UNIVERSIDAD PONTIFICIA COMILLAS

ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

OFFICIAL MASTER'S DEGREE IN THE ELECTRIC POWER INDUSTRY

Master's Thesis

Modelling of the current RES remuneration scheme in Spain since 2013

Author: Paulo Brito Pereira
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Madrid, July 2019

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Abstract

This Master's Thesis describes the creation of an Excel model used to calculate the regulated revenues to be obtained by any renewable energy source (RES) power plant that participates in the support scheme present in Spain (Royal Decree 413/2014).

In order to achieve this, it was necessary to analyze all the legislation that is relevant to the matter, to understand the issue at hand and to envision the proper way of implementing it into a model. The model was then created, taking into account the particularities of the Spanish support scheme, and considering that new power plants could be added to this scheme, so the model would have to cope with those too.

With this model it was possible to analyze how different scenarios would affect the regulated revenues of different RES power plants. It was also possible, due to estimations on the installed capacity of the different power plants, to approximate the variation in cost for the electric system of these scenarios. Finally, this model yielded results in order to assess the profitability of a hypothetical power plant associated to this support scheme, given variations with respect to a reference RES power plant.

In conclusion, this model is able to obtain results that are useful for businesses that are owners of RES power plants, or that are willing to enter into the sector, academics that wish to study the effects of this support scheme, and regulators that wish to assess changes in the scheme.

This Master's Thesis is dedicated to my parents. Without them, I would not be where I am today, everything I am is thanks to their constant support and sacrifice. I owe them my life. Thank you.

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Nomenclature

General terms

VNA	—	Net asset value per unit of power, expressed in €/MW.
t	—	Return rate.
Ing	—	Revenues for the installation type, including all remuneration from the support scheme, expressed in €/MW.
$Cexp$	—	Total operation costs, expressed in €/MW.
$Vajdm$	—	Adjustment due to deviations in market price, expressed in €/MW.
$Rinv$	—	Annual investment remuneration per unit of power that is awarded to the IT, expressed in €/MW. The value of *Rinv* is the same for each year of the smi-period.
C_a	—	Adjustment coefficient of the IT with authorization year "a" expressed in per unit. It represents the amount of the investment that cannot be recovered through operation in the market.
VR	—	Residual life of the IT, understood as the number of years that are left from the beginning of the semi-period for the IT to reach the end of the regulatory life of the asset.
VU	—	Regulatory life of the IT, expressed in years.
$Ingf$	—	Future estimated revenues for the installation type until the end of its regulatory life, including all remuneration from the support scheme, expressed in €/MW.
$Cexpf$	—	Future estimated total operation costs until the end of its regulatory life, expressed in €/MW.
VI	—	Standard value of the initial investment for the IT, expressed in €/MW.
d	—	Factor determining the percentage of regulated revenues the IT is allowed to perceive, expressed in p.u.

$Nhinst$ or Nh — Equivalent number of functioning hours, expressing the equivalent number of hours the IT would have been operating at maximum power, in hours. Can be obtained by multiplying the capacity factor by the number of hours in a year, 8760.

$Nhmin$ — Minimum number of functioning hours, describing the minimum number of equivalent hours above which the IT can receive all the regulated revenues.

Uf — Operating threshold, describing the minimum number of equivalent hours below which the IT will not receive any regulated revenues.

Pm — Average day ahead and intraday market price.

$LS2$ — Second upper bound for $Vajdm$ calculation.

$LS1$ — First upper bound for $Vajdm$ calculation.

$LI1$ — First lower bound for $Vajdm$ calculation.

$LI2$ — Second lower bound for $Vajdm$ calculation.

$\frac{Cvg_j}{Egbc_j}$ — Variable generation cost per unit of energy of the system, expressed in €/MWh.

A — Term used to determine the amount of system cost reduction required to obtain cost reduction incentive remuneration, expressed in p.u.

$Iinv$ — Cost reduction incentive remuneration that an IT can receive, expressed as €/MWh.

B — Term used to determine the amount of system cost reduction that an IT can receive as cost reduction incentive remuneration, expressed in p.u.

Cogeneration and biomass terms

CF — Estimation of the frontier cost of gas, expressed in c€/kWh$_{PCS}$.

mt — Transport maiming expressed in p.u.

β — Gas supply in the Spanish market that has been covered by regasification plants.

mr — Regasification maiming expressed in p.u.

PA_j — Estimation of the access tolls cost applicable for a customer subject to step "j" of Group 2, expressed in c€/kWh$_{PCS}$.

A — Term that determines the price cost sensitivity of an IT on the fuel cost, expressed in p.u.

B	—	Term used to update the operation remuneration of a cogeneration IT, expressed in p.u.
C	—	Term used to balance the operation remuneration of a cogeneration IT, expressed in €/MWh.
RC	—	Semisum of the daily stock prices averages for the previous semester with deliveries in the current semester, in the Henry Hub (HH) market, published by the New York Mercantile Exchange (CME Group) and in the National Balancing Point (NPB) market, published by the Intercontinental Exchange (ICE), expressed both in c€/kWh$_{\text{PCS}}$. The average of $/€ of the European Central Bank (ECB) for the last month of the previous semester is used to calculate this.
Br	—	Brent futures, obtained as the average of the daily stock prices for the previous semester with deliveries in the current semester, published by ICE, expressed in $/barrel.
T	—	$/€ exchange rate calculated as the average of the values published by the ECB for each day of the last month of the previous month.
Trf	—	Fixed term of the regasification toll, expressed in c€/kWh/day/month.
Trc	—	Capacity reserve term of the transport and distribution toll, expressed in c€/kWh/month.
Tfc_j	—	Conduction fixed term of step "j" of Group 2, expressed as c€/kWh.
Tvc_j	—	Conduction variable term of the transport and distribution toll of step "j" of Group 2, expressed in c€/kWh.
Tvr	—	Variable term of the regasification toll, expressed in c€/kWh.
$Tgnl$	—	LNG storage toll, expressed in c€/MWh/day.
Cas	—	Underground storage cost, expressed in c€/kWh.
Drs	—	Number of strategic storage days.
$Tfas$	—	Fixed term of the underground storage canon, expressed in c€/kWh/month.
Tvi	—	Injection term of the underground storage canon, expressed in c€/kWh.
Tve	—	Extraction term of the underground storage canon, expressed in c€/kWh.
PCI	—	Inferior calorific power depending on the fuel, expressed in MWh$_{\text{PCI}}$/t.
PI	—	International price of fuel estimation, expressed in €/t.
t	—	Semi-annual increment rate of the biomass price, expressed in p.u.

Ta	—	Annual increment rate of the biomass price, expressed in p.u.

Modelling terms

CP	—	Captured price factor, reflecting the actual average market price perceived by a particular technology with respect to the general average market price, expressed in p.u.
Rev	—	Revenues obtained by IT, expressed in €/MW.
$ORev$	—	Other sources of revenue obtained by the particular IT, expressed in €/MWh.
Tg	—	Toll on accessing the grid, which takes the value of 0,5 €/MWh.
Dev	—	Deviation costs associated to the particular technology, expressed in €/MWh.
C_F	—	Fuel costs, including the cost associated to the special tax on hydrocarbons, expressed in €/MWh.
$IVPEE$	—	Costs associated to the tax on the value of the production of electrical energy, expressed in €/MWh.
T_{IVPEE}	—	Value of the tax on the value of the production of electrical energy, which currently stands at 7%.
C_{CO2}	—	CO_2 emission allowances costs, expressed in €/MWh.
$OPEX$	—	Rest of operational expenses, expressed in €/MWh.
$PMar$	—	Perceived margin by the IT, expressed in €/MW.
$RMar$	—	Regulated margin for net asset value calculations, expressed in €/MW.
T_{CO2}	—	CO_2 emission allowances price, expressed in €/tCO_2.
EF	—	CO_2 emissions of the fuel used, expressed in tCO_2/MWh$_{\mathrm{PCI}}$.
η_E	—	Electrical efficiency, expressed in p.u.
η_H	—	Thermal efficiency, expressed in p.u.
δ	—	Percentage of CO_2 emission allowances given for free for thermal generation, expressed in p.u.
$R_{exp/gross}$	—	Relationship between the final exported energy and the generated energy, expressed in p.u.
EEE	—	Equivalent electrical efficiency, expressed in p.u.
T_F	—	Fuel price, expressed in €/MWh$_{\mathrm{PCI}}$. It is the fuel cost C_F minus the costs associated to the special tax on hydrocarbons.

STH_E	—	Special tax on hydrocarbons of the fuel used to produce electrical energy, expressed in €/MWh$_{PCI}$.
STH_{H-CHP}	—	Special tax on hydrocarbons of the fuel used to produce thermal energy, expressed in €/MWh$_{PCI}$.
C_{STH}	—	Cost associated to the special tax on hydrocarbons of the fuel used, expressed in €/MWh.
$RefH$	—	Reference thermal efficiency of separated thermal generation, expressed in p.u.
Ny_j	—	Number of years the IT will operate in semi-period "j".

Subindeces

a	—	Definitive year of authorization of the IT.
j	—	Regulatory semi-period.
p	—	First year of the regulatory semi-period.
sm	—	Number of years of the regulatory semi-period, which is equal to 3.
s	—	Semester.

Chapter 1

Introduction

Renewable energy sources (RES) have been one of the main focus points of European policy in terms of energy regulation and prevention of climate change policies for over a decade. The danger of climate change, and the need for regulatory entities to provide a solid answer that could prevent its potential dangers, has put RES in the spotlight, as energy sources with zero contaminating emissions and no use of fossil fuels.

The Kyoto Protocol was the stepping stone of all future international agreements on climate change, in 1998. However, in this international agreement there was little focus on RES, mentioned only once in the whole agreement, and instead focused more on mechanisms to reduce greenhouse gas emissions without the use of alternative sources of energy, such as the International Emissions Trading scheme, Joint Implementation (JI) and Clean Development Mechanism (CDM). This approach was followed in the European Union with the implementation of the EU Emissions Trading System (EU ETS), adopted in 2005, which set a cap on the amount of carbon dioxide (CO_2), nitrous oxide (N_2O) and perfluorocarbons (PFCs) to be emitted. Nevertheless, this approach did not include RES at all. Later international agreements like the Paris Agreement in 2015 were similar in this regard; the focus was set on reducing greenhouse emissions, not specifically on RES.

On the other hand, the European Union has been significantly ahead in terms of promotion of RES. This promotion commenced in 2001, with the approval of the Directive 2001/77/EC [11], which started establishing objectives for RES production for the different member states by 2010. It also stated the possibility of implementing different RES support schemes by the different member states in order to achieve these objectives. This continued more clearly in 2008, with the 2020 climate & energy package by the European Union, which set requirements on the member states to achieve a reduction of 20% of greenhouse gas emissions (compared to 1990), a 20% share of EU energy to come from renewables, and a 20% improvement in energy efficiency by 2020. This was the first clear mandate on individual member states to achieve certain amount of energy production from RES, and was defined in law more clearly with the Directive 2009/28/EC [12]. In October of 2014 these objectives were expanded with the 2030 climate & energy framework, increasing the reduction of greenhouse gas emissions to 40% (compared to 1990), increase the share of renewable energy to 32% and to improve energy efficiency to 32.5% by 2030. These objectives were described more clearly, and enforced by legislation with the Clean Energy for all Europeans package, being the Directive 2018/2001 the legislation related with RES [13]. Finally, the European Union has also set long-term objectives with the 2050 long-term strategy, which sets guidelines and steps to take until 2050, which was outlined in November of 2018, including RES.

These three European Directives were the first pieces of concrete legislation, forcing Member States to integrate RES more effectively in their power systems. This led to Member States implementing different support schemes to aid RES, which were quite immature in 2001, with each of them deciding on different alternatives to aid these technologies. Some of them decided to implement these schemes previous to 2008, as even before that it has been clear that RES have an important role in fighting climate change, as they allow for the production of energy without the burden of producing greenhouse effect gases for it. This characteristic has made them an extremely versatile tool for countries to achieve the reduction of emissions without risking their energy supply. However, traditionally, RES have been very costly and have not been competitive against conventional energy sources. This is why, for more than a decade, countries have implemented different support schemes, to increase the competitiveness of these forms of generation. These support schemes have been extremely varied, not only varying in each country during time, but also varying between countries, with different degrees of success.

As in most policies, success can be very hard to measure, and RES support schemes are no different. The ambitious objectives of international agreements and of national legislators have often led to success being defined as the share of RES of the national generation mix. In some cases, the outcome has been an inefficient over-cost, which in some cases meant a change in the support scheme to a more efficient approach.

Understanding these different policies function and the different regulatory effects they have is crucial, not only from a regulator or governmental body perspective, but also from a business standpoint, as it is incumbent that they adapt correctly to the different incentives and opportunities of these support schemes.

1.1 Different RES support schemes around the world

There are different methods that have been used to support RES, with varying degrees of success. The most prominent methods of RES support include [1]:

1. Feed-in tariff: The RES receives a fixed price on the energy produced and exported to the grid, which effectively implies that the producer is taken out of the market for the production it offers. This method implies low risk for the RES producer, but there can be great risk for the regulator in terms of setting a price which is too low (less entry of RES into the system than expected) or too high (greater entry of RES into the system than expected). Nevertheless, the European Union has been trying to phase out feed-in tariff schemes, as there is hardly no integration in the market, and trying to encourage other sorts of support schemes, such as feed-in premiums [11][9].

2. Feed-in premium: The RES receives the market price plus an adder at each hour it produces. This adder can have a fixed value for all the hours, be dependent on the market price (for example having greater values for low market prices and low values for high market prices), or be set as a fixed value using weekly/monthly/yearly price averages. Each of these methods having certain benefits and drawbacks between each other. The main difference between this method and the feed-in tariff is that the RES producer is exposed to the market prices.

3. Contract for differences (CfD): In this method a strike price is determined, and a contract is performed between the RES generator and a counterpart (generally a governmental body). If the market price is below the strike price, the counterpart has to pay the difference to the RES generator, and vice-versa if the market price is above the strike price. The settlement of the market price can be hourly, in which case the mechanisms acts the same as a feed-in tariff, or in longer periods, in which case the system is slightly different, as the agent is subject to market forces and incentives the RES producer to produce during higher prices.

4. Renewable Portfolio Standards / Green Certificates: In this method, energy suppliers are forced to purchase certain quantity of renewable energy to sell to their clients. This renewable energy is traded through the use of certificates, which are purchased from RES producers.

5. Capacity based: The RES receives a payment depending on the amount of power installed, which can be an annual payment or in a single amount. This payment does not depend on energy production, although in some cases there might be a requirement of certain amount of production to be eligible for this sort of payment.

Other kinds of support methods could include loans with lower interest rates or tax deductions; however, this are not exclusive to RES, and can be applied to other kinds of businesses and industries for varying reasons.

1.1.1 Germany

Since 2010, Germany has been trying to adapt their energy production to a low-carbon mix in which RES are one of the main focus points. This is part of what is called Energiewende ("Energy transition"). However, Energiewende has been used as a term long before 2010, but after the implementation of the Energiekonzept ("Energy concept") by the German government the Energiewende has clearer objectives. These objectives include the phasing out of Germany's nuclear power plants and the introduction of further RES into the system. To achieve these objectives, Germany has established several policies in order to aid RES and ensure enough renewable power is installed. The latest reform in this regard occurred in 2017, with the reform to the Renewable Energy Sources Act (EEG)[15], where the support schemes that were present up until then were modified.

1.1.1.1 Feed-in tariff

In Germany, since 2017, RES power plants with installed power below 100 kW are eligible for a feed-in tariff in all cases. RES power plants with installed capacity above this limit are also able to receive this feed-in tariff, but reduced by 20%, for no longer than 3 consecutive months and up to 6 months a year. Plants that receive this kind of aid may perceive it for a duration of 20 years.

1.1.1.2 Feed-in premium

All RES power plants are eligible to receive a feed-in premium for actual energy sold in the market or directly to a third party. In this case, there are particular requirements to be met so that this can be done:

1. The power plant should incorporate devices that allow the grid owner to reduce its output.
2. The grid owner should be able to measure directly the amount of energy exported to the grid.

On the other hand, there is a "sliding" feed-in premium for big power plants (>750 kW), by which the feed-in premium is obtained through a bidding procedure in which the winning offers are pay as bid. As in the case with the feed-in tariff, plants can receive this form of remuneration for up to 20 years.

1.1.1.3 Loans and subsidies

Germany also has several loan programs for several RES projects such as:

- For general RES investment.
- For offshore wind projects in the German Exclusive Economic Zone or in 12 nautical-mile zone of the North and Baltic Sea.
- For onshore wind projects and solar PV plants.
- For deep geothermal generation.
- For energy storage systems associated to PV power plants.

All these loans are intended as low interest rate loans, to provide cheap financing for these projects. Additionally, biogas power plants are subject to receive subsidies if they offer generation on demand by the system operator.

1.1.2 United Kingdom

Even though the United Kingdom has only had two forms of RES support schemes in the last years, its policies are usually taken into consideration for having a clear market approach. The first measure was introduced in 2012 with a feed-in tariff approach [2], later incorporating a CfD in 2014 [3].

1.1.2.1 Feed-in tariff

As has been mentioned before, this form of RES aid was introduced in 2012, and all RES power plants with installed capacity below 5 MW were eligible. RES power plants with installed capacity below 50 kW were, and are determined microgeneration and have a slightly different feed-in tariff scheme.

However, new applications for this scheme will be officially closed as of April 1st, but RES power plants that were already in the scheme will still receive this form of remuneration.

1.1.2.2 Contract for Differences

Since 2014, CfD has been the main form of support for RES in the UK. This CfD is a contract between the RES producer and a counterparty, this being the Low Carbon Contracts Company (LCCC), which is a company owned by the UK government. In this case, a strike price is agreed. If market prices are inferior to this strike price LCCC will have to pay the RES generator the difference and vice versa, if the market price is above the strike price the RES generator must pay the difference to LCCC.

In order to assign these contracts, a competitive auction is created. This is a multi-unit, sealed bid auction, in which the RES generator can offer several power plants in the bid at different bid prices, being the strike price what is being bid [31]. Therefore, the government establishes the total capacity available for the auction and an administrative price (as a cap) is set, in case the capacity being auctioned is not fulfilled. In both cases, all RES generators that are awarded a CfD will have the same strike price, which will be the strike price of the last bid or the administrative strike price.

1.1.3 Spain

1.1.3.1 Support schemes before 2013

There have been various RES support schemes in Spain, the most prominent being the ones determined by Royal Decree 436/2004 [19] and Royal Decree 661/2007 [20]. Both of these cases had very similar schemes, characterized by the existence of the "special regime" to which RES were ascribed to. RES power plants in this regime could decide whether to earn a feed-in tariff or a feed-in premium.

Royal Decree 436/2004 was the first to establish this choice in the remuneration support, with the RES power plants that decided to operate in the market, and receive the feed-in premium, earning an additional incentive to promote operation in the market. Royal Decree 661/2007 decided to maintain this support scheme but limiting it in some aspects. On the one hand, it decided to set an hourly price cap and floor for the feed-in premium remuneration, and to limit the amount of RES power plants that could be awarded this support scheme, by setting a cap on the power installed per technology. Nevertheless, the cost of these schemes continued to increase, as seen in figure 1.1, with the cost being presented in millions of euros:

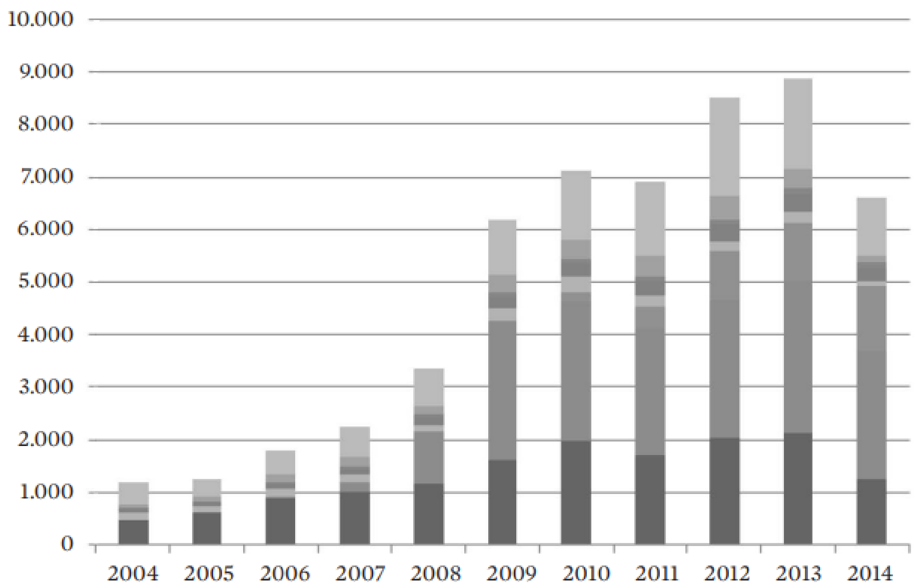

Figure 1.1 Evolution of renewable cost in Spain. Source: Informe: El sector eléctrico en España (Consejo Económico y Social España)

It is clear that these limits established in 2007, to contain the cost off the support scheme to the system as a whole, were not enough, and the Royal Decree-law 1/2012 [26] was set in place to eliminate these aid schemes for any RES power plant that had not finalized administrative formalization. The main reason for this was that the system regulated costs had increased dramatically, whilst the system revenues had not done so, creating a system deficit that was becoming hard to cope with. With this Royal Decree-law, the government hoped to put an end to this system wide deficit, by eliminating these increasing costs. This actually worked, as it can be seen in figure 1.2, with the negative values being the deficit and the positive values being a system surplus, all values in millions of euros:

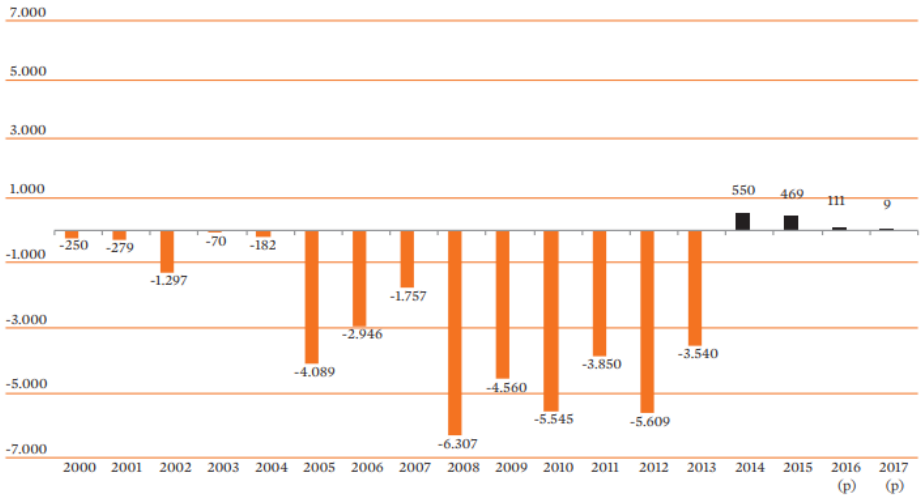

Figure 1.2 Evolution of the electric system deficit in Spain. Source: Informe: El sector eléctrico en España (Consejo Económico y Social España)

Nevertheless, even though these support schemes were finally eliminated due to the increasing costs, they had several positive elements to them. On one hand, it encouraged producers to participate in the market, giving them an additional incentive when doing so. On the other hand, it made producers responsible of their own planning and production, penalizing them if they ended up deviating from their expected production program. It also allowed for power plants associated to these support schemes to change from the feed-in tariff to the feed-in premium, and vice versa, once in a year. Furthermore, they increased the installation of RES considerably, albeit with too big of a cost associated to it. This increase in installed capacity can be seen more clearly in figure 1.3, where the installed capacity increased from 35.000 MW in 2006 to around 57.000 MW in 2013, which meant an increase of almost 63% in only 7 years.

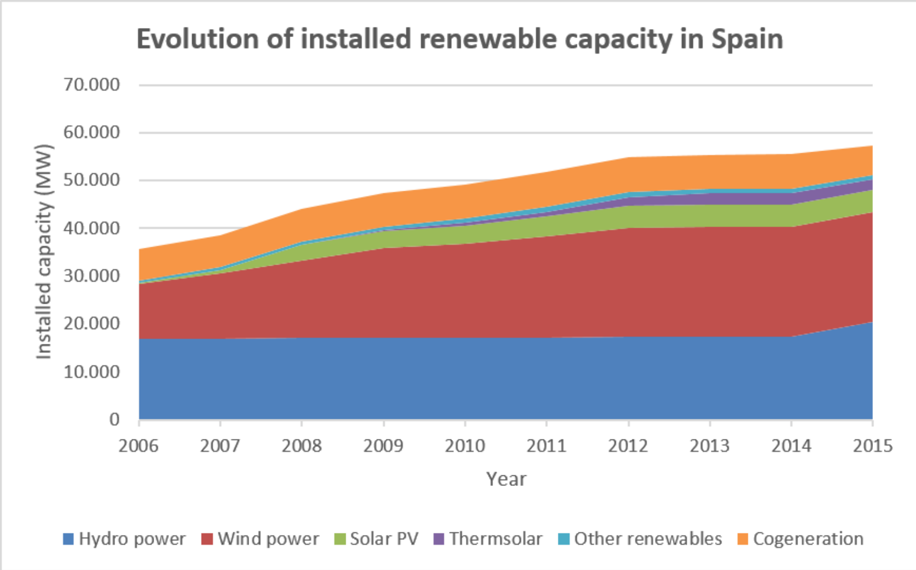

Figure 1.3 Evolution of the renewable installed capacity in Spain. Source: Red Eléctrica de España, own elaboration.

The suspension of any RES support scheme for any future installations in 2012 meant that companies would not be as willing to invest in new RES plants as before, as they no longer had governmental aid to support them. This also meant that the government would risk not achieving the renewable penetration objectives fixed for 2020 and the ones started to be outlined for 2030. To avoid this, the Spanish government stated its desire to design a new RES support scheme in 2013, with the Royal Decree Law 9/2013 [28], in its second final provision. This was expanded further with the Law 24/2013 [29] of the Electric Sector, which outlined in its article 14 point 7 how this future support scheme would be designed. Finally, in 2014, the Spanish government signed the Royal Decree 413/2014 [21], in which it regulated the production of electrical energy from renewable, cogeneration and waste energy sources. The European Commission ratified the implementation of this legislation in 2017, allowing it even though it was a state-aid [10], as the Spanish government followed all legal proceedings to guarantee its approval.

1.1.3.2 Royal Decree 413/2014

Royal Decree 413/2014 created a RES support scheme that is quite different to both the theoretical forms of RES support and the real applications described. Firstly, the Spanish legislation is based on installation types (ITs), these being efficient power plants operating in the market with costs and other operation characteristics being audited, and are characterized by the year of installation, type of technology, power range etc. All RES power plants that want to operate within this support scheme must be ascribed to one of this ITs, meaning that all plants associated to a particular IT receive the same amount of remuneration. So that the RES support scheme guarantees cost recoveries in the short term and investment recovery in the long term, there are different forms of remuneration, which can be described as the following [21]:

1. Investment remuneration: This is an annuity lump sum payment that the IT receives for the amount of the investment that it will not be able to recover during its life cycle, plus a return on the investment, given normal operation in the market. The investment remuneration is also inversely proportional to the amount of investment the IT would be able to recover in the market; therefore, this form of remuneration would only pay for the non-recovered investment plus this return on the investment. This remuneration method is a clear example of capacity based remuneration, as the IT is paid according to its installed capacity; therefore, it is expressed in €/MW.

2. Operation remuneration: The value of this remuneration is the difference between the operation costs and revenues obtained in the market, if the costs are higher than the revenues for the IT. This form of remuneration depends on the quantity of energy produced by the RES power plant; therefore, it is expressed in €/MWh. It is similar, in many aspects, to some sort of contract for differences or a feed-in premium on top of market revenues, as the RES power plant is paid an amount per MWh sold into the market when its operating costs for generating that electricity sold are greater than the revenues it would obtain. This way, it is similar to a contract for differences in which the strike price is the operating costs of the power plant, therefore obtaining nor profits or losses for selling energy into the market.

   Nevertheless, the strike price, and the operation remuneration to be perceived, are not constant through time, as the operating costs may vary depending on different parameters. In the case that the IT has higher earnings in the market than the value of its operating costs, meaning that the market price is higher than the operating costs, it receives no operation remuneration. This is an important difference to normal contracts for differences, as in a normal example a company selling above the strike price would have to return the difference to the counterparty. This is not the case, as it would mean that the IT would never receive any profits from its operation.

3. Cost reduction incentive remuneration: In Spain there are several territories which are not physically connected to the Iberian Peninsula (mainland Spain), and are therefore

isolated systems. This is the case of the cities of Ceuta and Melilla, and the Balearic and Canary Islands. Due to this electrical isolation, they suffer from higher costs to produce the electricity needed by their systems. This way, the government has established another form of remuneration that is assigned to RES power plants that reduce the total cost of the system to supply the electricity required. The quantity of this remuneration, given as a feed-in premium, will depend on the amount of cost reduction provided to the system. This means that if conditions change, and the savings provided to the system vary, so will the cost reduction incentive remuneration to be perceived.

The parameters involved in the calculation of these forms of remuneration are updated before each regulatory period, 6 years each, and some of them can be updated before each semi-period, which is 3 years. Cogeneration and biomass installations, which depend greatly on fuel prices to determine their operation costs, have the parameters that affect their fuel costs directly updated every 6 months, in order to update the operation remuneration they receive.

1.2 Objectives

Knowing the importance of RES in international and national legislation, the objective of this Master's Thesis is to provide a model, using Excel, that allows users to obtain present and future forecasts on regulated remuneration for RES, according to Spanish legislation (RD 413/2014). This model will have to achieve certain goals and be able to perform several analyses. Firstly, it should act as a database for parameters that have been used in the past, to calculate remuneration for RES according to present legislation, and also as a way to predict future remuneration based on these parameters and forecasts. This should be used both for individual IT analysis, to assess how different scenarios will affect its particular revenues, and for a system wide analysis, calculating how the system costs will vary according to the different scenarios analyzed. Finally, it should act as a tool to perform financial analysis based on these results, which can be useful not only to provide information for present and future investments on RES, but also to analyze the regulatory framework as a whole.

The model must not only obtain results which are correct, but also that takes into account the user that might end up using it and the particularities of the legislation being used. This means that the model must be easy to understand, so that users that are not proficient in the legislation at hand, or the model itself, can be able to use it without much hardship. On the other hand, it must be easy to introduce new data into the model, as the present legislation introduces new parameters every 6 months, therefore introducing this information must be straightforward and not disrupt the model and its results.

In order to illustrate how this model works, it will first be necessary to explain the current RES support legislation in Spain in further detail. This will lay the groundwork to describe the model that incorporates the support scheme that exists presently in Spain, that can be used by businesses, regulators and other agents to perform short and long term analysis with the present legislation.

1.3 Structure of the document

In order to present the results of the objectives that have been mentioned before, the document will be structured to best describe these results:

- Chapter 1 has described briefly the context in which the current RES support scheme present in Spain has come to be, and how it operates in comparison with other similar support schemes around the world. It has described the previous RES support schemes that operated in Spain, both the positive and negative elements, and how the current scheme wishes to correct those negative measures.
- Chapter 2 will describe the support scheme initiated by RD 413/2014 in detail, as well as how it has been implemented in the Excel model, explaining both the formatting as well as the coding behind it, that is the main objective of this Master's Thesis.
- Chapter 3 will explain the different model applications, presenting different scenarios to see how they affect the ITs and the system cost as a whole. It will also show another model application, which is the profitability analysis of RES power plants associated to this support scheme.
- Chapter 4 will serve as a conceptual analysis of the RES support scheme in Spain. This analysis will not relate, exclusively, to the information that has been gathered through the use of the model, but rather a conceptual analysis, in terms of incentives and consequences of the scheme. This chapter will also propose several adaptations to this scheme as well as possible alternative support methods.

Chapter 2

Explanation and modelling of RD 413/2014

2.1 Detailed functioning of RD 413/2014

The end of the first chapter described, very briefly and simply, the different forms of remuneration that are present in the current renewables, cogeneration and waste energy sources support scheme in Spain. However, it will be necessary, at this point, to acquire a deeper understanding of how it operates so as to understand how the model was developed, analyzing the formulation that takes place and the different parameters that are used for the calculations.

The first thing that is important to mention is that the main objective of this support scheme is to guarantee the investment recovery, whilst controlling the total cost of the scheme. This is done by analyzing and auditing the costs and revenues of the different ITs, in order to update their net asset value over time and guarantee that return on the investment. This means that the support scheme is focused on these ITs and not necessarily on the different RES power plants that operate in the system. This way, power plants that operate in equal or better terms than their corresponding IT will also guarantee their return on the investment. In order to guarantee the recovery of the investment for the different ITs, the different elements that are taken into account are updated every semi-period, except the reasonable return on the investment, which can be updated before each six-year period.

2.1.1 List of parameters

There are many parameters that are necessary to calculate the operation, investment and cost reduction incentive remuneration. In order to adjust these different forms of remuneration over the years, many of these parameters might be updated over time. Parameters that may vary substantially from time to time, and that affect what a RES power plant, subject to this regulatory scheme, would earn by selling in the market, are updated every regulatory semi-period:

1. Market price (as well as the captured price for each technology): As the market price can vary very easily, the Spanish government provides estimation of the market price for the next semi-period and for periods ahead of the next semi-period, as well as a factor to be applied to determine the captured price (representing the actual average market price perceived by a particular technology with respect to the general average market price) of each RES technology.

