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Coordination of Independent Distributed Generation and Controllable Load

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"I have nothing to offer but blood, toil, tears and sweat."

Winston Churchill

Abstract

The research carried out focuses on the way generators connect to distribution networks. Permission to connect a generator to the distribution system is generally obtained on the basis that the generator's effect is limited and that the network voltages and currents remain acceptable at all times. This firm access connection policy limits the capacity of generation that can be connected.

Generators may be allowed to connect to distribution networks above the limit defined by the firm access connection policy. When there is inadequate capacity in the system, the non-firm generators are generally constrained off on a "last-in, first-off" basis (the last to connect is the first to be affected). Only the order of connection of the generators is taken into account. Different costs of operation and ability to be dispatched are not considered. Thus, the firm access connection policy does not maximise the economic value of the generators.

The coordination of independent distributed generators is formulated in this research to maximise the income received by the generators. The coordination schedules generators connected to the same circuit according to their different costs of operation and ability to be dispatched, without exceeding the power limit of the circuit. Additional income is obtained by the generators for the additional electricity sold and the substitution of expensive generators by cheaper ones. An income-sharing mechanism based on cooperative game theory to share the additional income is outlined. The objective is to provide the generators an economic incentive to be operated in a coordinated manner.

Demand side flexibility can be used to maximise the production of the generators. The coordination of generators and controllable load is devised in this research to maximise the income of the generators. Controllable load is asked to shift its consumption to allow the generators to maximise their production. The additional income resultant of the coordination is allocated to the generators and the controllable load. A bargaining approach of game theory is used to determine this allocation. The controllable load receives part of the additional income to cover the increase of its electricity bill and to incentivise its coordination with the generators. This study is then extended to consider energy storage systems instead of controllable load, in coordination with non-dispatchable generators.

A representative of the Portuguese distribution network is used to validate the coordination of independent distributed generators and the coordination of generators and controllable load. Four independent distributed generators and a load equivalent are connected to the network. A number of cases of wind power, price of electrical energy and load consumption are considered. Different costs of operation of the generators are analysed. Different levels of load flexibility and load capacity are evaluated.

Resumo

A investigação desenvolvida concentra-se na ligação de geradores às redes de distribuição. A permissão para ligar um gerador à rede de distribuição é geralmente obtida no pressuposto que o seu efeito é limitado e que as tensões e correntes na rede se mantêm aceitáveis em todas as circunstâncias. Esta política de acesso firme limita a capacidade de geração que pode ser ligada.

Geradores podem obter autorização de ligação às redes de distribuição acima do limite definido pela política de acesso firme. Quando existe capacidade inadequada no sistema, os geradores sem acesso firme são geralmente restringidos segundo a regra "último a entrar, primeiro a sair". Só a ordem de ligação à rede é tida em consideração. Diferentes custos de operação e capacidades de serem despachados não são considerados. Assim, a política de acesso firme não maximiza o valor económico dos geradores.

A coordenação de produtores dispersos independentes é formulada nesta investigação para maximizar o rendimento recebido pelos geradores. A coordenação escalona geradores ligados no mesmo circuito de acordo com os seus diferentes custos de operação e capacidades de serem despachados, sem exceder o limite de potência do circuito. Rendimento adicional é obtido pelos geradores pela energia adicional vendida e pela substituição de geradores caros por geradores mais baratos. Um mecanismo de partilha de rendimentos, baseado na teoria dos jogos cooperativos, para partilhar o rendimento adicional é delineado. O objectivo é fornecer aos geradores um incentivo económico para a sua operação de forma coordenada.

A flexibilidade da procura pode ser usada para maximizar a produção dos geradores. A coordenação de geradores e carga controlável é desenvolvida nesta investigação para maximizar o rendimento dos geradores. A carga controlável é chamada a transferir o seu consumo de forma a permitir aos geradores a maximização da sua produção. O rendimento adicional resultante da coordenação é alocado por geradores e carga controlável. Uma abordagem de negociação da teoria dos jogos é usada para determinar esta alocação. A carga controlável recebe parte do rendimento adicional para cobrir o aumento da sua conta da electricidade e para incentivar a sua coordenação com os geradores. Este estudo é em seguida estendido para incorporar sistemas de armazenamento de energia em vez de carga controlável, em coordenação com geradores não despacháveis.

Uma secção da rede de distribuição portuguesa é usada para validar a coordenação de produtores dispersos independentes e a coordenação de geradores e carga controlável. Quatro produtores dispersos independentes e um equivalente de carga estão ligados à rede. Alguns casos de potência de vento, preço da energia eléctrica e consumo da carga são considerados. Diferentes custos de operação dos geradores são analisados. Diferentes níveis de flexibilidade e de capacidade da carga são avaliados.

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List of Abbreviations and Acronyms

AC – Alternate current

AHP - Analytic hierarchy process

CHP – Combined heat and power

CIGRE - *Conseil International des Grands Réseaux Électriques* (in French), International Council on Large Electric Systems

CO_2 – Carbon dioxide

DG – Distributed generation

DNO – Distribution network operator

DSI – Demand-side integration

EU – European Union

FACTS – Flexible AC transmission system

FENIX – Flexible Electricity Network to Integrate the eXpected 'energy evolution'

HV – High voltage

LMP – Locational marginal pricing

MV – Medium voltage

OPF – Optimal power flow

PFSF – Power flow sensitivity factors

p.u. – per unit

OFGEM - Office of Gas and Electricity Markets

TNO – Transmission Network Operator

TU-game – Cooperative game with transferable utility

UK – United Kingdom

USA – United States of America

VAT – Value added tax

VPP – Virtual power plant

Chapter 1 - Introduction

1.1 - Scope of the research

The research carried out focuses on the way generators connect to distribution networks. Generation in distribution networks is designated in this research as "distributed generation", following the definition given in section 1.4.1. However, this research is expected to be applicable to other network voltage levels.

Large amounts of "fit-and-forget" connection of generation are expected in distribution networks. In this policy, one generator's effect is assumed to be limited and network voltages and currents are expected to remain acceptable at all times. This firm access connection policy limits the amount of generation capacity that can be connected. Increased difficulty to get permission to install new power system equipment (e.g, overhead lines) and the costs required are barriers to network capacity expansion [1-3]. Network capacity expansion is not considered in this research.

Permission to connect generation without firm access rights is generally obtained on the basis that when there is inadequate capacity in the system, the non-firm generators are constrained off on a "last-in, first-off" basis (i.e., the last to connect is the first to be affected). Different costs of operation and ability to be dispatched are not considered. Thus, the economic value of the generators is not maximised.

1.2 - Research questions

This research aims to address the following questions:

- Can independent distributed generators be operated in a coordinated manner so that all increase their income for selling electricity?
- Can the flexibility of the demand side be used to maximise the income of the generators?

1.3 - Objectives of the research

The following objectives are set to answer the research questions mentioned in section 1.2:

- Definition of a methodology to coordinate independent distributed generators:
    - The objective is to maximise the income of the generators for selling electricity;
- Integration of controllable load and energy storage systems in the coordination to allow the generators to maximise their production;
    - The flexibility of the demand side is aimed to allow the generators to maximise their income;
- Establishment of an income-sharing mechanism to share the income obtained in coordination, so both generators and demand have an economic incentive to participate.

The definition of distributed generation and the drivers for its increased connection are presented in section 1.4. The definition of demand-side integration and the drivers for its implementation are shown in section 1.5.

1.4 - Distributed generation

1.4.1 - Definition

The definition adopted in this research for distributed generation is the one described in [2] for “embedded or dispersed generation”. Distributed generation is defined as:

- Being non-centrally planned (i.e., not planned by the network operator);
- Being non-centrally dispatched;
- Having less than 100 MW of installed capacity;
- Being connected to the distribution system.

1.4.2 - Drivers for the increase of the connection of distributed generation

Connection of increased amounts of distributed generation is a result of technical/commercial, strategic/regulatory and environmental drivers [2, 3]:

<u>Technical/commercial drivers</u>

- Smaller periods of construction, lower capital expenditure and shorter amortisation periods, when compared to centralised generators;
- Possibility of modular projects;
  - New generators can be added to the project along time, e.g. according to the availability of capital;
- Low energy density in the case of renewable energy sources;
  - Renewable generators need to be smaller and geographically dispersed.
- Facility in finding sites for smaller generators;
- Connection closer to demand to reduce network and operation costs;
  - For instance, combined heat and power schemes require close location to heat load due to the cost of transporting heat. This leads to the construction of small generation units, geographically dispersed and connected to distribution networks.

<u>Strategic/regulatory drivers</u>

- Deregulation of electric power systems;
  - Modifications in the commercial structure of electric power systems;
  - Open access to distribution networks;
- National/international targets;
- The interest of some countries to diversify energy sources (energy security concerns).

<u>Environmental drivers</u>

- Effort to reduce the emission of greenhouse effect gases (mainly CO_2);
  - Many governments have programmes to support the utilisation of low-carbon energy resources for the production of electricity [4];

- Public opposition to the construction of centralised generators and over-head transmission circuits.

1.4.3 - Commercial incentives for the connection of distributed generation

Connection Feed-in Tariffs (FITs) and quota obligations (QO) are widely adopted forms of incentives to the connection of distributed generation (renewable and low carbon). FITs are price-based mechanisms while QO are volume-based mechanisms. FITs are in place in countries as Portugal and Germany. Some examples of QO schemes are the Renewable Obligation in the UK and the Renewable Portfolio Standard in the USA. Currently both approaches tend to be technology-specific, based on “bands”. Banding has been introduced to distinguish levels of support that renewable and low carbon generators receive based on their type of technology. This has been implemented to reflect differences across technologies such as those related to planning, implementation costs and level of maturity of technology [3].

Several applications of smart grid technologies in literature introduce dynamic price or price-related control signals in distribution systems [4]. A spot pricing algorithm in radial distribution systems that takes into account power flows and circuit constraints is proposed in [5]. Nodal pricing in distribution networks with DG based on the resolution of the economic dispatch problem is formulated in [6]. Locational Marginal Pricing (LMP) with system state prediction and load uncertainty simulation is presented in [7]. Cooperative game theory is used to determine the share of each DG in the reduction of the loss element of the LMP.

1.5 – Demand-side integration

1.5.1 - Definition

The term demand-side integration (DSI) was adopted at the CIGRE Paris Session 2006 to represent the technical area focused on the demand side and its potential as a source of supply [5]. DSI covers all activities focused on advanced end-use efficiency and effective electricity utilisation, in particular:

- Demand Response – mechanisms to manage the demand in response to supply conditions:
    - Peak clipping – reduction of peak demand especially when it approaches the thermal limits of feeders/transformers or the supply limits of the network;
    - Valley filling – introduction of load in off-peak periods in the form of energy storage;
    - Load shifting – movement of loads during the day to minimise the electricity bill;
    - Dynamic energy management – integrated approach that addresses permanent energy savings, permanent demand reductions and temporary peak load reductions;

- Energy efficiency – programmes to reduce the overall consumption of energy while maintaining user comfort or level of service;
- Strategic load growth – programmes to increase load in a strategic manner, e.g. to increase supply from low-carbon energy sources.

1.5.2 - Drivers for the increase in demand-side integration

The implementation of DSI is encouraged by technical/commercial, industrial, social and environmental drivers [1, 5]:

Technical/commercial drivers

- System reliability concerns due to increase in demand and increased difficulty to get permission for the installation of new power system equipment;
- Possibility of energy and cost savings for network operators through customer participation;
- Integration of non-dispatchable generation using the flexibility of the demand side.

Industrial drivers

- Increased availability of demand-side resources such as flexible loads, distributed generation and energy storage devices (including electric vehicles);
- Introduction of smart metering, that allows: i) the provision of signals to incentivise customer participation; ii) the implementation of advanced control actions. Considering two-way communication is available, smart meters allow the measurement, collection, analysis and management of customer energy use. This ultimately leads to increased load flexibility which can be used to meet the power system needs [1].

Social drivers

- Public opposition against capacity expansion to accommodate increased levels of demand;
- Public awareness to the possibility of meeting demand by combining grid-purchased electricity with onsite energy production. This allows customers to trade electricity produced onsite and increases flexibility of demand.

Environmental drivers

- Effort to decarbonise electric power and transport systems, which leads to:
    - the need for conservation and energy efficiency measures;
    - the integration of new electrical loads such as electric vehicles and heat pumps. This leads to an increase in demand.

1.6 - Thesis structure

The structure of this thesis is given in the following summary:

Chapter 2

Literature review on the integration of distributed generation is presented. The challenges of the “fit-and-forget” connection of distributed generation are identified. Contributions for the mitigation of its effects are reviewed. Research on the coordination of independent distributed generators is reported. Game theory is introduced to address the allocation of the additional income obtained by independent generators in coordination. An overview of demand-side integration is provided regarding: i) the mechanisms for its implementation; ii) its benefits to the integration of generation; iii) its benefits to the consumers.

Chapter 3

The limitations of the firm access connection policy are investigated. A representative of the distribution system of Northeast Portugal is used as an illustrative example. Distributed generation with different costs of operation and ability to be dispatched is considered. The technical possibility of connecting generation capacity above the limits defined by the firm access connection policy is introduced. The economic inefficiency of the operation of the distribution network is identified.

Chapter 4

The coordination of independent distributed generators is outlined. The aim is to maximise the income of generators for selling electricity. An income-sharing mechanism based on cooperative game theory is introduced to share the additional income obtained in coordination. The coordination of independent distributed generators is evaluated on a reduced version of the distribution network introduced in Chapter 3. The coordination is evaluated during a selected period of six days. This period consists of different cases of price of electrical energy, wind power and load consumption. Comparison against the non-coordinated operation of generators is provided. The effect of different costs of operation of the generators in the value of the coordination is evaluated. The willingness of the generators to participate in the coordination considering different allocations of the additional income is analysed.

Chapter 5

The coordination of distributed generators and controllable load is presented. The operation of the Aggregator considering the flexibility of controllable load is described. The aim of the coordination of generators and controllable load is to maximise the income of generators for selling electricity. An income-sharing mechanism to allocate the additional income to the generators and the controllable load is detailed. The coordination of generators and controllable load is evaluated on the reduced version of the distribution network. The same period of six days is used. Different load capacities and fractions of flexible consumption are analysed. Comparison against the non-coordinated operation of generators and controllable load is provided. Economic incentives to generators and controllable load for operating in a coordinated manner are quantified.

Chapter 6

The coordination of independent non-dispatchable generators and energy storage systems is presented. Energy storage systems are asked to change their schedule to allow generators to maximise their production. The operation of the Aggregator considering the connection of energy storage systems is described. Additional income is obtained from the coordination for the additional energy produced. This additional income is allocated to the generators and the energy storage systems using a bargaining approach of game theory. The coordination is evaluated on a two-busbar distribution network with two generators and an energy storage system connected. The evaluation is performed using a set of extreme cases of price of electrical energy and wind power. The impact on the additional income of different orders of connection to the network is analysed. Comparison against the non-coordinated operation of generators and energy storage systems is provided. Economic incentives to generators and energy storage system for operating in a coordinated manner are quantified. Then, the evaluation is extended to a year of operation to assess the impact on the additional income of different installed capacities of the energy storage system.

Chapter 7

The contribution of this research is presented. Conclusions are drawn, addressing: i) the limitations of the firm access connection policy; ii) the coordination of independent distributed generators; iii) the coordination of generators and controllable load; iv) the coordination of non-dispatchable generators and energy storage systems. Suggestions for extending the work carried out in this research are provided.

Appendices

In Appendix A are presented the cost-benefit analyses behind the determination of the ratings of generators connected without firm access rights. In Appendix B are provided details of the AC optimal power flow (OPF) carried out in the representative of the Portuguese MV distribution network introduced in Chapter 3. Details of the six days of operation used to validate the coordination of independent distributed generators and the coordination of distributed generators and controllable load are given in Appendix C. Results of the implementation of the coordination of independent distributed generators to each of the six days of operation are provided in Appendix D. Results of the implementation of the coordination of distributed generators and controllable load to each of the six days of operation are provided in Appendix E.

1.7 - Publications during the research

Directly related with the research

J. A. Barros, H. Leite, "Coordinating Independent Non-Dispatchable Generation and Energy Storage Systems," International Journal of Electrical Power & Energy Systems, accepted for future publication in April 2014.

J. A. Barros, H. Leite and N. Jenkins, “Coordinating Independent Distributed Generators”, *in 3rd IEEE PES Innovative Smart Grid Technologies Conference*, *2012 ISGT Europe,* Berlin, 14 – 17 October 2012.

J. Barros and H. Leite, “Feed-In Tariffs for Wind Energy in Portugal: Current Status and Prospective Future”, *in 11th International Conference on Electrical Power Quality and Utilization*, *IEEE EPQU 2011,* Lisbon, 17 – 19 October 2011.

Collateral work

J. Carvalhosa, **J. Barros**, H. Leite, A. Barbosa, P. Pereira and P. Alves, “Technical and Economic Impacts of the 2010's Grid Code Requirements for Wind Energy in Portugal”, *in 11th International Conference on Electrical Power Quality and Utilization*, *IEEE EPQU 2011*, Lisbon, 17 – 19 October 2011.

H. Leite, **J. Barros**, V. Miranda and R. Fiteiro, “Application of a Methodology based on the Evolutionary Particle Swarm Optimization to Protection Coordination”, *in 21st International Conference and Exhibition on Electricity Distribution*, *CIRED 2011,* Frankfurt, 6 – 9 June 2011.

H. Leite, **J. Barros**, and V. Miranda, "The Evolutionary Algorithm EPSO to Coordinate Directional Overcurrent Relays," *in 10th International Conference on Developments in Power System Protection*, *IET DPSP 2010,* Manchester, 29 March – 1 April 2010.

H. Leite, **J. Barros**, and V. Miranda, "Evolutionary Algorithm EPSO Helping Doubly Fed Induction Generator with Ride-Through-Fault," *in International Conference on Power Systems, IEEE PowerTech 2009,* Bucharest, 28 June – 2 July 2009.

Chapter 2 - Background and literature review

2.1 - Introduction

An overview of the challenges to the connection of distributed generation is given in this chapter. Contributions to facilitate the integration of increased amounts of distributed generation are reviewed. Particular attention is paid to the coordination of independent distributed generation. Game theory is presented as a tool to encourage independent generators to be coordinated. The potential of demand-side integration to allow the integration of additional amounts of distributed generation is analysed.

2.2 - Integration of Distributed Generation

Distribution networks were traditionally designed to accept bulk power from the transmission network and to distribute it to consumers. Power flows were considered to be unidirectional, from the higher to the lower voltage levels. However, with increasing penetration of distributed generation (DG) power flows may become reversed. DG is operated on a must-run basis due to environmental, commercial and political drivers [2-4]. Increasing levels of "fit-and-forget" connection of DG are expected in distribution networks. The challenges introduced by the "fit-and-forget" connection of generation are identified in section 2.2.1. Contributions to integrate DG are covered in sections 2.2.2 and 2.3.

2.2.1 - Challenges to the connection of additional amounts of distributed generation

Concerns with the "fit-and-forget" connection of DG include [6, 7]:

- voltage regulation;
- thermal limits of lines and transformers;
- effect on network losses;
- behaviour of DG in the case of network perturbations ("survival" to voltage dips);
- higher need of balancing and reserve services;
- increased harmonic distortion;
- network protection issues:
    - modifications in network short-circuit levels;
    - modifications in fault current profiles;
    - impact on fault location and clearing practices;

Many DG schemes are connected in rural zones (with low demand). There are voltage constraints that limit the amount of DG capacity that can be connected [8]. Traditional line drop compensation techniques lose their effectiveness with the connection of DG.

