OFFICIAL MASTER´S DEGREE IN THE ELECTRIC POWER INDUSTRY

Master´s thesis

ECONOMIC ANALYSIS OF THE INCREASE IN NUMBER OF INTRADAY MARKET SESSIONS IN THE IBERIAN MARKET

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Madrid, July 2016

Master's Thesis Presentation Authorization

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Abstract

This project aims to assess the economic impact on thermal plants with outages due to a forecasted increase of the number of sessions of the intraday market, from the current six to twenty-four, one every hour.

In order to estimate the economic impact, it has been needed to quantify the current cost of the adjustment services, such as the tertiary regulation, secondary regulation and deviation management, used to correct the current deviations. In addition, it is necessary to infer the behavior of agents, i.e, why they operate as they do under the current model.

An estimation of volumes traded under the new model was obtained, as well as prices, both from intraday operations and adjustment services.

A reasonable estimation of the savings for thermal units with the new model was obtained.

Resumen

En este Proyecto se ha evaluado el impacto económico sobre las plantas térmicas con indisponibilidades de aumentar el número de sesiones del mercado intradiario, pasando de las seis actuales a veinticuatro, una cada hora.

Para conseguir este objetivo, ha sido necesario, en primer lugar, entender y cuantificar los servicios de ajuste del sistema, como pueden ser la regulación terciaria, secundaria y gestión de desvíos. Posteriormente, se ha valorado el coste que tienen actualmente los desvíos para los agentes que incurren en ellos. Además, se ha tratado de inferir el comportamiento de los agentes, es decir, por qué operan como lo hacen bajo el modelo actual.

Posteriormente, con los datos obtenidos, se han estimado los volúmenes operados bajo el nuevo modelo, así como los precios, tanto te las operaciones intradiarias como de los servicios de ajuste.

Con toda esta información se ha proporcionado una estimación razonada del ahorro que supondría el nuevo modelo de mercado para los agentes térmicos con desvíos.

1. Introduction

The Iberian Electricity market, as many others in the world, allows buyers and sellers to trade under different contracting options: the Forward Markets, as the ones managed by OMIP, Day Ahead and Intraday markets, managed by OMIE (Iberian Market Operator), and Ancillary services market, managed by Red Electrica de España (REE, the Spanish System Operator). The most important one is the Day-ahead market, because it is the one in which the vast majority of the energy is assigned. This market is not mandatory, since bilateral contracts are allowed.

The European Commission has established a Target Model for Intraday, based on continuous energy trading where cross-zonal transmission capacity is allocated through implicit continuous allocation, with the possibility to run regional intraday auctions. This model has been laid down into the Framework Guidelines for Capacity Allocation and Congestion Management (CACM).

The European Power Exchanges APX, Belpex, EPEX Spot, GME, Nord Pool and OMIE are responding to the needs of the market by establishing a transparent and efficient continuous intraday trading environment to enable market parties to easily trade out their intraday positions. The possibility for market parties to trade out their imbalances will thereby be significantly improved as they do not only benefit from the national available intraday liquidity, but also from the available liquidity in other areas. Later on in the Iberian market there will be national intraday sessions in order to be able to offer the net position in the continuous trading.

In order to help to realize this goal of a continuous trading, the PXs, together with the Transmission System Operators from 12 countries, have launched an initiative called the XBID Market Project to create a joint integrated intraday cross-zonal market. The purpose of the XBID Market Project is to enable continuous cross-zonal trading and increase the overall efficiency of intraday trading on the single cross-zonal intraday market across Europe. The wider XBID solution will create one integrated European Intraday market.

This single Intraday cross-zonal market solution will be based on a common IT system forming the backbone of the European solution, linking the local trading systems operated by the Power Exchanges, as well as the available cross-zonal transmission capacity provided by the TSOs. Agents will participate in a portfolio base. Orders entered by market participants in one country can be matched by orders similarly submitted by market participants in their own country or in any other country interconnected, provided there is cross-zonal capacity available. XBID market solution allows, apart from the continuous trading, to implement periodic regional auctions. The Iberian scheme will be based on 24 intraday sessions, in order to schedule a physical program for every unit instead of 6 sessions as today.

Additionally, due to the volatility of renewables, the necessity to trade these units as close to real time as possible has become necessary. In order to do so, it is possible to increase the number of intraday sessions even before the implementation of the continuous trading.

2. Objectives of the Master Thesis

The objectives of this master thesis are shown below:

- **To understand the ancillary services markets and its economic impact:** understand how tertiary, secondary and deviations management, are used to keep the system balanced and how are they priced.
- **To assess the economic cost of thermal plants deviations, due to unexpected outages, under current model:** Once the deviation cost is calculated, it is needed to analyze the agent's behavior and their ability to renegotiate on Intraday Sessions and, in case of failure, the expected deviation costs.
- **To estimate the impact of covering those deviations on a new scheduled intraday market:** With an increased number of intraday sessions, the agents will have more opportunities to renegotiate their production and reduce their deviation costs.
- **To show the savings achieved:** by comparing the current model with the proposed one.
- **To estimate the volume/price of transactions on this market.**

3. Description of the Iberian Market

The Iberian Electricity market, as many others in the world, allows buyers and sellers to trade under different contracting options: The Forward Markets, as the ones managed by OMIP, Day Ahead and Intraday markets, managed by OMIE (Iberian Market Operator), and Ancillary services market, managed by Red Electrica de España (REE, the Spanish System Operator). The most important one is the Day-ahead market, because it is the one in which the vast majority of the energy is assigned. This market is not mandatory, since bilateral contracts are allowed.

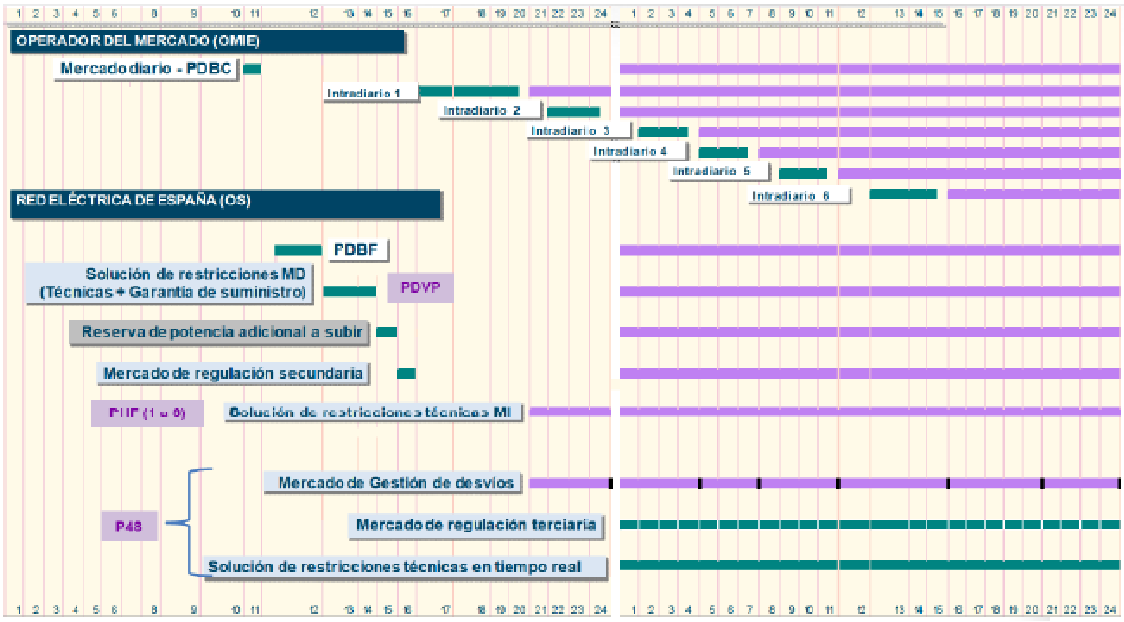

Chart 1. Spanish energy markets scheduling

3.1. Forward Contracts:

OMIP trades futures contracts as well as the registration of forward and swap contracts. One of the key characteristics, which differentiate a futures contract from a forward contract, is that in the former, the gains and losses resulting from price fluctuation, during the trading phase, are settled on a daily basis, while in the latter this only occurs during the contract delivery period and on a monthly basis. Various types of futures are traded on OMIP:

- Spanish and Portuguese electricity.
- Baseload (24h) and spot charge (12h).
- With physical settlement and with financial settlement, where both types of contract benefit from a single order book.

- With maturities of days, weekends, weeks, months, quarters and years.

Besides providing a registration platform for OTC transactions to be cleared on OMIClear, for all these futures contracts, OMIP also allows the registration of forward and swap trades:

- Foreseeing for the former, physical delivery and settlement of VAT and for the latter, a purely financial settlement excluding VAT.
- Both on Spanish and Portuguese electricity.
- With the same maturities as futures contracts.

The size of all of these contracts is 1 MW, with a 0.01 Euros/MWh tick.

3.2. Day Ahead Market:

The daily market is the main market for contracting electricity in the Iberian Peninsula. It operates 365 days a year and is managed by the Market Operator, OMIE. On it, buying and selling transactions are carried out for the next day. It is a marginal market where price and volume for each hour of programming the next day is set at the matching point between supply and demand. This market is operated by OMIE for the Spanish and Portuguese system.

Agents must submit their offers before 12 am of the previous day to the delivery day. Each offer consists of energy terms in MWh with their corresponding hourly prices in €/MWh. Sale bids may be simple or incorporate complex conditions in terms of their content. Sellers for each hour and production unit can present simple bids, indicating a price and an amount of power. Complex bids are those that incorporate complex sale terms and conditions and those which, in compliance with the simple bid requirements, also include one or some of the following technical or economic conditions:

- **Indivisibility:** The indivisibility condition enables a minimum operating value to be fixed in the first block of each hour. This value may only be divided by applying distribution rules if the price is other than zero.
- **Load gradients:** The load gradient enables the maximum difference between the energy in one hour and the energy in the following hour of the production unit to be established, limiting maximum matchable energy by matching the previous hour and the following hour, in order to avoid sudden changes in the production units that the latter are unable to follow from a technical standpoint.

- **Minimum income:** The minimum income condition enables bids to be presented in all hours, provided that the production unit does not participate in the daily matching result if the total production obtained by it in the day does not exceed an income level above an established amount, expressed in euros, plus a variable remuneration established in euros for every matched MWh.
- **Scheduled stop:** The condition of scheduled stop enables production units that have been withdrawn from the matching process because they fail to comply the stipulated minimum income condition to carry out a scheduled stop for a maximum period of three hours, avoiding stoppages in their schedules from the final hour of the previous day to zero in the first hour of the following day, by accepting the first slot of first three hours of their bids as simple bids, the only condition being that energy offered in bids must drop in each hour.

The above mentioned offers are shown jointly with bilateral contracts with physical delivery in ascending order of bid prices thus forming the aggregate supply curve (bilateral contracts are evaluated at 0€/MWh for sales and at 180.3 €/MWh for purchases, but only for volume issues, since they are not really offering any energy in the Day Ahead Market).

Similarly, purchase offers curve is developed. In this case, offers are sorted by descending price. After the bid acceptance, a matching process, run by EUPHEMIA algorithm, sets the daily market price, which is marginal and equal to every agent on the Iberian market, unless there is a congestion in the transmission lines connecting Spain and Portugal. When that happens,

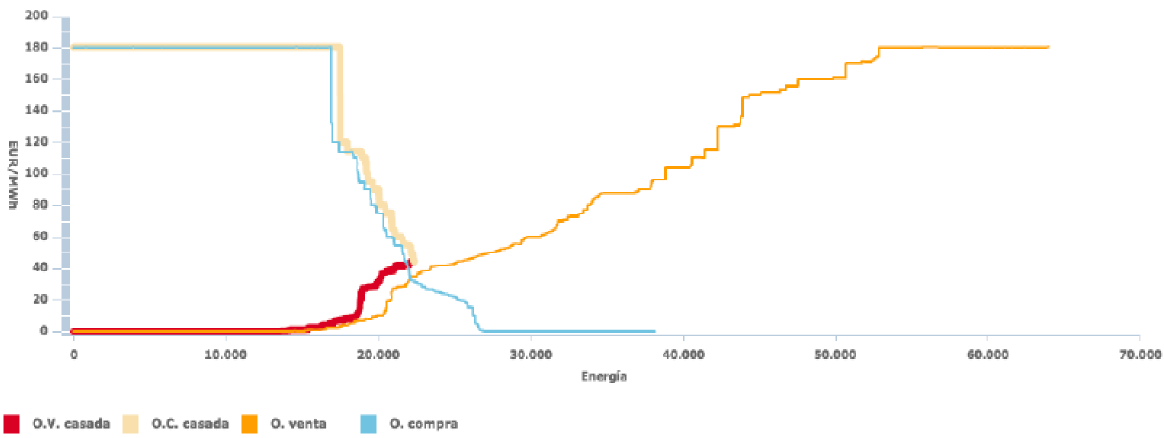

Chart 2. Market clearing. Source: OMIE

both markets are cleared separately (market splitting).

This matching process is the Daily Base Operating Program (PDBF), daily energy program programming periods breakdown of the different programming units corresponding to sales and purchases of electricity.

Day Ahead market price

Day ahead market price varies for several reasons, as:

- RES penetration: windy days are cheaper, as windfarms bid on the market as close to zero price. A wet month, with plenty of water, brings cheaper energy to the system and vice versa.
- Day of the week: Weekdays usually are more expensive than weekends.
- Hour of the day: Peak hours are more expensive than off peak hours.
- System needs: If the system need energy, prices will rise and vice versa.
- Month of the year: As can be appreciated on chart 3, there is a big difference on monthly DAM prices. This is due to the reasons mentioned above, but also to the average temperature. Colder and Hotter months, above and below the comfort temperature for humans, the need of air conditioning and heating systems which increase electricity demand and its pricing.

The average Day Ahead price for 2015 was **50.3€/MWh.** Detailed monthly prices are shown below:

Day Ahead prices (€/MWh)					
Jan	Feb	Mar	Apr	May	Jun
53,54	44,62	44,24	46,59	45,91	55,52
Jul	Aug	Sept	Oct	Nov	Dec
60,53	56,71	52,62	50,84	52,68	54,39

Chart 3. Monthly DAM prices. Source: OMIE

3.3. Intraday Markets:

The intraday market allows different market players to make their adjustments with respect to the Definitive Viable Daily Schedule (resulting from daily market, bilateral contract and the resolution of technical restrictions) by submitting bids for sale and purchase of electricity. The need to make adjustments to the program may be due to changes in the wind/sun forecast for renewable energy, unforeseen production outages for conventional units or demand forecast changes.

Participation in this market is not mandatory for any of the agents. It is structured currently in six sessions held approximately every six hours, in which each scheduling period may be several sessions. Table 3 shows the opening and closing of each session, as well as the scheduling horizon covering each of them.

