13:00	1564	431	80	634
14:00	1562	419	76	642
15:00	1562	397	71	664
16:00	1553	350	58	689
17:00	1523	284	41	730
18:00	1432	171	15	764
19:00	1330	59	0	800
20:00	1233	43	1	752
21:00	1028	39	1	665
22:00	1001	34	1	637
23:00	1000	27	0	620

Figure 242: Heat map of the hourly desegregated energies from the PDBF in 2020. Source: Own elaboration.

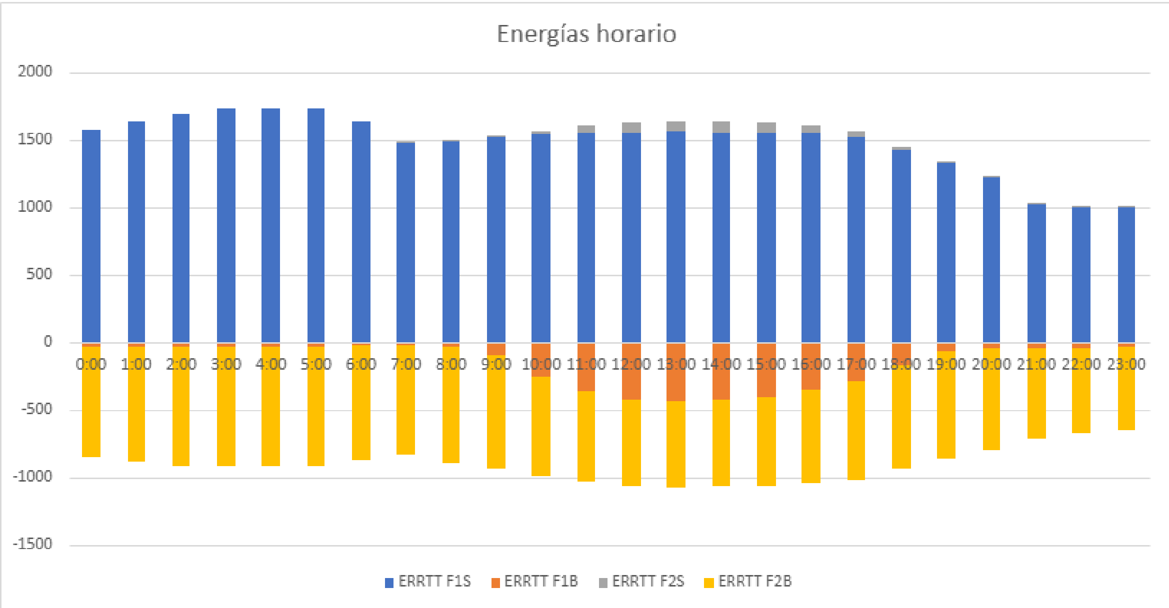


Figure 243: Hourly desegregated energies from the PDBF in 2025. Source: Own elaboration.

MES/ENEI	EBSCA	ESSCA	EBSCB	ESSCB	EBRTD	ESRTD	EBSOT	ESSOT	EBPEV	ESCOT
ENERO	77	112	32	5	40	136	0	376	2	189
FEBRERO	15	73	0	2	22	214	0	350	1	191
MARZO	12	282	40	2	24	181	0	441	3	328
ABRIL	0	164	35	0	9	141	0	674	5	606
MAYO	3	232	48	0	84	143	0	893	7	1429
JUNIO	32	193	145	1	30	132	0	550	3	1041
JULIO	468	573	608	11	77	171	0	256	24	647
AGOSTO	419	576	218	1	81	128	0	314	2	697
SEPTIEMB	343	418	72	1	66	156	0	472	1	709
OCTUBRE	227	304	48	34	40	352	0	533	15	788
NOVIEMB	73	210	22	2	65	425	0	680	3	925
DICIEMBR	33	238	8	0	12	488	0	641	3	642

Figure 244: Heat map of the monthly desegregated energies from the PDBF by labels in 2025. Source: Own elaboration.

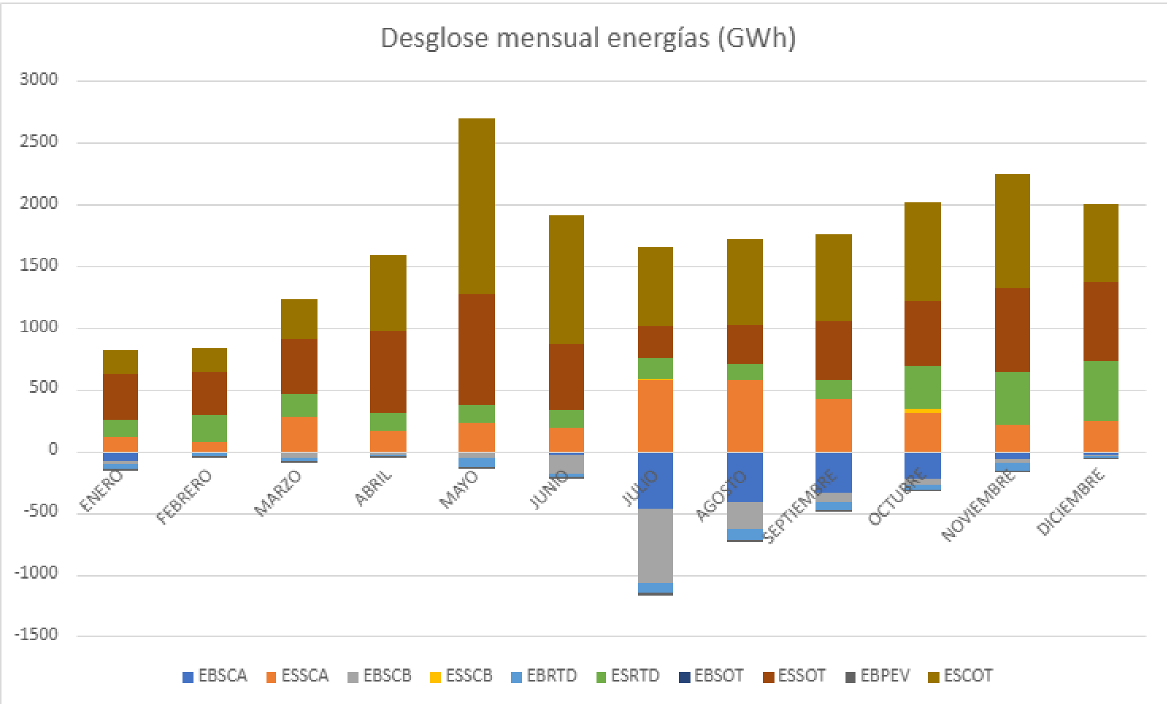


Figure 245: Monthly desegregated energies from the PDBF by labels in 2025. Source: Own elaboration.

HORA/EN	EBSCA	ESSCA	EBSCB	ESSCB	EBRTD	ESRTD	EBSOT	ESSOT	EBPEV	ESCOT
0:00	9	75	6	0	11	48	0	722	2	7
1:00	9	76	6	0	11	48	0	751	2	7
2:00	8	76	6	0	11	51	0	776	1	7
3:00	7	34	5	0	11	60	0	813	1	9
4:00	7	32	5	0	11	60	0	816	1	9
5:00	6	31	5	0	11	61	0	813	1	8
6:00	5	32	4	0	10	65	0	764	1	8
7:00	5	59	5	0	11	72	0	365	1	292
8:00	5	86	9	0	14	141	0	212	2	394
9:00	18	150	44	1	24	155	0	80	4	512
10:00	98	192	107	1	40	171	0	7	5	574
11:00	175	210	135	3	46	180	0	6	5	573
12:00	216	212	150	6	47	182	0	5	5	572
13:00	226	214	152	7	48	183	0	5	5	572
14:00	222	213	146	7	46	183	0	5	5	571
15:00	210	215	140	8	42	182	0	5	5	567
16:00	180	202	127	8	38	178	0	5	5	565
17:00	138	190	107	7	34	165	0	5	5	546
18:00	69	190	74	4	25	107	0	5	3	507
19:00	19	177	22	0	16	89	0	4	2	466
20:00	19	150	10	0	12	82	0	4	2	435
21:00	20	191	6	1	11	75	0	4	2	318
22:00	16	186	5	1	11	68	0	4	2	327
23:00	11	181	3	1	11	66	0	4	2	347

Figure 246: Heat map of the hourly desegregated energies from the PDBF by labels in 2025. Source: Own elaboration.

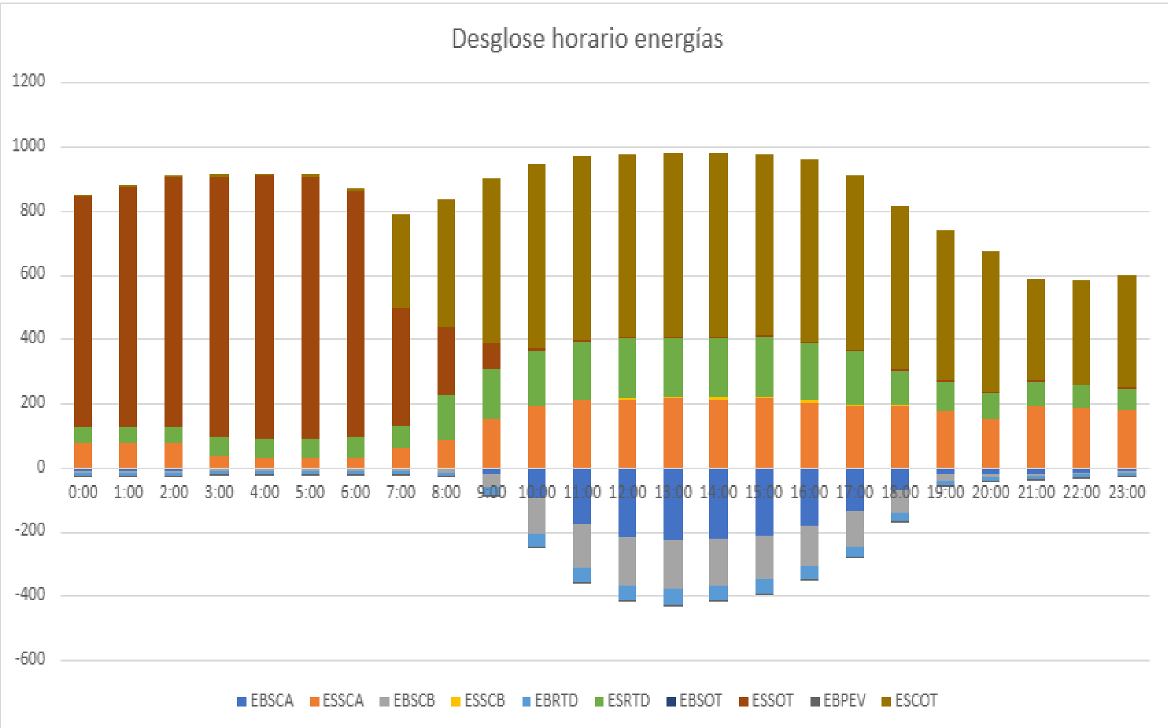


Figure 247: Hourly desegregated energies from the PDBF by labels in 2025. Source: Own elaboration.

Hora/mes ESSCA (GWh) 2025	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	0	18	37	14	3	0	2
1	0	0	0	0	0	0	20	38	14	3	0	2
2	0	0	0	0	0	0	20	37	13	3	0	2
3	0	0	0	0	0	0	8	13	8	3	0	2
4	0	0	0	0	0	0	8	13	6	3	0	2
5	0	0	0	0	0	0	7	13	6	2	0	2
6	0	0	0	0	0	0	7	12	5	4	0	2
7	3	1	5	7	5	0	7	11	6	6	4	5
8	4	2	16	8	12	4	9	8	4	8	9	4
9	5	5	21	11	15	10	21	14	9	16	14	9
10	6	6	22	14	16	15	27	19	18	21	19	10
11	7	7	24	12	16	16	29	21	21	24	22	12
12	7	7	24	10	16	16	29	21	22	25	23	12
13	8	7	24	10	16	17	30	22	22	25	23	12
14	8	7	24	10	16	17	30	22	22	25	22	12
15	7	6	24	12	17	18	30	24	22	24	20	11
16	5	5	22	14	17	19	31	25	22	23	12	7
17	3	3	20	14	21	18	32	26	21	20	8	4
18	6	1	15	14	20	17	32	25	18	13	7	21
19	9	4	10	14	18	14	33	22	14	8	8	23
20	10	4	8	5	13	5	27	20	19	11	7	22
21	10	5	6	2	5	3	41	44	36	12	4	21
22	9	3	10	2	5	3	39	44	37	11	4	20
23	5	0	7	4	6	3	39	45	38	11	3	20

Figure 248: Heat map of the ESSCA of the PDBF by hours and months in 2025. Source: Own elaboration.

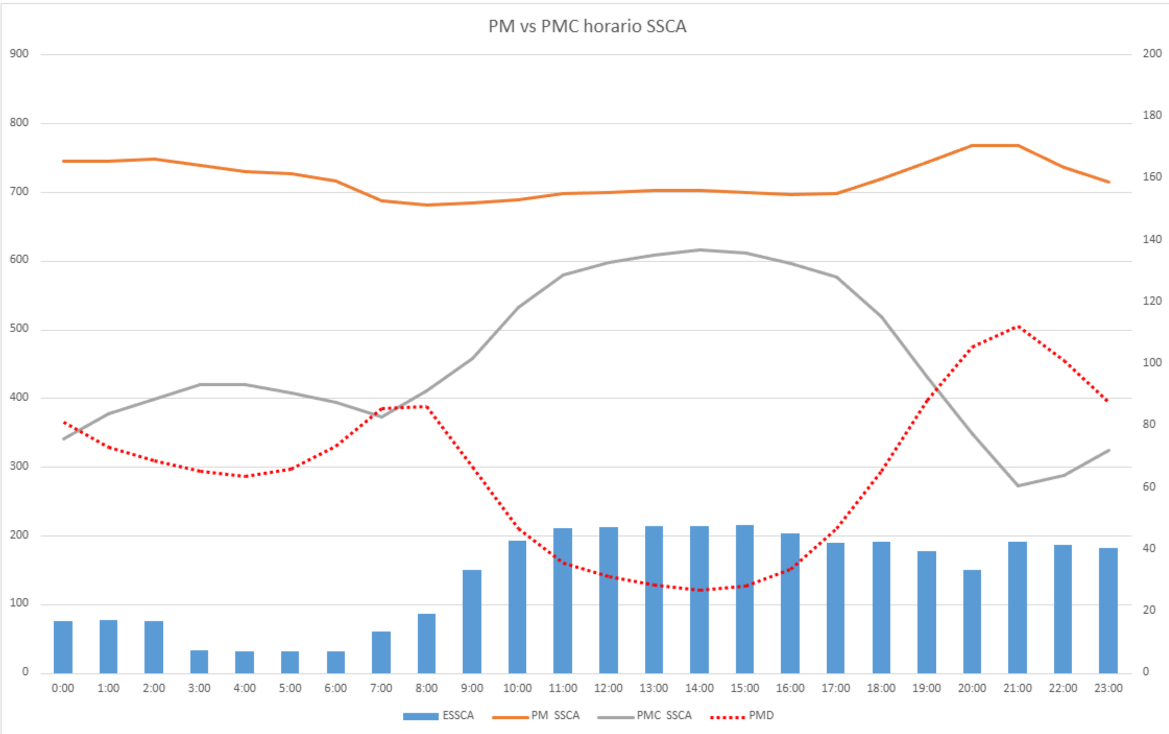


Figure 249: ESSCA, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2025. Source: Own elaboration.

Hora/mes ESRTD 2025	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	3	4	5	5	6	4	5	6	5	5
1	0	0	3	4	5	5	6	4	5	6	5	5
2	1	1	4	4	5	5	6	4	5	6	5	5
3	3	5	7	5	5	5	6	4	5	6	5	5
4	3	5	7	5	5	5	6	4	5	6	5	6
5	3	5	7	5	5	5	6	4	5	6	5	6
6	4	5	7	5	5	5	6	4	6	6	6	8
7	4	6	7	5	5	5	6	5	6	9	6	9
8	4	9	8	5	5	5	6	5	6	20	32	36
9	6	10	8	6	6	5	7	6	7	22	34	37
10	8	12	10	8	7	6	9	7	8	25	34	38
11	10	13	10	8	8	7	9	8	8	26	34	39
12	10	14	10	8	8	7	10	8	8	26	35	39
13	10	14	10	8	8	7	10	8	8	26	35	39
14	10	14	10	8	8	7	10	8	9	26	35	39
15	10	13	10	8	7	7	9	7	8	26	36	40
16	9	12	9	7	7	7	9	7	8	25	37	40
17	7	11	9	7	7	7	8	6	8	25	34	37
18	7	12	8	6	7	6	8	6	7	19	10	11
19	6	12	8	6	7	5	7	4	6	11	7	10
20	6	11	8	6	6	5	7	4	6	8	7	9
21	5	10	7	5	6	5	6	4	6	7	6	8
22	5	9	7	4	5	5	6	4	5	6	5	7
23	4	8	7	4	5	5	6	4	5	6	5	7

Figure 250: Heat map of the ESRTD of the PDBF by hours and months in 2025. Source: Own elaboration.

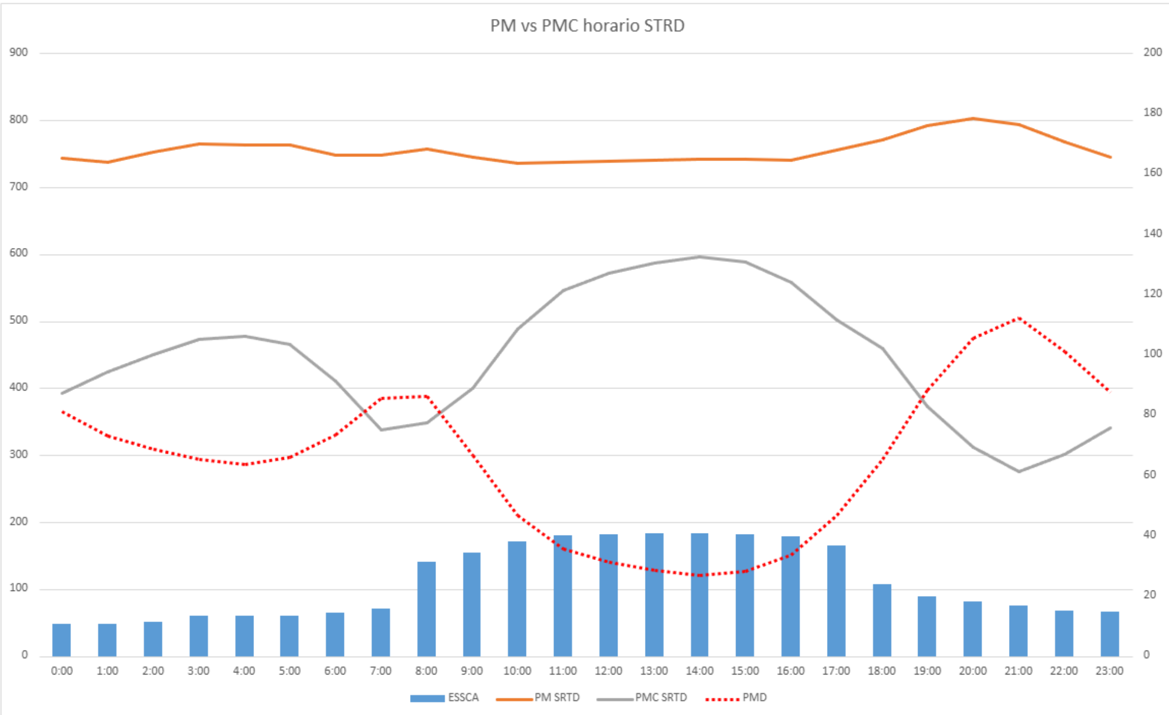


Figure 251: ESRTD, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2025. Source: Own elaboration.

Hora/mes ESSOT 2025	1	2	3	4	5	6	7	8	9	10	11	12
0	40	39	52	75	110	67	25	27	54	67	87	80
1	45	44	56	77	114	69	26	27	55	68	87	82
2	51	50	55	81	114	71	27	28	57	73	88	82
3	51	50	59	83	114	73	36	45	61	70	88	82
4	52	50	60	83	115	73	36	45	63	70	88	82
5	51	50	60	82	114	72	35	46	63	70	88	82
6	43	41	51	74	112	71	34	46	60	64	87	80
7	23	17	24	45	60	29	17	23	26	23	37	42
8	12	7	9	29	28	20	10	21	22	20	20	16
9	6	2	3	12	1	4	1	7	11	9	10	14
10	1	0	1	3	1	0	1	0	0	0	0	0
11	0	0	1	3	1	0	1	0	0	0	0	0
12	0	0	1	3	1	0	1	0	0	0	0	0
13	0	0	1	3	1	0	1	0	0	0	0	0
14	0	0	1	3	1	0	1	0	0	0	0	0
15	0	0	1	3	1	0	1	0	0	0	0	0
16	0	0	1	3	1	0	1	0	0	0	0	0
17	0	0	1	3	1	0	0	0	0	0	0	0
18	0	0	1	3	0	0	1	0	0	0	0	0
19	0	0	1	2	0	0	1	0	0	0	0	0
20	0	0	1	1	0	0	1	0	0	0	0	0
21	0	0	1	1	0	0	1	0	0	0	0	0
22	0	0	1	1	0	0	1	0	0	0	0	0
23	0	0	1	1	0	0	1	0	0	0	0	0

Figure 252: Heat map of the ESSOT of the PDBF by hours and months in 2025. Source: Own elaboration.

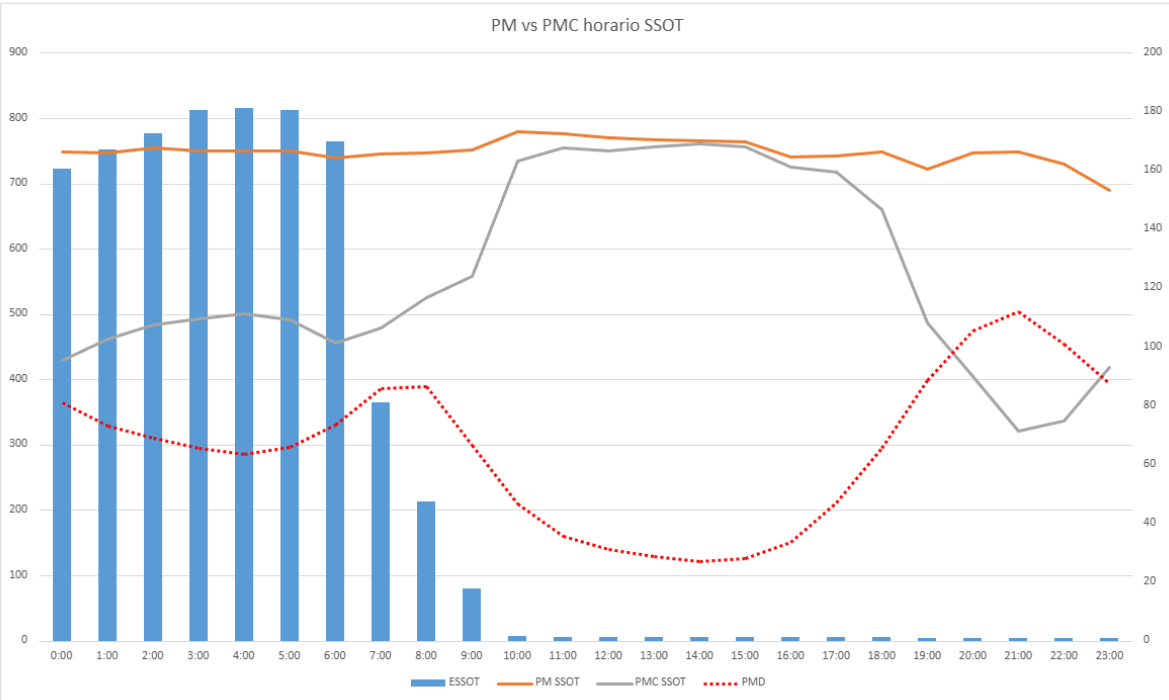


Figure 253: ESSOT, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2025. Source: Own elaboration.

Hora/mes ESCOT 2025	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	5	0	0	0	0	0	1	0	0
1	0	0	0	5	0	0	0	0	0	1	0	0
2	0	0	0	5	0	0	0	0	0	1	0	0
3	0	0	0	5	0	0	2	0	0	1	0	0
4	0	0	0	5	0	0	2	0	0	1	0	0
5	0	0	0	4	0	0	2	0	0	1	0	0
6	0	0	0	4	0	0	2	0	0	1	0	0
7	7	7	12	17	41	38	19	20	29	33	40	29
8	11	10	17	23	69	54	33	27	33	32	46	39
9	11	12	20	36	94	70	46	45	44	43	55	37
10	14	14	22	41	93	71	47	52	52	58	61	49
11	14	14	20	42	93	70	47	52	51	61	59	49
12	15	14	22	41	93	69	46	52	51	61	59	49
13	15	14	22	41	93	69	46	52	51	61	59	49
14	15	14	22	41	93	69	46	52	51	60	59	49
15	14	14	22	40	92	68	46	52	51	60	60	48
16	14	13	22	40	92	67	46	52	51	59	62	48
17	13	13	21	39	89	67	45	51	50	57	59	43
18	9	10	19	35	89	65	44	50	48	51	62	26
19	7	7	17	31	88	63	39	44	44	42	59	24
20	7	7	16	27	85	63	33	37	38	39	59	24
21	7	7	17	25	74	45	18	19	21	20	40	24
22	8	9	17	27	74	45	19	19	21	21	41	25
23	9	12	18	29	77	47	19	20	22	23	44	26

Figure 254: Heat map of the ESCOT of the PDBF by hours and months in 2025. Source: Own elaboration.

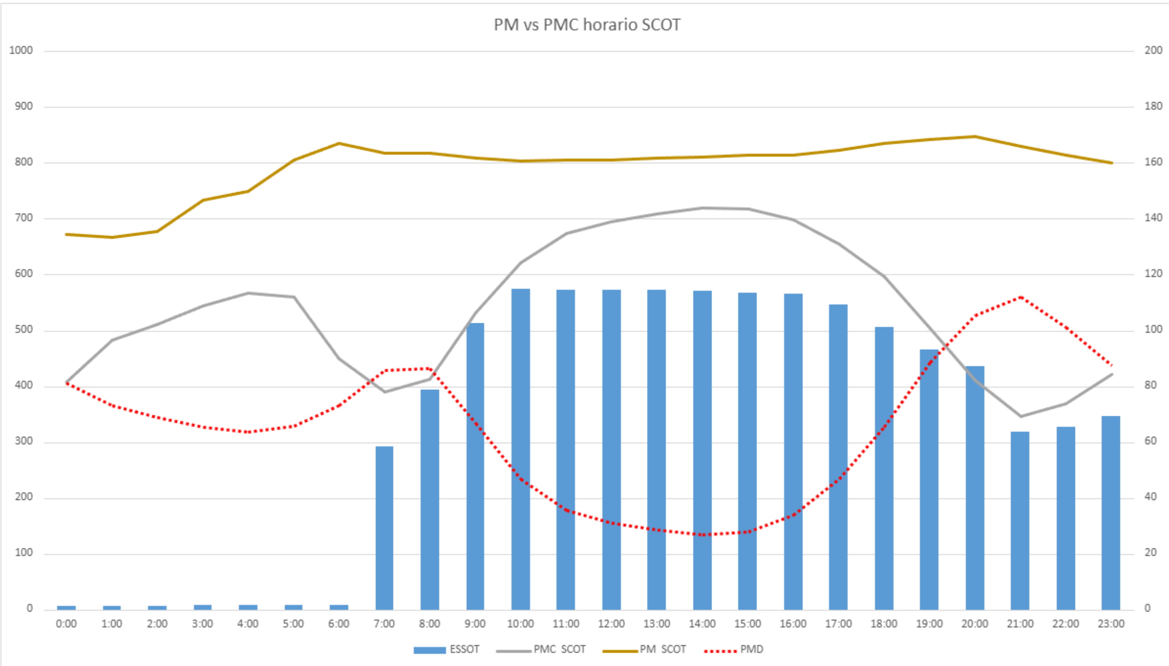


Figure 255: ESCOT, average price of the restriction, average price of the overcost in the PDBF and day ahead market price in 2025. Source: Own elaboration.