2. Upper and lower bounds of market price: As the market price may vary from the estimation made by the Spanish government, there are upper and lower bounds above and below the market price. If prices go above certain threshold part of that increase in prices isn't passed on to the RES agents, and if the market price goes even beyond that threshold until the final upper bound, then that further increase isn't taken into account. The same happens if the market price goes below certain levels. This is to prevent high market price variability whilst still maintaining market signals.

3. Deviation costs: The costs related to deviating from the program can be updated every 3 years. This is a regulated concept for the ITs, however the different power plants must pay deviation costs according to the mistakes they make in their programming.

4. Operation costs: Different parameters affecting operation, such as the evolution of equivalent hours or evolution of operation costs, determine the profits that would be earned in the market and the value of the operation remuneration if there was any.

5. Operating threshold and minimum number of equivalent functioning hours (for an explanation of equivalent functioning hours see Nh in nomenclature): Although in practice they are not updated and are maintained constant or varying according to preset conditions, these requirement of functioning hours are subject to change each semi-period.

6. Other regulated costs: Regulated costs, such as taxes or tolls, affect the operation remuneration that would be perceived by the IT, and are therefore updated every 3 years.

7. Variable generation cost per unit of energy for the different non mainland electricity systems (as well as other parameters related to the cost reduction incentive remuneration): This parameter is necessary to calculate the cost reduction incentive to be applied in the different isolated systems, and reflects the general cost of energy production. This is then used to evaluate the cost reduction that would be exercised by the operation of the RES power plants.

In truth, the only parameter that can only be updated every 6 years is the reasonable return on investment, as the rest of parameters affect either the operation remuneration or the cost reduction incentive and therefore affect directly what the RES power plants would earn selling into the market.

Finally, parameters that involve calculating the fuel cost evolution, present in cogeneration and biomass plants, are updated every 6 months. These include:

1. Brent price: The Brent value is used to calculate the fuel costs for fuel oil, diesel oil and natural gas based cogeneration power plants.

2. Exchange rate: The dollar to euro exchange rate is needed to convert the Brent price from dollars to euros.

3. Henry Hub market rates: These are used to obtain the fuel cost for natural gas based cogeneration power plants.

4. A, B and C parameters: Multipliers and adders that are specific for each IT, that serve to determine the operational cost of each IT depending on the fuel costs. These will be explained in further detail when detailing the model and how they have been implemented.

5. Gas grid access tariffs and taxes: Although they have remained constant throughout the implementation of this last support scheme, the different tolls affecting natural gas supply are subject to be changed as parameters every six months.

2.1.2 General principles

A common aspect to all IT's, irrespective of their technology, is the net investment value (VNI), which is the investment value in €/MW of said installation, and the net asset value (VNA), being the current value of that investment, expressing in this case the amount of investment that is still yet to be recovered. The main objective of RD 413/2014 is precisely for companies to recover the investments made, so both the VNI and VNA are crucial aspects of this piece of legislation. The VNI is a value given once an IT is approved for functioning, whilst the VNA is updated each semi-period, taking into account revenues in the market, operation costs and variation in the market price from expected values. The formula used can be seen in equation 2.1:

$$VNA_{j,a} = \overbrace{VNA_{j-1,a}(1+t_{j-1})^{sm}}^{\text{Net asset value update}} - \overbrace{\sum_{i=p-sm}^{p-1}(Ing_{i,j-1} - Cexp_{i,j-1} - Vajdm_{i,j-1})(1+t_{j-1})^{p-i-1}}^{\text{Discounted cash flow updating}} \tag{2.1}$$

It should be noted that the terms used in this equation, and the rest that will be mentioned hereinafter, are the ones used in the RD 413/2014, which correspond to the normal notation in Spanish. This is done to avoid confusion when consulting the legislation, so from now on that notation will be the one used in this document. The different notations can be consulted in the Nomenclature section.

It can be seen that the previous formula updates the net asset value at the start of each semi-period j, taking into account the value of the previous semi-period $j-1$, updated to present values with the update rate (which corresponds to the reasonable return rate, t that has been defined before). This value is then corrected, considering the revenues, Ing, costs, $Cexp$, and adjustments, $Vajdm$, for each year i of the previous semi-period, also taking into account the update rate. The formula also takes into account the number of years of the semi-period, sm, which in this case is three, the year of authorization of the plant, a, and the final year of the semi-period, p.

The previous formula is slightly different if the final year of authorization was during the previous semi-period. This would mean that the discounted cash flow analysis would have to be updated for the number of years of operation of that semi-period. If the installations were subject to previous support schemes and wished to be eligible for this remuneration scheme their initial net asset value at the start of the first regulatory cycle would be calculated in the same manner, but with one year less for the cash flow discount analysis.

One term that is included in the revenues is the investment remuneration *Rinv*, which is common for all IT's. It is calculated taking into account the net asset value that would not be recovered through market operation, accounting for a discount analysis. The investment remuneration is determined by equation 2.2:

$$Rinv_{j,a} = C_{j,a} \cdot VNA_{j,a} \cdot \frac{t_j \cdot (1+t_j)^{VR_j}}{(1+t_j)^{VR_j} - 1} \tag{2.2}$$

This equation expresses the investment remuneration that should be paid each year until the end of the regulatory life of the asset, in order to recover the investment plus the return on it. In order to guarantee that this investment remuneration supplies enough income to recover those investments, but not over that value, an adjustment factor $C_{j,a}$ is used, that represents the percentage of the net asset value that cannot be recovered through normal operation in the market, which is obtained through the equation 2.3:

$$C_{j,a} = \frac{VNA_{j,a} - \overbrace{\sum_{i=p}^{a+VU-1} \frac{Ingf_i - Cexpf_i}{(1+t_j)^{i-p+1}}}^{\text{Discounted cash flow}}}{VNA_{j,a}} \tag{2.3}$$

Similar to the net asset value, this coefficient will vary depending if the installation received the final authorization during the current semi-period, becoming equation 2.4:

$$C_{j,a} = \frac{VI_a - \sum_{i=a}^{a+VU-1} \frac{Ingf_i - Cexpf_i}{(1+t_j)^{i-a+1}}}{VI_a} \tag{2.4}$$

In equation 2.4, the term VI_a represents the standard value of the initial investment for the IT with authorization year "a" per unit of power, expressed in €/MW.

The adjustment coefficient will have a value between 0 and 1, depending on the expected income of the IT until the end of the life cycle. This way, if the IT is expected to recover part of the investment then the value of $C_{j,a}$ will be smaller than 1, therefore reducing the investment remuneration to be perceived by the IT. This ensures that there is no over recovery of investments, although variation in revenues, due to changes in market price for instance, would change $C_{j,a}$ and therefore vary the amount to be perceived through investment remuneration during the life cycle of the power plant.

Nevertheless, the investment remuneration, as well as the other kinds of remuneration obtained through this support scheme, are subject to be reduced in case the equivalent functioning hours are below certain thresholds. This way, there are 3 possible cases:

1. If the functioning equivalent hours of the installation are higher than the minimum number of functioning equivalent hours ($Nhmin$) for that IT, there will be no reduction in the annual remuneration received by the power plant.

2. If the equivalent functioning hours are between the operating threshold (Uf) and the minimum equivalent functioning hours, the annual remuneration to be perceived will be reduced proportionally. This way, the annual remuneration will be reduced according to a factor "d" calculated as:

$$d = \frac{Nhinst - Uf}{Nhmin - Uf} \tag{2.5}$$

3. If the equivalent functioning hours of the installation are below the operation threshold of the particular IT for that particular year, the power plant will receive no remuneration for that year.

This can be seen more easily in figure 2.1:

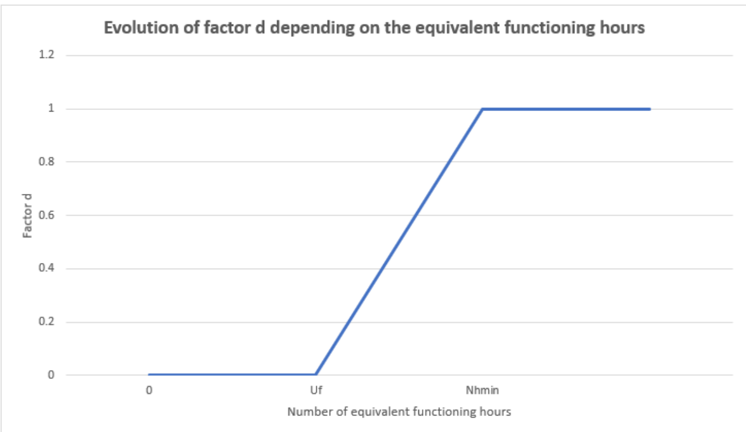

Figure 2.1 Evolution of parameter d

One term that is yet to be described in detail is $Vajdm$, which represents an adjustment due to deviations in the market price (Pm) with respect to the expected market price in the previous semi-period. As it was mentioned earlier, there are upper and lower bounds to the expected market price determined by the Spanish government, and any deviation above the upper bounds or below the lower bounds creates a correction in the incomes obtained by the different power plants due to this concept. There are four bounds, two upper bounds, $LS2$ being the higher upper bound and $LS1$ being the lower upper bound, and two lower bounds, $LI1$ being the higher lower bound and $LI2$ being the inferior lower bound. Depending on the position of the market price between the different bounds, the value of $Vajdm$ will vary. This is done for each year of each semi-period. Therefore, there are five possible cases depending on the value of the average day ahead and intraday market price:

1. In case the annual average day ahead and intraday market price has been higher than LS2 in year "i" of period "j":

$$Vajdm_{i,j} = Nh_{i,j} \cdot 0,5 \cdot (LS1_{i,j} - LS2_{i,j}) + Nh_{i,j} \cdot (LS2_{i,j} - Pm_{i,j}) \tag{2.6}$$

2. In case the annual average day ahead and intraday market price has been between LS1 and LS2 in year "i" of period "j":

$$Vajdm_{i,j} = Nh_{i,j} \cdot (LS1_{i,j} - Pm_{i,j}) \tag{2.7}$$

3. In case the annual average day ahead and intraday market price has been higher than LI1 and lower than LS1 in year "i" of period "j":

$$Vajdm_{i,j} = 0 \tag{2.8}$$

4. In case the annual average day ahead and intraday market price has been between LI1 and LI2 in year "i" of period "j":

$$Vajdm_{i,j} = Nh_{i,j} \cdot (LI1_{i,j} - Pm_{i,j}) \tag{2.9}$$

5. In case the annual average day ahead and intraday market price has been lower than LI2 in year "i" of period "j":

$$Vajdm_{i,j} = Nh_{i,j} \cdot 0,5 \cdot (LI1_{i,j} - LI2_{i,j}) + Nh_{i,j} \cdot (LI2_{i,j} - Pm_{i,j}) \tag{2.10}$$

The evolution of $Vajdm$ can be seen more clearly in figure 2.2:

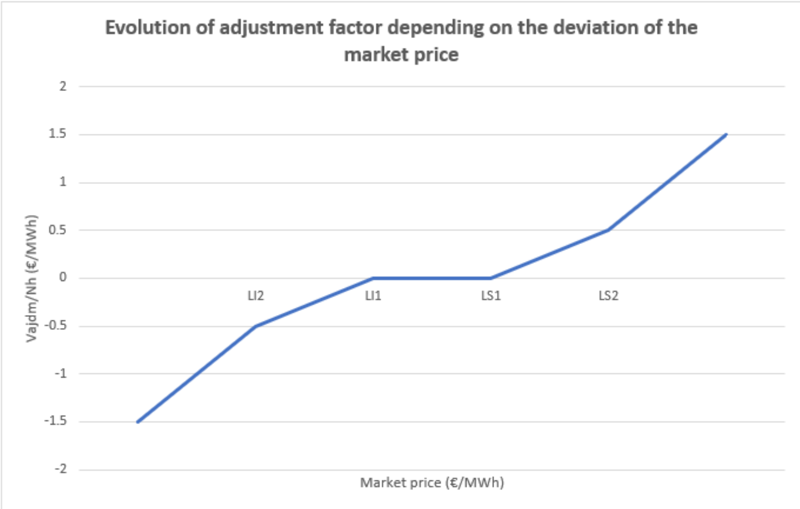

Figure 2.2 Evolution of $Vajdm$

$Vajdm$ is a crucial term that is necessary to guarantee the investment recovery of the different ITs in case there is a market price deviation. Nevertheless, as there are upper and lower bounds there could be price deviations that are not corrected, that could lead to a higher or lower return of the investments both for the ITs and their associated power plants. This is perhaps the element that adds uncertainty to this support scheme, but allows economic signals to be maintained.

There are other aspects that affect the revenues and expenses that an IT receives, such as the captured price, regulated costs or operation costs, and that therefore lead to a variation in the remuneration a power plant would receive. However, how these parameters affect revenues and expenses will be analyzed when describing the model, as this explanation will be much clearer.

2.1.3 Particular aspects

As it has been briefly mentioned before, there are various groups of ITs which are subject to other kinds of remuneration (such as the cost reduction incentive), or the calculation of their operation remuneration is significantly different from the rest. Royal Decree 413/2014 also considers different IT groups depending on each technology, several parameters actually depending on the technology of the particular IT.

2.1.3.1 Cost reduction incentive

The cost reduction incentive only applies to ITs that have been installed in Spanish extra-peninsular territories i.e. the Canary and Balearic Islands, Ceuta and Melilla. However, these ITs will only receive this remuneration if they create a system-wide cost reduction, represented by parameter A (in per unit), as shown in equation 2.11:

$$\left[\overbrace{\frac{Cvg_j}{Egbc_j}}^{\text{Variable generation cost}} - \overbrace{\left(\frac{Rinv_j}{Nh_j} + Ro_j + Pm_j\right)}^{\text{Cost of renewable installation}}\right] \geq A_j \cdot \frac{Cvg_j}{Egbc_j} \tag{2.11}$$

As it can be seen, the IT will only be eligible to receive this remuneration if it allows for a cost reduction in the system, taking into account what it earns in the market and the operation and investment remuneration it will receive in the semi-period, in €/MWh. If this is the case, the IT will obtain a cost reduction incentive remuneration, in €/MWh, according to equation 2.12, where the IT receives part of the savings of the system, represented by B (in per unit):

$$Iinv_j = \left[\frac{Cvg_j}{Egbc_j} - \left(\frac{Rinv_j}{Nh_j} + Ro_j + Pm_j\right)\right] \cdot B_j \tag{2.12}$$

2.1.3.2 Different IT groups

As mentioned before, IT's are grouped depending on their technology, which then serves to adjust certain parameters common to IT's of the same group. The groups and subgroups are described in tables 2.1 and 2.2 (a more detailed description can be found in Article 2 of RD 413/2014).

Some of these groups have different rules applied that have to be taken into consideration. The most important ones, such as groups a.1, b.6 and b.8, which are cogeneration and biomass ITs, will be described in this document; however, the small exceptions of the rest of the groups will not be detailed here, but can be found in RD 413/2014.

Table 2.1 Different IT technology groups

Technology groups	
Group	Description
a.1	Cogeneration
a.2	Residual energy cogeneration
b.1	Solar
b.2	Wind
b.3	Geothermal/Hydrothermal/Aerothermal
b.4	Hydro with installed power < 10 MW
b.5	Hydro with installed power > 10 MW
b.6	Crop biomass
b.7	Bioliquids
b.8	Industrial installation biomass
c.1	Domestic waste
c.2	Other waste
c.3	Mining waste
b.6/b.8	Hybrid biomass

Table 2.2 Different IT technology subgroups

Technology subgroups	
Subgroup	Description
a.1.1	Natural gas based cogeneration
a.1.2	Petroleum or coal based cogeneration
b.1.1	Solar PV
b.1.2	Solar thermal energy
b.2.1	Onshore wind
b.2.2	Offshore wind
b.4.1	Hydro with installed power < 10 MW, only hydrological use
b.4.2	Hydro with installed power < 10 MW, existing infrastructure for other use
b.5.1	Hydro with installed power > 10 MW, only hydrological use
b.5.2	Hydro with installed power > 10 MW, existing infrastructure for other use
b.7.1	Controlled landfills biogas
b.7.2	Rest of biogas or bioliquids

2.1.3.3 Operation remuneration of cogeneration plants

In the case of ITs which depend on a fuel for their operation, namely cogeneration and biomass plants, their operation remuneration determination procedure is significantly different to the rest of installations. Whilst installations that do not use fuels receive operation remuneration if their costs are greater than the revenues, and the value being the difference of both terms, the operation remuneration of biomass and cogeneration installations are determined by what is described in Order IET 1345/2015 [23]. This ministerial order establishes the methodology used to update the operation remuneration of these plants, depending on the fuel used. This update is done every semester s, taking into account changes in that time.

Installations that use natural gas as a fuel have their operation remuneration determined as shown in equation 2.13:

$$Ro_s = \overbrace{A_s \cdot \frac{10}{0,9} \cdot \left[\frac{CF_s}{(1-mt_s)\cdot(1-\beta_s\cdot mr_s)} - \frac{CF_{s-1}}{(1-mt_{s-1})\cdot(1-\beta_{s-1}\cdot mr_{s-1})} + PA_{s,j} - PA_{s-1,j}\right]}^{\text{Variation in fuel cost for gas cogeneration ITs}} + B\cdot Ro_{s-1} + C_s \tag{2.13}$$

The first part of the equation is how a change in the fuel price, or the tolls or taxes applied to it, will affect the fuel cost associated to the IT analyzed. The second part of the equation just takes into account the previous value of the operation remuneration, $B \cdot Ro_{s-1}$, so the update is just with respect to that value, and the final part, C, serves as adjustment, in case other parameters vary with respect to previous values [25]. The estimation of the frontier cost of gas, CF_s, is obtained by using the expression described in equation 2.14:

$$CF_s = CF_{s-1} \cdot \left[1 + \overbrace{\beta_s \cdot \frac{RC_s - RC_{s-1}}{RC_{s-1}}}^{\text{NBP and HH purchase cost}} + \overbrace{(1-\beta_s)\cdot\frac{RL_s - RL_{s-1}}{RL_{s-1}}}^{\text{Brent purchase cost}}\right] \tag{2.14}$$

Being RL_s calculated taking into account the Brent futures, Br_s, and the exchange rate, T_s, as shown in equation 2.15:

$$RL_s = \frac{0,710093 + 0,027711 \cdot Br_s}{T_s} \tag{2.15}$$

The final term needed to calculate the operation remuneration is the estimation of the grid access costs, $PA_{s,j}$, calculated according to equation 2.16:

$$PA_{s,j} = \overbrace{12 \cdot \left(\beta_s \cdot \frac{Trf_s}{241} + \frac{Trc_s}{296} + \frac{Tfc_{s,j}}{248}\right) + Tvc_{s,j}}^{\text{Gas grid access costs}} + \overbrace{\beta_s \cdot \left(Tvr_s + 7 \cdot \frac{Tgnl_s}{1000}\right) + Cas_s}^{\text{Regasificacion costs}} \quad (2.16)$$

The cost of underground storage, Cas_s, also being calculated as shown in equation 2.17:

$$Cas_s = \frac{Drs_s}{365} \cdot [12 \cdot Tfas_s + 0,3 \cdot (Tvi_s + Tve_s)] \quad (2.17)$$

For cogeneration plants that use fuels which are different from natural gas (diesel and fuel oil), operation remuneration is calculated as described in equation 2.18:

$$Ro_s = \overbrace{A_s \cdot \left[\frac{1}{PCI} \cdot (PI_s - PI_{s-1})\right]}^{\text{Variation in fuel cost for fuel and diesel oil cogen. ITs}} + B_s \cdot Ro_{s-1} + C_s \quad (2.18)$$

Being the international price of fuel estimation, PI_s, calculated as shown in equation 2.19

$$PI_s = PI_{s-1} \cdot \frac{\frac{Br_s}{T_s}}{\frac{Br_{s-1}}{T_{s-1}}} \quad (2.19)$$

2.1.3.4 Operation remuneration of biomass installations

Order IET/1345/2015 also determines operation remuneration for biomass installations. In this case, operation remuneration is calculated as described in equation 2.20:

$$Ro_s = \overbrace{A_s \cdot \Delta Pcomb_s}^{\text{Variation in biomass fuel cost}} + B_s \cdot Ro_{s-1} + C_s \quad (2.20)$$

Being $\Delta Pcomb_s$ calculated as $Pcomb_{s-1} \cdot t$, and t calculated as shown in equation 2.21, where Ta is the annual increment in the biomass fuel cost, which is set at 1%, so t is calculated as shown in equation 2.21:

$$t = \sqrt{(1+Ta)} - 1 \tag{2.21}$$

2.1.3.5 Slurry and sledge installations

With the implantation of Order IET/1345/2015, most of ITs had their support scheme defined correctly. This was not the case for slurry and sledge installations. Initially they had their support scheme defined in the same regulation as cogeneration and biomass installations, however slurry and sledge installation owners argued against it. This led to several lawsuits being presented by IT owners against the Spanish government due to Order IET/1345/2015. Some of these lawsuits were resolved in the Spanish Supreme Court, such as those with resolution numbers 1463/2016, 1592/2016 and 770/2017. The owners claimed that the values used for investment, operating costs and other revenues obtained were erroneous, operating costs and investment values being undervalued and the other revenues being overvalued.

This led to Order IET/1345/2015 having to be modified and the support scheme for these ITs was suspended. The competent ministry was then forced, by order of the Supreme Court, to elaborate a new Order that developed a support scheme for these ITs correctly. This resulted in the implementation of Order TEC/1174/2018, which determined the remuneration scheme for these installations for the semi-period starting in 2017 and ending in 2019.

However, even though this Order is in force, due to the fact that many of these IT owners have presented lawsuits against Order TEC/1174/2018, as shown by communications by the Supreme Court such as Roj: ATS 2162/2019, ATS 2728/2019 and ATS 2166/2019, there is still a risk that a new support scheme needs to be elaborated. This is why slurry and sledge ITs support scheme will not be presented in this document or in the model, as it could lead to misinterpretation if their support scheme is revoked again.

2.2 Modelling of RD 413/2014

After describing the general functioning of the RES support scheme in Spain, it is now possible to describe the development of the model that wants to represent these calculations.

2.2.1 General layout

The first thing is to understand how the model should be laid out, knowing the different parameters and IT groups in play. As has been described before, there are certain aspects that are common for all ITs, such as market price, tolls or other regulated costs, whilst others are specific to certain groups of ITs. This means that it makes sense, when creating the model, using Excel, to create different sheets when listing these parameters. There should also be a different sheet in which to group the specific data of each IT that has been made public and also a sheet for each of the ITs, in which to publish the calculations done for the different ITs. Finally, there should be a sheet that calculates the different remunerations and costs for the ITs that are wanted, and another one that is able to take real data from a power plant associated to this support scheme and a particular IT, and compute the financial outcome of that plant until the end of its life cycle. It is not strictly necessary to create these different sheets, and an alternative solution could be envisioned, but a separation as has been described, that takes into account specificities within RD 413/2014 is an advantage, specially for users that might not be familiar with the legislation at hand.

It should be noted that each of these sheets should be adapted so that the introduction of new information, after each regulatory semi-period, or every 6 months in the case of cogeneration, should not impact the functioning of the model negatively. This does not have to be a problem in the case of the sheets that just contain parameters, however if not done correctly it could affect the calculation sheets significantly.

2.2.1.1 Common parameters

In order to group the parameters that are common to all ITs an individualized sheet was created. This sheet includes the following parameters:

1. Real average market price
2. Estimations of the average market price done by the competent ministry
3. Upper and lower bounds of the market price ($LS2_{i,j}$,$LS1_{i,j}$,$LI2_{i,j}$ and $LI1_{i,j}$)
4. Adjustment coefficients associated to each bound
5. Generation toll
6. Tax on the value of the production of electric energy (IVPEE)
7. Reasonable return

A simple table was created for all of them, so that the user could introduce values from 2014 to 2043. However, for the estimations of the average market price a more complex table was created, creating one row for each of the estimations that could be done in each semi-period by the ministry. This is done because the ministry, before each semi-period, establishes its market price estimations not only for the following semi-period, but also for following years. These estimations must be also taken into account, as they affect the future cash flow evaluation and therefore the investment remuneration to be perceived by the IT. The result of all of this was a sheet with the parameters explained before, represented as shown in figure 2.3:

Prices and deviations

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Real average market price (€/MWh)	42,06	50,3	38,33	52,22	57,27	61,7	53,43	50,45	47,93	52	52	52	52	52	52

Estimations on market price Ministry (€/MWh)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Semi-period 1	48,21	49,52	49,75	52,00	52,00	52,00	52,00	52,00	52,00	52,00	52,00	52,00	52,00	52,00	52,00
Semi-period 2				42,84	41,54	41,87	52,00	52,00	52,00	52,00	52,00	52,00	52,00	52,00	52,00
Semi-period 3							53,43	50,45	47,93	52,00	52,00	52,00	52,00	52,00	52,00
Semi-period 4										52,00	52,00	52,00	52,00	52,00	52,00
Semi-period 5													52,00	52,00	52,00
Semi-period 6															
Semi-period 7															
Semi-period 8															
Semi-period 9															
Semi-period 10															

Bounds over market price (€/MWh)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
LS2	8	8	8	6,97	6,76	6,81	8	8	8	8	8	8	8	8	8
LS1	4	4	4	3,49	3,38	3,41	4	4	4	4	4	4	4	4	4
LI1	-4	-4	-4	-3,49	-3,38	-3,41	-4	-4	-4	-4	-4	-4	-4	-4	-4
LI2	-8	-8	-8	-7,47	-6,76	-6,81	-8	-8	-8	-8	-8	-8	-8	-8	-8

Adjustment coefficients	
Coef LS2	1
Coef LS1	0,5
Coef LI1	0,5
Coef LI2	1

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Deviation adjustment (€/MWh)	1,075	0	5,42	-4,15	-10,66	-14,72	0	0	0	0	0	0	0	0	0

Rest of common parameters

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Generation toll (€/MWh)	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5
Tax on production of energy on market (%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Tax on production of energy Rinv (%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Reasonable return (%)	7,40%	7,40%	7,40%	7,40%	7,40%	7,40%	7,09%	7,09%	7,09%	7,09%	7,09%	7,09%	7,09%	7,09%	7,09%

Figure 2.3 Common parameters sheet

The deviation adjustment $Vajdm$ is calculated as was described in equations 2.6 to 2.10, but without taking into account the equivalent functioning hours, as that will depend on the specific IT being computed.

2.2.1.2 Semi-common parameters

There are several parameters that are used for all the ITs but have different values depending on the ITs technology. This is why a different sheet was created, to be able to obtain these parameters depending on the technology of the IT. These include:

1. Deviation cost
2. Captured price factor
3. Years until a decrease in number of equivalent functioning hours
4. Increase in operation costs

5. Increase in fuel cost
6. Increase in avoided costs or other revenues
7. Decrease in number of equivalent functioning hours

The parameters were structured in the sheet as shown in figure 2.4:

General parameters per plant type

	Group	Deviation cost 2014 (I/MWh)	Deviation cost 2015 (I/MWh)	Deviation cost 2016 (I/MWh)	Deviation cost 2017 - 2019 (I/MWh)	Deviation cost > 2020 (I/MWh)	Capt. Price factor 2014-2016	Capt. Price factor 2017-2019	Capt. Price factor 2020-2022	Capt. Price factor 2023-2025
Cogeneration	a.1	0	0	0	0	0	0,9997	1,024	1,0079	1,0079
Residual energy cogeneration	a.2	0	0	0	0	0	0,9997	1,024	1,0079	1,0079
Solar PV	b.1.1	0	0	0	0	0	1,0207	1,0495	1,003	1,003
Solar thermal energy	b.1.2	0	0	0	0	0	1,0207	1,0495	1,003	1,003
Onshore wind	b.2.1	1	0,8	0,6	0,6	0,6	0,8889	0,8521	0,9386	0,9386
Offshore wind	b.2.2	0	0	0	0	0	-	0,8521	0,9386	0,9386
Geothermal	b.3	0	0	0	0	0	-	0,9479	0,9479	0,9479
Ocean thermal energy	b.3	0	0	0	0	0	0,9721	0,9479	0,9479	0,9479
Tidal energy	b.3	0	0	0	0	0	0,88	0,9479	0,9479	0,9479
Hydro P<10MW	b.4	0	0	0	0	0	0,939	0,9581	0,9721	0,9721
Hydro P>10MW	b.5	0	0	0	0	0	0,939	0,9581	0,9721	0,9721
Crop biomass	b.6	0	0	0	0	0	0,9643	1,0047	1,0019	1,0019
Bioliquids	b.7	0	0	0	0	0	0,9643	1,0047	1,0019	1,0019
Industrial installation biomass	b.8	0	0	0	0	0	0,9643	1,0047	1,0019	1,0019
Domestic waste	c.1	0	0	0	0	0	0,9997	1,024	1,0079	1,0079
Other waste	c.2	0	0	0	0	0	0,9997	1,024	1,0079	1,0079
Mining waste	c.3	0	0	0	0	0	0,9997	1,024	1,0079	1,0079

	Capt. Price factor 2026-2028	Capt. Price factor 2029-2031	Capt. Price factor 2032-2034	Capt. Price factor 2035-2037	Capt. Price factor 2038-2040	Capt. Price factor 2041-2043	Years until decrease in hours	Increase in OPEX	Increase in OPEX estimation	Increase in fuel cost	Increase in fuel cost estimation	Increase avoided costs and other revenues	Inc avoided costs and other rev estimation	% decrease in hours
Cogeneration	1,0079	1,0079	1,0079	1,0079	1,0079	1,0079	30	1%	1%	0%	-	0%	-	0,0%
Residual energy cogeneration	1,0079	1,0079	1,0079	1,0079	1,0079	1,0079	30	1%	1%	0%	-	0%	-	0,0%
Solar PV	1,003	1,003	1,003	1,003	1,003	1,003	1	1%	1%	0%	-	0%	-	0,5%
Solar thermal energy	1,003	1,003	1,003	1,003	1,003	1,003	1	1%	1%	0%	-	0%	-	0,2%
Onshore wind	0,9386	0,9386	0,9386	0,9386	0,9386	0,9386	16	1%	1%	0%	-	0%	-	0,5%
Offshore wind	0,9386	0,9386	0,9386	0,9386	0,9386	0,9386	30	1%	1%	0%	-	0%	-	0,0%
Geothermal	0,9479	0,9479	0,9479	0,9479	0,9479	0,9479	30	1%	1%	0%	-	0%	-	0,0%
Ocean thermal energy	0,9479	0,9479	0,9479	0,9479	0,9479	0,9479	30	1%	1%	0%	-	0%	-	0,0%
Tidal energy	0,9479	0,9479	0,9479	0,9479	0,9479	0,9479	30	1%	1%	0%	-	0%	-	0,0%
Hydro P<10MW	0,9721	0,9721	0,9721	0,9721	0,9721	0,9721	30	1%	1%	0%	-	0%	-	0,0%
Hydro P>10MW	0,9721	0,9721	0,9721	0,9721	0,9721	0,9721	30	1%	1%	0%	-	0%	-	0,0%
Crop biomass	1,0019	1,0019	1,0019	1,0019	1,0019	1,0019	30	1%	1%	1%	1%	0%	-	0,0%
Bioliquids	1,0019	1,0019	1,0019	1,0019	1,0019	1,0019	30	1%	1%	0%	0%	0%	-	0,0%
Industrial installation biomass	1,0019	1,0019	1,0019	1,0019	1,0019	1,0019	30	1%	1%	1%	1%	0%	-	0,0%
Domestic waste	1,0079	1,0079	1,0079	1,0079	1,0079	1,0079	30	1%	1%	0%	0%	1%	1%	0,0%
Other waste	1,0079	1,0079	1,0079	1,0079	1,0079	1,0079	30	1%	1%	0%	0%	1%	1%	0,0%
Mining waste	1,0079	1,0079	1,0079	1,0079	1,0079	1,0079	30	1%	1%	1%	1%	0%	-	0,0%

Specific deviation costs for solar PV in extra-peninsular territories

		Deviation cost 2014 (I/MWh)	Deviation cost 2015 (I/MWh)	Deviation cost 2016 (I/MWh)	Deviation cost 2017 - 2019 (I/MWh)	Deviation cost > 2020 (I/MWh)
Solar PV	b.1.1	1,15	0,92	0,92	0,92	0,92

Figure 2.4 Semi-common parameters sheet

The parameters needed to calculate the cost reduction incentive were also included in this sheet, as it could be perceived by any IT, independent of its technology, provided that they operate in extra-peninsular territory. The parameters included in this sheet are:

1. $\frac{Cvg_j}{Egbc_j}$
2. A_j and B_j

These parameters were also represented in this sheet as shown in figure 2.5:

Cost reduction incentive parameters

Cvg/Egbc	2014-2016	2017-2019	2020-2022	2023-2025	2026-2028	2029-2031	2032-2034	2035-2037	2038-2040	2041-2043
Mallorca	84,60	108,00	108,00	108,00	108,00	108,00	108,00	108,00	108,00	108,00
Menorca	84,60	108,00	108,00	108,00	108,00	108,00	108,00	108,00	108,00	108,00
Ibiza	162,40	134,60	134,60	134,60	134,60	134,60	134,60	134,60	134,60	134,60
Formentera	162,40	134,60	134,60	134,60	134,60	134,60	134,60	134,60	134,60	134,60
Gran Canaria	190,70	166,40	166,40	166,40	166,40	166,40	166,40	166,40	166,40	166,40
Tenerife	184,40	164,20	164,20	164,20	164,20	164,20	164,20	164,20	164,20	164,20
Lanzarote	202,80	167,50	167,50	167,50	167,50	167,50	167,50	167,50	167,50	167,50
Fuerteventura	202,80	167,50	167,50	167,50	167,50	167,50	167,50	167,50	167,50	167,50
La Palma	193,90	172,80	172,80	172,80	172,80	172,80	172,80	172,80	172,80	172,80
La Gomera	220,90	215,00	215,00	215,00	215,00	215,00	215,00	215,00	215,00	215,00
El Hierro	263,20	252,60	252,60	252,60	252,60	252,60	252,60	252,60	252,60	252,60
Ceuta	205,30	179,50	179,50	179,50	179,50	179,50	179,50	179,50	179,50	179,50
Melilla	215,30	194,50	194,50	194,50	194,50	194,50	194,50	194,50	194,50	194,50

	2014-2016	2017-2019	2020-2022	2023-2025	2026-2028	2029-2031	2032-2034	2035-2037	2038-2040	2041-2043
A	0,45	0,45	0,45	0,45	0,45	0,45	0,45	0,45	0,45	0,45
B	0,06	0,06	0,06	0,06	0,06	0,06	0,06	0,06	0,06	0,06

Figure 2.5 Semi-common parameters sheet, cost reduction incentive

2.2.1.3 Specific parameters

There are certain parameters that only affect a small number of ITs. This is the case for ITs that belong to groups a.1, b.6, b.7, b.8, c.1, c.2 and c.3, basically being those ITs that depend on some kind of fuel for their operation. There are several components included here that are not directly determined by legislation, but that are necessary to compute all the costs for these kind of power plants. This is the case with data that is needed to calculate the cost of CO_2 for these plants, as well as part of their operation cost. These include:

1. CO_2 price
2. Factor determining the amount of free emission allowances
3. Inferior/Superior calorific power of the different fuels
4. Emissions factor of the different fuels (in case of cogeneration)

The rest of parameters that are included in this separate sheet are:

1. Hydrocarbon tax for fuels (for fuel oil, diesel oil and natural gas)
2. Initial price of the fuels (for the rest of the periods the value is calculated)
3. Tolls and other parameters that are used to calculate the price for natural gas
4. Factors *t* and *Ta* for biomass

In this case, the parameters directly involved with biomass and cogeneration plants and that are present in Order IET/1345/2015 are updated every 6 months, whilst others like the free emissions allowances factor or taxes are updated, if any, annually. Therefore, the disposition for parameters that are updated every 6 months will have to be different than those that might change annually.