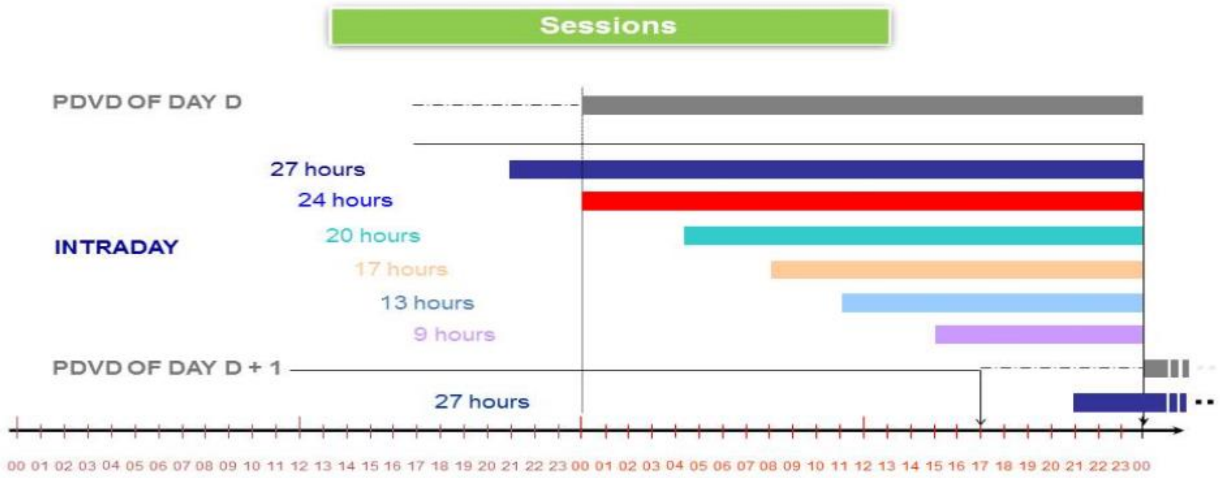

Chart 4. Day ahead and Intraday scheduling. Source: OMIE

	SESSION 1º	SESSION 2ª	SESSION 3ª	SESSION 4ª	SESSION 5ª	SESSION 6ª
Session Opening	17:00	21:00	01:00	04:00	08:00	12:00
Session Closing	18:45	21:45	01:45	04:45	08:45	12:45
Matching Results	19:30	22:30	02:30	05:30	09:30	13:30
Reception of Breakdowns	19:50	22:50	02:50	05:50	09:50	13:50
Publication PHF	20:45	23:45	03:45	06:45	10:45	14:45
Schedule Horizon (Hourly periods)	27 horas (22-24)	24 horas (1-24)	20 horas (5-24)	17 horas (8-24)	13 horas (12-24)	9 horas (16-24)

Chart 5. Intraday market scheduling. Source: OMIE

Offers include an energy term in MWh and their corresponding price in €/MWh. As in the case of daily market, offers can be simple or add a complex condition, presenting the same conditions mentioned above for the day-ahead market plus some others. The matching process is similar as in the day ahead market.

The sum of the day ahead and intraday offers shall not exceed the technical limitations of the power units.

Intraday market price

Intraday market prices vary in two ways, depending on the hour of the day and on the session in which that hour is negotiated. The average prices per session for 2015 is shown in the following chart:

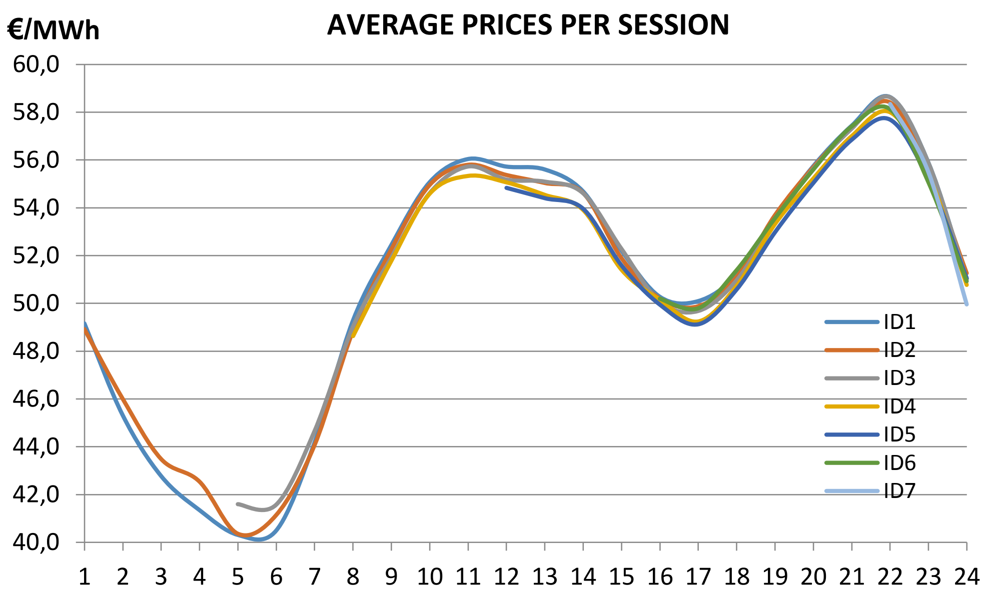

Chart 6. Average prices per session

As can be appreciated, the price variation between sessions can be neglected compared with the hourly changes.

3.4. Balancing Markets:

The results of the daily market, as determined by the free trade between buying and selling agents, are the most efficient solution from an economic perspective. Nonetheless, given the nature of electricity, this process also needs to be feasible in physical terms. Accordingly, once these results have been obtained, they are sent to the System Operators (REN for Portugal and REE for Spain) for their validation from the standpoint of technical feasibility. This process is known as the management of the system's technical constraint resolution and ensures that the market results can be technically managed. Usually there are no constraints due to the fact that the System Operators can establish limitations to the participation in the intraday market for security reasons. The system operators, apart from technical constraints management, establish tertiary regulation, secondary regulation and deviations management markets. The prices of these markets are usually higher than the Day ahead and Intraday ones, due to the cost of keeping some plants on standby and ready to produce with only some minutes of notification, or even to curtail their production to allow them some margin in order to solve contingencies.

3.4.1 Deviations management

The purpose of this procedure is to solve the deviations between generation and consumption that may appear between the close of each intraday market session and the start of the horizon effectiveness of the next session. Deviation management plays a role as a link between the intraday markets and real time management, providing the System Operator with a competitive market service, and greater flexibility to solve imbalances between generation and demand, identified after the intraday market, without compromising the availability of required reserves for secondary and tertiary regulation.

Before each hour, planed/unplanned deviations within the time horizon until the next session of the intraday market are assessed and, if the volume identified is higher than 300 MWh, held several hours, the system operator can proceed to convene the market deviation management.

The allocation is based on offers to increase or decrease generation and consumption, paid at the highest bid accepted (marginal price). The deviation management mechanism is established in P.O.-3.3 "Resolving generation-consumption deviations", published by REE.

The following figure shows the process graphically:

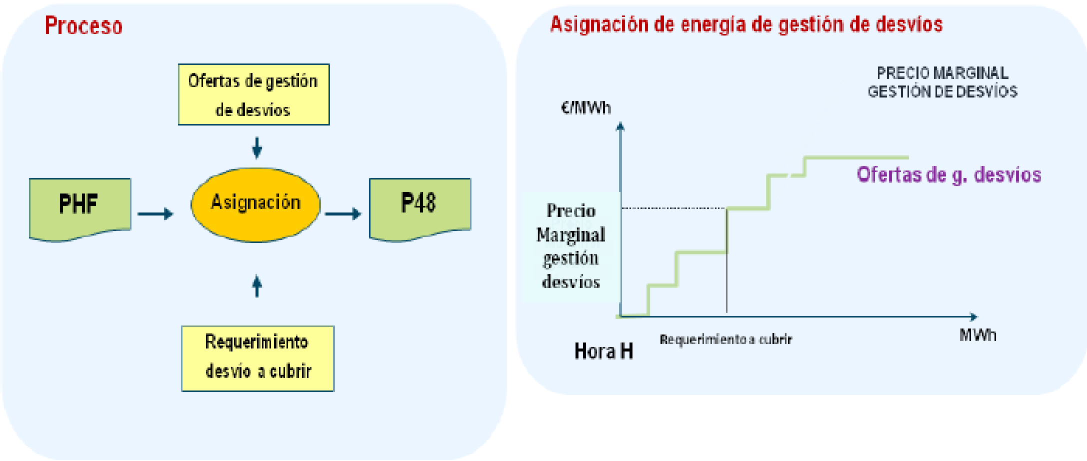

Chart 7. Deviations management pricing. Source: REE

Deviations management pricing

Prices of deviation management are usually lower than real time services, as tertiary and secondary regulation. The energy managed on this balancing market is shown on the following chart, both for 2014 and 2015:

Energy managed on deviation management (GWh)			
2014		2015	
Up	Down	Up	Down
1865	571	2214	549

Chart 8. Energy managed on deviations management. Source: REE

The pricing of this service for 2014 and 2015 is shown below:

Weighted average price of deviation management (€/MWh)			
2014		2015	
Up	Down	Up	Down
54,9	12,2	62,3	33,5

Chart 9. Pricing of deviation management procedure. Source: REE

3.4.2 Tertiary regulation

Tertiary Regulation reserve is defined as the maximum power variation which can be performed by a production unit in a time no longer than 15 minutes, maintained for at least two consecutive hours.

Tertiary regulation seeks to restore the Secondary Reserve that has been used and the adjustment of the generation-demand balance in periods less or equal than an hour. It is a complementary service of mandatory offer for the units enabled as providers of service, managed through market mechanisms. The allocation of this service is based on minimum cost criteria and establishes marginal prices, that may differ if the requirement is to go up or down.

Tertiary Regulation reserve is provided manually (up or down). The allocation process offers tertiary regulation is shown graphically:

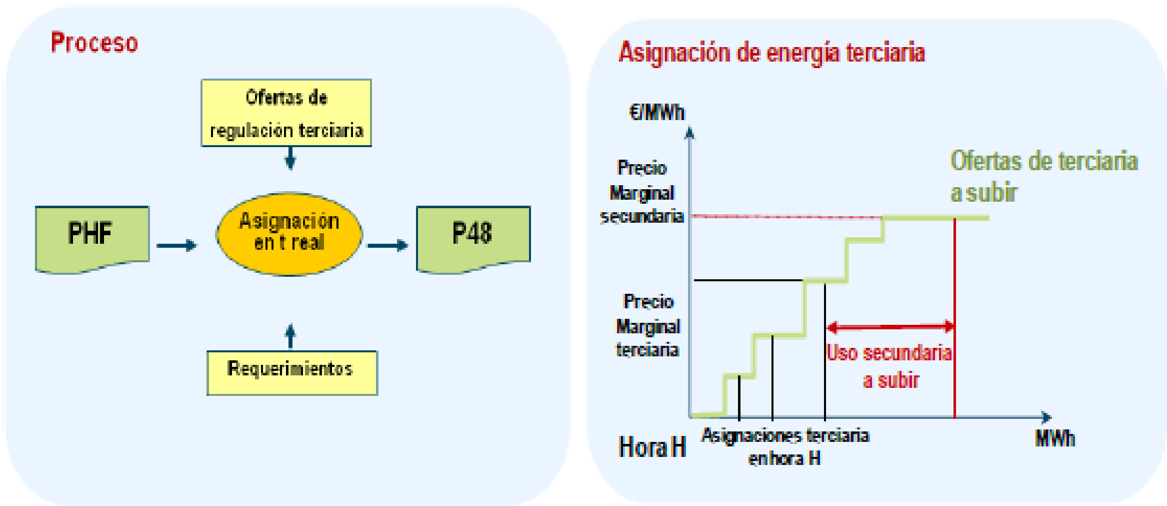

Chart 10. Tertiary reserve pricing. Source: REE

Tertiary regulation pricing

Prices of tertiary reserve, since closer to real time operation, are usually higher than deviations management. Energy managed on this balancing market in 2014 and 2015 is shown below:

Energy managed on tertiary reserve (GWh)			
2014		2015	
Up	Down	Up	Down
3066	1765	3126	1627

Chart 11. Energy managed on tertiary reserve. Source: REE

Prices of this service for 2014 and 2015 are stated on the following chart:

Weighted average price of tertiary reserve (€/MWh)			
2014		2015	
Up	Down	Up	Down
58,2	11,9	63,7	24,8

Chart 12. Pricing of tertiary reserve. Source: REE

3.4.3 Secondary regulation

Secondary regulation is an optional complementary service managed through competitive market mechanisms which aim is to maintain generation-demand balance, correcting the instantaneous deviation from the generation program and frequency with respect to its setpoint set (typically 50 Hz). The time horizon extends from 30 seconds to 15 minutes.

The provision of this service is performed by control zones. Each control zone is constituted by a group of plants with the capacity to provide the service of secondary regulation, accredited by the System Operator, and other generating units (control zone play the role of aggregators).

This service is paid by two concepts:

- Availability (power band)
- Use (energy).

Every day, the System Operator publishes the secondary reserve requirements, both up and down, for each hour of the next day. Generators eligible to participate in this service send their offers secondary reserve and the service is assigned (before the deadline established operating procedures) to meet the needs of the system, applying criteria of minimum cost and respecting the limitations program established for safety in the settlement process PDBF restrictions, establishing a marginal price of secondary regulation band every hour.

The following figure shows schematically the process of allocating secondary regulation reserve

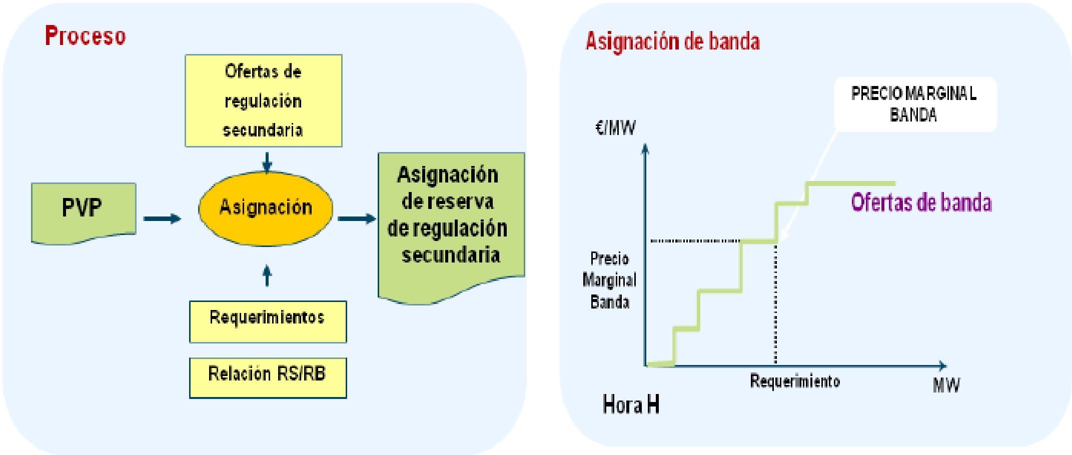

Chart 13. Secondary regulation pricing. Source: OMIE

At real time, control zones are commanded by Peninsular Common Regulation System (RCP) system that is established as the main driver of this system, and is managed by the System Operator. The requirement of dynamic response of each regulation zone corresponds to a time constant of 100 seconds.