2025 RT

MES/ENERGIAS GW	ESASE	EBASE	ESSOT	EBSOT	ESCOT	EBPEV	ESEST	EBEST	ESRSI	EBRSI	ESRBI	EBRBI	ESRTD	EBRTD	ESSCA	EBSCA	ESSCB	EBSCB
ENERO	0	1	22	5	11	0	0	0	428	0	0	0	7	2	9	25	2	2
FEBRERO	0	2	8	3	4	0	0	0	786	0	0	0	7	1	16	5	3	0
MARZO	0	5	31	1	9	4	0	0	597	0	0	0	4	2	20	9	7	48
ABRIL	0	3	26	1	10	1	0	0	323	0	0	0	0	4	13	25	2	41
MAYO	0	6	38	2	21	1	0	0	144	0	0	0	0	3	25	79	0	23
JUNIO	0	1	37	1	22	0	0	0	400	0	0	0	2	10	81	158	5	35
JULIO	1	0	15	4	8	3	0	0	326	0	0	0	1	13	75	278	45	155
AGOSTO	1	0	24	0	8	5	0	0	264	0	0	0	0	3	64	98	34	66
SEPTIEMBRE	1	1	21	1	3	3	0	0	395	3	0	0	0	6	81	38	10	23
OCTUBRE	0	1	28	13	10	2	0	0	343	3	0	0	21	20	28	85	5	65
NOVIEMBRE	0	1	56	10	12	3	0	0	71	0	0	0	1	5	37	18	4	18
DICIEMBRE	0	0	55	20	12	1	0	0	73	0	0	0	2	0	21	23	9	39

Figure 256: Heat map of the monthly desegregated energies from the RT by labels in 2025. Source: Own elaboration.

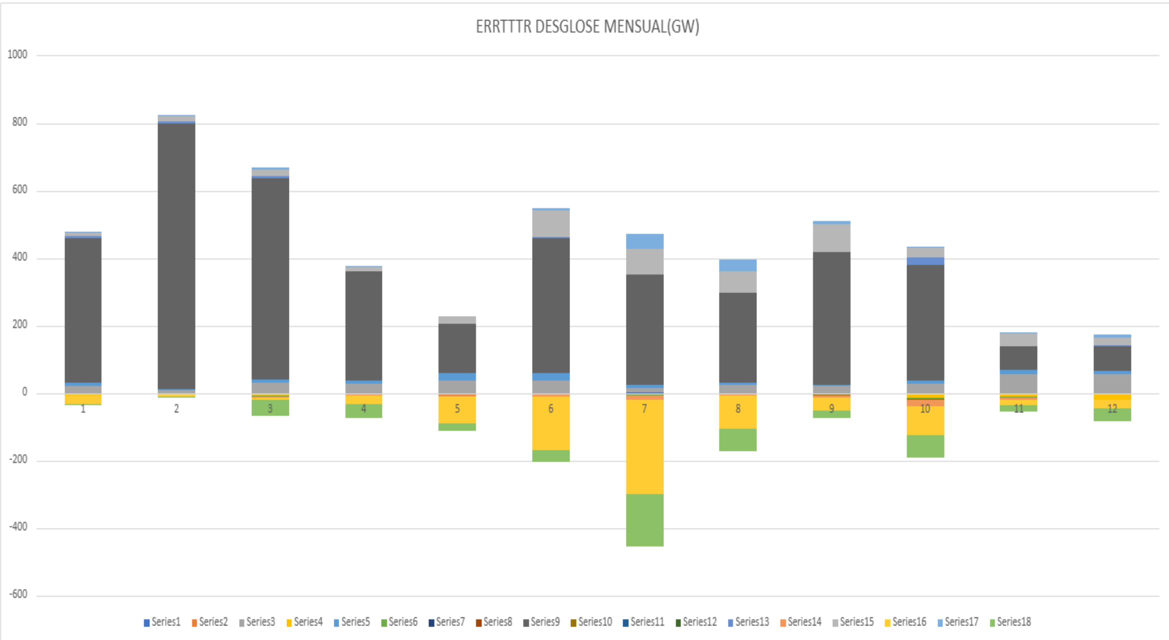


Figure 257: Monthly desegregated energies from the RT by labels in 2025. Source: Own elaboration.

HORA/ENERGIAS GW	ESASE	EBASE	ESSOT	EBSOT	ESCOT	EBPEV	ESEST	EBEST	ESRSI	EBRSI	ESRBI	EBRBI	ESRTD	EBRTD	ESSCA	EBSCA	ESSCB	EBSCB
0:00	0	0	23	3	3	0	0	0	89	0	0	0	1	2	12	14	5	18
1:00	0	0	24	5	3	0	0	0	57	0	0	0	1	2	8	12	4	14
2:00	0	0	24	7	2	0	0	0	33	1	0	0	1	2	6	10	2	11
3:00	0	0	27	8	2	0	0	0	28	1	0	0	1	2	5	8	0	9
4:00	0	0	27	8	2	0	0	0	28	1	0	0	1	2	6	7	0	8
5:00	0	0	27	9	2	0	0	0	42	1	0	0	1	2	5	6	0	7
6:00	0	0	19	6	1	0	0	0	168	0	0	0	1	2	6	6	0	7
7:00	0	0	15	3	1	0	0	0	354	0	0	0	1	2	5	6	0	7
8:00	0	1	12	1	3	0	0	0	349	0	0	0	2	2	7	8	0	6
9:00	0	3	17	0	7	0	0	0	205	0	0	0	2	3	14	11	2	8
10:00	0	4	18	0	11	0	0	0	81	0	0	0	2	3	20	28	6	16
11:00	1	2	15	0	11	0	0	0	34	0	0	0	2	4	27	47	8	24
12:00	0	0	13	0	9	2	0	0	18	0	0	0	2	4	32	61	7	30
13:00	0	0	12	1	10	3	0	0	15	0	0	0	2	4	36	73	7	34
14:00	0	3	12	1	10	2	0	0	16	0	0	0	2	3	37	79	6	35
15:00	0	0	13	1	11	2	0	0	23	0	0	0	3	3	39	79	6	34
16:00	0	1	11	1	9	1	0	0	63	0	0	0	4	4	39	86	8	36
17:00	1	0	9	1	8	2	0	0	165	0	0	0	3	3	37	91	9	35
18:00	0	1	9	3	6	4	0	0	251	0	0	0	2	3	37	88	11	32
19:00	0	3	6	2	5	1	0	0	365	0	0	0	2	3	28	54	12	31
20:00	0	1	4	0	3	1	0	0	507	0	0	0	2	3	14	18	9	31
21:00	0	0	5	0	3	1	0	0	535	0	0	0	2	3	16	15	8	30
22:00	0	0	8	0	3	1	0	0	430	0	0	0	2	3	15	16	7	27
23:00	0	0	12	1	4	0	0	0	295	0	0	0	2	3	17	16	6	24

Figure 258: Heat map of the hourly desegregated energies from the RT by labels in 2025. Source: Own elaboration.

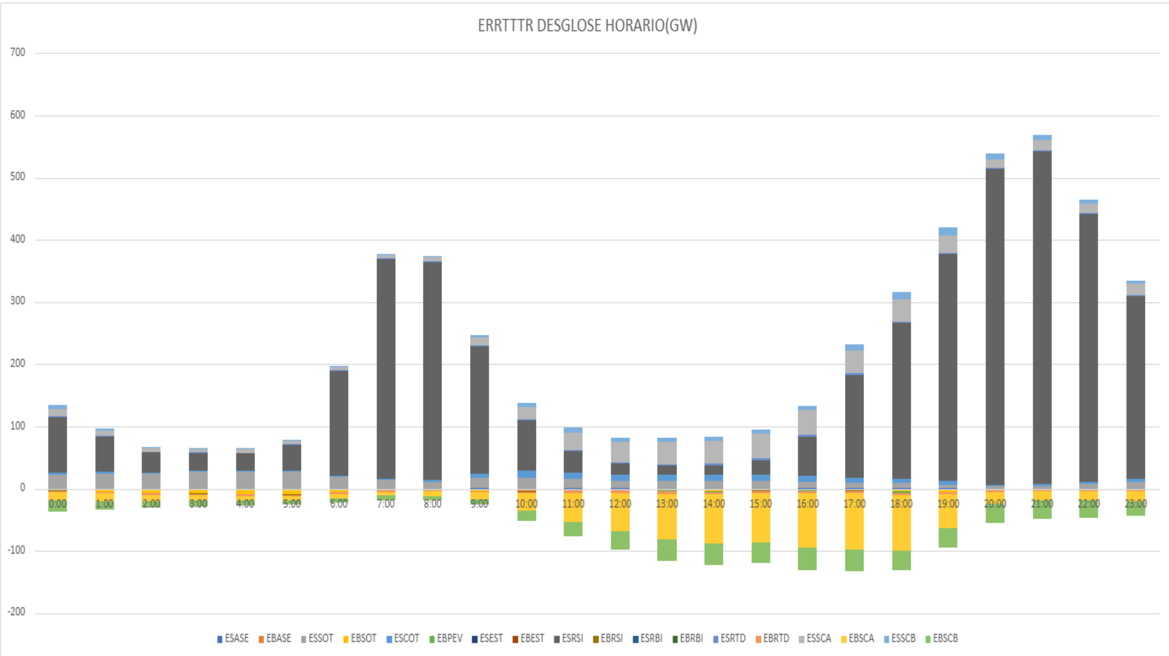


Figure 259: Hourly desegregated energies from the RT by labels in 2025. Source: Own elaboration.

HORA/ MES ESSOT (GWh)	1	2	3	4	5	6	7	8	9	10	11	12
0	1	1	2	3	0	2	1	2	2	3	2	5
1	2	1	2	2	1	1	1	1	2	2	4	4
2	2	1	2	1	1	2	1	1	2	2	5	4
3	1	1	2	2	2	2	2	2	2	2	6	5
4	1	0	2	2	2	2	1	2	1	2	6	5
5	1	0	2	2	2	2	1	2	1	2	6	5
6	1	0	1	1	1	1	1	1	1	1	5	4
7	0	0	2	1	1	1	1	1	0	0	3	3
8	1	0	1	1	1	2	1	1	0	0	1	2
9	1	0	3	1	2	3	1	1	1	1	1	1
10	1	0	2	1	2	2	1	1	2	1	1	2
11	1	1	1	1	2	2	1	1	1	1	1	3
12	1	1	1	1	2	2	1	1	1	1	1	2
13	1	0	1	1	2	2	1	1	1	1	1	1
14	1	0	1	1	2	2	0	1	1	1	1	1
15	1	0	1	1	2	2	0	1	1	1	1	1
16	1	0	1	1	2	2	0	1	1	1	1	1
17	0	0	1	0	2	1	0	1	0	1	1	1
18	0	0	1	1	2	2	0	1	0	1	1	0
19	0	0	0	1	2	1	0	0	0	0	1	0
20	0	0	0	0	2	0	0	0	0	0	0	0
21	0	0	0	0	1	0	0	0	0	0	2	0
22	0	0	1	0	1	0	0	0	0	0	3	1
23	1	0	1	0	1	0	0	1	1	0	4	2

Figure 260: Heat map of the ESSOT of the RT by hours and months in 2025. Source: Own elaboration.

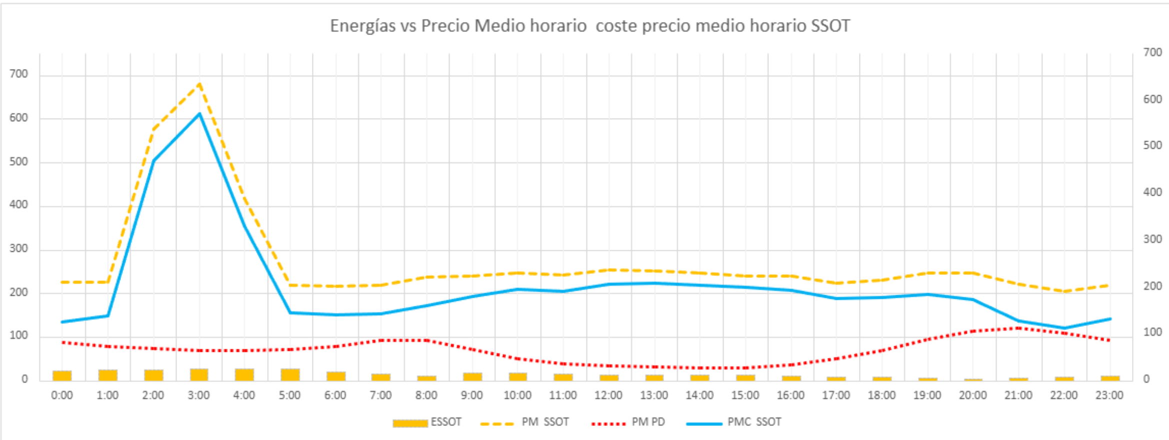


Figure 261: ESSOT, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2025. Source: Own elaboration.

HORA/ MES ESCOT	1	2	3	4	5	6	7	8	9	10	11	12
0	1	0	0	1	0	0	0	0	0	0	0	0
1	1	0	0	1	0	0	0	0	0	0	0	0
2	1	0	0	1	0	0	0	0	0	0	0	0
3	1	0	0	1	0	0	0	0	0	0	0	0
4	0	0	0	1	0	0	0	0	0	0	0	0
5	0	0	0	1	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	1	1	0	0	0	0	0	0
9	0	0	1	0	1	2	0	1	0	1	1	0
10	1	0	1	1	1	2	1	1	0	1	1	1
11	1	1	0	1	1	2	1	1	0	1	1	1
12	1	1	0	1	1	2	1	1	0	1	1	1
13	1	1	1	1	2	2	1	1	0	1	1	1
14	1	1	1	0	1	2	1	1	0	1	1	1
15	1	1	1	0	2	2	1	0	0	1	1	1
16	1	0	1	0	2	1	1	0	0	1	1	1
17	0	0	0	0	2	1	1	1	0	1	1	1
18	0	0	0	0	2	2	0	1	0	1	0	0
19	0	0	0	0	2	1	0	0	0	0	0	0
20	0	0	0	0	1	0	0	0	0	0	0	0
21	0	0	0	0	1	0	0	0	0	0	1	0
22	0	0	0	0	1	0	0	0	0	0	1	0
23	0	0	0	0	1	0	0	0	0	0	2	0

Figure 262: Heat map of the ESCOT of the RT by hours and months in 2025. Source: Own elaboration.

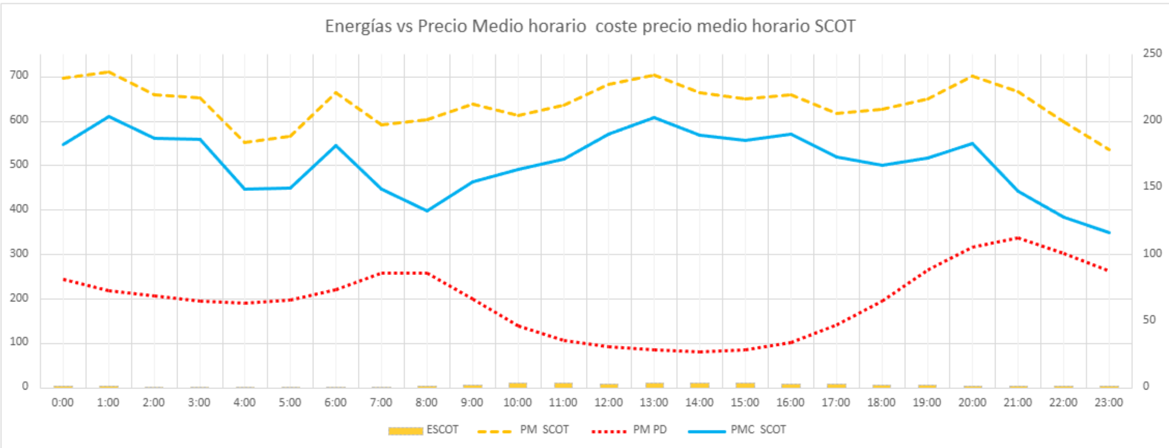


Figure 263: ESCOT, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2025. Source: Own elaboration.

HORA/ MES ESRSI 2025	1	2	3	4	5	6	7	8	9	10	11	12
0	1	7	5	3	2	22	23	11	10	5	0	0
1	0	5	1	1	0	17	17	5	7	4	0	0
2	0	0	0	0	0	12	12	2	5	1	0	0
3	0	0	0	0	0	10	10	3	4	1	0	0
4	0	0	0	0	0	10	10	3	4	1	0	0
5	0	2	2	2	0	13	13	3	5	3	0	0
6	6	29	23	17	4	26	26	11	15	10	1	0
7	30	59	51	40	14	33	30	22	38	26	7	4
8	39	65	49	42	11	20	22	21	39	28	6	7
9	37	65	31	16	1	4	4	5	15	18	3	5
10	18	33	14	2	0	1	0	1	4	6	1	1
11	4	11	6	0	0	0	0	0	4	6	0	1
12	1	3	4	0	0	0	0	0	4	6	0	1
13	1	1	2	0	0	0	0	0	4	7	0	1
14	1	2	2	0	0	0	0	0	4	7	0	2
15	4	4	3	0	0	0	0	0	4	7	0	2
16	21	19	9	0	0	0	0	0	4	7	1	2
17	47	63	28	0	0	1	1	0	4	8	6	7
18	49	82	54	3	0	5	1	4	11	20	11	9
19	45	78	71	21	7	19	10	22	36	36	11	11
20	44	75	77	49	23	44	30	46	57	41	10	10
21	41	74	71	56	36	60	42	44	54	42	8	6
22	28	67	59	43	30	55	41	35	36	31	3	3
23	11	43	37	28	17	47	33	28	26	23	1	1

Figure 264: Heat map of the ESRSI of the RT by hours and months in 2025. Source: Own elaboration.

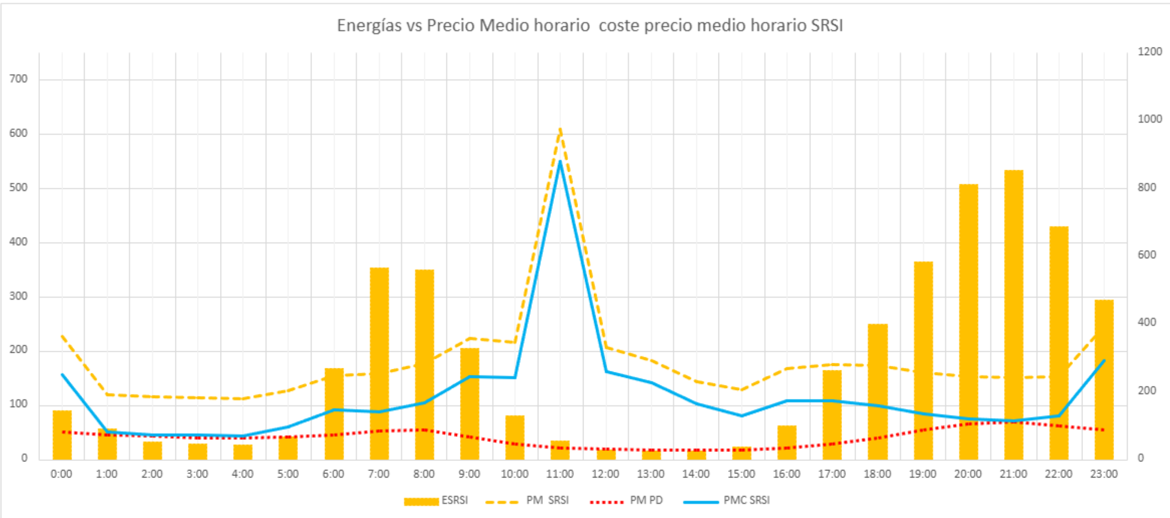


Figure 265: ESRSI, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2025. Source: Own elaboration.

HORA/ MES ESSCA	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	0	3	3	2	1	0	1
1	0	0	0	0	0	0	3	2	1	0	0	0
2	0	0	0	0	0	0	2	2	1	0	0	0
3	0	0	0	0	0	0	1	2	1	0	0	0
4	0	0	0	0	0	0	1	2	2	0	0	0
5	0	0	0	0	0	0	1	2	2	0	0	0
6	0	0	0	0	0	0	1	2	2	1	0	0
7	0	0	0	0	0	0	1	2	2	1	0	0
8	0	0	0	0	0	1	2	2	1	1	0	0
9	0	0	0	0	1	2	3	1	3	0	1	0
10	0	1	1	1	1	3	4	2	3	0	2	1
11	0	2	1	1	2	5	4	2	5	1	3	1
12	1	2	1	1	2	7	4	3	5	1	5	1
13	1	2	3	1	2	8	3	3	6	1	5	2
14	1	2	2	1	2	8	4	3	6	2	5	2
15	0	2	3	1	2	8	4	3	7	2	6	1
16	1	1	3	2	2	9	4	4	6	2	4	1
17	1	1	3	1	3	9	5	5	7	2	2	0
18	0	1	2	1	3	9	5	7	6	1	1	1
19	0	0	0	1	3	6	6	5	5	0	1	2
20	1	0	0	0	2	2	3	2	0	1	0	2
21	1	1	1	1	0	0	2	3	1	3	0	3
22	1	0	0	1	0	0	2	2	2	3	1	2
23	0	0	0	1	0	0	4	2	4	3	1	1

Figure 266: Heat map of the ESSCA of the RT by hours and months in 2025. Source: Own elaboration.

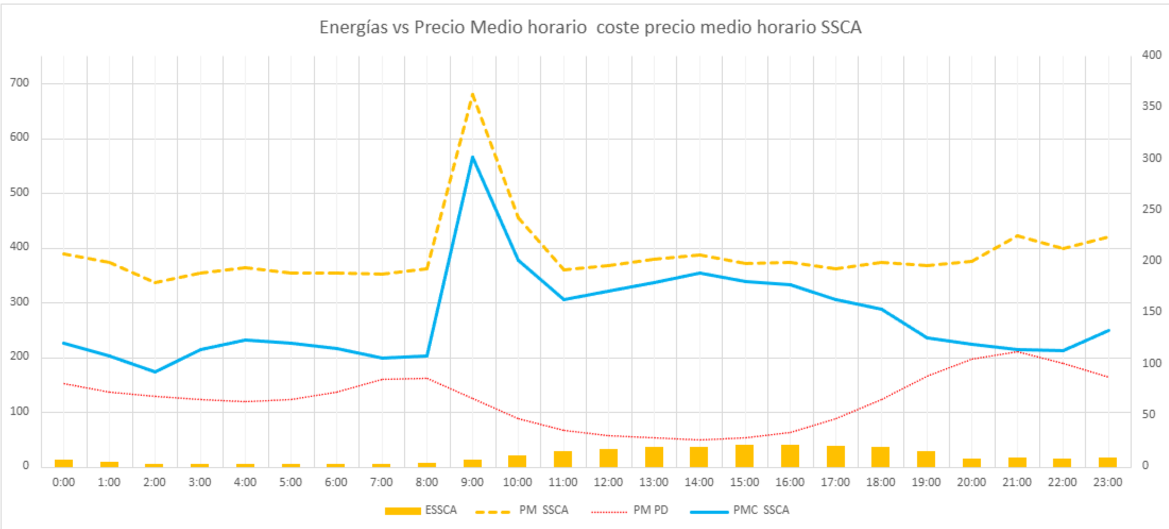


Figure 267: ESSCA, average price of the restriction, average price of the overcost in the RT and day ahead market price in 2025. Source: Own elaboration.