The annual parameters are represented as shown in figure 2.6:

Particular parameters	2014	2015	2016	2017	2018	2019	2020	2021
CO2 price (I/t)	5,96	7,68	5,35	5,83	15,88	25,08	25,30	25,05
Hydrocarbon tax diesel oil (I/m3)	29,15	29,15	29,15	29,15	29,15	0,00	0,00	0,00
Hydrocarbon tax fuel oil (I/t)	12,00	12,00	12,00	12,00	12,00	0,00	0,00	0,00
Hydrocarbon tax natural gas	0,65	0,65	0,65	0,65	0,65	0,00	0,00	0,00
Hydrocarbon tax diesel oil for heat (I/m3)	29,15	29,15	29,15	29,15	29,15	0,00	0,00	0,00
Hydrocarbon tax fuel oil for heat (I/t)	12,00	12,00	12,00	12,00	12,00	0,00	0,00	0,00
Hydrocarbon tax natural gas for heat (I/GJ)	0,15	0,15	0,15	0,15	0,15	0,00	0,00	0,00
Free emission allowances factor (p.u.)	0,72	0,63	0,56	0,48	0,40	0,33	0,26	0,18
Hydrocarbon tax natural gas	0,65	0,65	0,65	0,65	0,65	0,65	0,65	0,65

Figure 2.6 Specific parameters sheet, annual parameters

Whilst the cogeneration parameters that are subject to be updated every semester are presented as seen in figure 2.7:

Cogeneration parameters		2ª semester 2014	1ª semester 2015	2ª semester 2015	1ª semester 2016	2ª semester 2016	1ª semester 2017	2ª semester 2017	1ª semester 2018	2ª semester 2018	1ª semester 2019
Pas	c€/kWh	0,621284465	0,618645803	0,618645803	0,619965134	0,619965134	0,613368478	0,613368478	0,613368478	0,613368478	0,613368478
Cas	c€/kWh	0,027641096	0,027641096	0,027641096	0,027641096	0,027641096	0,027641096	0,027641096	0,027641096	0,027641096	0,027641096
CF	c€/KWhPCS	2,5898	2,5400565	2,2892	2,096557383	1,618574259	1,964149382	1,94371704	1,902984294	2,126941873	2,132126341
RL $RL_s=\frac{0,710093+0,027711\cdot Br_s}{T_s}$		2,696740867	2,643995937	2,35860356	2,083510802	1,675303352	2,01183622	1,957852862	1,92087423	2,256534096	2,266017462
mr		0,00005	0,00005	0,00005	0,00005	0,00005	0,00005	0,00005	0,00005	0,00005	0,00005
mt		0,002	0,002	0,002	0,002	0,002	0,002	0,002	0,002	0,002	0,002
β		0,48	0,46	0,46	0,47	0,47	0,42	0,42	0,42	0,42	0,42
RC	c€/kWhPCS	1,7611	1,728	1,576	1,5011	1,1046	1,3597	1,3774	1,3446	1,3969	1,3969
Br	$/bbl	106,6478	92,0291	66,1198	58,8478	42,9264	50,9179	53,7108	56,4269	69,4783	71,17
T	$/€	1,3592	1,2331	1,0779	1,1235	1,1339	1,0543	1,1229	1,1837	1,1679	1,1837
Trf	c€/kWh/day/month	1,9612	1,9612	1,9612	1,9612	1,9612	1,9612	1,9612	1,9612	1,9612	1,9612
Trc	c€/kWh/day/month	1,0848	1,0848	1,0848	1,0848	1,0848	1,0848	1,0848	1,0848	1,0848	1,0848
Tfc2	c€/kWh/day/month	6,8683	6,8683	6,8683	6,8683	6,8683	6,8683	6,8683	6,8683	6,8683	6,8683
Tfc3	c€/kWh/day/month	4,4971	4,4971	4,4971	4,4971	4,4971	4,4971	4,4971	4,4971	4,4971	4,4971
Tfc4	c€/kWh/day/month	4,121	4,121	4,121	4,121	4,121	4,121	4,121	4,121	4,121	4,121
Tfc5	c€/kWh/day/month	3,7887	3,7887	3,7887	3,7887	3,7887	3,7887	3,7887	3,7887	3,7887	3,7887
Tfc6	c€/kWh/day/month	3,4848	3,4848	3,4848	3,4848	3,4848	3,4848	3,4848	3,4848	3,4848	3,4848
Tvc2	c€/kWh	0,154	0,154	0,154	0,154	0,154	0,154	0,154	0,154	0,154	0,154
Tvc3	c€/kWh	0,1249	0,1249	0,1249	0,1249	0,1249	0,1249	0,1249	0,1249	0,1249	0,1249
Tvc4	c€/kWh	0,1121	0,1121	0,1121	0,1121	0,1121	0,1121	0,1121	0,1121	0,1121	0,1121
Tvc5	c€/kWh	0,0983	0,0983	0,0983	0,0983	0,0983	0,0983	0,0983	0,0983	0,0983	0,0983
Tvc6	c€/kWh	0,0852	0,0852	0,0852	0,0852	0,0852	0,0852	0,0852	0,0852	0,0852	0,0852
Tvr	c€/kWh	0,0116	0,0116	0,0116	0,0116	0,0116	0,0116	0,0116	0,0116	0,0116	0,0116
Tgnl	c€/MWh/day	3,24	3,24	3,24	3,24	3,24	3,24	3,24	3,24	3,24	3,24
Drs	days	20	20	20	20	20	20	20	20	20	20
Tfas	c€/kWh/month	0,0411	0,0411	0,0411	0,0411	0,0411	0,0411	0,0411	0,0411	0,0411	0,0411
Tvi	c€/kWh	0,0244	0,0244	0,0244	0,0244	0,0244	0,0244	0,0244	0,0244	0,0244	0,0244
Tve	c€/kWh	0,0131	0,0131	0,0131	0,0131	0,0131	0,0131	0,0131	0,0131	0,0131	0,0131

International price	€/t	2ª semester 2014	1ª semester 2015	2ª semester 2015	1ª semester 2016	2ª semester 2016	1ª semester 2017	2ª semester 2017	1ª semester 2018	2ª semester 2018	1ª semester 2019
Diesel oil	€/t	591,49	562,6077996	462,4150185	394,8535313	285,3833189	364,0702138	360,5781538	359,3547712	448,4586411	453,2462189
Fuel oil	€/t	384,55	365,7725901	300,6334771	256,7092012	185,5384796	236,6958033	234,4254832	233,6301159	291,5599088	294,672494

ICP diesel or PLG	MWh/t	11,777
ICP Fuel oil	MWh/t	11,161
SCP Natural gas	MWh/m3	0,1198

ICP Natural gas	GJ/t	48,1

Emissions factor		
Natural gas	tCO2/TJpci	56,4
Diesel oil	tCO2/TJpci	74,1
Fuel oil	tCO2/TJpci	77,4
Coal	tCO2/TJpci	101

Conversion	TJ/MWh	0,0036

Figure 2.7 Specific parameters sheet, cogeneration parameters

The biomass and waste parameters are also represented as figure 2.8 shows:

Biomass parameters		2ª semester 2014	1ª semester 2015	2ª semester 2015	1ª semester 2016	2ª semester 2016	1ª semester 2017	2ª semester 2017	1ª semester 2018	2ª semester 2018	1ª semester 2019
Biomass price b.6	€/MWhpci	13,38569217	13,45245414	13,51954909	13,58697868	13,65474458	13,72284846	13,79129202	13,86007695	13,92920494	13,99867772
Biomass price b.8	€/MWhpci	10,7263741	10,77987256	10,83363784	10,88767128	10,94197422	10,996548	11,05139396	11,10651348	11,1619079	11,21757861
t	p.u.	0,004987562	0,004987562	0,004987562	0,004987562	0,004987562	0,004987562	0,004987562	0,004987562	0,004987562	0,004987562
Ta	p.u.	0,01	0,01	0,01	0,01	0,01	0,01	0,01	0,01	0,01	0,01

Biomass price b.6 2014	€/t	46,6
Biomass price b.8 2014	€/t	38,84

ICP b.6	MWhpci/t	3,49
ICP b.8	MWhpci/t	3,63

ICP c.1	MWhpci/t	2,33
ICP c.2 residuos	MWhpci/t	2,91
ICP Black liquors	MWhpci/t	3,63
ICP c.3	MWhpci/t	2,91

Figure 2.8 Specific parameters sheet, biomass and waste parameters

2.2.1.4 Information per IT

It is also necessary to know certain information that is specific to each of the ITs, such as functioning hours, operating costs or fuel costs, amongst others. There are several ways in which this can be done, either uniting this information in a single sheet, and/or consulting this information in that particular ITs sheet. In this case, both approaches were used simultaneously, on one hand creating a single sheet acting as a database, with information from 2014 until present day for all of the ITs, and an individual sheet with information for each of the ITs. This is beneficial as it allows for information to be compared easily between ITs in the common sheet, and also to be able to check information more specifically in the individual sheet for each IT. Having a sheet per IT also allows the ability to present calculation results in this same sheet. On the other hand, the individual sheet for each IT is extracted from data provided by the ministry, which varies depending on some of the ITs (mainly cogeneration), therefore extracting information from these sheets is more complex than displaying most of the information in a common database. The list of parameters in this case is quite extensive, as it groups any given information of the ITs since 2014 until 2019:

1. Net asset value
2. Estimated equivalent functioning hours (this includes estimations until 2022 in some cases)
3. Operation expenses
4. Fuel cost
5. Revenues from other sources
6. IT group (both in present legislation and in the previous scheme RD 661/2007)
7. IT subgroup (both in present legislation and in the previous scheme RD 661/2007)
8. Power range (both in present legislation and in the previous scheme RD 661/2007)
9. Fuel used
10. Technology subtype (in the case of solar energy and of cogeneration)
11. Climatic zone (in the case of solar PV)
12. Substantial modification (in the case that the particular IT has been modified substantially)
13. Final year of authorization
14. Electrical subsystem (in case of ITs in extra-peninsular territories)
15. Deviation adjustment
16. Regulatory life
17. Adjustment coefficient $C_{j,a}$
18. Investment remuneration (for 2014-2016 and 2017-2019)
19. Minimum equivalent functioning hours and operating threshold
20. Adjustment factors for minimum equivalent functioning hours and operating threshold in case the power plant associated to that IT started operating during the year
21. Operation remuneration
22. Maximum equivalent functioning hours allowed to perceive operation remuneration
23. A, B and C coefficients (for cogeneration plants)
24. Relationship between electricity exported/produced (for cogeneration plants)
25. Cost reduction incentive remuneration

Some parameters are not directly provided by the legislation, but serve to calculate operational or fuel costs for several ITs. These parameters include:

1. Electrical efficiency (in the case of cogeneration plants)
2. Thermal efficiency (in the case of cogeneration plants)
3. Normalized efficiency value according to the European Commission (in the case of cogeneration plants)
4. Equivalent electrical efficiency
5. Biomass and bioliquids efficiency

This information is classified as shown in figure 2.9:

IT	NAV 2017 (€/MW):	Equivalent functioning hours estimated 2014 in OM 1045	Equivalent functioning hours estimated 2015 in OM 1045	Equivalent functioning hours estimated 2016 in OM 1045	Equivalent functioning hours estimated 2017 in OM 1045	Equivalent functioning hours estimated 2018 in OM 1045	Equivalent functioning hours estimated 2019 in OM 1045	Equivalent functioning hours estimated 2020 in OM 1045	Equivalent functioning hours estimated 2021 in OM 1045	Equivalent functioning hours estimated 2022 in OM 1045
IT00001	7.622.909	1648	1640	1632	1623	-	-	-	-	-
IT00002	7.420.710	1648	1640	1632	1623	-	-	-	-	-
IT00003	6.881.374	1648	1640	1632	1623	-	-	-	-	-
IT00004	6.919.323	1648	1640	1632	1623	-	-	-	-	-
IT00005	6.536.840	1648	1640	1632	1623	-	-	-	-	-
IT00006	6.658.670	1648	1640	1632	1623	-	-	-	-	-
IT00007	6.827.608	1648	1640	1632	1623	-	-	-	-	-
IT00008	5.357.773	2102	2091	2081	2071	-	-	-	-	-
IT00009	5.896.987	2102	2091	2081	2071	-	-	-	-	-
IT00010	6.037.922	2102	2091	2081	2071	-	-	-	-	-
IT00011	7.092.511	2102	2091	2081	2071	-	-	-	-	-
IT00012	6.831.597	2102	2091	2081	2071	-	-	-	-	-
IT00013	7.055.542	2102	2091	2081	2071	-	-	-	-	-
IT00014	8.415.253	2102	2091	2081	2071	-	-	-	-	-
IT00015	7.834.289	2102	2091	2081	2071	-	-	-	-	-
IT00016	6.649.856	2124	2113	2103	2092	-	-	-	-	-
IT00017	5.659.271	2124	2113	2103	2092	-	-	-	-	-
IT00018	6.208.205	2124	2113	2103	2092	-	-	-	-	-
IT00019	6.337.624	2124	2113	2103	2092	-	-	-	-	-
IT00020	6.426.308	2124	2113	2103	2092	-	-	-	-	-
IT00021	6.822.078	2124	2113	2103	2092	-	-	-	-	-
IT00022	7.515.939	2124	2113	2103	2092	-	-	-	-	-

IT	Operating cost 2014	Operating cost 2015	Operating cost 2016	Operating cost 2017	Operating cost 2018	Operating cost 2019
IT00001	74,75	75,21	75,92	76,7	77,43	78,17
IT00002	72,6	73,05	73,75	74,51	75,23	75,96
IT00003	69,07	69,5	70,18	70,93	71,63	72,34
IT00004	68,42	68,85	69,53	70,27	70,96	71,67
IT00005	65,99	66,4	67,07	67,79	68,48	69,17
IT00006	65,9	66,31	66,98	67,7	68,39	69,08
IT00007	66,06	66,47	67,14	67,86	68,55	69,24
IT00008	58,34	58,71	59,34	60,03	60,68	61,33
IT00009	59,69	60,07	60,71	61,4	62,06	62,72
IT00010	59,51	59,89	60,52	61,21	61,86	62,52
IT00011	62,73	63,12	63,77	64,48	65,15	65,82
IT00012	61,13	61,52	62,16	62,86	63,52	64,19
IT00013	61,34	61,73	62,37	63,07	63,73	64,4
IT00014	65,46	65,87	66,53	67,25	67,93	68,62
IT00015	62,96	63,35	64,01	64,71	65,38	66,06
IT00016	63,27	63,66	64,32	65,03	65,7	66,38
IT00017	58,53	58,91	59,53	60,23	60,87	61,53
IT00018	59,9	60,28	60,92	61,61	62,27	62,93
IT00019	59,72	60,09	60,73	61,42	62,08	62,74
IT00020	59,44	59,82	60,45	61,14	61,79	62,45
IT00021	60,28	60,66	61,3	61,99	62,65	63,31
IT00022	62,12	62,51	63,16	63,86	64,52	65,2

Figure 2.9 Information per IT sheet

2.2.1.5 IT calculation

Once all the parameters are introduced into the model, there needs to be an independent sheet where all the calculations must be made. This section will just describe the general layout of this sheet, and how these calculi are done. Later sections will describe the specific functioning of this tool, and the logic behind the coding.

The objective, in this case, is to present all possible information regarding the IT whose results are trying to be computed, not only in terms of these results but all relevant information regarding this IT. This is not only advisable in terms of providing context on the terms of the IT (year of authorization, technology employed etc.) but also to be able to detect possible errors in the result i.e. the first year of operation being before the year of authorization, the IT receiving a cost reduction incentive when it is not located in extra-peninsular territories etc. This information is obtained from the sheet containing the information for all ITs and presented in this sheet for that particular IT. In order to achieve this, the general information of the IT is displayed at the side of the sheet, providing important details, as shown in figure 2.10:

	A	B	C	D	E
1					
2		**1**			
3		**IT00001**			
4					
5					
6		**Parameters**			
7					
8		VNA 2014 (l/MW):		8.299.915	
9		NAV 2017 (l/MW):		7.622.909	
10		Useful regulatory life (years):		30	
11					
12					
13		Equivalent functioning hours estimated 2014 in OM 1045		1.648	
14		Equivalent functioning hours estimated 2015 in OM 1045		1.640	
15		Equivalent functioning hours estimated 2016 in OM 1045		1.632	
16		Equivalent functioning hours estimated 2017 in OM 1045		1.623	
17		Equivalent functioning hours estimated 2018 in OM 1045		-	
18		Equivalent functioning hours estimated 2019 in OM 1045		-	
19		Equivalent functioning hours estimated 2020 in OM 1045		-	
20		Equivalent functioning hours estimated 2021 in OM 1045		-	
21		Equivalent functioning hours estimated 2022 in OM 1045		-	
22		2014 Vadj (l/MW):		0	
23		2015 Vadj (l/MW):		0	
24		2016 Vadj (l/MW):		0	
25					
26		**Annex I**			
27		Group 661		b.1	
28		Subgroup 661		b.1.1	
29		Fuel 661		-	
30		Power range 661		≤ 100 kW	
31		Type		-	
32		Convocation		-	
33		Group 413		b.1	
34		Group 413_2		Solar	
35		Subgroup 413		b.1.1	
36		Subgroup 413_2		Solar PV	

Figure 2.10 Information of the IT

It is also necessary to display the expected costs and revenues from this IT, including the different kind of remuneration types present in the current support scheme. It is also crucial that this is done for each semi-period until the end of the timeframe, as the expected revenues to be obtained are taken into account when calculating the investment remuneration. This is represented as it can be seen in figure 2.11:

		SEMI-PERIOD	1	2014	2015	2016	2017
		VNA	8.299.915				
		Equivalent annual hours (h)		1648	1640	1632	1623
		Price (l/MWh)		48,21	49,52	49,75	52,00
		Captured price factor		1,0207	1,0207	1,0207	1,0207
	No Cogeneration	Operation remuneration (l/MWh)		25,55	24,67	25,14	23,62
Cogeneration	1ª semester	Operation remuneration (l/MWh)		-	-	-	-
	2ª semester	Operation remuneration (2) (l/MWh)		-	-	-	-
		Other revenues (l/MWh)		-	-	-	-
		Relationship between electricity exported/produced		-	-	-	-
Biomass	1ª semester	Operation remuneration (l/MWh)		-	-	-	-
	2ª semester	Operation remuneration (2) (l/MWh)		-	-	-	-
		Otros ingresos de expl. (l/MWh)		0	0	0	0
		Cost reduction incentive (l/MWh)		**0**	**0**	**0**	**0**
		Revenues (l/MW)		**123.196**	**123.346**	**123.908**	**124.484**
		Toll (l/MWh)		0,5	0,5	0,5	0,5
		Deviation (l/MWh)		0	0	0	0
Cogeneration		Hydrocarbon tax (l/MWh)		-	-	-	-
	1ª semester	CO2 cost (l/MWh)		-	-	-	-
	2ª semester	CO2 cost (2) (l/MWh)		-	-	-	-
	1ª semester	Fuel cost (l/MWh)		-	-	-	-
	2ª semester	Fuel cost (2) (l/MWh)		-	-	-	-
		Fuel cost (l/MWh)		0	0	0	0
		Fuel cost (2) (l/MWh)		0	0	0	0
		IVP (l/MWh)		5,23	5,26	5,31	5,37
		IVP of Rinv (l/MWh)		35,13	35,31	35,48	35,68
		Rest of OPEX (l/MWh)		33,88	34,14	34,63	35,16
		Total operation costs (l/MW)		**123.188**	**123.344**	**123.901**	**124.484**
		Regulated margin (l/MW)	**14**	**8**	**2**	**6**	**0**
		Perceived margin (l/MW)	**14**	**8**	**2**	**6**	**0**

Figure 2.11 IT calculation

Finally, the information about the remuneration to be obtained by the IT each year should be presented clearly and graphically for the user to analyze in further detail, without needing to check each semi-period independently. This can be seen in figure 2.12:

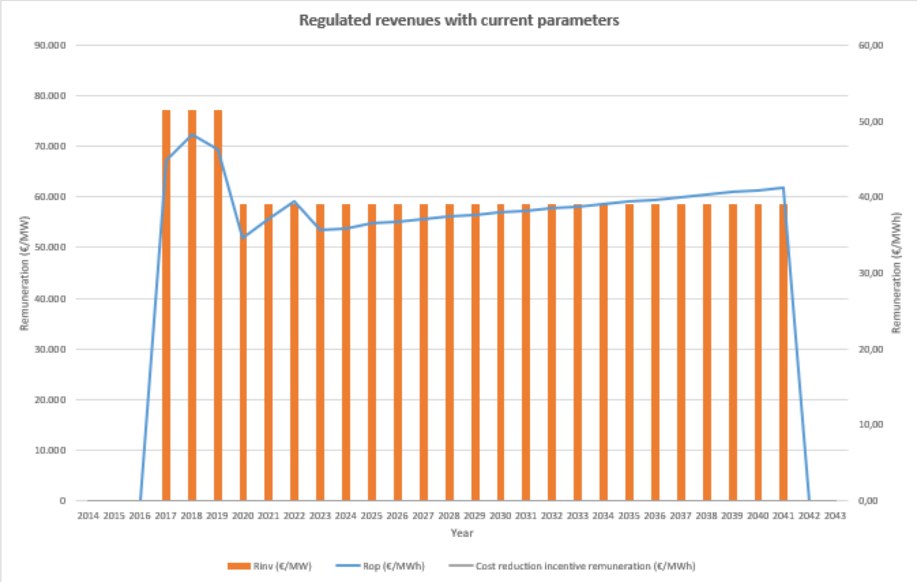

Figure 2.12 Graphical representation of the remuneration to be perceived by the IT

This is a similar way of representing the information to how it will be presented in chapter 3.

2.2.1.6 Real plant calculation

The objective of this model is not only to be used as a tool to analyze the amount of regulated remuneration each IT is going to obtain through the Spanish support scheme, but also that by using that information a user can obtain the economic forecast for any real power plant associated to that IT. In this case, the representation of the sheet in which these calculations are made is quite similar to the one explained before. The only difference is the indication that some values are taken as input data (operation, investment and cost reduction incentive remuneration, previous values of market price and the costs associated to the tax on the value of the production of electric energy), whilst others are modifiable, considering the real characteristics of the power plant (OPEX, fuel costs, equivalent functioning hours etc.). This differences would be represented by highlighting in orange the values that are given, in yellow the values that are calculated and in blue the ones that may be modified by the user, as seen in figure 2.13:

	R	S	T	U	V	W	X	Y	Z
2									
3									
4									
5									
6				SEMI-PERIOD	1	2014	2015	2016	2017
7				VNA	8.299.915				
8				Equivalent annual hours (h)		1648	1640	1632	1623
9				Price (€/MWh)		42,06	50,30	38,33	52,22
10				Captured price factor		1,0207	1,0207	1,0207	1,0207
11			No Cogeneration	Operation remuneration (€/MWh)		25,55	24,67	25,14	23,62
12		Cogeneration	1º semester	Operation remuneration (€/MWh)		-	-	-	-
13			2º semester	Operation remuneration (2) (€/MWh)		-	-	-	-
14				Other revenues (€/MWh)		-	-	-	-
15				Relationship between electricity exported/produced		-	-	-	-
16		Biomass	1º semester	Operation remuneration (€/MWh)		-	-	-	-
17			2º semester	Operation remuneration (2) (€/MWh)		-	-	-	-
18				Otros ingresos de expl. (€/MWh)		0	0	0	0
19				Cost reduction incentive (€/MWh)		0	0	0	0
20				**Revenues (€/MW)**		**112.851**	**124.652**	**104.884**	**124.849**
21				Toll (€/MWh)		0,5	0,5	0,5	0,5
22				Deviation (€/MWh)		0	0	0	0
23		Cogeneration		Hydrocarbon tax (€/MWh)		-	-	-	-
24			1º semester	CO2 cost (€/MWh)		-	-	-	-
25			2º semester	CO2 cost (2) (€/MWh)		-	-	-	-
26			1º semester	Fuel cost (€/MWh)		-	-	-	-
27			2º semester	Fuel cost (2) (€/MWh)		-	-	-	-
28				Fuel cost (€/MWh)		0	0	0	0
29				Fuel cost (2) (€/MWh)		0	0	0	0
30				IVPEE (€/MWh)		4,79	5,32	4,50	5,38
31				IVPEE of Rinv (€/MWh)		35,13	35,31	35,48	35,68
32				Rest of OPEX (€/MWh)		34,32	34,08	35,44	35,14
33				**Total operation costs (€/MW)**		**123.188**	**123.344**	**123.901**	**124.484**
34									
35				**Margin (€/MW)**	-4.234	**-10.337**	**1.307**	**-19.017**	**364**

Figure 2.13 Real plant calculation

2.2.2 Model programming

Most of the programming in the model is located in the sheet where the IT remuneration is calculated. Even though there are certain calculus done in other areas of the model, such as calculating the biomass cost for each semester or the parameters that are necessary to calculate the operation remuneration for cogeneration plants, these are merely simple arithmetic calculations that are not necessary to detail. However, the functioning of the calculus sheets uses logical functions and iterative processes that need to be explained.

2.2.2.1 Generalities

Except some particular cases that will be described later on, most ITs have the same methods of calculating their forms of revenues and costs, with some having small exceptions that may vary some particular concept but maintaining the general formula constant. It is important, therefore, to demonstrate the methods of calculating the revenues and costs of the ITs that use this general methodology.

<u>Revenues</u>

This section will describe the general revenues formulation, whilst following sections will describe particular ways to describe the revenues obtained by cogeneration ITs. To obtain the revenues by the different ITs for every year the market price, *Pm*, the captured price factor, *CP*, the operation remuneration, other sources of revenue, *ORev*, and the cost reduction incentive remuneration must be taken into account. Therefore, the revenues, *Rev* will be calculated as shown in equation 2.22:

$$Rev_i = \overbrace{\left(Pm_i \cdot CP_j + Ro_i + ORev_i + Iinv_i\right)}^{\text{General operation revenues (€/MWh)}} \cdot Nh_i + Rinv_i \tag{2.22}$$

The equivalent functioning hours, *Nh*, will be either the values given by the ministry, if provided for the year being calculated, or updated from the year before according to ministry criteria. Although these two should be equal, this is not the case, probably due to the government presenting whole values only. When doing calculations, if the equivalent functioning hours are zero then the rest of the components will also be zero, as it means that the IT is not in operation. The values for the other sources of revenue are obtained as information from the ministry, and are updated according to ministry rules. The operation remuneration is calculated as the difference between the rest of the revenues, excluding the investment and cost reduction incentive remuneration, the first as it is not a remuneration that depends on operation and the second because is an extra form of remuneration, and the costs, in the case that the other revenues are smaller than the costs, unless there is already a published value by the ministry. The investment remuneration is determined either by ministry values, if they have been published, or according to equation 2.2. The investment remuneration as well as the total revenues ar the only terms to be represented as €/MW.

In the case of biomass and cogeneration ITs, it is important to say that the operation remuneration that is described in equation 2.22 is the average of the operation remuneration of the first and second semester of year "i", as biomass and cogeneration ITs have their operation remuneration updated every 6 months. Therefore, the process when calculating the operation remuneration of biomass ITs is done for both semesters, taking into account the fuel cost for each semester, as described in equation 2.20. The way to calculate the operation remuneration for cogeneration ITs will be explained later on, in section 2.2.2.2. This way, the logical process followed when calculating the revenues to be obtained in year "i" for the corresponding IT is described in figure 2.14. This represents how equation 2.22 has been implemented in the model, not the exact model formulation. The exact formulation in the model will not be represented here, as it would be harder to explain it than a graphical representation of that formulation.

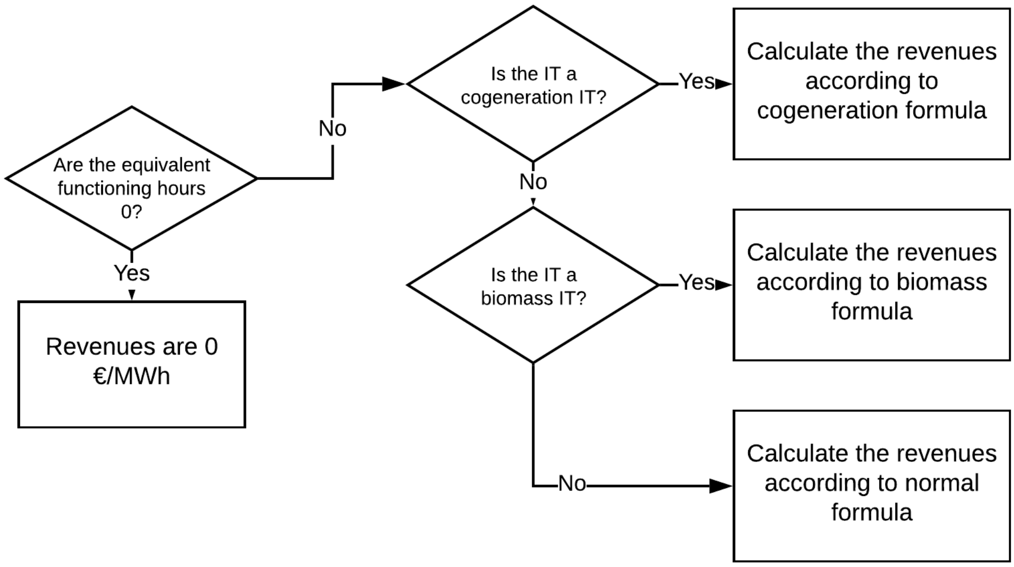

Figure 2.14 Decision making when calculating revenues

<u>Costs</u>

In the case of costs, there is also a general formula, but there are many specific details concerning different types of ITs. This must take into account the different operational expenses. The general formulation would be the one described in equation 2.23:

$$Cexp_i = \left(\overbrace{Tg_i + Dev_i + IVPEE_i}^{\text{Regulated costs}} + \overbrace{C_{F_i} + C_{CO2_i}}^{\text{Fuel \& emissions cost}} + OPEX_i \right) \cdot Nh_i \tag{2.23}$$

The generation toll, Tg, is common for all ITs, whilst the deviation costs, Dev, depend on the technology type of the IT. The fuel costs for most of the ITs are zero, except for cogeneration, biomass and certain waste plants, whilst in the case of cogeneration ITs and ITs from group b.7 this term also includes the special tax on hydrocarbons for the fuel associated. The CO_2 allowances cost is something that is only present for cogeneration ITs and does not affect any other. There is also the rest of operation expenses, $OPEX$, that will be described later on.