Secondary Regulation energy distribution is performed automatically by the CPR, which distributes the requirements of secondary regulation between different of regulation areas based on the allocation of secondary reserve established by the System Operator the day before.

The energy of secondary regulation used as a result of real-time monitoring of regulatory requirements is valued at marginal price of tertiary regulation energy that would have been necessary to schedule every hour, both up and down, to replace this net use energy of secondary regulation.

Secondary regulation pricing

As mentioned before, secondary reserve has two components: Band and energy. Average energy prices of this service is shown on the following chart:

Energy managed on secondary reserve (GWh)			
2014		2015	
Up	Down	Up	Down
1746	995	1366	1193

Chart 14. Energy managed on secondary reserve. Source: REE

Average prices for secondary reserve energy are stated on the following chart:

Weighted average price of secondary reserve (€/MWh)			
2014		2015	
Up	Down	Up	Down
45,4	31,6	53,7	38,5

Chart 15. Pricing of secondary reserve. Source: REE

Average band for 2014 and 2015 is shown below:

Average band of secondary reserve (MW)			
2014		2015	
Up	Down	Up	Down
677	502	685	511

Chart 16. Average band of secondary reserve. Source: REE

Average band prices for 2014 and 2015 is stated below:

Weighted average price of secondary reserve - band (€/MW)			
2014		2015	
Up	Down	Up	Down
23,3		19,6	

Chart 17. Secondary reserve band pricing. Source: REE

REE manages as well some other markets as Power factor control, interruptibility services, or real time technical constraints. Since they are not relevant for the purpose of this thesis, they are going to be explained just briefly on the next section.

3.5. Other markets

In order to ensure the proper and efficient operation of the energy system, it is necessary, apart from the balancing services mentioned before, to provide some other services:

- **Power factor and Voltage control:** Generation units and consumers are required to have a determined power factor, comprised between 0,98 reactive and 0,98 capacitive. In some cases, generators are required to increase the voltage of the network (committed to produce or to be connected, even if not cleared on the energy market)
- **Interruptibility service:** This service is a demand-side management tool aimed at providing flexible and rapid response to the needs of the electricity system operator in situations of imbalance between generation and demand. This service is activated in response to a power reduction order issued by REE to large consumers that are

providers of this service, and that are mainly large-scale industry. They are required to disconnect under some circumstances (high demand episodes, scarcity events… and compensated economically.

- **Additional upwards reserve:** The aim of this service is to provide additional upwards power in case of a sharp increase of the demand
- **Real time technical constraints:** Some consumers or generators may be required to be connected or disconnected if some node of the system suffers a congestion.

3.6. Final Program (P48)

This program is established at the end of the daily scheduling horizon. It contains all energy programs: those resulting from the Daily Base Operating Program (PDBF); those resulting from the different sessions of the intraday markets, i.e, the final hourly schedule (PHF), program modifications associated with the processes of technical constraints and the involvement of different services units in secondary, tertiary regulation and deviation management process.

Final pricing

Final average price is composed of the wholesale DAM and ID price, plus the weighted average of the adjustment services mentioned before, Capacity payments and adjustment services. The final price components for 2015 are shown below:

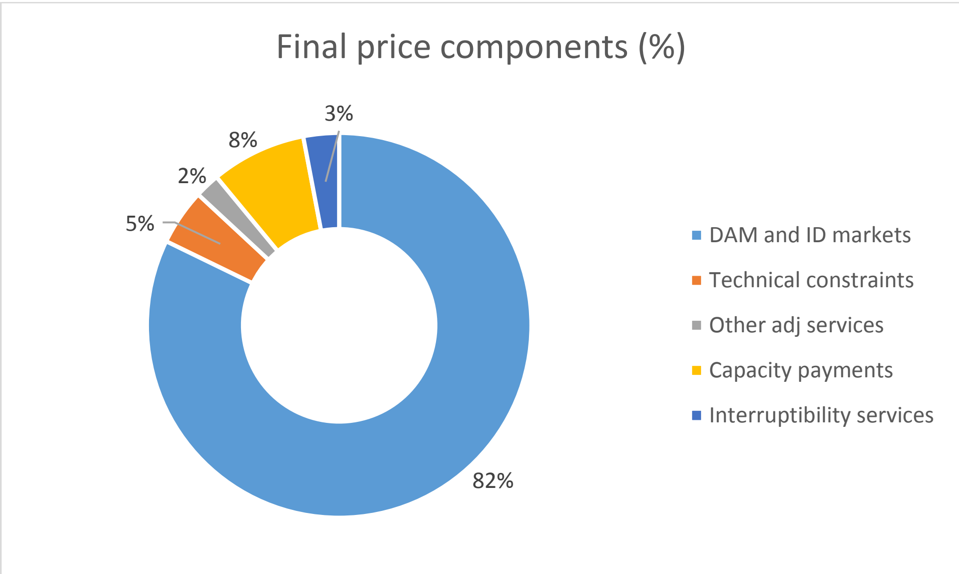

Chart 18. Final price components. Source: REE

4. Deviations

Deviations are stated as the difference between the energy measured at generation plants busbars (real production) and energy scheduled in different markets established production in the final program. Deviations may be due to an excess in generation (deviation up) or to a lack of generation (deviation down) generally:

$$DEVu = MBCu\text{-}PHLu$$

where:

- $MBCu$: Energy measured at busbars of each production / acquisition unit.
- $PHLu$: Final program of the production / acquisition unit.

Deviations are usually caused by failures in the primary resource forecast as is the case of renewable technologies, or unforeseen outages that could affect thermal units. Demand forecast error may induce to an error on the acquisition units.

When they occur, deviations cause a mismatch in the system that has to be corrected by the call for balancing markets by the System Operator. Deviations have an associated cost which can generate a collection right or an obligation to pay, depending on the system requirements. This cost should be paid by causing agents and is determined both for the "up" and "down" energy by the following criteria:

	System needs "up"	System needs "down"
DEV > 0	***DAM***	*Min (DAM, WAPEU)*
DEV < 0	*Max (DAM, WAPED)*	*DAM*

Chart 19. Deviations pricing

Where:

- *DAM* Daily Market Price
- *WAPED* weighted average price per unit of energy for the system to go down, including Deviations Management, Tertiary Regulation and Secondary Regulation

- *WAPEU* weighted average price per unit of energy for the system to go up, including Deviations Management, Tertiary Regulation and Secondary Regulation

From the upper chart we can derive that the deviations that favor the system needs are for free, they receive or they have to pay the same amount of money that would have resulted from the DAM operation. On the other hand, If the deviation goes against the system requirements, the corresponding unit will incur on a loss.

Let us introduce an example, extracted from the market data published by OMIE and REE:

Date	Month	Hour	DAM	Payment deviations down	Collection deviations up	System Requirements
J 01	January	8	36,22	37,8	36,22	up
J 01	January	10	36,6	36,6	21,65	down

Chart 20. Example of deviations pricing

The upper chart shows the DAM price and the payment/collection price for deviations up/down. As can be appreciated, when the system needs energy (requirements up), the DAM coincides with the payment for deviations up. On the other hand, if the system has plenty of energy (requirements down), the unit that deviates down is the one which losses nothing.

On the first case, if a unit incurs on a deviation up, she losses nothing, as the payment for deviations down (36,22€/MWh) is the same as the DAM price (36,22€/MWh). On the contrary, if the deviation is down, that unit would have to pay 37,8 €/MWh so she losses 37,8-36,22 = 1,58 €/MWh of deviation.

On the second one, if a unit incurs on a deviation down, she losses nothing, as the DAM price (36,6€/MWh) coincides with the payment for deviations down (36,6€/MWh). However, if the deviation is up, she losses 36,6-21,65 = 14,95 €/MWh.

As may have been noticed, the cost of a contrary deviation is much higher on the second case. This is not casual. Performing an analysis for the year 2015, it can be appreciated that the average cost of a positive deviation in the case the system needs to go down is more than twice than the opposite.

	System needs "up"	System needs "down"
DEV > 0	**0,00**	**18,95**
DEV < 0	**8,56**	**0,00**

Chart 21. Deviations economic loss

This fact may be crucial in case of developing a strategy. When, as an example, the wind forecast is not clear, it should be less "harmful" to plan the commitment of the unit in order to have a slight deviation down (schedule more than the expected production) However, in the thermal plants case, since we are studying thermal outages, which are always deviations down, it has no further importance.

It should be noticed that those deviation cost are always calculated in comparison with the DAM price, which is stated as the reference. Intraday markets allow more negotiations, and the price is usually slightly different than the DAM. With that on mind, it is possible to make money with a deviation (if the ID price is higher than the deviation cost). This will be explained on further chapters.

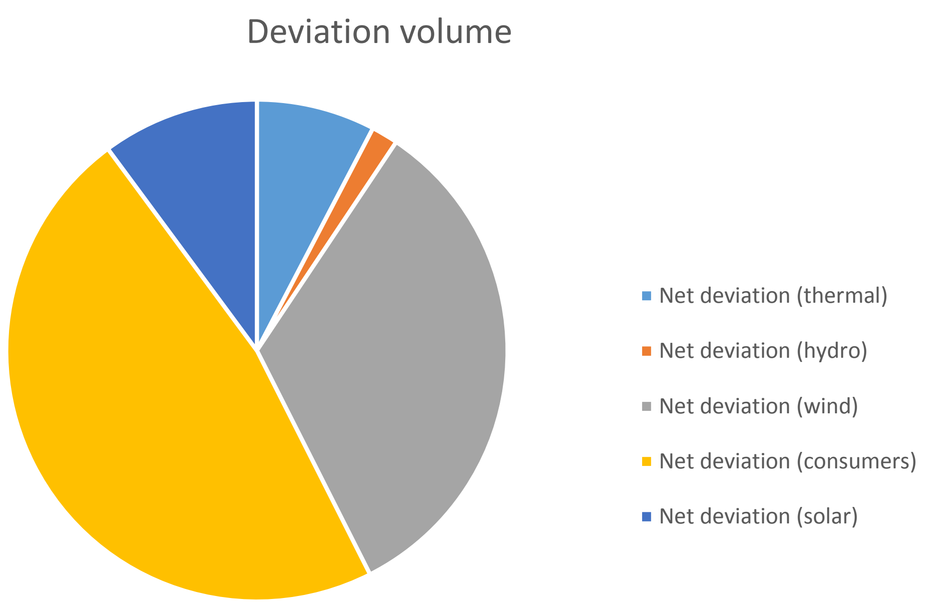

Chart 22. Deviation volumes by technology

4.1. Deviation causers

As stated before, deviations are caused by a mismatch between planned and real production. There are some technologies that are more likely to cause that deviation, as wind, or more reliable ones, as thermal units

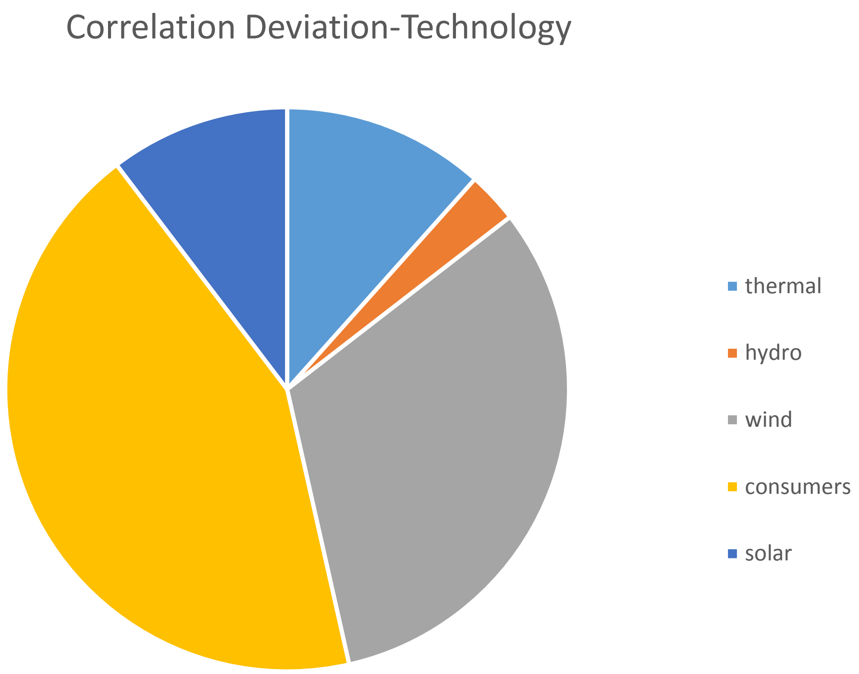

Chart 23. Correlation between deviation and technology

As can be observed, hydro units are usually the most reliable ones, followed by solar, thermal, wind and consumers. On the following sections, a brief analysis of the different drivers by group of agents will be provided.

4.1.1 Main drivers on consumer's deviations

Consumers deviations are usually driven by an error on their consumption estimation. This consumption is normally guided, in the short term, by:

- Weekday-Weekend: the consumption is higher on the weekdays, normally the day of higher consumption is on Wednesday.
- Hour of the day: there are peak hours (wake up time, dinner time) and valley hours (night). Of course, it will depend on the kind of consumer. Industrial ones will have higher consumption on working hours (usually office hours, but some industries would have two-three shifts so they would have almost a flat demand curve. On the other hand, Households will have a classic shape, with peak on morning-night.
- Temperature: residential and office consumption is usually higher on cold and hot days, due to an increased use on heating/cooling system, whilst is lower on mid temperature days.