ANEX III: REGRESSION MODELS

2023 PDBF

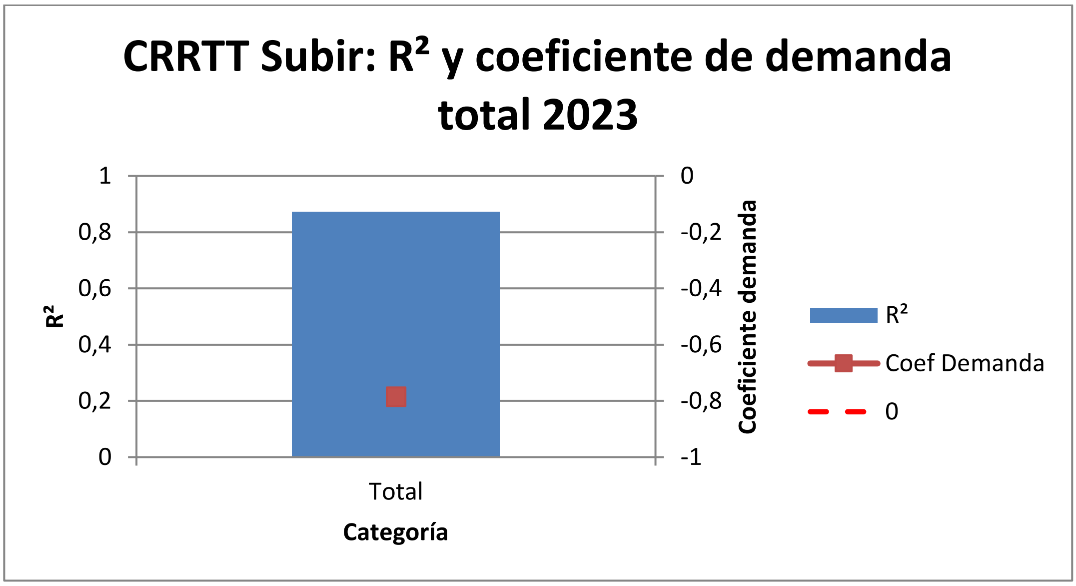


Figure 268: Multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2023 in PDBF

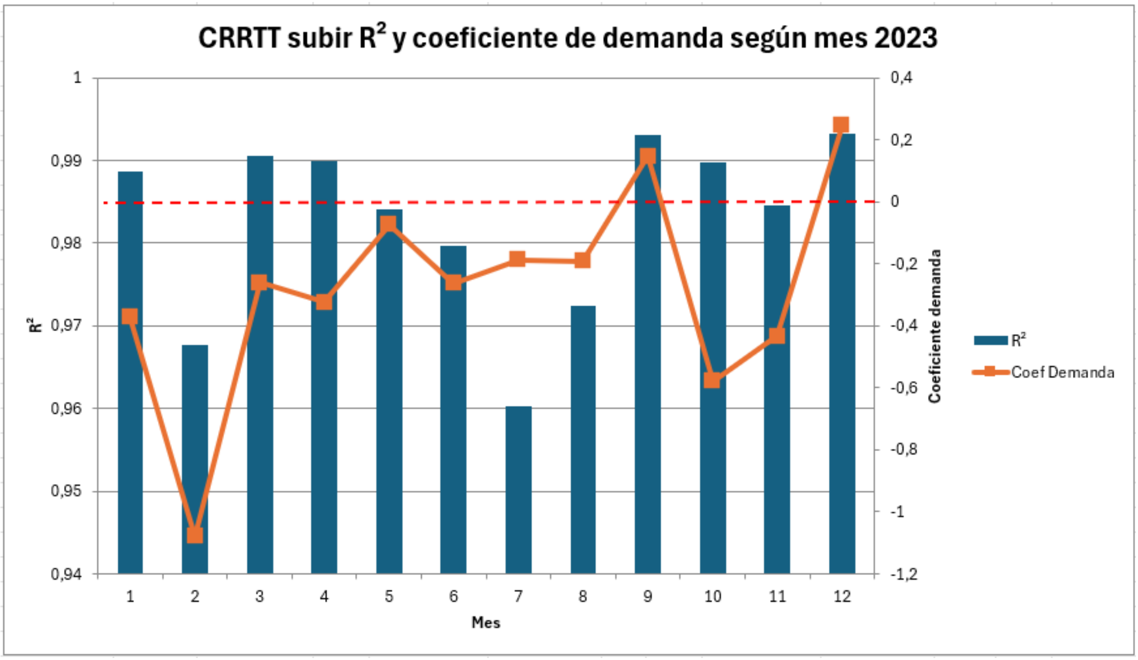


Figure 269: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2023 by month in PDBF

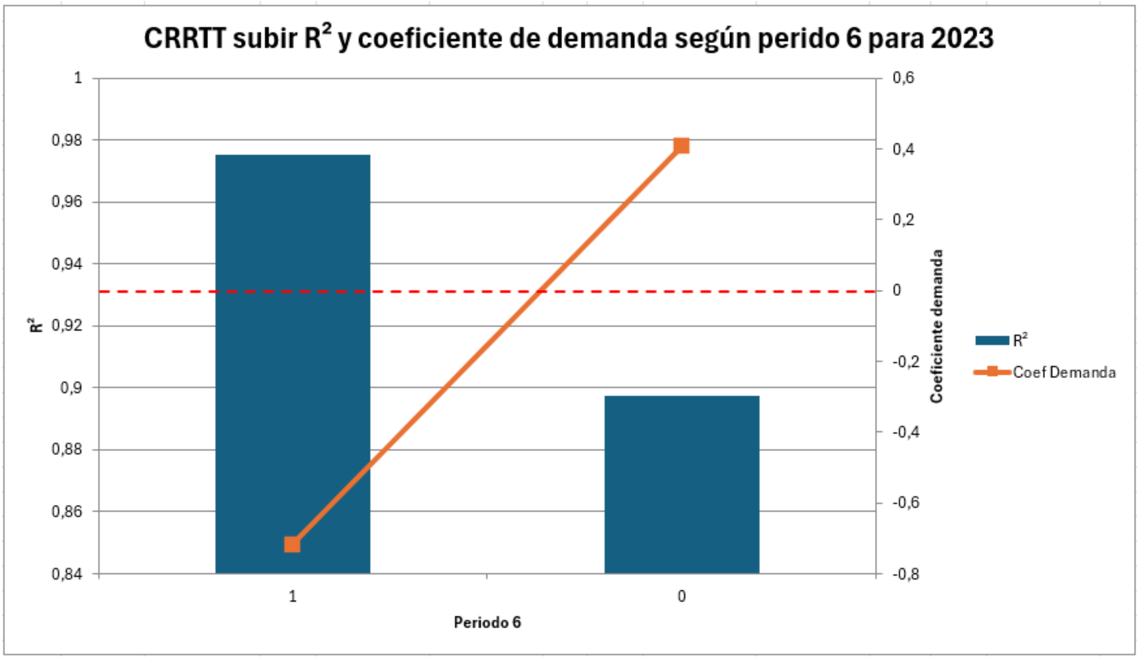


Figure 270: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2023 by period in PDBF

UPWARDS REAL TIME 2023

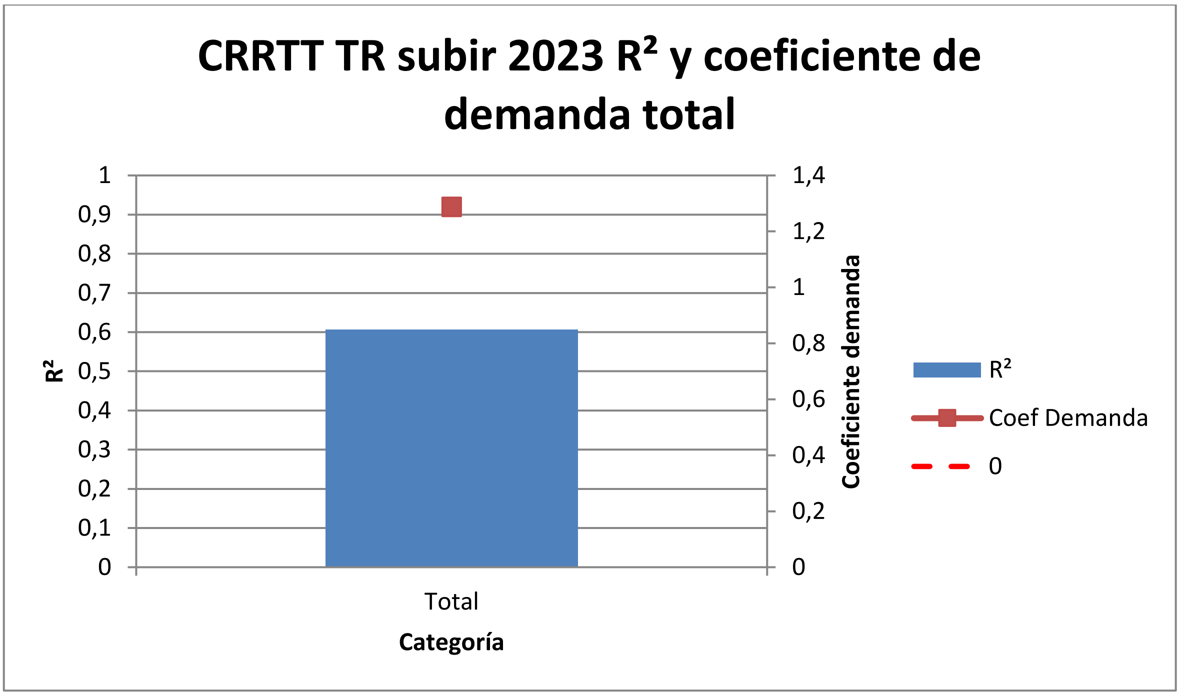


Figure 271: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2023 in real time

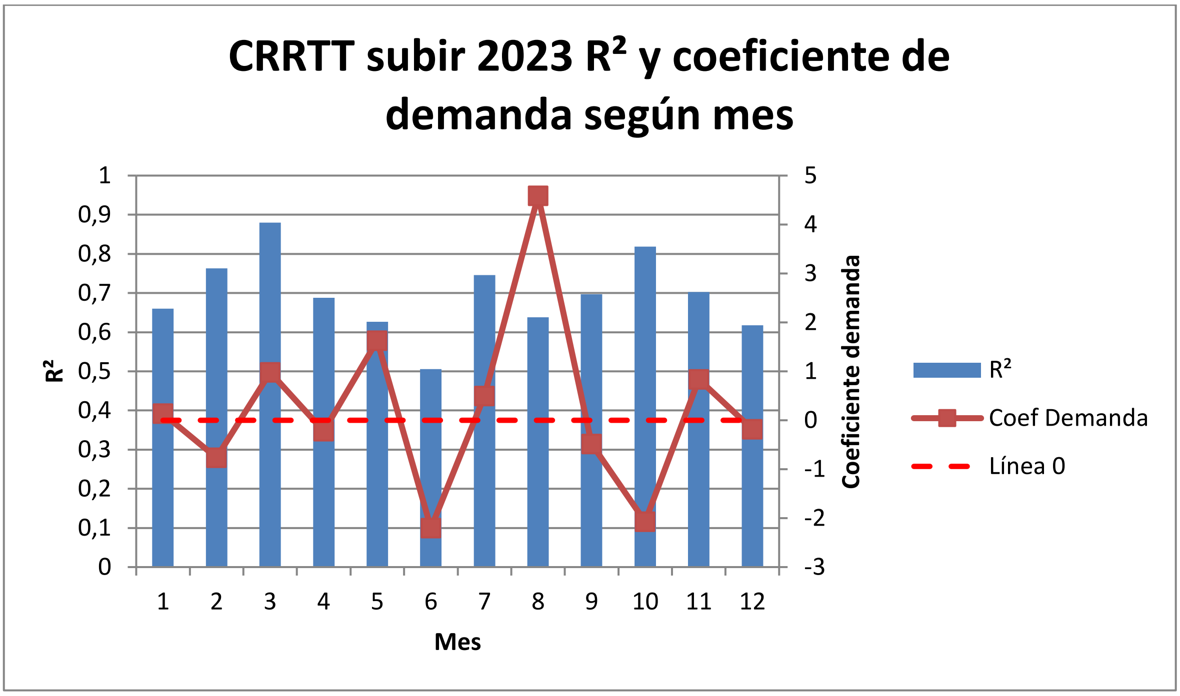


Figure 272: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2023 in real time by month

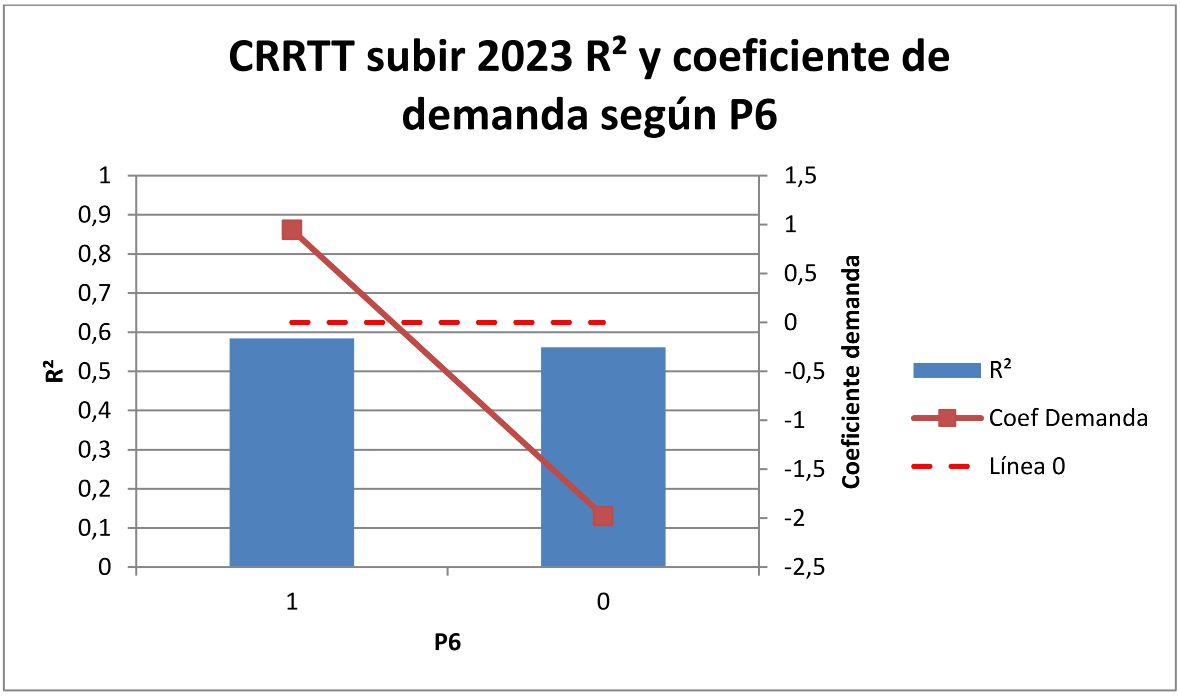


Figure 273: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2023 in real time by period

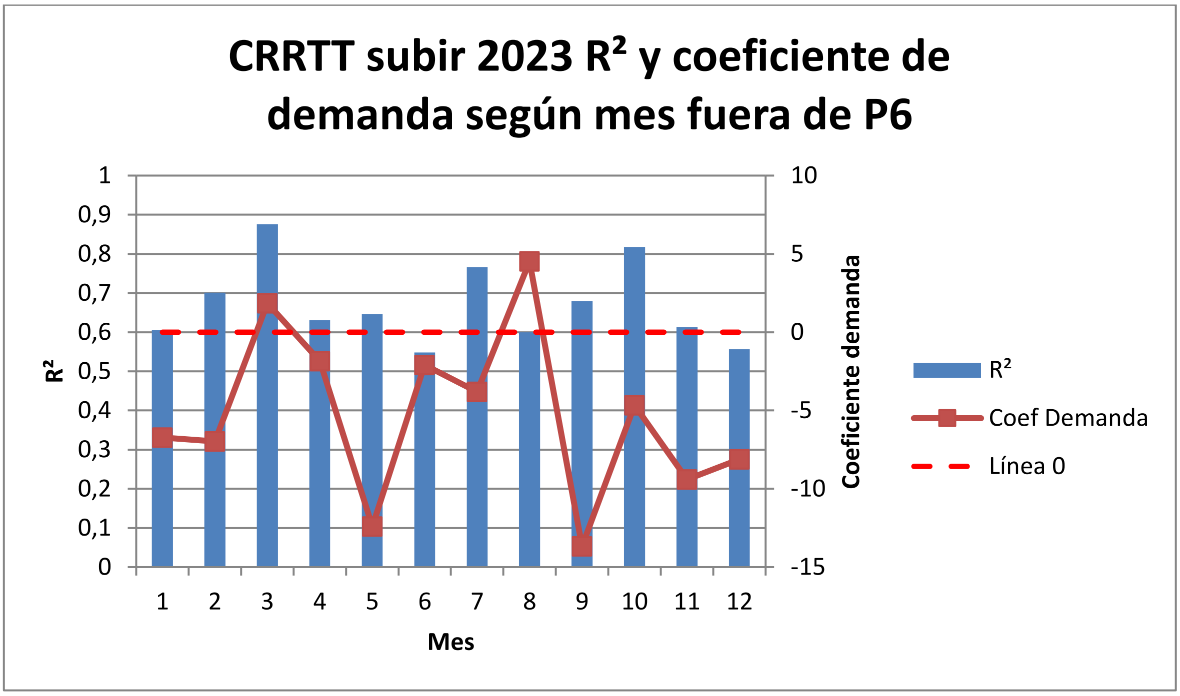


Figure 274: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2023 in real time by month outside the P6

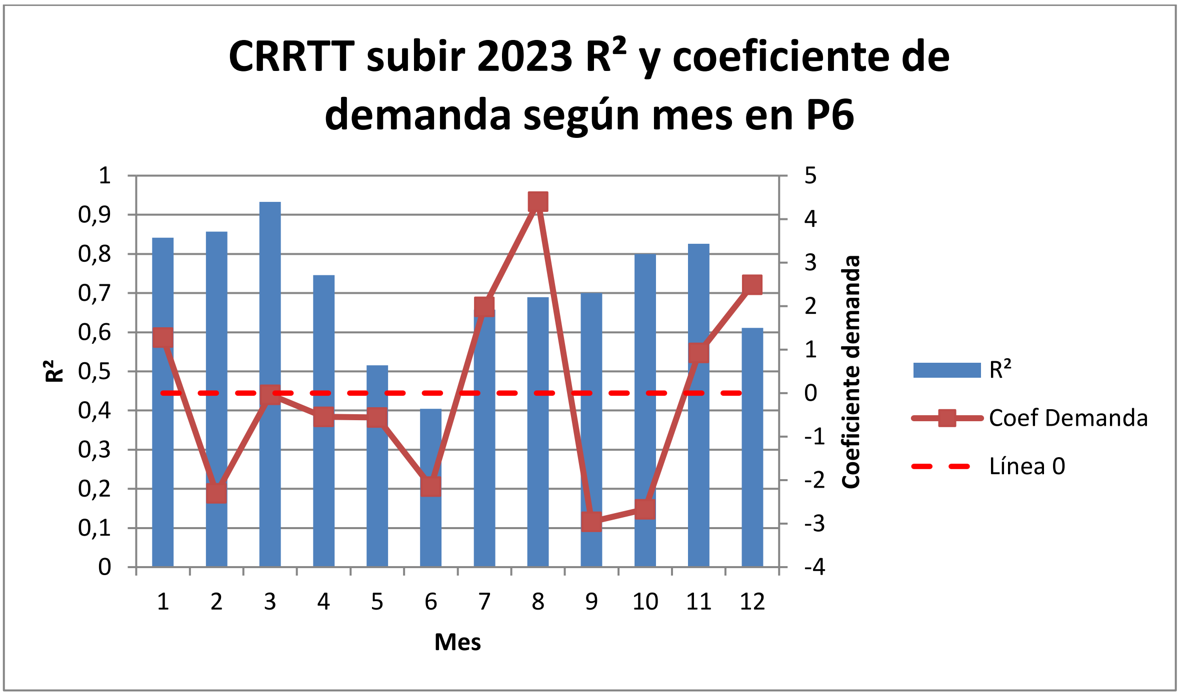


Figure 275: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2023 in real time by month in P6

DOWNWARD 2023 REAL TIME

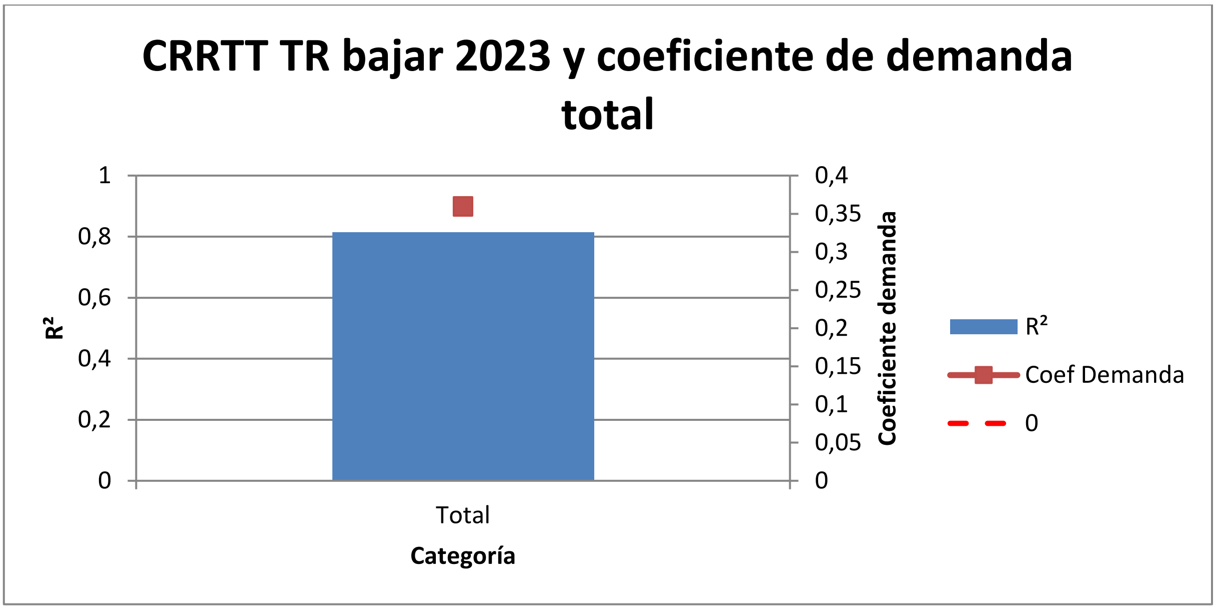


Figure 276: Downward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2023 in real time

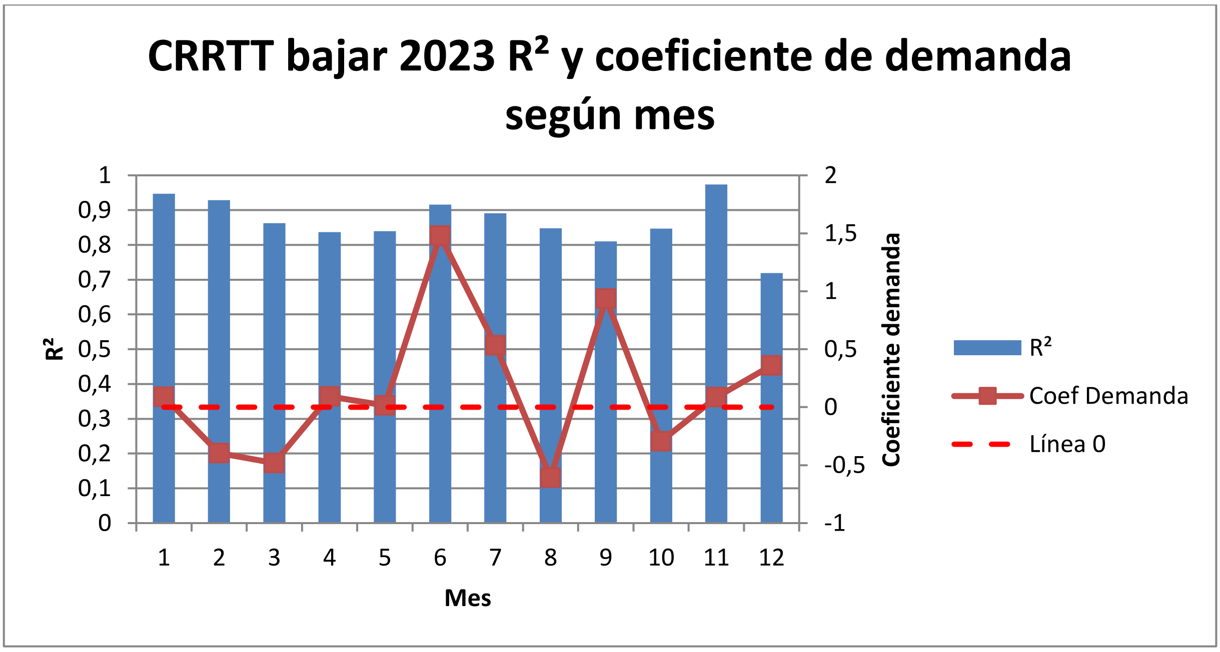


Figure 277: Downward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2023 in real time by month

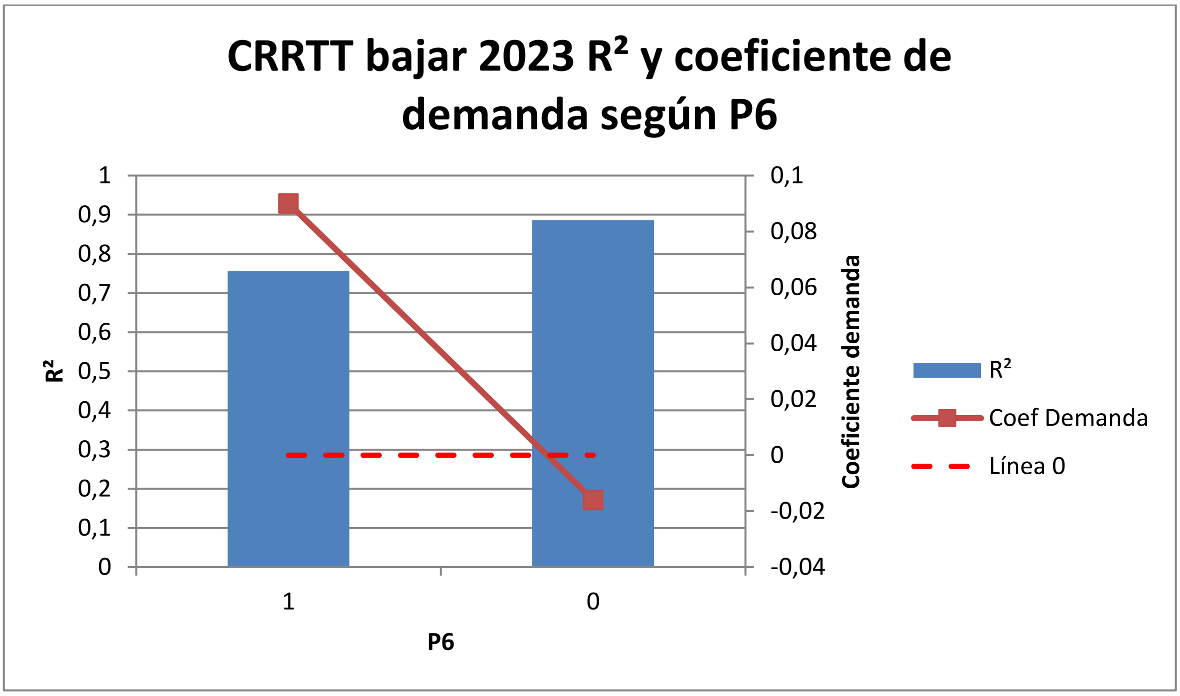


Figure 278: Downward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2023 in real time by period

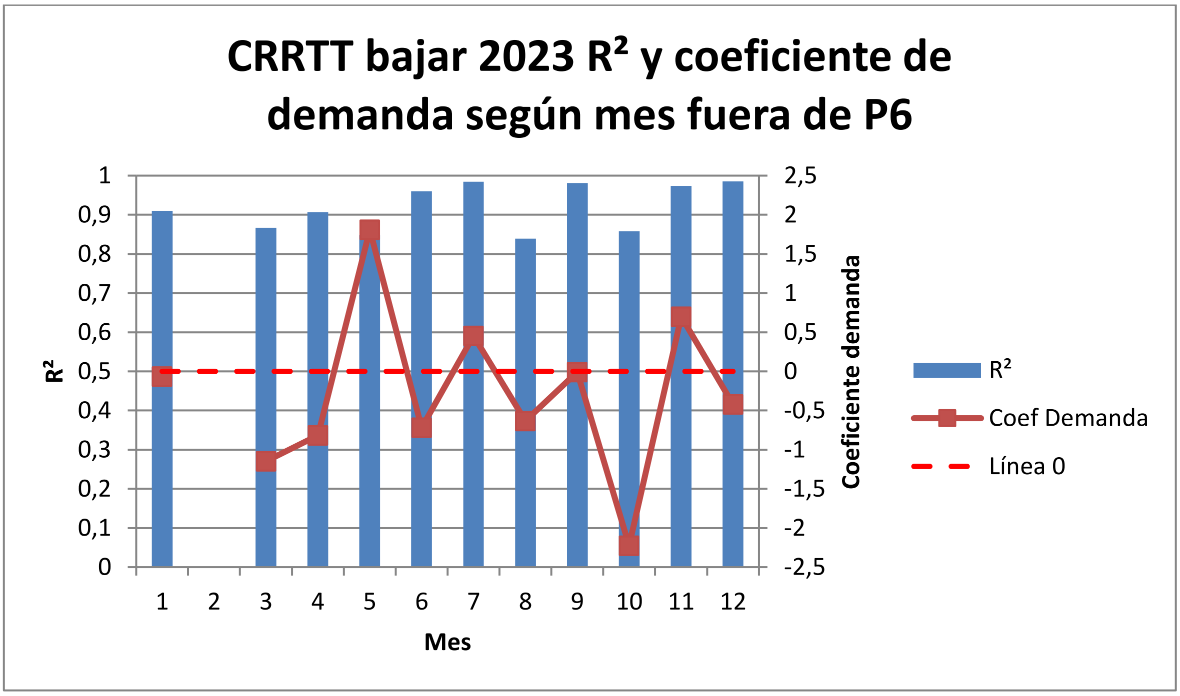


Figure 279: Downward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2023 in real time by month outside P6