The cost associated to the tax on the value of production of energy, $IVPEE$, includes the effect on the tax on the revenues from selling energy into the market, including operation remuneration, and also the investment remuneration (expressed in €/MWh taking into account the equivalent functioning hours). In general terms, this cost would be represented as shown in equation 2.24, where the value of the tax is T_{IVPEE_i}:

$$IVPEE_i = T_{IVPEE_i} \cdot \left(\overbrace{Pm_i \cdot CP_j}^{\text{Market revenues}} + \overbrace{Ro_i + \frac{Rinv_i}{Nh_i}}^{\text{Regulated revenues}} \right) \tag{2.24}$$

For biomass and cogeneration plants, this cost must take into account that there is a different operation remuneration for both semesters of a year. This way, the previous formula would have to be adapted as described in equation 2.25:

$$IVPEE_i = T_{IVPEE_i} \cdot \left(Pm_i \cdot CP_j + \frac{Ro_{i,s1} + Ro_{i,s2}}{2} + \frac{Rinv_i}{Nh_i} \right) \tag{2.25}$$

It is important to mention that the cost reduction incentive remuneration is also subject to this tax; however, as this form of remuneration is not taken into account to update the net asset value, neither are the costs associated to the application of the tax on the value of the production of electric energy. Nevertheless, a real power plant associated to an IT that can receive this form of remuneration will have to pay the costs associated to the application of this tax on those revenues.

The operation expenses are a value given by the ministry, however this value must have the generation toll, deviation costs, tax on the value of production of energy costs, and, in the case of cogeneration plants, the CO_2 allowances cost deduced. These operation expenses value is designed to increase in 1% each year, however if the ministry value is taken each year, and the values mentioned before are eliminated it can be observed that this value does not increase by this 1%. Given this there are 2 alternatives:

1. Use the value given by the ministry and then take away associated costs to represent it correctly.
2. Use an initial value provided by the ministry and then update it annually.

The decision was made to use the value provided by the ministry, unless there was no value given for the current year being analyzed, in which case the value would be the one of the year before and increased by 1%. The method to calculate the operation expenses follows figure 2.15:

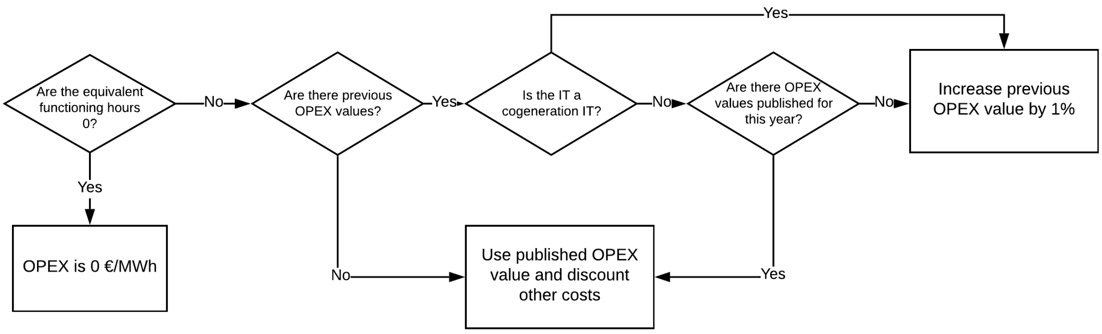

Figure 2.15 Decision making when calculating OPEX

The reason for the difference between the normal approach, described in the paragraph before, and the approach with cogeneration ITs, is due to the way to calculate the CO_2 emission allowances cost, which will be explained in section 2.2.2.2. The only possible way to calculate that cost is to update the OPEX with a 1% increase, and not leave it as a variable term, or a paradoxical result would occur, where the OPEX would never increase.

Margin

In general, the margin that is perceived by a company is the difference between the revenues and the costs. In this case, the margin obtained by the ITs is used to vary the amount of investment remuneration to be perceived by them in the long term. Nevertheless, there is a part of the revenues that should not be considered when computing the margin for this calculation, which is the cost reduction incentive remuneration. This form of remuneration is to be perceived as an extra and therefore should not be used to reduce other forms of revenue. This way, two different margins are calculated, the perceived margin *PMar*, which takes into account all revenues and costs, and the regulated margin *RMar*, which is the one used to update the net asset value and the investment remuneration. The perceived margin would be calculated as described in equation 2.26:

$$PMar_i = Rev_i - Cexp_i \tag{2.26}$$

Whilst the regulated margin will be calculated following equation 2.27:

$$RMar_i = PMar_i - Iinv_i \cdot Nh_i \tag{2.27}$$

Nevertheless, for the calculation of the adjustment factor $C_{j,a}$, that takes into consideration future revenues and costs, the investment remuneration cannot be included, as it is precisely used to calculate how much investment remuneration the IT should receive. Therefore, the term $Ingf_i - Cexpf_i$ will be calculated according to equation 2.28:

$$Ingf_i - Cexpf_i = RMar_i - Rinv_i \tag{2.28}$$

Nevertheless, for current revenues and costs, which are mentioned in equation 2.1, *Rinv* is included in the revenues to update the net asset value. Therefore, $Ing_i - Cexp_i$ will be calculated as shown in equation 2.29:

$$Ing_i - Cexp_i = RMar_i \tag{2.29}$$

<u>Net asset value update calculation</u>

After each semi-period, the net asset value of the IT must be calculated. In order to do so equation 2.1 must be applied. These equations do not require much explanation, as it is calculated and modelled precisely as the equations described, with the calculation of $Vajdm$ according to equations 2.6 to 2.10, and taking into account that $Ing_i - Cexp_i$ is calculated according to equation 2.29.

2.2.2.2 Cogeneration ITs particularities

Previous sections have explained in detail how the operation remuneration, in the case of cogeneration plants, is calculated, however the application of the calculations in the model is considerably more complex than simple arithmetic. Every semester, the ministry provides the different parameters necessary to calculate the operation remuneration of these ITs, and every time a new cogeneration IT is installed or a new semi-period is about to begin it also gives information on fuel cost, other sources of revenue, operation costs and equivalent functioning hours. However, there are certain rules included by Order IET/1045/2014 that make it necessary to depict this information even further, and that require significant analysis in order to model them correctly.

CO_2 emission allowances cost

The clearest reason for this is that there is an increment of 1% in the operation expenses that remains after taking away tolls and taxes. In the case of cogeneration, the cost of the CO_2 allowances is included in the general operating costs, therefore it must be taken out in order to apply the 1% increment. This is actually more important than it may seems at first. In the formulas that are used to calculate the operation remuneration for cogeneration plants, the CO_2 allowances cost is not taken into account at any point. The only aspect that is considered is the variation of the fuel cost and the previous value of the operation remuneration. It is true that parameter C_s allows for certain adjustment of the operation remuneration considering a change in other values used to calculate it, nevertheless there is no clear way to assign this cost in the current legislation. This will lead to problems that will be described more clearly in chapter 3. There are two possible ways to solve this issue that can be summarized as:

1. Calculate the real CO_2 emission allowances cost based on available information (CO_2 allowances price, emission rate, efficiency etc.) for each year.
2. Calculate an initial value of CO_2 allowances cost and then update it according to the variation in operation remuneration, market price and costs.

The first is the more technical approach, and probably the one that yields results that are closer to reality, however this application is quite impractical. The reason for this is that ITs that rely on operation remuneration have revenues equal to their costs. This means that, in the end, the operation remuneration must compensate the difference between revenues and costs, and that the variation of the operation remuneration is correlated to the evolution of these revenues and costs. This means that even though CO_2 allowances have increased in price, and therefore increased in cost, this might not be reflected in the operation remuneration (as it is not formally taken into account in the formula), so reflecting this real cost would cause an imbalance in the calculation. The solution to this was to create a mixture of both approaches. This method can be described more easily with the flow diagram of figure 2.16.

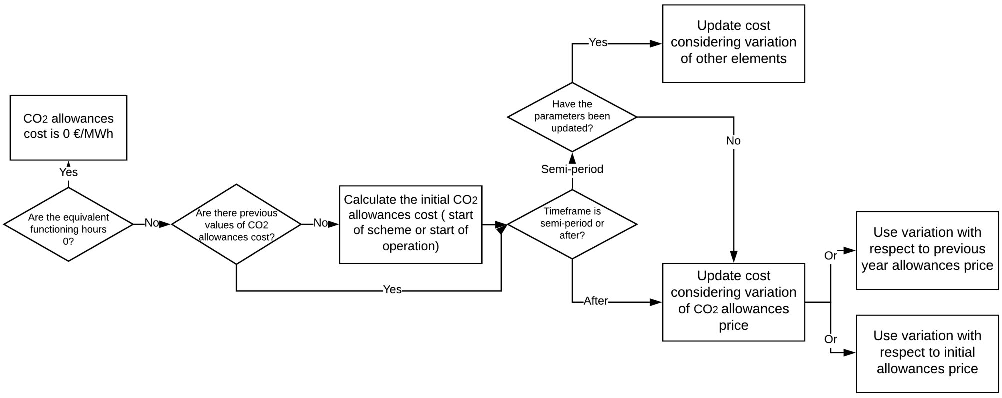

Figure 2.16 Decision making when calculating CO_2 allowances cost

The first part of the diagram (at the left) describes a checking process that must be made at the start of this decision making. If there were no ITs that were introduced after 2014, or no possibility that ITs could be introduced in the future, it would not be needed as all considerations would begin in 2014, when the support scheme started. It is then necessary to check if the equivalent functioning hours are zero in that year, meaning that the IT is not in operation at that moment, if it is zero then logically so is the CO_2 allowances cost, but if it is higher then the CO_2 allowances cost will have to be calculated initially. For calculations that are done for the regulatory semi-period of analysis (for example for the first semi-period that would be from 2014 to 2016) there are two options:

1. If the parameters needed for the operation remuneration have been given, then the CO_2 allowances cost is calculated taking into account these variations.

2. If there are no parameters that have been given yet for the semester being taken into consideration, then the value is updated taking into account the variation of the CO_2 allowances cost. This can be done either by comparing it to the value of the year before or to the value of the first year the CO_2 allowances cost was calculated.

The reason for this is simple. If there is no way to evaluate the difference of the cost, taking into account the formula applied by the ministry, the best way to estimate its variation is by using the change in the CO_2 allowances cost. For periods after the regulatory semi-period it can only be calculated by this method, as during that semi-period there is no information on the next. The decision on whether to update the CO_2 allowances cost comparing the CO_2 allowances prices from the year of calculus to the first value calculated or the previous year is not trivial. Comparing and updating the CO_2 allowances cost comparing the price to the initial calculation value is probably more precise, as it will calculate the real cost assumed by the IT, however it goes against how the ministry updates the cost, therefore the other approach will be used. Nevertheless, this causes problems of its own that will be analyzed later on, in section 3.1.9.

It is now crucial to describe how the initial value of the CO_2 allowances cost has been calculated, and how its value is updated in the cases described beforehand. The initial CO_2 allowances cost has been calculated following the methodology explained by the competent ministry and the Institute for the Diversification and Energy savings (IDAE) [24]. The CO_2 allowances cost would be calculated like described in equation 2.30:

$$C_{CO2} = \overbrace{T_{CO2}}^{\text{CO2 allowances price}} \cdot \left(\overbrace{\frac{EF}{\eta_E}}^{\text{Electricity gen. emissions}} - \overbrace{\delta \cdot \frac{\eta_H}{\eta_E} \cdot EF}^{\text{Heat gen. emissions}} \right) \tag{2.30}$$

The electrical, η_E, and thermal efficiencies, η_H, for each IT was taken from the very same document, considering the fuel, rated power, year of installation and technology used by the power plant, as well as the emissions factor, EF, which depends on the fuel used. However, as the cited document was published in 2015 only values up until 2013 are considered, therefore efficiency values for plants with a year of installation after 2013 have been considered to have the same efficiency values as the equivalent 2013 plants. The percentage of CO_2 allowances given for free, δ was obtained from Annex VI of the Decision of the European Commission of the 27$^{\text{th}}$ of April of 2011 [8].

In the case that the ministry had published and updated the parameters for the semester that is going to be calculated, the CO_2 allowances cost would be updated as shown in equation 2.31:

$$C_{CO2_s} = C_{CO2_{s-1}} + \overbrace{C_s \cdot R_{exp/gross_j}}^{\text{C adjustment}} + \overbrace{(Pm_i - Pm_{i-1}) \cdot CP_j \cdot R_{exp/gross_j}}^{\text{Market revenues var. adjustment}} + \overbrace{(OPEX_{s-1} - OPEXs)}^{\text{OPEX variation}} + \overbrace{T_{IVPEE_s} \cdot (Pm_{s-1} - Pm_s) \cdot R_{exp/gross_j}}^{\text{IVPEE of market price var.}} \tag{2.31}$$

It is important to comment on various things that are of importance of equation 2.31. The operation remuneration provided by the ministry is expressed in € per MWh that is exported into the grid, similarly to the concepts that are described in the formula to calculate it. On the other hand, the fuel cost and the operation expenditures, provided by the ministry as information for the various cogeneration ITs, are expressed in € per MWh generated as gross value. This is why the ministry also provides the term $R_{exp/gross_j}$, in order to convert what the cogeneration plant generates into what it finally exports into the grid. This is why some values are considered as €/MWh_{exp} or €/$\text{MWh}_{\text{gross}}$. Final values of revenues and costs, as well as all information of operation and investment remuneration and costs associated with the IVPEE are expressed per MWh_{exp} and the OPEX, fuel costs (including the hydrocarbon tax) and CO_2 emission allowances costs are expressed per $\text{MWh}_{\text{gross}}$. There is a possiblity of expressing all the values as per $\text{MWh}_{\text{gross}}$, nevertheless all the the information by the ministry is provided in terms of energy exported into the grid.

It is also necessary to explain the purpose of the previous formula. As it was described before, parameter C acts as a balancing tool when there are small deviations in different parameters, so it is used to make sure that the operation remuneration is enough but not above what is necessary. Therefore, in order to calculate parameter C the ministry has had to analyze the variation of market price, OPEX, IVPEE related costs and CO_2 allowances costs. What is done is to calculate the variation of the CO_2 allowances cost taking into account the variation of the different elements and the value of C, as the variation of the CO_2 allowances is the only unknown. In the case of the costs associated to the tax on the value of the production of electric energy, only the associated costs due to the market price are considered. The costs related to the application of the tax on the operation remuneration will be considered in the next section, when describing the breakdown of the fuel costs, as the operation remuneration has a direct relationship with the fuel costs in the case of cogeneration ITs.

In case the ministry had not presented information for the semester being calculated, the CO_2 emission allowances cost would be updated according to the variation of their price and of the percentage of allowances given for free. The calculus would be done as described in equation 2.32, taking into consideration equation 2.30:

$$C_{CO2_s} = C_{CO2_{s-1}} \cdot \overbrace{\left(\frac{T_{CO2_s} \cdot (1-\eta_H \cdot \delta_s)}{T_{CO2_{s-1}} \cdot (1-\eta_H \cdot \delta_{s-1})}\right)}^{\text{Variation in emissions price perceived by IT}} \tag{2.32}$$

The reason for doing the calculation after the semi-period like this is that if the different parameters, such as the fuel or the market price, are maintained constant the CO_2

allowances cost will decrease according to the increase in OPEX, according to equation 2.31. This, in turn, would cause the operation remuneration to remain constant throughout the rest of the regulatory lifetime. This result does not make sense, as assuming the rest of the parameters as constants, the operation remuneration should be the one to compensate for this increase in costs.

<u>Fuel cost</u>

As the variation in operation remuneration, in the case of cogeneration plants, depends on the variation of the fuel price, determining the fuel cost is extremely important. However, taxes related to the fuel, such as the special tax on hydrocarbons, STH_E for electricity generation and STH_{H-CHP} for heat generation, used are also included as part of the fuel cost, which is why this tax cost must be taken out of the fuel cost, to evaluate the variation in fuel price correctly. The fuel cost of a cogeneration would be determined by equation 2.33:

$$C_F = \overbrace{\frac{1}{EEE} \cdot (T_F + STH_E)}^{\text{Electricity generation fuel cost}} + \overbrace{\left(\frac{1}{\eta_E} - \frac{1}{EEE}\right) \cdot (T_F + STH_{H-CHP})}^{\text{Heat generation fuel cost}} \tag{2.33}$$

Being the equivalent electrical efficiency (EEE) the efficiency of the fuel used to generate electricity in the cogeneration plant, represented by equation 2.34:

$$EEE = \frac{\eta_E}{1 - \frac{\eta_H}{RefH}} \tag{2.34}$$

In this case, $RefH$ is the reference thermal efficiency for separate generation of heat (MWh_T/MWh_{PCI}) which is obtained through Annex I of the Decision of the European Commission of the 19th of December 2011 [7], depending on the fuel used by the IT. Therefore, the cost of the taxes paid on the use of hydrocarbon fuels would be represented as expressed in equation 2.35:

$$C_{STH} = \frac{STH_E}{EEE} + \left(\frac{1}{\eta_E} - \frac{1}{EEE}\right) \cdot STH_{H-CHP} \tag{2.35}$$

Knowing the cost associated to the special tax on hydrocarbons means this cost can be separated from the actual fuel cost that is needed to operate the cogeneration IT. However, as in the case of the CO_2 emission allowances cost, there is an important question on how to update the fuel cost over time. One solution would be to use equation 2.33 taking away the hydrocarbon tax associated cost and taking into account changes to the fuel price, another would be to use the operation remuneration equations 2.13 and 2.18 to update the fuel cost. This can be done because the first part of these two equations represent precisely how the variation of the fuel price affects the cost associated to each particular cogeneration IT. In this case, parameter A would reflect the sensitivity of the cogeneration plants fuel costs with respect to a variation of the associated fuel price. However, parameter A also considers the fact that the operation remuneration also carries a cost due to the tax on the value of the production of electric energy. This way, parameter A includes both the variation in cost due to the change in the fuel price and also the own variation of the operation remuneration. In order to compensate for this the difference in operation remuneration would have to be deduced from the fuel cost.

This was the approach that has been used finally, as it made the most sense taking into account the individual ITs characteristics and would replicate the calculations done by the ministry. Therefore, the variation in the total fuel cost (including the special tax on hydrocarbons) would be represented according to equation 2.36. If there are no values published for A in that semester then the previous published value will be used.

$$C_{F_s} - C_{F_{s-1}} = A_s \cdot \overbrace{(T_{F_s} - T_{F_{s-1}})}^{\text{Var. in fuel price}} + \overbrace{(C_{STH_s} - C_{STH_{s-1}})}^{\text{Var. in hydroc. tax cost}} - \overbrace{T_{IVPEE_s} \cdot (Ro_s - Ro_{s-1})}^{\text{Var. in IVPEE tax related to Ro}} \tag{2.36}$$

This way, the process followed to determine the fuel price for each semester was the one described in figure 2.17. The decision-making when calculating the fuel cost is considerably simpler than in the case of the CO_2 allowances cost. It is important to say that the fuel cost is recalculated each semi-period and may have little to do with the semester before the new semi-period starts, therefore the first semester of each semi-period the fuel cost is recalculated as if it was the first semester of operation or the start of the support scheme. If there are existing values of the fuel costs, and it is not the first semester of the semi-period, then the value can be calculated according to equation 2.36.

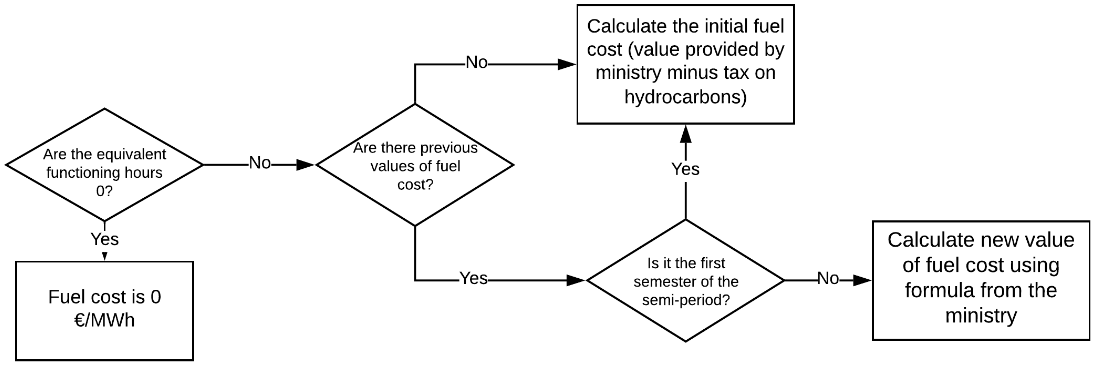

Figure 2.17 Decision making when calculating fuel cost

Nevertheless, equation 2.36 does not work every time, due to Excel limitations, as the change in fuel cost depends on the variation of the operation remuneration and vice-versa. In order to avoid this, this will only be done when there are values published for the operation remuneration on the semi-period under calculation. When values have not yet been published, or the period being studied is after the current semi-period, the formulation to be used is the one according to equation 2.37:

$$C_{F_s} - C_{F_{s-1}} = \overbrace{\frac{A_s \cdot (T_{F_s} - T_{F_{s-1}})}{1 + T_{IVPEE_s}}}^{\text{Var. in fuel price and IVPEE}} + \overbrace{(C_{STH_s} - C_{STH_{s-1}})}^{\text{Var. in hydroc. tax cost}} \tag{2.37}$$

This formulation creates the same effect as equation 2.36, but avoiding the problems that Excel might have concerning iterations.

Operation remuneration

Other sections have described in detail how the operation remuneration in the case of cogeneration ITs is calculated. However, there are important differences on how the ministry proposes this calculation and how it is done in the model. This is because the different terms used in the calculation of the operation remuneration are already taken into account in the costs; therefore, it is only necessary for the operation remuneration to be calculated as the difference between the rest of the revenues and costs if the rest of the revenues are smaller than the costs. This is because if market prices (and therefore revenues) as well as OPEX values are assumed constant the variation in operation remuneration as a difference between other revenues and costs would be represented as in equation 2.38, taking into account equations 2.31 and 2.36:

$$\triangle Ro_s = \triangle Cexp_s - \triangle Rev_s = A_s \cdot (\triangle T_{F_s}) + C_s \tag{2.38}$$

It can be seen that this representation is exactly the formula used by the ministry to calculate the operation remuneration, so it is actually beneficial to perform the calculations in this method, as it will ensure revenues and costs match.

<u>Revenues</u>

Previously, the general method to calculate revenues was described, as well as some particularities for biomass ITs. Nevertheless, in the case of cogeneration ITs, this calculation is slightly more complex, as can be deduced for what has been prefaced in previous sections. Therefore, the revenues for cogeneration ITs would be calculated following equation 2.39:

$$Rev_i = \left(Pm_i \cdot CP_j + \left(\frac{Ro_{s2} + Ro_{s1}}{2} \right) + \left(\frac{ORev_i}{R_{exp/gross_j}} \right) + Iinv_i \right) \cdot Nh_j \tag{2.39}$$

Other sources of revenue are a value given by the ministry, and are represented as €/MWh$_{\text{gross}}$, therefore it needs to be converted to €/MWh$_{\text{exp}}$, as the rest of the terms of the equation are represented in this way. In the end the revenues are obtained as €/MW. The operation remuneration will also be calculated considering the differences between revenues and costs, in case the revenues are smaller than the costs, also considering the fuel cost for the semester being calculated.

There are some cogeneration ITs that do not use a specific fuel, but rather operate with residual energy from other processes. These cogeneration ITs have a unique annual value for the operation remuneration, so Ro_{s1} and Ro_{s2} will be modified to Ro_i, but the rest of the equation would be the same. Therefore, the revenues would be calculated as presented in equation 2.40:

$$Rev_i = \left(Pm_i \cdot CP_j + Ro_i + \left(\frac{ORev_i}{R_{exp/gross_j}} \right) + Iinv_i \right) \cdot Nh_j \tag{2.40}$$

These cogeneration ITs that do not have a specific fuel do not have associated fuel costs or CO_2 emission allowances costs.

Costs

The cost calculation is very similar to the one described in equation 2.23, however in the case of cogeneration ITs it is slightly different, as the some of the costs have semi-annual values and it also depends if they are represented as €/MWh$_{\text{gross}}$ or €/MWh$_{\text{exp}}$. Therefore, the costs are calculated as expressed in equation 2.41:

$$Cexp_i = \left(Tg_i + Dev_i + \left(\frac{C_{F_{i,s2}} + C_{F_{i,s1}}}{2 \cdot R_{exp/gross_j}} \right) + IVPEE_i + \left(\frac{C_{CO2_i,s2} + C_{CO2_i,s1}}{2 \cdot R_{exp/gross_j}} \right) + OPEX_i \right) \cdot Nh_i \tag{2.41}$$

2.2.2.3 Cost reduction incentive remuneration

Although the formulation of the cost reduction incentive remuneration is quite straightforward, there are certain aspects that need to be commented, as they are not stated clearly in the legislation. On one hand, as the value of this remuneration is set for a semi-period, taking also into account values of operation and investment remuneration and market prices for the whole semi-period, these need to be determined beforehand. So, it will be necessary to calculate the average value of the operation and investment remuneration the IT will receive in the semi-period as well as the average market price perceived by the IT. Therefore, for ITs other than cogeneration or biomass equation 2.11 will be represented by equation 2.42:

$$\left[\frac{Cvg_j}{Egbc_j} - \left(\left(\frac{\frac{Rinv_{j,i1}}{Nh_{j,i1}} + \frac{Rinv_{j,i2}}{Nh_{j,i2}} + \frac{Rinv_{j,i3}}{Nh_{j,i3}}}{Ny_j} \right) + \left(\frac{Ro_{j,i1} + Ro_{j,i2} + Ro_{j,i3}}{Ny_j} \right) + CP_j \cdot \left(\frac{Pm_{j,i1} + Pm_{j,i2} + Pm_{j,i3}}{Ny_j} \right) \right) \right] \geq A_j \cdot \frac{Cvg_j}{Egbc_j} \tag{2.42}$$

Whilst equation 2.12 would be represented by equation 2.43:

$$Iinv_j = \left[\frac{Cvg_j}{Egbc_j} - \left(\left(\frac{\frac{Rinv_{j,i1}}{Nh_{j,i1}} + \frac{Rinv_{j,i2}}{Nh_{j,i2}} + \frac{Rinv_{j,i3}}{Nh_{j,i3}}}{Ny_j} \right) + \left(\frac{Ro_{j,i1}+Ro_{j,i2}+Ro_{j,i3}}{Ny_j} \right) + CP_j \cdot \left(\frac{Pm_{j,i1}+Pm_{j,i2}+Pm_{j,i3}}{Ny_j} \right) \right) \right] \cdot B_j \tag{2.43}$$

This formulation takes into account that some ITs may not start operation at the start of the semi-period or finish operation before the end of the semi-period. Nevertheless, it is important to mention that the market price for the years of no operation are considered as 0 €/MWh so that the formulation makes sense.

In the case of cogeneration and biomass ITs, the formulation would be quite similar, but the operation remuneration would have to be considered per semester, therefore the number of years (Ny_j) would have to be substituted for number of semesters (Ns_j) and the operation remuneration of all 6 semesters of the semi-period.

Even though the mathematical formulation is quite straightforward, the practical implementation in the model is slightly different and is represented by figure 2.18:

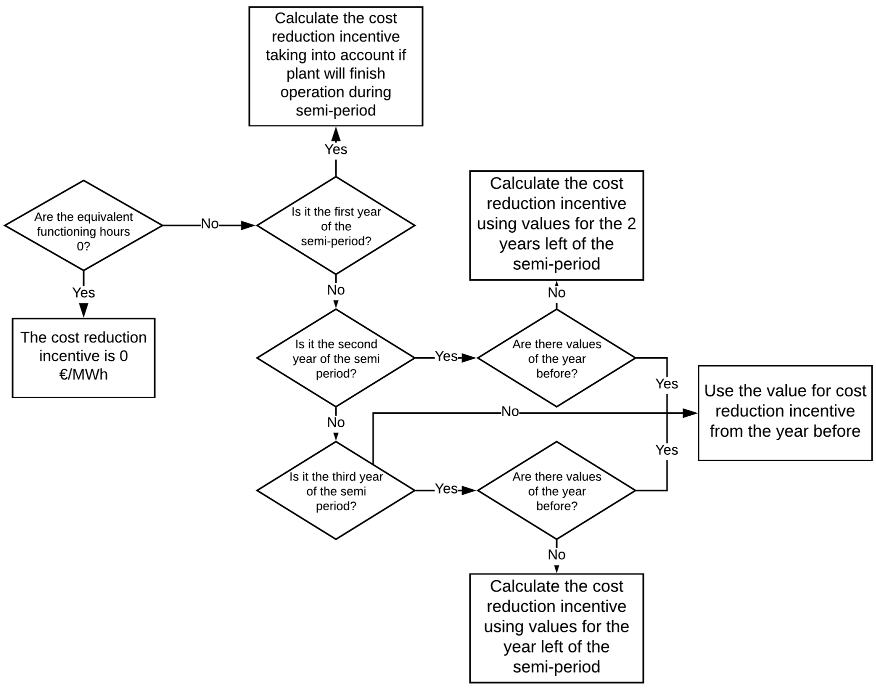

Figure 2.18 Decision making when calculating the cost reduction incentive remuneration

The reason why for the years two and three of the semi-period the calculation does not take into account whether the IT will finish operation during the semi-period is that it is not possible. An IT without operation in the first year of the semi-period (meaning that it was authorized for operation after the first year of operation) and having a regulated lifetime of 20 years or more, will not finish operation before the end of that same semi-period. If for some reason a new set of ITs were introduced with a single year of regulated lifetime then the logic behind the formulation would have to change. However, this is highly unlikely and would only require changing the formulation for the second year of the semi-period, as in the case of the third year of the semi-period it would only account for the parameters of the same third year of the semi-period.

2.2.2.4 Real plant modelling

The real plant modelling takes some values directly from the particular IT calculation and others are user inputs, however, other values are calculations that have to be done considering the equivalent hours of operation of the real plant. This is because of equation 2.5 and the explanations around it, as if the equivalent hours of operation drop below certain thresholds the regulated revenues will decrease and also some associated costs. Therefore, the operation and investment remuneration of the real power plant would vary and so would the costs associated to the tax on the value of production of energy, as it takes into account the remuneration obtained by the operation, investment and cost reduction incentive remuneration.

<u>Costs</u>

In the case of both the IT and the real plant calculation, the costs associated to the tax on the value of production of energy are differentiated into two terms, as the calculation of the operation remuneration requires that the cost associated to the investment remuneration is taken into account, but not the revenues associated to it. This means that there is a component of the tax on the value of production of energy that corresponds to the operation of the IT or real plant, including operation and cost reduction incentive remuneration, and the cost associated to the investment remuneration. Therefore, the costs associated to the tax on the value of production of energy for the normal plant operation will be calculated normally, as the operation and cost reduction incentive remuneration revenues will be computed according taking into account equation 2.5 and so adjusting the total revenues obtained by operation, whilst in the case of the costs due to the investment remuneration will also be adjusted according to equation 2.5.

Operation remuneration

Another thing that must be taken into account is that in some cases the operation remuneration is capped and can only be perceived for a maximum number of hours. For power plants that require operation remuneration to not incur in losses when operating, this effectively means that they will not operate above this maximum number of equivalent hours of operation. This is why what has been done for the operation remuneration is what is shown in figure 2.19:

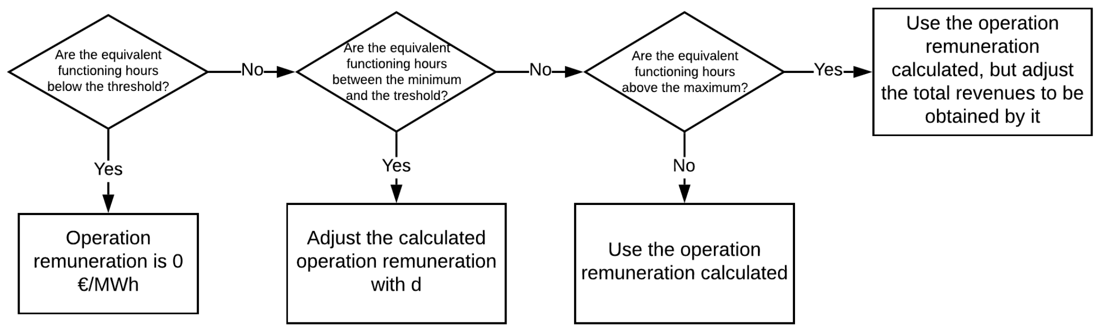

Figure 2.19 Decision making when calculating the operation remuneration of a real power plant

As it can be seen, it is first necessary to calculate the operation remuneration that would correspond to the IT associated to the real power plant and then take into account the equivalent functioning hours of operation. In case the equivalent hours of operation are higher than the maximum, it is better to maintain the operation remuneration as the nominal value but then adjust the maximum revenues associated to it. This is because if this value was adjusted considering the real equivalent hours of operation it would show as if the operation remuneration, as €/MWh, would have been reduced, which is not exactly the case.

Adjustment due to market price deviations

One term that is calculated for the different ITs, but that is not taken into account here, is the adjustment due to market price deviations $Vajdm$, as it is used to adjust the net asset value of the IT in case the market price ends up being different than the one predicted by the ministry. As this is an adjustment that is made for the ITs only it is not used in the real power plant calculation, but it is perceived indirectly as a change in the investment remuneration that is obtained throughout the regulatory life of the power plant. Given that the market price might end up being different than expected, it is possible that the real power plant will end up incurring in losses (which is likely to happen if the market price ends up being lower than expected).