A failure on forecasting that consumption will lead on a deviation. The following graph shows a typical aggregate load profile, in Spain

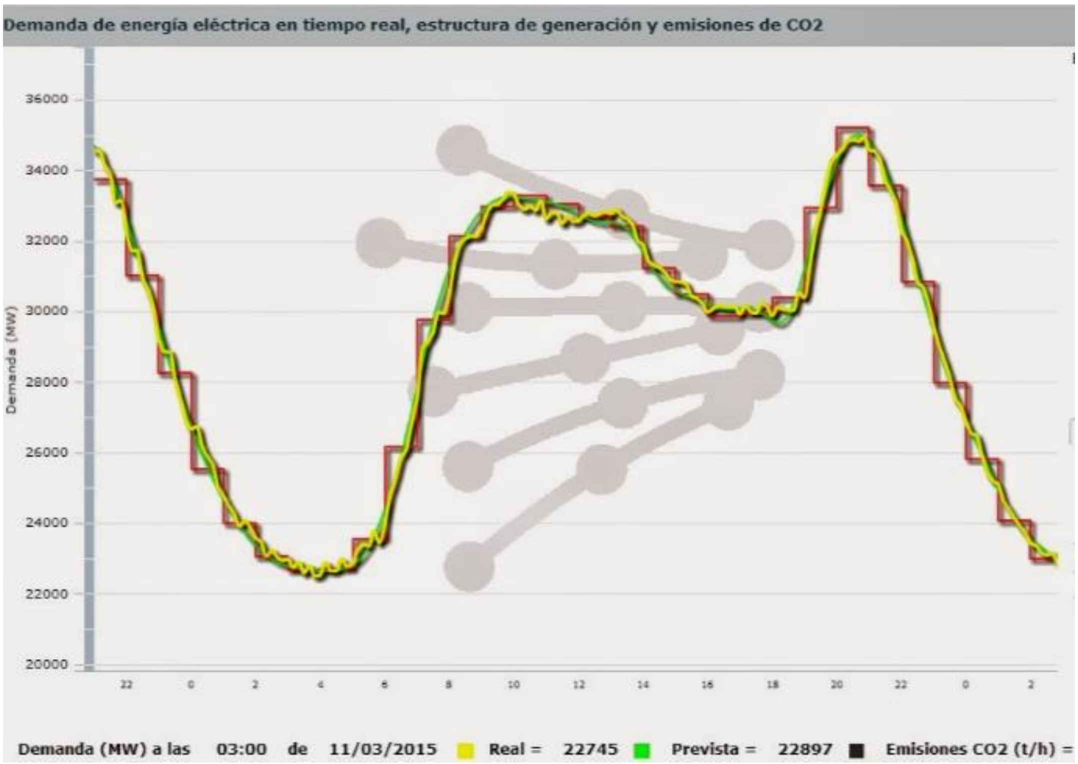

Chart 24. Typical daily load profile. Source. REE

4.1.2 Main drivers on wind deviations

Wind unit's production depends on the forecast. This forecast is more accurate when approaching to the real time, but is usually available from a week ahead. Wind turbines have a maximum output production that cannot be surpassed. When wind speed exceeds a certain threshold, turbines have to stop to protect themselves. This will lead to a deviation down, so when the wind is very high, it is more likely to have a deviation down. On the other hand, wind may blow higher than expected. On that case, a deviation up will appear.

However, wind units usually bid in groups. This can reduce significantly the deviation, since it groups turbines from different geographic areas which can have deviation of different direction. It and is called "portfolio effect"

Failures can appear, as in any other technology.

4.1.3 Main drivers on solar deviations

Solar units depend as well on the forecast. But also have a big seasonality. Winter days, with less sun hours, will lead to a decreased production, and summer days, which are longer, will lead to a higher production. However, this fact does not lead to uncertainty. On the short term, solar production depends on the forecast: cloudy days will lead to a decrease on the production.

5. Classification of ID operations

In order to assess the expected operations on the new Intraday schedule, it is necessary to classify the ID operations. Depending on the assumed purpose of the transactions, those will be classified and then quantified by volume and number of operations. After that, an estimation on the increase of each type of operation will be performed and, as a result, the expected volume under de new schedule will be obtained

5.1 Agents behavior

Unexpected outages affect thermal units on different ways. In order to assess the impact of the increased Intraday sessions, a classification is needed:

- If they notice the problem after the negotiation time and have no time to reschedule
- If they notice the problem and have time to reschedule on the next ID
- If they notice that they no longer have the problem and can commit the available power on the next ID
- A speculative behavior
- If they expect the problem to be fixed at certain time and finally it is not possible and they incur on a deviation
- If there is no deviation

A detailed description of each case will be provided below

5.1.1 No time to renegotiate

Outages, as will be justified on later chapters, are assumed equally distributed along the day. They may happen before the negotiating time for the next Intraday session, during or after. If it happens on the two first cases, the reschedule will be applied on the next ID session, with a waiting time (at which units will have to pay deviations) that depends on the session and it is shown below

	SESSION 1º	SESSION 2ª	SESSION 3ª	SESSION 4ª	SESSION 5ª	SESSION 6ª
Session Opening	17:00	21:00	01:00	04:00	08:00	12:00
Session Closing	18:45	21:45	01:45	04:45	08:45	12:45
Matching Results	19:30	22:30	02:30	05:30	09:30	13:30
Reception of Breakdowns	19:50	22:50	02:50	05:50	09:50	13:50
Publication PHF	20:45	23:45	03:45	06:45	10:45	14:45
Schedule Horizon (Hourly periods)	27 horas (22-24)	24 horas (1-24)	20 horas (5-24)	17 horas (8-24)	13 horas (12-24)	9 horas (16-24)

Chart 25. Intraday market scheduling. Source: OMIE

As can be appreciated, on session 1, the session closing happens at 18:45, and the schedule horizon starts at 21. This leads to a 2:15 hours waiting time. However, If the outage happens at 19:00, they will have to wait for the reschedule until 00:00 of the next day. This leads to a 5 hours waiting time.

Agents that do not modify their Day Ahead schedule on the Intraday sessions and they incur on a deviation are assumed to be in this first case. An example is shown below:

DATE	UNIT	HOUR	PMAX	P_AVAIL	PDVP	PHF1 (1-24)	PHF2 (1-24)	PHF3 (5-24)	PHF4 (8-24)	PHF5 (12-24)	PHF6 (16-24)	PHF7 (22-24)	DEVIATION_LAST NEGOTIABL	DEVIATION_PDVP
01/01/2015	COM5	21	340,65	0	320	320	320	320	320	320	320	0	320	320
01/01/2015	COM5	22	340,65	0	320	320	320	320	320	320	320	320	320	320
01/01/2015	COM5	23	340,65	0	320	320	320	320	320	320	320	320	320	320
01/01/2015	COM5	24	340,65	0	320	320	320	320	320	320	320	320	320	320

Chart 26. No time to renegotiate example

The upper chart shows that Compostilla 5, on January the 1st, 2015 was unavailable (P_AVAIL=0) from 21 to 24. On its PDVP, which is the day ahead program, including technical constraints, that unit had 320 MW scheduled from 21 to 24. On the Intraday sessions, despite the unavailability, it does not reschedule, so the final deviation (DEVIATION_LAST NEGOTIABLE) is 320 MW

5.1.2 Reschedule down on ID

If a plant detects that an outage will happen on the next hours, the most reasonable way to solve it is to bid on the next Intraday session in order to adequate the program to the available energy. On the next example, that happened on January the 4th, 2015 on Arrubal 2, it can be appreciated that, with the original schedule, it would have incurred on a 280, 331, 330 and 330 MW deviations from 14 to 17. However, they manage to bid on the intraday 1 in order to make their schedule 0 and finally the don't incur in any penalty

DATE	UNIT	HOUR	PMAX	P_AVAIL	PDVP	PHF1 (1-24)	PHF2 (1-24)	PHF3 (5-24)	PHF4 (8-24)	PHF5 (12-24)	PHF6 (16-24)	PHF7 (22-24)	DEVIATION_LAST NEGOTIABL	DEVIATIO N_PDVP
04/01/2015	ARRU2R	14	390,06	0	280	0	0	0	0	0	0	0	0	280
04/01/2015	ARRU2R	15	390,06	0	331,1	0	0	0	0	0	0	0	0	331,1
04/01/2015	ARRU2R	16	390,06	0	330,5	0	0	0	0	0	0	0	0	330,5
04/01/2015	ARRU2R	17	390,06	0	330	0	0	0	0	0	0	0	0	330

Chart 27. Reschedule down on ID example

5.1.3 Reschedule up on next ID

If a thermal unit that had some problems and consequently bid on the DAM an amount lower than the available energy, and finally is able to solve its problem, it has the possibility to sale some more energy on the ID market. On the next example, which happened on January the 4th, 2015 on the power plant Lada 4, they had scheduled, after technical constraints, 0 MW for the time horizon shown in the figure. However, they bid on the ID market to increase their production until almost its maximum available (185MW)

DATE	UNIT	HOUR	PMAX	P_AVAIL	PDVP	PHF1 (1-24)	PHF2 (1-24)	PHF3 (5-24)	PHF4 (8-24)	PHF5 (12-24)	PHF6 (16-24)	PHF7 (22-24)	DEVIATION_LAST NEGOTIABL	DEVIATIO N_PDVP
04/01/2015	LAD4	1	347,7	190	0	175	185	0	0	0	0	0	0	0
04/01/2015	LAD4	2	347,7	190	0	175	185	0	0	0	0	0	0	0
04/01/2015	LAD4	3	347,7	190	0	175	185	0	0	0	0	0	0	0
04/01/2015	LAD4	4	347,7	190	0	175	185	0	0	0	0	0	0	0
04/01/2015	LAD4	5	347,7	190	0	175	185	185	0	0	0	0	0	0
04/01/2015	LAD4	6	347,7	190	0	175	185	185	0	0	0	0	0	0

Chart 28. Reschedule up on ID example

5.1.4 Speculative behavior / error

Deviation costs can be estimated. As explained on previous sections, the average loss when deviating from DAM schedule is 8,56 €/MWh deviated when the system needs to go up and we go down and 18,95 €/MWh deviated when the system needs to go down and we go up. Thermal units with outages will always go down, so the situation will be:

- System needs up and we go down: loss of 8,56 € per MWh deviated, compared with DAM price
- System needs down and we go down: no loss compared with DAM price.

Although if a production unit suffers an outage it is obliged to notify the System Operator and its offers will be retired, before that notification, If the ID price in some session is higher than the DAM price + 8,56, a profit, despite the deviation, would be certain even if the system needs to go up. However, if the system needs to go down, any price above the DAM will be profitable, even if we have to pay for the deviation cost. Agents can develop a model to predict the system needs (until 2014 they were able to predict it 85% of the time). Then next chart shows an example:

DATE	UNIT	HOUR	PMAX	P_AVAIL	PDVP	PHF1 (1-24)	PHF2 (1-24)	PHF3 (5-24)	PHF4 (8-24)	PHF5 (12-24)	PHF6 (16-24)	PHF7 (22-24)	DEVIATION_LAST NEGOTIAI	DEVIATIO N_PDVP
07/03/2015	CTGN3	19	412,77	55,04	0	217,5	249	249	259,5	280,5	291	0	235,96	0

Chart 29. Speculative behavior example 1

As can be appreciated, Cartagena 3 had a partial outage in which it has only 55 MW available. This is reflected on the PDVP program, which is 0. Despite that, they commission power on the ID sessions until 291 MW. Finally, they will incur on a deviation of 236 MW. This behavior may have two explanations:

- A failure that was expected to be solved and finally was not
- A speculative behavior

Since that unit keeps increasing its sale offer, but the ID price is low compared with the DAM, I will assume an error.

Date	Month	Hour	DAM	1	4	8	11	15	19	25	Payment de	collection dev	System Require
S 07	marzo	16	43,4	43,4	45,03	43,4	43	42,1	38,8	0	43,4	31,24	down
S 07	marzo	17	43	39	43	42,68	41,71	40,1	38,8	0	43	33,11	down
S 07	marzo	18	43,08	39,08	40,08	42,08	42	40,08	38,8	0	43,08	34,6	down
S 07	marzo	19	46,1	42,1	43,2	43,1	43,8	45	45,6	0	46,1	33,64	down
S 07	marzo	20	56,4	56,4	55,42	55,24	55	56,3	56	0	56,4	16,52	down
S 07	marzo	21	60,75	60,75	59,91	59,11	59,91	60,55	63,9	0	60,75	36,87	down

Chart 30. Speculative behavior example 2

On the upper chart, the DAM, ID sessions, deviation price and system needs are shown. As can be seen, the system needs to go down, The DAM price (46,1 €/MWh) is much more expensive than the ID price on the first sessions (42,1; 43,2; 43,1…) If that unit sells energy

at ID price but incurs on a deviation, it will make a loss (ID-DAM price). However, on that particular case, since the unavailability is not complete, it does not make a net loss

DATE	UNIT	HOUR	ID profits	DAM profits	Deviation costs over last ID	Deviation costs over DAM	Net profit (DAM-Deviatio	Net profit (DAM+ID-Deviations)	Benefits from ID market	System needs
07/03/2015	CTGN3	19	12401,25	0	10877,756	0	**0**	**1523**	**1523**	down

Chart 31. Speculative behavior example 3

As can be seen, the ID profits stands for 12401€ and deviation costs stands for 10877€, which makes a net profit of 1523€. Those profits are lower than the 55 MW available times the DAM price (55*46,1=2530€).

On the next example, a speculative behavior is more obvious. Since that CHP plant had no power available, its ID offer is 0. However, on ID4 it sells 42,6 MWh at 37,4 €/MWh. The DAM price for that hour is 10,55€, so it makes a profit of 27 €/MWh deviated.

DATE	UNIT	HOUR	PMAX	P_AVAIL	PDVP	PHF1 (1-24)	PHF2 (1-24)	PHF3 (5-24)	PHF4 (8-24)	PHF5 (12-24)	PHF6 (16-24)	PHF7 (22-24)	DEVIATION_LAST NEGOTIAt
29/03/2015	COGPLA	16	94,07	0	0	0	0	0	42,6	42,6	42,6	0	42,6

Chart 32. Speculative behavior example 4

This can be seen on the following chart. The total benefits are 1037 €, despite not producing any MW.

DEVIATION_LAST NEGOTIAt	DEVIATION_PDVP	LAST ID NEGOT	ID profits	DAM profits	Deviation costs over last ID	Deviation costs over DAM	Net profit (DAM-Deviatio	Net profit (DAM+ID-Deviations)	Benefits from ID market	System needs
42,6	0	6	1486,74	0	449,43	0	**0**	**1037**	**1037**	down

Chart 33. Speculative behavior example 5

Date	Month	Hour	DAM	1	4	8	11	15	19	25	Payment de	collection dev	System Require
D 29	marzo	16	10,55	39,4	40,9	37,4	34,9	26,5	0,1	0	10,55	0	down

Chart 34. Speculative behavior example 6

5.1.5 Expect to fix the problem before incurring on a deviation

If the units are expecting to fix the problem before the commission hour, they will keep its position close to the DAM values. If finally, they are not able to restart, they will incur in a loss. An example is shown below:

DATE	UNIT	HOUR	PMAX	P_AVAIL	PDVP	PHF1 (1-24)	PHF2 (1-24)	PHF3 (5-24)	PHF4 (8-24)	PHF5 (12-24)	PHF6 (16-24)	PHF7 (22-24)	DEVIATION_LAST NEGOTIAI	DEVIATION_PDVP
28/03/2015	COGPLA	12	94,07	0	88	72	72	66,6	64,8	64	0	0	64	88
28/03/2015	COGPLA	13	94,07	0	88	72	72	66,6	64,8	64	0	0	64	88
28/03/2015	COGPLA	14	94,07	0	88	72	72	66,6	64,8	64	0	0	64	88
28/03/2015	COGPLA	15	94,07	0	88	72	72	69,3	65,7	64	0	0	64	88
28/03/2015	COGPLA	16	94,07	0	88	72	69,3	65,7	64,5	64	64	0	64	88

Chart 35. Expectation to fix the problem example

As can be appreciated, that CHP unit has a deviation over DAM of 88 MWh, and ends up with a deviation of 64 MWh over the last ID.