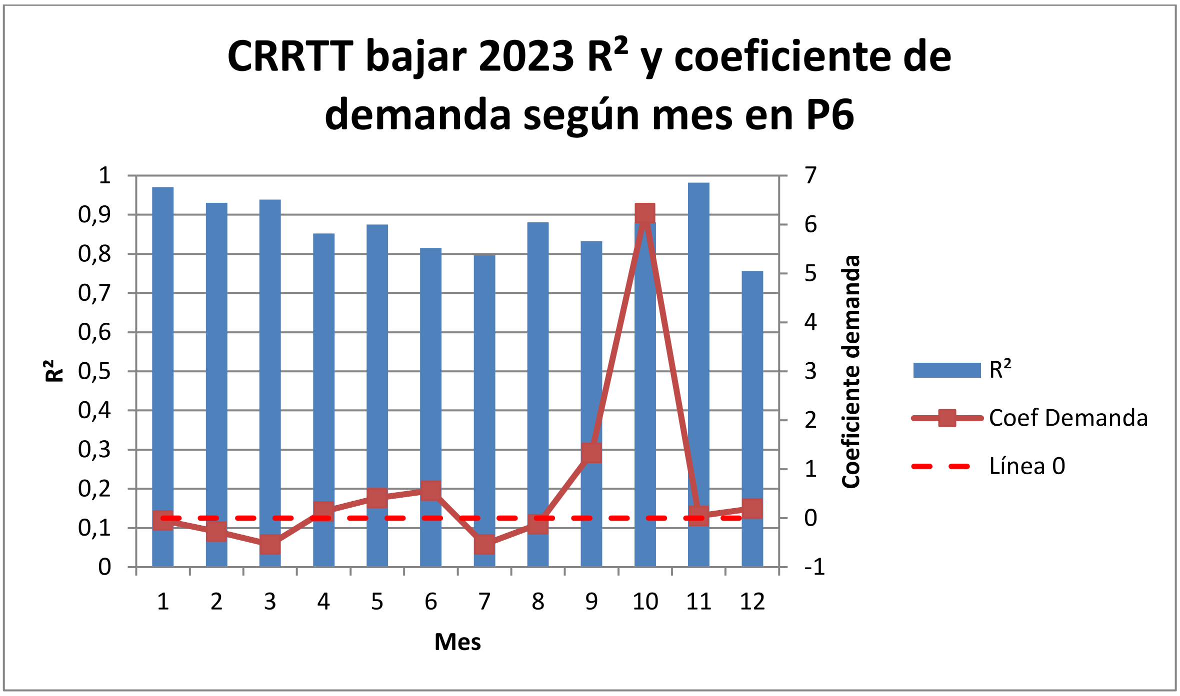
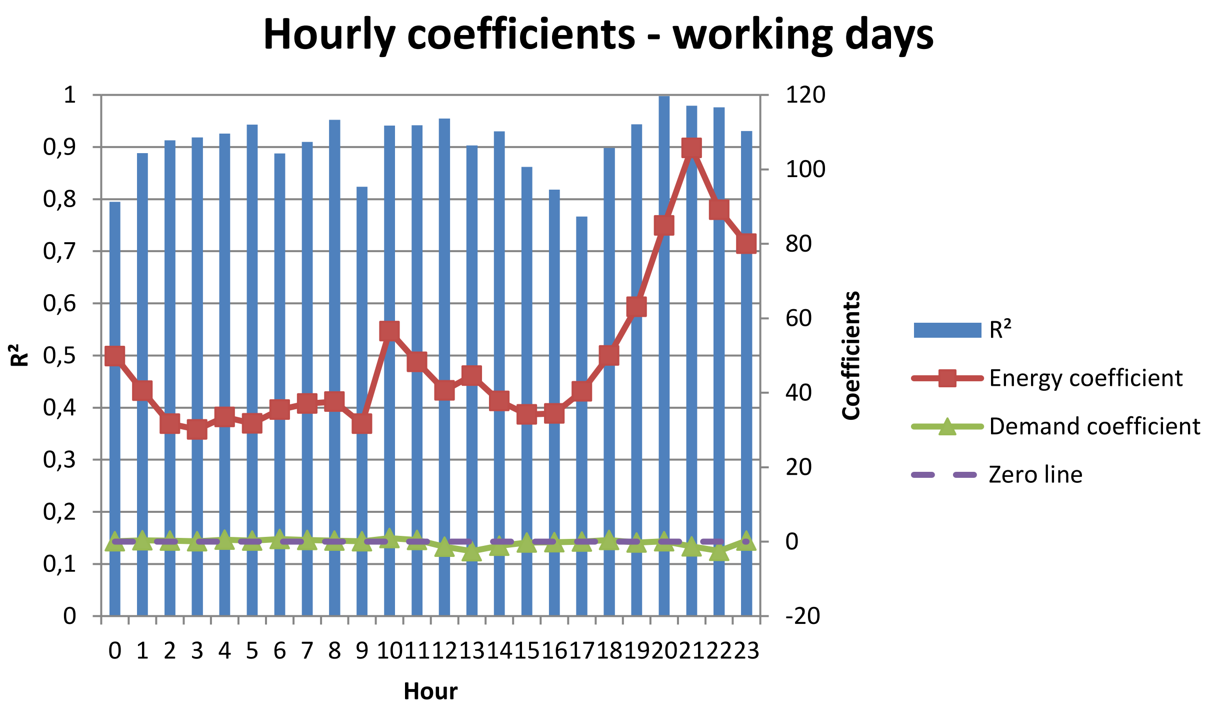
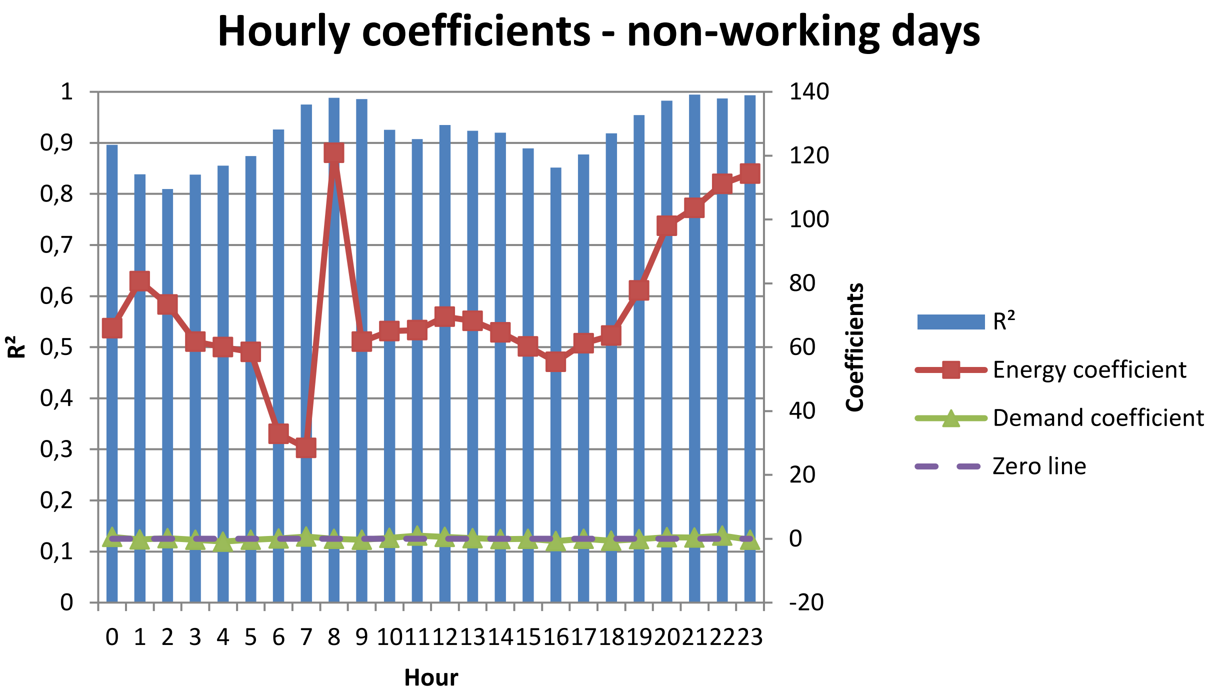


Figure 280: Downward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2023 in real time by month in P6.




Hourly coefficients - non-working days
R^2
Coefficients
Hour
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
1
0,9
0,8
0,7
0,6
0,5
0,4
0,3
0,2
0,1
0
140
120
100
80
60
40
20
0
-20
R^2
Energy coefficient
Demand coefficient
Zero line

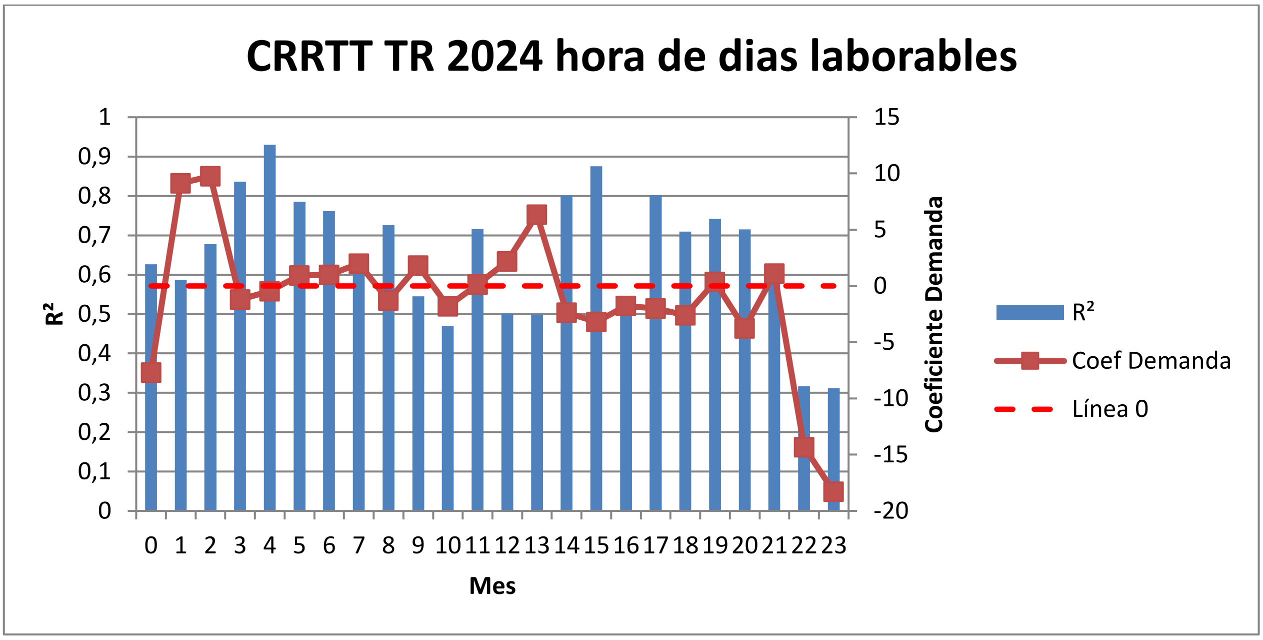


Figure 281: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time by hours of a labor day

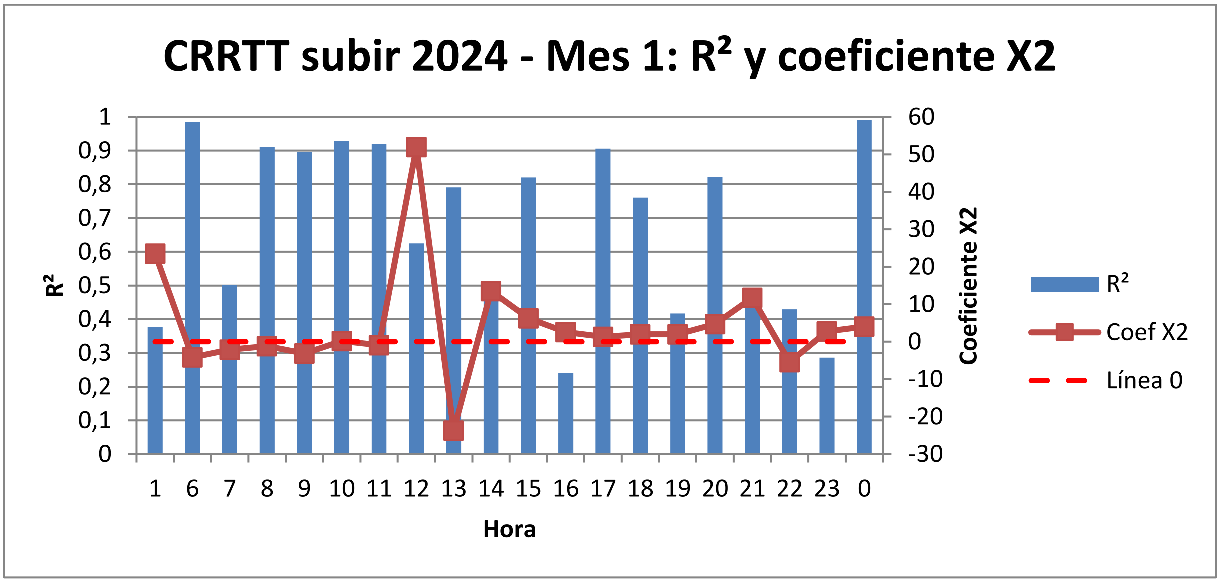


Figure 282: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time by hours and month 1

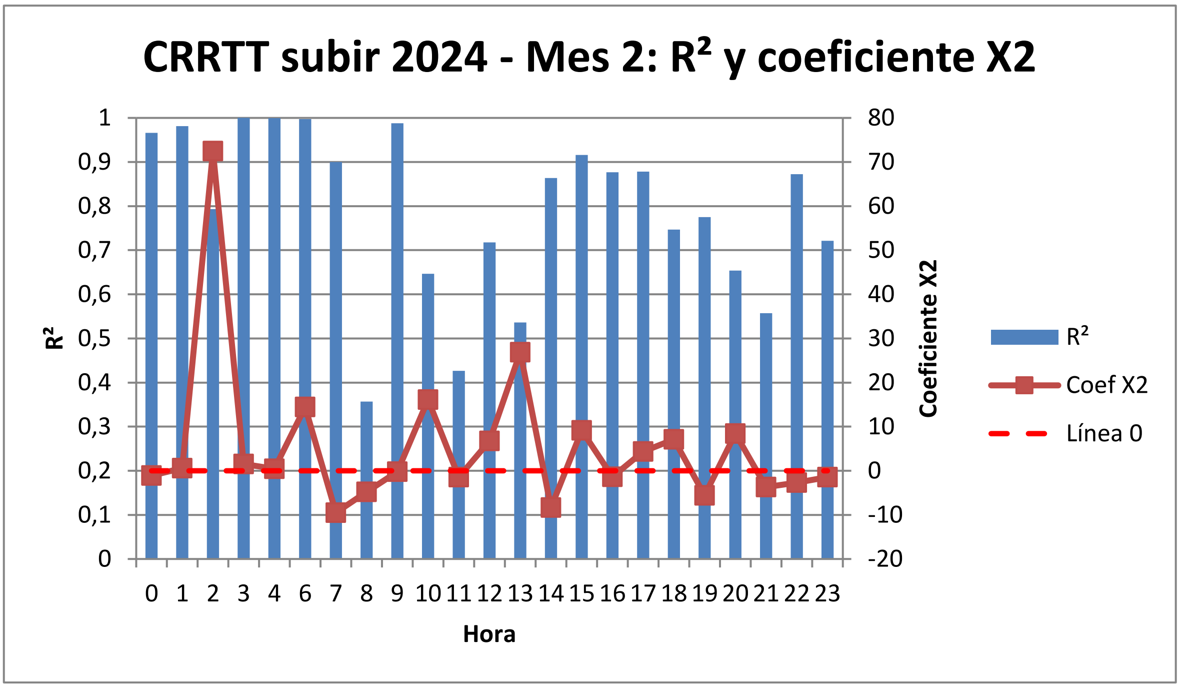


Figure 283: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time by hours and month 2

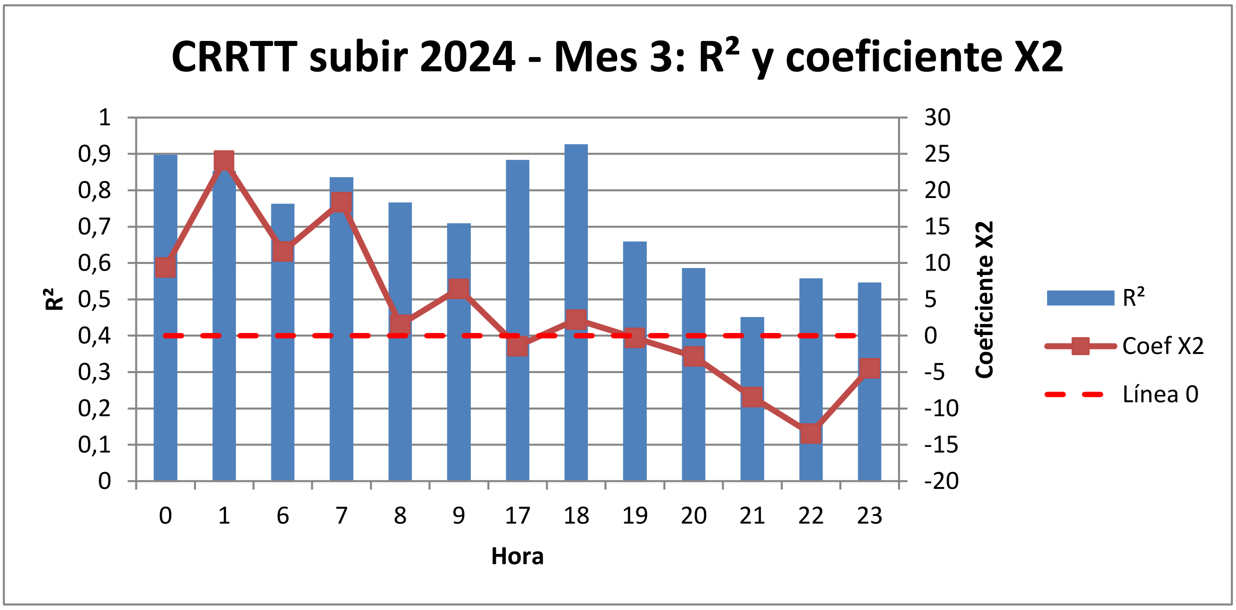


Figure 284: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time by hours and month 3

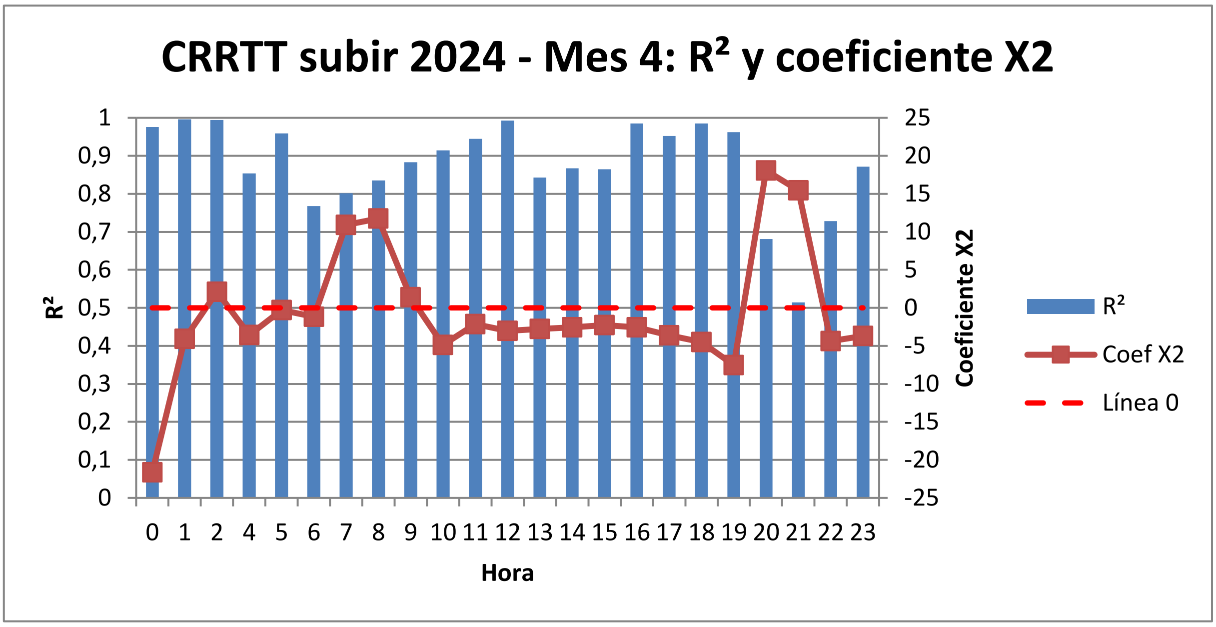


Figure 285: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time by hours and month 4

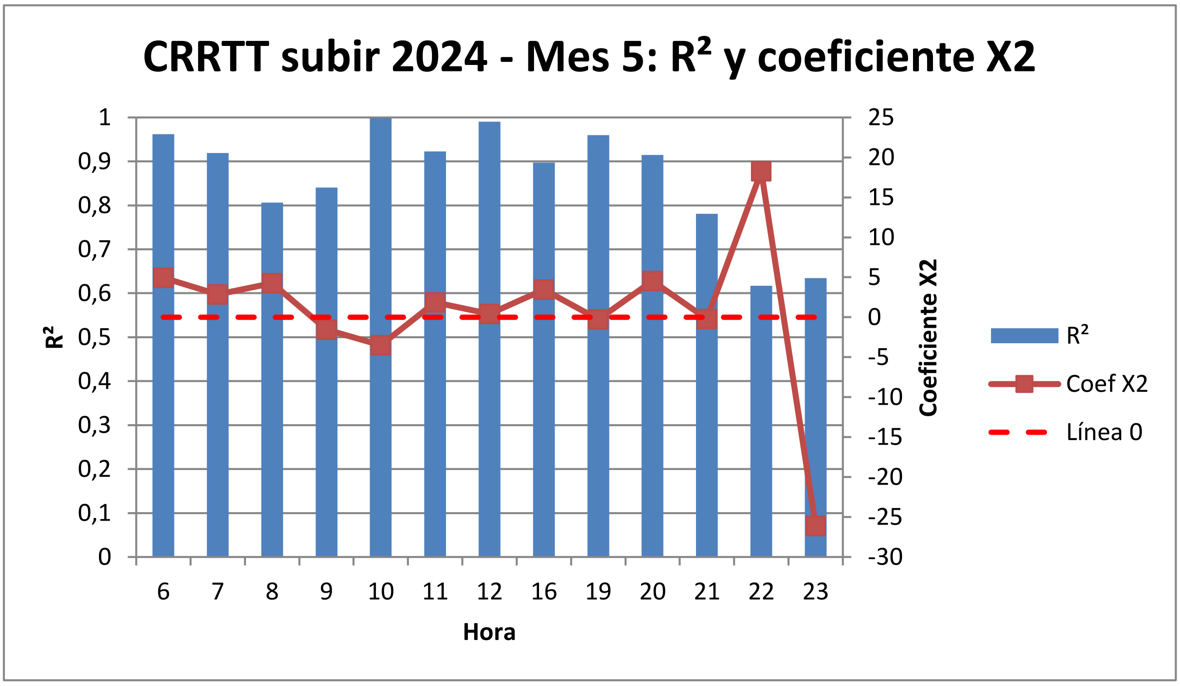


Figure 286: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time by hours and month 5

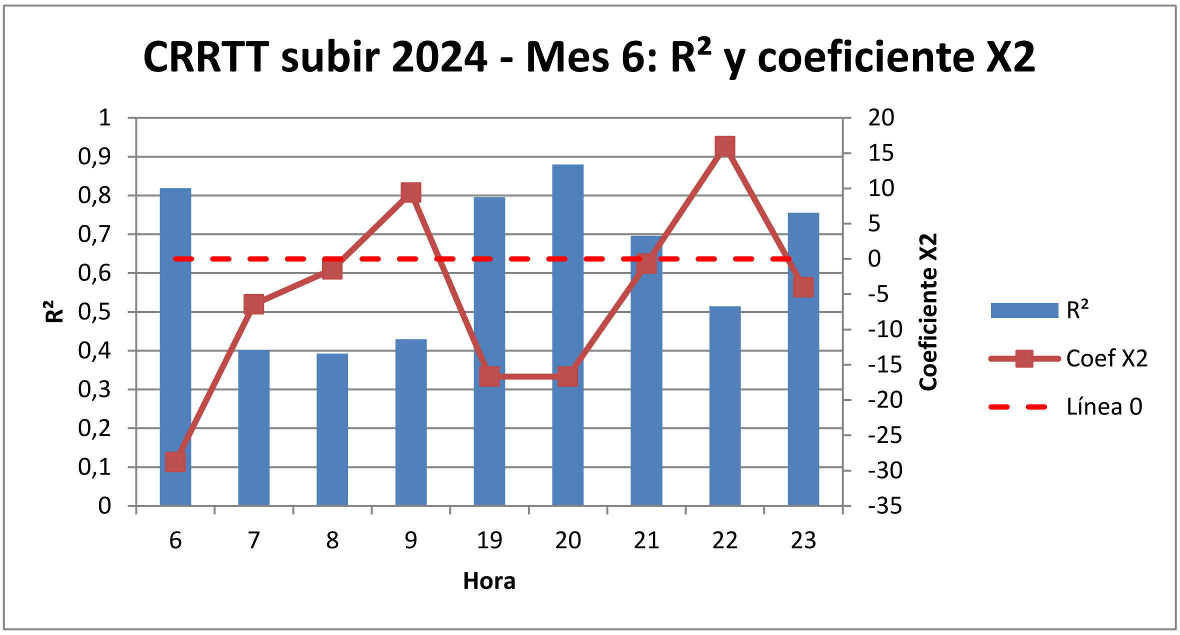


Figure 287: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time by hours and month 6

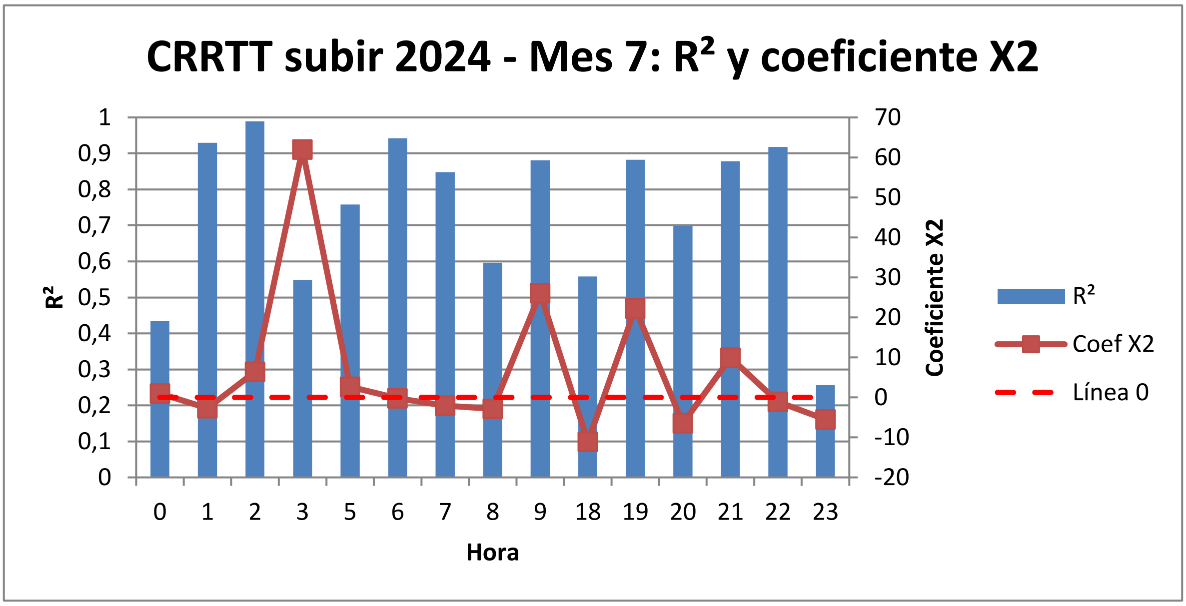


Figure 288: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time by hours and month 7