Margin

The calculation of the margin for real power plants is slightly different to that of an IT. There is no difference between the perceived margin and the regulated margin, the margin obtained by the power plant is the perceived margin. This is because in order to obtain the net asset value of the power plant it is necessary to take into account all the sources of revenue of the power plant. In terms of revenues it is important to take into account what was described in figure 2.19, meaning that if the equivalent functioning hours is greater than the maximum equivalent hours in which to receive the operation remuneration, that number of hours will be used to calculate the revenues obtained due to the operation remuneration, instead of the actual equivalent functioning hours of the power plant.

Chapter 3

Calculations performed and analysis of results

After both RD 413/2014 and the model that has been created have been discussed in detail, it is now possible to elaborate on some of the applications of the model. One of the possible uses is the impact of the regulated revenues of the different ITs due to different scenarios. Since the model is able to obtain present and future values of operation, investment and cost reduction incentive remuneration, it is possible to see the variations in these revenues due to a variation of market price, reasonable return etc. This is interesting from an academic, regulatory and business perspective, as it can evaluate, precisely, changes that can occur in the market or due to regulatory change, and serves as an useful tool for these kinds of analyses.

It is also possible, as the model allows for these analyses to be done on all the ITs, to do an electricity system wide analysis, in order to evaluate changes in the total system cost, due to the change in regulated revenues. This is only an estimation, taking into account an estimation of the installed capacity associated to each IT done by Endesa. A table will be presented for each scenario analyzed, in order to show the change in the support scheme costs to the system, compared with the base case. This variation in cost will be represented as a yearly variation, corresponding to the first year in which the change is effective, and it must be noted that this cost variation will not be constant through time, as different ITs will reach the end of their regulatory life. It might be self-evident, but this is a very useful tool from a regulators point of view, as it can assess precisely the changes in cost for the system.

Another use that has been outlined before is the use of the model to assess the profitability of a real power plant associated to an IT, given its real operating and investment information. As the model can easily compute the regulated revenues that will be obtained over time, it is possible to assess the merits of this real power plant taking that income into account.

3.1 Scenario analyses

The main use of this model is to assess the impact of different scenarios on the revenues of the different ITs. These scenarios can be affected by variations in the market or from a regulatory perspective, and although these changes do not affect the return on the investment, which is guaranteed, they do affect the revenues obtained by this support scheme and therefore the cash flows of the ITs and the power plants.

In order to assess these changes in the revenues obtained, a code in VBA has been created, in order to modify the necessary parameters automatically and to calculate the IT desired in the fastest possible way. After the calculation is done, the program copies the results and places them in the individual sheet for the IT. Once this is done for all the scenarios analyzed, the program elaborates the graphs with the information that has been created, allowing an easy comparison of the results.

Even though these scenarios can be analyzed for any existing IT, barring the exceptions that have been mentioned in this document, it does not make sense to provide the results for all the different ITs, but to show those that provide the most information given the scenarios analyzed. Given that there are three possible forms of remuneration, it is clear that the results shown provide information on each of these forms of remuneration. This is why the ITs that will be analyzed will be the following:

1. A cogeneration IT (IT01396 a natural gas fueled IT commencing in 2015): given that cogeneration ITs have high operation costs (due to their fuel costs), they are a positive way to analyze how these different scenarios affect ITs with high operation costs. It also makes it possible to evaluate changes in the fuel price and the CO_2 emission allowances price.

2. A wind power IT in mainland Spain (IT00662 commencing operation in 2012): wind power ITs do not require operation remuneration, only investment remuneration, which make them very interesting to analyze to see how this component is affected.
3. A wind power IT not in mainland Spain (IT03103, in Gran Canaria, commencing operation in 2014): there are very few ITs which receive cost reduction incentive remuneration, as there very few RES power plants in extra-peninsular territories and that also provide a system wide cost reduction. However, some ITs do receive this kind of remuneration, so it is crucial to analyze them to see how the cost reduction incentive varies.
4. A photovoltaic (PV) power plant IT installed before the implementation of RD 413/2014 (IT00004 commenced in 2005): even though it is regarded that PV power plants do not require operation remuneration most of the older PV ITs do require this form of remuneration. However, this operation remuneration is mostly due to the tax on the value of the production of electric energy, so they are interesting in order to evaluate the impact of this tax more clearly.

These ITs should provide enough information in order to analyze the different scenarios that will be posed, and also show the effectiveness of the model when calculating different ITs and years of starting operation.

3.1.1 Scenarios analyzed

There have been several scenarios that have been analyzed:

1. Variation in the market price estimated by the ministry
2. Variation in the reasonable return rate
3. Variation in the maintenance or suppression of the tax on the value of the production of electric energy
4. Methods of updating the net asset value after the temporary suppression of the tax on the value of the production of electric energy
5. Variation of the captured price coefficient

6. Variation of the Brent oil price
7. Variation of the CO_2 emission allowances price

Each of these scenarios have at least two possibilities being considered (such as the price or the suppression of the tax on the value of production of electric energy), whilst other have several possibilities. The following sections will describe each one of them in further detail, as well as the base case that will be used as comparison.

In order for the model to be able to perform all of these scenarios for the desired ITs, a VBA code was formulated. For each IT and scenario wanted the VBA code performs the following actions in this order:

1. Changes the parameters desired for the scenario
2. Calculates the IT with the parameters modified
3. Copies and pastes the results on the specific IT page
4. Repeats 1., 2. and 3. for all the wanted changes within the scenario
5. Elaborates graph obtaining the information from the different cases

The code then repeats all these steps for all the scenarios and for all the ITs that are wanted.

3.1.2 Base case

In order to analyze different possible scenarios, it is necessary to have a base case, so that the only thing that varies is the variable being analyzed. This base case has been considered taking into account the most likely scenario given the information readily available and the general approach by the ministry. Given the scenarios, the base case has considered:

1. That the market prices up until 2022 will be taken from Endesa's estimation, being 53,43 €/MWh for 2020, 50,45€/MWh for 2021 and 47,93 €/MWh, and prices beyond 2022 will be considered to be 52 €/MWh (this has been the price considered by the ministry for years beyond the semi-period being studied).
2. That the reasonable return will be 7,09%, which is the preference value by the Spanish regulator, the CNMC.

3. That the tax on the value of the production of electrical energy will be maintained.
4. That there is no net asset value update after the temporary suppression of the tax on the value of the production of electric energy that occurred between the last trimester of 2018 and the first trimester of 2019.
5. That the captured price coefficient will be the one calculated by the CNMC for the different technologies, given the earnings in the market and the production of each technology.
6. That the price for Brent oil for the future years will be the ones determined by ICE Futures, being these values taken the 9^{th} of April of 2019.
7. That the price of the CO_2 emission allowances price will be the ones determined by ICE EUA Futures, being these values taken the 9^{th} of April of 2019.

Each one of these components will be analyzed in further detail when each of the individual scenarios is commented. The graphs that will be presented will have the investment remuneration represented as bar graphs with reference to the left y-axis, whilst the operation and cost reduction incentive remuneration will be represented as line graphs making reference to the right y-axis.

3.1.3 Variation in the estimated market price

Before the start of a new semi-period, the ministry does an estimation of the market prices for the semi-period that is about to start and also sets an estimation for the years after the semi-period. Although the ministry could estimate these values according to certain future markets, the general approach has been to set the estimation at 52 €/MWh. This has been done for the two semi-periods that have passed so far, and it is likely that it will happen again after the third semi-period.

Even though this might not seem very relevant, given the fact that before each semi-period the ministry will do estimations with better criteria, the price estimations set a clear parameter for the different kinds of remuneration to be perceived. This way, different price estimations will yield vastly different results, increasing the difficulty on estimating real cash flows and increasing the uncertainty, therefore making harder to attract investors and lenders.

For this scenario analysis there have been 2 different estimations, on one hand a price of 52 €/MWh for 2023 and beyond, which is the general approach of the ministry, and on the other hand a price of 47,93 €/MWh, using the estimated value of 2022 to be carried on.

Cogeneration IT (IT01396)

The results of a change in the expected market price from 2023 onward were the ones shown in figure 3.1:

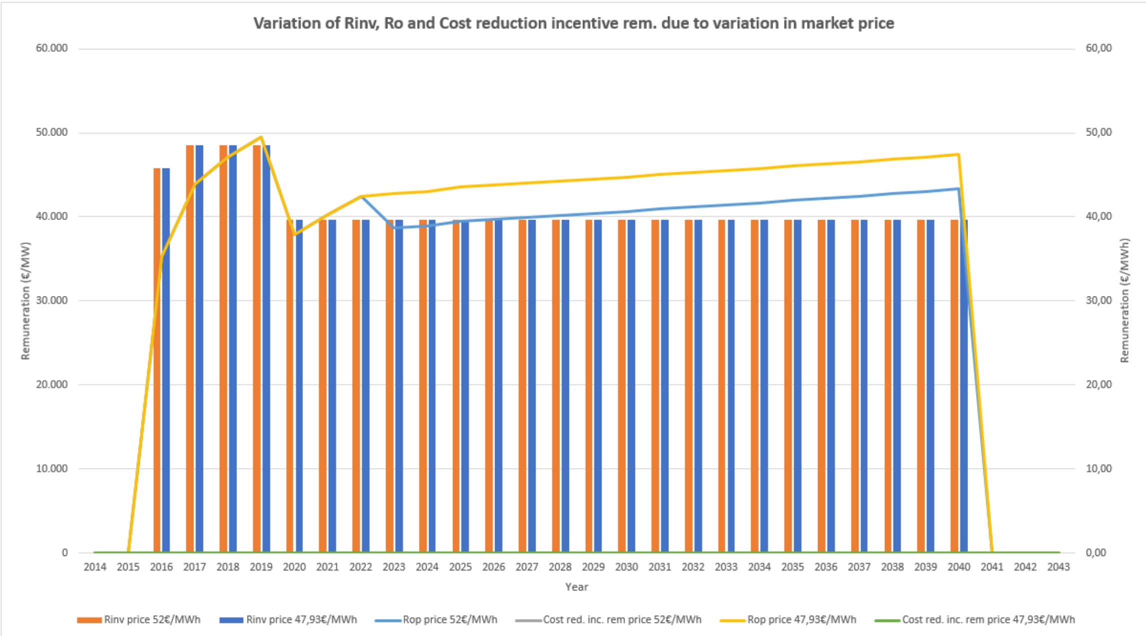

Figure 3.1 IT01396 variation in remuneration due to a change in expected price

As it can be seen, the only noticeable variation is in the amount of operation remuneration to receive. The difference between the two cases is precisely the difference between 52 and 47,93, being 4,07 €/MWh. In the case of cogeneration ITs, which rely heavily on operation remuneration due to their fuel costs this difference is not substantial.

Wind power IT in mainland Spain (IT00662)

The results of a change in the expected market price from 2023 onward were the ones shown in figure 3.2:

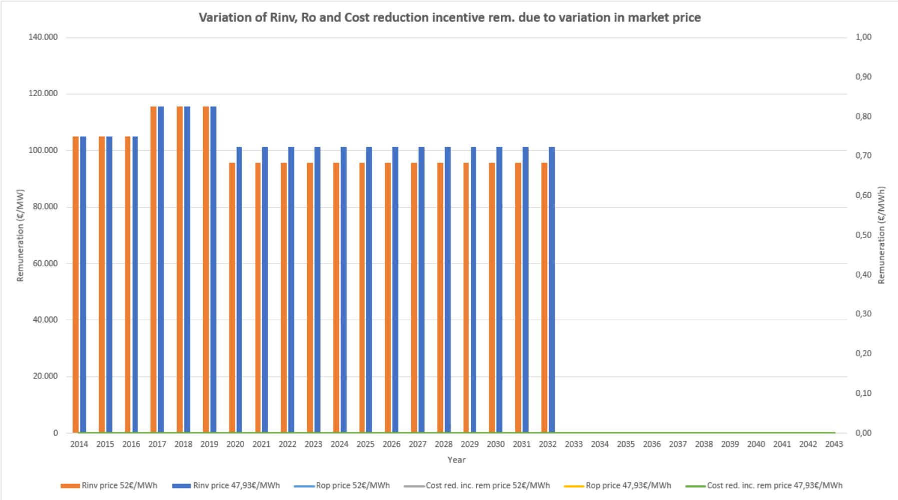

Figure 3.2 IT00662 variation in remuneration due to a change in expected price

It can be seen that in this case, as there is no operation remuneration, the variation in market price will affect the investment remuneration. Intuitively this difference will be the one obtained by multiplying the market price, the equivalent functioning hours and the captured price factor, from the fourth semi-period onward, this being a discounted cash flow analysis.

Wind power IT not in mainland Spain (IT03103)

The results in this case were the ones shown in figure 3.3:

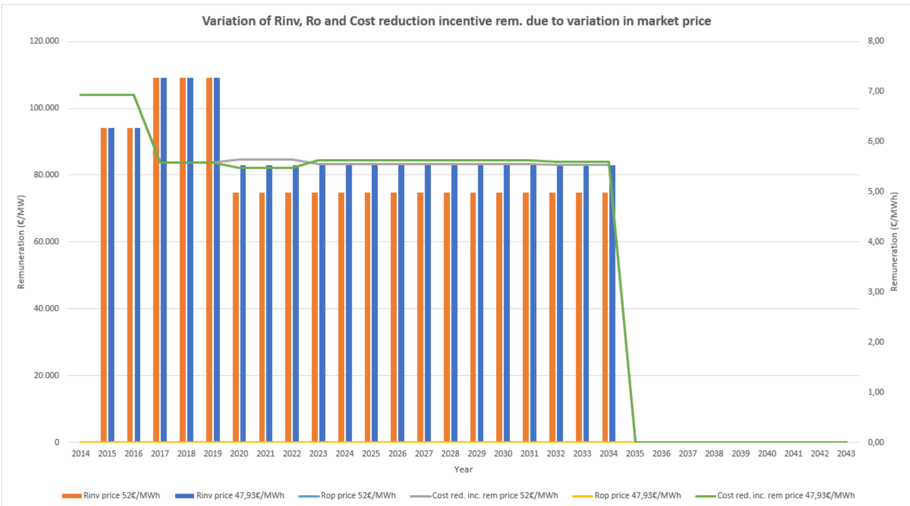

Figure 3.3 IT03103 variation in remuneration due to a change in expected price

This is perhaps the most interesting analysis. As the investment remuneration takes into account changes in the expected cash flows from the semi-period analyzed onward, in this case from the third semi-period, it is from this point where it is adjusted, even though in the third semi-period the prices are the same. In this case, as the investment remuneration increases when the expected market price decreases in the third semi-period the cost reduction incentive also decreases. This is because the market price in that semi-period is the same, but the investment remuneration has gone up because of the difference in the expected market prices. However, this changes from the fourth semi-period onward, where the cost reduction incentive remuneration is higher for the lower expected market price. The reason for this is that as the investment remuneration has anticipated that market price difference some of that change has been accounted for (which is why the cost reduction incentive remuneration was lower in the third semi-period), this means that the market price reduction is more significant than the investment remuneration increase, leading to a higher cost reduction incentive remuneration.

PV IT (IT00004)

The results in this case were the ones shown in figure 3.4:

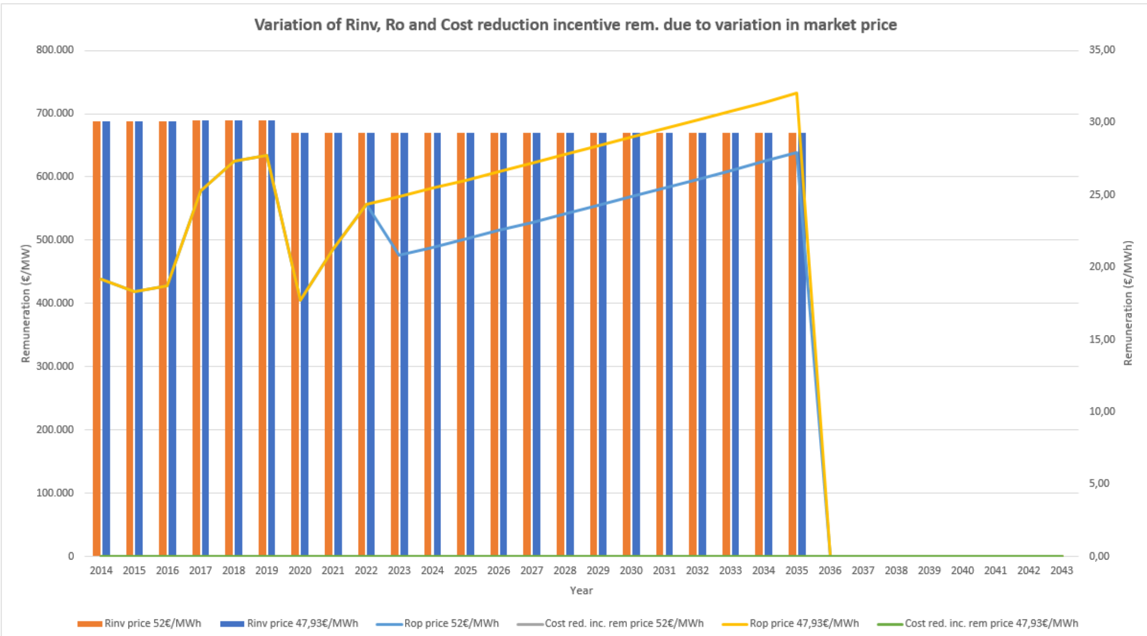

Figure 3.4 IT00004 variation in remuneration due to a change in expected price

The results in this case are similar to the one obtained with the cogeneration IT, being the difference in operation remuneration in both cases the same, which is the difference of both expected market prices. However, as the operation remuneration in the case of the PV IT is smaller the percentage change impact is higher.

Change in system cost

As a decrease in market price estimation causes an increase in expected regulated revenues, the total system cost will be expected to increase for 2023 by the values presented in table 3.1. The biggest cost increase appears in cogeneration, as there will be an increase in operation remuneration and these ITs have the greatest equivalent functioning hours, so the increase in total operation remuneration revenues will be higher.

Table 3.1 Variation in system yearly cost in 2023 due to a market price estimation of 47,93 €/MWh from 2023 onward, instead of 52 €/MWh

Description	Group	Variation in system cost (€)
Cogeneration	a.1	102.184.320
Residual energy cogeneration	a.2	345.799
Solar energy	b.1	52.959.837
Wind energy	b.2	60.478.711
Geothermal	b.3	0
Hydro <10MW	b.4	10.444.037
Hydro >10MW	b.5	2.760.008
Crop biomass	b.6	8.574.067
Biogas and bioliquids	b.7	7.763.392
Industrial biomass	b.8	3.384.015
Domestic waste	c.1	2.613.701
Other waste	c.2	5.024.209
Mining waste	c.3	0
Total		**256.532.095**

Conclusions

The variation in market price causes changes in either the operation, investment or cost reduction incentive remuneration, or some or all of them, depending on the particular IT. It is hard to determine what scenario is better, both from and IT owner and the regulator point of view, when the graphs are analyzed, as $Vajdm$ needs to be taken into account. Even though deviations in market price are corrected by this term, from an IT or power plant owner it is better for the market price to be underestimated. This can be seen from equations 2.6 to 2.10, as if prices end up being higher than expected the IT does not have to adjust its net asset value by the total amount of the price deviation. In the best-case scenario, the price ends up being higher than expected but below the first upper bound $LS1$, as it will mean extra market revenues that will not have to be deduced from future revenues to be earned. However, even a price above this $LS1$ means a positive outcome for the IT and power plant owner, as the difference between $LS1$ and $LS2$ will only be reduced by half of the difference. This makes it so an underestimation of the market price is always positive, meaning that from an IT and power plant owner the desired outcome would be that the regulator placed the expected market price at the lowest possible level, in the case of Spain of 0€/MWh. Nevertheless, as the expected market price is calculated taking into account Future contracts at OMIP [22], it is unlikely that this will ever occur, and that the expected market price is somewhat similar to the final market price.

From the regulators point of view, the opposite scenario might be considerably more desirable. If the main objective of the regulator is to maintain this support scheme with the lowest possible cost, then an overestimation of the market price would be desirable. This is for precisely the same reasons that were mentioned before, but for lower bounds $LI1$ and $LI2$.

3.1.4 Variation in the reasonable rate of return

The reasonable return rate that is determined by the ministry is one of the most important aspects of the current support scheme in Spain. Even though different aspects might affect the cash flows for certain years, IT owners are guaranteed their return on their investment. However, the reasonable return rate changes completely the total regulated revenues to be perceived by the RES power plant owners, and therefore their return on their investments.

A change in the reasonable return rate also causes changes in the cash flows of the RES power plant owners. This seems evident in the case of the investment remuneration, given that an increase in the reasonable return rate will increase the investment remuneration; however, this will also vary the operation remuneration if the IT receives this kind of remuneration. This might not seem logical at first; however, an increase in the investment remuneration also causes an increase in the costs due to the tax on the value of production of electric energy. As this tax applies to all revenues, if there is an increase in the investment remuneration, the cost will increase proportionally. In the case of ITs that receive operation remuneration, this increase in investment remuneration will cause an increase in operation remuneration, and in the case of those ITs that only receive investment remuneration this will increase more than the amount needed to provide the increase in return, to compensate for the increase in costs.

The different reasonable return rates will be 7,09%, which is the value that is most likely, given that it is the one being presented by the CNMC, 7,398%, which has been the reasonable return rate for the first period, 8,09% and 6,09%, that will show a variation of 1% in the reasonable return rate with respect to the most likely scenario.

Cogeneration IT (IT01396)

The results in this case were the ones shown in figure 3.5:

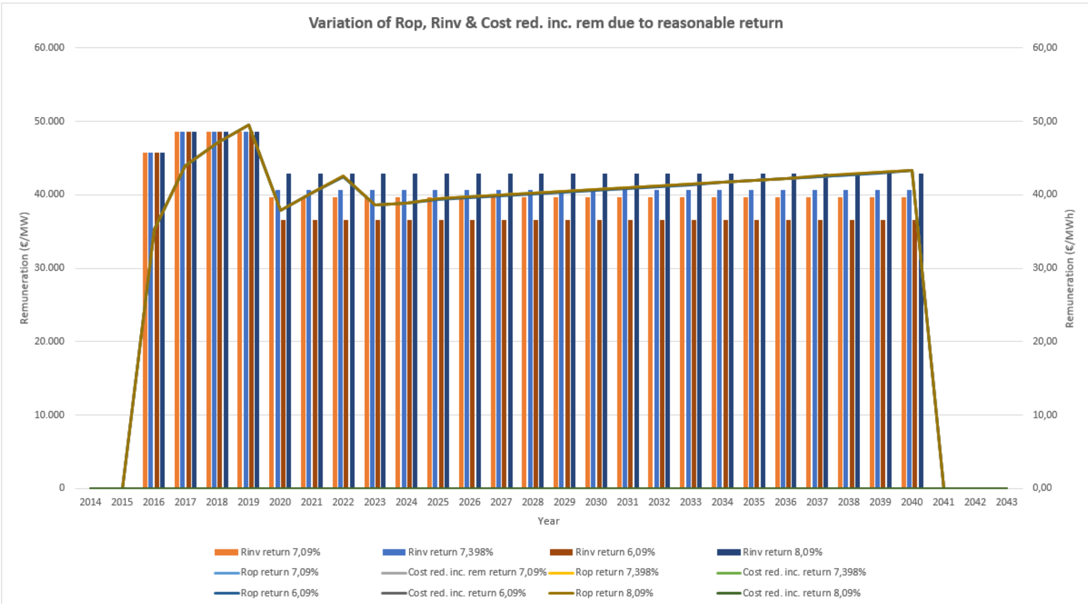

Figure 3.5 IT01396 variation in remuneration due to a change in the reasonable return rate

As it can be seen the most noticeable differences occur in the investment remuneration, where an increase in the reasonable return rate increases the investment remuneration, and the opposite occurs in case there is a decrease in the reasonable return rate. Even though it is not quite visible, there is a slight difference in the operation remuneration, however this change is not very significant because the investment remuneration is not very significant, therefore, the changes do not represent a significant increase in associated costs.

Wind power IT in mainland Spain (IT00662)

The results in this case were the ones shown in figure 3.6:

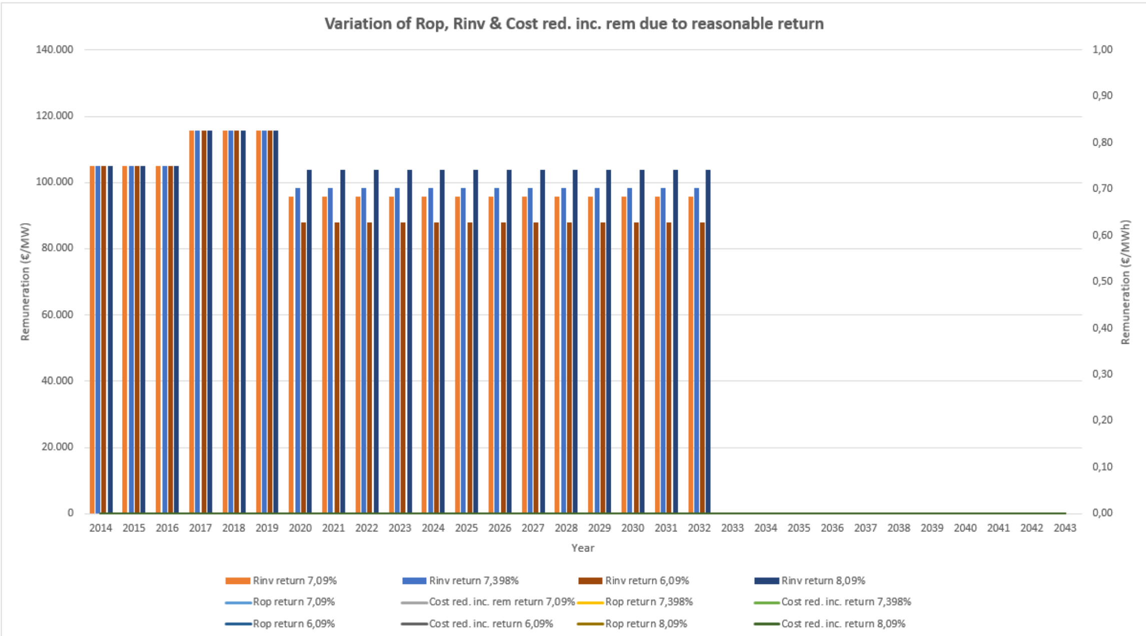

Figure 3.6 IT00662 variation in remuneration due to a change in the reasonable return rate

As this IT does not receive operation remuneration, the only change occurs in the investment remuneration. Nevertheless, as mentioned before, due to the tax on the value of production of electric energy this change in investment remuneration will have to be bigger than just to increase the reasonable return rate, in order to take into account the associated costs.

Wind power IT not in mainland Spain (IT03103)

The results of a change in the reasonable return rate in the case of IT03103 were the ones shown in figure 3.7:

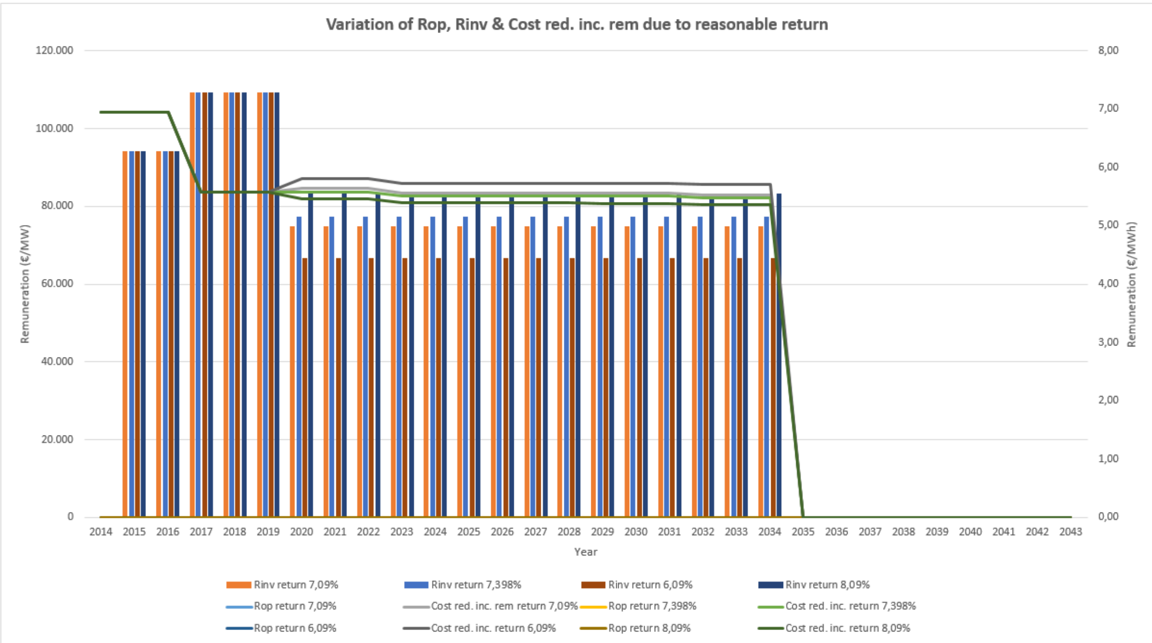

Figure 3.7 IT03103 variation in remuneration due to a change in the reasonable return rate

This case very interesting. If the investment remuneration increases because of the reasonable return rate the cost reduction incentive remuneration decreases. This makes sense according to equation 2.12, as the cost to the system increases when there is an increase in the investment remuneration. This makes sense from the regulators perspective, although this means that an increase in the return rate will not be as substantial for an RES power plant owner associated to this IT, as the revenues obtained from the cost reduction incentive remuneration will decrease. On the other hand, a reduction in the reasonable rate of return would cause an increase in the cost reduction incentive remuneration, signifying that the loss in return is not as important as intended.

PV IT (IT00004)

The results of a change in the reasonable return rate in the case of IT00004 were the ones shown in figure 3.8:

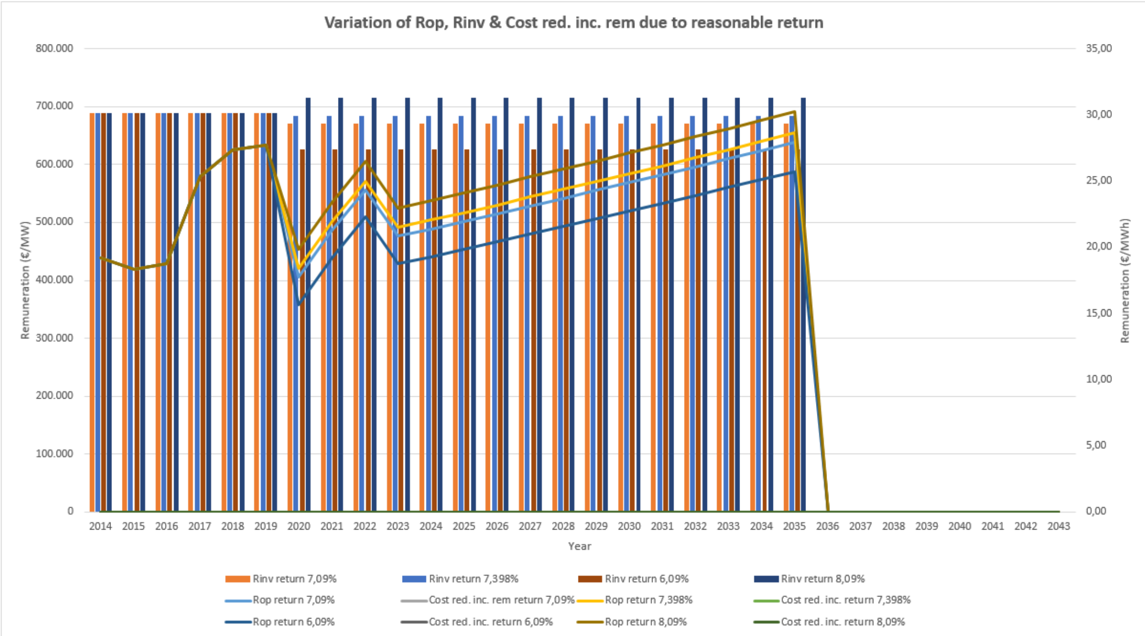

Figure 3.8 IT00004 variation in remuneration due to a change in the reasonable return rate

This case is quite similar to the cogeneration IT, however as the investment remuneration is considerably higher the impact of the costs associated to the tax on the value of production of electric energy is considerably larger. This causes a significant variation in the operation remuneration to receive, which was mentioned at the beginning of the description of this scenario.

Change in system cost

The change in the reasonable return rate causes great changes in the system cost. An increase in the reasonable rate of return causes an increase in costs, whilst a decrease causes a reduction in this cost. Whilst the other scenarios are a question of "what if", or technical decisions on how to approach the support scheme, a variation in the reasonable return rate also reflects how much the system is willing to support RES power plants, and therefore it is crucial, from the system point of view, the variation in the cost of the system. If we use the reasonable return rate of 7,09% as base case, the variation in system cost with the different return rates will be the ones shown in table 3.2. It can be seen that any change causes a significant impact in the cost of the system as a whole.