5.1.6 There is no deviation

Information about deviation has been obtained from OMIE databases. This data includes all the unavailabilities of thermal units for year 2015. However, sometimes those unavailabilities do not end up in a deviation. As an example, on the following chart, can be appreciated that Castellón 4 had 417 MW available from its nominal power of 839. However, its production schedule is 180 MW, which is below that. No deviation happened

DATE	UNIT	HOUR	PMAX	P_AVAIL	PDVP	PHF1 (1-24)	PHF2 (1-24)	PHF3 (5-24)	PHF4 (8-24)	PHF5 (12-24)	PHF6 (16-24)	PHF7 (22-24)	DEVIATION_LAST NEGOTIAI	DEVIATION_PDVP
23/03/2015	CTN4	1	839,35	417,81	180	180	180	0	0	0	0	0	0	0
23/03/2015	CTN4	2	839,35	417,81	180	180	180	0	0	0	0	0	0	0
23/03/2015	CTN4	3	839,35	417,81	180	180	180	0	0	0	0	0	0	0
23/03/2015	CTN4	4	839,35	417,81	180	180	180	0	0	0	0	0	0	0

Chart 36. No deviation example

5.2 Classification by number of operations

This classification tries to reflect the number of times that agents bid on the Intraday market in order to deal with the above mentioned types of events. These percentages are based on thermal plants with unavailabilities, no other technology is included. The timeframe is from January, 1st, 2015 to December, 31st, 2015. The data was provided by OMIE.

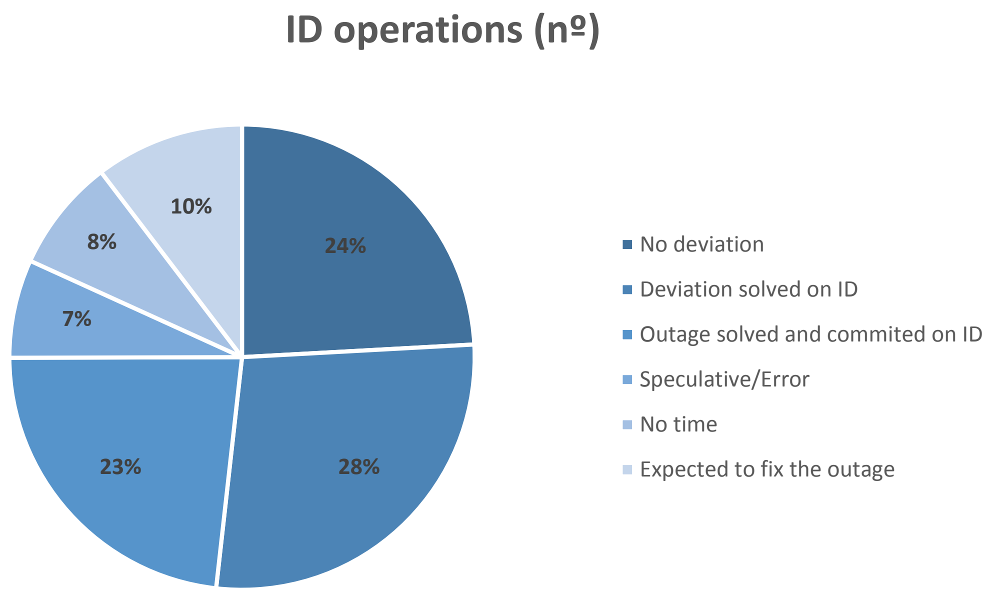

Chart 37. Breakdown of ID operations

As can be appreciated, the largest amount of operations belongs to units that solve their deviation on the ID, and to units that are able to fix the outage and commit some power on the ID sessions. The number of operations with no deviation is quite significant, due to the composition of the database, which includes all the unavailabilities, even the ones which do not compromise the scheduled production. The Speculative, no time and the ones which expect to fix the outage are not really significant.

5.3 Classification by volume of energy traded

Despite illustrative, the classification by number of operation is not really useful, if the objective is to estimate volumes. For that reason, I will perform a classification by volume of energy traded. There will be a separation, in order to separate energies negotiated to increase the production and the ones negotiated to decrease it.

5.3.1 Volumes negotiated to increase production

The following chart shows the volume of ID operations performed on 2015 by thermal plants with outages, in order to increase its production. As can be appreciated, the highest amount belongs to units that have supposedly solved their problems and are able to produce. For that reason, they increase their position on the ID sessions. On a smaller amount, but still significant, stands the speculative/error behavior. As already mentioned, this tries to reflect the units that intend to make money from a deviation, and the ones that have an error on their scheduling.

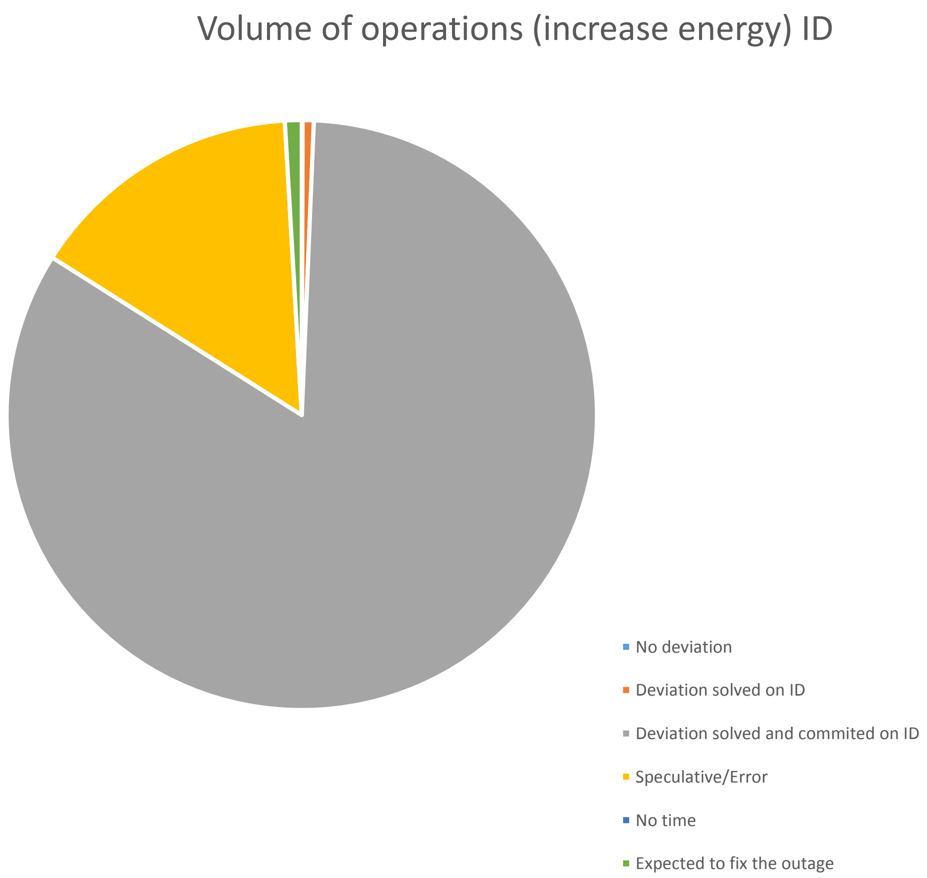

Chart 38. Volume of ID operations to increase energy

Numeric values are provided below:

Energy to increase production (MWh)	
Dev corrected on ID (down)	4692
Dev corrected on ID (up)	642028
Speculative/Error	116476
No deviation	354
No time	0
Expected to fix the outage	7066
Total	**770615**

Chart 39. Energy to increase production

As can be appreciated, the total volume traded to increase production is, roughly, 770 GW.

5.3.2 Volumes negotiated to decrease production

The same reasoning applied on the volume to increase production will be used here. In this case, the highest amount stands for the deviations solved on ID, meaning that when a unit detects an outage, It goes to the ID market and reduces its production until no deviation is incurred. Deviations solved and committed on ID, although they are expected to increase its net production, can reduce partially its output buying energy but, as can be seen, in a not significant amount. The other appreciable percentage are the units expected to fix the outage, which reduce its output to accommodate that unavailable power, but still incur on a deviation.

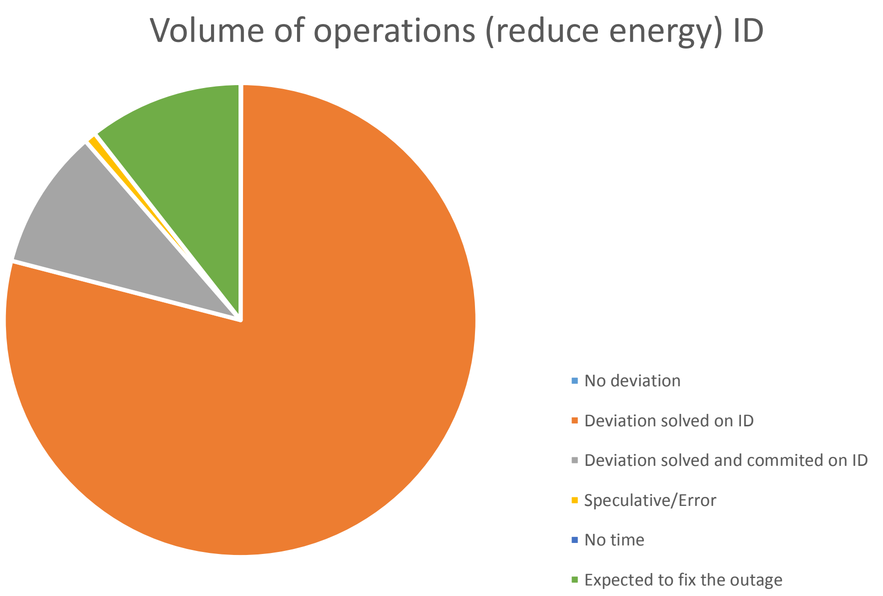

Chart 40. Volume of ID operations to reduce energy

Numeric values show a total of 978 GWh of energy traded by these agents during the year. This number is higher than in the previous section due to the outages: If one of the possible uses of the Intraday sessions is to reduce deviations, it is logic to think that the total amount traded by agents with problems will be negative (expected production will be reduced)

Energy to decrease production (MWh)	
Dev corrected on ID (down)	772398
Dev corrected on ID (up)	93850
Speculative/Error	7807
No deviation	377
No time	0
Expected to fix the outage	103363
Total	**977795**

Chart 41. Energy to decrease production

Units that had no time to renegotiate appear as transactions since they incur on a deviation. However, as they are not able to bid properly on the ID sessions, they won’t solve the deviation, and that´s the reason why the energy of this group is 0.

6. Economic impact of current Intraday Market

The current Intraday model allows agents to adjust their production schedule close to the real time. As already mentioned, there are currently 6 sessions:

	SESSION 1º	SESSION 2ª	SESSION 3ª	SESSION 4ª	SESSION 5ª	SESSION 6ª
Session Opening	17:00	21:00	01:00	04:00	08:00	12:00
Session Closing	18:45	21:45	01:45	04:45	08:45	12:45
Matching Results	19:30	22:30	02:30	05:30	09:30	13:30
Reception of Breakdowns	19:50	22:50	02:50	05:50	09:50	13:50
Publication PHF	20:45	23:45	03:45	06:45	10:45	14:45
Schedule Horizon (Hourly periods)	27 horas (22-24)	24 horas (1-24)	20 horas (5-24)	17 horas (8-24)	13 horas (12-24)	9 horas (16-24)

Chart 42. Intraday sessions scheduling

If a unit is not able to renegotiate its production, it will incur a loss. The cost of that loss, has already been discussed on previous sections. At the end, the profit obtained from a unit will be:

$$Benefit = \sum_{ij}(DAM + IDup - IDdown - DEV)$$

For every thermal unit *i* and for every day of the year *j,* in which an unavailability exists.

Where:

- *Benefit*= net benefit for the agent
- *DAM* = Day Ahead market volume traded * Price, taking into account the day and hour in which the operation had taken place
- *IDup* = Intraday volume traded to increase* Price, subject to the day and hour at which the operation had taken place
- *IDdown* = Intraday volume traded to decrease * Price, subject to the day and hour at which the operation had taken place.
- *DEV* = Cost of deviations from the last Intraday session.

6.1 Impact for thermal units:

The economic benefit of current ID model is shown below:

BENEFITS OF CURRENT ID (thermal units) - year 2015				
	Income (€)	Deviations costs (€)	Deviations volume (MWh)	Net profit (€)
DAM	133.650.760,28 €	71.362.980,94 €	1186828	62.287.779,34 €
ID	119.539.383,98 €	26.226.513,35 €	438158	93.312.870,63 €
Benefits ID	- 14.111.376,30 € -11%	- 45.136.467,59 € -63%	-748669 -63%	31.025.091,29 € 50%

Chart 43. Benefits of current ID on thermal units

As can be seen on the previous chart, the total income from the mentioned agents on the DAM stands for 133 mill €. The total volume traded by agents with unavailabilities on the DAM is 2475 GWh. This makes an average price for those transactions of 53.72 €/MWh. The cost of deviations directly from the DAM, supposing no ID sessions, is around 71,3 mill €, and the deviations volume is around 1,2 GWh. With that, assuming no ID sessions, the net profit would be around 62,2 mill €.

Considering the current Intraday market, the income from the combined DAM+ID is 119,6 mill €. This is 11% lower than the previous case. This reduction is logic, due to the necessary production reduction in order to decrease deviations. However, this income reduction is not as big as it should be considering only production reductions. As already mentioned, ID sessions are also used to increase the selling positions, when a plant that was not available fixes its problems.

Regarding deviation costs, the reduction is quite significant. With current ID sessions, those cost are reduced to 26,2 mill €. This is a reduction of 63%. Deviation volume is reduced as well by 63%, until 438 GWh.

The total benefit is increased by 50%, up to 93 mill €. With that in mind, it can be said that Intraday sessions increase the benefit from thermal units with deviations, helping them to reduce deviation costs and to increase its final welfare.