The value of losses in each node depends of the penetration level of DG. Typically, losses decrease with low DG penetration levels. However, after a certain penetration level they start to increase [9].

Many DG schemes are based on intermittent energy sources (e.g., wind and photovoltaic). The massive connection of these DG schemes introduces an increased demand for balancing and reserve provision services from the transmission networks [10]. A methodology to identify the appropriate level of reserves and their cost in a power system with high penetration of wind power is presented in [11]. Performance metrics are used to clarify conflicting economic effects of wind power penetration: fuel cost reduction and reserve cost increase. It is reported that reserve costs vary significantly due to wind power uncertainty.

Thus, the “fit-and-forget” connection of further DG will be technically limited in the near future. The installed capacity of new DG schemes will be limited by this firm access connection policy. The amount of energy exported will be constrained. On the point of view of network operators, quality of supply may be affected. An increase in network operation costs is expected. Therefore, the value of DG may be reduced if no changes are made to the planning and operation of distribution networks.

Network reinforcement programmes are underway in many countries to allow the massive connection of DG [12]. However, in other countries regulation and economic reasons are likely to prevent network reinforcement to be effective in the timely connection of greater amounts of generation. For instance, in Great Britain energy regulator OFGEM only allows for generator-driven investment when there is contracted generation requiring connection [13]. Thus, Distribution and Transmission Network Operators (DNOs and TNOs, respectively) in Great Britain cannot invest ahead of need under the current regulatory framework. In addition, there is currently a “£200/kW installed” cost cap on socialised investment in any upgrade to the distribution network. This means that large upgrades to DNO’s assets to connect generation, which might benefit the DNO and the customers in the long term, should be financed in great part by the generator [13]. This is likely to impact the economic return of prospective generation projects at distribution level and deter the connection of new generation.

On the other hand, contributions are being presented to integrate DG without considering such reinforcements. These contributions aim to mitigate the issues related with the “fit-and-forget” connection of DG and allow the integration of additional generation capacity [14-16].

2.2.2 - Contributions to the integration of distributed generation

An overview of the contributions to allow the integration of additional generation capacity is provided as follows.

<u>Voltage coordination by voltage changing devices and DG</u>

- When a DG scheme is connected, its active power export reduces the power flow from the primary substation and so it reduces the voltage drop along the feeder. If the power export from the DG is larger than the feeder load, the power flows from the DG to the primary substation and this causes a voltage rise between the primary substation and the generator [2];

- Several publications address the coordination between on-load tap changers, capacitor and inductor banks, FACTS (flexible AC transmission systems) and DG (active and reactive power flow) towards the regulation of network voltage profiles [17-19];
- By controlling distribution network voltage profiles it is possible to integrate increased capacity of DG.

Provision of ancillary services by DG

- Depending on their generation technology, DG schemes may supply several ancillary services to Distribution Network Operators (DNOs). The provision of ancillary services to DNOs by DG can lead to a more economically efficient power system [20];
- These DNO ancillary services include power balance, local voltage and reactive power support, mitigation of losses, congestion management and black start (power system restoration after a fault) [21, 22];
- More flexible operation of DG according to network price signals can save investment or delay network reinforcement [23];
- Operation schemes for DG to mitigate fast voltage fluctuations, voltage dips and harmonic distortion are addressed in [24].
- A global restoration procedure for a power system with the participation of DG is presented in [22]. The procedure allows DG schemes with black start capability to accelerate network re-energising, restoring clients faster than in the conventional procedure. The results obtained show an increased performance of the restoration procedure with the contribution of DG compared with the base case (where no DG is directly involved). No commercial mechanisms to reward this participation are presented;
- Different levels of participation of DG in the provision of ancillary services can be found in Europe. In most European countries, there is little contribution of DG to network ancillary services [23]. Current contributions of DG are: to keep their power factors within certain ranges, and; through aggregators, to participate in the balancing market or provide reserves.

New Regulatory frameworks / Grid Codes

- The establishment of commercial arrangements between DNOs and DG to recognize the contribution of DG to network efficiency are being sought in some countries [23]:
    - Regulated payments to the owners of DG schemes (e.g. reflected in use-of-system tariff charges).
    - Bilateral contracts between DG and DNOs.

    - Participation of DG in the markets: (i) energy balancing and reserve markets; and (ii) network related markets, such as local balancing, reactive power, congestion management and energy losses compensation;
- The importance of shifting the current EU prohibition (European Directive 2003/54/EC) of DG ownership by DNOs is addressed in [25, 26];
- This rule was designed to avoid that a DNO favours with a generation business within the same group. This may lead to a lack of integration between network and generation planning. The importance of allowing DNOs to deploy DG in well-defined circumstances is highlighted in [25]. These circumstances include: if deploying DG at specific network locations is more economically favourable than investing in network infrastructure; when overall network efficiency can be improved (e.g., by reducing losses) without altering market competitiveness. Other approach to consider the ownership of DG by DNOs is to adapt a USA regulatory approach that introduces an obligation for DNOs to acquire DG. This is put to DNOs as an alternative to network reinforcement [25].
- The creation of carbon taxes is proposed as a form of promoting the integration of renewable DG [27]. A carbon tax addresses the carbon content of fuels used for energy production. Carbon taxes might increase the competitiveness of renewable DG when compared to conventional generation. However, this consideration depends on the price and market context of each country [27].

<u>Modifications in the structure of electricity markets</u>

- The creation of wholesale electricity markets introduced a competitive framework for the appearance of new players in the electricity sector (as new generators and retailers). These markets appeared as a result of a deregulation process that aimed to [28]:
    - provide better incentives for controlling capital and operating costs of new and existing generating capacity;
    - encourage innovation in power supply technologies, and;
    - shift the risks of technology choice, construction cost and operating inefficiencies from consumers to suppliers.
- Existing electricity markets have been operated in various arrangements, such as electricity pools or bilateral contracts. Electricity pools enable competition in generation as they allow a merit order on the dispatch of generation. They also facilitate the mechanisms to support competition in supply where customers can freely choose their supplier. On bilateral trading, customers have the opportunity to negotiate the best energy price from suppliers and generators without being constrained by any official price [28];
- Alterations in the electricity market design to enable the integration of further amounts of wind power are presented in [29, 30]:
    - Creation of “faster markets” (intraday schedule of generators);

        - May reduce costs with reserves, forecasting and increase revenues for wind power producers as they are able to make more accurate bids;
    - Implementation of broader-area markets;
        - Cooperation between control areas to:
            - reduce the effect of wind intermittency;
            - stabilise prices within control areas, regulating power flows.
    - Widespread application of implicit auctioning to allocate cross-border power capacity [29];
        - To promote the efficient use of interconnectors of neighbouring countries:
            - by means of mechanisms such as market coupling and market splitting;
- A market interface for the participation of DG in wholesale electricity markets is presented in [31]. DG is interfaced as an "Equivalent Power Producer" on a pool-based market. Changes to spot price computation and capacity payments are described. A mechanism to mitigate the volatility of spot prices due to the integration of DG is introduced. The market interface is evaluated on the Chilean electricity market.

<u>Islanded operation of distribution networks</u>

- Considering network islanding operation is allowed, DG may find attractive economic opportunities [32, 33]:
    - Important loads (e.g., large consumers) may be maintained in service by DG;
    - Financial penalties for DNOs due to consumer interruptions and network unavailability may be reduced;
    - DG may be able to continue to sell energy during islanding;
- Maintaining in service important loads is addressed in a number of publications:
    - A load shedding optimisation problem is formulated in [34]. The objective is to minimise the cost of load shedding after a disturbance. The optimisation problem is non-linear. Load priorities are pre-set offline and do not vary with changes in network operating conditions;
    - A load shedding scheme based on a dynamic priority list is presented in [32]. The dynamic priority list is determined using the real-time decision making technique AHP (Analytic Hierarchy Process).

<u>Non-firm access to the networks</u>

- Network operators may allow the connection of generation without firm access rights – non-firm access to the networks [35-37];
- Non-firm access to the networks is aimed to allow generation to be connected in advance of necessary reinforcement works to remove a network constraint (such as circuit capacity limits, static or dynamic as

presented in [38]). However, on occasions the output of the generators with non-firm access may need to be curtailed;

- Non-firm access to the networks implies the usage of one or more of the following strategies when there is inadequate capacity in the system [39, 40]:
    - Power curtailment;
    - Coordinated Voltage Control;
    - Adaptive power factors for DG power plants;
    - Local reactive power compensation;
- Power curtailment is generally associated with the partial or full reduction of the generator output in case of network constraints.
- Contributions presenting power curtailment as a way to integrate further amounts of generation have been presented [36, 40-42];
- Curtailment of active power to increase reactive power injection in distribution networks in proposed in [41, 42]. Results show that reactive power compensation increases the amount of generation that can be connected, especially in networks with a high reactance to resistance ratio. Active power curtailment reduces the income of the generators;
- An online AC Optimal Power Flow algorithm to manage the power flows of DG when network voltage or current limits are exceeded is presented in [40]. "Last-in, first-off" power curtailment is included in the formulation.
- Financial and technical impacts of the connection of further amounts of DG considering different connection policies are demonstrated in [36]. Three connection policies are considered: firm connection policy, non-firm connection policy and the "first firm then non-firm" connection policy. Five sections of the 38 kV distribution network of Ireland are used to evaluate the potential benefits of each connection policy. An optimisation procedure is presented with the objective of maximising the energy delivered per unit of investment. Capital, operation, maintenance, connection, reserve and cycling costs are considered. Significant differences in DG scheduling are reported along a year depending on the connection policy. Differences are observed also in cycling costs, emission benefits and fuel usage. The non-firm connection policy presents a greater net benefit for the case study and optimisation methodology described.
- The commercial rules for allocating curtailed capacity supported by active management solutions have been designated as "Principles of Access" (POAs), following a paper from Currie et al. [43]. Such active management solutions adjust the amount and frequency of curtailment in order to provide system reliability, minimise social costs and attract DG investment. These Principles of Access are expected to promote [44, 45]:
    - Cost effectiveness - for both generators and distribution network operators;

    - Network efficiency - maximise the amount of generation that can be economically connected in any constrained zone and promote efficient network operation;
    - Certainty - provide each generator with certainty as to the long term level of curtailment;
    - Simplicity - methodology should be easy to implement and understand;
    - Fairness - be equitable in its allocation of curtailment costs between generators;
- Different Principles of Access (POAs) establish differently physical curtailment and financial payment rules. The way curtailment is allocated will influence the distribution of risks among parties (DNOs, generators and consumers);
- The following Principles of Access are being trialled and implemented internationally to regulate the access to distribution network capacity when non-firm access is permitted [43, 44, 46]:
    - *Last-in, first-off (LIFO)*: generators are given a specific order for being curtailed (normally based on the date of application for connection or date of connection). The last on the list (based on the ranking) is the first to be disconnected under a network constraint.
    - *Pro Rata*, equal percentage basis or shared percentage: curtailment is equally allocated between all generators that contribute to the constraint. The amount of curtailment can be computed as a percentage of available capacity, installed capacity, or other ratio.
    - *Market-based approaches*: generators bid for curtailment by offering a price based on market mechanisms.
- Figures 2.1 to 2.3 illustrate these Principles of Access. Only generators without firm access rights are shown. The dotted line in Figures 2.1 and 2.2 refers to a generic capacity factor below which the generators are not willing to accept further curtailment. This is related to the savings made by the generators for connecting without firm access rights (and therefore not paying for network reinforcements to obtain firm access rights).

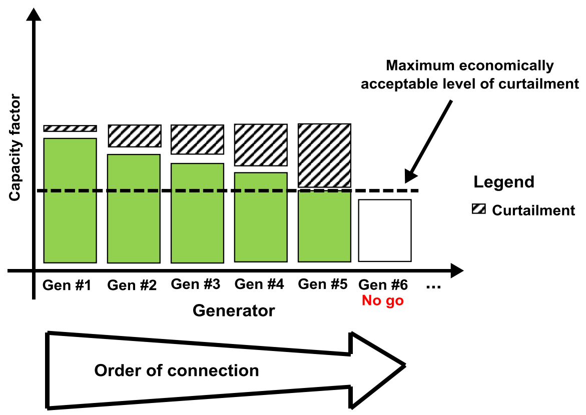

Figure 2.1 - “Last-in, first-off” access (based on [44])

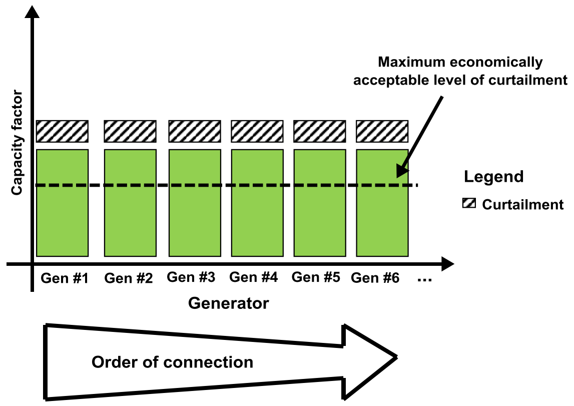

Figure 2.2 - Pro-rata access (based on [44])

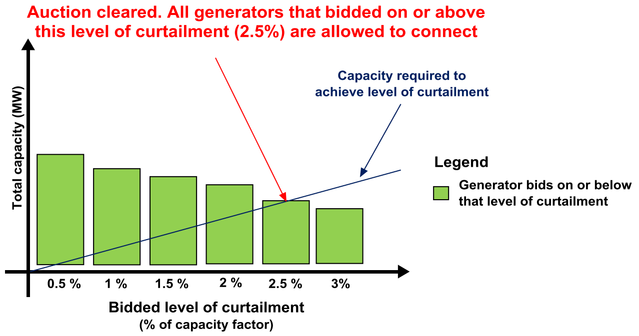

Figure 2.3 - One form of market-based access: capacity auction (based on [44])

These Principles of Access are described with more detail as follows.

- Last-in, first-off (LIFO) access

The “last-in, first-off” (LIFO) approach prioritises the access of generators to the networks on the basis of their order of connection. It aims to ensure that no generator can be adversely affected by the arrival of new generators. Therefore, the latest generator to connect (having non-firm access rights) is the first to be curtailed.

LIFO offers a simple and transparent allocation. In addition, it does not need major technological changes in order to be applied [43]. However, this option does not necessarily incentivise nor support the connection of new and more efficient generation. This is due to the fact that the new generation is taken off first than older generation, which may have already repaid their initial investment [45]. Additionally, it does not take into account different abilities of generators to be dispatched. This way, non-dispatchable generation may be taken off first and see its production lost. The economic value of generators is also not taken into account, as generators with lower costs of operation will be curtailed first if they were the last to be connected.

The risk allocation of being curtailed is transferred to the marginal generator (the last generator is the first to be curtailed in case of constraints). Under current commercial arrangements e.g. in the Great Britain, compensation to curtailed generators is not regulated and hence cannot be passed back to customers. This is opposed to the arrangements at the transmission level, where generators may be able to recover losses with curtailment through use of system charges [47].

LIFO has been applied in the Orkney Isles Project in the UK by DNO Scottish and Southern Energy Power Distribution (SSEPD). It also serves as baseline for pilot projects on the active management of distribution networks in the UK, supported by DNOs and the Regulator under the Low Carbon Networks Fund (e.g., UK Power Networks – Flexible Plug and Play project; Scottish Power – Aura-NMS project) [48].

The distribution network in Orkney is connected to the Scottish mainland via two 50 km 33kV submarine cable circuits with capacities of 20 MVA and 30 MVA. Gas, wind and wave energy generators with either firm or non-firm access rights are currently connected to this network. The DNO controls the electricity output of the generators in real time in order to match the available capacity using the LIFO principle. Generation is actively managed based on the N-1 subsea circuit capacity limit (20 MVA) plus the maximum demand on the network.

- Pro Rata access

Under a Pro Rata approach, generators are equally curtailed regardless of their order of connection when a constraint occurs. Thus, the risk is transferred equitably among generators, reducing the risk to the last generator (when compared to LIFO access). However, the last generator may be cross-subsidised by not being exposed to the curtailment costs it imposes on all generators behind the constraint. This could mean that an excessive amount of generation may connect behind a constraint when compared with the “social optimum”. The “social optimum” is obtained when the marginal connection cost of an additional unit of capacity is equal to its marginal benefit (e.g., the value of the energy produced) [45].

Pro Rata curtailment for wind generators has been recently proposed by the Single Electricity Market operator (SEM) for Ireland and Northern Ireland. It is also being applied by network operator Southern California Edison (United States) in specific conditions such as planned outages for maintenance purposes. The Federal Energy Regulatory Commission (FERC, United States) supports Pro Rata as a non-discriminatory approach to the curtailment of non-firm connections [49].

The Single Electricity Market (SEM) operator has proposed the use of Pro Rata (with defined curtailment limits) as replacement of a LIFO approach. Wind generator curtailment is only considered after other solutions involving conventional generation are exhausted.

Distribution network operator UK Power Networks is currently trialling a Principle of Access to the networks based on Pro Rata access called Reinforcement Quota [44]. This trial is part of a project entitled "Flexible Plug & Play", funded by the regulator OFGEM under the Low Carbon Networks Fund. The project aims to provide cheaper and faster connections to generators connecting to the networks operated by UK Power Networks. Under Reinforcement Quota, the network operator determines for each constrained section of the network a reinforcement trigger above which the cost of curtailment (i.e., loss of income of generators as a result of curtailment) exceeds the cost of reinforcing that section. When this trigger is achieved, network reinforcement is actioned being the costs apportioned pro rata to the non-firm connected generators. These non-firm generators receive in return firm access rights to the network.

Generators with non-firm access rights are allowed to connect under a Reinforcement Quota approach unless the quota or the reinforcement trigger presents "unacceptably high" curtailment levels [44]. This curtailment level limit is being refined with stakeholders, taking into account factors as capital costs, capacity factors and required rate of return/capital structures. If curtailment levels following a number of generation applications are above acceptable, the DNO analyses the case for strategic investment in the area to reduce the worst case curtailment level to the maximum acceptable level. Factors taken into consideration include the local availability of primary resources and the number of pending connection requests. If business case for reinforcement is identified, it is carried out and costs are apportioned to the non-firm generators once the Reinforcement Quota is full and the reinforcement trigger is met. If no business case for reinforcement is identified, the existing network capacity is auctioned to the highest bidding generators willing to connect to that network section.

Reinforcement Quota allows the DNO to set the quota and reinforcement trigger without having to consider the internal economics of different generators. Reinforcement Quota also allows a coordinated and overall cheaper connection solution for generators (when compared to the "fit-and-forget" policy) minimizing network investment ahead of need.

One of the limitations of the Reinforcement Quota is that its viability varies with the particulars of the network and the cost and nature of the possible reinforcement solution. Other limitation is that generators will be required to pay a deferred connection charge which could create financing challenges. Furthermore, this connection charge will not be applied if the reinforcement trigger is never met. So a generator is left with the uncertainty of putting in place a contingent amount of cash that may not be necessary (but that increases its financing costs).

- Market-based access

Marked-based approaches explore financial contracts and/or the performance of individual generators [45].