Table 3.2 Variation in system yearly cost in 2020 due to variation in the return rate with respect to 7,09%

Description	**Group**	**7,398%**	**6,09%**	**8,09%**
Cogeneration	a.1	884.044	-2.809.162	2.901.360
Res. energy cogen.	a.2	89.640	-285.416	293.932
Solar energy	b.1	79.347.364	-252.077.556	260.442.491
Wind energy	b.2	20.174.973	-64.623.089	65.960.560
Geothermal	b.3	0	0	0
Hydro <10MW	b.4	4.670.964	-14.858.103	15.340.095
Hydro >10MW	b.5	1.142.793	-3.558.151	3.752.805
Crop biomass	b.6	1.278.618	-4.081.661	4.187.160
Biogas and bioliquids	b.7	1.053.091	-3.351.887	3.453.489
Industrial biomass	b.8	216.488	-692.021	708.494
Domestic waste	c.1	2.236.883	-7.117.466	7.335.128
Other waste	c.2	1.073.148	-3.420.192	3.517.090
Mining waste	c.3	0	0	0
Total (€)		**112.168.007**	**-356.874.704**	**367.892.604**

Conclusions

The change in the reasonable return rate causes a considerable impact in the investment remuneration the IT will receive. This variation causes differences in the operation remuneration for the ITs that receive them, due to the tax on the value of production of electric energy. This might not make much sense from a regulator's perspective, as the reasonable return is related directly with the investment whilst the operation remuneration is associated with the profitable operation of the IT. This means that a variation of the amount to be recovered by the IT directly impacts the operation of the RES power plant, which is quite contradictory if the objectives of the investment and operation remuneration and differentiated, the former for the investment recovery and the latter for normal operation.

In the case of ITs, and the associated RES power plants, that receive cost reduction incentive remuneration, the reasonable return rate change is quite different to the rest. The change in the reasonable return rate is not as significant as the regulator intended for the other ITs, therefore a change of 1% in the reasonable return rate does not cause a change in 1% in the return of these ITs and associated power plants. Whilst this is certainly negative when the return rate increases, it is positive for the IT and associated power plant owners when the return rate decreases. This makes sense when analyzing equation 2.12, and in terms of the total savings of the system, however the change in the return rate will not provide the same economic signals to these ITs than to the rest, which might be an unwanted effect.

3.1.5 Variation in the maintenance or suppression of the tax on the value of the production of electric energy

This tax was introduced in 2012, by the Law 15/2012 [27], and has had important controversies, as electricity producers accused it as being against the Spanish Constitution and European regulation. With the change of government, this tax was temporarily suspended for 6 months by Royal Decree-law 15/2018 [30], so it is interesting to analyze the impact if this tax was completely eliminated and not just suspended for a limited time. As has been mentioned in the previous and the current chapter, the tax on the value of the production of electric energy is very impactful for the different ITs, having a significant economic effect and complications when trying to calculate revenues and costs. However, the next examples will show how big this economic impact can be for certain ITs. This will then clearly demonstrate the possible economic impact on the associated RES power plants to different ITs when this tax was temporarily suspended for 6 months.

It is also important to say that whilst, for the government, applying this tax to conventional power plants is a revenue collection tool, in the case of RES power plants associated to an IT this is not the case. As this tax is a recognized cost for these ITs, this means that the system must pay back this concept in terms of operation or investment remuneration, to guarantee the return on the investments.

As has also been mentioned, and will also be mentioned in other cases, this tax also causes several secondary effects, which might be unwanted from a regulator's perspective. Nevertheless, this impact will be analyzed for each case in particular.

Cogeneration IT (IT01396)

The results in this case were the ones shown in figure 3.9:

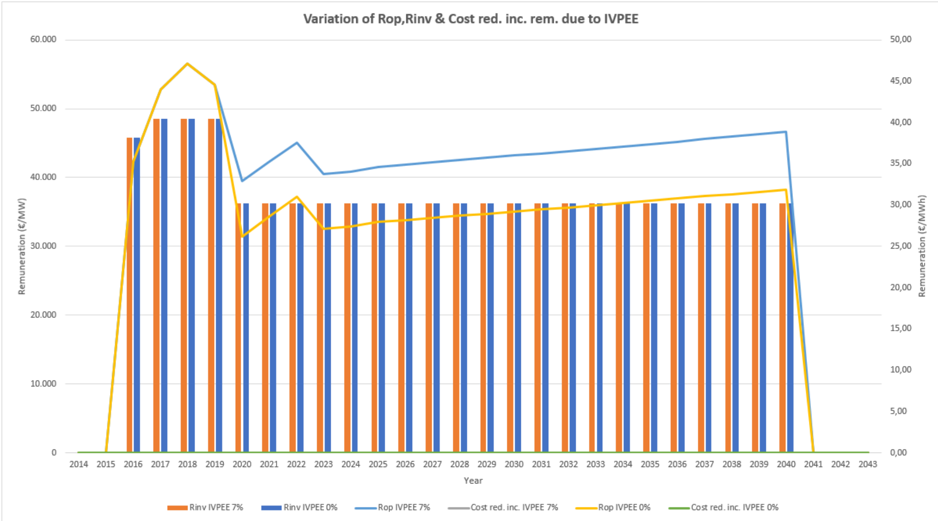

Figure 3.9 IT01396 variation in remuneration due to suppression of the IVPEE tax

As it can be seen, the effect in the operation remuneration is quite significant, being a bigger change than the variation of price (although this will depend on the price variation that is wanted). In this particular case, the difference in operation remuneration is almost 10 €/MWh, which is quite significant.

Wind power IT in mainland Spain (IT00662)

The results in this case were the ones shown in figure 3.10:

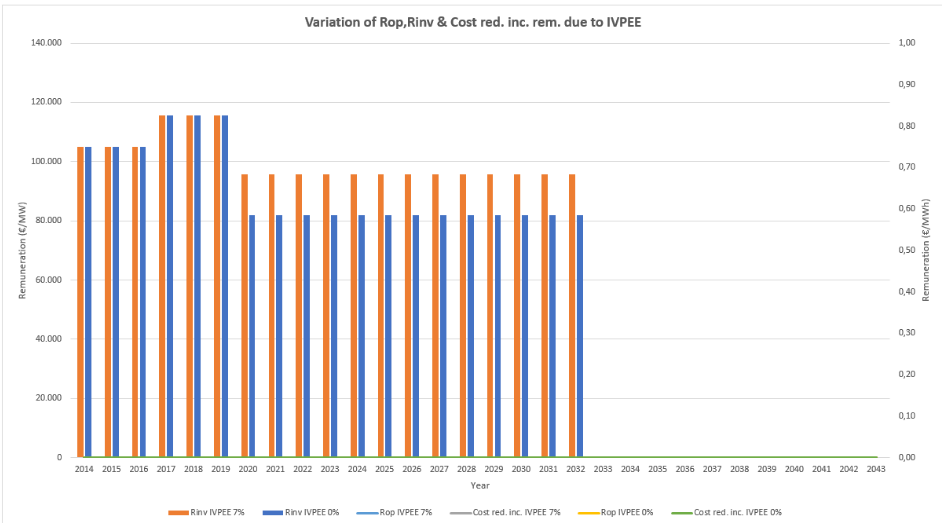

Figure 3.10 IT00662 variation in remuneration due to suppression of the IVPEE tax

As this IT does not receive operation remuneration, all the change occurs with the investment remuneration, being the effect quite similar to the variation in price. The change in investment remuneration occurs because there is an increase in the margin of the IT, therefore requiring less support to guarantee the investment recovery.

Wind power IT not in mainland Spain (IT03103)

The results in this case were the ones shown in figure 3.11:

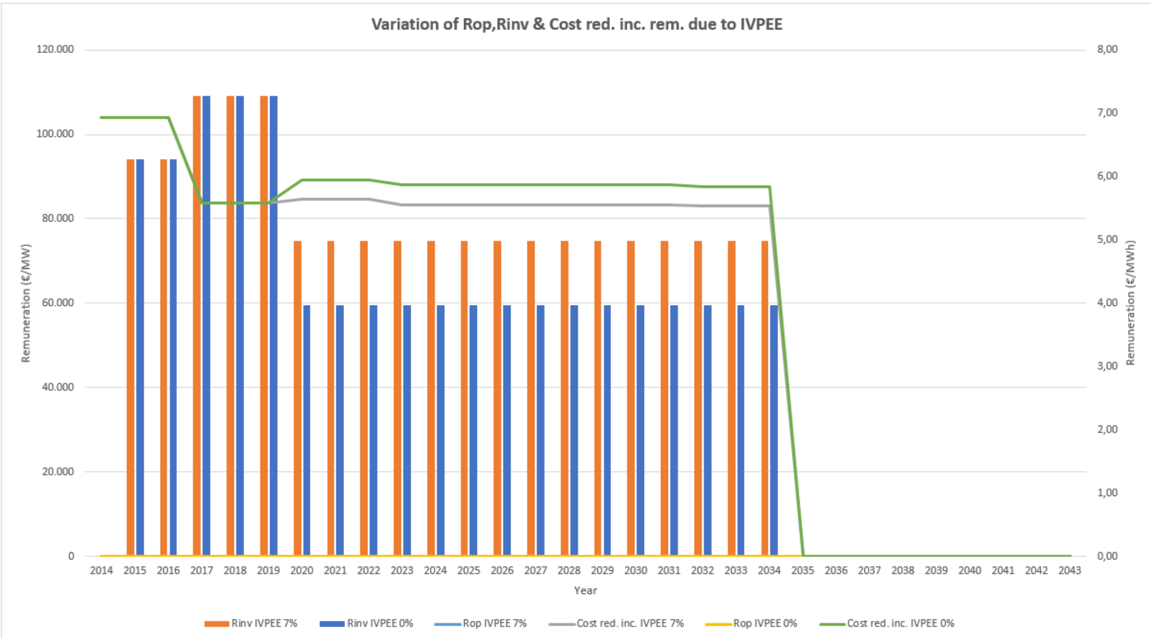

Figure 3.11 IT03103 variation in remuneration due to suppression of the IVPEE tax

In this case, the investment remuneration change is quite similar to the example described before. Nevertheless, the change in the cost reduction incentive remuneration is quite significant. This is quite likely an unwanted outcome. Although the elimination of the tax on the value of the production of electric energy reduces the amount of investment remuneration given to this IT, and therefore reduces the cost of the system, so do the revenues of the system. In this case, there is an increase in the cost reduction incentive remuneration whilst there is no change in the total savings of the system. This is why it is likely that this is an unwanted outcome from a regulators perspective, as it is not rewarding the wanted effect on the system.

The solution to this would be to consider not only the total costs that the ITs pose on the system, but also the total revenues that they provide, in terms of taxes and tolls, so that the variation of these elements do not pose contradictory results such as this one.

PV IT (IT00004)

The results in this case were the ones shown in figure 3.12:

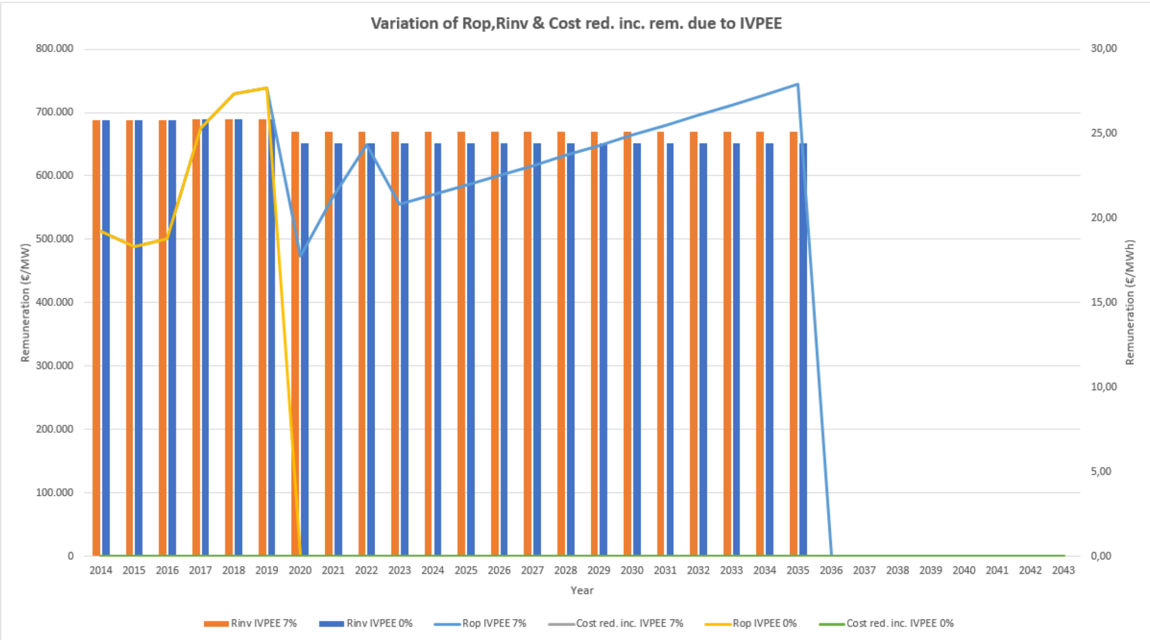

Figure 3.12 IT00004 variation in remuneration due to suppression of the IVPEE tax

This is the clearest example of the economic impact the tax on the value of the production of electric energy, as the suppression of this tax would not only lead to an elimination of the operation remuneration required to operate profitably, but also reduce the amount of investment remuneration required. This shows that some power plants may not be able to operate simply because of the existence of this tax, as it is a tax on revenues and not directly on profits, therefore allowing the possibility of a RES power plant or IT not being able to operate without losses due to the existence of this tax.

Change in system cost

The suppression of the tax on the value of the production of electric energy has a significant impact of the different ITs that have been studied in this section. Furthermore, the elimination of this tax causes a great reduction in the total system costs, as the different ITs do not require as much revenues to recover their investments. The estimation of the variation of the system costs can be seen in table 3.3. It can be seen that this causes the greatest change in the system costs out of all the scenarios analyzed.

Table 3.3 Variation in system yearly cost in 2020 due to the suppression of the IVPEE tax

Description	**Group**	**Variation in system cost (€)**
Cogeneration	a.1	-204.033.911
Residual energy cogeneration	a.2	-431.403
Solar energy	b.1	-358.126.045
Wind energy	b.2	-158.341.964
Geothermal	b.3	0
Hydro <10MW	b.4	-25.088.443
Hydro >10MW	b.5	-5.277.862
Crop biomass	b.6	-21.449.631
Biogas and bioliquids	b.7	-14.422.586
Industrial biomass	b.8	-12.087.554
Domestic waste	c.1	-7.511.212
Other waste	c.2	-7.847.080
Mining waste	c.3	0
Total		**-814.617.691**

Conclusions

It is clear that the tax on the value of the production of electric energy has great economic effect on the different ITs. This is the case specially in ITs that have great investment remuneration, as the suppression of this tax even eliminates the need of having operation remuneration. It is also the case that this tax is of no use for the system as a whole, as it is a cost that must be paid back to ITs in order to guarantee their investment recovery.

However, it is not as simple as just eliminating this tax. As it was seen for IT03103, the suppression of this tax causes an unwarranted increase in the cost reduction incentive remuneration, as there is no actual savings for the system. This poor formulation leads to this incoherence that would increase remuneration beyond what was the initial purpose. On the other hand, the suppression of this tax would likely change the market price, as it is a variable cost that must be assumed by generators, therefore including it in their bidding price in the wholesale market. This cost reduction would lead to a price reduction, which would in turn increase the operation or investment remuneration to be perceived by the ITs and associated power plants. Therefore, even though the previous cases have shown the economic impact of eliminating this tax, this is a static analysis, not taking into account the change that would occur on the system as a whole by the elimination of this tax.

One way to avoid this would be to exempt ITs and their associated power plants of paying this tax. This would not vary the wholesale market price, at least not significantly, and thus maintaining the levels of operation and investment remuneration, however it would still maintain the distortion regarding the cost reduction incentive remuneration. Therefore, in order to avoid this the equations 2.11 and 2.12 would have to be changed, to avoid this conflict, but how this modification should be done is not clear in the current legislation.

It is true, nevertheless, that this suppression, whether to the whole system or only the ITs and power plants subject to this support scheme, would reduce the total system cost also reducing unnecessary costs to the ITs that would have to be paid back eventually, whilst decreasing the revenues for the central government.

3.1.6 Methods of updating the net asset value after the temporary suppression of the tax on the value of the production of electric energy

As was mentioned in the previous example, the tax on the value of the production of electric energy was temporarily suspended for 6 months, beginning on the 5th of October of 2018, due to the approval of the Royal Decree-law 15/2018 [30]. This temporary suspension has caused several questions, as this tax suspension was not taken into account when computing the remuneration to be received by the different ITs and associated power plants. Given these extra profits that have been received by the ITs and their corresponding power plants, as the amount of costs was reduced, there is a question if this will be taken into account when recalculating the net asset value of the ITs for the next-semi-period.

In order to assess the effect of the different forms of updating the net asset value of the ITs due to the suppression of this tax, different scenarios have been studied. On one hand, it is possible that the regulator does not update the net asset value, either because it does not wish to do so (or cannot, as it is not addressed in the regulation), or because it asks for the profits received as a lump sum from the generators, on the other the net asset value might be updated on a quarterly or an annual basis. Each of these have slightly different outcomes for the ITs, which have to be analyzed.

Cogeneration IT (IT01396)

The results obtained due to a change in the method of updating the net asset value, in this case, were the ones shown in figure 3.13:

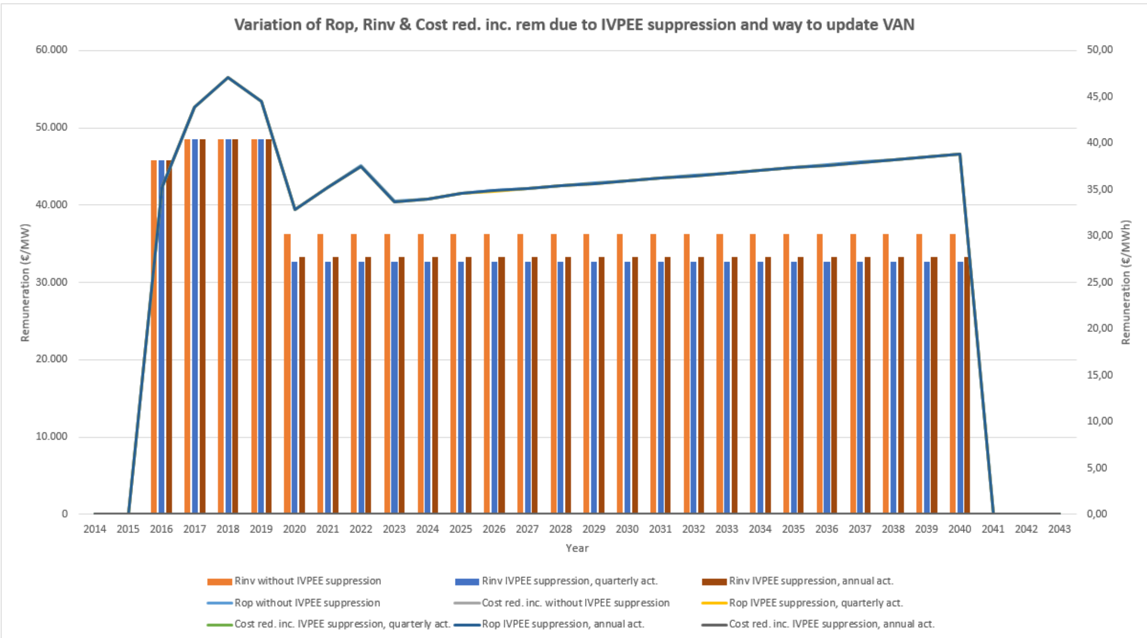

Figure 3.13 IT01396 variation in remuneration due to suppression of the IVPEE tax and method of updating the net asset value

It must be said that in this case the results corresponding to no tax suppression are equivalent to the suppression of the tax but not updating of the net asset value, which can occur because of the two cases described before.

It can be observed that the variation in investment remuneration, that is the one that would be affected in case of a net value updating, is quite small in either of the cases, as less costs assumed during 6 months are compensated during the regulatory life of the IT. This also causes variation in the operation remuneration, due to the tax on the value of the production of electric energy, as less investment remuneration is paid there is less operation remuneration required, however as in this case the change in investment remuneration is small, the change in operation remuneration is smaller.

Wind power IT in mainland Spain (IT00662)

The results obtained due to a change in the method of updating the net asset value, in this case, were the ones shown in figure 3.14:

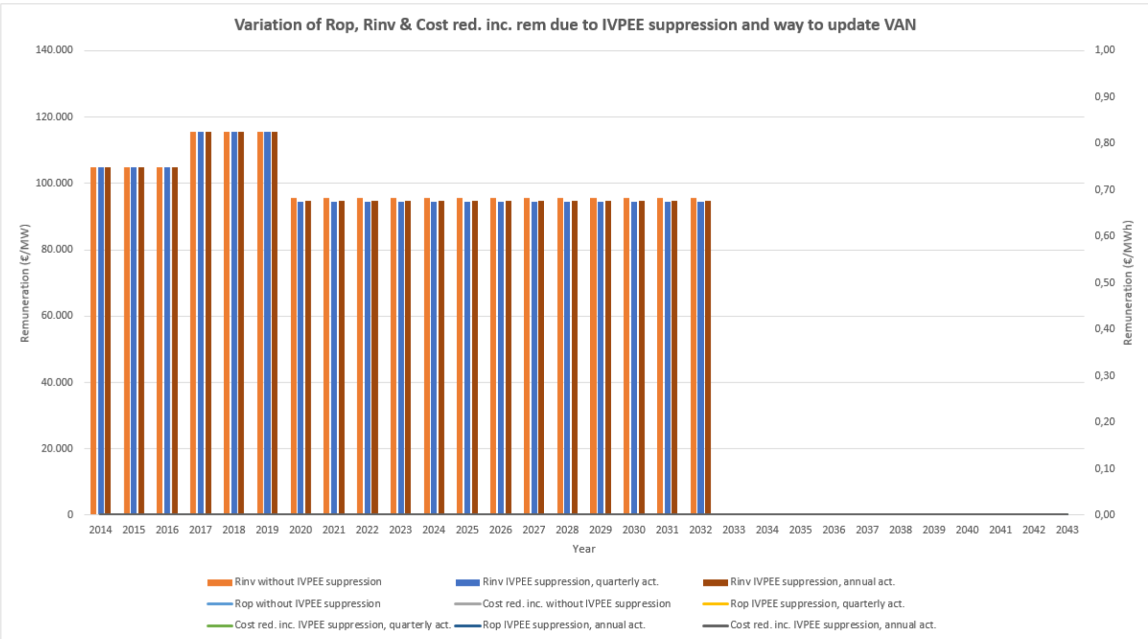

Figure 3.14 IT00662 variation in remuneration due to suppression of the IVPEE tax and method of updating the net asset value

In this case, the impact is even smaller, as the revenues both through the market and due to the support scheme are significantly lower than the case before, lowering the amount of update needed, as the heightened profits were smaller. Furthermore, as there was no operation remuneration required for this IT there is no difference in that aspect

Wind power IT not in mainland Spain (IT03103)

The results obtained due to a change in the method of updating the net asset value, in this case, were the ones shown in figure 3.15:

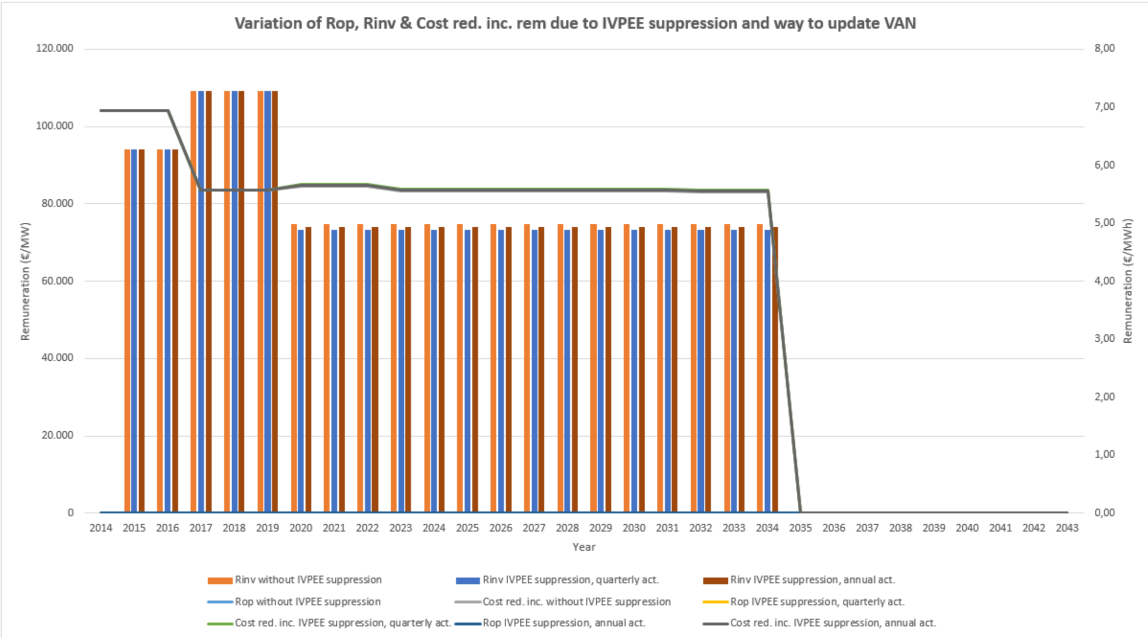

Figure 3.15 IT03103 variation in remuneration due to suppression of the IVPEE tax and method of updating the net asset value

The outcome in this case is very similar to the wind IT analyzed just before. The only difference in this case is the existence of the cost reduction incentive, which varies very slightly. In both of the cases there is an increase in the cost reduction incentive remuneration to be received, as there is less investment remuneration that the IT will receive. This is a further unwanted consequence, as the idea behind updating the net asset value due to the suppression of the tax on the value of production of electric energy is precisely to reduce the revenues to be obtained by the IT throughout its regulatory life; nevertheless, due to the cost reduction incentive remuneration, this is not the case, as the IT increases that revenue in particular.

PV IT (IT00004)

The results obtained due to a change in the method of updating the net asset value, in this case, were the ones shown in figure 3.16:

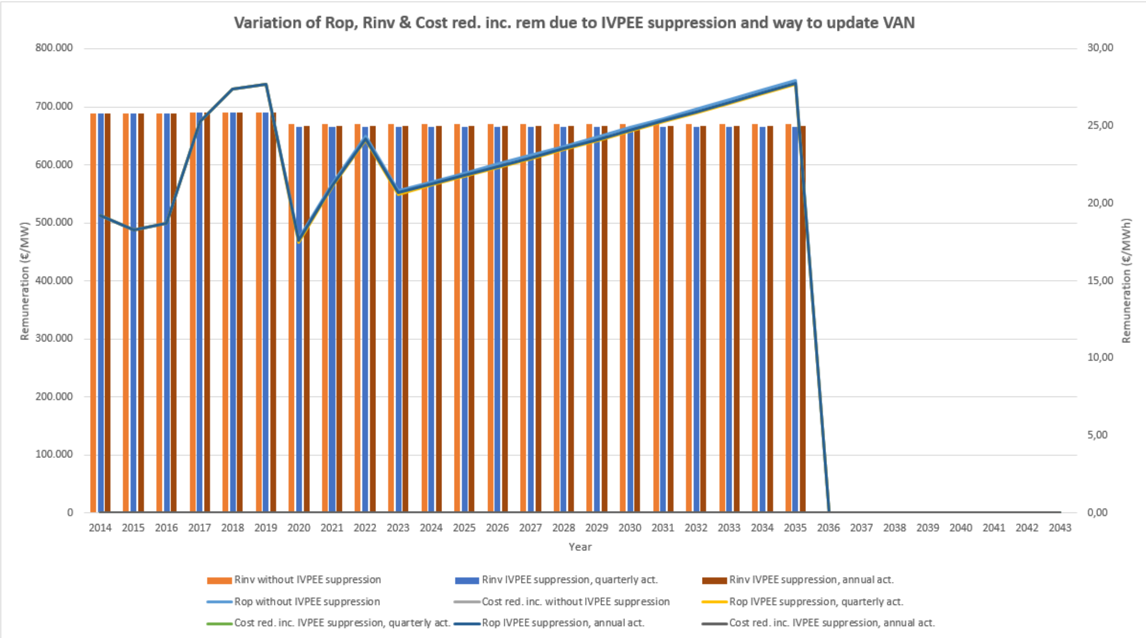

Figure 3.16 IT00004 variation in remuneration due to suppression of the IVPEE tax and method of updating the net asset value

Even though the relative variation of the investment remuneration is somewhat similar to the cases analyzed before, the actual variation in considerably higher, although it is still minute by comparison.

Change in system cost

Even though an update in the net asset value does not cause a significant impact in the different ITs, in terms of remuneration, it does affect the system as a whole more significantly. An updating of the net asset value, whether annually or quarterly, causes a reduction in the regulated remuneration to be paid to the ITs and their associated RES power plants. This reduction in revenues causes a system wide cost reduction, although it will depend on the quantity of net asset updated, which depends on the extra revenues perceived by the ITs due to the temporary suspension of the tax on the value of production of electric energy. The estimation of the variation of the system cost due to these changes, for 2020, can be seen in table 3.4:

Table 3.4 Variation in system yearly cost in 2020 due to the method of updating the net asset value due to IVPEE suppression

Description	**Group**	**Annual update**	**Quarterly update**
Cogeneration	a.1	-3.495.642	-4.197.590
Residual energy cogeneration	a.2	-70.529	-92.021
Solar energy	b.1	-108.342.636	-115.284.522
Wind energy	b.2	-13.761.707	-23.906.524
Geothermal	b.3	0	0
Hydro <10MW	b.4	-1.745738	-2.693.348
Hydro >10MW	b.5	-313.147	-449.875
Crop biomass	b.6	-1.917.369	-2.711.534
Biogas and bioliquids	b.7	-8.970.410	-9.186.170
Industrial biomass	b.8	-6.503.618	-6.710.783
Domestic waste	c.1	-510.849	-896.138
Other waste	c.2	-428.254	-699.223
Mining waste	c.3	0	0
Total (€)		**-146.059.899**	**-166.527.728**

Conclusions

Although there is a great economic effect on the different ITs due to the suppression of the tax on the value of the production of electric energy, the effect is very much diluted when the net asset value is updated to compensate the extra profits obtained by its temporary suppression. Nevertheless, the direct impact of having to provide a lump sum to the regulator if needed is quite more significant. Furthermore, for the system as a whole, it does make a significant impact, being an annual update the biggest cost saver.

3.1.7 Variation of the captured price coefficient

As shown by equations 2.22, 2.24, 2.25, 2.31, 2.39 and 2.40, the captured price factor is of great importance. This factor multiplies the average market price and determines the average market price perceived, in general, by the different technologies. Companies can analyze their own captured price factor, taking into account the total remuneration earned in the market and dividing this by the total energy sold into the market and the average market price. For technologies as a whole, a possible way to do this is to analyze the information provided by the Spanish regulator, the CNMC. The CNMC provides information on the total market remuneration obtained by each technology in the market, and also the total energy sold into the grid [5]. As it can be seen, this factor varies through time, as it depends on the electrical mix of the system, market price, and in the case of intermittent RES of climatic conditions.

What has been done in this case is to compare the effect of the captured price factor that is now in place for the calculations, and the captured price factor obtained by the information provided by the CNMC. In some cases, the captured price factor increases whilst in others it might decrease. In this particular example, it would make more sense to analyze an example of each technology, but due to the amount of technology groups and subgroups, that can be seen in tables 2.1 and 2.2, this will not be done.

Cogeneration IT (IT01396)

For cogeneration ITs, the captured price factor for the semi-period from 2017 to 2019 was of 1,024, whilst the expected captured price factor, calculated by the CNMC is of 1,0079. This means that the IT will need to receive higher operation remuneration to deal with lower revenues in the market. The final results in this case were the ones shown in figure 3.17:

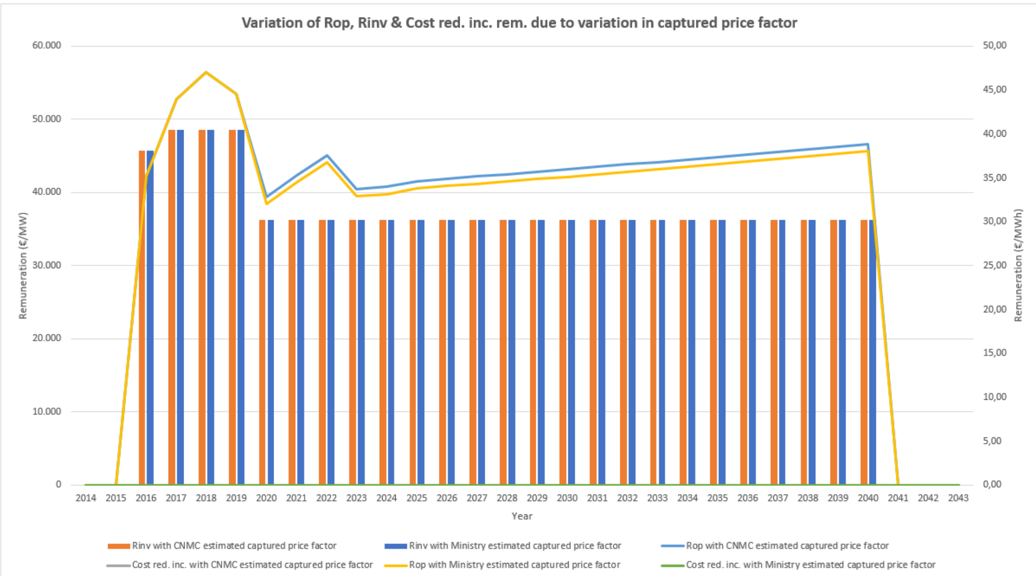

Figure 3.17 IT01396 variation in remuneration due to variation of the captured price factor

It can be observed that the resulting graph is very similar to a variation in market price, which makes sense considering that a variation in either means a variation in the perceived price by the IT. It should be noted that the lower the captured price factor the higher the regulated revenues needed, as the revenues obtained in the market will be expected to be lower and so more operation and/or investment remuneration will be needed to compensate.