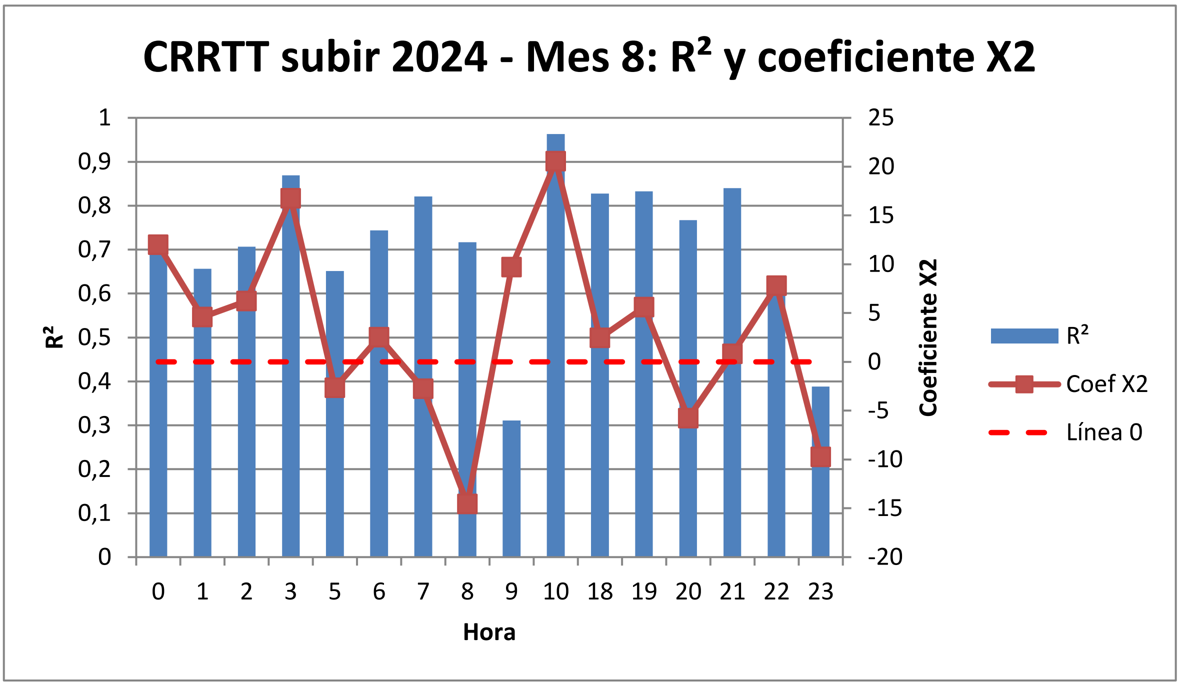


Figure 289: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time by hours and month 8

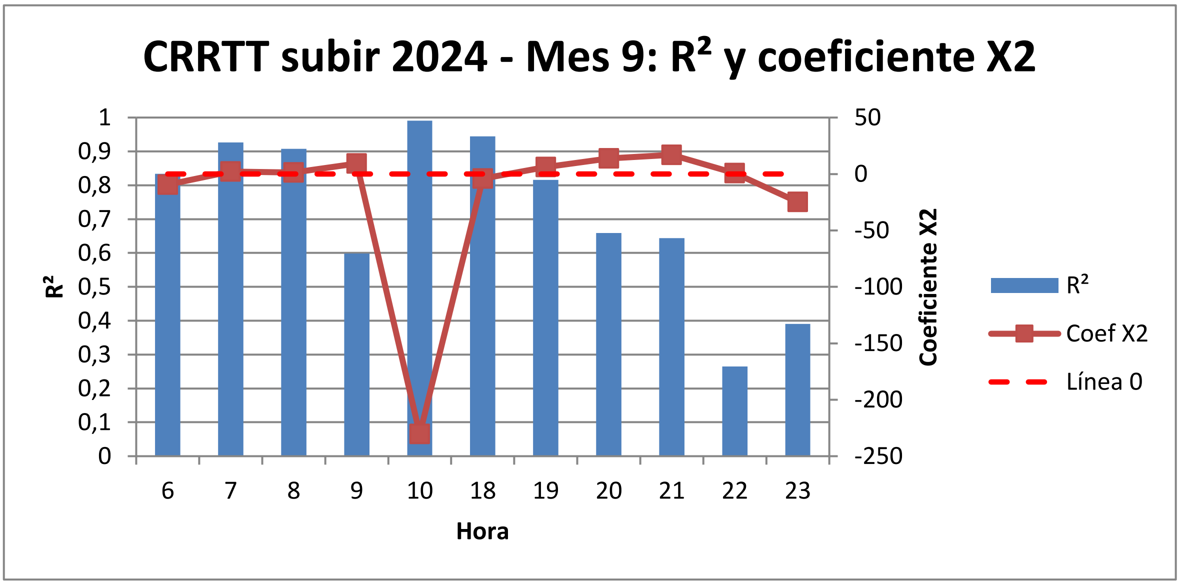


Figure 290: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time by hours and month 9

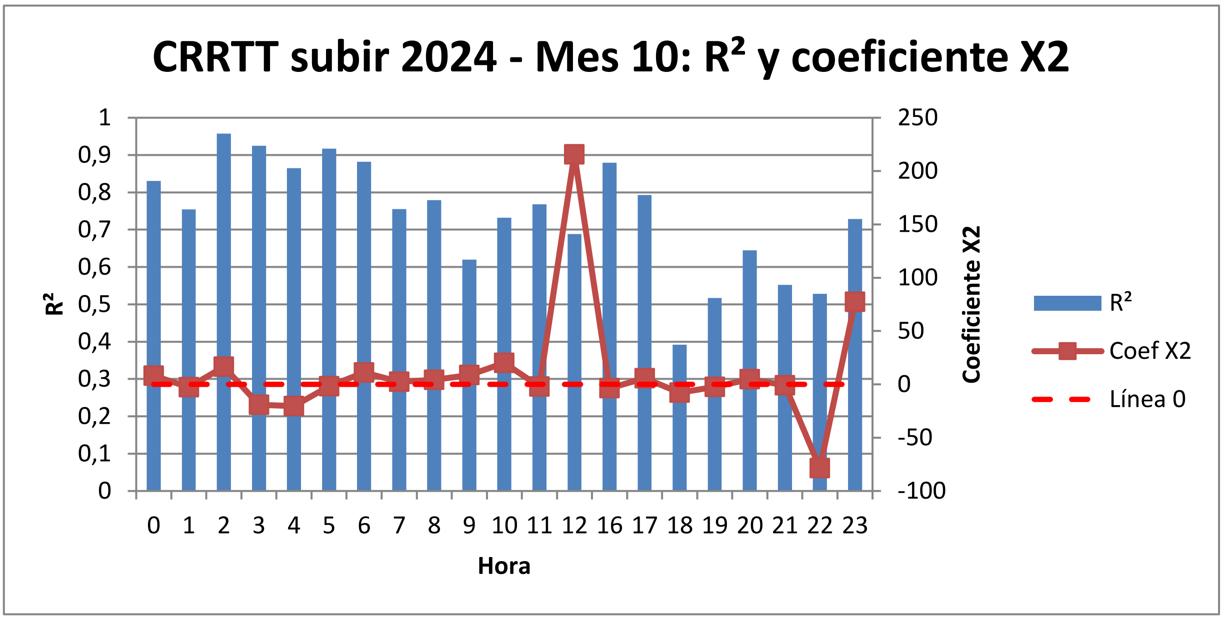


Figure 291: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time by hours and month 10

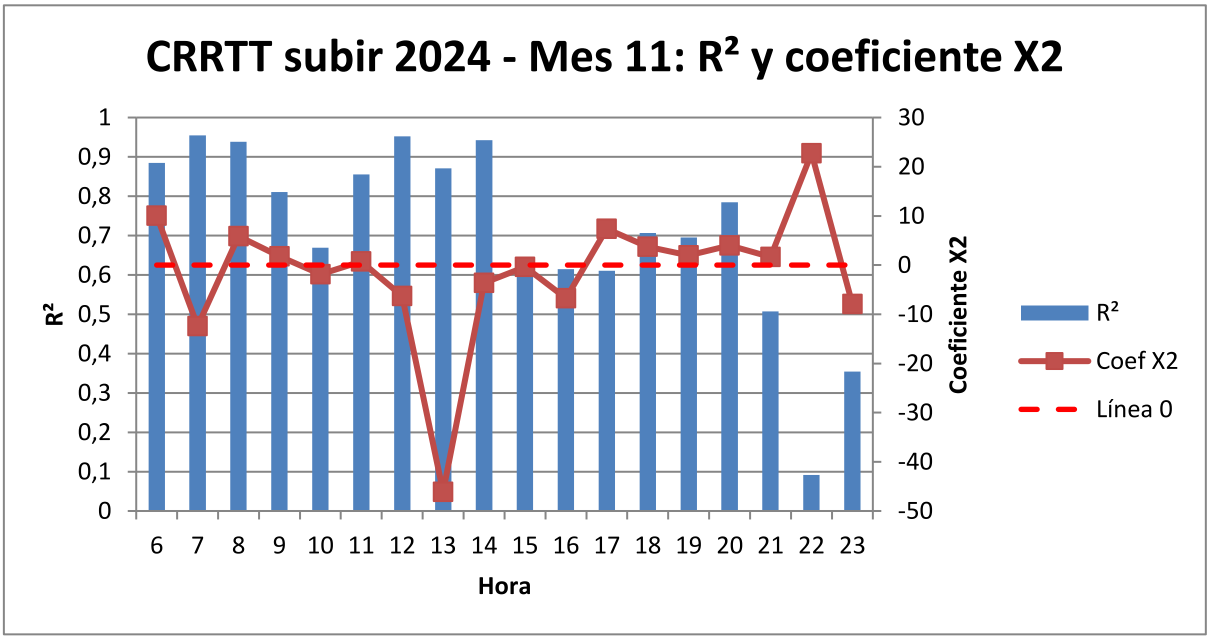


Figure 292: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time by hours and month 11

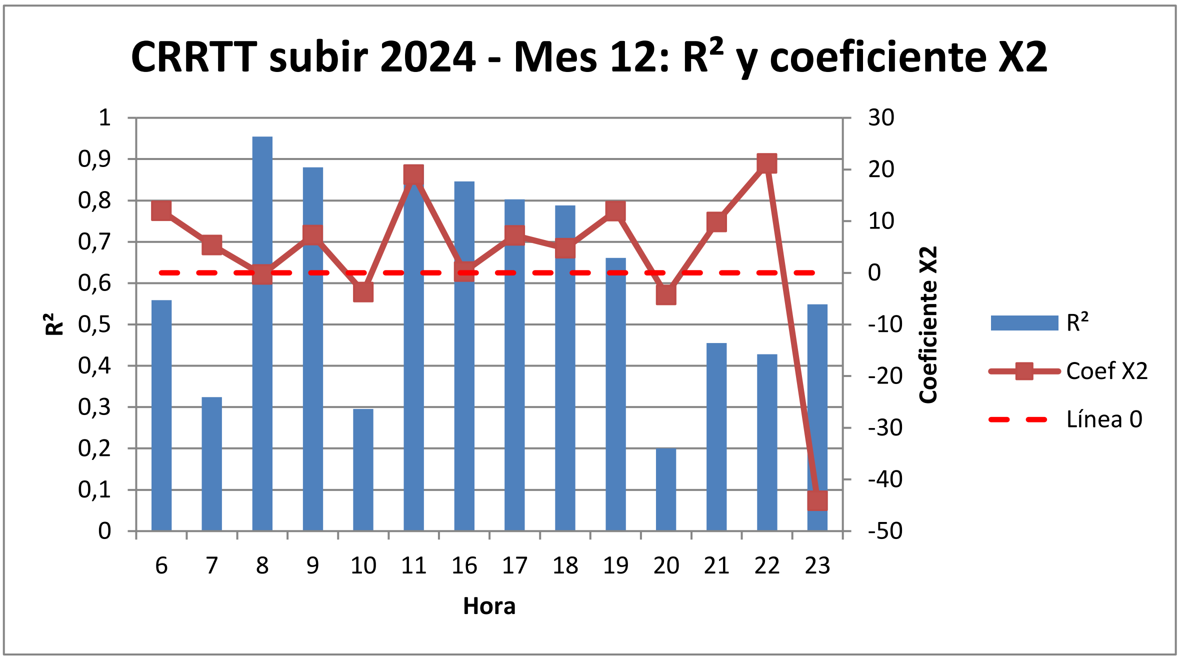


Figure 293: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time by hours and month 12

DOWNWARD 2024 REAL TIME

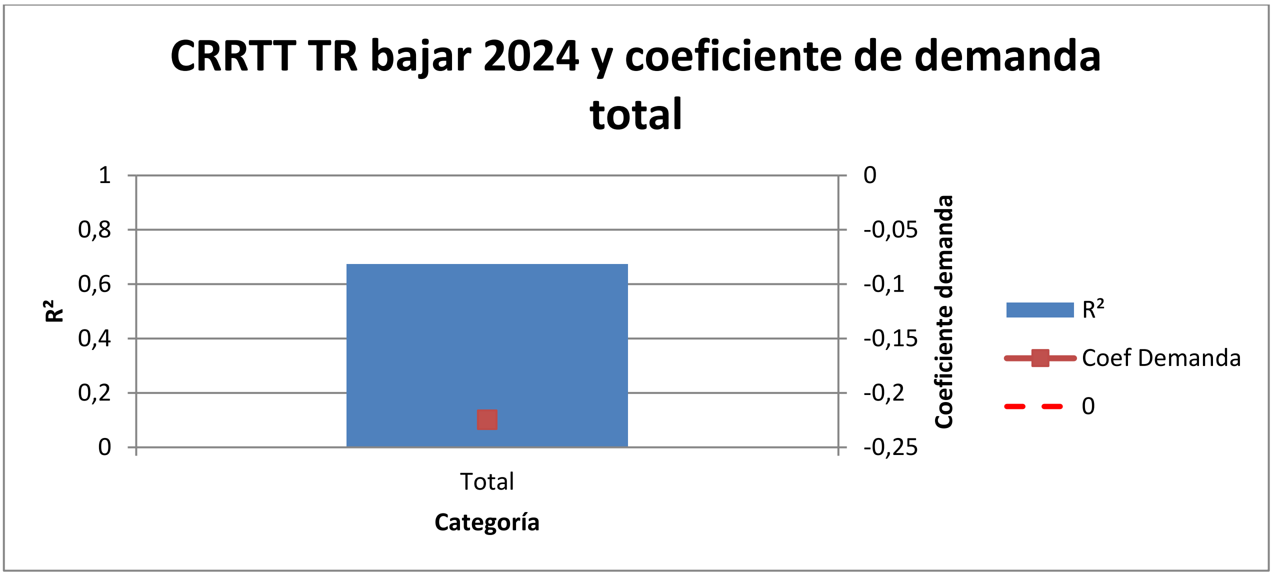


Figure 294: Downward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time

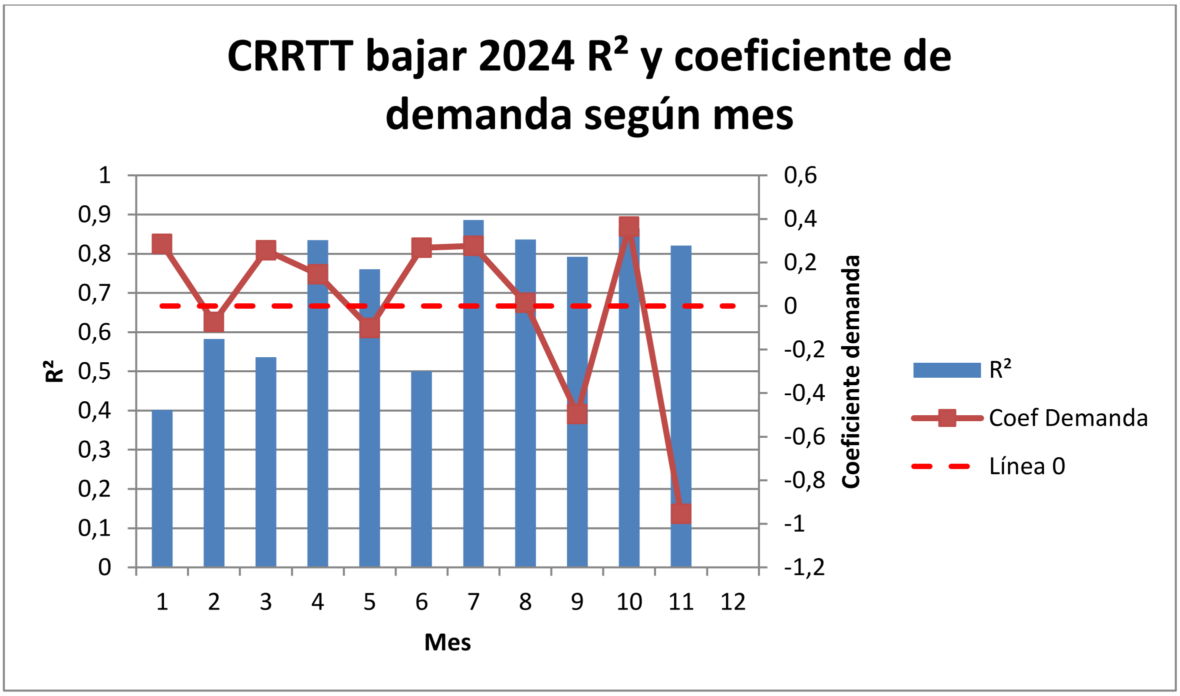


Figure 295: Downward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time by month

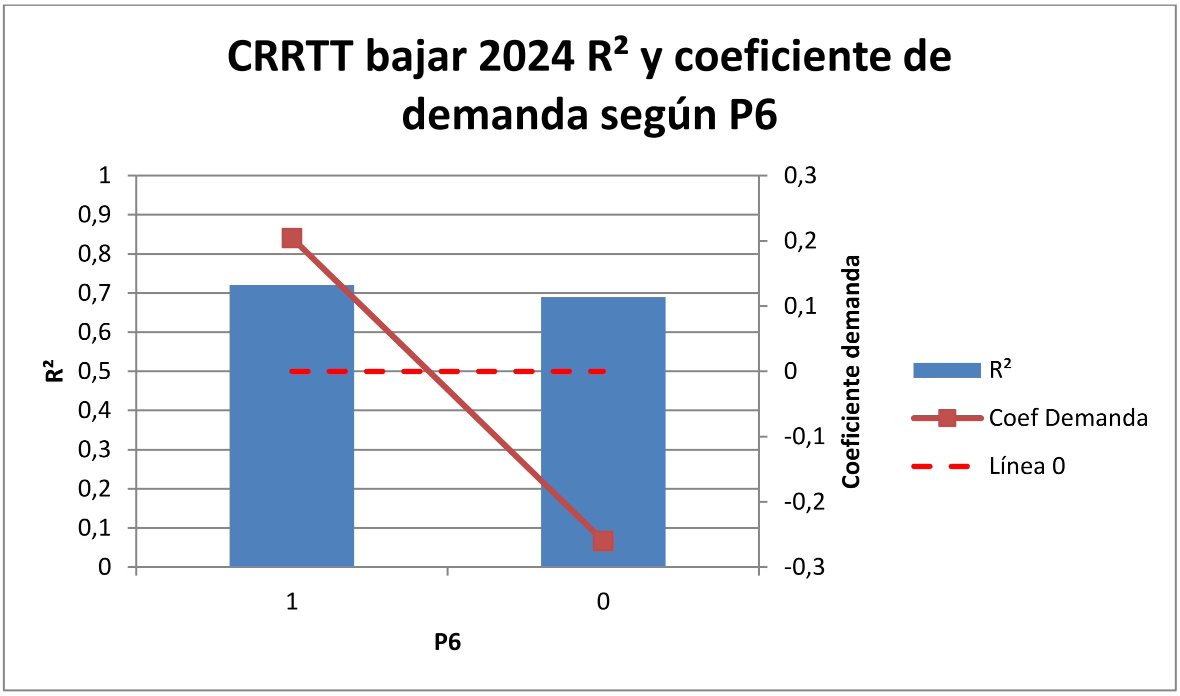


Figure 296: Downward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time by P6

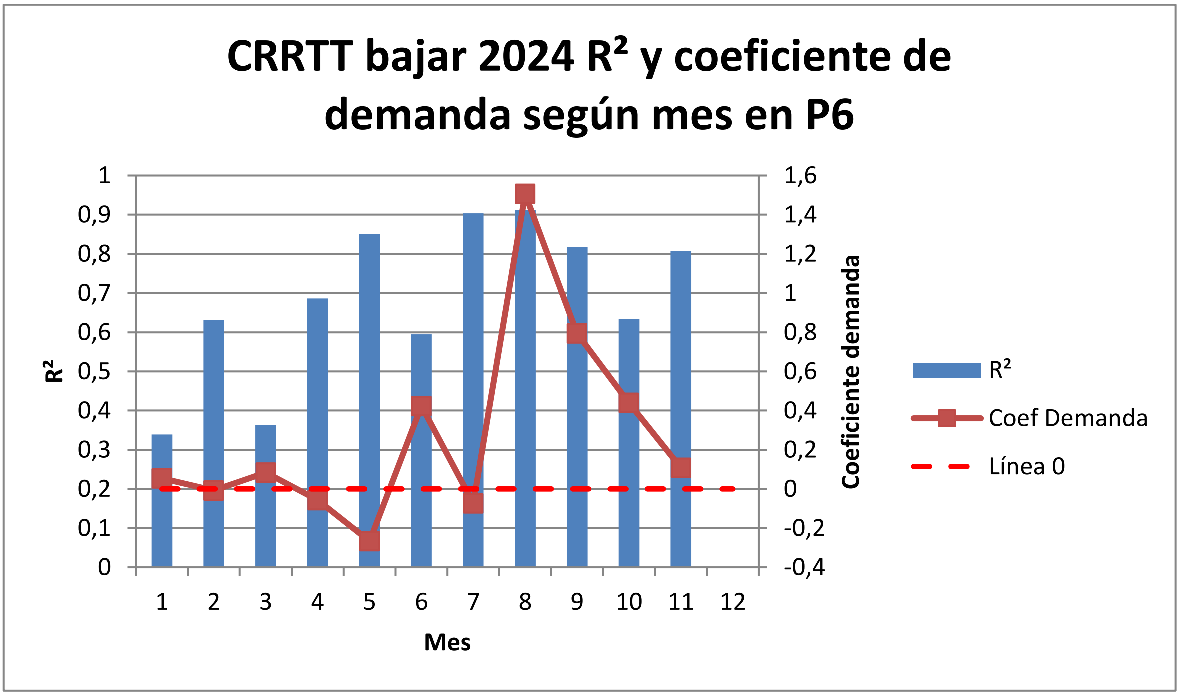


Figure 297: Downward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time by month in P6

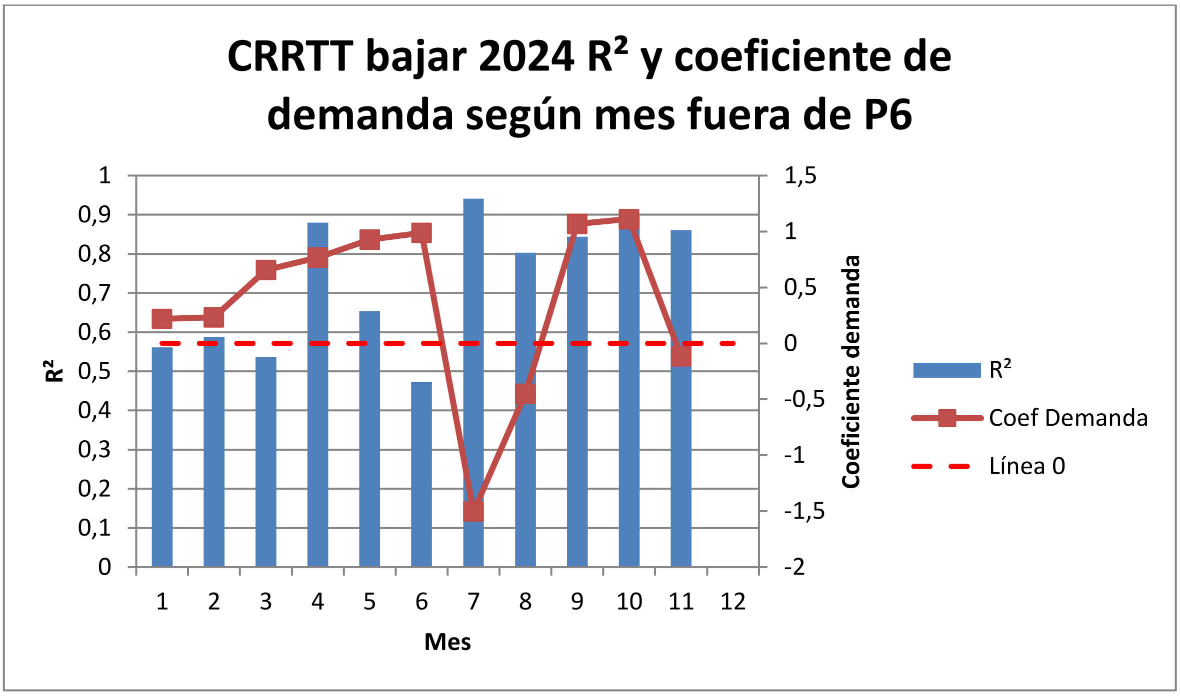


Figure 298: Downward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2024 in real time by month outside P6

2025 PDBF

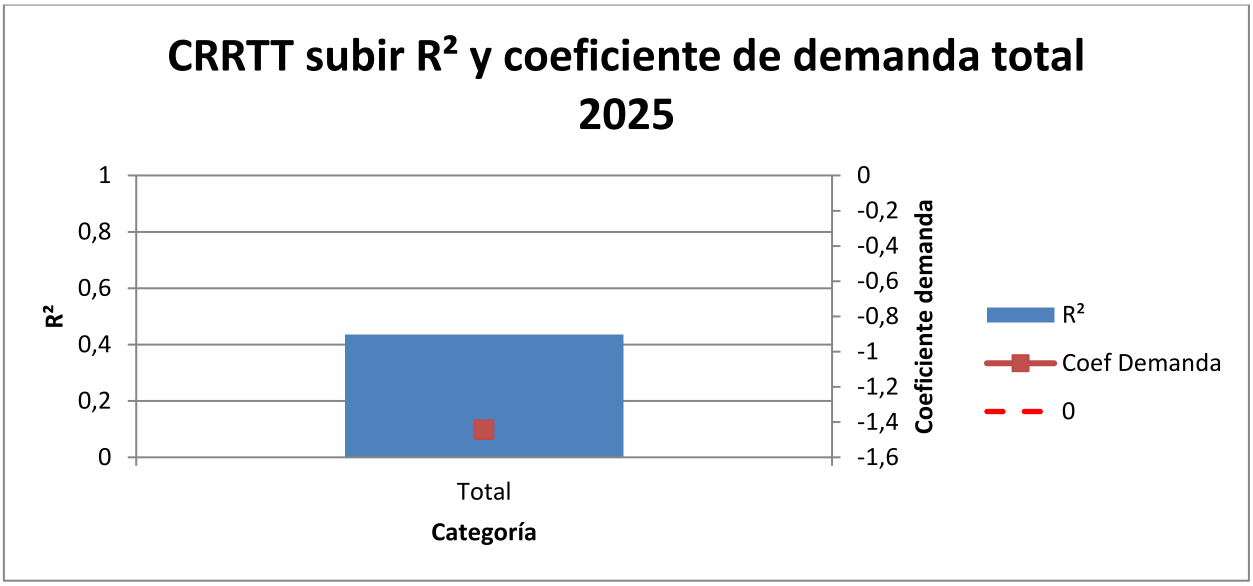


Figure 299: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2025 in PDBF

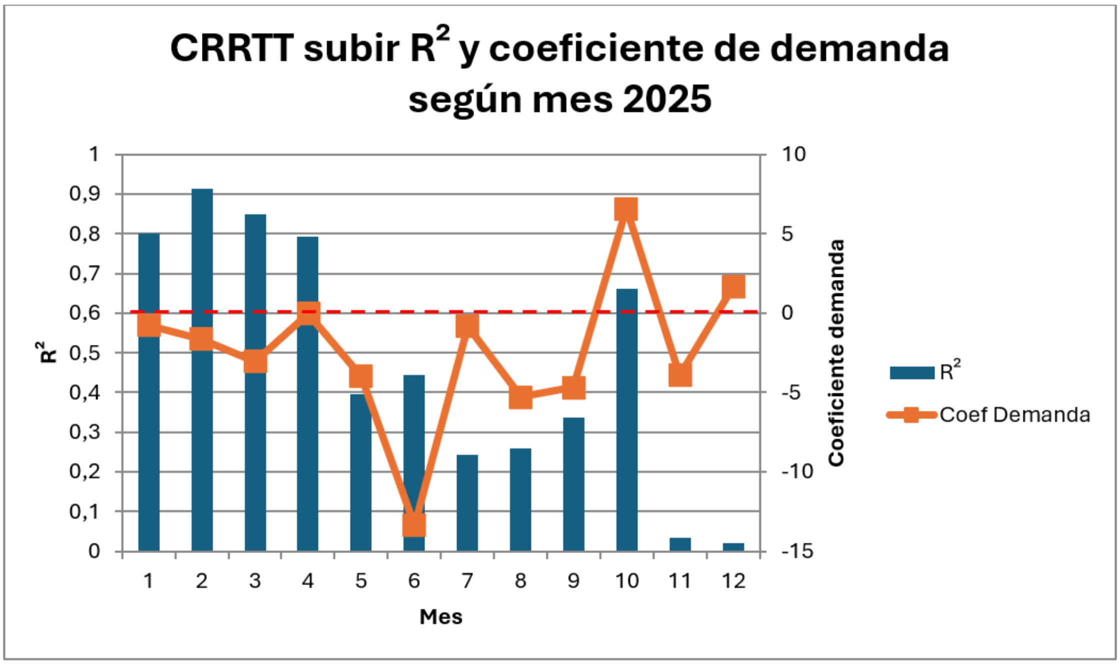


Figure 300: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2025 in PDBF by month