In a market-based approach, the risk is transferred to the generator that bids (for being curtailed) and whose offer is accepted. This has the advantage of allowing generators to accept curtailment according to their costs of doing so, encouraging generator investment in flexibility. If market conditions are ideal, the selected generator to be curtailed is the one with the lowest bid price. Nevertheless, it may not always be possible to select cost-effective bidders if low competition between bidders behind individual constraints is identified. In addition to this, the size of generators is also relevant, as transaction costs for small generators may be an issue. The administrative burden for a DNO to set up a bidding mechanism may also be a source of difficulty.

A market-based approach has been implemented under the “Connect and Manage” approach used in Great Britain. “Connect and Manage” has been created by National Grid (transmission system operator for England and Wales) in 2010 to address network reinforcement [44]. This was triggered by the large number of renewable generation connection applications. The “Connect and Manage” scheme considers the connection of distributed generation to the transmission or distribution system. Distributed generation refers here to those generators that are large enough to have or are considered to have a significant impact on the transmission system [44]. Under “Connect and Manage”, generators get firm access rights to the network before necessary major reinforcements works are put in place. In the meantime, generators may have to be curtailed. For such, National Grid allocates curtailment using a market-based scheme called Balancing Mechanism. The Balancing Mechanism enables supply and demand to be balanced across the electricity transmission system whilst resolving system constraints. The network operator tries to find the most cost-effective offers for balancing the system taking into account diversity of supply in order to maintain system reliability. Bids are in general accepted in cost order, but dynamic limitations communicated by the bidder and specific geographical conditions may prevent this. Compensation for curtailment costs is recovered via Balancing Services Use of System charges. Generators are not required to participate in the Balancing Mechanism and are not subject to any limitation in the prices they may offer to be curtailed. Generators that do not participate in the Balancing Mechanism can have a bilateral contract with the network operator for providing balancing services. The costs associated with these actions are also transferred to transmission users via Balancing Services Use of System charges.

“Connect and Manage” has demonstrated significant reduction in the waiting time for connecting to the transmission network. The implementation of this approach accelerates the granting of firm access rights to the network. However, this approach cannot be currently implemented in distribution networks in Great Britain due to differences in the regulatory principles affecting connection charging. The risk of network reinforcements is generally transferred to the generators when an upgrade to the distribution network is required, whereas in the transmission network these costs may be socialised via transmission networks use of system charges. Also, compensation for curtailment at distribution level is not regulated and hence cannot be passed back to the users of the system. At transmission level curtailment costs may be recovered through the Balancing Mechanism via Balancing Services Use of System charges. In addition, when the number of generators behind an individual constraint is small, the network operator may not be able to select cost-effective bidders. The network operator may be obliged to pay very high prices to generators for them to accept curtailment. These payments do not necessarily reflect the subsidies that generators receive (such as Renewable Obligations or Feed-in Tariffs) and are ultimately passed to the users of the system.

Summary of the contributions reviewed

A summary of the contributions to the integration of DG reviewed is presented in Table 2.1. Main objective(s) and direct involvement of DG in the contributions are shown.

The coordination of independent distributed generators is reviewed in section 2.3. The coordination operates generators to fulfil network operation objectives (e.g., voltage regulation) and/or commercial objectives (e.g., maximisation of the income of the generators).

Table 2.1 – Summary of the contributions to the integration of DG

Contribution	Main objective(s)	Direct involvement of DG
Voltage coordination by voltage changing devices and DG	• Regulate network voltages to increase the connection capacity of DG;	Yes
Provision of ancillary services by DG	• Improve network operation; • Reduce network operation costs;	Yes
New Regulatory frameworks / Grid Codes	• Implement technical and commercial arrangements to increase the value of DG;	No
Modifications in the structure of electricity markets	• Increase production from DG; • Allow the participation of DG in electricity markets;	No
Islanded operation of distribution networks	• Reduce network outage times; • Increase production from DG;	Yes
Non-firm access to the networks	• Allow the integration of increased capacities of DG; • Increase production from DG; • Reduce time and cost required for connection.	Yes

2.3 - Coordination of independent distributed generators

Contributions that address the coordination of independent DG may be divided in three categories:

- Planning and economic assessment: techno-economic analyses of the value of coordinating DG;
- Network operator-driven coordination: planning and operation determined by network operators to address network operation objectives;
- Market-driven coordination: market-based solutions to increase the income of the owners of DG schemes.

2.3.1 - Planning and economic assessment

The use of biodiesel DG for providing balancing services in the case of shortfall in wind power production is introduced in [50]. This possibility is assessed against: spinning reserve provision; hydro storage and standing reserve provision. The choice of biodiesel DG supporting wind power is supported by its small scale (50 kW to 5 MW installed capacity) and fast synchronisation times (less than a minute). The Northern Irish power system is used to demonstrate the environmental and financial benefits of the methodology. Extreme wind power scenarios are considered. Results of one month of operation demonstrate fast response to wind power fluctuations. The use of remotely controlled biodiesel DG reduced system operational fuel costs in the practical example analysed.

An overall strategy for the planning and operation of non-firm connected DG is given in [37]. The probability of occurrence of critical network operating points that affect the connection of non-firm connected DG is assessed. Voltage sensitivity factors are calculated across the distribution network for such. The financial risk to the owners of the DG schemes is quantified. A minimum cost curtailment method based on the coordination of DG and the usage of voltage sensitivity factors is introduced. The ability of certain DG schemes to be dispatched is utilised to enable this minimum cost curtailment. A rural section of the Irish 38 kV distribution network is used to validate the methodology. DG availability and load profile data are obtained from one year of historical data.

Multi-period optimal power flow (OPF) procedures to evaluate the maximum possible penetration of non-dispatchable DG capacity are presented in [39, 51]. Non-firm access to the networks is allowed. The following strategies to integrate DG are included: coordinated voltage control, adaptive power factors and generation curtailment. The results obtained are compared against the “last-in, first-off” connection of DG on a 33 kV distribution network of the UK. Coincident data of load and wind power over a year of operation is available. The installed capacity of DG increases significantly with the use of the strategies to integrate DG. An increase in losses is observed due to the integration of newer DG power plants.

A methodology to coordinate the approval and integration of new independent DG is introduced in [52]. The objective is to maximise the connection of generation while complying with network voltage and current limits. The income of the owners of DG is maximised taking into consideration different generation sites, sizes, commissioning dates and production schedules. Then, the generator sizes and production schedules are forwarded to the network operator. In turn, network operators run optimal power flow studies with the data provided. When excesses in network voltages occur, the methodology runs a “Domains and Commons Module”, which determines the contribution of each generator to these excesses. An “Output Reduction Module” determines the generation curtailment required by means of an optimisation algorithm. Generators are ultimately offered firm access rights of connection. The methodology is evaluated on a 32-bus radial distribution network, on a 5-year planning time horizon. Four independent generators ask permission to connect to the network, all having different technologies. An increased global income for DG is demonstrated. Reduction in the energy import from the interconnections, improvements in voltage regulation and reduction of losses are also reported.

2.3.2 - Network operator-driven coordination

The concept of delegated dispatch is introduced in [53]. Delegated dispatches are control centres designed to operate on behalf of network operators when critical network operating points occur (such as network voltage issues and congestion). A delegated dispatch includes DG with different ability to be dispatched (wind-based generation, small hydro, photovoltaic, and others) in a certain region of the system. When corrective actions are needed, the system operator communicates them to the delegated dispatches. In this paper, only wind generation is considered to be available. Both active and reactive power commands are considered. Wind DG is divided in three groups, each representing different capabilities to control active and reactive power outputs.

A delegated dispatch is formulated as a nonlinear optimisation algorithm. The global income of wind generators is maximised on a market environment subject to the restrictions issued by the system operator. A section of the Spanish distribution network is used to validate the methodology. The price of electricity (feed-in tariffs, bilateral contracts) is already determined by the time of running of the delegated dispatch. Each delegated dispatch covers the entire distribution network below the interconnection with the transmission network. An operation time step of 15 minutes is considered between the communication by the network operator and the corrective action performed by the delegated dispatches.

A centralised control system to manage active and reactive powers produced by wind and diesel generators and set transformer taps online is presented in [54]. The objective is to minimise total network costs. Network voltage stability constraints are considered. The control system is designed to have near real-time operation. No commercial arrangements are considered to promote the coordinated operation of the generators.

Real-time thermal constraint management using DG is addressed in [55]. The output powers of DG are set with the objective of minimising the power curtailment required to meet static network current limits. Two techniques are evaluated: a constraint programming algorithm and a current tracing algorithm. The constraint programming algorithm consists in “shaping” the desired solution using a backtrack approach. The solution obtained satisfies the order of connection of the generators and load flow constraints. The current tracing algorithm is an upstream search procedure that tracks the usage of the constrained line by each DG scheme. Based on the tracing obtained, the output power of each DG scheme is set in proportion until line thermal limits are met. This algorithm does not consider the order of connection of the generators. Both techniques are applied to a distribution network. Computational times are suitable for real-time implementation. The current tracing algorithm presents a smaller amount of power curtailed and a faster performance.

An optimal power flow algorithm is introduced in [56] as an alternative to the constraint programming-based and current tracing algorithms described in [55]. The optimal power flow algorithm considers the order of connection of the generators.

The coordination of the output powers of DG when network congestion occurs is detailed in [57]. Three possible strategies based on the evaluation of network power flow sensitivity factors (PFSFs) are presented. PFSFs measure the change in network voltages and angles with marginal changes in the injection of active and reactive power. PFSFs are used to evaluate the impact of power injection in each busbar to network congestion. Variable thermal ratings are considered for the transmission/distribution lines. Thermal state estimation is used in areas where no real-time thermal rating control systems are available. The three strategies to schedule the generators are: “last-in, first-off” approach based on PFSFs; an equalitarian approach, that determines the schedule of the generators based on a weighted proportion of PFSFs; and a “technically most appropriate” approach, which ranks generators by their PFSFs and actuates when necessary according to that ranking. The three strategies are compared against “last-in, first-off” operation of the generators, considering static thermal limits of the lines.

The comparison of strategies is performed considering the annual energy income, network losses and voltage profiles. Costs of real-time thermal rating equipment and communication facilities are considered. Reactive power is assumed to be constant during the year of simulation. The time step between measurements is 30 minutes. Net present values and profitability indexes of each strategy for each generator are presented. The control actions are implemented by a rule-based inference system. This system collects all information regarding power flows, meter data and constraint limits. The system also sets, at every time step, the commands to be sent to the DG schemes. For computation efficiency, PFSFs are pre-calculated being collected in real-time from a look-up table. Results show an increase in the aggregated amount of energy produced using any of the three strategies. However, the authors stress the need to devise commercial arrangements to promote the use of the methodology.

2.3.3 - Market-driven coordination

A virtual power plant (VPP) is an infrastructure that aggregates distributed energy resources (generation and demand) to address technical and commercial operation objectives, see Figure 2.4 [58].

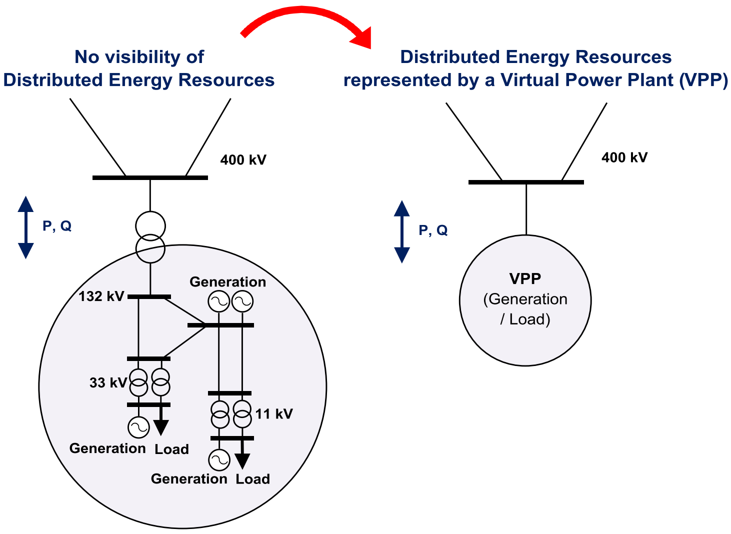

Figure 2.4 - The concept of virtual power plant [58]

The VPP is controlled centrally by an operator or aggregator. A review of the concepts of virtual power plant and virtual utility is presented in [59]. VPP is defined as a "new model of energy infrastructure which consists of integrating different kind of DG in an energy (electricity and heat) generation network controlled by a central energy management system" [59]. The FENIX project [58] was a European Union (EU) project to develop the concept of VPP. The aim was "to conceptualise, design and demonstrate a technical architecture and commercial framework for enabling DG to become the solution for the future cost efficient, secure and sustainable EU electricity supply system" [58]. The FENIX Project produced three main outcomes:

- FENIX Box server, which serves to aggregate demand and generation and ensure their operation according the optimisation model;
- Commercial VPP server, that schedules and provides energy optimisation functions for the DG;
- Technical VPP in the distribution management system server, that validates the generation schedules taking into account network voltages and currents.

A number of contributions address the mitigation of power imbalances of wind generation using the coordination of generation on a market environment [60-63]. A combined bidding and operating market strategy for hydro and wind generation is presented in [62]. Hydro generation is used to minimise imbalance penalties of wind generation in day-ahead markets. The objective is to maximise the total income for selling electricity. The generators are owned by the same producer.

The coordinated operation of wind and thermal generators to reduce the risk of wind imbalance penalties is presented in [63]. The objective function is to maximise the total expected income subject to the trading risk attitude of the owner of the generators. Generators are assumed to be owned by the same producer. Uncertainty of wind power outputs, energy prices and imbalance prices is considered. Traded energy volumes are lower with risk-averse bidding. This is because wind generators reduce their bids to avoid under-generation penalties and thermal generators do not produce to avoid periods of lower income.

The utilisation of water storage to increase the penetration of wind generation is presented in [64]. Water storage is controlled to smooth wind power fluctuations and maximise the wind-hydro global income for selling active power. A day-ahead hourly discretised optimization algorithm sets the schedule of both wind generators and hydraulic pumping. Generators may be owned by the same producer. Inputs are the wind power forecast, the estimation of price of electricity and the boundaries of the desired aggregated power profile. Wind power forecast is a stochastic quantity given by two series of hourly values: wind power average values and its standard deviation magnitude. The forecasting error is incorporated in the model by means of a neuro-fuzzy methodology. The estimation of price of electricity is made considering the feed-in tariff system in Portugal. The boundaries of the desired aggregated power profile are set by the network operator. The methodology runs a number of Monte Carlo simulations to collect different cases of available wind power for the next operating day. The optimisation algorithm is then run for each case of available wind power. The optimal wind-hydro dispatch is a “band” of possible solutions.

A day-ahead planning algorithm for a multi-reservoir hydro system coordinated with wind power is developed in [60]. The objective is to minimise wind energy curtailment. Wind and hydro generators are owned by different producers. Hydro generators have priority access to the network. Uncertainty of wind power outputs and market prices is considered. It is assumed that the hydro generators are paid for reducing power production to allow wind generators to produce. The price paid to the hydro generators for the coordination service is agreed beforehand by the generators. This price is based on average annual economic losses of the wind generators due to curtailment, based on historical data. Results show that both wind and hydro generators receive a greater income if they coordinate their output powers.

Coordination of independent generators to maximise the income of the generators is presented in [61]. Wind and hydro generators are connected to different feeders but sharing the same grid connecting point. Wind generators are connected without firm access rights. The methodology is set on the day-ahead market. The storage capacity of the hydro generation is used to define a joint power schedule for the next day of operation (24 market periods of one hour). Penalisations for over/underproduction of the generators are included. A seven-day time span is considered to account with basin management constraints. Uncertainties in both prices and wind speeds are incorporated. Results show an increase in global electricity selling revenues. The extra income obtained by the coordination is shared by the generators using the Shapley Value (game theory approach). Shapley Value is an approach for the allocation of gains obtained in coalition and recognises the contribution of each player to these gains. Each generator receives a greater income in comparison to what they would have received without coordination. The methodology is validated on the Swedish transmission network.

2.3.4 - Comments on the reviewed approaches of the coordination of independent generation

The technical and economic benefits of coordinating generation are addressed in the “Planning and Economic Assessment” contributions reviewed. These contributions do not address the allocation of the benefits obtained to the generators. Limited details of the technical implementation of these methodologies are provided.

“Network-operator driven” contributions envisage the improvement of network operation and are generally operated by network operators. These contributions do not deliver economic signals to promote the coordinated operation of DG. The coordination of DG is then a mandatory requirement of network operators.

“Market-driven coordination” contributions aim to maximise the electricity produced and the income of DG. However, most contributions reviewed do not provide details on how to allocate the additional income obtained by the generators.

Game theory provides tools to allocate the income originated by different players in a coalition. The application of game theory to the coordination of independent DG is addressed in section 2.4.

2.4 - Applicability of game theory to the coordination of independent generation

Game theory deals with problems of conflict amongst interacting decision makers. It may be regarded as a generalisation of decision theory to include multiple decision makers [65, 66]. These decision makers are usually called “players”. Game theory can be classified in two major areas: non-cooperative and cooperative game theory.

2.4.1 - Non-cooperative and cooperative game theory

Game Theory provides tools to study the non-cooperative interactions between participants (commonly designated as “players”) looking to maximise their income. In a non-cooperative game, each player has a number of choices/strategies available and a set of returns (commonly designated as "payoffs") corresponding to these strategies. Examples of these interactions are wholesale electricity markets, which are normally established on the assumption that participants do not cooperate.

Non-cooperative games can be zero-sum games or nonzero-sum games [67]. In zero-sum games, gains of one player equal the losses of the other player(s). In nonzero-sum games, gains of one player do not equal the losses of the other player(s). A solution to non-cooperative games is the concept of *Nash equilibrium*. A *Nash equilibrium* exists if, for all players, one player's strategy is the best response to the strategies of the other players [68]. Multiple *Nash equilibria* may exist for a given game.

In non-cooperative game theory, the payoff of a player depends not only on the strategy chosen but also on the strategies adopted by the remaining players. In addition, the rules of the game, the strategies available and their associated payoffs are of common knowledge. Each player is assumed to act rationally to maximise its own payoff [65]. The solution of non-cooperative games is the set of strategies adopted by each player individually and their outcome [67]. Non-cooperative games are believed to promote competition, driving players to bid near their marginal costs as competition grows. Therefore market efficiency is increased and prices are reduced [65].

Cooperative game theory is a branch of Game Theory that focuses on how an amount obtained in a coalition should be divided equitably amongst players. Particulars such as how players behave and how coalitions are formed (e.g., order of entrance in the coalition) are not addressed. The various solutions proposed for cooperative games can be interpreted as alternative solutions to an allocation problem [65]. Coalitions are formed to allow players to benefit from economies of scale, increasing their payoffs when compared to individual operation [67, 69]. The solution of cooperative games refers to the "grand coalition", i.e. the coalition of all players. Although being in a coalition, players ultimately aim to maximise their own income [65].

Cooperation in wholesale electricity markets is normally not accepted by regulators as it may lead to market distortions due to the reduction in the number of players and the increase of the relative weight of certain players. This may give market power to some players (e.g., by means of cartelisation), which would harm competition, reduce market efficiency and drive up prices for consumers [28, 70]. However, in cases where players share a scarce resource (e.g., a distribution circuit) or when players can obtain cost savings with economies of scale, cooperative game theory is reported to be an efficient way to promote efficiency in electricity networks [71-73]. Proposed applications of cooperative game theory to electricity markets include the reduction of network losses [71] and the reduction in transaction charges and costs of operation of generators [72, 73].