7. Design of the new Intraday Market

The new intraday market is attempted to reduce the waiting time until the next session as much as possible. On the next figure, the hold on time until the next scheduled session can be seen:

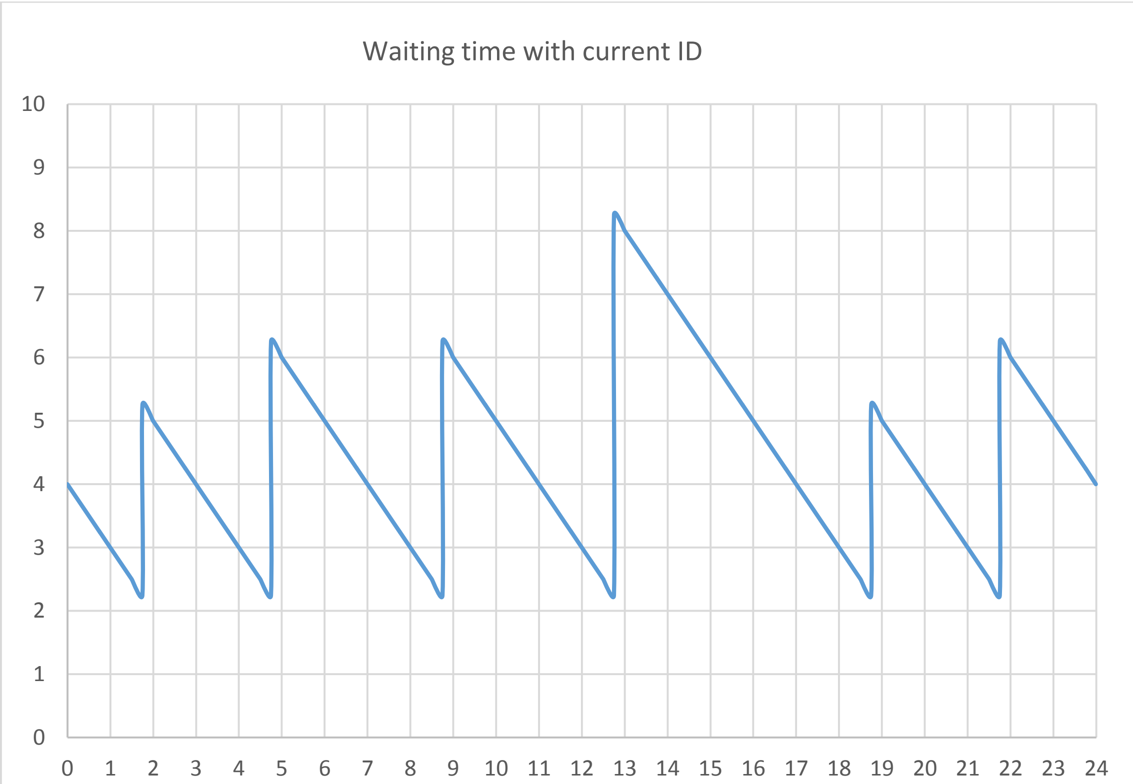

Chart 44. Waiting time under current ID model

The chart shows the time that a unit has to wait from the last possible bidding moment to the start of the next Intraday session. The average waiting time is 4 h 24 min, with a maximum of 8 h 15 min at 12:15. This makes difficult to trade close to the real time, with the subsequent loss of welfare due to deviations and late time adjustments.

The proposed schedule for the new Intraday is based on hourly sessions, with a gate closure closer to the real time. The schedule of sessions is shown below:

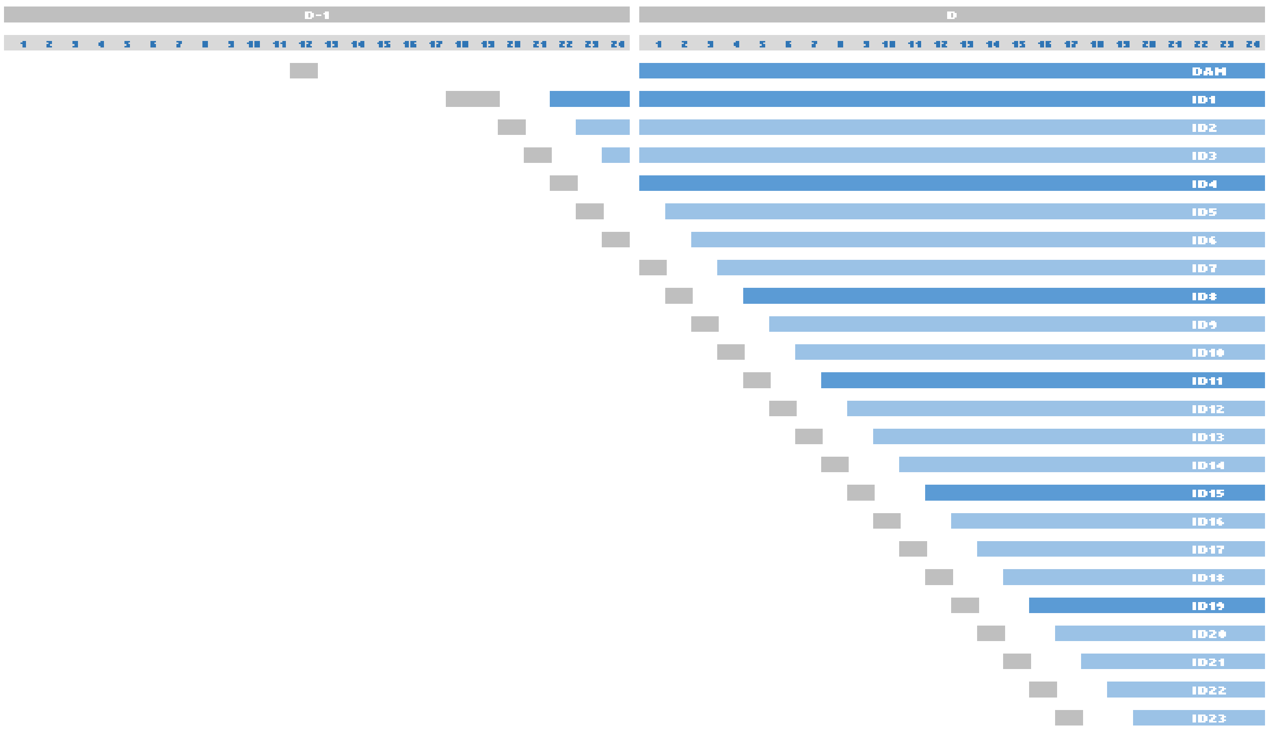

Chart 45. New ID scheduling

The existing sessions are displayed in dark blue, while the new ones in light blue. Gate closure is at T-75min, in order to allow REE (Spanish system operator) to perform the technical analysis of the market solution, and gate opening at T-135min, which leaves one hour to negotiate. There will always be one session open.

Waiting time period will be the next:

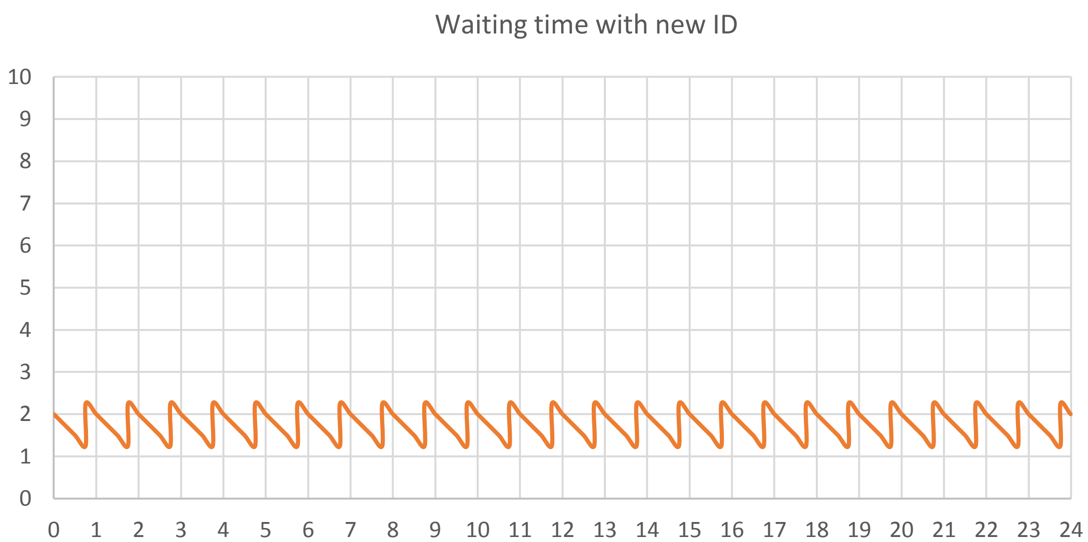

Chart 46. Waiting times for new ID

As can be appreciated, the waiting time has been reduced drastically. Now, the average is 1 h 45 min, which is 2 h 40 min lower than on the original case. This will allow an operation much closer to the real time, reducing deviations and increasing the benefits for the agents.

The expected deviations reduction may be estimated as follows:

If the waiting time is reduced, as an example, by 10%, all the outages that happen during this reduced time will possibly be solved. The thermal outages distribution for year 2015 is shown in the following graph:

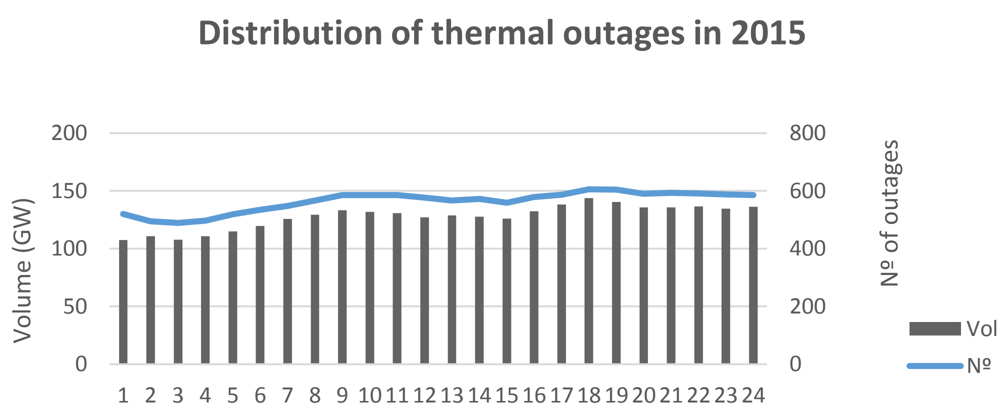

Chart 47. Hourly distribution of thermal outages

As can be appreciated, the outage distribution, although not constant (shows a decrease during night hours due possibly to the load reduction) can be assumed so, both by number of outages and by volume of unavailable power.

It is needed then to calculate the total reduction of the waiting time. This has been performed by calculating the difference of areas between the original and the new waiting times. i.e.,

$$\sum_{t=1}^{96} w_o^t - w_n^t$$

Where:

- w_o is the waiting time for period t under the original scheme.
- w_n is the waiting time for period t under the new schedule.

For higher precision, periods have a resolution of 15 min. That is the reason for the 96 periods instead of 24. Next chart shows it graphically:

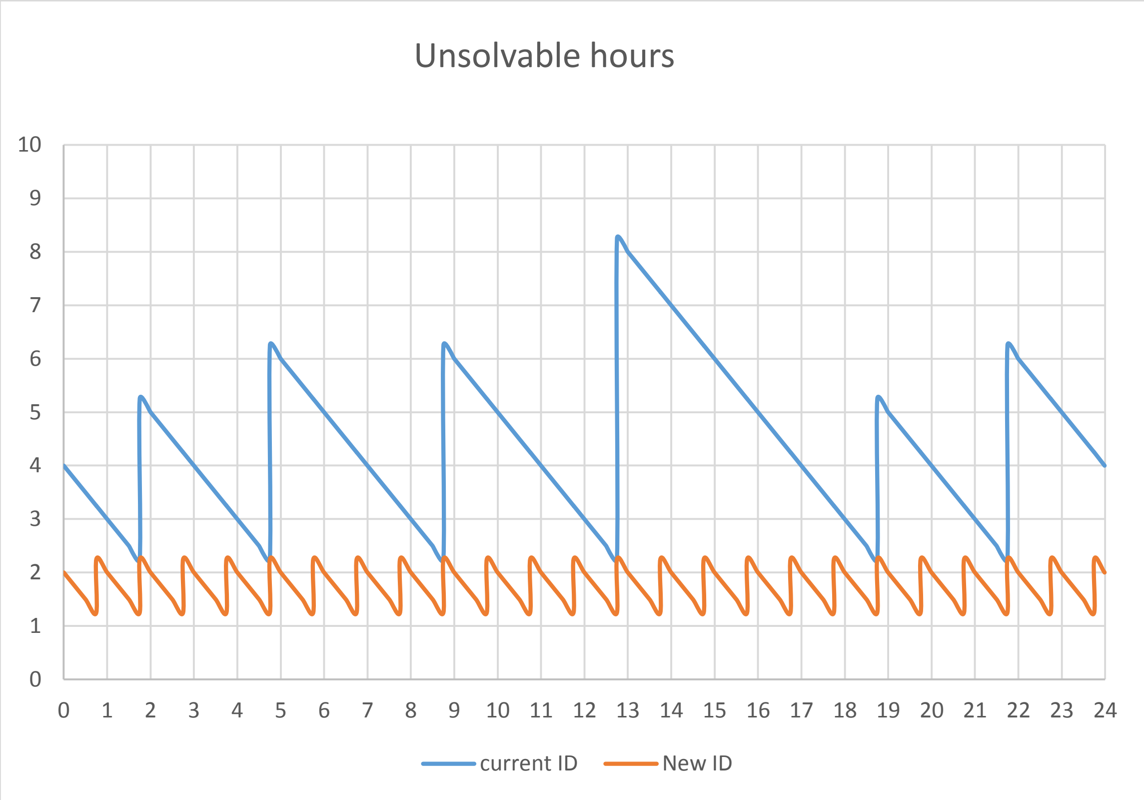

Chart 48. Comparison between current and future ID waiting times

As an example, let us imagine that an outage is detected at 12:50. Following the chart, we can see that under the current model, waiting time will be around 8 hours. This means 8 hours paying deviation price, and losing money. On the other hand, if we look at the new model, waiting time will be around 2 hours. This implies a reduction of the waiting time of around 75%. An analysis of the full day will show that 60% more outages will likely be solved under the new scheme. The economic assessment of this will be performed on further chapters.

7.1 Expected prices of the new market design

Prices on the new Intraday market are not expected to change pretty much. A spline based interpolation has been performed in order to estimate them. As can be appreciated on the chart below, Intraday prices do not vary significantly across sessions. There is a higher difference during first peak hours and also during valley hours. Middle ones, and also second peak hours, suffer from a lower price difference. A possible explanation for that is provided below:

- First peak hours (commercial schedule, offices, industry loads) vary significantly from weekdays to weekends and holidays. On the other hand, the second peak is usually due to households' activities (TV, cooking, computers) that people use to perform at the end of the day.

- Night hours' intraday market volumes are low compared with day ones. Due to this, volatility may be increased.