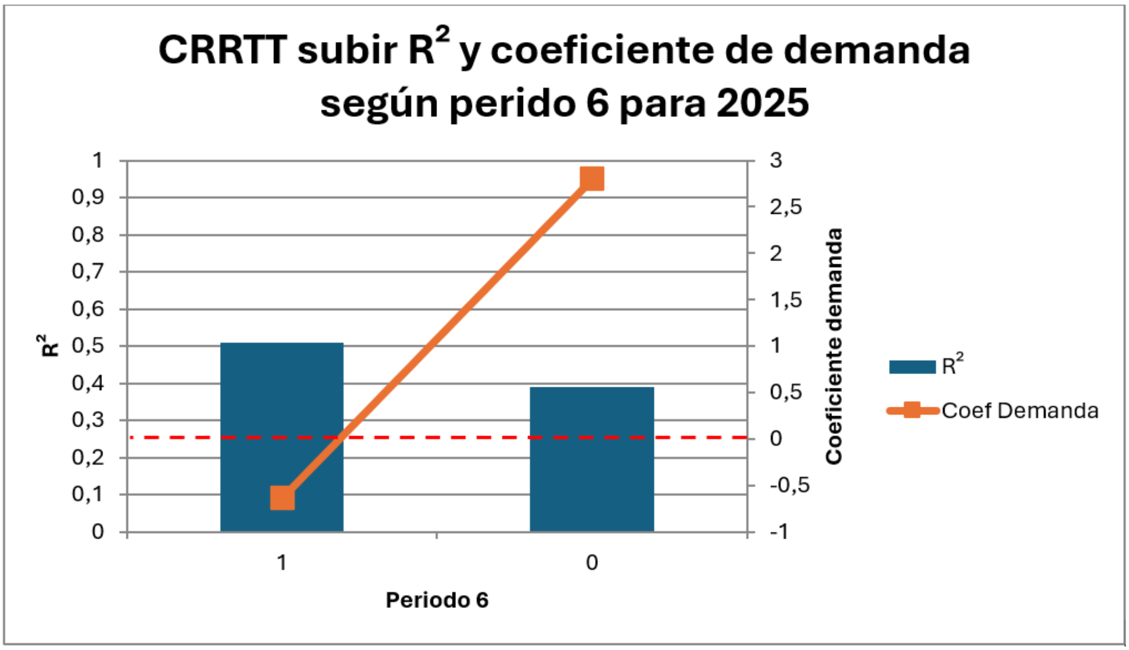


Figure 301: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2025 in PDBF by P6

UPWARD 2025 REAL TIME

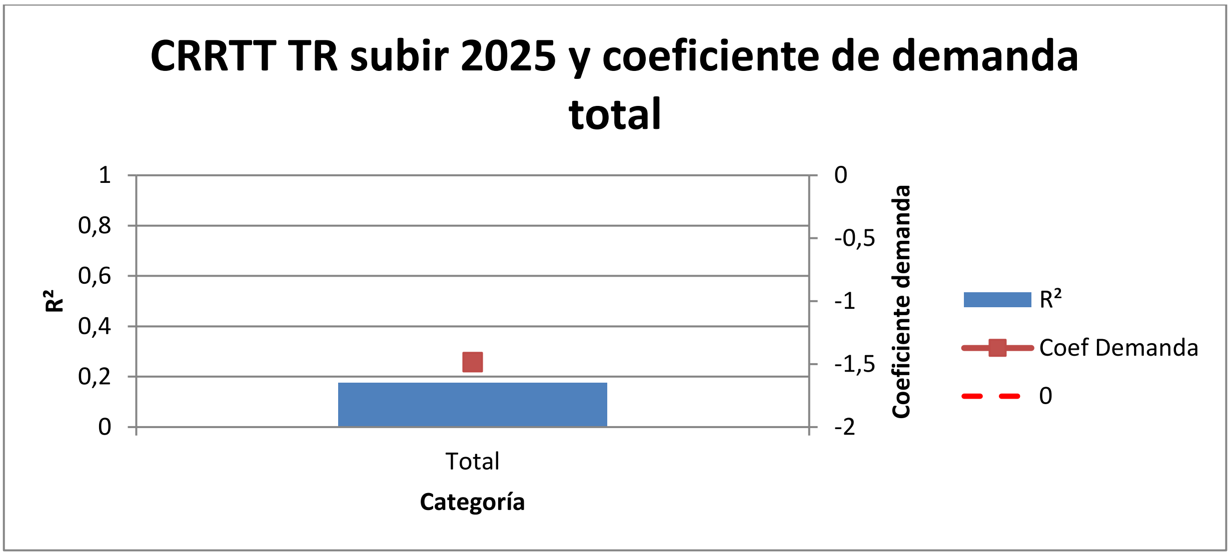


Figure 302: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2025 in real time

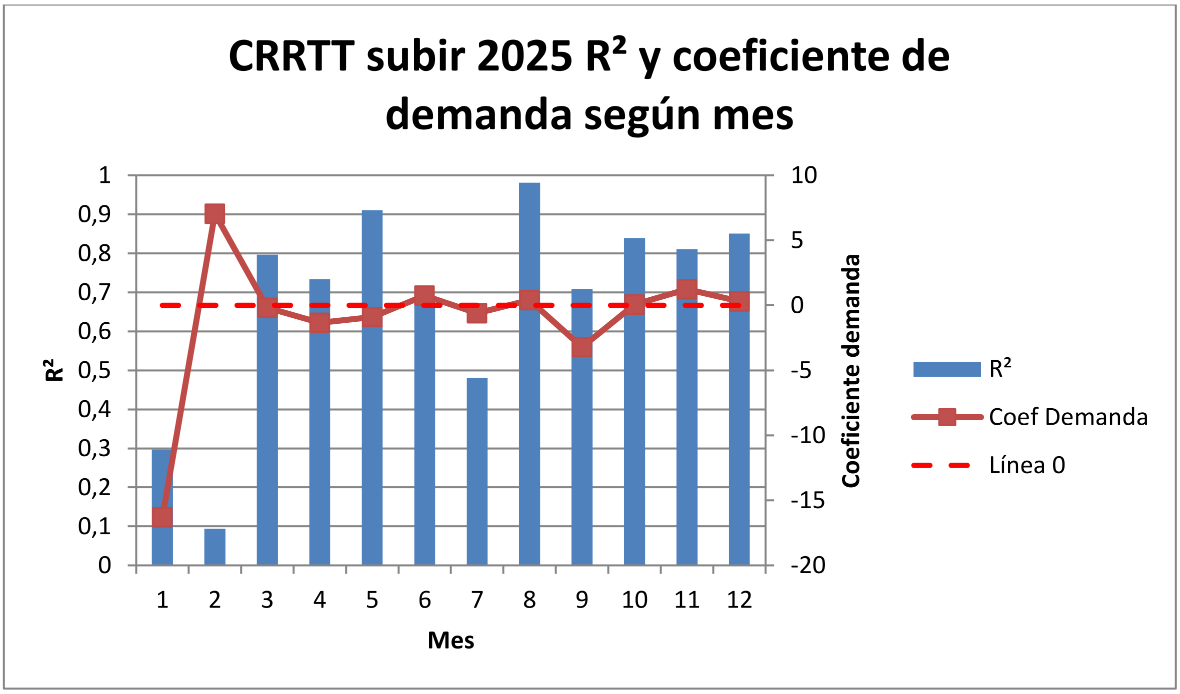


Figure 303: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2025 in real time by month

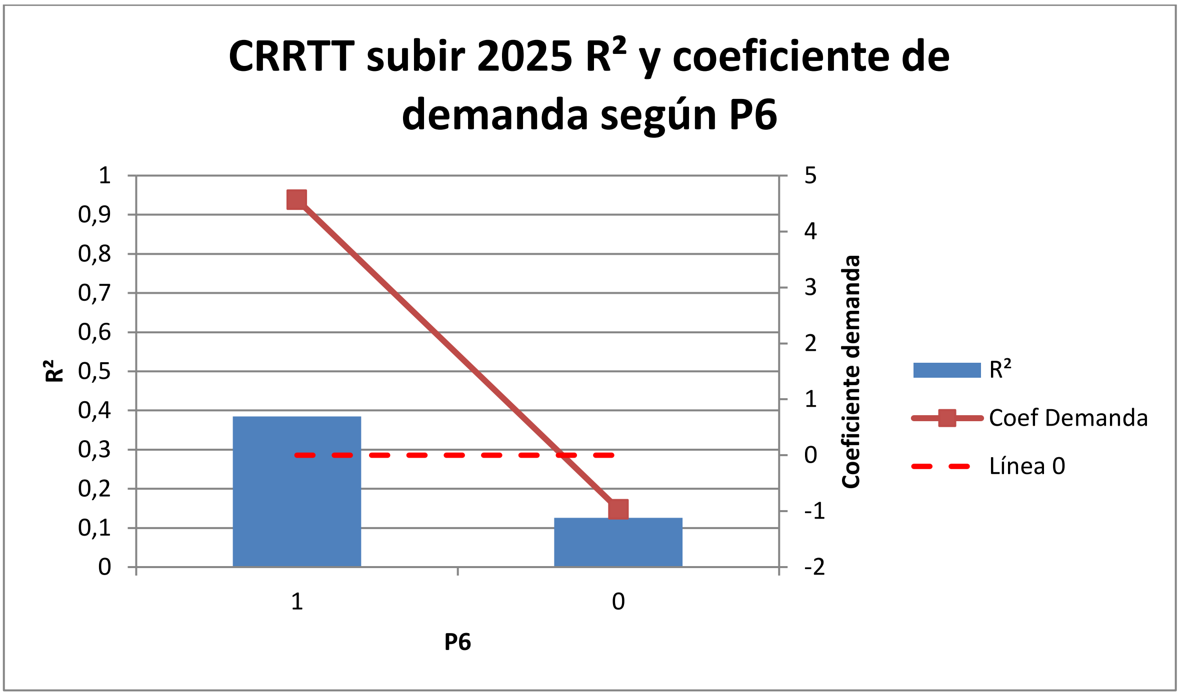


Figure 304: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2025 in real time in P6

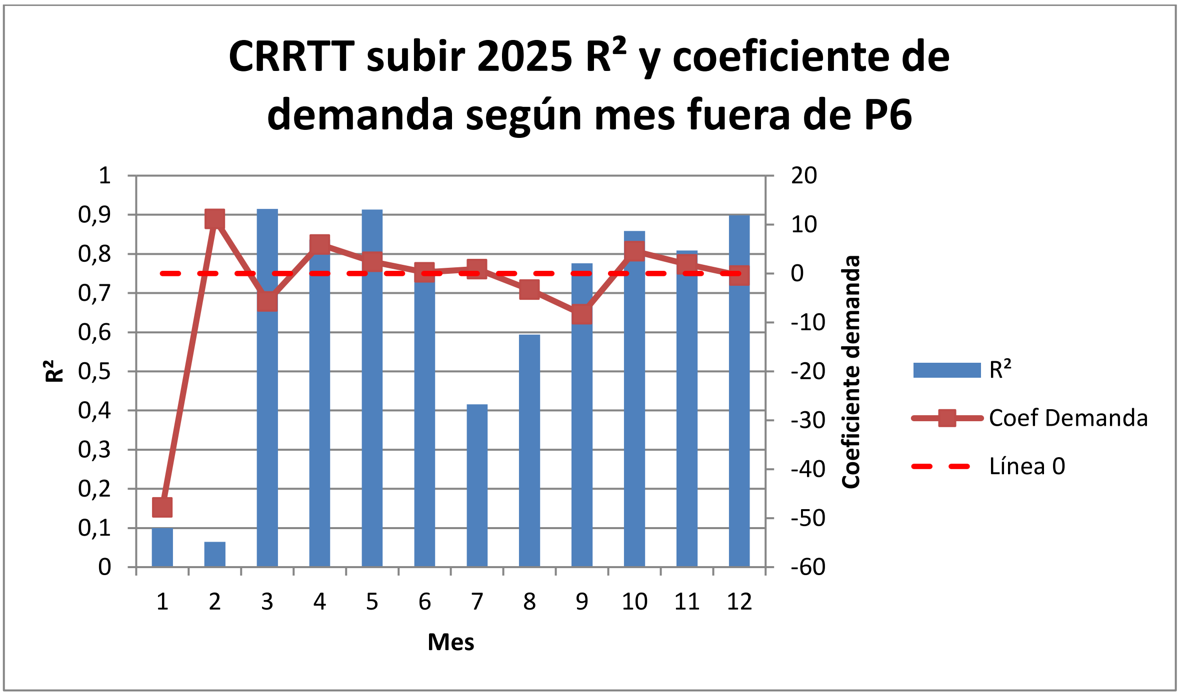


Figure 305: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2025 in real time by month outside P6

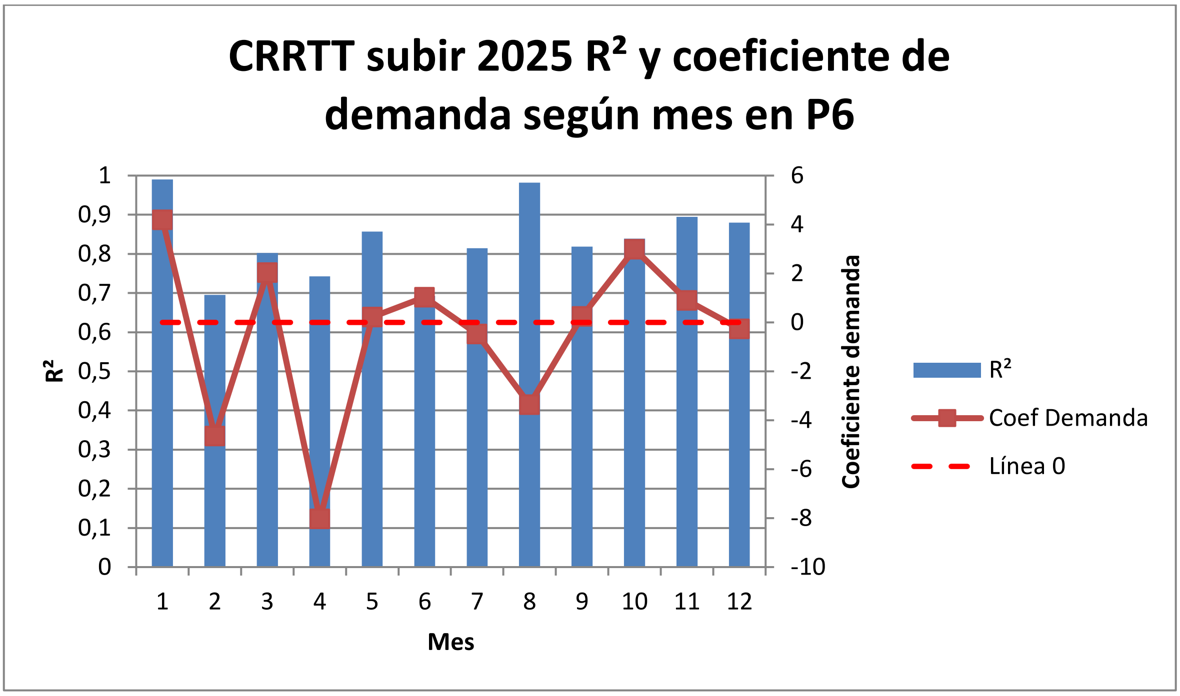


Figure 306: Upward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2025 in real time by month in P6

DOWNWARD 2025 REAL TIME

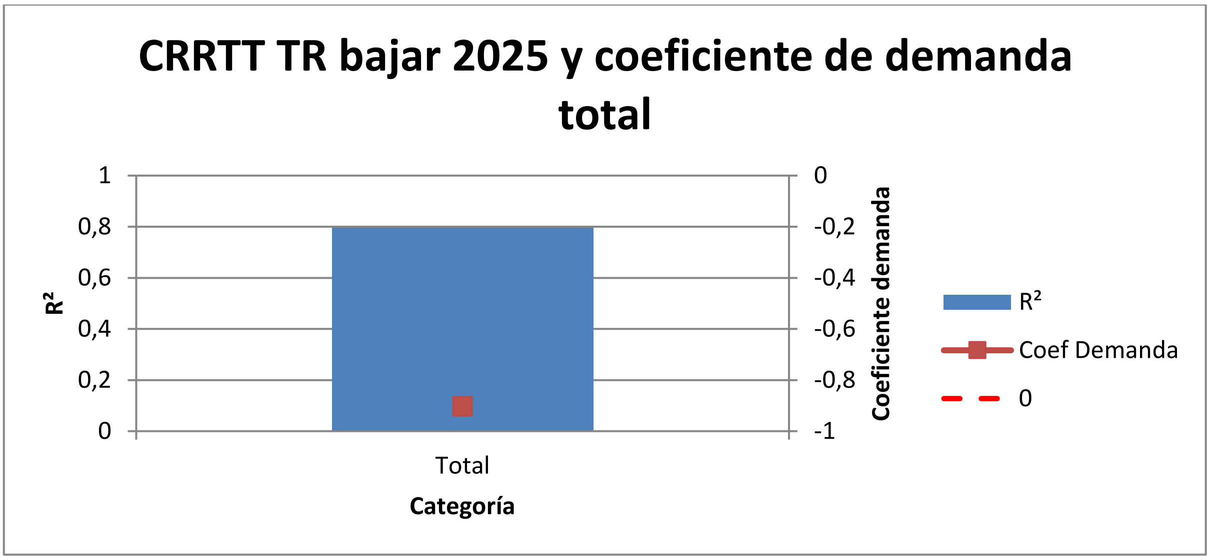


Figure 307: Downward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2025 in real time

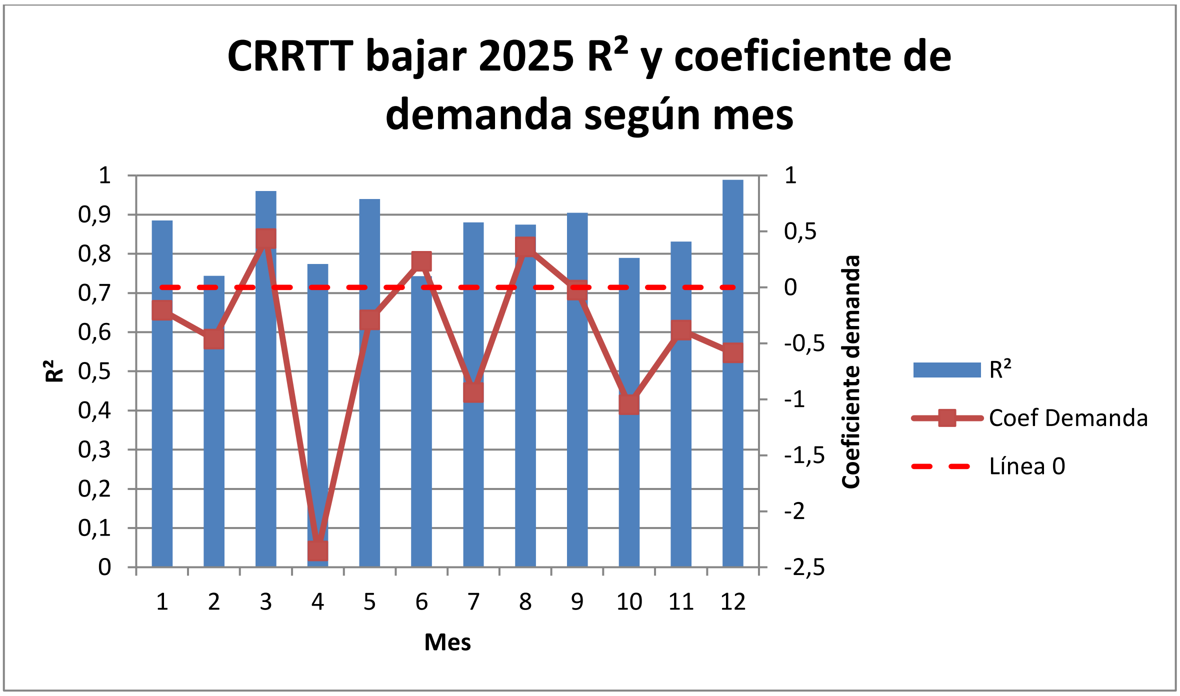


Figure 308: Downward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2025 in real time by month

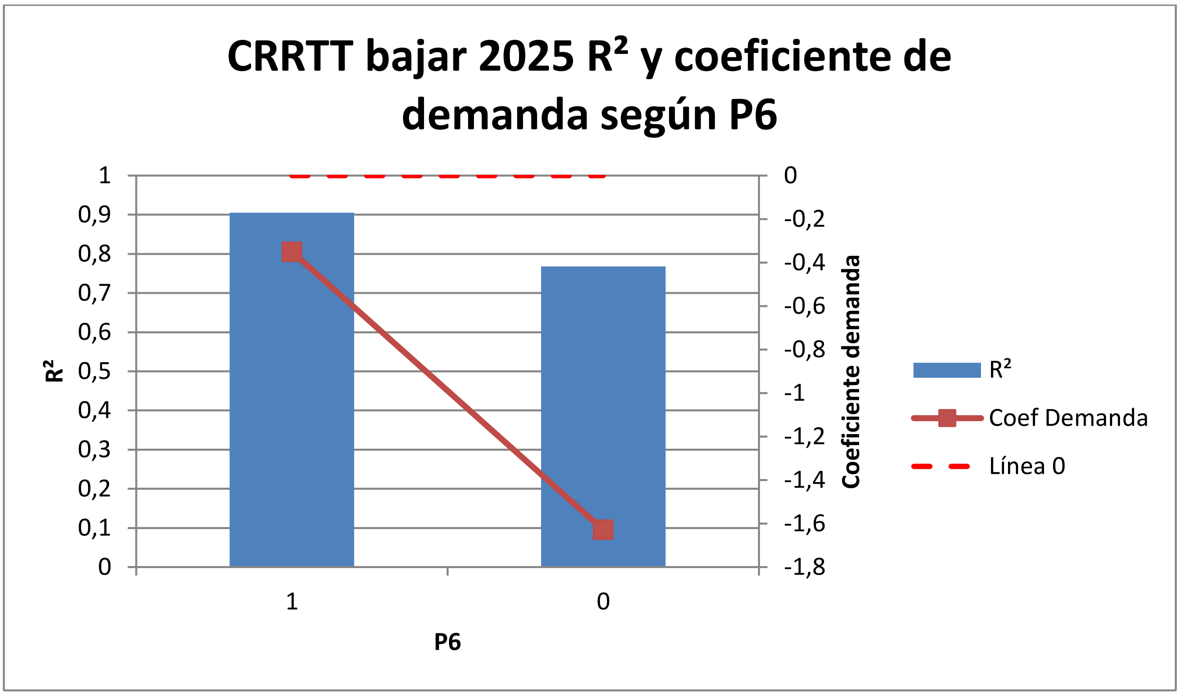


Figure 309 : Downward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2025 in real time in P6

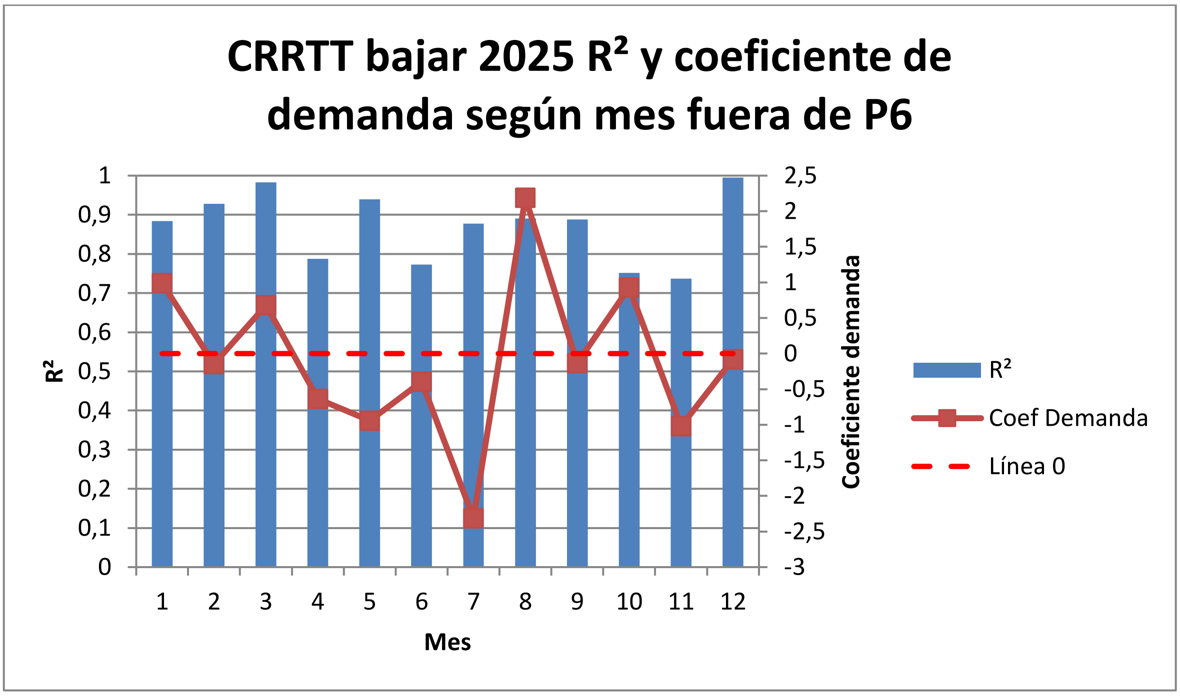


Figure 310: Downward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2025 in real time by month outside P6