The allocation of the additional income obtained in coordination by independent generators connected to the same circuit can be formulated using cooperative game theory. A branch of cooperative game theory, cooperative games with transferable utility, is presented in section 2.4.2. In a cooperative game with transferable utility it is assumed that the earnings of a group of players can be expressed by an amount of *utility* [68]. This amount of utility is transferred without loss to the players.

2.4.2 - Cooperative games with transferable utility

A cooperative game with transferable utility (TU-game) is described by a pair (N, v), where $N = \{1, 2, \ldots, n\}$ is a finite set with *n* elements (players) and v is the "characteristic function" [68]. A subset *S* of the player set *N* is called "coalition". *N* is the grand coalition, i.e. the coalition of all players. The number of players in a coalition *S* is denoted by s. The characteristic function v assigns a "worth" $v(S)$ to each coalition S [74]. The worth of a coalition is the amount of *utility* (which can be expressed in monetary terms) to be allocated to the players [68]. If for all $S, T \subseteq N$, being $S \cap T = \varnothing$,

$$v(S \cup T) \geq v(S) + v(T) \tag{2.1}$$

then the cooperation has greater value than the sum of the value obtained by coalitions alone. The property described by condition (2.1) is known as *superadditivity*. A stronger notion than superadditivity is *convexity* (see condition (2.2)).

$$v(S \cup T) + v(S \cap T) \geq v(S) + v(T) \tag{2.2}$$

The total payoff $v(N)$ of the grand coalition should be allocated to the players so that their cooperation is incentivised. Let $v(i)$ be the worth of the individual operation of player i. An *allocation* is a vector $x = (x_1, \ldots, x_n) \in \Re^N$, where x_i is the payoff due to player i. Allocations are *efficient* if the payoff is entirely distributed, i.e. $\sum_{i \in N} x_i = v(N)$. The payoff received by each player i should be at least equal to the amount it would have received individually, i.e. $x_i \geq v_i$ for all $i \in N$. This property is called *individual rationality*. Allocations that meet the *efficiency* and the *individual rationality* properties are called *imputations*. Thus, $I(v)$ is the set of imputations of v (see condition (2.3)).

$$I(v) := \left\{ x \in \Re^n \mid \sum_{i \in N} x_i = v(N),\, x_i \geq v(i)\ \forall i \in N \right\} \tag{2.3}$$

2.4.3 - Methods to solve cooperative games with transferable utility

The solution to TU-games is an allocation or set of allocations admissible to all players. There are two groups of solution methods for TU-games [67, 68, 75, 76]: (a) subset methods (e.g.: the Core, Least Core, Bargaining Set, Weber Set, Selectope) and (b) one-point methods (e.g: Nucleolus and Prenucleolus, the Shapley value, τ-value). The solution method for a given game should be chosen according to the particulars of that game [69].

2.4.3.1 – Subset-based methods

Subset methods provide a "range" of allocations that satisfy the players. This flexibility allows players to consider various solutions.

Core of a Cooperative Game

An imputation is an efficient allocation that satisfies individual rationality, see condition (2.3). By extending the property of individual rationality to coalitions, then for all non-empty coalitions S:

$$\sum_{i \in S} x_i \geq v(S), \text{for all } S \subseteq N \tag{2.4}$$

The property described by condition (2.4) is called *group rationality*. The set of imputations (condition (2.3)) that fulfil group rationality (condition (2.4)) form the *core* [68]. Formally,

$$C(v) := \left\{ x \in \Re^n \mid \sum_{i \in N} x_i = v(N), \text{ and } \sum_{i \in S} x_i \geq v(S), \forall S \subseteq N \right\} \tag{2.5}$$

Being $C(v)$ the core of v. The lower bound of the core is the baseline for all players: no player will have incentive to cooperate if it receives less than in individual operation. The upper bound of the core is the set of allocations that one player can request without harming the other players' payoffs. The core can be empty or non-empty.

Least Core

Considering an imputation x, the excess vector

$$e(S, x) = v(S) - \sum_{i \in S} x_i \tag{2.6}$$

is regarded as the *objection* raised by a coalition S against imputation x (see equation (2.6)). Let $e_1(x)$ be the largest excess of any coalition relative to x, $e_2(x)$ the second largest excess and so forth. The Least Core of a TU-game is the set X_1 of all imputations x that minimise $e_1(x)$, i.e., that minimise the biggest complain of S [69].

2.4.3.2 – One-point methods

One-point methods aim to select one allocation that satisfies all players.

Nucleous and Prenucleous

Considering the definition of Least Core, let X_2 be the set of all x in X_1 that minimises $e_2(x)$, X_3 be the set of all x in X_2 that minimises $e_3(x)$, and so forth. This process will ultimately lead to a set X_k consisting of a sole imputation x, called the *nucleolus*. The nucleolus Nu is the imputation that minimises the maximum complaint of all coalitions. Formally (see condition (2.7)) [68]:

$$Nu(v) := \min \left\{ \max \left[v(S) - \sum_{i \in S} x_i \right] \right\} \tag{2.7}$$

This minimisation is subject to the constraints of the core (efficiency, individual and group rationality).

The prenucleolus is the efficient allocation that minimises the maximum complaint of all coalitions [66]. The prenucleolus does not guarantee the individual rationality property, which may lead to a solution outside the core.

Shapley Value

Consider $H(N)$ to be the set of superadditive games with N players. The Shapley Value is the unique value $\phi : H(N) \to \Re^n$ that satisfies simultaneously the following four properties (equations 2.8 to 2.12) [76]:

- *Efficiency*: for every supperadditive game $v \in H(N)$,

$$\sum_{i \in N} \phi_i(v) = v(N) \tag{2.8}$$

- *Symmetry*: If two players i and j contribute by the same amount to all coalitions – for all $S \subset N \setminus \{i, j\}$, $v(S \cup \{i\}) = v(S \cup \{j\})$), then

$$\phi_i(v) = \phi_j(v) \tag{2.9}$$

- *Dummy Player*: If the contribution of a player i to any coalition is the same that player i is able to achieve individually – for all S such that $i \in S$,

$$v(S \cup \{i\}) - v(S) = v(\{i\}) \tag{2.10}$$

This means that player i receives a payoff exactly equal to the amount that it is able to achieve individually. For any v, if i is a dummy player then

$$\phi_i(v) = v(\{i\}) \tag{2.11}$$

- *Additivity*: ϕ satisfies additivity if, for every superadditive game $v, w \in H(N)$

$$\phi(v + w) = \phi(v) + \phi(w) \tag{2.12}$$

Provided that the aforementioned properties are fulfilled, the Shapley value ϕ for player $i \in N$, for all $v \in H(N)$, is given by equation (2.13):

$$\phi_i(v) := \sum_{S \subset N \setminus \{i\}} \frac{s!(n - s - 1)!}{n!} \cdot \left(v(S \cup \{i\}) - v(S) \right) \tag{2.13}$$

s and n denote the number of elements of S and N, respectively. $v(S \cup \{i\} - v(S))$ is defined as player i's *marginal contribution* to coalition S. Term $\frac{s!(n-s-1)!}{n!}$ means that players are randomly ordered and all permutations (i.e., orders of entrance in the coalition) have equal probability. Thus, the Shapley value of player i is the average of player i's marginal contribution to all coalitions, including the empty coalition. The marginal contributions of each player in a 3-player game (players p_1, p_2, p_3) is given in Table 2.2.

If game v is a convex game (see constraint (2.2)) then the Shapley Value is in the core.

Computational effort required to obtain the Shapley Value increases significantly with the increase in the number of players. This is due to the increase in the number of permutations.

Table 2.2 - Marginal contributions of each player in a 3-player game

Player i	Permutation	$s!\,(n-s-1)!/n!$	$v(S \cup \{i\} - v(S))$
$\{p_1\}$			
	p_1	0! (3 - 0 - 1)!/3!= 0.33(3)	$v(\{p_1\})$ - v ($\emptyset$)
	(p_2) p_1	1! (3 - 1 - 1)!/3!= 0.16(6)	v ($\{p_1, p_2\}$) - v ($\{p_2\}$)
	(p_3) p_1	1! (3 - 1 - 1)!/3!= 0.16(6)	v ($\{p_1, p_3\}$) - v ($\{p_3\}$)
	(p_2, p_3) p_1	2! (3 - 2 - 1)!/3!= 0.33(3)	v ($\{p_1, p_2, p_3\}$) - v ($\{p_2, p_3\}$)
$\{p_2\}$			
	p_2	0.33(3)	v ($\{p_2\}$) - v ($\emptyset$)
	(p_1) p_2	0.16(6)	v ($\{p_1, p_2\}$) - v ($\{p_1\}$)
	(p_3) p_2	0.16(6)	v ($\{p_2, p_3\}$) - v ($\{p_3\}$)
	(p_1, p_3) p_2	0.33(3)	v ($\{p_1, p_2, p_3\}$) - v ($\{p_1, p_3\}$)
$\{p_3\}$			
	p_3	0.33(3)	v ($\{p_3\}$) - v ($\emptyset$)
	(p_1) p_3	0.16(6)	v ($\{p_1, p_3\}$) - v ($\{p_1\}$)
	(p_2) p_3	0.16(6)	v ($\{p_2, p_3\}$) - v ($\{p_2\}$)
	(p_1, p_2) p_3	0.33(3)	v ($\{p_1, p_2, p_3\}$) - v ($\{p_1, p_2\}$)

τ-value

The *τ-value* (or *tau value*) is the trade-off between two vectors: $M(v)$, the *marginal contribution* vector, and; $m(v)$, the *minimum right* vector [69]. For player i, $M(v)$ is given by equation (2.14):

$$M_i(v) := v(N) - v(N \setminus \{i\}) \tag{2.14}$$

$M_i(v)$ is the marginal contribution of player i to the grand coalition. It is the best payoff player i can expect (see equation (2.15)).

$$m_i(v) := \max_{S; i \in S} \left(v(S) - \sum_{j \in S \setminus \{i\}} M_j(v) \right) \tag{2.15}$$

$m_i(v)$ is the *minimum right* of player i, if all other players in S obtain their marginal contributions.

To compute the τ-value, let τ be the imputation that fulfils $\sum_{i=1}^{n} \tau_i = v(N)$, such that $\tau = m + \alpha \cdot (M - m)$ for some value α. In a 3-player game, the 4-equation and 4-unknowns system necessary to obtain τ is given by equation (2.16). The values for *m* and *M* are obtained as shown in Table 2.3.

$$\begin{cases} \tau_1 = l\_bound_{p1} + \alpha\left(u\_bound_{p1} \text{ - } l\_bound_{p1}\right) \\ \tau_2 = l\_bound_{p2} + \alpha\left(u\_bound_{p2} \text{ - } l\_bound_{p2}\right) \\ \tau_3 = l\_bound_{p3} + \alpha\left(u\_bound_{p3} \text{ - } l\_bound_{p3}\right) \\ \tau_1 + \tau_2 + \tau_3 = v(p_1, p_2, p_3) = v(N) \end{cases} \tag{2.16}$$

Table 2.3 - Marginal contribution vectors of a 3-player game

Vector	Player 1 - p_1	Player 1 - p_2	Player 1 - p_3
M	$u_{bound_{p1}} = v(N) - v(N\backslash\{p_1\})$	$u\_bound_{p2} = v(N) - v(N\backslash\{p_2\})$	$u\_bound_{p3} = v(N) - v(N\backslash\{p_3\})$
m	$l\_bound_{p1} = v\{p_1\})$	$l\_bound_{p2} = v\{p_2\}$	$l\_bound_{p3} = v\{p_3\}$

2.4.4 - Application of game theory to electric power systems

The strategic behaviour of electricity market participants and solutions to avoid market power are addressed in [77-82]. The allocation of network costs using cooperative game theory is addressed in [83, 84]. The allocation of transmission network losses is presented in [85]. A contribution to transmission congestion pricing is investigated in [86]. Cooperative game theory is used to compensate generators for congestion relief in [87]. The pricing of reactive power support is addressed in [88].

Demand-side integration strategies using game theory are described in [89, 90]. Game theory is used to encourage consumers to adopt the expected behaviour and obtain cost savings.

The allocation of the benefits of firm energy bids of independent hydro generators is presented in [91]. The coordination of independent generators connected to the same network using cooperative game theory is presented in [61, 72]. The objective is to increase the income of the generators.

2.5 - Demand-side integration in distribution network operation

Demand-side integration is a set of methodologies to use demand and local generation to support network operation/management and improve the quality of power supply [1]. The term “demand-side integration” is used by *CIGRE* to congregate different nomenclature such as demand-side management and demand response [5, 92].

Demand-side integration is expected to increase so as to limit the growth in demand and make better use of the networks. Also, the flexibility of demand is being presented to allow the integration of additional amounts of non-dispatchable generation [93, 94]. Demand-side integration is expected to allow [95, 96]:

- Reduction of demand peaks;
- Load shifting and valley filling;
- Reduction in overall demand without reducing services (energy efficiency);

The participation of the demand-side aims to promote [95, 96]:

- Power system balancing in systems with high penetration of non-dispatchable generation;
- Increase of the share of load supplied by low-carbon generation;
- Provision of ancillary services by the demand;
- Reduction in network operating costs;
- Deferment of investments in transmission and distribution systems.

Energy storage systems

Energy storage systems are an example of demand-side resources able to respond to electric power system or market conditions. Different applications of energy storage systems are presented in Table 2.4 [96]. Benefits are referred to the United States network operators.

Table 2.4 - Applications of energy storage systems [96]

Application	Benefit	Quantification	Power Requirement	Duration
Storing renewable distributed generation (DG) production	Capture renewable DG production for use when wanted and reduce grid consumption; mitigate capacity charges as well	Benefit up to value of renewable energy at peak hour's pricing	Equal to local DG peak production	Hours
Time shifting of demand to avoid peak prices	Avoid high real-time prices at peak	$100/MWh or more	Equal or less than peak load	Hours
Price arbitraging in real-time pricing situation	Same as for storage in generation balancing energy	May mitigate high ramping balancing costs	As desired	30 minutes
Reliability enhancement	Avoid interruptions	Linked to value of production and cost of interruption	Equal to peak load protected	Minutes to hours
Utility reliability enhancement	Allow utility control for targeted enhancement	Linked to utility capital deferral	Equal to peak load typically	Minutes to hours
Plug-in hybrid electric vehicle Integration	Lower cost of charging by only using off-peak power	Lower cost of driving plus utility capital deferral	Equal to vehicle power draw	Hours
Demand response / load management integration	Make demand response / load management participation in markets more attractive	Not quantified as of yet	Similar to demand response / load management that is replaced	Minutes to hours
Renewable demand response / load management	Renewable volatility and difficulty of control make them unreliable for demand response / load management applications. Storage can be an enabler	Not quantified as of yet	Similar to demand response / load management that is replaced	Minutes to hours
Railroad acceleration support	Avoid significant variable (I2R) losses	Catenary losses are 15–20%	10 MW per station	Minutes to hours

The penetration of electric vehicles may bring a widespread availability of energy storage. Apart from allowing the connection of larger amounts of electric vehicles, the development of electric vehicle aggregators in electricity markets aims to allow [97-99]:

- the production of additional electricity from non-dispatchable generation;
- the prevention of network congestion;
- improvements in network voltage regulation;

Heat pumps can also be used as energy storage to increase production from non-dispatchable generation [100, 101].

Difficulties to the implementation of distributed energy storage systems include [96]:

- Regulatory barriers: regulated utilities may face difficulties to ensure return of capital costs and thus in obtaining regulatory approval for such investments;

- Market structure: many consumers are still under a flat price scheme, which does not provide incentive for the use of storage.

In addition, shifting large amounts of consumption can result in changes in wholesale electricity prices [102].

2.5.1 - Mechanisms to implement demand-side integration

The implementation of demand-side integration is facilitated by smart metering. Smart metering allows real-time information exchange and the implementation of control actions. This way, two approaches to implement demand-side integration are considered: price-based schemes (e.g., time of use rates) and incentive-based schemes (e.g., direct load control) [92, 103, 104].

Price-based schemes promote changes to load consumption by means of electricity price signals. Incentive-based schemes provide incentives to modify the load. The remuneration of incentive-based schemes is separate from the electricity bill.

Price-based and incentive-based implementations are also classified by timing requirements, see Figure 2.5 [5]. Incentive-based schemes tend to be implemented nearer to real-time operation.

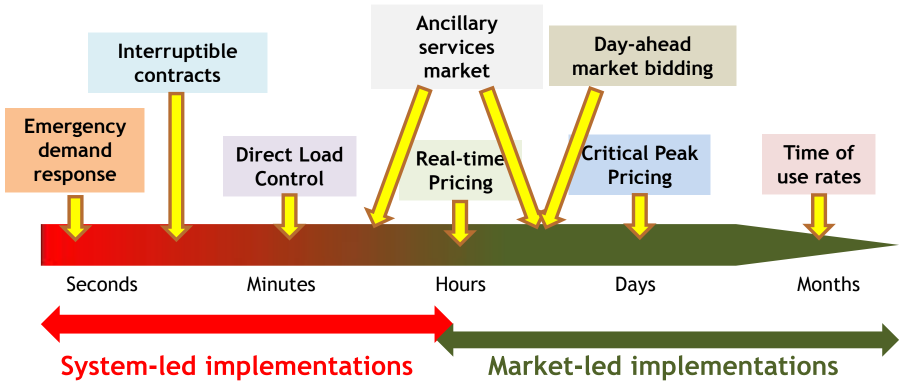

Figure 2.5 - Classification of demand-side integration implementations by timing requirements [5]

Price-based schemes are detailed in section 2.5.1.1 and incentive-based mechanisms are addressed in section 2.5.1.2.

2.5.1.1 - Price-based schemes

In price-based schemes, dynamic pricing is used to promote changes in demand consumption. Both prices and time periods can be fixed and pre-defined. Schemes include time of use rates, real-time pricing and critical peak pricing [1, 92] (see Figure 2.6):

- Time of use rates: different prices are used for different time periods. This is usually set for a 24-hour period. These prices vary according to the cost of generating and delivering power during different periods;
- Real-time pricing: the electricity price fluctuates during the time period considered following changes in the wholesale electricity price.

This fluctuation usually occurs with a granularity of one hour. Demand is notified of the real-time prices on a day-ahead or hour-ahead basis;

- Critical peak pricing: this scheme is a mixture of time of use and real time prices. The basic rate structure is a time of use rate. However, the normal peak price is replaced by a much higher price. This very high price reflects predefined trigger conditions (e.g., network congestion).