Wind power IT in mainland Spain (IT00662)

In the case of wind ITs the captured price factor for the second semi-period was 0,8521, whilst the captured price coefficient calculated by the CNMC was of 0,9386. The results in this case were the ones shown in figure 3.18:

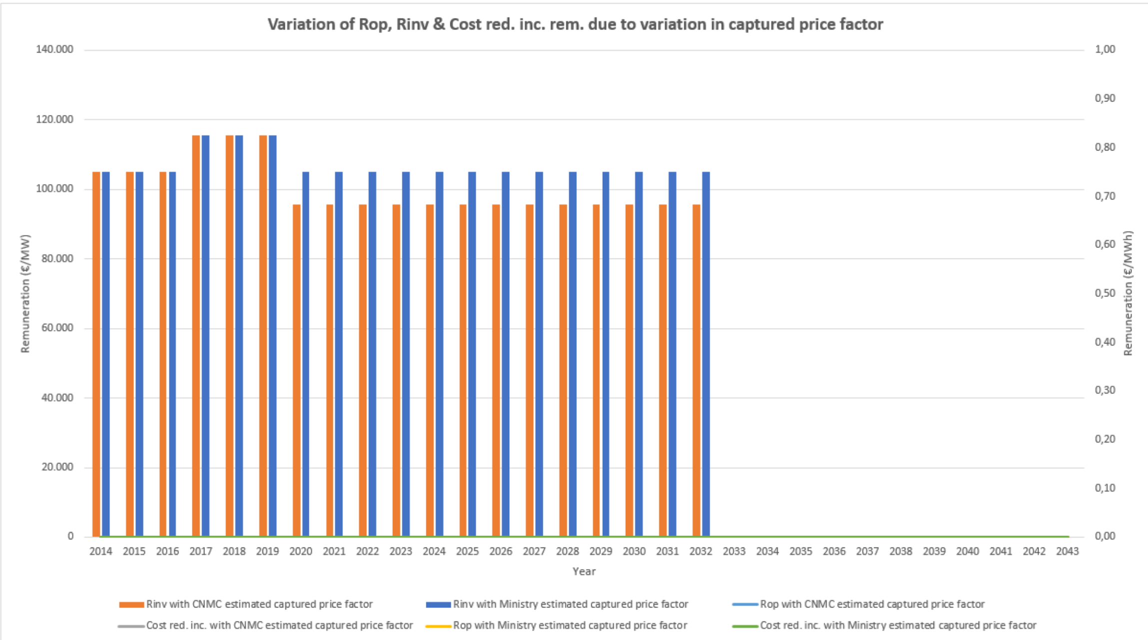

Figure 3.18 IT00662 variation in remuneration due to variation of the captured price factor

The outcome is, again, quite similar to a variation in market price. However, in this case, as there is no operation remuneration, the variation is observed solely in the investment remuneration. As the captured price coefficient rose, the investment remuneration required was reduced.

Wind power IT not in mainland Spain (IT03103)

The change in the captured price factor is exactly the same than in the previous case, changing from 0,8521 in the second semi-period, to 0,9386 for the third semi-period onward, being the results the ones shown in figure 3.19:

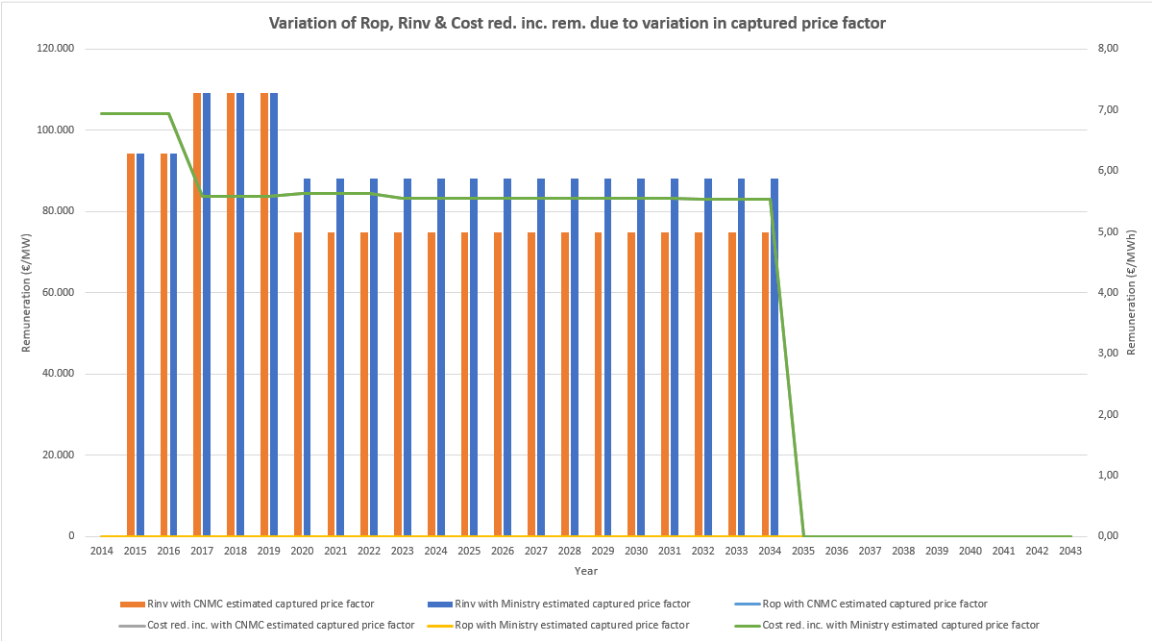

Figure 3.19 IT03103 variation in remuneration due to variation of the captured price factor

The effect in this case is not exactly the same as with a variation in the market price. This is because in the variation of market price example this variation was applied from the fourth semi-period and beyond, which created a discrepancy in the investment remuneration from the third semi-period, thus changing the cost reduction incentive remuneration in both cases. Nevertheless, as the change in the captured price factor, in this case, is applied in the third semi-period directly, the change in market revenues is compensated by the change in investment remuneration, which causes the cost reduction incentive remuneration to be the same in both cases. This is a desirable outcome of the cost reduction incentive remuneration described in equation 2.12, as the IT in itself has not provided a reduction in the total system cost.

PV IT (IT00004)

The captured price coefficient for PV ITs was of 1,0495 during the second semi-period. However, the information from the CNMC revealed a change in the captured price down to 1,003. The results of this change were the ones shown in figure 3.20:

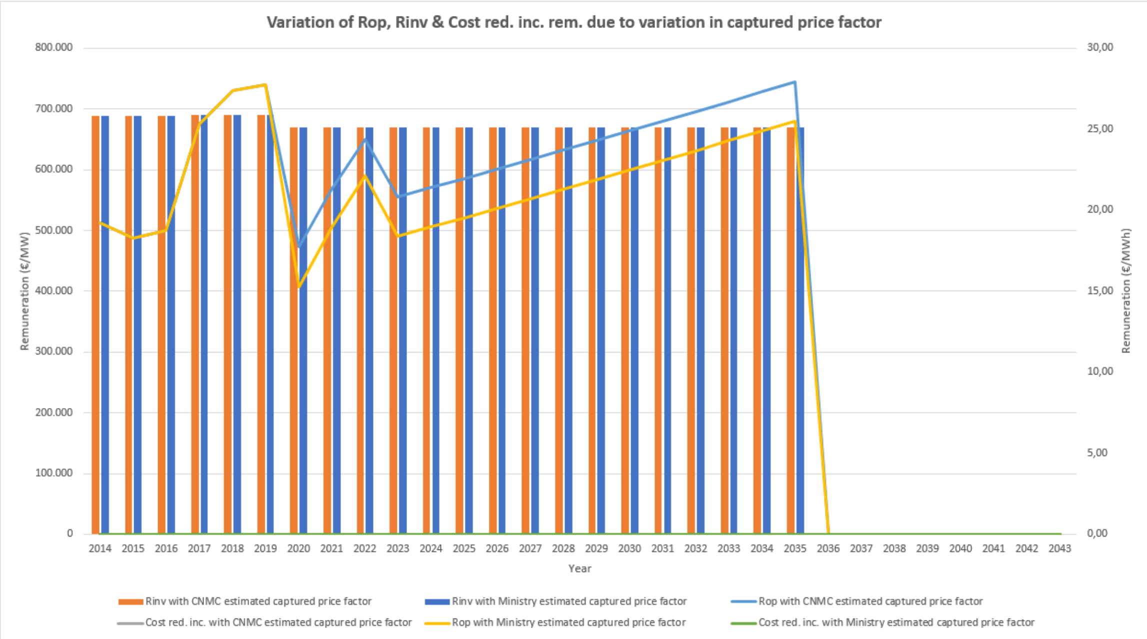

Figure 3.20 IT00004 variation in remuneration due to variation of the captured price factor

The results of this scenario are quite similar to the case of the cogeneration IT, as both saw a decrease in the market revenues, causing an increase in the operation remuneration required.

Change in system cost

In this particular case, the variation in the captured price factor influences the ITs that have been studied quite differently, as some see their regulated revenues increased, due to a decrease in market revenues, whist others see their regulated revenues decreased. It is interesting, at this point, to evaluate what is the impact of these captured price factors in the system as a whole, in terms of costs. If the electric system was only formed by RES power plants the effect would likely be zero, as the increase in the captured price factor by certain technology would be compensated by the decrease of another. Nevertheless, the existence of other power plants makes it important to analyze how the system costs are affected. The estimation on the variation of system costs can be seen in table 3.5. The base case used for this example was having the captured price factor as the CNMC data revealed. Therefore, the change in system cost is from changing from that scenario to the previous ministry calculated captured price factor. In the case of wind , as the captured price factor for the ministry was considerably lower, wind power is the biggest cost driver in this case and would imply a great increase in cost for the system.

Table 3.5 Variation in system yearly cost in 2020 due to the application of the ministry captured price factor with respect to the CNMC calculated captured price factor

Description	Group	Variation in system cost (€)
Cogeneration	a.1	-26.275.890
Residual energy cogeneration	a.2	-98.622
Solar energy	b.1	-31.440.321
Wind energy	b.2	135.336.905
Geothermal	b.3	0
Hydro <10MW	b.4	2.271.533
Hydro >10MW	b.5	726.879
Crop biomass	b.6	-314.566
Biogas and bioliquids	b.7	-277.732
Industrial biomass	b.8	-120.830
Domestic waste	c.1	-785.349
Other waste	c.2	-1.211.275
Mining waste	c.3	0
Total		**77.810.733**

Conclusions

Similarly to the expected market price, the IT and power plant owners would want to have the lowest captured price factor for their technology, as the revenues received would be higher. In other words, there is an incentive for power plant owners associated to this support scheme, to beat the captured price factor for their technology. This is a very positive incentive, as it encourages investors and power plant owners to seek the best possible scenarios to beat the captured price factor, whether it is investing in higher resource areas or adapting their operation to try to manage it.

3.1.8 Variation of the Brent oil price

It is important to try to analyze the impact of the variation of the Brent oil price, which is a standard used when analyzing the fuel price. Therefore, it will be key as to determine the variation in costs, and consequently the remuneration to be obtained by the ITs.

For this analysis only a cogeneration IT, IT01396, has been considered, as the rest of the examples used throughout this chapter do not depend on fuel for their operation. A variation of the Brent oil price means a variation in the fuel costs assumed by the IT, as can be observed by equations 2.33 and 2.36. The effect of this Brent oil price variation will be quite similar for diesel fueled cogeneration ITs and fuel oil fueled cogeneration ITs, as their formulas updating their fuel cost are quite similar, as seen in equation 2.18, however the effect on natural gas fueled cogeneration ITs will be more diluted, as this term is less significant, as seen in equation 2.13.

The values for the Brent ICE futures used as base case for this analysis were the following:

1. For the first semester of 2019: 71,17$/bbl
2. For the second semester of 2019: 69,55$/bbl
3. For the first semester of 2020: 67,94$/bbl
4. For the second semester of 2020: 65,95$/bbl
5. For the first semester of 2021: 64,59$/bbl
6. For the second semester of 2021: 62,62$/bbl
7. For the first semester of 2022: 61,74$/bbl
8. For the second semester of 2022 and onward: 61,04$/bbl

The other two alternatives studied were an increase and a decrease of 5$/bbl on the base case prices.

Cogeneration IT (IT01396)

The results of a variation in the Brent price of 5\$/bbl, for IT01396, were the ones shown in figure 3.21:

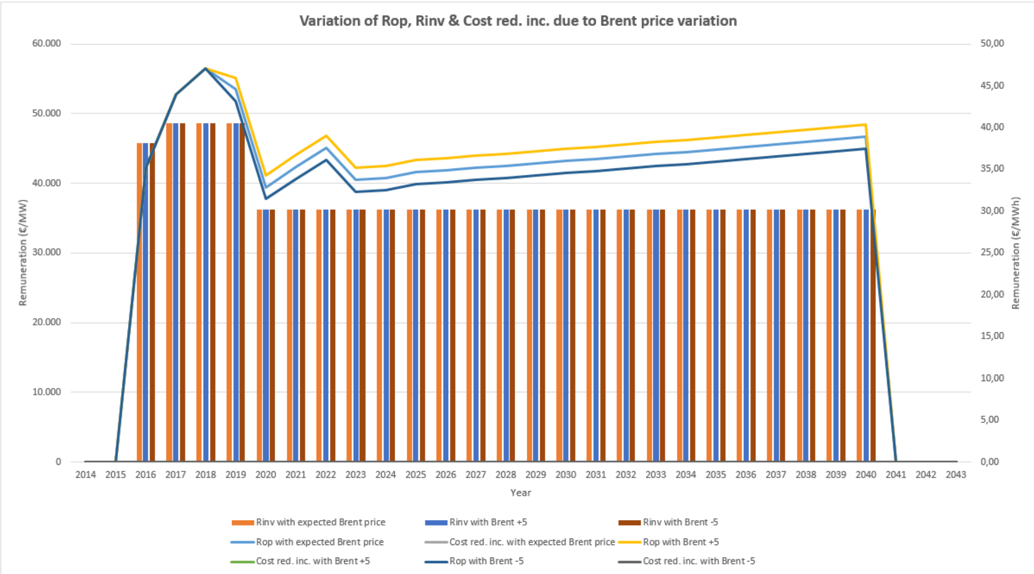

Figure 3.21 IT01396 variation in remuneration due to variation of the Brent oil price

It can be seen that an increase in the Brent oil price increases the amount of operation remuneration received by the IT. This makes sense considering there is an increase in the costs assumed by the IT. The effect is quite similar to a variation of the market price, but more powerful than the change in the captured price factor of this IT.

Change in system cost

The variation in the Brent price will cause a change in the total system cost; however, it will be limited to cogeneration power plants, as they are the only ones affected by a variation in the Brent price. The system cost variation will depend, in this case, of the total cogeneration installed power, and the percentage of those which are diesel or fuel oil based, as they are more affected by a variation in the Brent price, as seen by equation 2.18 in comparison to equation 2.13. The estimated variation in system costs due to these changes can be seen in table 3.6. Both cases should cause the same difference in cost to the system; however, inaccuracies in Excel's iterative process causes these slight differences.

Table 3.6 Variation in system yearly cost in 2020 due to a variation in the Brent price

Description	**Group**	**+5$/bbl**	**-5$/bbl**
Cogeneration	a.1	47.583.031	-47.647.174
Residual energy cogeneration	a.2	0	0
Solar energy	b.1	0	0
Wind energy	b.2	0	0
Geothermal	b.3	0	0
Hydro <10MW	b.4	0	0
Hydro >10MW	b.5	0	0
Crop biomass	b.6	0	0
Biogas and bioliquids	b.7	0	0
Industrial biomass	b.8	0	0
Domestic waste	c.1	0	0
Other waste	c.2	0	0
Mining waste	c.3	0	0
Total (€)		**47.583.031**	**-47.647.174**

Conclusions

The variation in regulated revenues due to a variation in the Brent price is very linked to parameter A of each IT, meaning the higher this term is the higher the variation in the revenues due to a change in Brent price. From an IT and plant owner perspective there is no benefit from having A be any different than the sensitivity of the fuel costs with respect to the fuel price. The reason for this is that having an A be greater than the sensitivity would benefit the generator when the fuel price increases, as it will receive further remuneration than needed to cope with the increase in costs, but it would be detrimental if the fuel price decreases, the opposite happening for a lower A than the real sensitivity of the IT. If there is fuel price uncertainty, there is no benefit from having A being different than the sensitivity.

3.1.9 Variation of the CO_2 emission allowances price

In order to generate electricity cogeneration plants produce CO_2. In Europe, since 2003 [6], a CO_2 allowances trading scheme has been slowly been developed in order to be able to reduce greenhouse gas emissions. Therefore, it is now mandatory for companies that produce CO_2 to buy emission allowances for those very same emissions. This means that a company that has the necessity to buy these allowances must incur in a greater cost, discouraging the emission of these gases. This also means that a variation of the price of these emission allowances will vary the costs assumed by a company that has to purchase them, this cost being higher the greater the amount of CO_2 generated.

Due to the direct impact on the costs incurred by an IT that has to purchase these emission allowances, if they emit CO_2, it is crucial to analyze the impact on costs, and therefore on regulated revenues, on the different ITs. A base case of CO_2 emissions allowances price was done, using ICE EUA Futures values, which rendered the following values to be used:

1. For 2019: 25,08€/t
2. For 2020: 25,30€/t
3. For 2021 until 2024: 25,05€/t
4. For 2025 onward: 27,22€/t

Similar to the variation in Brent oil price, only IT01396 has been considered, as the rest of the ITs used for the scenarios do not require purchasing CO_2 emission allowances, and are therefore not a cost. Furthermore, both an increase and a decrease in price of 5€/t, for each year after 2018, considering the base case values, were evaluated as alternatives for this case.

Cogeneration IT (IT01396)

The results, for IT01396, due to the change in CO_2 emission allowances price were the ones shown in figure 3.22. The results only show a small variation in the operation remuneration, which is hardly observable. The result in this case is quite surprising, as a variation of 5 €/t in the price of allowances meant an increase of 100% in 2016 and 2017. This can be seen in figure 3.23.

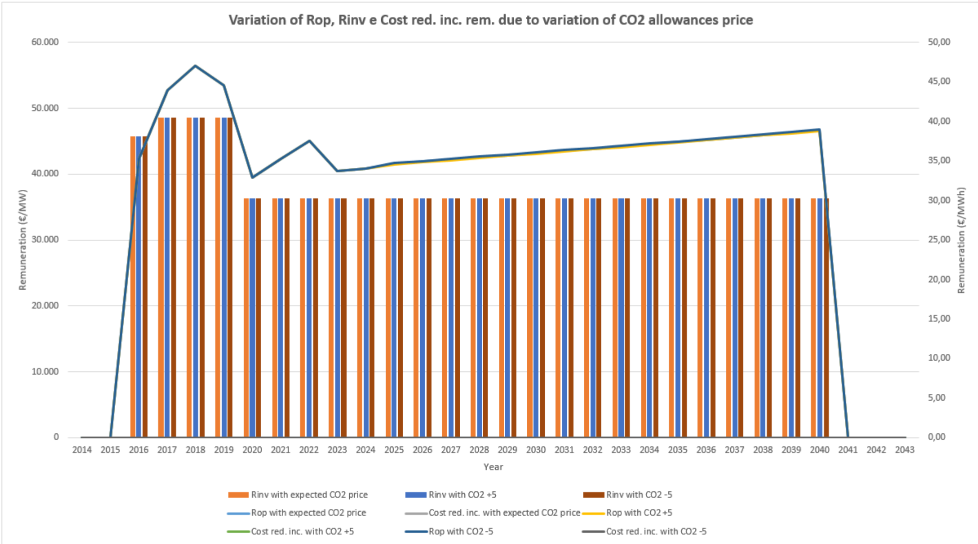

Figure 3.22 IT01396 variation in remuneration due to variation of the CO_2 allowances price

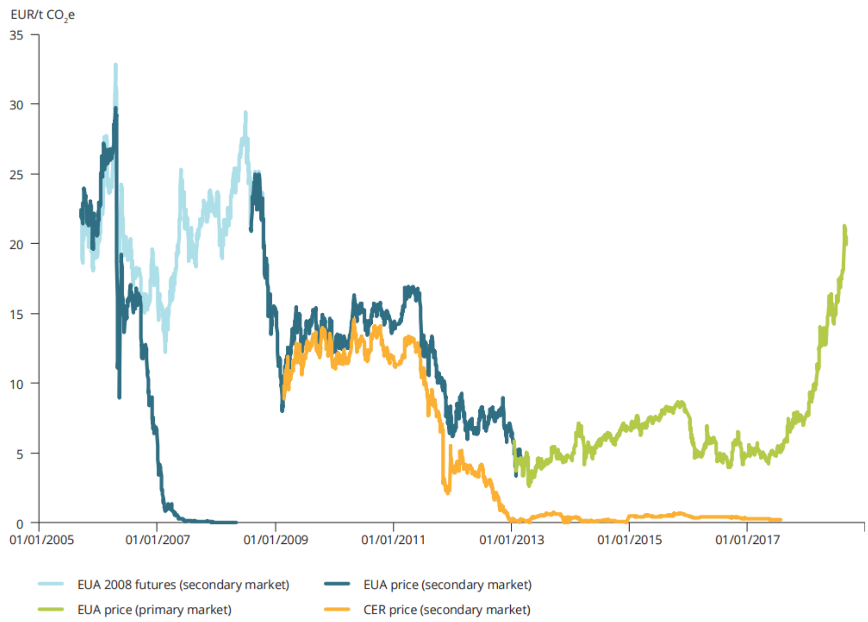

Figure 3.23 Evolution of emission allowances prices. Source: Trends and projections in the EU ETS in 2018 (EEA)

One could think that the reason for this lack of change is due to the fact that the CO_2 emission allowances cost in cogeneration plants is not very significant, but this is not the case. Initial calculated values of the CO_2 emission allowances cost range between 2 and 4 €/MWh, between 2014 and 2016, when the price was around 5 €/t, therefore an variation in price of 5 €/t should lead to an variation in the cost in the same proportion. However, this is not what is observed.

Change in system cost

Similarly to the variation in Brent price, this change in the CO_2 emission allowances cost only affects cogeneration ITs and their associated power plants. Nevertheless, as it has been seen in the previous example, this cost is not correctly taken into account for cogeneration ITs, so it is likely that the variation of this cost will not be very coherent when analyzing the system as a whole. Regardless, the estimation of the change in the total system costs can be seen in table 3.7:

Table 3.7 Variation in system yearly cost in 2020 due to a variation in the CO_2 emission allowances price

Description	Group	+5€/t	-5€/t
Cogeneration	a.1	-55.506	83.148
Residual energy cogeneration	a.2	0	0
Solar energy	b.1	0	0
Wind energy	b.2	0	0
Geothermal	b.3	0	0
Hydro <10MW	b.4	0	0
Hydro >10MW	b.5	0	0
Crop biomass	b.6	0	0
Biogas and bioliquids	b.7	0	0
Industrial biomass	b.8	0	0
Domestic waste	c.1	0	0
Other waste	c.2	0	0
Mining waste	c.3	0	0
Total (€)		**-55.506**	**83.148**

These results are quite contradictory to what would be expected. Nevertheless, attending to equation 2.32 these results make complete sense, although they reflect that the ministry has not taken into account this cost for the first two semi-periods. A higher CO_2 emission allowances price increases far more the associated cost for the first year after there are no values for the operation remuneration, 2019, however it decreases the increment for the following semi-periods, as the percentage increase in subsequent years is smaller. This causes the lower CO_2 emission allowances price scenario to increase the system costs as a whole, which seems counter intuitive. Nevertheless, if the cogeneration ITs finished their regulatory life in the third semi-period the opposite would be the case, as the higher the CO_2 emission allowances price in that semi-period the higher the increase in the associated cost.

Conclusions

As was mentioned in section 2.2.2.2, when describing how the CO_2 emission allowances cost was calculated, although the approach used made the most sense according to how the ministry updated the operation remuneration, it caused problems that had to be described.

The reason for this lack of change in the operation remuneration, due to a lack of change in the CO_2 emission allowances cost, is because for the first 2 semi-periods, that have already passed, this cost has been updated like described in equation 2.31. Although this makes sense in order to compute the total costs as the ministry does, it does not reflect the actual cost assumed by these emissions. Even though after this period this cost is updated according to the variation in CO_2 emission allowances price and the free assignation of these rights, as this update is done taking into account the price and cost for the previous year, the real update in costs does not show correctly.

Even though this approach does not correctly reflect the real cost assumed by these ITs, it is actually beneficial to calculate it in this manner, as it shows clearly that the regulator has not considered this cost correctly. It is unknown at this point how this cost is updated if at all and if it will be considered in the future, but the error is still present. This error is even more evident when analyzing the variation in the system costs, as the unacknowledged costs during the first two semi-periods causes these inconsistencies when analyzing the evolution in the system costs in the future.

3.1.10 General conclusions of scenario analysis

As it has been shown throughout section 3.1, the use of the model for future events predictions and analysis is extremely useful. It allows the user to evaluate different scenarios and how it will affect the different ITs. Even though it has not been shown in this document, due to the great amount of ITs present in this support scheme, it is actually possible to do the scenario analysis for all the ITs in the support scheme (except the ITs that have incorrect information and slurry and sledge ITs).

These scenarios can be used for many different purposes, to obtain the expected revenues in order to try to attract investors, to analyze the results from a regulatory or academic perspective or to analyze the behaviour of your own power plants or your competitors. This scenario analysis can also be expanded to other hypothesis, although this requires changing the VBA code, which in some cases can be quite problematic.

Apart from takeaways that could occur from other possible scenarios, that have not been considered here, there are several conclusions that can be extracted from the different scenarios studied in section 3.1:

1. The tax on the value of the production of electric energy causes distortions on the operation remuneration, meaning that a change in investment remuneration, due to a change in reasonable return for example, causes also a change in operation remuneration. This causes a linkage between the investment and operation remuneration, if operation remuneration exists, that complicates the differentiation of these two elements of remuneration. This would not be a problem if both of these served the same purpose, but the investment remunerations objective is to recover the investment and the objective of operation remuneration is to guarantee no losses in operation. This tax is also incoherent, as it applies to revenues obtained by operation and investment remuneration. This means that either the investment (for ITs that do not require operation remuneration) or operation remuneration need to be increased in order to account for that cost. This causes a cyclical effect, in which the system must pay ITs for the cost that the government is later going to collect, which ends up being a transfer from the electrical system to the government.

2. The cost reduction incentive remuneration creates contradictions with the rest of the support scheme. This can be seen with the changes in reasonable return, the suppression of the tax on the value of production of electric energy or the market price estimation.

In the case of the reasonable return rate, it causes the IT to not obtain the same increase or decrease of the reasonable return, the suppression of the tax causes an increase in this remuneration although there is no change in costs by the system and a simple price estimation causes discrepancy in the current semi-period. This is because the regulator has not taken into account that some of the changes in market price, operation or investment remuneration are due to regulators decision. If the government decides to increase the value of the tax on the value of production of electric energy, increasing the operation or investment operation to cope with this increase in cost, the cost reduction incentive remuneration would decrease, even though there has been no reduction in the savings. If these variations due to regulators decisions, like this hypothetical increase in this tax, were not taken into account the cost reduction incentive remuneration would not change, which is precisely what should happen. Another solution is to consider also the revenues provided by the power plant to the system, to really take into account the total savings by the IT.

3. The CO_2 emission allowances cost is not correctly considered, which creates uncertainty on the actual return of the cogeneration ITs. The main objective of this support scheme is to guarantee the return on the investment, however the fact that the real costs of the ITs are not being considered creates doubts on how these ITs are going to recover their investments.

3.2 Real plant calculation

The other main application of the model is to be able to analyze the profitability of a real power plant associated to a particular IT. Using this tool, it is possible to introduce the operating parameters as well as the total investment of an existing or planned RES power plant that would be associated to an IT.

This is specially useful given how new RES power plants are allowed to enter the current support scheme, which is through regulated auctions. RES power plant owners must present a sealed bid, representing a percentage reduction with respect to the IT investment costs that are being presented. Winners are selected by choosing first bidders with the highest investment cost reduction. This does not mean the only way to approach these auctions is to try to reduce the investment or financing costs, but to translate different operation advantages into an investment cost reduction. This can be done by calculating the net present value of the RES power plant given the operating life cycle. Using this, the investment cost reduction to be presented to the auction can be easily calculated.

The ideal scenario would have been able to obtain information from a real power plant, in order to analyze their profitability and if the results obtained by the model were accurate. However, this was not possible, so an alternative solution was created in order to evaluate this tool. This way, an artificial RES power plant would be created with similar characteristics but modifying certain functioning parameters each time and evaluating the profitability of the power plant. The different cases analyzed were the following:

1. Same investment and operation parameters as the normal IT: in order to make sure that the net asset value, considering the reasonable return rate, is zero (or close, as due to market price deviations this might not happen) at the end of the regulatory life of the power plant.

2. A reduction in investment costs of 10% with respect to the corresponding IT: this will make it possible to evaluate the change in profitability in the case that the real power plant is more efficient in its investment.

3. A reduction in operation costs of 10% with respect to the corresponding IT: this will make it possible to evaluate the change in profitability in the case that the real power plant is more efficient in its operation.

4. The equivalent functioning hours to be in between the minimum number and the operating threshold: when a power plant operates in this range it only receives certain part of the regulated revenues associated to its IT, according to equation 2.5.

5. The equivalent functioning hours to be below the operating threshold: when a power plant operates with equivalent functioning hours below the operating threshold it will not receive any kind of regulated revenues.

6. The equivalent functioning hours to be above the maximum equivalent hours: for equivalent hours above the maximum the power plant will not receive any operation remuneration.

Another possible analysis would be to analyze the power plant if it operates between the normal equivalent functioning hours and the maximum, however the change in profitability will depend on the specific IT and the power plant. For instance, a power plant with the same operation costs and receiving operation remuneration will not increase profitability; only a power plant with less operating costs or that does not require operation remuneration will experience a change in profitability.

For all of these analyses IT00004 has been chosen, as it was used before and it has a maximum number of equivalent functioning hours, therefore allowing for all the possible cases.

It must also be said that for the different analysis that are going to be made the method for updating the net asset value has been the one used by the ministry. This means that the net asset value is updated after each semi-period, and not from present value into the future. This causes differences when analyzing net asset values in the classical way, analyzing the value of the asset today given future cash flows, as the values are updated differently; however, the result at the end of the regulatory life is the same.

3.2.1 Same parameters as associated IT

The real evolution of the net asset value of the IT, taking into account the evolution throughout the first two semi-periods and comparing it to the estimations done by the ministry, would be the one shown in figure 3.24:

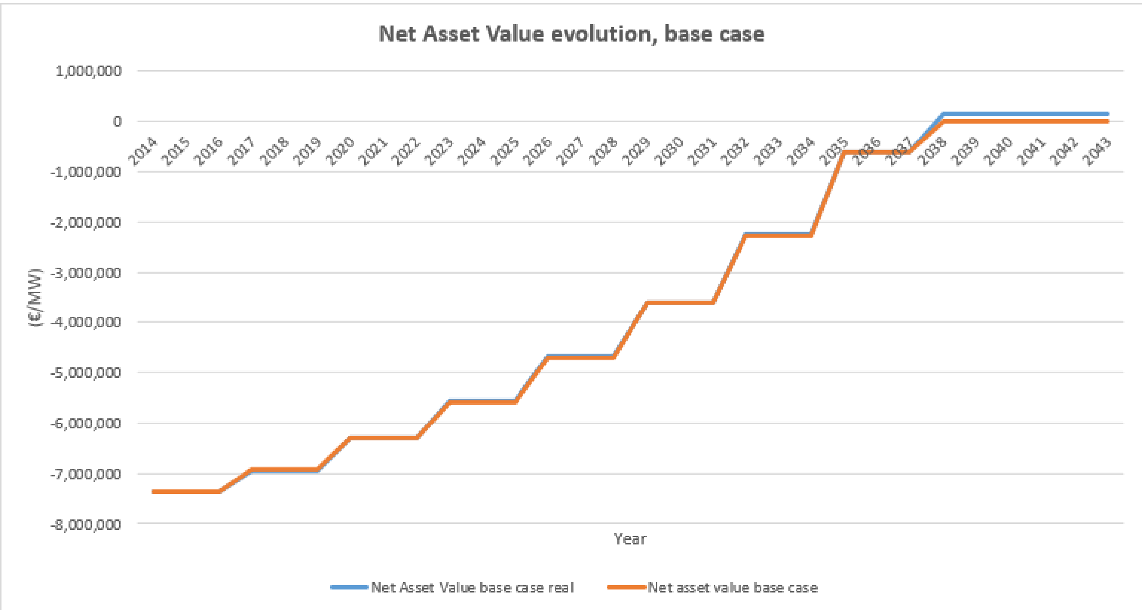

Figure 3.24 Evolution of the net asset value of IT00004 over time

Even though the expected outcome is for the net asset value to be equal to zero, which is shown by the orange line, at the end of the regulatory life the actual value is above it, which is shown by the blue line. This is because of what was explained in section 3.1.3, which showed that the net asset value could differ from zero at the end of the regulatory life cycle, due to deviations in market price. Even though the greatest deviations are corrected, when the deviation from the expected market price is small these differences are not corrected, therefore creating different net asset values than expected. This is why, due to deviations of the market price from 2014 to 2018, the real net asset value is different from zero and having a positive value, although if the market price deviations would have been different the value could have been negative.