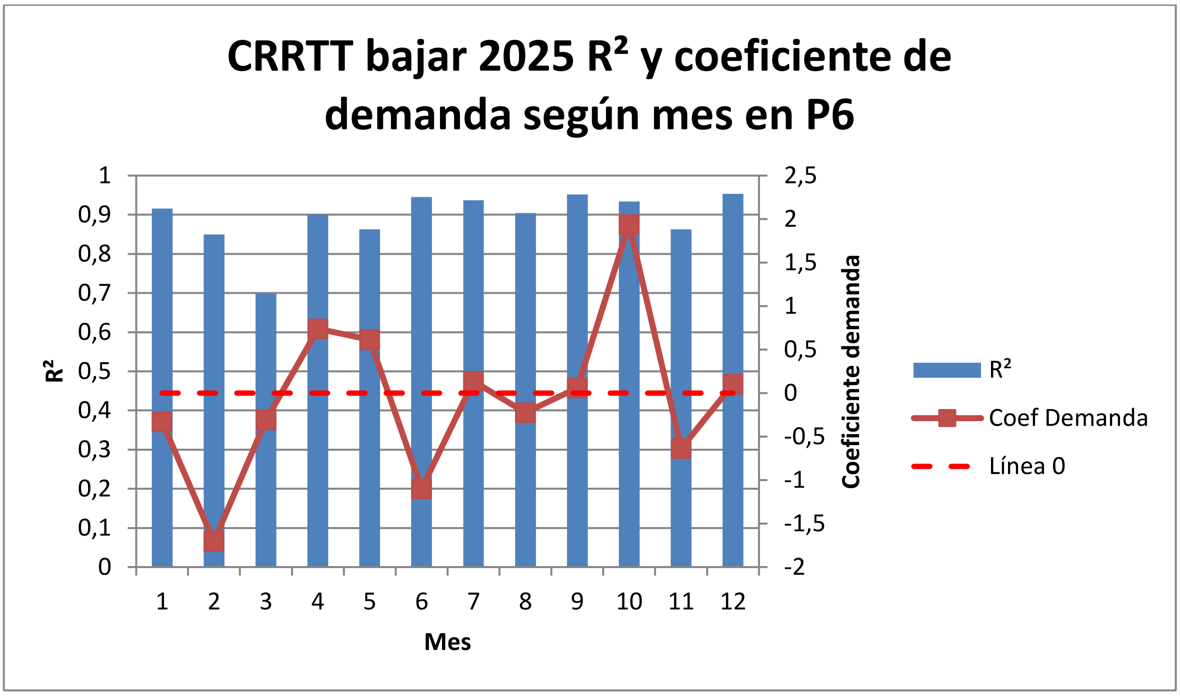


Figure 311: Downward multiple regression model of the annual CRRTT and the demand coefficient related to it, for the year 2025 in real time by month in P6

GLOBAL MULTIPLE PDBF

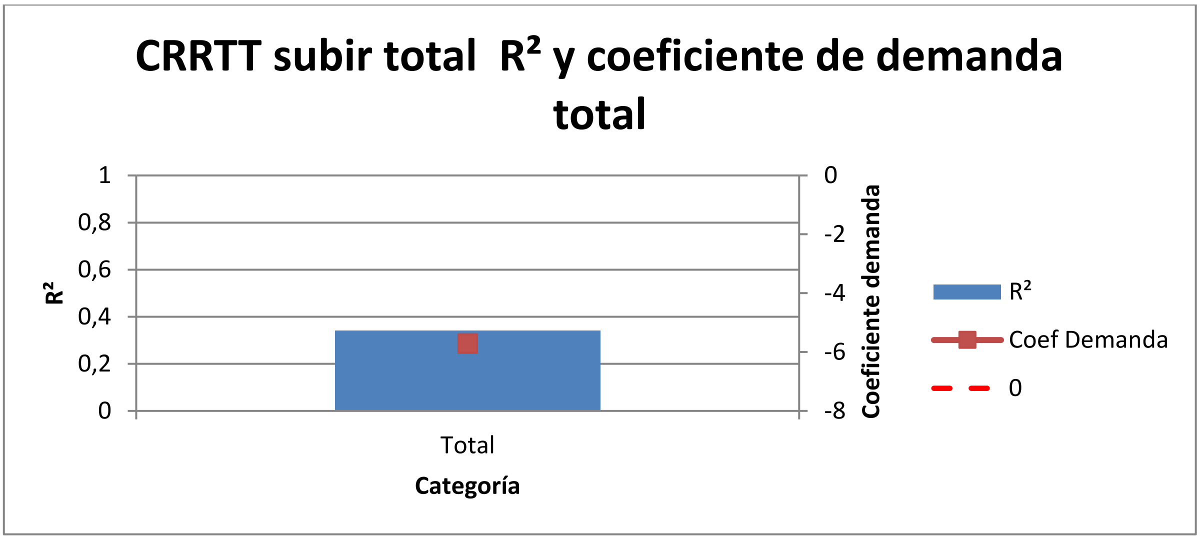


Figure 312: Total upward multiple regression model of the annual CRRTT and the demand coefficient related to it in PDBF

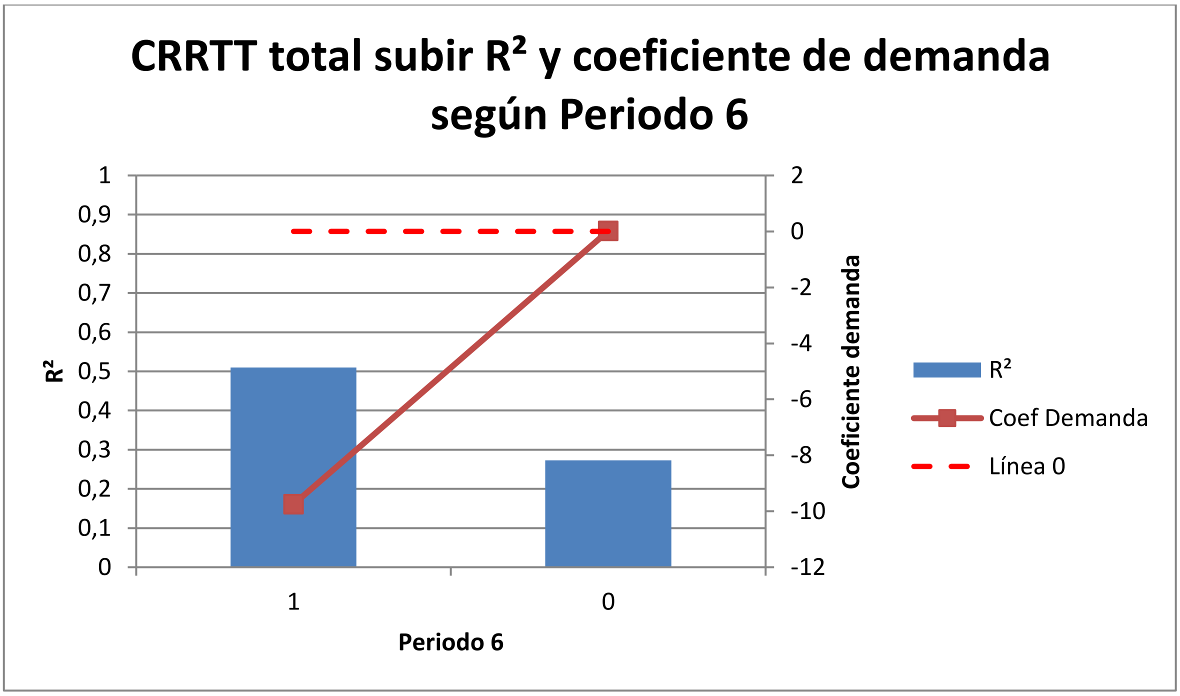


Figure 313: Total upward multiple regression model of the annual CRRTT and the demand coefficient related to it in PDBF by P6

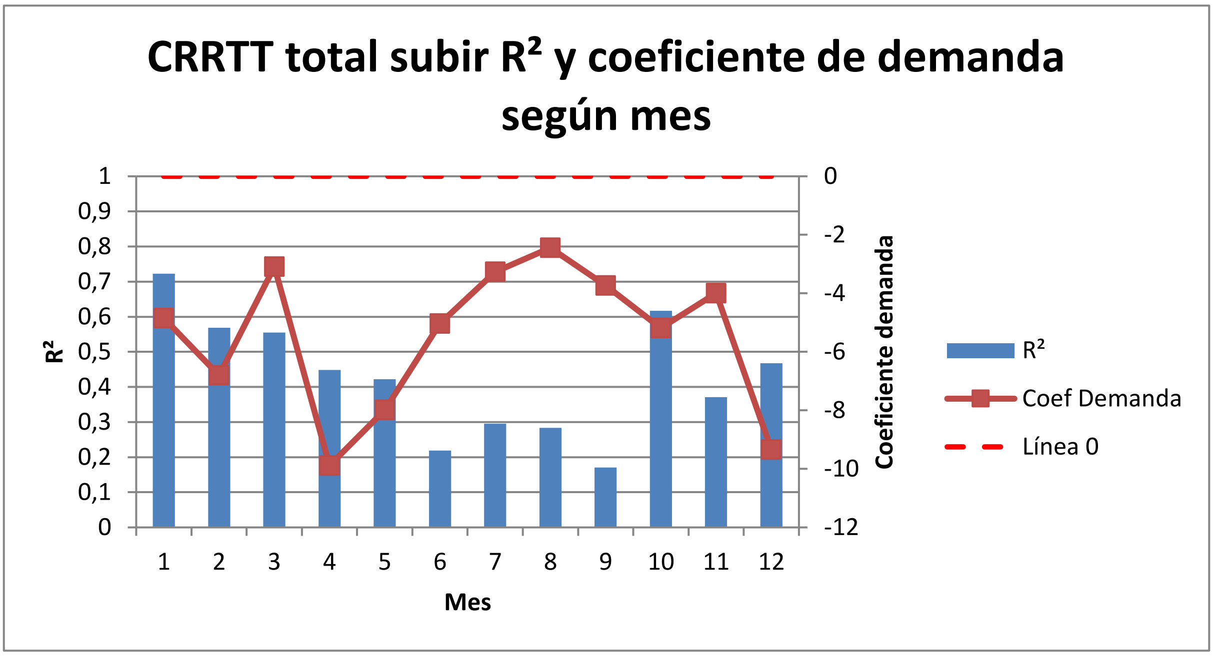


Figure 314: Total upward multiple regression model of the annual CRRTT and the demand coefficient related to it in PDBF by month

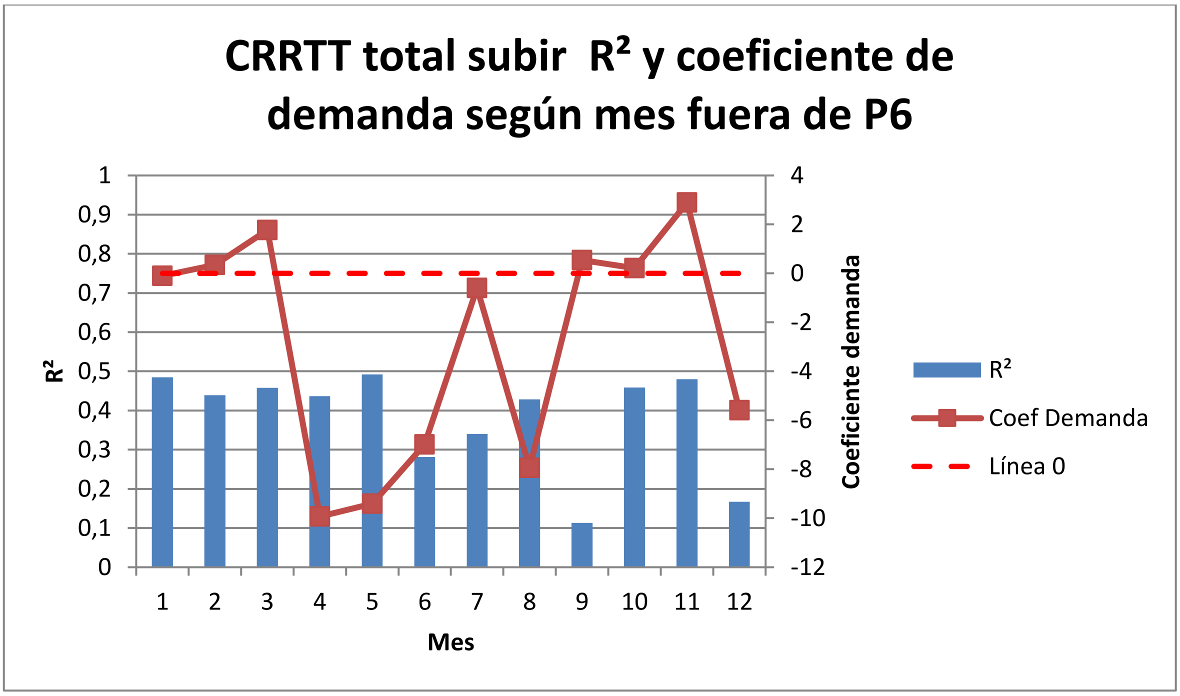


Figure 315: Total upward multiple regression model of the annual CRRTT and the demand coefficient related to it in PDBF by month outside P6

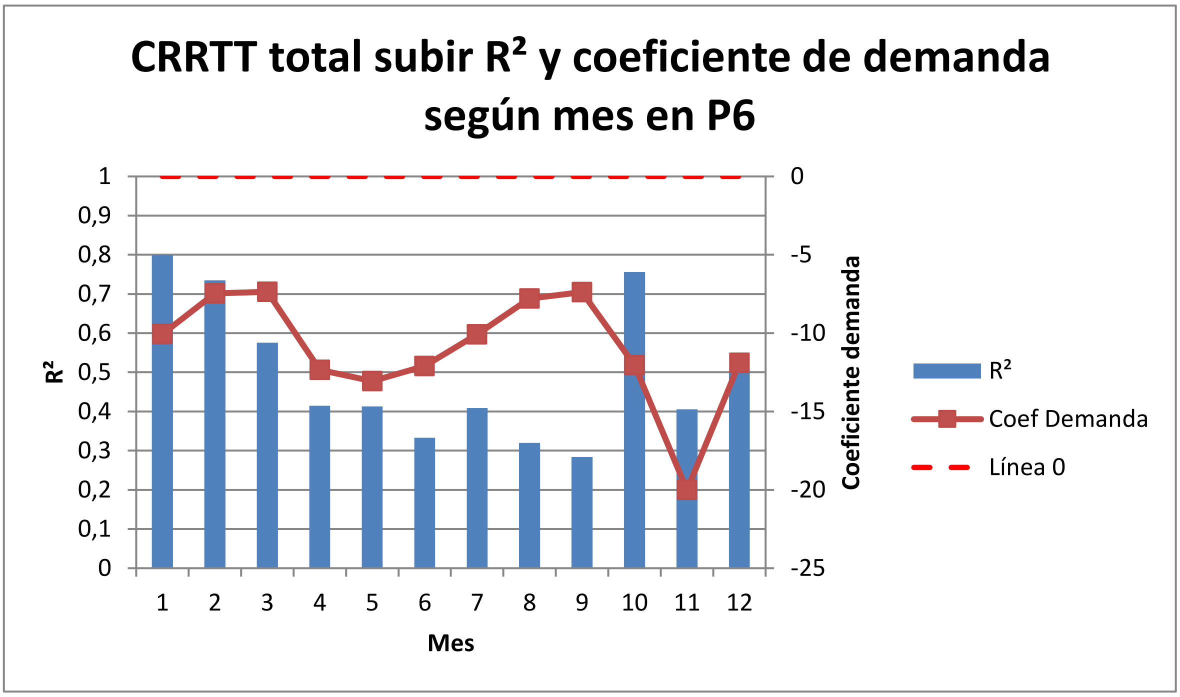


Figure 316: Total upward multiple regression model of the annual CRRTT and the demand coefficient related to it in PDBF by month in P6

GLOBAL MULTIPLE RT

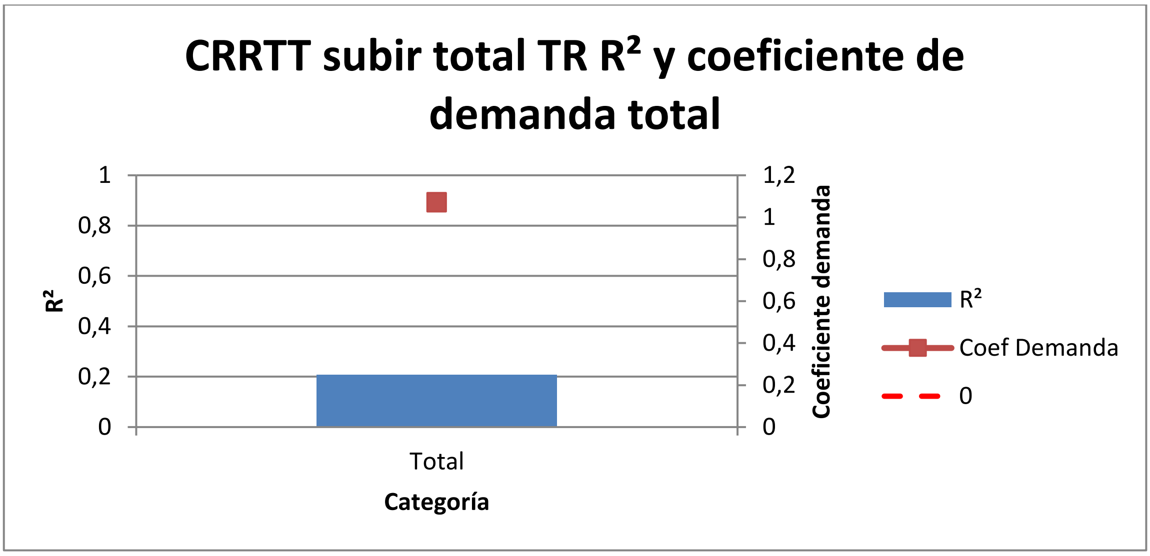


Figure 317: Total upward multiple regression model of the annual CRRTT and the demand coefficient related to it in real time

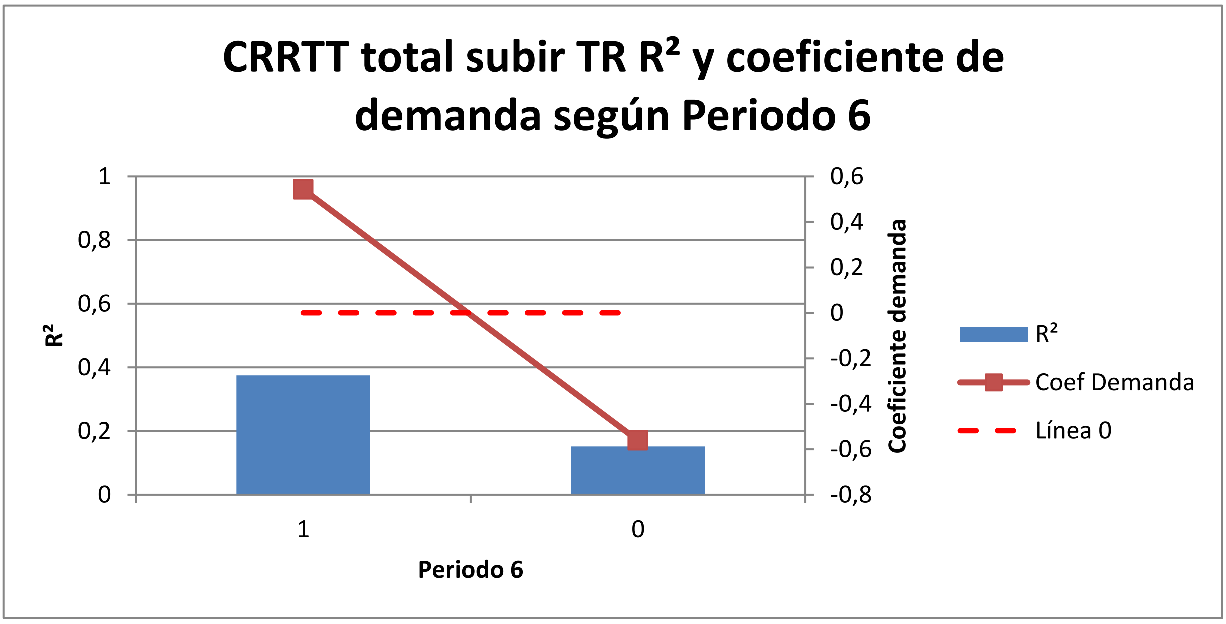


Figure 318: Total upward multiple regression model of the annual CRRTT and the demand coefficient related to it in real time by P6

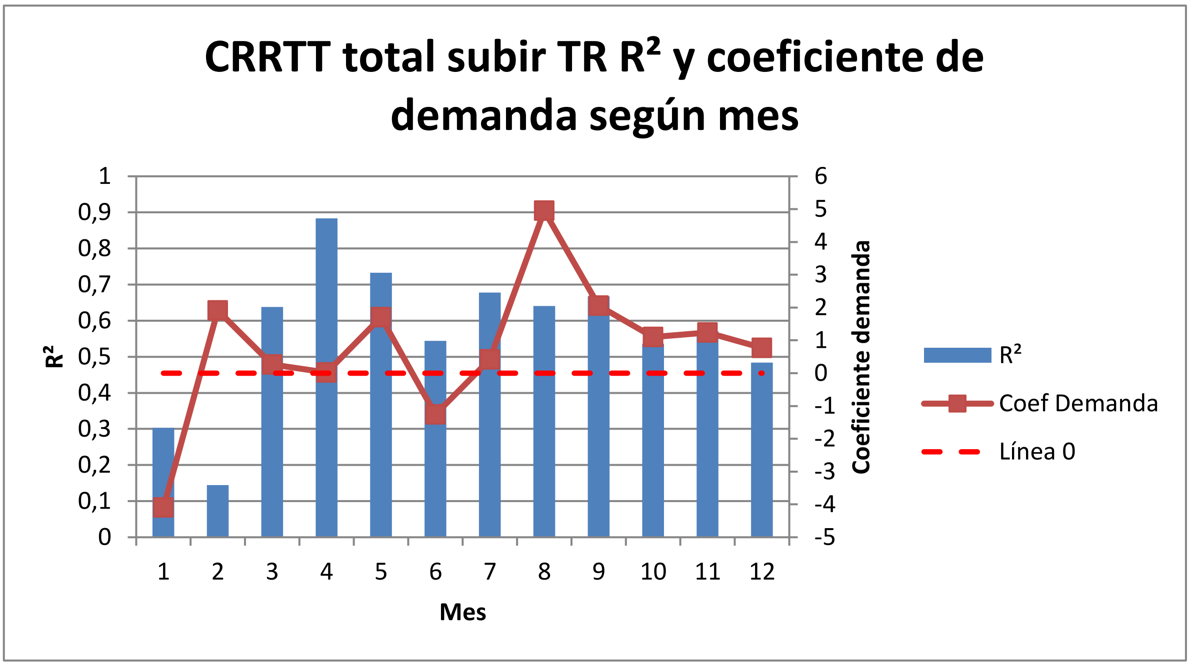


Figure 319: Total upward multiple regression model of the annual CRRTT and the demand coefficient related to it in real time by month

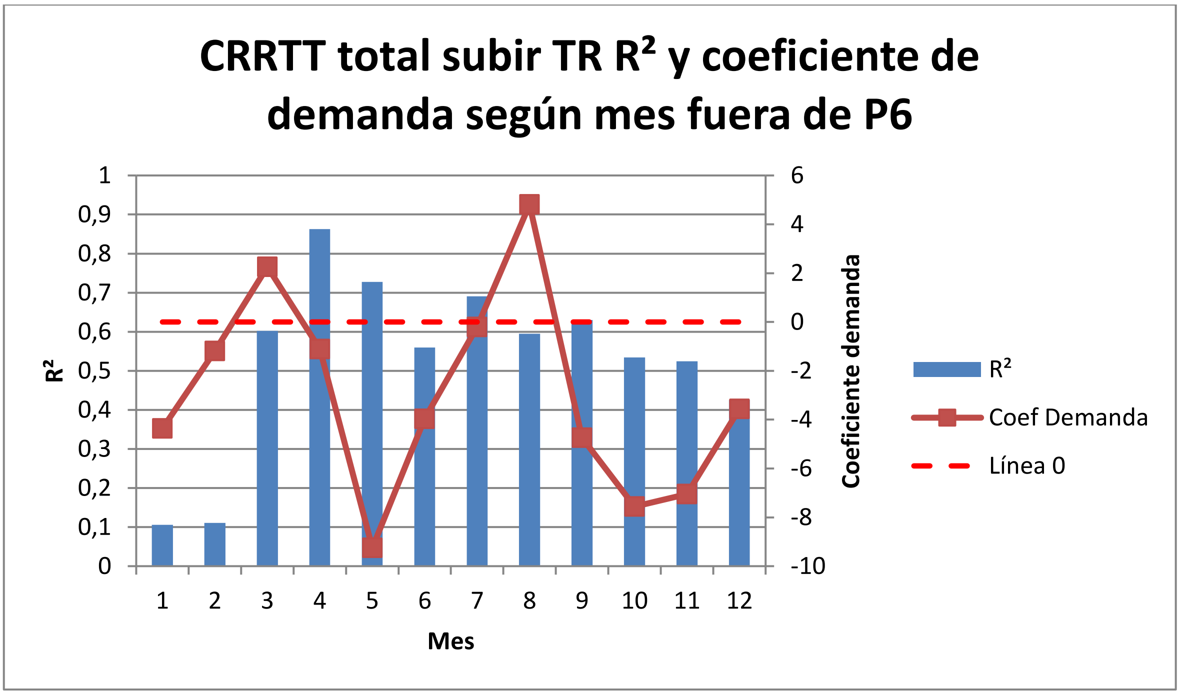


Figure 320: Total upward multiple regression model of the annual CRRTT and the demand coefficient related to it in real time by month outside P6

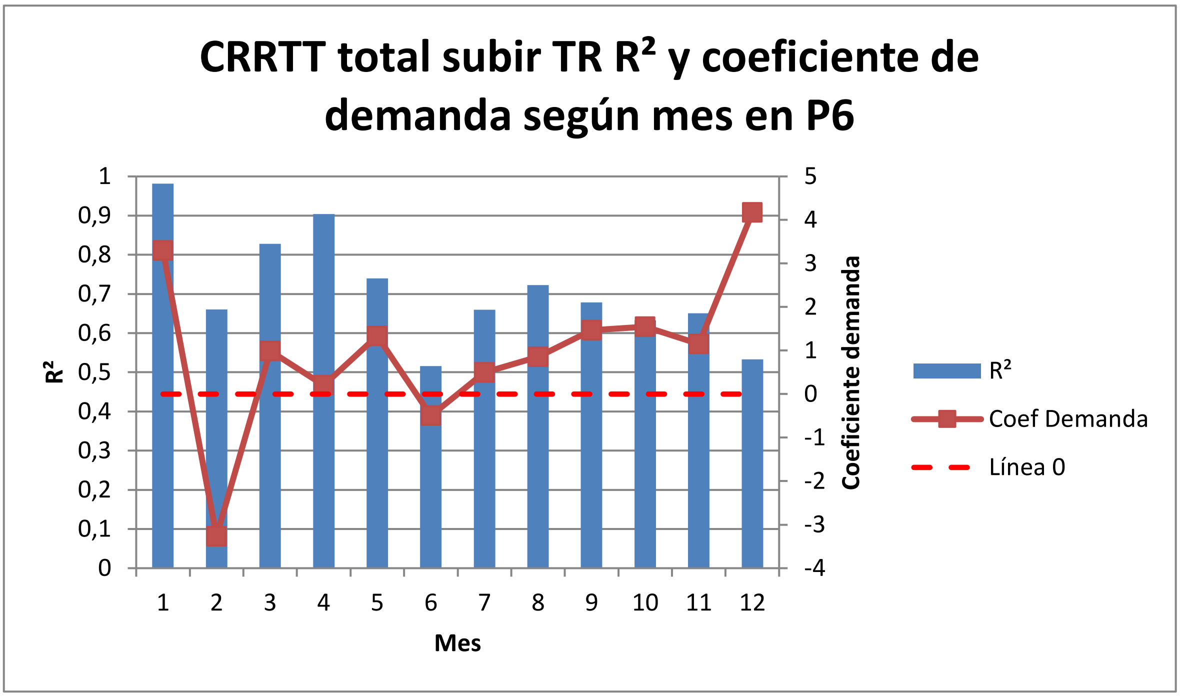


Figure 321: Total upward multiple regression model of the annual CRRTT and the demand coefficient related to it in real time by month in P6