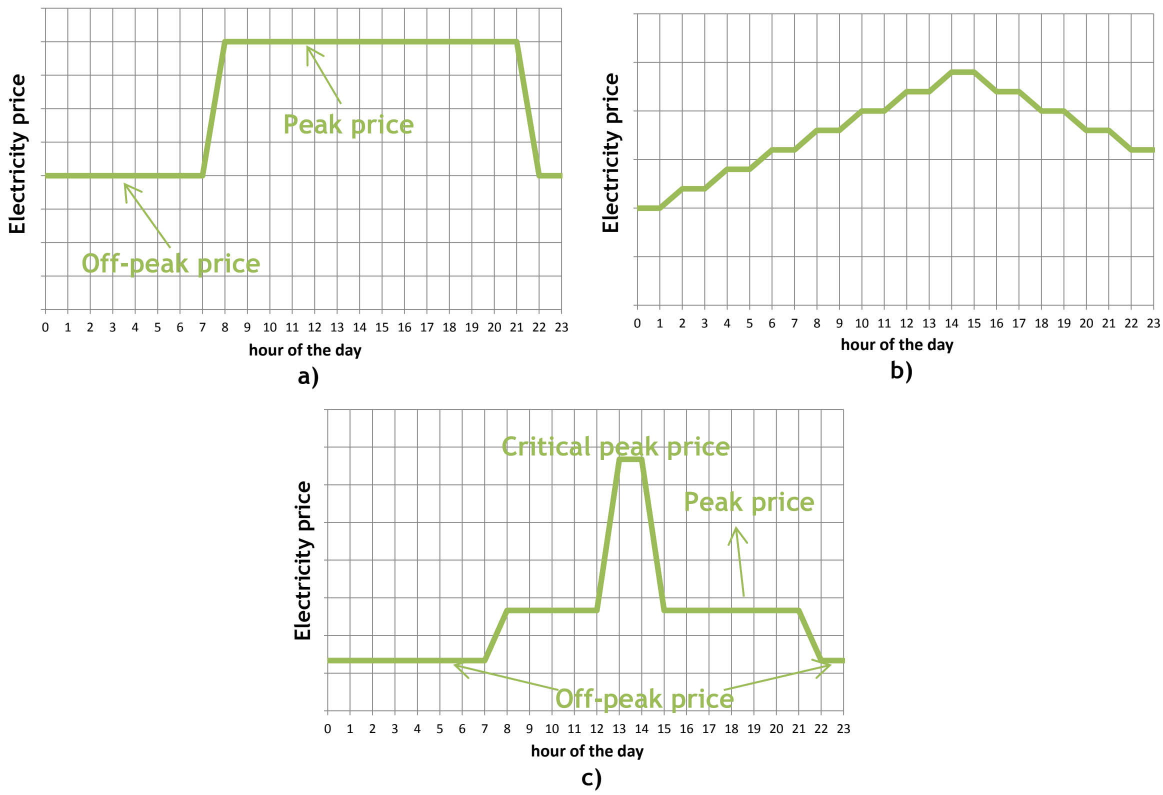

Figure 2.6 - Example of pricing schemes [1]: a) time of use rates b) real-time pricing c) critical peak pricing

The performance of price-based schemes is assessed by the response of demand to price signals. This can be measured by calculating the price elasticity of load, which gives the rate of change of consumption per unit of change in price.

2.5.1.2 - Incentive-based schemes

Different incentive-bases schemes are listed as follows [1, 92]:

- Load curtailment programmes: notify large consumers to reduce their consumption during system contingencies. Reduction is operated by the consumer;
- Interruptible contracts: commit consumers to reduce a given amount of consumption when requested. Number of reduction requests, economic incentives and notification times are pre-established by consumer contract. This scheme is usually considered for large consumers;
- Direct load control programmes: allow network operators to directly control end-use equipment (e.g, air conditioners, water and space

heaters). Direct communication links between the program facilitator and participating consumer equipment are required;

- Demand-side bidding: allow consumers to offer load reduction at a given price. If the bid is accepted, consumers operate the agreed reduction. Small consumers need to be aggregated to be able to apply for this scheme;
- Emergency demand response/ capacity market programmes: provides incentives for load reduction when the system is short of reserve. Load curtailment is regarded as system capacity to replace conventional generation;
- Ancillary services market programmes: consumers are able to bid load curtailments as operational reserves. If bids are accepted, consumers are paid for their availability to be curtailed. If curtailment is operated, they are paid according to the electricity market price.

2.5.2 - Benefits of demand-side integration to the integration of generation

Demand-side integration facilitates the integration of generation as it allows [93, 94, 104, 105]:

- Maximisation of the utilisation of generators (increase production export, reduce total generation costs);
- Attenuation of the variability of non-dispatchable generators.

A stochastic optimisation model for aggregating wind power and flexible loads in day-ahead electricity markets is presented in [106]. The joint offering of a demand response provider and wind power aims to reduce wind power imbalance penalties. A virtual power plant is implemented as an aggregator of the wind generators and the demand response provider. The possibility of load shifting is accounted. Uncertainty in wind power forecasts is included. Historical data of market prices and demand consumption are considered. Also, imbalance prices are deterministic, being a percentage of the market clearing price. Results demonstrate the benefit of the joint offering of wind power and demand. The correlation between wind power production and load consumption increases. However, as the amount of load flexibility grows the benefit obtained in joint operation tends to stabilise.

An energy management system acting as an aggregator of distributed energy resources in the free market is presented in [107]. This aggregator aims to maximise the local production of non-dispatchable generators, as well as minimise the electricity bill of the load. Active management schemes (such as transformer on-load tap changing algorithms and generator power factor management) are included. Real-time pricing of the load is considered. The energy management system presented is based on the manual response of end users to real-time pricing.

In [108], controllable load is incentivised to coordinate with wind power by means of a discounted price of electricity offered by the wind generators. Direct control of flexible loads by the wind generators is employed, interfaced by a control centre. Dynamic programming algorithms and adaptive stochastic controllers are used.

A model predictive controller to solve the economic dispatch problem at the transmission level considering large penetration of non-dispatchable generation and flexible load is presented in [109]. Non-dispatchable generator and demand outputs are decision variables. No congestion is considered. Load responsiveness to price is modelled using a demand function. Demand functions between hours are uncorrelated to alleviate computational effort. Results are analysed against a base case that: i) does not consider non-dispatchable generation and demand as decision variables; ii) assumes the demand to be inelastic. A greater utilisation of the available non-dispatchable generation and the reduction of total generation cost are observed with the controller. Also, demand reduces its total amount in comparison with the base case.

2.5.3 - Benefits of demand-side integration to the consumers

Demand-side integration aims to promote benefits for consumers [102, 104, 110]:

- Savings in the electricity bill;
- Revenue collection for providing ancillary services;

The aforementioned benefits are aimed not to reduce services to consumers or decrease their comfort.

A decentralised consumption scheduling methodology for consumers of the same energy company is presented in [89]. Two objective functions are considered: the minimisation of the cost of energy supply (consumer objective); and the minimisation of the peak-to-average ratio of the load (energy company objective). A scheduling algorithm is installed in the smart meters to allow their interaction. Smart meters exchange limited amount of information. Results show that the minimum cost scheduling of the load also reduces the peak-to-average ratio of the load.

The promotion of voluntary energy conservation is proposed in [111]. Real-time monitoring of the price of electricity and visibility of potential energy savings is used to provide incentives for consumers to shift peak demand. A hardware-based approach is presented to: i) curtail peak load and reduce electricity consumption using air conditioners; ii) emit real-time pricing signals to motivate end users to shift peak demand. Results obtained rely on the response of end users to price signals.

2.5.4 - Benefits of coordinating independent distributed generation and demand

Coordination of independent distributed generation and demand (such as controllable load and energy storage systems) has potential to:

- Increase energy export in distribution networks;
- Maximise the production of non-dispatchable generators;
- Maximise the income of the owners of distributed generators;

- Provide additional revenues to demand, so as to incentivise its coordinated operation.

Commercial mechanisms should be implemented so that both distributed generators and demand are incentivised to operate in a coordinated manner.

2.6 - Summary

The “fit-and-forget” connection of distributed generation introduces challenges to the connection of further capacity. Contributions to allow the connection of additional amounts of distributed generation were presented. The coordination of independent distributed generators was identified as a way to integrate greater capacities and maximise the income of the generators. Game theory was introduced to provide mechanisms to allocate the income obtained in coordination by all generators. The participation of the demand side in distribution network operation was analysed. The potential benefits of coordinating independent generation and demand were presented.

The limitations of the “fit-and-forget” connection of generation are evaluated in Chapter 3. The coordination of independent distributed generators to mitigate these limitations is addressed in Chapter 4. The income obtained by the distributed generators is allocated using a mechanism based on cooperative game theory. The integration of controllable load in the coordination is considered in Chapter 5. The coordination of non-dispatchable generators and energy storage systems is presented in Chapter 6. The additional income obtained is allocated to generators and demand (controllable load/energy storage systems). The demand receives part of the additional income to incentivise its operation in a coordinated manner.

Chapter 3 - Connection of generation to distribution networks

3.1 - Introduction

The connection and operation of distributed generators under the firm access connection policy is described. A representative of the distribution system of Northeast Portugal is used as an example. The connection of distributed generation without firm access rights is considered. The limitations of the firm access connection policy are then discussed.

3.2 - Modelling of the distribution system analysed

The firm access connection policy is described using the distribution system of Northeast Portugal as an example, see Figure 3.1. A 60 kV distribution network is illustrated. There are fifteen distribution substations and three interconnections with the transmission network. Wind and hydro distributed generation is connected.

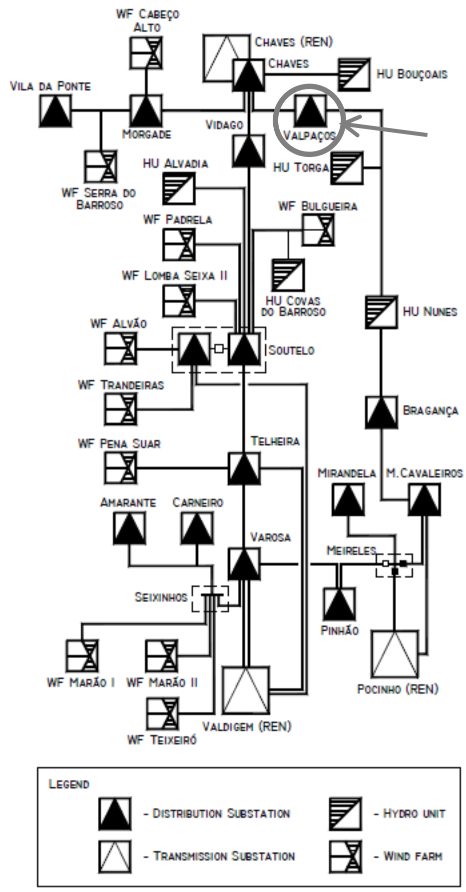

Figure 3.1 – 60 kV distribution network of Northeast Portugal (source: [112])

Load consumption and distributed generation output at the medium voltage (MV) side of the distribution network is shown in Table 3.1. Values were obtained at 8.30 a.m. on 20/12/2007 [112].

Table 3.1 - Distribution substation loads and MV-connected distributed generation output, 20/12/2007 at 8.30 a.m. (source: [112])

			Wind DG (MVA)		Hydro DG (MVA)		Thermal DG (MVA)	
	Load (MVA)	Total DG (MVA)	Generation	Maximum injection	Generation	Maximum injection	Generation	Maximum injection
Amarante	19.1	5.1	-	-	0.0	0.6	5.1	5.2
Bragança	21.9	0.0	-	-	0.0	4.2	-	-
Carneiro	2.8	0.0	0.0	1.5	-	-	-	-
Chaves	20.0	3.2	3.2	3.3	-	-	-	-
Mirandela	11.1	Without DG						
Morgade	3.6	2.5	2.5	3.0	-	-	-	-
M. Cavaleiros	14.2	1.7	1.7	2.0	-	-	-	-
Pinhão	10.0	Without DG						
Soutelo	8.4	8.0	8.0	8.0	-	-	-	-
Telheira	27.0	7.2	2.6	2.5	4.6	20.0	-	-
Valpaços	5.7	Without DG						
Varosa	36.3	41.5	41.2	39.4	0.3	13.0		
Vidago	11.2	2.7	1.2	1.2	1.5	4.2	-	-
Vila da Ponte	10.1	Without DG						
Total	201.4	71.9	60.4	60.8	6.4	42.0	5.1	5.2

There is no distributed generation connected to the distribution substation indicated in Figure 3.1 (*Valpaços*), see Table 3.1. *Valpaços* distribution substation has a single 60kV/15kV transformer with 15 MVA of installed capacity. The MV network below *Valpaços* substation is shown in Figure 3.2. This MV network is a representative of a rural distribution network in Portugal. The short-circuit power behind *Valpaços* substation, Scc, is provided in [112]. xf is the leakage reactance of the transformer. Sb and Vb_MV are the base power and the base voltage of the distribution network, respectively. Total load consumption in Figure 3.2 is equal to the consumption mentioned in Table 3.1, i.e. 5.7 MVA. Loads are considered to operate with a fixed power factor of 0.95 (inductive).

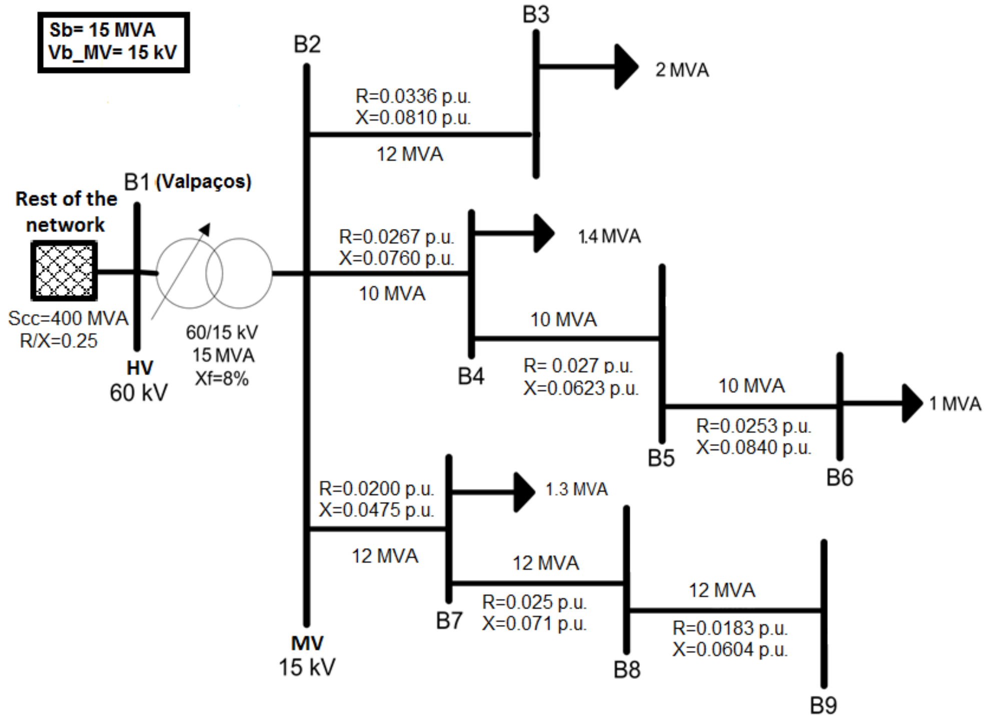

Figure 3.2 - Distribution network below *Valpaços* substation (rural distribution network)

3.3 - Operation of generators with firm access rights

Generators get permission to connect to distribution networks in Portugal on the basis of power flow studies with the following conditions [113]:

- Generators must be operating at their maximum power, with unity power factor;
- The voltage magnitude in the busbar of connection should not change more than +0.02 p.u., with all loads equal to zero;
- Line capacity limits and voltage magnitude limits ([0.9 p.u.; 1.1 p.u.]) must be observed in all busbars.

Generators who fulfil these and other non-technical requirements are allowed to connect to the distribution network with firm access rights.

To exemplify the connection of generation with firm access rights, two independent distributed generators are connected to the distribution network of Figure 3.2. Generator GenA connected first to the network (on busbar B3) and has an installed capacity of 10 MVA. Generator GenB connected later (on busbar B9) and has an installed capacity of 5 MVA. Both generators are connected with firm access rights.

GenA is a non-dispatchable generator (wind generator) and GenB is a dispatchable generator (thermal generator). A dispatchable generator has the ability to produce and store according to the strategy of the producer. Non-dispatchable generators only produce electricity when their primary resource comes available and do not have ability to store their production.

3.3.1 - Limitation in the capacity that can be connected

The operation of the distribution network is analysed considering two extreme power flow cases:

- Case 1 → <u>Minimum MV-side voltage magnitudes</u>: transformer operates at its highest tap on the HV side (1.06), loads are at their maximum value, generators do not operate;
- Case 2 → <u>Maximum MV-side voltage magnitudes</u>: transformer operates at its lowest tap on the HV side (0.94), no loads, generators operate at maximum output power with unity power factor;

Figure 3.3 shows the operation of the distribution network in case 1. Power flows are indicated. In case 1 all network voltage and current limits are observed. As the generators are not operating, power flows from the HV to the MV side of the distribution network.

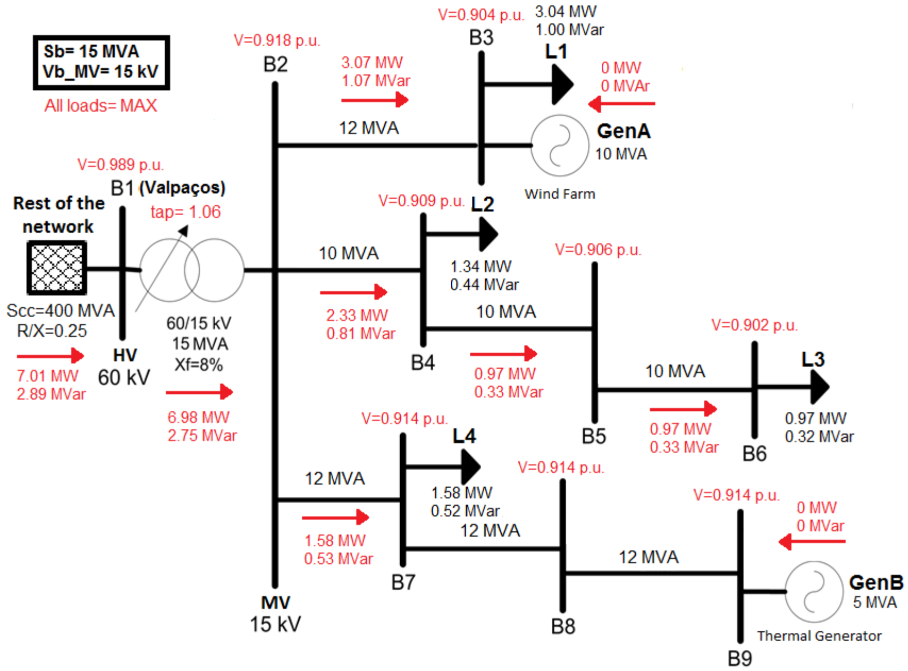

Figure 3.3 - Case 1 → Operation of the distribution network with the highest transformer tap on the HV side, maximum load and generators not operating

Figure 3.4 shows the operation of the distribution network in case 2.