3.2.2 Reduction of 10% in investment costs

If we compare now the actual net asset value of IT00004, taking into account the market price deviations mentioned before, to one having a 10% reduced investment costs the results would be the one shown by figure 3.25:

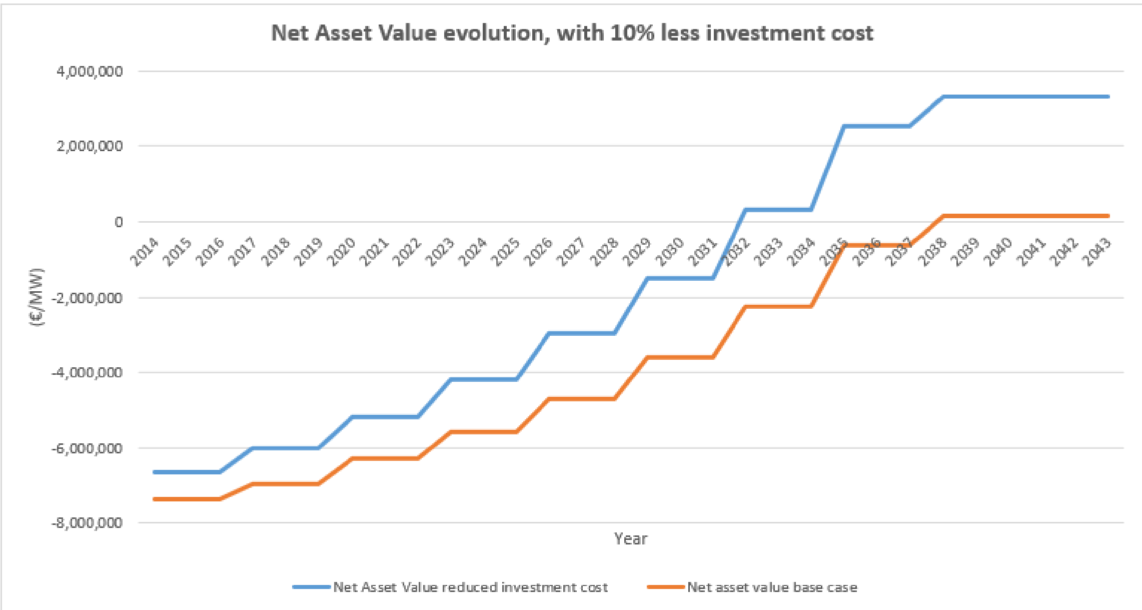

Figure 3.25 Evolution of the net asset value a real power plant with 10% less investment cost

It can be seen that the net asset value increases dramatically due to this reduction in investment cost. However, this great difference is mostly due to the great amount of investment cost of this particular IT and that the variation was represented as a percentage.

3.2.3 Reduction of 10% in operation costs

The effect of reducing the operation costs by 10% can be seen in figure 3.26:

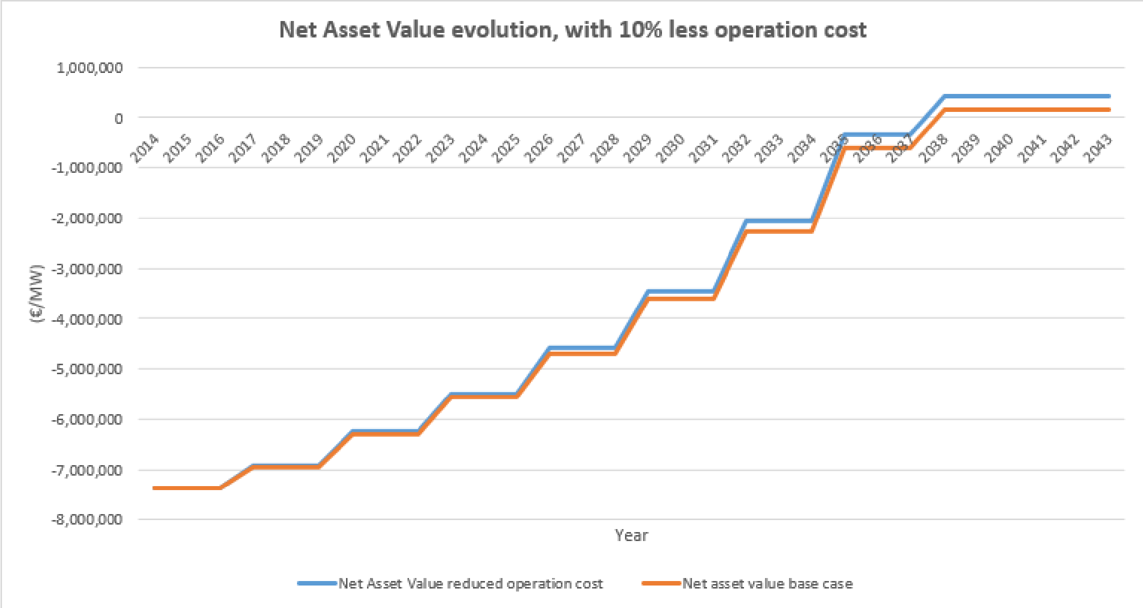

Figure 3.26 Evolution of the net asset value of a real power plant with 10% less investment cost

The results are what is expected, as a reduction of 10% on operation costs, given the considerably higher amount of investment costs in this particular case, is significantly smaller than the net asset value due to an investment cost reduction. If this example was done with an IT with low investment cost but higher operation costs, such as a cogeneration IT, the effect would be significantly more relevant.

3.2.4 Equivalent functioning hours between the minimum hours and operating threshold

As the minimum equivalent hours for this particular IT is of 989 hours for the first semi-period and of 974 for the second, whilst the operating threshold for the first and second semi-period is of 577 and 568 hours respectively, the equivalent functioning hours were modified to maintain a constant value of 800 hours. The results were the ones described by figure 3.27:

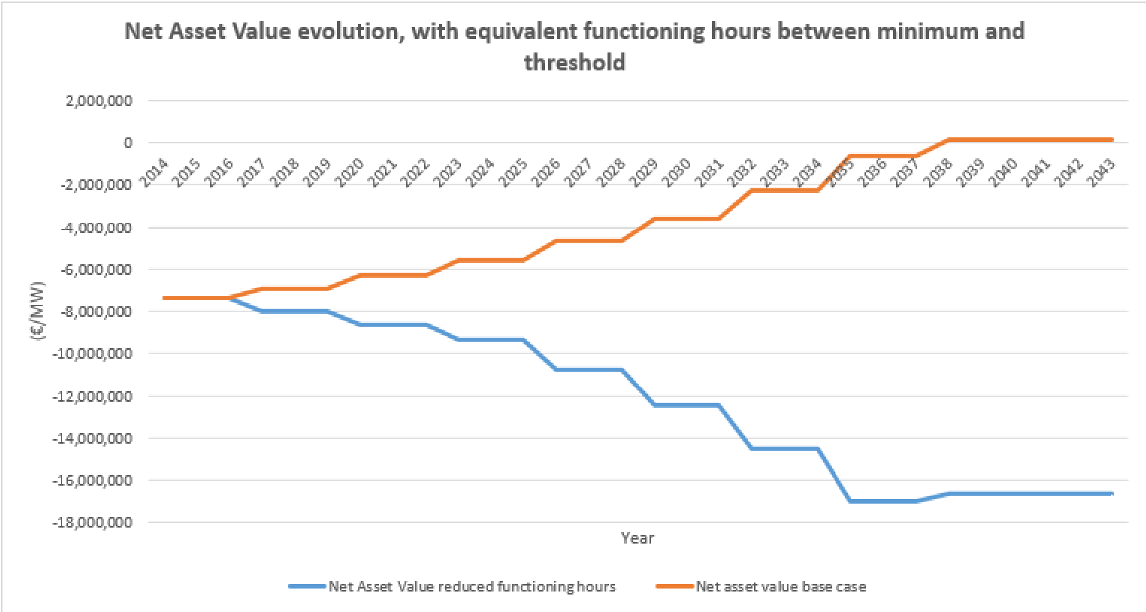

Figure 3.27 Evolution of the net asset value of a real power plant with equivalent functioning hours between the minimum and operating threshold

This result is what was expected, considering that the amount of revenues was cut down according to equation 2.5, meaning that it was impossible for the power plant to recover the investment. In this case, as there was operation remuneration required to operate without losses, the effect was that the net asset value decreased.

3.2.5 Equivalent functioning hours below the operating threshold

Given the operating threshold given before, the equivalent functioning hours were set at 400, so that the value was well below this threshold. The results were the ones shown in figure 3.28.

As was expected, the outcome is worse than the previous case, as the power plant is not awarded any regulated revenues, therefore not being able to get any return on the investment. In this case, it would not be worth for the power plant to operate even, as it requires operation remuneration to be able to operate without losses, but in this particular scenario it would not receive any operation remuneration.

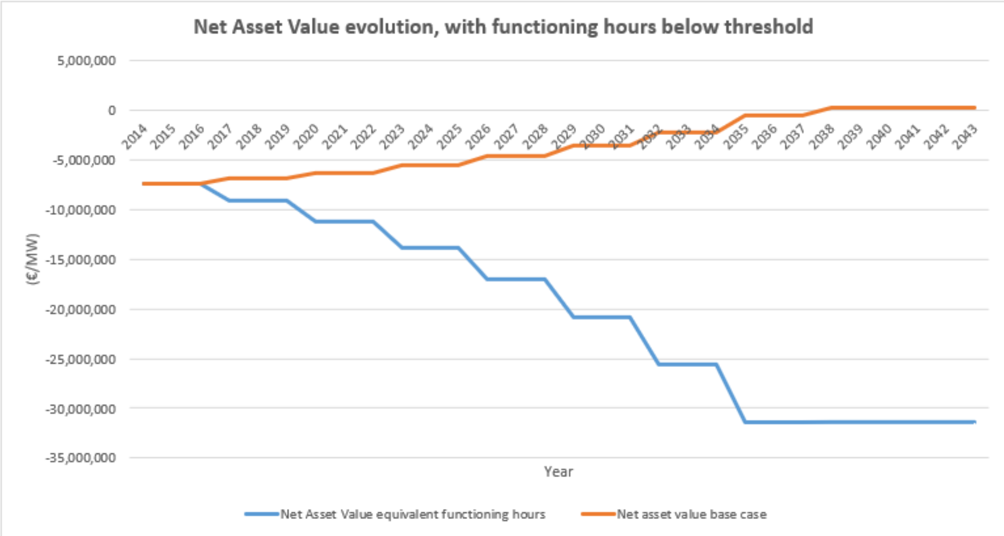

Figure 3.28 Evolution of the net asset value of a real power plant with equivalent functioning hours below the operating threshold

3.2.6 Equivalent functioning hours above the maximum

Since the maximum number of hours, in which the power plant is allowed to receive operation remuneration, is 1648 (which is equal to the normal functioning hours for the first year of operation set for the IT), in this case the equivalent functioning hours has been set at 2000. The results are shown in figure 3.29:

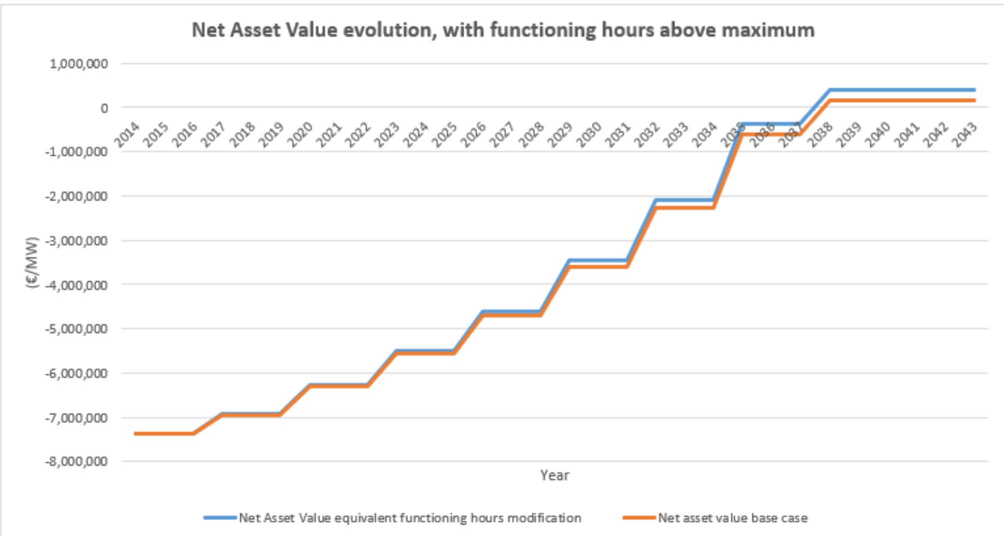

Figure 3.29 Evolution of the net asset value of a real power plant with equivalent functioning hours above the maximum

The results in this case are initially surprising. It seems contradictory that a power plant that requires operation remuneration increases the net asset value when operating without receiving this operation remuneration. The explanation is the existence of the tax on the value of the production of electric energy. It is important to mention that the operation remuneration is calculated taking into account the cost associated to this tax both on the operation remuneration, the market revenues and the investment remuneration. The cost associated to the investment remuneration is converted into €/MWh taking into account the normal equivalent functioning hours. When the functioning hours of a power plant increases beyond that level the cost associated to the application of the tax onto the investment remuneration actually decreases in terms of € per MWh. Furthermore, as there is no operation remuneration beyond the maximum number of hours there is no tax-associated costs to the operation remuneration as well. All of this makes it so the net asset value actually increases when operating beyond the maximum. This also means that a power plant operating below the normal functioning hours, but above the minimum level, will have a net asset value below the value obtained in normal operation.

3.2.7 General conclusions

With these analyses, it is clear that the model that has been developed can properly use the information from the ITs and use it to analyze the profitability of a real plant associated with it. This is a tool that can be used by RES power plant owners or investors to decide whether or not to invest in a particular power plant given the characteristics of the specific IT. Furthermore, the results of having lower operation costs, for instance, can be easily translated into net asset value, which is crucial when participating into an auction where the bid is actually investment cost. New ITs are determined by auctions, being the reduction in investment cost with respect to a particular IT what is bid. This means that any operation benefit can be translated into net asset value and consequently into part of the bid.

On the other hand, it is clear, with these analysis in hand, that in order to ensure a higher return on the investment the power plant associated to an IT must operate more efficiently than the IT, either by having less operating costs, by having greater equivalent functioning hours, or having less investment costs.

3.3 Model limitations

Even though the model can perform many features, at has been shown throughout this chapter, it faces several limitations. The first one is that complex formulation is really unclear in Excel, meaning that large, complex logical formulas can be very hard to understand and follow, leading to numerous mistakes. Another problem occurs when Excel is not able to find convergence in the results, which is not usual but can definitely happen, causing ridiculous results. In some cases, this is totally inexplicable, as another calculation will lead to a normal result, but it most likely is due to precedence in formula resolution by Excel. Furthermore, sometimes Excel will display #NUM! errors in a seemingly random fashion, even though there is no reason to display it according to the terms being calculated. In order to avoid this error a macro has to be created, with the only function of reintroducing the formula in each particular cell with a #NUM! error. Finally, VBA does not allow for automation in terms of graph axis labelling, which means that output graphs need to be labelled manually, which can require a great amount of time.

In terms of functionality, any important modifications of the current support scheme would lead to great problems in the application of the model, as it would probably mean it would have to be entirely remodeled. This is due to how Excel works, with cells being referenced in the different formulas, meaning that important changes might not only require introducing new parameters, but also the complete formulation, taking into account again that new information might be introduced at a later date.

Chapter 4

Positives, negatives and alternatives for the current RES support scheme in Spain

After describing the RES support scheme present in Spain, as well as some results being obtained through the use of the model that has been elaborated for this Master Thesis, it is possible to discuss, in further detail, the positive and negative elements of the legislation surrounding this support scheme.

On the other hand, after discussing the positive and negative elements of the current support scheme in Spain, it will be possible to analyze possible alternatives. This discussion will be centered around the different support schemes that were described in chapter 1, as they are the main forms of RES support around the world.

4.1 Positive aspects of the current support scheme in Spain

From a policy makers perspective, there are two main objectives when designing a RES support scheme, that there is a good development of RES because of the support scheme and that the cost for the system is not too high. In occasions, these two objectives might be conflicting, as usually the best way to promote RES is through reduced risk, which tends to imply higher forms of regulated revenues [18].

In the case of the support scheme that is present in Spain, it manages to balance risk reduction and cost control. This is due to its inherent characteristics, controlling the amount of remuneration necessary to somewhat guarantee the return on the investment but not further than necessary. This is done by separating the remuneration to be obtained through normal operation (operation remuneration) and the investment decision (investment remuneration), therefore using the investment remuneration to guarantee the return on the investment and the operation remuneration to do the same in the operation department.

This separation can be quite useful [17], as it separates the investment decision from the normal operation, making the investment decision far easier, as the need for long-term estimations, for supply, demand or prices, are not as necessary as before. It also helps to solve the "missing money" problem [16], which has plagued electricity energy only markets, as the investment is almost guaranteed through the investment remuneration. Furthermore, in order to ensure that RES power plants investment is efficient, RES power plant owners must operate under certain conditions to be allowed to receive this remuneration (minimum equivalent functioning hours, operation threshold etc.). It is true, however, that the return on the investment is not completely guaranteed, as there is the need to evaluate future revenues, which causes deviations from the expected return rate, as seen in section 3.2.1. This deviation, however, corresponds to the normal risk associated to operation in the power market, which could only be eliminated through the use of support schemes such as the feed-in tariff. Nevertheless, having associated market risk and price signals might actually be positive in certain aspects [14]. The reason for this is that it encourages taking better operation decisions and maintenance scheduling, whilst also setting incentives for technologies that adapt better to short-term wholesale price curves. Therefore, having an operation remuneration, which can be described as a sliding feed-in premium, on top of the market price increases the risk somewhat, but has its own benefits. It is true that as the operation remuneration is a sliding feed-in premium, as it varies each year for most of the ITs, or 6 months in the case of biomass and cogeneration ITs, the RES power plants are not as exposed to the market price, and so these benefits might be more diffuse [14]. Nevertheless, as the operation remuneration is updated every year, which is a considerable amount of time in the power market, the benefits are mostly retained.

Another positive aspect of the Spanish RES support scheme is that it can be said to be technology neutral. Even though certain technologies receive different forms of remuneration in practice, in theory there is no distinction between the remuneration forms that the different technologies can receive, the rules being exactly the same for all of them. It is true that given the characteristics of the support scheme ITs are guaranteed investment recovery, which means that different technologies receive different forms of support, which goes against the main purpose of technology neutrality, which is to detect and promote the most efficient technologies. This is also enhanced in the case of cogeneration and biomass, which do have a special way of calculating their operation remuneration; however, the general rules are still the same. Therefore, all technologies have a clear shot to try to be more efficient than their corresponding ITs and increase their return rate.

Even though it is generally more difficult to analyze the positive elements of this kind of legislation, as the general objectives are normally diffuse and the cost-benefit requires a deeper analysis, whilst the negative elements can be very clear, it is possible to see some success of the current RES support scheme in Spain. In the last years, there has been an increase in wind power installation in Spain, after almost a decade of decreasing installation. This can be seen more clearly in figure 4.1, where the blue bars represent the total wind power installed, and the green the wind power installed in that year (all represented in MW):

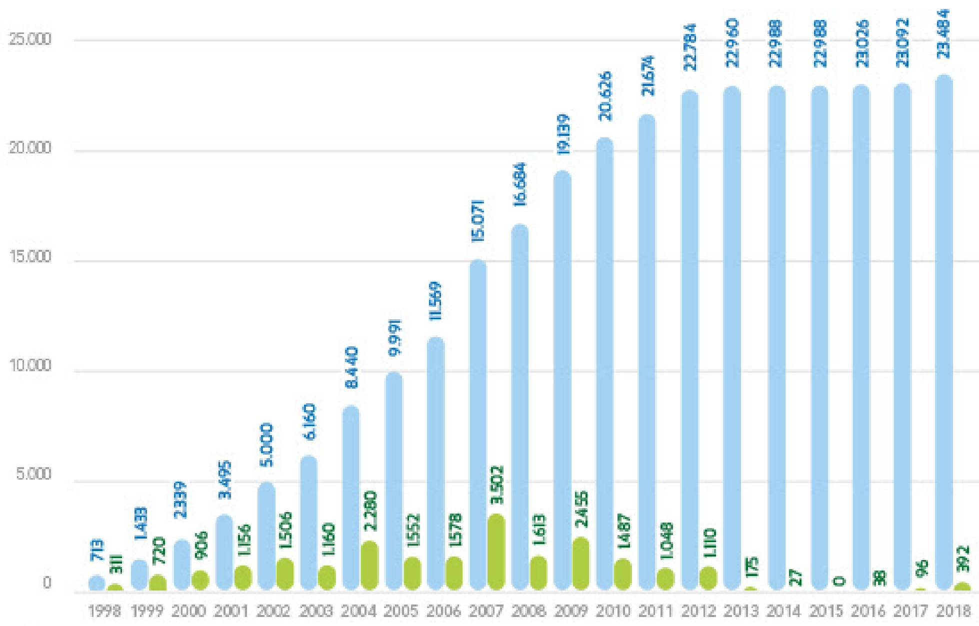

Figure 4.1 Evolution of Spain's installed wind power. Source: AEE

It is true that the increase of wind power installed is not very significant, compared to the period between 1998 and 2012, but it represents a steady increase. It is also important to take into consideration that new RES power plants that want to participate in this support scheme must go through an auction process, which began a few years ago, meaning that the increase in wind power installation will be seen in the next years, and this evaluation will be more precise.

4.2 Negative aspects of the current support scheme in Spain

As was stated beforehand, it is actually easier to observe the negative aspects of the current RES support scheme in Spain, as the results are far more visible and predictable than the benefits. Many of the positive elements that have been described before, such as the investment recovery without incurring in costs which are too high, have a very clear negative aspect. This negative aspect is that in order to guarantee this investment recovery the ministry must analyze over 1600 ITs and take into account the associated power plants. This is an enormous amount of information that has to be handled correctly, but that can easily end up with grave mistakes. This can include minor mistakes, such as slight deviations in the expected margins when ITs receive operation remuneration, which should be zero but ends up being slightly different. Other mistakes can be quite severe, such as important miscalculations regarding the operation remuneration to be received, greatly underestimating the costs of a certain IT. This is what happens to some cogeneration ITs in the first semi-period such as IT01396, which was studied beforehand. In this case, the margin in 2016, which should be zero as it is receiving operation remuneration, ends up being negative by a significant margin. This can be seen more clearly in figure 4.2:

	S	T	U	V	W	X	Y
4							
5							
6			SEMI-PERIOD	1	2014	2015	2016
7			VNA	514.860			
8			Equivalent annual hours (h)		0	0	6454
9			Price (l/MWh)		0,00	0,00	49,75
10			Captured price factor		0	0	0,9997
11		No Cogeneration	Operation remuneration (l/MWh)		0,00	0,00	-
12	Cogeneration	1ª semester	Operation remuneration (l/MWh)		0	0	39,965
13		2ª semester	Operation remuneration (2) (l/MWh)		0	0	30,507
14			Other revenues (l/MWh)		0	0	35,97
15			Relationship between electricity exported/produced		0	0	0,955
16	Biomass	1ª semester	Operation remuneration (l/MWh)		0	0	-
17		2ª semester	Operation remuneration (2) (l/MWh)		0	0	-
18			Otros ingresos de expl. (l/MWh)		0	0	-
19			Cost reduction incentive (l/MWh)		**0,00**	**0,00**	**0,00**
20			**Revenues (l/MW)**		**0**	**0**	**791.493**
21			Toll (l/MWh)		0	0	0,5
22			Deviation (l/MWh)		0	0	0
23	Cogeneration		Hydrocarbon tax (l/MWh)		0	0	4,790179
24		1ª semester	CO2 cost (l/MWh)		0	0	2,219001
25		2ª semester	CO2 cost (2) (l/MWh)		0	0	2,219001
26		1ª semester	Fuel cost (l/MWh)		0	0	93,61982
27		2ª semester	Fuel cost (2) (l/MWh)		0	0	84,58872
28			Fuel cost (l/MWh)		0	0	-
29			Fuel cost (2) (l/MWh)		0	0	-
30			IVPEE (l/MWh)		0,00	0,00	6,18
31			IVPEE of Rinv (l/MWh)		0,00	0,00	0,50
32			Rest of OPEX (l/MWh)		0,00	0,00	22,67
33			**Total operation costs (l/MW)**		**0**	**0**	**849.052**
34							
35			**Regulated Margin (l/MW)**	**-49.903**	**0**	**0**	**-57.559**
36			**Perceived Margin (l/MW)**	**-49.903**	**0**	**0**	**-57.559**

Figure 4.2 Ministry error in IT01396 for 2016

Another problem arises with ITs that have obtained their return on the investment but that are still within their regulatory life cycle. This is the case of some cogeneration ITs, which have no investment to be paid back, probably due to previous support schemes, but that are still eligible for this support scheme, receiving mostly operation remuneration. This might not seem problematic, however the net asset value updates due to market price deviations do cause a significant problem. In most cases, if the market price ends up being higher than expected the net asset value is decreased according to equation 2.1 and equations 2.6 to 2.10. However, due to the legislation, the net asset value cannot be reduced below zero, therefore the ITs that have net asset value of zero never have to pay back the extra regulated remuneration received (in terms of reduced investment remuneration throughout the years). Nevertheless, they do perceive extra investment remuneration if the market price ends up being below the market price, as the net asset value is updated positively according to equation 2.1. This is what can be seen in certain cogeneration ITs, such as IT01061, represented in figure 4.3:

ID code	IT-01061
Characterization of Installation Type	
Net asset value 2014 (€/MW):	0
Net asset value 2017 (€/MW):	32.512
Regulatory life (years)	25

Figure 4.3 Net asset value update for IT01061

This is actually quite an important mistake, as it means that these ITs, and their associated power plants, will receive a higher return rate than actually intended. One sensible way to approach this problem would have been to allow the ITs that had zero net asset value, when the support scheme started, to have their net asset value end below zero, and therefore be able to compensate for underestimations of the market price. It is understandable that the ministry decided to avoid this issue, as it would have caused the ITs to effectively owe a debt to the government, which would decrease the investment in this support scheme as the risk increased. Nevertheless, one simple solution would have been to not force the ITs to pay back the investment remuneration, if the net asset value went below zero, and just store that value in order to compensate for the over estimations of the market price. The possibility of over return of the investment could still occur but the amount of that overcompensation would be corrected, therefore correcting inequalities between different ITs.

There are other problems that have more to do with estimations on ITs operation. The ministry acknowledges that operating costs will increase throughout the years, therefore including an annual regulated increase of 1%, due to inflation. This regulated update was probably done to avoid having to review these costs for all the ITs every year, which given the amount of ITs would have been a titanic task. It could also entail problems of asymmetry of information, as the IT owners would try to increase these costs artificially to increase the regulated revenues. Nevertheless, this estimation could be faulty in the long term, as the costs could increase by a higher or lower amount, therefore impacting the return rate and operation profitability of the power plant. However, it is true that in order to avoid this issue, the ministry updates these costs every semi-period, thus correcting the differences between estimated and real values.

Finally, it is important to mention again some of the problems that were highlighted when examining the different scenarios. These include the distortionary effect of the tax on the value of the production of electric energy, the flaws in the calculation of the cost reduction incentive remuneration, the lack of CO_2 emission allowances cost acknowledgement and the incentives for erroneous market price estimations, both from a regulator and a RES power plant owner.

4.3 Possible alternatives

Throughout the years, there have been numerous RES support schemes that have been implemented all around the world, as was described in chapter 1. In the case of Spain, both a feed-in tariff and premium have been tried, but have been eventually been disregarded. The main reason for this was the high cost assumed by the system when incorporating these support schemes, as there is high risk in overestimating the support needed by RES power plants, therefore attracting more investment than desired initially. There is also the opposite risk, to underestimate the support needed and attract less investment than required, which also leads to undesirable outcomes. Nowadays, there is a clear approach to avoid these problems, which is to set auctions determining the amount of RES needed (can be for a specific technology or technology neutral) and then let the market agents determine the amount of support needed, taking only those which require less regulated support.

Nevertheless, this does not clarify which sort of support scheme would be needed, merely the form of assigning the rights to the support scheme itself. It is important to mention again which are the main objectives of a RES support scheme; to ensure an adequate development of RES, their integration in the market and the power system as a whole, and in a cost-efficient manner. Knowing this, there are no clear-cut answers to which support scheme is better, only trade-offs, and the determination of which one is better must be done after some time has passed and a serious analytical comparison can be done. However, there seems to be a trade-off between reduced investment risk and market participation. There is the general consensus that Feed-in Tariffs reduce the investment risk and promote RES further than other forms of support [1], however they isolate the RES producers from the market, which might not be desirable [14].

Other support schemes, such as feed-in premiums, whether constant or sliding, contracts for differences or renewable portfolio standards, expose the agents to the market considerably more. At this point it is normally a balance between the exposure to the market and the investment security desired for RES power plant owners. It is considered that sliding feed-in premiums protect more from the market than fixed feed-in premiums [14], as the objective of a sliding premium is to obtain a somewhat fixed price, therefore becoming similar to a feed-in tariff. This way, the sliding premium is similar to a contract for differences, as in both cases a strike price is set (in the case of the CfD, in the case of the premium it is more a reference price), and the regulated payment depends on the difference between this price and the market price. Nevertheless, in the case of a CfD. the agent must pay back the difference if the market price is above the strike price, whilst this does not happen generally in the case of a sliding feed-in premium. Renewable portfolio standards are sometimes considered to be less risky than contracts for differences [4], as the first does not have a risk associated to the amount of production, as the CfD does.

The Spanish RES support scheme can be described as a sort of contract for difference, in the case of operation remuneration, and a capacity-based support payment, in the case of the investment remuneration. The operation remuneration could also be described as a sliding feed-in premium as it does not require a payback if the market price is above the "strike price", however in reality is what ends up happening, but by reducing the amount of investment remuneration to be received throughout the RES power plant lifetime. Understanding this, one could argue that a CfD could be a plausible alternative to the current support scheme in Spain, given the similarities in terms of the operation remuneration. It is true that this could increase the risk that RES power plants would face, as the guaranteed return on their investment, given as investment remuneration, albeit with some requirements in terms of operation, would disappear, and require the power plants to acquire their return on their investment with their production.

As was mentioned before, at that point it is a question, from a regulator's standpoint, how much should a RES power plant owner depend on the market to obtain its revenues. A CfD, with annual market price averages (similar to the how the operation remuneration is determined) in order to compare to the strike price, will operate quite similarly to the current RES support scheme in Spain, although all revenues would entirely depend on the operation of the power plant and the market price perceived by it.

4.4 Final remarks

As closing comments of this Master Thesis, I would like to remark again the positive aspects of the support scheme that has been described in this document, that solves many of the issues that plagued previous RES support schemes in Spain. Even though there are several mistakes in the different pieces of legislation that surround this scheme, it is a very positive design, that manages to take into account various different aspects that might affect the viability of the RES power plants, in order to try and guarantee a certain return of the investment.

It is also necessary, at this point, to emphasize again the need of tools like the model that has been presented in this document, in order to be able to analyze positive and negative elements of these kinds of support schemes. Well-designed models can, as has been shown, detect unusual patterns and spot flaws in the design of these policies, therefore being an invaluable tool both for regulators and for market agents. It can also, as it has been shown, be used to analyze the electric system behaviour as a whole, analyzing variations in the cost of the system. The results presented in chapter 3 show quite clearly that the objectives presented in chapter 1 have been completely fulfilled. In many cases, it would be a great achievement to create a model that could realize any one of the three main objectives presented, either to analyze individual ITs, the system as an aggregate or to analyze the profitability of a RES power plant; however, this model can achieve all three in a very precise manner.

In terms of future developments, the model could be used as basis for dynamic scenarios, analyzing how the different results could affect the market as a whole and its consequences. These consequences could then be used again to reevaluate how the ITs, and the associated power plants, would be affected by these developments. Furthermore, the fact that the model allows for a system-wide analysis in terms of cost means that it could be a useful tool to help to determine the tariff structure considering variations in the model parameters. The fact that this model can be used both for micro and macro analysis means that there are a great number of applications for this model that are yet to be envisioned.

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