GLOBAL SIMPLE PDBF

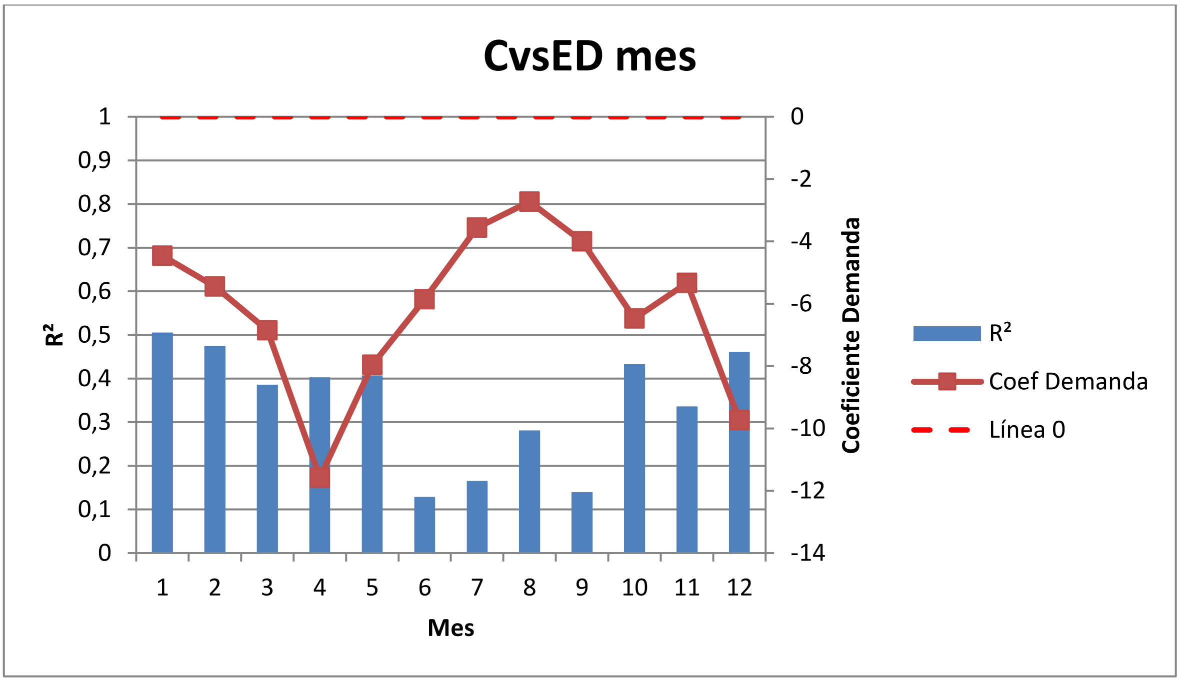


Figure 322: Total upward simple regression model CRRTT vs Energy and demand by month in PDBF

GLOBAL SIMPLE RT

RT	R2	X COEFFICINET
ERRTTvsD	0,25	0,095
PRTvsERRTT	-8,2E-06	-0,02214
PRTvsD	0,000224	0,010701
PRTvsPMD	0,0023	2,87
CRRTTvsERRTT	0,23	150,042

CRRTTvsD	0,064	15,082
CRRTTvsPRT	0,040	18,46
CRRTTvsPMD	0,029	931,43

Table 43: Summary of R2 and X-coefficient from simple regression models. Source: Own elaboration.

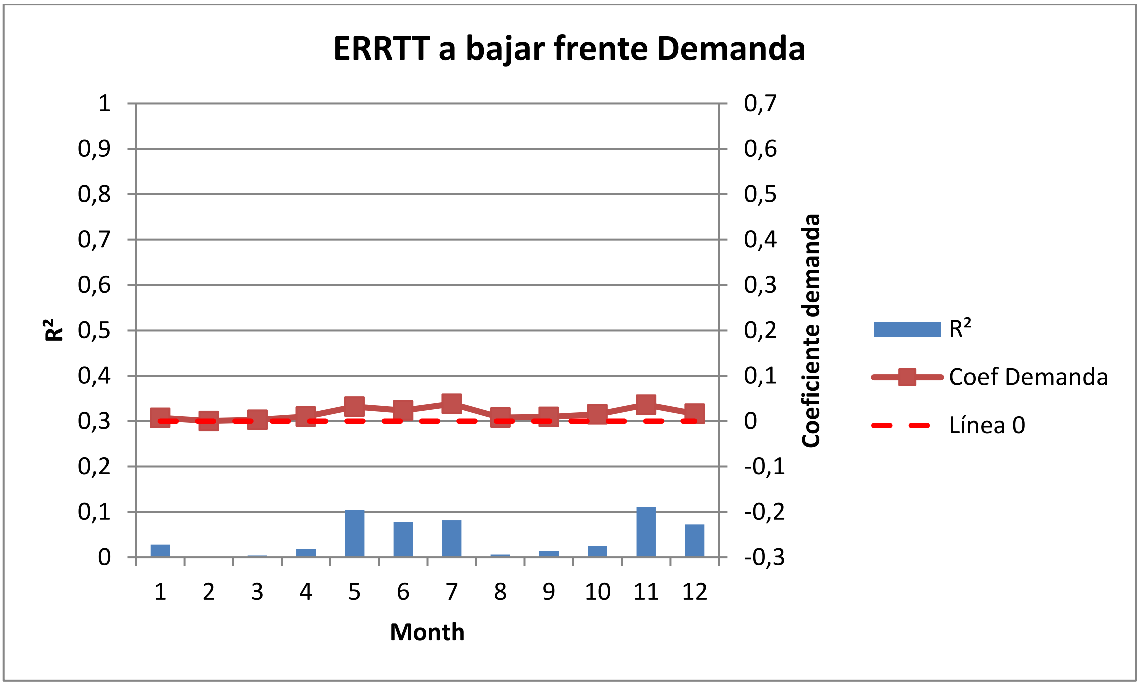


Figure 323:Downward simple regression model for the total of years in PDBF E vs Demand

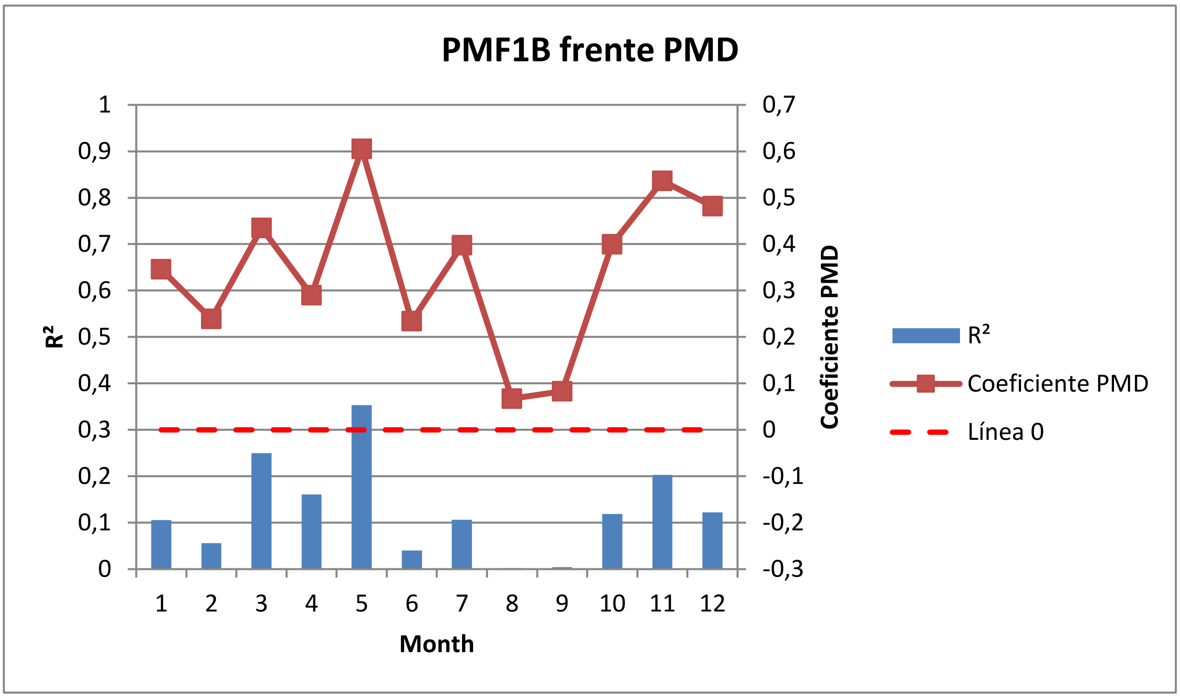


Figure 324: Downward simple regression model for the total of years in PDBF PRT vs PMD

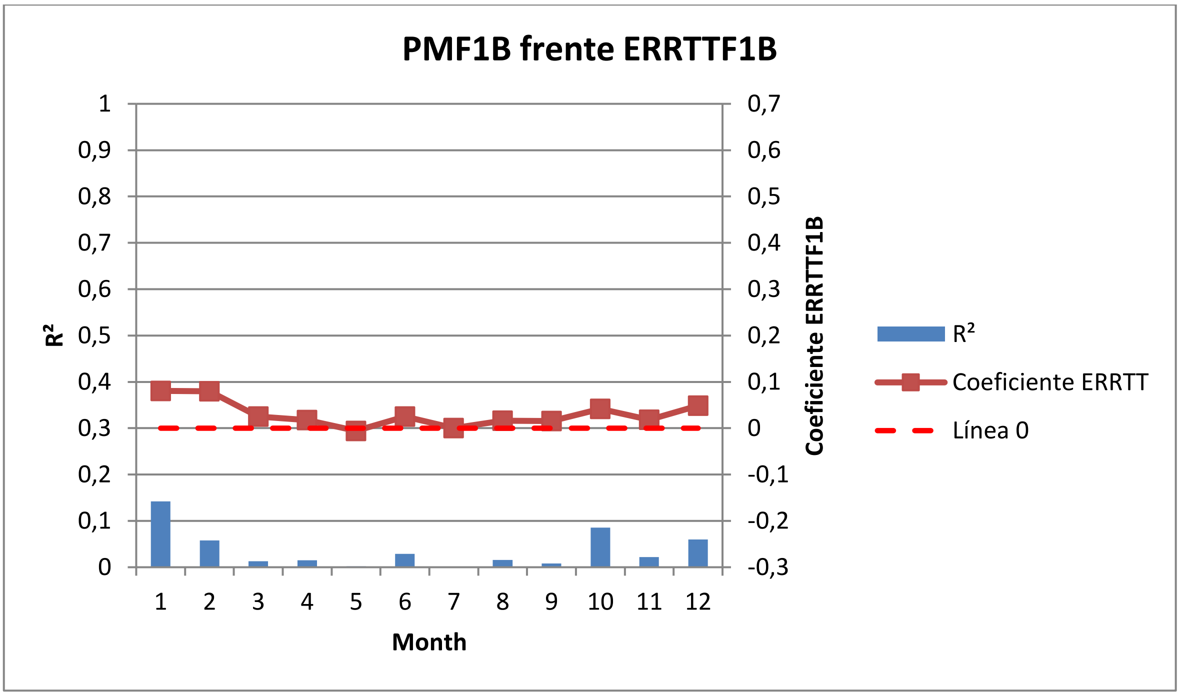


Figure 325: Downward simple regression model for the total of years in PDBF PRT vs Energy.

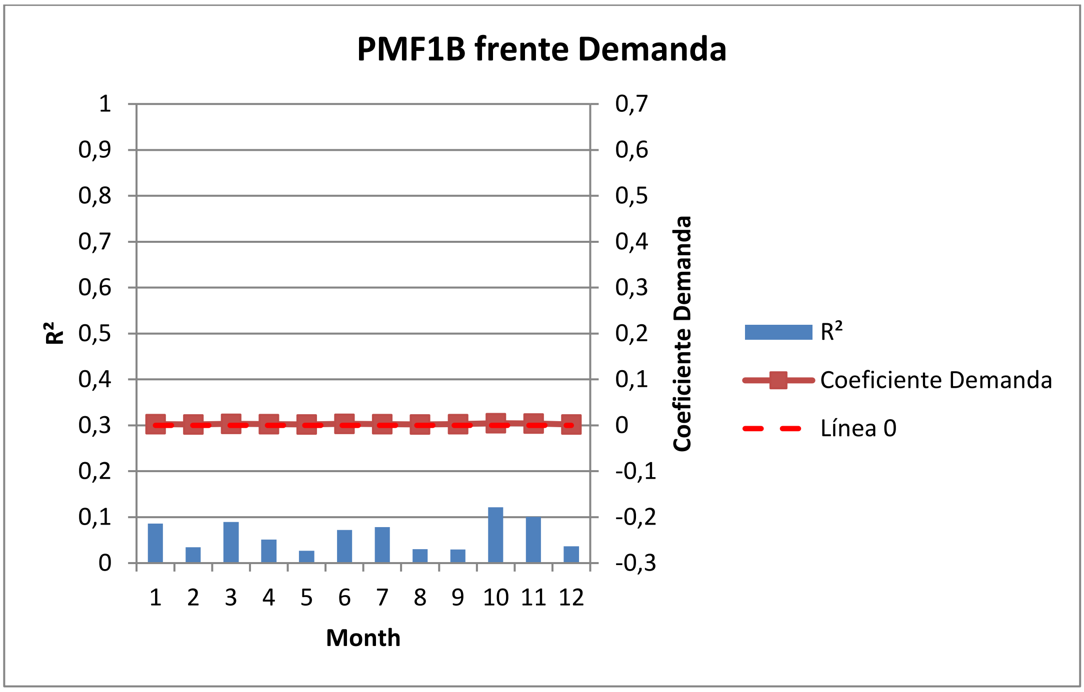


Figure 326: Downward simple regression model for the total of years in PDBF PRT vs D

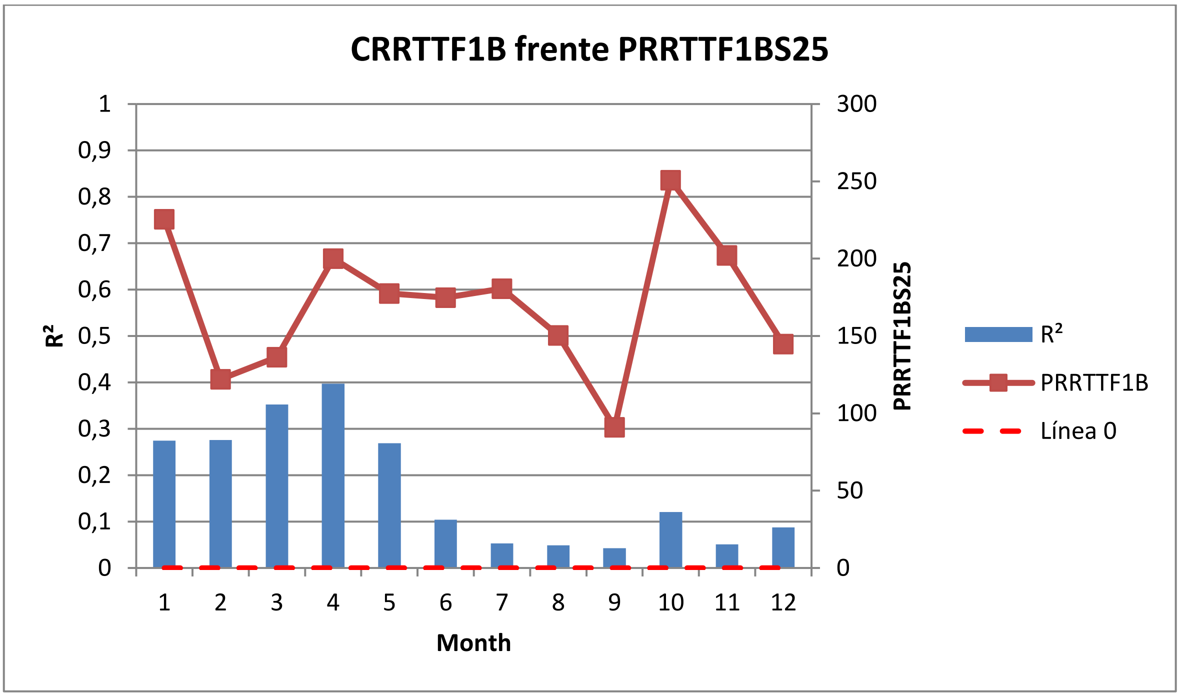


Figure 327: Downward simple regression model for the total of years in PDBF CRRTT vs PRT

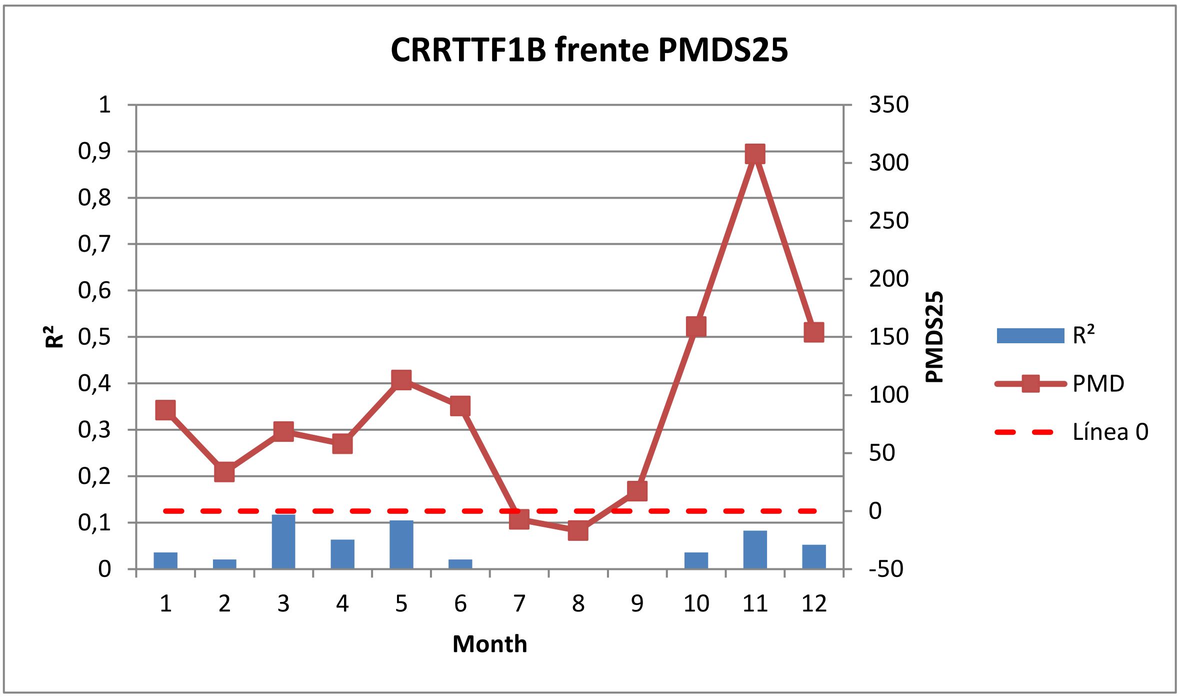


Figure 328: Downward simple regression model for the total of years in PDBF CRRTT vs PMD

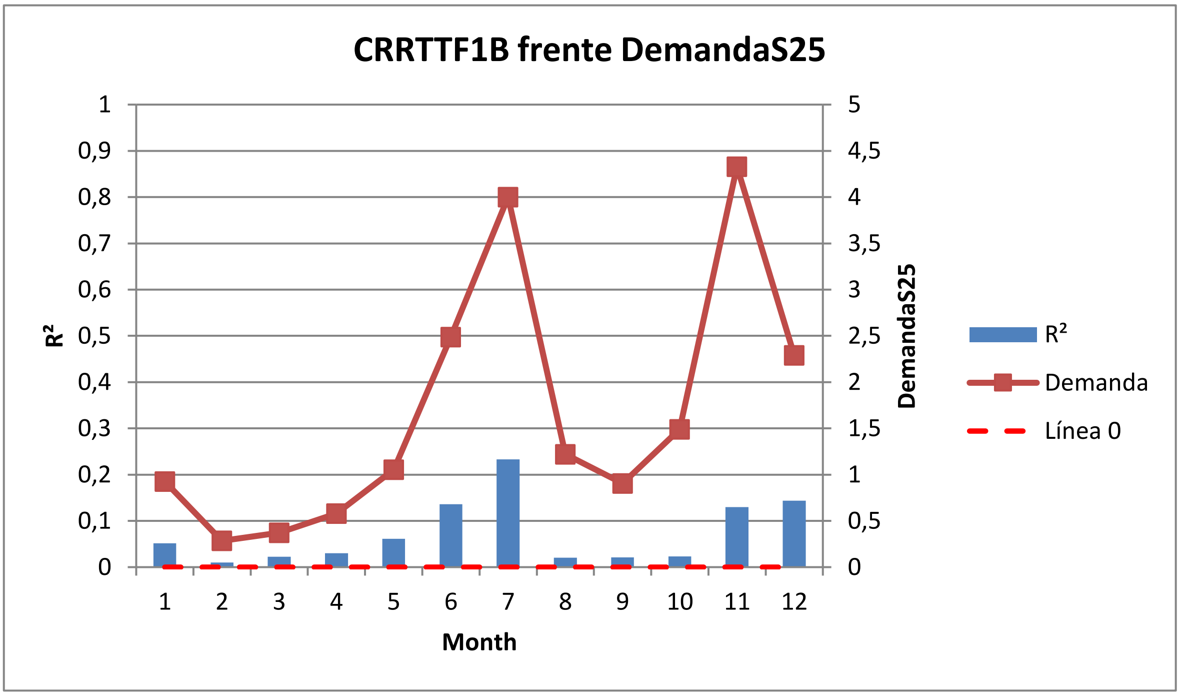


Figure 329: Downward simple regression model for the total of years in PDBF CRRTT vs D

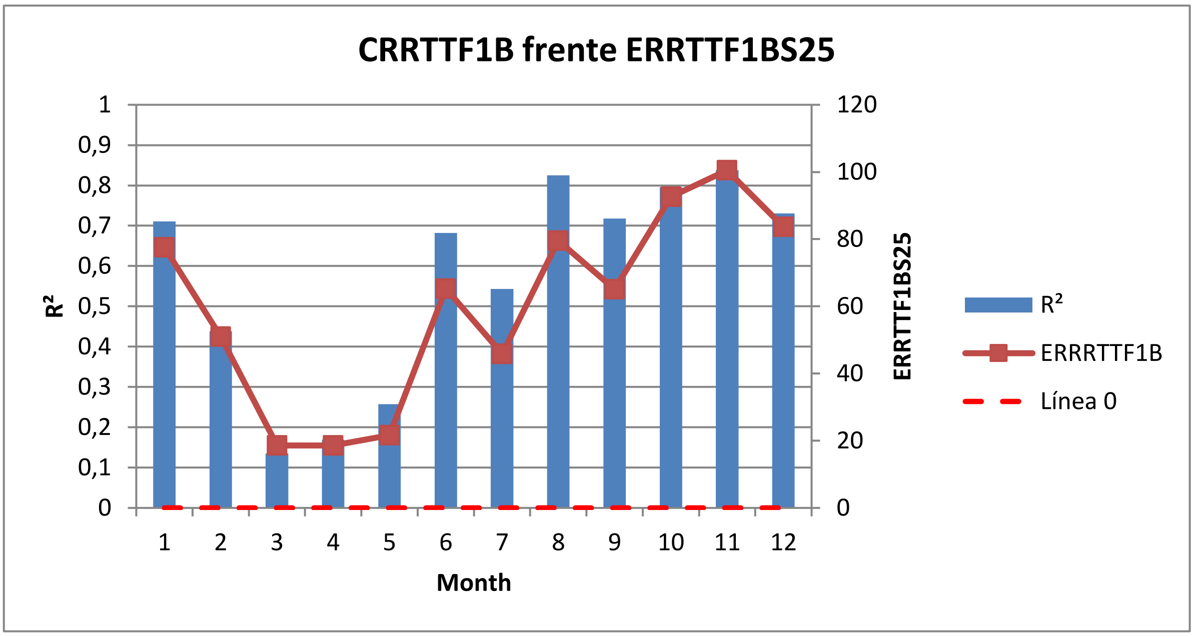


Figure 330: Downward simple regression model for the total of years in PDBF CRRTT vs E

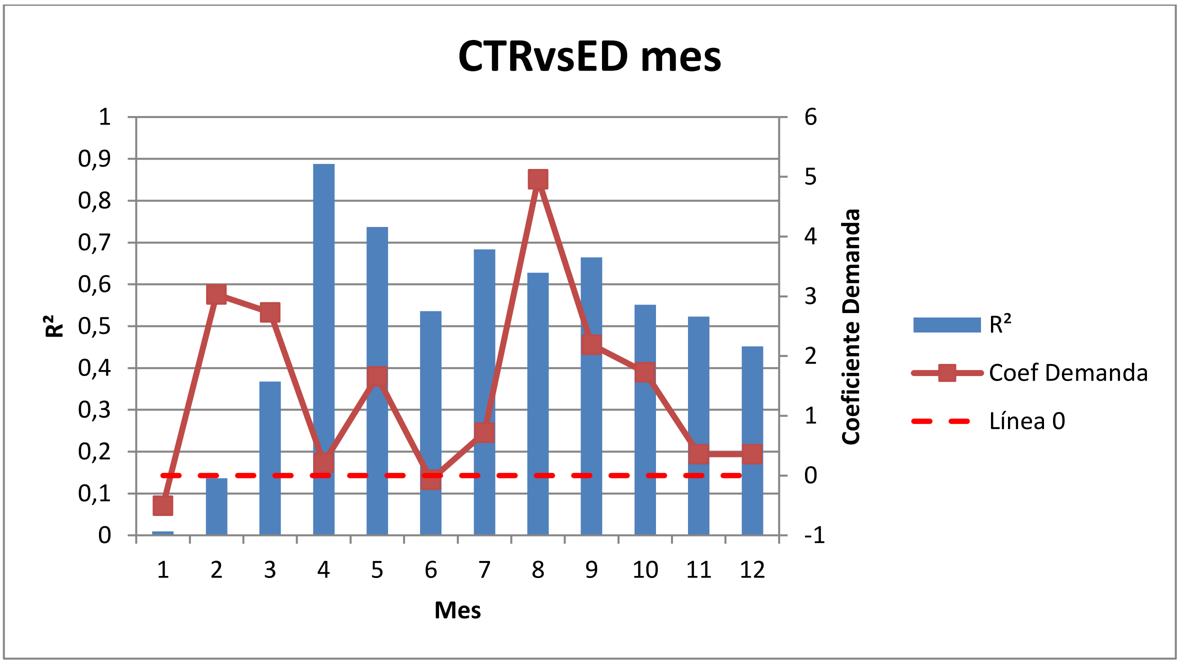


Figure 331: Total upward simple regression model CRRTT vs Energy and demand by month in real time