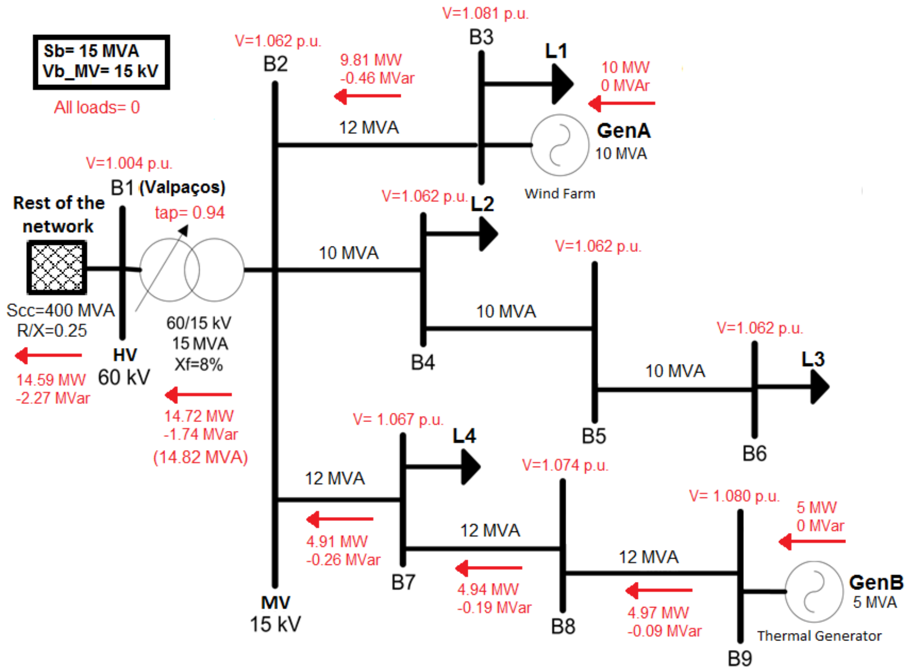

Figure 3.4 - Case 2 → Operation of the distribution network with the lowest transformer tap on the HV side, no load and generators operating at maximum output

In case 2 all network voltage and current limits are respected. Active power flows from the MV to the HV side, while reactive power flows in the opposite direction due to the reactive losses. If losses were not considered, power flowing through the substation transformer would reach the transformer capacity. This way, no further generation can connect with firm access rights.

3.3.2 - Technical possibility of connecting additional generation capacity

The operation of the distribution network in case 2 (transformer operating at its lowest tap on the HV side, no loads, generators operating at maximum output power with unity power factor) is extended to 24 hours, see Figure 3.5. The time granularity considered is one hour. The consumption of all loads is represented by a typical winter consumption profile [114], with a fixed power factor of 0.95 (inductive). The total load consumption at 8.30 a.m. is 5.7 MVA, as indicated in Table 3.1. The maximum consumption of the loads during the 24 hours is 7.3 MVA. The production of GenA follows the availability of wind. GenB schedules its production according to the price of electrical energy shown in Figure 3.5. The price of electrical energy considered was obtained in [115]. Both generators receive their income according to this price of electrical energy (no feed-in tariff schemes are considered). GenB does not produce between hours 0 and 8 because its costs of operation are higher than the price of electrical energy. GenB produces reactive power between hours 9 to 21. In Portugal, MV-connected generators below 6 MW of installed capacity must produce an amount of reactive power equal to 30% of their active power produced on peak hours (from 8 a.m. to 10 p.m.) [113].

During the 24 hours of operation considered, the power flowing through the distribution transformer is significantly below the rated capacity. Additional electrical energy could be produced on the MV side of the distribution network if further generation capacity was connected.

3.4 - Connection of generators without firm access rights

The connection of two other independent generators to the MV distribution network is considered (see Figure 3.6). Generator GenC connected to the network on busbar B8 and has an installed capacity of 4 MVA. Generator GenD connected last (on busbar B5) and has an installed capacity of 3 MVA. The installed capacities of generators GenC and GenD were obtained following cost-benefit analyses, available in Appendix A. GenC is a dispatchable generator (thermal generator) and GenD is a non-dispatchable generator (wind generator).

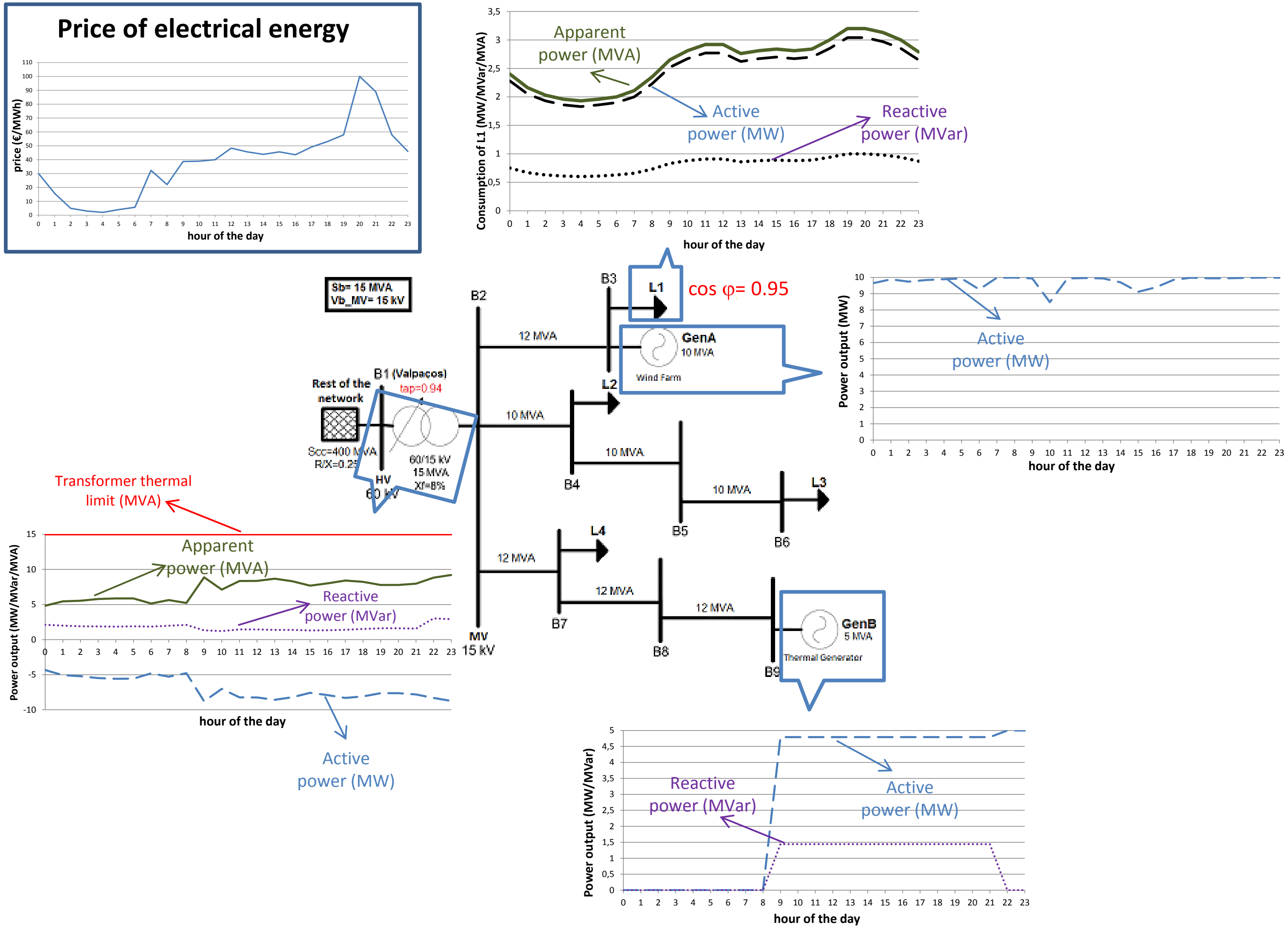

Figure 3.5 - Operation of the distribution network during 24 hours, with the generators producing and with a typical load curve

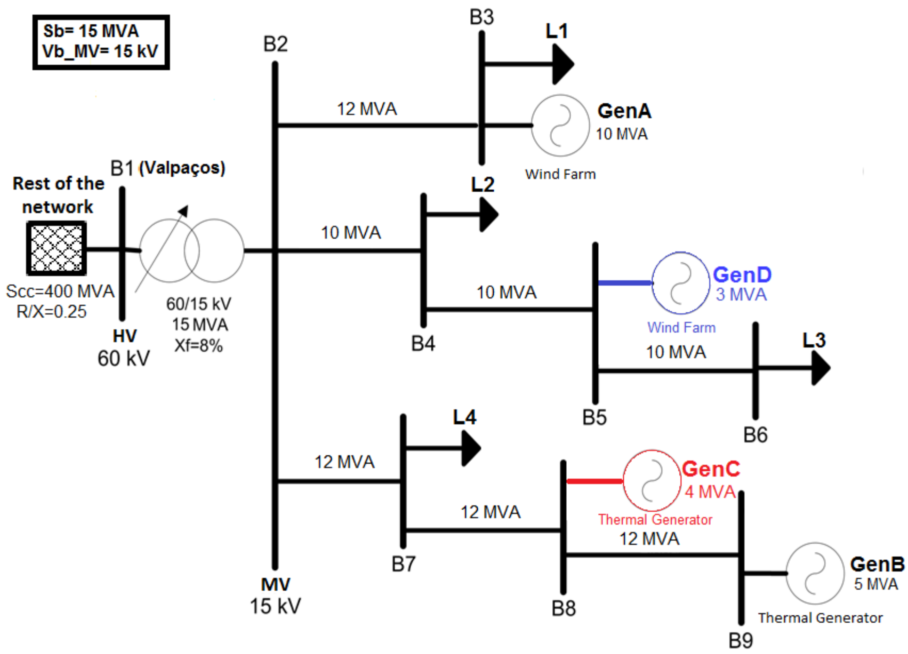

Figure 3.6 - Distribution network with the four generators (GenA and GenB are firm connected, GenC and GenD have no firm access rights)

As the connection of further generation with firm access rights is not possible, both GenC and GenD agreed to connect without firm access rights. Generators connected without firm access rights are constrained off on a “last-in, first-off” basis when there is inadequate capacity in the export circuit.

3.4.1 - Minimum cost operation of the distribution network

The distribution network of Figure 3.6 is operated with minimum cost if the generators with lower costs of operation are scheduled first. An AC optimal power flow (AC OPF) is run in the distribution network of Figure 3.6. The objective function is the minimisation of the costs of producing active power. *Matlab*-based package *MATPOWER* is used to run the AC OPF [116]. The distribution transformer tap is adjusted manually. Generation and load consumption data of hour 23 are considered (data shown in Figure 3.5). All generators are able to operate up to their rated powers and operate with unity power factor. GenA and GenD have no operation costs. The operation of GenB and GenC costs 35€ per MWh produced. Generators located upstream *Valpaços* substation are more expensive than GenB and GenC. The total load consumption is 6.04+j1.98 MVA. The results of the AC OPF are given in Figure 3.7. Full details of the AC OPF implementation are provided in Appendix B.

The distribution network is operated with the minimum cost of 272.3€ in hour 23, that corresponds to the cost of operating generators GenB and GenC. GenA, GenC and GenD produce at full output power and GenB is constrained off to meet the transformer capacity limit. However, GenB was connected with firm access rights so it should not be curtailed. Therefore, the minimum cost schedule of the distribution network cannot be implemented due to the order of connection of the generators.

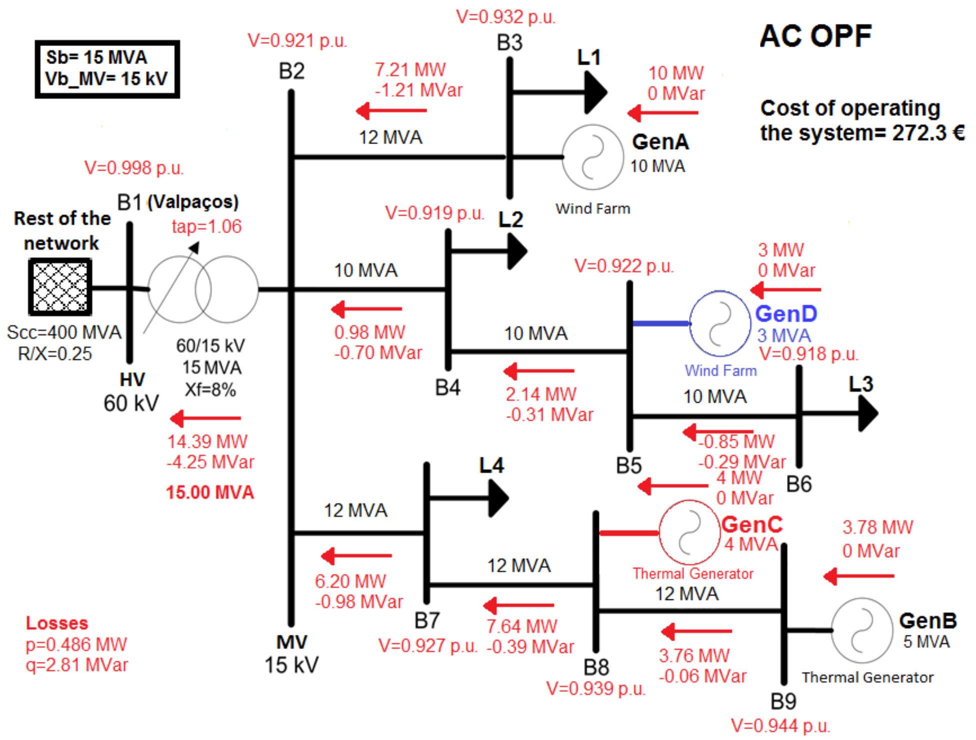

Figure 3.7 - Operation of the distribution network with the four generators in hour 23, with minimisation of the costs of producing active power (AC OPF)

3.4.2 - Operation of the generators connected without firm access rights

The operation of the distribution network during 24 hours (as described in section 3.3.2) is updated to consider generators GenC and GenD. The time granularity considered is one hour. GenC schedules its production according to the price of electrical energy shown in Figure 3.8 (same as in Figure 3.5). GenC does not produce between hours 0 and 8 because its costs of operation are higher than the price of electrical energy. The production of GenD follows the availability of wind. Both GenC and GenD are required to produce an amount of reactive power equal to 30% of their active power produced between 8 a.m. and 10 p.m., as their installed capacity is below 6 MW.

In hours 9, 13, 22 and 23, the production of the generators exceeds the capacity limit of the transformer. GenD is curtailed to meet this excess, see Figure 3.8. GenD is curtailed because it was the last generator to be connected. GenD only produces when wind comes available, so its curtailed power is lost.

Comparing the operation in hour 23 of Figure 3.8 with the results of the AC OPF in hour 23 (given in Figure 3.7), the cost of operating the distribution network is 315€ while with the AC OPF is 273€. This difference corresponds to the additional cost of operating generators GenB and GenC at full output power.

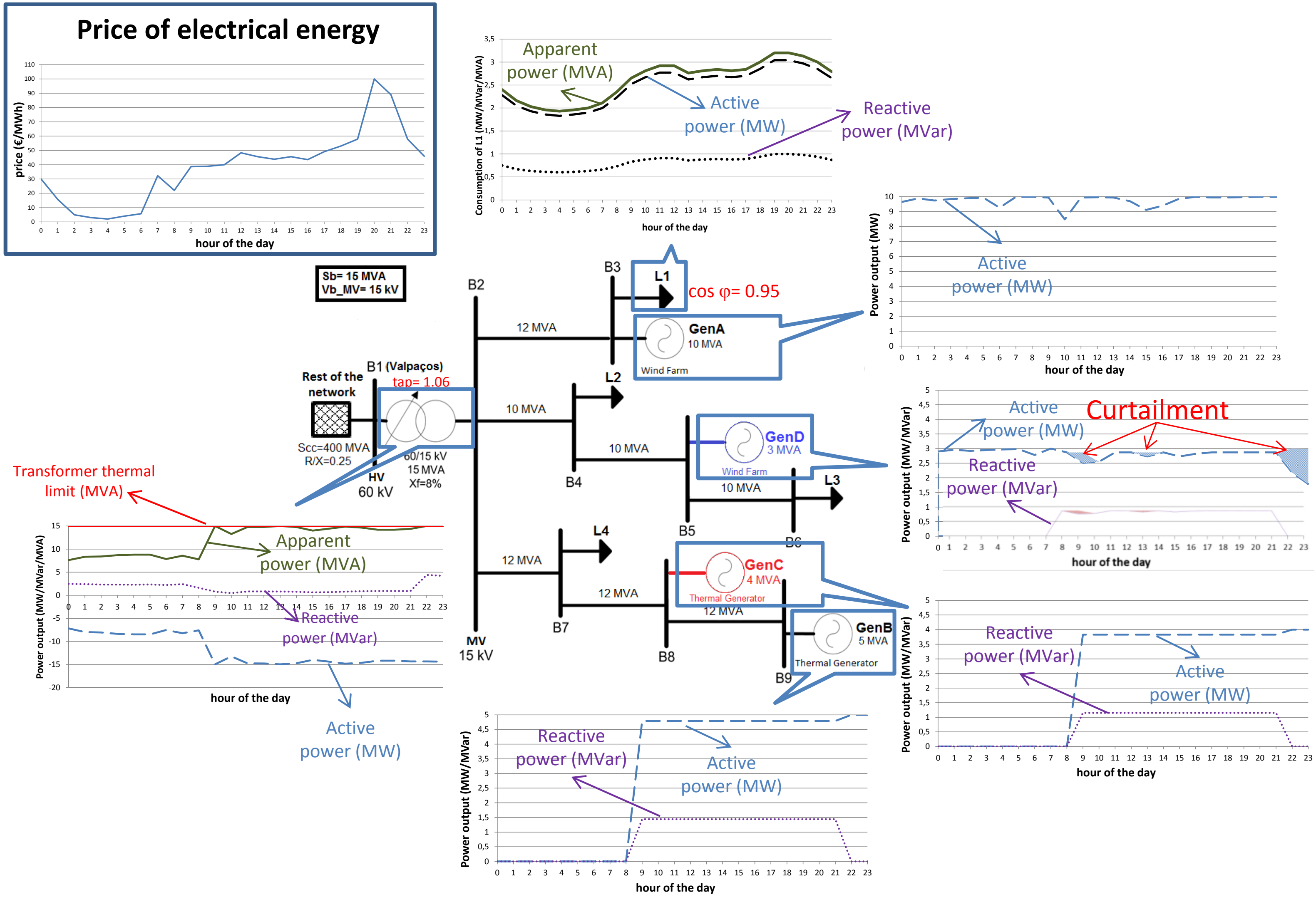

Figure 3.8 - Operation of the distribution network during 24 hours, with the four generators producing and with a typical load curve

3.5 - Summary

Permission to connect a generator to the distribution system is generally obtained on the basis that the generator's effect is limited and that the network voltages and currents remain acceptable at all times. This firm access connection policy limits the capacity of generation that can be connected.

Generators may be allowed to connect to distribution networks above the limit defined by the firm access connection policy. When there is inadequate capacity in the network, the non-firm generators are constrained off on the basis of "last-in, first-off" curtailment. Only the order of connection of the generators is taken into account. Different costs of operation and ability to be dispatched are not considered. Thus, the firm access connection policy does not maximise the economic value of the generators.

Chapter 4 - Coordination of independent distributed generators

4.1 - Introduction

This chapter first formulates the coordination of independent distributed generators. The coordination of independent distributed generators is presented as an alternative Principle of Access to the networks when non-firm access is allowed. The coordination of generators aims to maximise the income received by the generators. An Aggregator schedules the generators according to their costs of operation and abilities to be dispatched without exceeding the capacity limit of the constrained circuit. Additional income is obtained by the generators for the additional energy sold and by the substitution of expensive generators by cheaper ones. The income originated in coordination is allocated to all generators taking into account their electricity output and technology. This is done via an income-sharing mechanism based on cooperative game theory. An assessment of the willingness of the dispatchable generators to participate in the coordination is also presented.

4.2 - The coordination methodology

Operators of distribution networks limit the connection of generation in order to ensure acceptable voltages and currents at all times. However, to make projects more economically attractive, owners of distributed generator schemes often wish to increase the size of their generators. Also, new developers show interest in connecting to distribution networks even without having firm access rights of connection. “Last-in, first-off” operation is used by operators of distribution networks to curtail generation when the power limit of their circuits is exceeded. This rule only takes into account the order of connection of the generators.