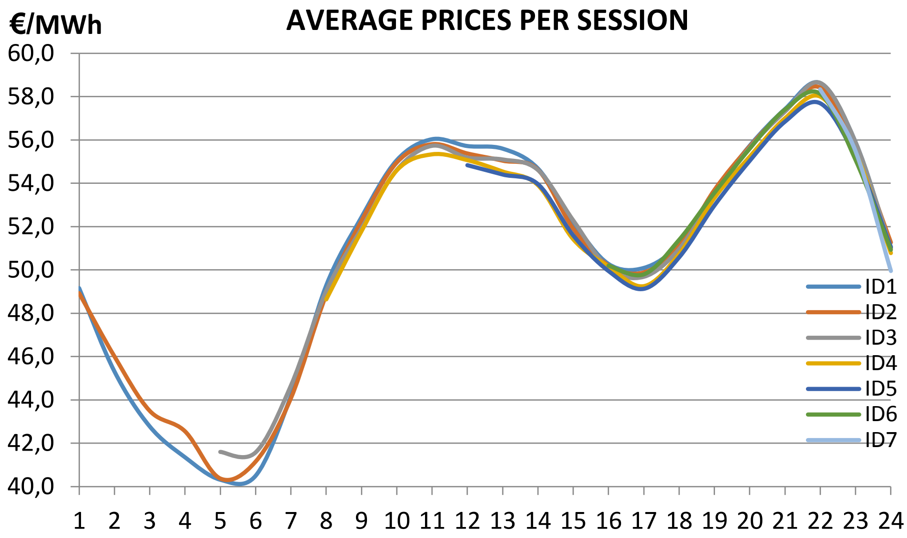

Chart 49. Average ID prices per session

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The following chart shows the average prices for all the DAM and ID sessions in 2015:

AVERAGE MARKET PRICES	
Columna1	**Columna2**
Day Ahead	50,32413356
ID1	51,2079261
ID2	50,77780201
ID3	51,90618167
ID4	53,27289584
ID5	53,32837092
ID6	53,56603044

Chart 50. Average ID market prices

7.2 Expected volumes of the new design

The chart below shows the volumes that current Intraday models had on January 2016:

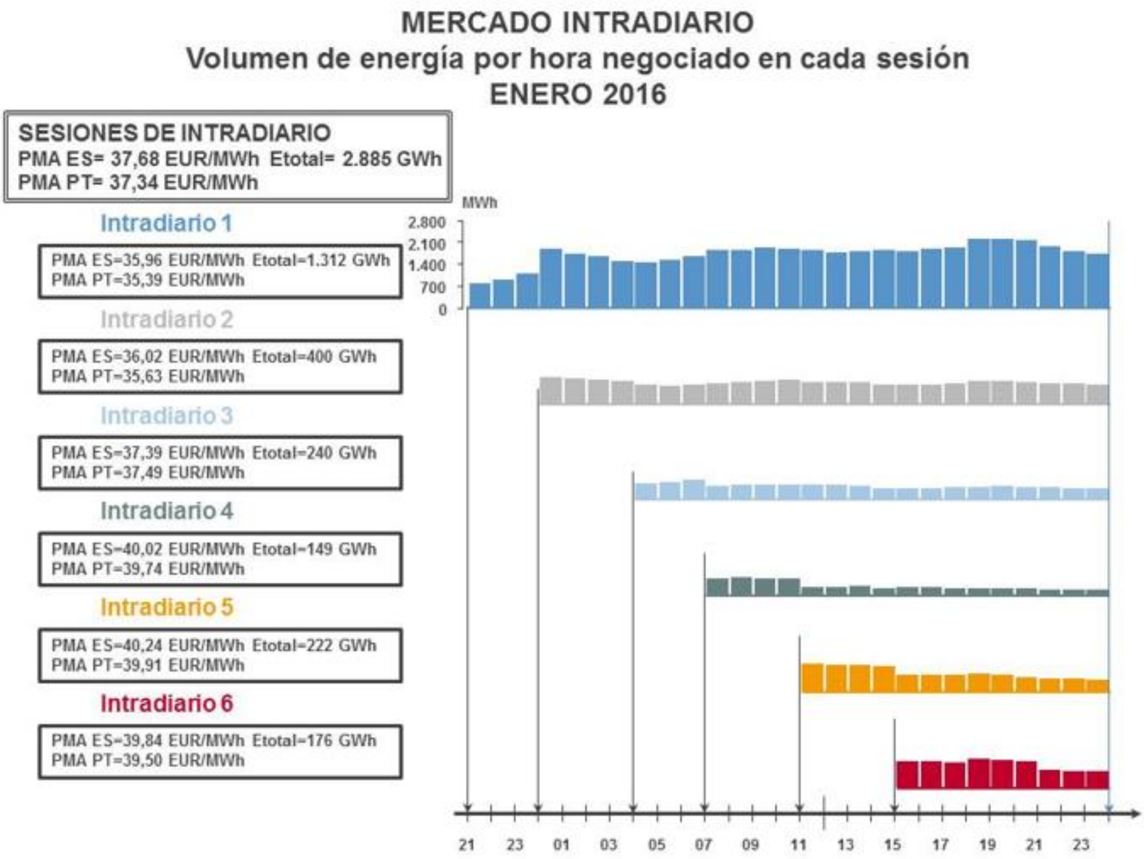

Chart 51.Intraday volumes per session. Source: OMIE

As can be appreciated, Intraday 1 has the highest liquidity and the lowest price. Second market shows higher volumes during the first hours. The reason for this is that there is no further opportunity to renegotiate these hours on later sessions so, if any agents needs to modify its position, he may have to pay a higher price or receive a lower income than he wanted. On the other hand, the rest of the hours are negotiable on next sessions so there is no need to pay an undesired price for that energy. This trend can be appreciated on the next ID markets, during the hours last traded by them.

Regarding average liquidity, as can be appreciated on the chart, the third and fourth markets can be seen as the less liquid ones, per hour. The most liquid is the first, followed by fifth and sixth.

Volumes under the new model are expected to suffer a higher impact. To asses that, it is necessary to discriminate between the different types of operations performed under the current scheme. The types of operations were already explained. The expected variation will be:

- For deviations corrected up, an increase of 60 %. The reason for that increase is that these units’ will be able to operate much closer to real time. Due to that, as explained previously 60% more solved outages will be detected on time to bid and produce on the next ID session
- For deviations corrected down, an increase of 60 % is expected. The reasons for that are the same as in the previous point but applied to deviations reduction.
- For Speculative behavior, no increase expected. This may not be accurate, as the agents will surely try to get advantage of the new markets in order to make some profit. However, as it is very difficult to assess that, we preferred to assume no increase than to provide a non-founded value.
- For no deviation, no increase expected. This kind of behavior, as mentioned before, was included on the database due to an unavailability declared by the agents, but this, as was lower than the program, didn´t lead to any deviation.
- For the units that were expecting to fix the outage, no increase expected. Since they were expecting to fix the problem and produce normally without deviation, no further correction is expected. However, some of them, if they notice the impossibility to solve the problem, would surely bid on the last session possible to adequate its production.

For the reasons provided above, and some others provided later on, the economic assessment of the new market has to be treated as orientative.

8. Economic analysis of new Intraday Market

New sessions, as mentioned before, will allow agents to bid closer to real time. This will cause an impact on their deviations and, consequently, to its profit. The impact to each individual agent will be difficult to assess. For this reason, a joint analysis has been performed, studying the variation of the deviations price, deviations volume and Intraday operations. Each of the parts will be explained individually.

8.1 Deviations price

As explained before, when a unit suffers a deviation which goes against the system requirements, it has to pay a price, higher than the Day Ahead Price for that hour if the system needs to go up and, on the contrary, earns a profit lower than the Spot Price if the system needs to go down. This is traduced on a loss of money per MWh produced. Under the current model and with current deviation volumes, the average loss is shown below:

	System needs "up"	System needs "down"
DEV > 0	**0,00**	**18,95**
DEV < 0	**8,56**	**0,00**

Chart 52. System needs pricing

Deviations volume are the sum of the deflections of every single agent on the system, compared with the Final Hourly Program (Spanish acronym is PHF). In order to assess the loss for the agents with different deviation volumes, a regression analysis was performed, differentiating hours with system needs up and down. While the output variable is pretty clear (economic loss) there were three possible inputs:

- **Deviation volume** is calculated as the net sum of deviations of every agent in the system. This may be the most logic input; deviation price is proportional to the agents' deviation. When increasing deviation, more adjustment services would be needed (tertiary reserve, secondary reserve, deviations management). Those services are paid by agents that provoke them.

- ***Gross adjustment services*** consist of the sum in absolute value of all the adjustment services convoked during an hour. System operator may not always call for the right amount of, for example, tertiary regulation. If it convokes more than needed, it may be necessary to use secondary regulation on the other sense, increasing the deviation price
- **Net adjustment services** consists of the net sum of all the adjustment services. This number shall be pretty similar than the deviation volume.

For example, if 300 MW of upwards tertiary reserve and 200 MW of downwards secondary reserve are convoked, the gross adjustment service value would be 500 MW, while the net adjustment service value would be 100 MW. The deviation volume would be around 100 MW.

The results of the regression study are shown below. Data was obtained from P48 program, provided by REE:

Correlation coefficients			
	Economic loss - Deviation volume	Economic loss - Adjustment services (gross)	Economic loss - Adjustment services (net)
system up	-0,382768739	0,449992585	0,384124544
system down	0,38129766	0,441410721	-0,354950385

Chart 53. Regression analysis

As can be appreciated, the highest correlation is obtained from Gross adjustment services, and the second best option would be the deviation volume, although pretty similar to net adjustment services. Negative correlation means inverse proportionality.

There is a problem when trying to estimate prices with gross adjustment services: it is difficult to estimate the reduction expected under the new model, while the deviation volume estimation is more straightforward. For that reason, and taking into account that the fit difference is small, the regression analysis has been performed with deviation volumes. Data was split in two, taking into account the system needs in each hour.

Correlation for system up is shown on the graph below. Following the least squares adjustment method, the best fitting curve is an order 1 polynomic which equation is included on the graph:

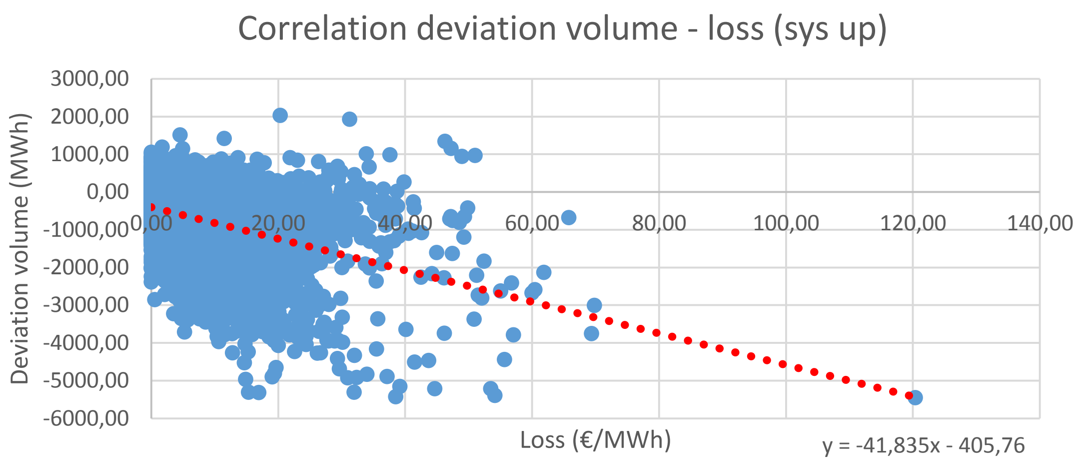

Chart 54. Correlation deviation volume – system loss (system up)

requirements are to go up, there is usually a negative deviation. The cost is higher as the volume of negative deviation increases.

Correlation for system down is shown on the graph below. Following the least squares adjustment method, the best fitting curve is an order 1 polynomic which equation is included on the graph:

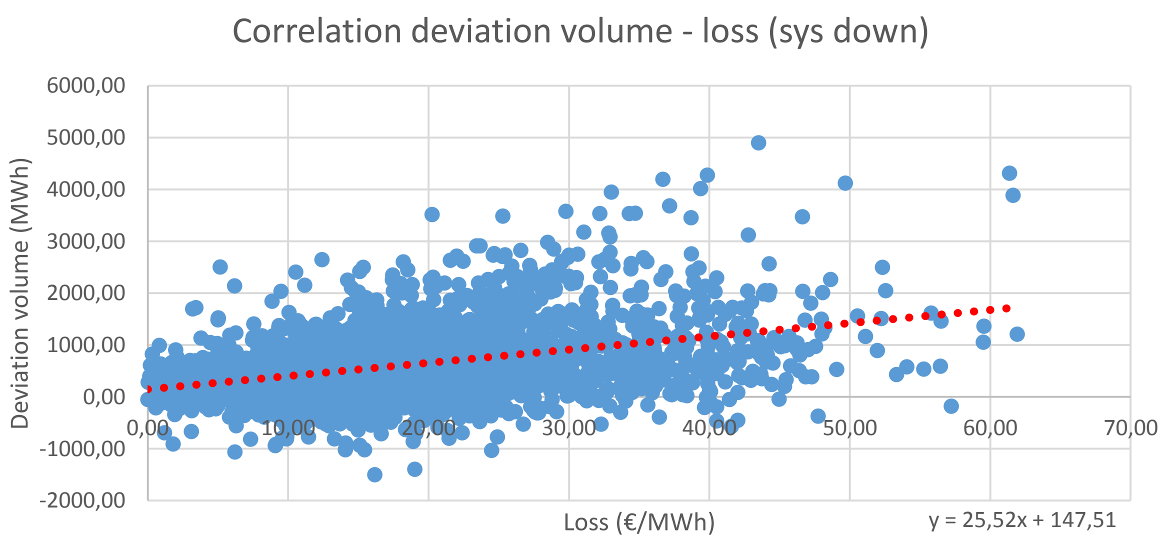

Chart 55. Correlation deviation volume - system loss (system down)

As can be appreciated, the data shows an upwards trend. This means that, when system requirements are to go down, there is usually a positive deviation. The cost is higher as the volume of positive deviation increases.

The next step would be to test the model, assessing how it estimates the current deviation cost, starting from deviation volume. The table below confirms that:

Deviation cost estimation							
	Fit	Average deviation (current)	Reduction coef	Average deviation (expected)	Average current loss (real)	Average current loss (expected)	Average expected loss
Up	-0,38276874	-763,74	0,40	-458,24	8,56	8,55685411	1,25449014
Down	0,38129766	630,83	0,40	378,50	18,94	18,9387554	9,05118427

Chart 56. Deviation cost estimation

As can be seen, the estimation for current loss is pretty accurate. The reduction coefficient shows the expected reduction on deviations. This number does not match with the expected reduction volume (which will be deducted later) but the regression model does not allow reductions under 47% (it results on negative prices). However, with a 40% of deviation reductions, the expected loss for the agents incurring deviations would be around 1,25 €/MWh when the system requires up and they go down (this will be applied to thermal units), and a loss of around 9,05 €/MWh when the system requires down and they go up.