The coordination of independent distributed generators connected to the same circuit schedules generators according to their different costs of operation and ability to be dispatched. The coordination aims to maximise the income received by the generators without exceeding the power limit of the circuit. The coordination is operated by an Aggregator, run by the generators. Generators are scheduled so as to benefit from their different costs of operation and abilities to be dispatched when network constraints occur. The generators considered are assumed to be connected on a “must-run” basis, following an European Directive for renewable and low carbon generation [117]. In this Directive is expressed the interest in maximising energy export from these forms of generation. When network constraints occur, the coordination sets the productions of these generators so as to allow cheaper generators to run first and maximise electricity export from all generators. The additional income originated (when compared to “last-in, first-off” operation) is allocated to all generators taking into account their amount of electricity produced and type of technology. This is done using cooperative game theory, which provides tools for the equitable allocation of an amount obtained in a coalition. Generators are then able to increase their income when compared to “last-in, first-off” operation and have an economic incentive to be operated in a coordinated manner.

The operation of the Aggregator is summarised as follows:

- The dispatchable generators change their output power to allow the non-dispatchable generators to operate;
- The dispatchable generators operate in hours of reduced output of the non-dispatchable generators only if their operating costs are lower than the income received in those hours;
- The non-dispatchable generators are curtailed when the circuit rating limit is still exceeded;
- “Last-in, first-off” curtailment is used when the costs of operation of the generators are the same.
- The generators receive their income as determined by an income-sharing mechanism based on cooperative game theory. The electricity output and technology of each generator are considered.

The assumptions and limitations of the coordination are given in section 4.2.1 and the operation of the Aggregator is detailed in section 4.2.2.

4.2.1 - Assumptions and limitations of the coordination

In this study, the coordination of independent distributed generators is formulated according to the following assumptions and limitations:

Related to the distribution network

- The distribution network considered is a two-busbar network;
- Losses are not considered – no voltage drop;
- The distribution circuit rating is fixed;
- The only network constraint is the rating of the distribution circuit;

Related to the distributed generators

- There are dispatchable and non-dispatchable generators connected;
- The capacity connected is higher than the rating of the circuit;
- The generators may be required by network regulations to produce reactive power;
- The generators are owned by independent producers;

Related to the local load

- The load is not controllable;
- The load operates with a constant power factor;
- The load profile is estimated by load forecasting;

Related to the optimisation

- The coordination optimises the production of electricity;
- The generators are considered to be price takers;

- The forecasts considered (available power of the non-dispatchable generators, price of electrical energy and load consumption) are entirely reliable;
- The dispatchable generators have fuel and start-up costs;
- No costs of operation of the non-dispatchable generators are considered;
- The costs of forecasting and telecommunication are not considered;

Losses are not considered when scheduling the generators in the coordination methodology. This is because a method to apportion the losses caused/avoided by each generator (e.g. as presented in [118, 119]) and respective income reconciliation (pay or be paid for losses caused/avoided) has not been adopted. The level of losses in the distribution network varies with the load conditions, network parameters and configuration (including location and order of connection of the generators), and the output of the generators. Losses in the distribution network may grow or reduce with the amount of generation connected. If losses were considered, the schedule of the generators in coordination and respective allocation of the additional income would be dependent on the level of losses in the distribution network. Ultimately, generators would have to pay or be paid respectively a compensation for the increased or decreased amount of losses in the network they caused (e.g. using a method as proposed in [118, 119]).

As in this work no losses are considered in the distribution network for determining the schedule of the generators in coordination, the distribution network may be reduced to a two busbar equivalent model. This two busbar network has the generators and the load connected to one busbar interconnected with the rest of the network via the distribution circuit that limits generation export.

4.2.2 - Operation of the Aggregator

The Aggregator uses the following parameters for the coordination of distributed generators (see Figure 4.1): distribution circuit rating; operating limits of the generators; fuel and start-up costs of the dispatchable generators; the order of connection of the generators. The operation of the Aggregator is described as follows:

(1) The Aggregator receives from the generators their anticipated outputs and the amount of time that the dispatchable generators can produce continuously at full output power. The non-dispatchable generators make their projections based on power forecasts. The dispatchable generators make their projections considering the prediction of the price of electrical energy and any need to produce heat;

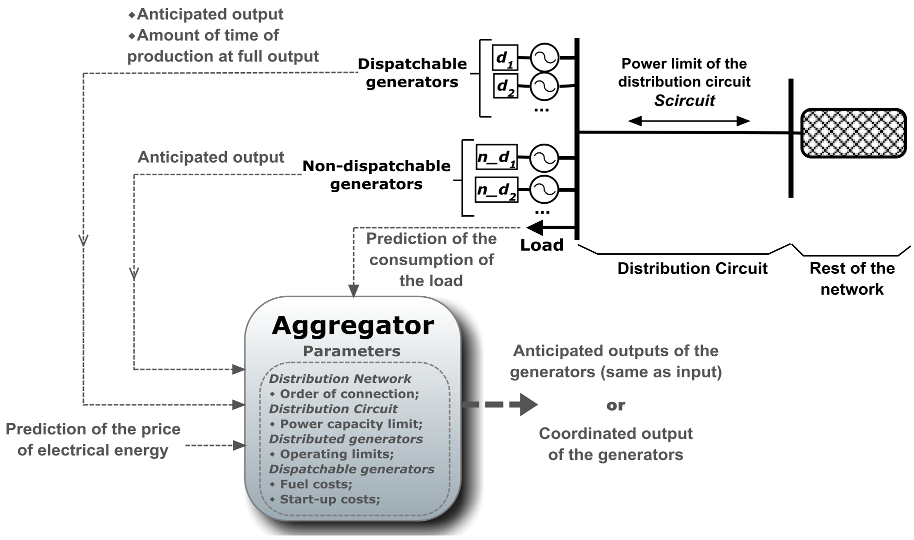

Figure 4.1 - The Aggregator operating the coordination of distributed generators

(2) The Aggregator assesses whether the circuit rating is exceeded by the anticipated outputs by considering an estimation of the load. If the limit is not exceeded, the Aggregator accepts the anticipated outputs and takes no further action. If the limit is exceeded, the Aggregator runs an optimisation algorithm to schedule the dispatchable generators, as described in point (3).

(3) The optimisation algorithm has an objective function (equation (4.1)) to maximise the income of the generators for selling electricity (variable *F*). The decision variables are the active power outputs of the distributed generators, *P*, and the binary variables that indicate the on/off state of the dispatchable generators, *u*, in each time step *h* of the optimisation.

$$\max\ F = \sum_{d=1}^{DIS} w_d \cdot \sum_{h=1}^{H}\left(\rho^h \cdot u_d^h \cdot P_d^h - Fuel_d^h - Start_d^h\right) + \sum_{n\_d=1}^{N\_DIS} w_{n\_d} \cdot \sum_{h=1}^{H} \rho^h \cdot P_{n\_d}^h \tag{4.1}$$

The first term of equation (1) is the income of the dispatchable generators and the second term is the income of the non-dispatchable generators. *d* is the index of the dispatchable generators and *DIS* is the total number of dispatchable generators; *n_d* is the index of the non-dispatchable generators and *N_DIS* is the total number of non-dispatchable generators; *w* is a weight to enforce the order of access to the network when the costs of operation of the generators are the same; *H* is the time span of the optimisation; *ρ* is the price of electrical energy; *Fuel* and *Start* are the terms for the fuel and start-up costs of the dispatchable generator *d* and are given by equation (4.2) and equation (4.3), respectively [63]:

$$Fuel_d^h = u_d^h \cdot fc_d \cdot P_d^h \tag{4.2}$$

$$Start_d^h = \max\left(0;\ su_d \cdot \left(u_d^h - u_d^{h-1}\right)\right) \tag{4.3}$$

fc_d and su_d are the fuel and start-up costs of the dispatchable generator *d*.

The constraints of the optimisation algorithm are the apparent power limit of the distribution circuit (constraint (4.4)), the reactive power requirements of the generators (equations (4.5) and (4.6)), the operating limits of the generators (constraints (4.7) and (4.8)), the amount of electrical energy that the dispatchable generators can produce (constraint (4.9)) and the power factor of the load (equation (4.10)).

Apparent power limit of the distribution circuit

$$\sqrt{\left(\sum_{d=1}^{DIS} P_d^h + \sum_{n\_d=1}^{N\_DIS} P_{n\_d}^h - Pload^h\right)^2 + \left(\sum_{d=1}^{DIS} Q_d^h + \sum_{n\_d=1}^{N\_DIS} Q_{n\_d}^h - Qload^h\right)^2} \leq Scircuit, \forall h \in H \quad (4.4)$$

Reactive power requirements of the generators

$$\begin{cases} Q_d^i = \tan\varphi \cdot P_d^i, \forall i \in I \subseteq H, \forall d \in DIS \\ Q_{n\_d}^i = \tan\varphi \cdot P_{n\_d}^i, \forall i \in I \subseteq H, \forall n\_d \in N\_DIS \end{cases} \quad (4.5)$$

$$\begin{cases} Q_d^j = 0, \forall j \in J \subseteq H \setminus \{I\}, \forall d \in DIS \\ Q_{n\_d}^j = 0, \forall j \in J \subseteq H \setminus \{I\}, \forall n\_d \in N\_DIS \end{cases} \quad (4.6)$$

Operating limits of the generators

Dispatchable generators

$$S\_\min_d \leq S_d^h \leq S\_\max_d, \forall d \in DIS, \forall h \in H \quad (4.7)$$

Non-dispatchable generators

$$S\_\min_{n\_d} \leq S_{n\_d}^h \leq S\_ant_{n\_d}^h, \forall n\_d \in N\_DIS, \forall h \in H \quad (4.8)$$

Amount of electrical energy that the dispatchable generators can produce

$$\sum_{h=1}^{H} \left(u_d^h \cdot S_d^h\right) - \left(TFull_d \cdot S\_\max_d\right) \leq 0, \forall d \in DIS \quad (4.9)$$

Power factor of the load

$$Pload^h = Sload^h \cdot \cos\varphi \quad (4.10)$$

Q is the reactive power output of the generators; φ is the phase angle between current and voltage; *i* and *j* are different time steps within the time span of the optimisation *H*; *S_min* refers to the minimum output powers of the generators; S_*max* is the rated power of the dispatchable generator *d*; *S_ant* is the anticipated power output of the non-dispatchable generator *n_d*; *TFull* is the amount of time that the dispatchable generator *d* can produce continuously at full output power.

(4) The outcome of the optimisation is the coordinated output of the generators that maximises the system income and does not exceed the circuit rating.

The coordination of independent distributed generators assumes a price-based mechanism/incentive that remunerates the generators for their production is already in place. This pricing mechanism is not determined or altered by the Aggregator. In this work, for illustration purposes, the spot price of the Iberian Electricity Market (Portuguese side) is used to evaluate the coordination methodology. Using this pricing signal, generators are scheduled by the Aggregator to maximise their production of electricity.

Some generators would not have an economic incentive to operate in coordination if their income came directly from the electricity they produce. Dispatchable generators connected without firm access rights would see their income reduced, as they are scheduled to operate in hours of lower price of electrical energy. Generators connected with firm access rights would not have any incentive to provide their anticipated outputs to the Aggregator. Therefore, the income received by each generator is determined using a mechanism based on cooperative game theory. Generators are paid what they would receive in "last-in, first-off" operation (i.e., without coordination) plus a share of the additional income obtained in coordination. The income-sharing mechanism is detailed in section 4.3.

4.3 - Sharing the additional income obtained in coordination

Additional income is obtained from the coordinated operation of the generators. This additional income is the result of: i) changing the output of the dispatchable generators (with higher costs of operation) to let the non-dispatchable generators operate; ii) asking the dispatchable generators to operate in hours of reduced output of the non-dispatchable generators (additional electricity production). The Aggregator allocates this additional income using a mechanism based on cooperative game theory. The amount of electrical energy produced and the type of each generator are considered. Each generator receives an allocation of the additional income in addition to the income they would have received in "last-in, first-off" operation. The income-sharing mechanism is explained in section 4.3.1. An assessment of the willingness of the dispatchable generators to participate in the coordination is presented in section 4.3.2.

4.3.1 - Income-sharing mechanism

The coordination of distributed generators produces a system income (*SINC*) given by equation (4.11).

$$SINC = \sum_{d=1}^{DIS}\sum_{h=1}^{H}\left(\rho^h \cdot u_d^h \cdot P_d^h - Fuel_d^h - Start_d^h\right) + \sum_{n\_d=1}^{N\_DIS}\sum_{h=1}^{H}\rho^h \cdot P_{n\_d}^h \qquad (4.11)$$

The system income determined by equation (4.11) is greater than the sum of the income received by the generators in "last-in, first-off" operation. The difference between these two values is the additional income obtained in coordination, δ (see equation (4.12)).

$$\delta = SINC - SINC\_LIFO \qquad (4.12)$$

Being:

$$SINC\_LIFO = \left(\sum_{d=1}^{DIS}\sum_{h=1}^{H}\left(\rho^h \cdot P\_lifo_d^h - Fuel\_lifo_d^h - Start\_lifo_d^h\right) + \sum_{n\_d=1}^{N\_DIS}\sum_{h=1}^{H}\left(\rho^h \cdot P\_lifo_{n\_d}^h\right)\right) \qquad (4.13)$$

The suffix *_lifo* in equation (4.13) refers to the values of the variables in "last-in, first-off" operation.

The Aggregator distributes the additional income considering the coordination as a cooperative game with transferable utility. The additional income is the worth of the coalition of all generators. The core of this cooperative game is the set of allocations that meet three criteria: (i) the additional income is entirely allocated; (ii) all generators receive a greater income in coordination in comparison to "last-in, first-off" operation; (iii) the coalition of all generators provides a greater income for any generator when compared to the income it would have received in a partial coalition (coalitions that do not include all generators). The generators are unable to form partial coalitions. This is because they would need to know the anticipated outputs of the generators outside the coalition and the estimation of load consumption to schedule their own production. Therefore, the criterion iii) is always met. Any allocation inside the core provides all generators an economic incentive to operate in coordination.

The core of this cooperative game can be a large set of allocations. Each of these allocations gives different economic incentives to the generators. So, the Aggregator chooses a single allocation from the core using equation (4.14). This allocation is determined by weighting the amount of electrical energy produced and the type of each generator. Generators at distribution level normally apply for a connection on the basis of the availability of local primary resources. In order to maximise the economic return of their projects, generators seek the cheapest point of connection to the distribution network. This point of connection, determined by the network operator, is normally the closest possible to the generator's site. Therefore, connection to other sections of the distribution network (if allowed by the network operator) to benefit from larger allocations of additional income is likely to affect the economic viability of the generators.

The type of each generator is differentiated using dimensionless technology coefficients (*coef*), agreed beforehand by the generators. The coefficients are reported to the Aggregator before its first operation. These coefficients are not expected to be modified unless an agreement between the generators to periodically revise them has been made. The coefficients are likely to be based on the technology coefficients defined in existing subsidy regimes.

$$\begin{cases} alloc_d = \dfrac{\sum_{h=1}^{H} coef_d \cdot u_d^h \cdot P_d^h}{\sum_{d=1}^{DIS}\sum_{h=1}^{H} coef_d \cdot u_d^h \cdot P_d^h + \sum_{n\_d=1}^{N\_DIS}\sum_{h=1}^{H} coef_{n\_d} \cdot P_{n\_d}^h}, \forall d \in DIS \\ alloc_{n\_d} = \dfrac{\sum_{h=1}^{H} coef_{n\_d} \cdot P_{n\_d}^h}{\sum_{d=1}^{DIS}\sum_{h=1}^{H} coef_d \cdot u_d^h \cdot P_d^h + \sum_{n\_d=1}^{N\_DIS}\sum_{h=1}^{H} coef_{n\_d} \cdot P_{n\_d}^h}, \forall n\_d \in N\_DIS \\ 0 \le alloc_d, alloc_{n\_d} \le 1, \forall d \in DIS, \forall n\_d \in N\_DIS \\ \sum_{d=1}^{DIS} alloc_d + \sum_{n\_d=1}^{N\_DIS} alloc_{n\_d} = 1 \end{cases} \quad (4.14)$$

The income that each generator receives in coordination is given in equation (4.15). Each generator receives an allocation of the additional income in addition to the income it would have received in "last-in, first-off" operation.

$$\begin{cases} income_d = \sum_{h=1}^{H}\left(\rho^h \cdot P\_lifo_d^h - Fuel\_lifo_d^h - Start\_lifo_d^h\right) + \left(alloc_d \cdot \delta\right), \forall d \in DIS \\ income_{n\_d} = \sum_{h=1}^{H}\left(\rho^h \cdot P\_lifo_{n\_d}^h\right) + \left(alloc_{n\_d} \cdot \delta\right), \forall n\_d \in N\_DIS \end{cases} \tag{4.15}$$

The modification of the coefficients alters the amount of additional income allocated to each generator. This affects the income received by each generator in coordination. However, regardless of the defined coefficients the allocations will still remain in the core. This means that the additional income originated is allocated in full and:

- the generators increase their income in coordination when compared to individual operation ("last-in, first-off" operation);
- the generators receive a greater income with the coalition of all generators than with partial coalitions;

Thus, all generators have an economic incentive to be operated in a coordinated manner.

4.3.2 - Assessment of the willingness of the dispatchable generators to participate in the coordination

The dispatchable generators are interested in participating in the coordination as long as their income continues to increase.

Consider the case of a dispatchable generator *d* that reduces its production by one unit of electricity (i.e., 1 MWh) in period *h* to allow a non-dispatchable generator *n_d* to operate. The dispatchable generator is not able to schedule this unit of production in other period. Also, this decrease in production does not lead to an additional start-up cost. The alteration in the production of generators *d* and *n_d* is described by equation (4.16):

$$\begin{cases} P_d^{new} = P_d^h - 1MWh \\ P_{n\_d}^{new} = P_{n\_d}^h + 1MWh \end{cases} \tag{4.16}$$

new refers to the value of the variables after the alteration. The alteration given in equation (4.16) modifies the additional income as shown in equation (4.17).

$$\delta^{new} = \delta + \left[\rho_d^h \cdot 1MWh\right] - \left[\left(\rho_d^h - fc\right) \cdot 1MWh\right] \Leftrightarrow \delta^{new} = \delta + fc \tag{4.17}$$

The additional income increases by the amount of the fuel cost of the dispatchable generator *d* with the alteration shown in equation (4.16). The dispatchable generator will only be interested to continue reducing its output to allow the non-dispatchable generator to produce if (see inequation (4.18)):

$$alloc_d \cdot \delta \le alloc_d^{new} \cdot \delta^{new} \tag{4.18}$$

Developing inequation (4.18):

$$alloc_d \cdot \delta \le alloc_d^{new} \cdot \delta^{new} \Leftrightarrow \frac{alloc_d}{alloc_d^{new}} \cdot \delta \le \left(\delta + fc\right) \Leftrightarrow \delta \cdot \left(\frac{alloc_d}{alloc_d^{new}} - 1\right) \le fc \tag{4.19}$$

The ratio $alloc_d/alloc_d^{new}$ is greater than 1 at all times. When the relation described by inequation (4.19) is not met, the dispatchable generator *d* is no longer interested in continuing to reduce its production.