8.2 Deviations volume for thermal units

The average volume of deviations, as explained before, will suffer a reduction of 60%, for a detailed explanation of this refer to chapter 7. The deviations volume for year 2015 was 438158 MWh. Consequently, the expected deviation for a year in which the new design is applied will be 438158 x 0.4 = 175263 MWh.

	Sessions	Deviation volume
No ID	0	1186828
Current ID	6	438158
New ID	24	175263

Chart 57. Deviation volume under current and new model

8.3 Variation on Intraday operations for thermal units

The variation on Intraday operations comes from the reduction of deviation volumes. That energy has to be traded on the ID market, and will be acquired at market price, instead of paying the deviation cost. The increase for the several agents' behavior is detailed on the following charts. The reason of the increase in volume of each individual behavior was explained previously.

Energy to increase production, this means, the energy that producers (always talking about thermal units) sell and consumers acquire, is shown on the following chart:

Energy to increase production (MWh)			
	Current	**Expected**	
Dev corrected on ID (down)	4692	7506,88	60%
Dev corrected on ID (up)	642028	1027244,8	60%
Speculative/Error	116476	116476	0%
No deviation	354	354	0%
No time	0	0	0%
Expected to fix the outage	7066	7066	0%
Total	**770615**	**1158647,38**	**50%**

Chart 58. Expected energy to increase production

Energy to decrease production, this means, the energy that producers (always talking about thermal units) buy and consumers sell, is shown below:

Energy to decrease production (MWh)			
	Current	**Expected**	
Dev corrected on ID (down)	772398	1235836,48	60%
Dev corrected on ID (up)	93850	150160,16	60%
Speculative/Error	7807	7807	0%
No deviation	377	377	0%
No time	0	0	0%
Expected to fix the outage	103363	103363	**0%**
Total	**977795**	**1497543,64**	**53%**

Chart 59. Expected energy to decrease production

The two previous charts showed the volumes traded by thermal units on the Intraday sessions, and the expected figures under the new model. The following chart states the number of operations performed under the current and future models:

	Operations (Nº)		
	Current	Expected	
Dev corrected on ID (down)	3739	5982,4	60%
Dev corrected on ID (up)	3135	5016	60%
Speculative/Error	925	925	0%
No time	1061	424	-60%
No deviation	3264	3264	0%
Expected to fix the outage	1401	1401	0%
Total	**13525**	**17012,8**	**26%**

Chart 60. Number of current operations vs expected

As can be seen, the increase in sales is expected to increase by 50 %. Increase in acquisitions is expected to suffer an increase of 50%, and the increase in number of operations is expected to grow by 26%. This lower increase is due partially to the fact that "no time" operations (which were the ones in which agents didn't have time to operate, in order to solve the deviation) are quantified in number, but have no energy associated, and are expected to be reduced proportionally to the waiting time.

The following chart shows the successive income reduction from the DAM to the current ID and the new model. This reduction, as explained before, comes from the increased solved deviations less the increase of sales due to the outages solved that lead to energy available to be sold:

	Income (€)
DAM	133.650.760,28 €
Current ID	119.539.383,98 €
New ID	107.514.377,87 €
Benefits new ID, compared with current ID	- 12.025.006,11 €
	-10%

Chart 61. Income variation under different schemes

As can be appreciated, the profit reduction against the current model stand for approximately 12 Million Euros, which is a 10% less than under the current model. This will be compensated by the reduction on deviations payments, both in quantity and in unitary price, as explained on previous sections.

8.4 Impact on thermal units

The purpose of this section is to put together all the concepts stated before (deviations volume, unitary cost reduction, and intraday income variation).

Estimation of deviation costs has been performed as follows:

- First, as explained before, estimation of deviation volumes has been carried out.
- Second, the pricing of this deviation was estimated on the following way:

  From the estimated deviation volume, using statistical data, the number of hours with system requirements up and down was estimated. As can be appreciated on the following chart, from the total of hours with deviations, 73% happened when system required more energy and 23% happened when the system required less.

Deviation - System requirements		
Deviation over last id - hours UP	319596	73%
Deviation over last id - hours DOWN	118562	27%
Deviation over last id - TOTAL	**438158**	**100%**

Chart 62. Hours with deviations, separated by system requirements

As explained before, referring to thermal deviations, (almost always deviations down), hours up are priced at DAM price and hours down are priced at the average loss incurred:

$$Dev\ cost = Dev\ volume * (hours\ up * (DAM\ price + Corrected\ dev\ loss) \\ + hours\ down * DAM\ price)$$

Corrected dev loss was already explained in detail.

Results are shown on the following chart:

Cost estimation for new ID						
	Sessions	**Deviation volume**	**Cost (real)**	**Cost (estimated)**	**Difference (real- est)**	**Savings**
No ID	0	1186828	71.362.980,94 €	66.655.452,40 €	6,6%	0,0%
Current ID	6	438158	26.226.513,35 €	24.752.369,33 €	5,6%	62,9%
New ID	24	175263	-	8.967.427,91 €	-	86,5%

Chart 63. Cost estimation for new ID

The chart shows that current ID model allows a deviation cost reduction of 62,9%, while new model allows a reduction of 86,5% compared with no intraday and a 63% reduction compared with current model. The real and estimated concepts show that the estimation process performed (explained on previous paragraph) is pretty accurate for current situation, obtaining an error of around 6%.

Income estimation was deducted before. The estimation for DAM was performed as follows:

$$Inc\ est\ (DAM) = hours\ UP * DAM\ price\ (up) + hours\ DOWn * DAM\ price\ (down)$$

This means, splitting DAM operations in hours with requirements up and down, and estimating them at the corresponding price. Volumes Up and Down were, respectively, 32 and 68 %. Prices were respectively 50,02 and 50,87 €/MWh, always referring to 2015.

Estimation for ID and new ID were performed on the same way, with the difference that ID operations were both Up and down, and there was necessary to make the netting of both concepts. ID income consists of the sum of DAM and ID, and new ID income comes from DAM + Current ID + new ID:

INCOME ESTIMATION FOR NEW ID					
	Income source	Income (real)	Income (estimated)	Difference (real-est)	income difference
No ID	DAM	133.650.760,28 €	125.278.671,23 €	6,3%	0,0%
Current ID	DAM + ID	119.539.383,98 €	114.412.336,32 €	4,3%	-10,6%
New ID	DAM + ID + New ID	-	107.514.377,87 €	-	-20%

Chart 64. Income estimation for new ID

Putting together Incomes and costs, the next chart shows the expected benefits of the new model, for thermal units. Comparing it with the current ID model, it is expected to have a 10% income reduction, which is compensated by a 66% reduction on deviation costs, providing a net profit of 5,2 Million € for deviated units:

EXPECTED BENEFITS OF NEW ID - year 2015				
	Income (€)	Deviations costs (€)	Deviations volume (MWh)	Net profit (€)
Current ID	119.539.383,98 €	26.226.513,35 €	438158	93.312.870,63 €
New ID	107.514.377,87 €	8.967.427,91 €	175263	98.546.949,96 €
Benefits new ID, compared with current ID	- 12.025.006,11 € -10%	- 17.259.085,44 € -66%	-262895 -60%	5.234.079,33 € 6%

Chart 65. Expected benefits of new ID, compared with current ID

By comparing the new design with a no intraday model, it shows a 20% income decrease, 87% deviation costs reduction and 58% increased benefit:

EXPECTED BENEFITS OF NEW ID - year 2015				
	Income (€)	Deviations costs (€)	Deviations volume (MWh)	Net profit (€)
DAM	133.650.760,28 €	71.362.980,94 €	1186828	62.287.779,34 €
New ID	107.514.377,87 €	8.967.427,91 €	175263	98.546.949,96 €
Benefits new ID, compared with DAM	- 26.136.382,41 €	- 62.395.553,03 €	-1011564	36.259.170,62 €
	-20%	-87%	-85%	58%

Chart 66. Expected benefits of new ID, compared with DAM

9. Conclusions

After concluding this study, the obtained results show that the new scheme looks pretty beneficial for agents bidding in the Intraday market. It allows them to operate much closer to real time, fine tuning their bids, reducing deviation costs and maximizing their profits.

European integration under XBID platform will provide more liquidity to most of the member states market´s. However, in the case of Spain and Portugal, the interconnection capacity with the rest of the continent is really low (around 3% of the installed capacity) and, since Spanish prices are much higher or lower (depending on the period of the year, hydrology, RES penetration…) than in France (French prices on 2015 were 38.5€/MWh while Spanish were, as mentioned before, 50,3€/MWh), interconnection is usually occupied by DAM assignments. Chart below shows the DAM prices for Spain and France, in 2015.

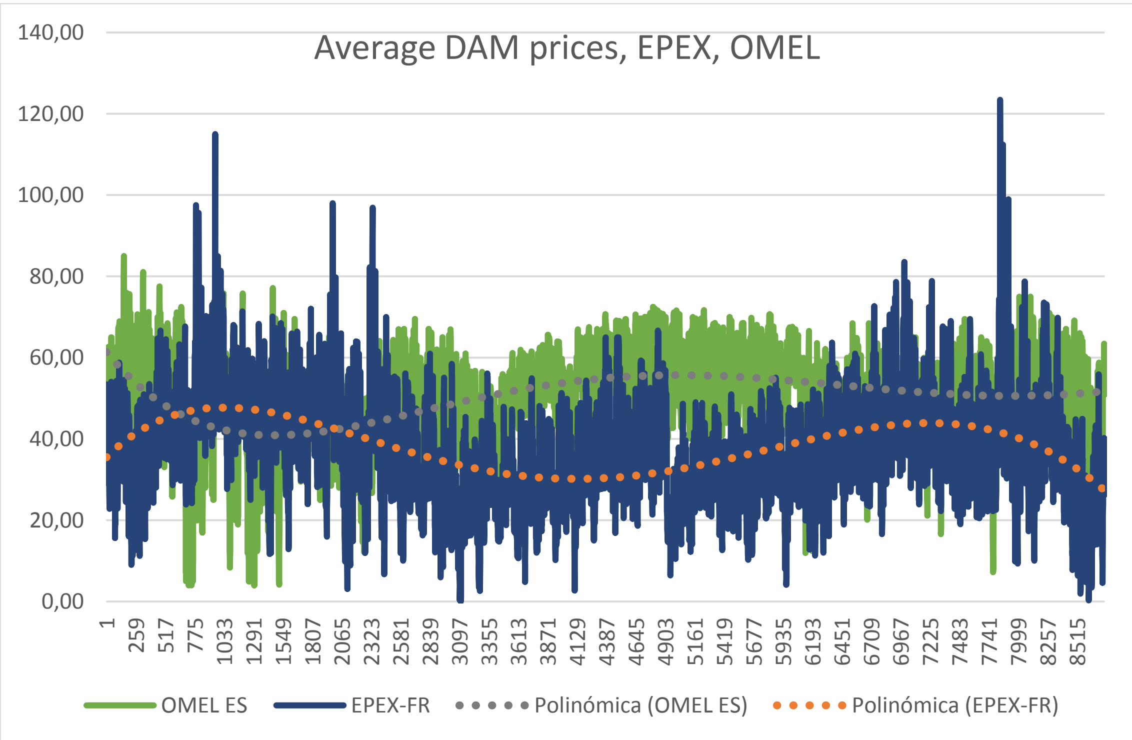

Chart 67. Spanish and French spot prices, 2015. Source: OMEL

Next graph shows the interconnection capacity between Spain and France. Import means a flow from France to Spain and vice versa. As can be appreciated, there is free capacity only 14% of the time

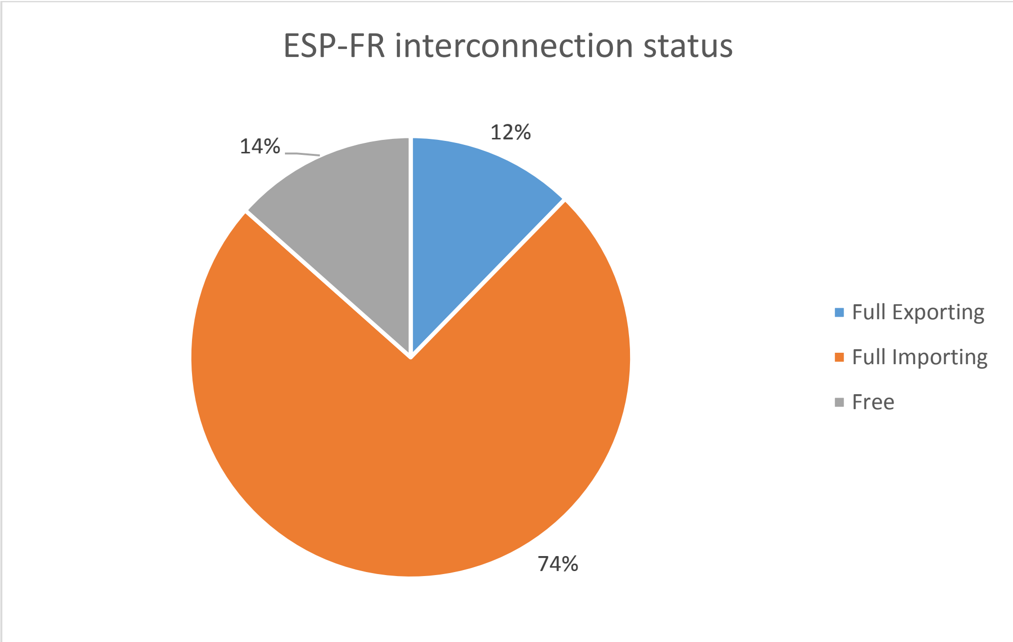

Chart 68. Status of the interconnection capacity

For this reason, unless there are punctual inverse prices (against the trend), Intraday liquidity will not be increased significantly by European flows. This may not be the case in well interconnected countries as Germany or Belgium, who has usually available capacity on both directions.

At some hours, expected usually at night, liquidity may be compromised, leading to an increased volatility on the Iberian sector. On the other hand, deviations volumes, and penalties will be reduced. The 5,3 Million € savings can increase the thermal agent's group rough benefit of 100 Million €, shows a 5% increase, which is significant.

For RES agents and traders, the gain will be even higher, since a closer to real time operation will allow them to use more precise weather and consumption forecasts. This study can be easily extended to those technologies, following the same technology but taking into account that both deviations up and down should be taken into account.

However, this study is based on reasoned estimations. The results obtained are estimative and subject to an error.

10. Bibliography

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- REE Operative Procedures:
  - P.O. 3.3 – Deviations Management
  - P.O. 7.2 – Secondary Regulation
  - P.O. 7.3 – Tertiary Regulation
  - P.O. 14.4 – Payment rights/obligations derived from balancing services
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