4.4 - Application of the coordination of generators to a two-busbar distribution network

The coordination of independent distributed generators is evaluated on a two-busbar version of the distribution network introduced in Chapter 3. Four generators are connected to the distribution network: a non-dispatchable generator and a dispatchable generator connected with firm access rights; a dispatchable generator and a non-dispatchable generator connected without firm access rights. An equivalent of the local load is also connected to the distribution network. The evaluation is performed during a selected period of operation of 6 days. This period of operation represents a set of extreme cases of price of electrical energy, wind power and load consumption. The influence of the costs of operation of the dispatchable generator without firm access rights in the additional income is investigated. The allocation of the additional income obtained is reported. The willingness of the dispatchable generators to participate in the coordination is analysed. For this, different technology coefficients are considered. The results of the application of the coordination of generators to the two-busbar distribution network are discussed in the summary.

4.4.1 - Modelling of the two-busbar equivalent of the typical distribution network

The two-busbar network used to evaluate the coordination of distributed generators is illustrated in Figure 4.2.

Generators GenA and GenB are generators connected with firm access rights. GenA is a wind generator (non-dispatchable) and GenB is a thermal generator (dispatchable). GenC and GenD are generators connected without firm access rights. GenC is a thermal generator and GenD is a wind generator. The parameters of the system are given in Table 4.1.

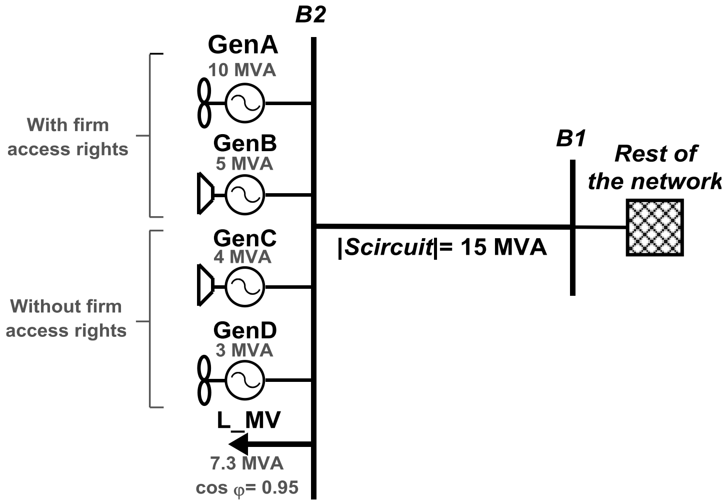

Figure 4.2 - Two-busbar distribution network used to evaluate the coordination

Table 4.1 – Parameters of the system

Parameter	Value	Unit
Power limit of the distribution circuit (Scircuit)	15	MVA
Minimum output power of GenA and GenD (S_minA, S_minD)	0	MVA
Operating limits of GenB ([S_minB; S_maxB])	[2; 5]	MVA
Operating limits of GenC ([S_minC; S_maxC])	[1.6; 4]	MVA
Fuel costs of GenB and GenC (fcB, fcC)	35	€/MWh
Start-up costs of GenB and GenC (suB, suC)	100	€
Load capacity (L_MV)	7.3	MVA
Power factor of L_MV	0.95 (ind)	-

Both active and reactive power flows are considered in the application of the coordination to the two-busbar equivalent of the distribution network. This is to reflect the requirement set in the Portuguese Grid Code with respect to reactive power export in generators below 6 MW of installed capacity. For such generators, reactive power export should be 30% of the active power exported during peak hours (8 a.m. to 10 p.m.) [113]. Therefore, the generators below 6 MW of installed capacity (GenB, GenC and GenD) are required to produce reactive power as follows [113]:

Peak hours (hours 8 to 22)

Reactive power output must be equal to 30% of the active power output ($\tan \varphi = 0.3$);

Off-peak hours (hours 23 to 7)

Reactive power output must be equal to zero;

Losses in the two-busbar equivalent are neglected. The distribution transformer is substituted by a lossless circuit (circuit *B1-B2*) with the same power capacity, *Scircuit*. The local load is represented by an equivalent load, *L_MV*.

4.4.2 - Description of the period of operation considered for evaluating the coordination of distributed generators

The coordination of distributed generators is evaluated on a selected period of six days that represents a set of extreme cases of price of electrical energy, wind power and load consumption (see Tables 4.2 to 4.5 and Figures 4.3 to 4.5).

Table 4.2 - Selected period of operation used for the evaluation of the coordination

Day	Price of electrical energy	Wind power	Load
Day 1	Large variation of price	High wind power	Winter load profile
Day 2	Medium magnitude of price	Medium wind power	Winter load profile
Day 3	High magnitude of price	Low wind power	Winter load profile
Day 4	Large variation of price	High wind power	Summer load profile
Day 5	Medium magnitude of price	Medium wind power	Summer load profile
Day 6	High magnitude of price	Low wind power	Summer load profile

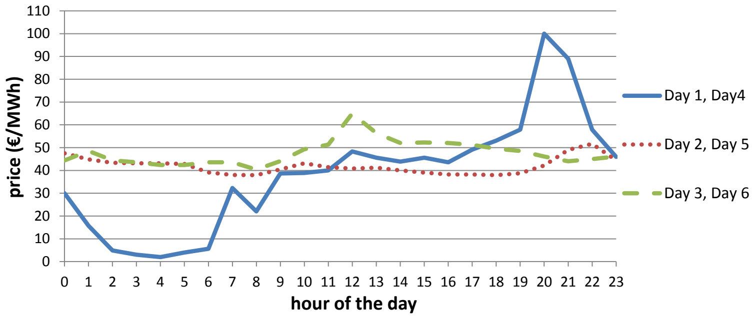

Figure 4.3 - Three profiles of one day of price of electrical energy [120]

Table 4.3 - Average price of electrical energy on each day of the selected period of operation

Average price of electrical energy (€/MWh)		
Day 1, Day 4	Day 2, Day 5	Day 3, Day 6
38.20	41.92	47.75

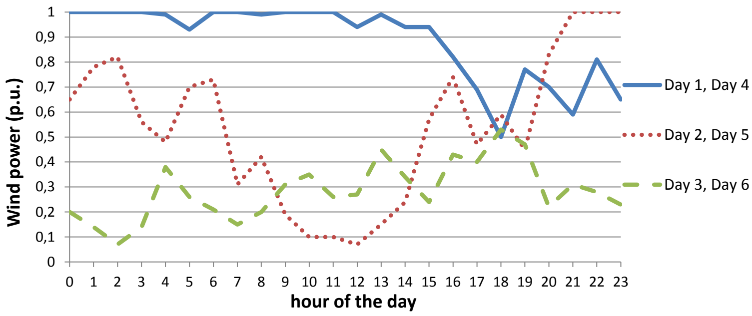

Figure 4.4 - Three profiles of one day of wind power

Table 4.4 - Average wind power on each day of the selected day of operation

Average wind power (p.u.)		
Day 1, Day 4	Day 2, Day 5	Day 3, Day 6
0.89	0.54	0.29

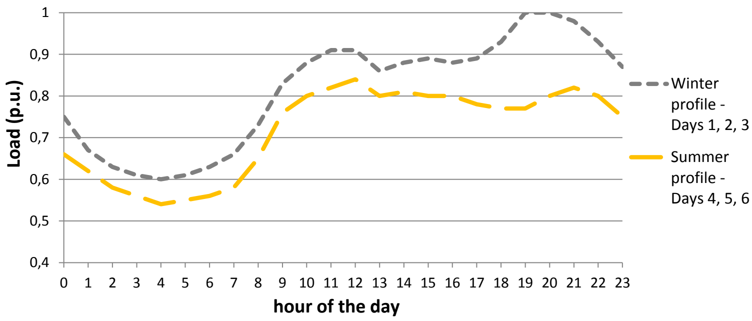

Figure 4.5 - Two profiles of one day of load [114]

Table 4.5 - Average load on each day of the selected period of operation

Average load (p.u.)	
Days 1, 2 and 3	Days 4, 5 and 6
0.81	0.72

The wind power data was obtained from the wind speed data (10-minute average series) of a Portuguese wind farm. This wind speed data was applied to the power curve of the wind turbine *Vestas V80* [121]. Price data was obtained from the Iberian Electricity Market (Portuguese side) [120]. Wind power and price data were not collected on the same days (there is no correlation between data). Load data corresponds to the average consumption profiles of a working day in Portugal from 2004 to 2007, provided by the Portuguese Energy Services Regulator [114]. The load profiles were normalised by the maximum value observed in the winter load profile. Tables with the values of wind power, price of electrical energy and load in each hour of the selected period of operation are given in Appendix C.

4.4.3 - Assessment of the coordination in the selected period of operation

The following considerations are made for the evaluation of the coordination of distributed generators:

- GenA and GenD follow wind power forecasts;
- GenB and GenC predict their output following the given price of electrical energy;
- GenB and GenC are able to operate at full output up to 16 hours;
- Without coordination, the generators access to the network by their order of connection;
- GenB and GenC have the same costs of operation. The costs of operation of GenA and GenD are nil. Therefore, the Aggregator uses weights $(w_A = w_B = 1; w_C = w_D = 0.5)$ to enforce the order of connection of the generators in the coordinated operation.

Tables with the output powers of the generators in each day of operation, without and with coordination, are available in Appendix D.

Day 1, Day 4

Without coordination

Figures 4.6 and 4.7 show the output powers of the generators considering winter (day 1) and summer load profiles (day 4), respectively. GenB and GenC do not produce between hours 0 and 8, because the price of electrical energy is lower than their costs of operation. GenB and GenC produce at full output in the other hours.

There is an excess of power in the distribution circuit on both days, indicated by the shaded areas in Figures 4.6 and 4.7. The Aggregator determines this excess by considering the anticipated outputs of the generators and the estimation of load consumption. The excess is met by GenD, as it was connected last to the network (“last-in, first-off” operation). Since GenD is a wind generator, its curtailed power is lost.

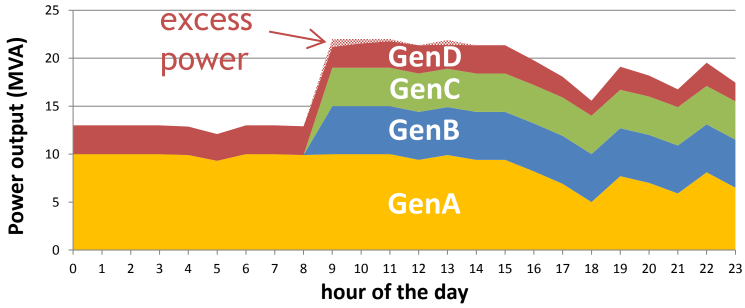

Figure 4.6 - Output powers of the generators without coordination (day 1)

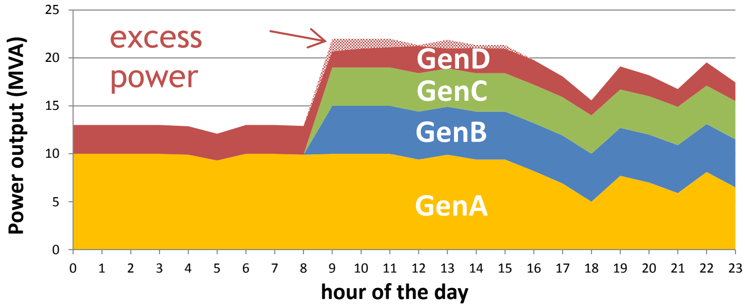

Figure 4.7 - Output powers of the generators without coordination (day 4)

With coordination

The Aggregator schedules GenD to produce up to its available power and reduces GenC to meet the circuit limit. GenC is scheduled because it is a dispatchable generator connected without firm access rights. GenC is not able to operate in other hours because the price of electrical energy is lower than its costs of operation. However, GenC is able to store its production and release it when more convenient. The coordination leads to an additional income due to the exchange of a generator with higher costs of operation by a cheaper one. Figures 4.8 and 4.9 show the coordinated output of the generators with the winter (day 1) and the summer load profiles (day 4), respectively.

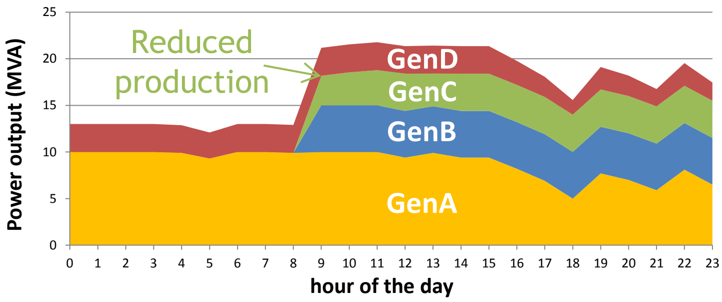

Figure 4.8 - Coordinated output powers of the generators (day 1)

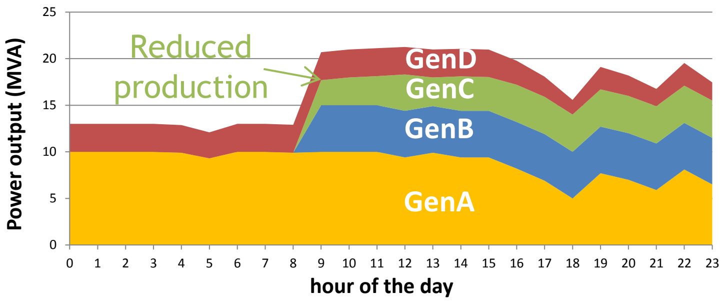

Figure 4.9 - Coordinated output powers of the generators (day 4)

In Tables 4.6 and 4.7 is presented the electrical energy produced and the income of each generator without and with coordination, respectively for day 1 and day 4. GenC produces less in day 4 when compared to day 1, as the amount of load consumption is lower.

Table 4.6 - Electrical energy produced and income received by each generator without and with coordination (day 1)

		GenA	GenB	GenC	GenD	TOTAL
WITHOUT COORDINATION	Electrical energy produced (MWh)	212.50	72.27	57.79	61.25	403.81
	Income received (€)	7511.63	1211.71	948.89	2153.94	11826.17
WITH COORDINATION	Electrical energy produced (MWh)	212.50	72.27	55.88	63.16	403.81
	Income received (€)	7511.63	1211.71	938.20	2231.45	11892.98

Table 4.7 - Electrical energy produced and income received by each generator without and with coordination (day 4)

		GenA	GenB	GenC	GenD	TOTAL
WITHOUT COORDINATION	Electrical energy produced (MWh)	212.50	72.27	57.79	58.50	401.06
	Income received (€)	7511.63	1211.71	948.89	2039.11	11711.33
WITH COORDINATION	Electrical energy produced (MWh)	212.50	72.27	53.13	63.16	401.06
	Income received (€)	7511.63	1211.71	919.38	2231.45	11874.17

The coordination leads to an additional income of 66.81€ in day 1 and 162.84€ in day 4. The total amount of electricity produced is the same with and without coordination in both days.

Day 2, Day 5

<u>Without coordination</u>

Figures 4.10 and 4.11 show the output powers of the generators considering a winter load profile (day 2) and summer load profile (day 5), respectively.

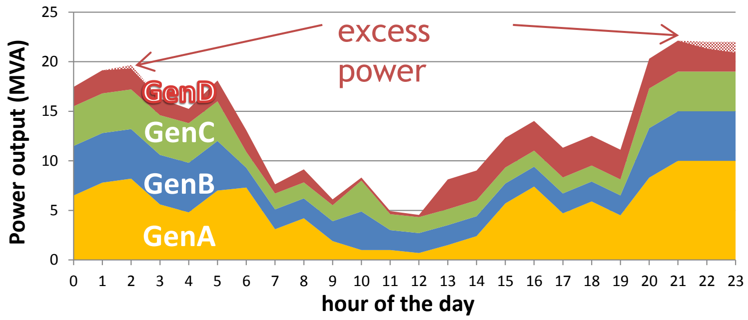

Figure 4.10 - Output powers of the generators without coordination (day 2)

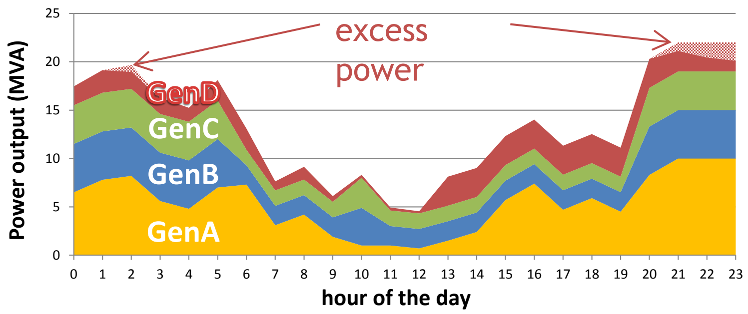

Figure 4.11 - Output powers of the generators without coordination (day 5)

There is an excess of power in the distribution circuit in both days, indicated by the shaded areas in Figures 4.10 and 4.11. This excess is met by GenD, as in days 1 and 4.

With coordination

The Aggregator schedules GenD to produce up to its available power and GenC operates in other hours to avoid exceeding the circuit rating. Figures 4.12 and 4.13 show the coordinated output powers of the generators with the winter (day 2) and the summer load (day 5) profiles, respectively.

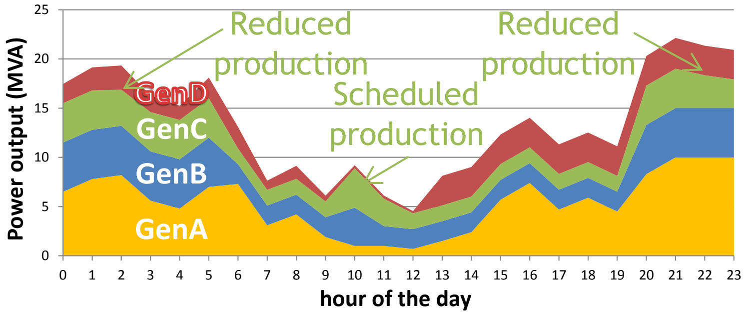

Figure 4.12 - Coordinated output powers of the generators (day 2)

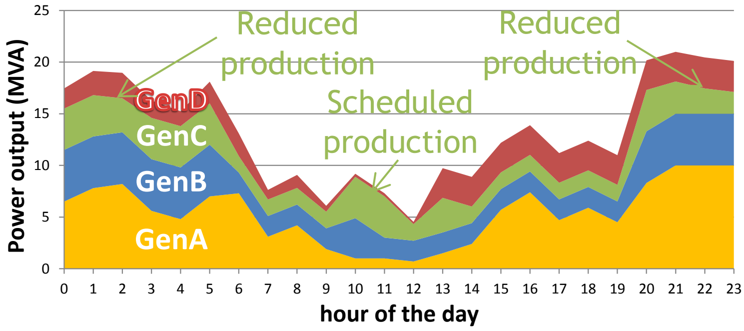

Figure 4.13 - Coordinated output powers of the generators (day 5)

The electrical energy produced and the income of each generator (without and with coordination) in days 2 and 5 is given in Tables 4.8 and 4.9, respectively. GenC has to schedule more production in day 5 when compared to day 2, as the amount of load consumption is lower. The electricity produced by GenC without and with coordination is slightly different in both days. This is due to the change of production from hours without reactive power production requirements to hours when that is required.

The coordination of distributed generators leads to an additional income of 86.62€ in day 2 and 217.40€ in day 5. The additional income originated is due to the exchange of a generator with higher costs of operation by a cheaper one and the additional amount of electricity that was able to be produced.

Table 4.8 - Electrical energy produced and income received by each generator without and with coordination (day 2)

		GenA	GenB	GenC	GenD	TOTAL
WITHOUT COORDINATION	Electrical energy produced (MWh)	129.50	78.43	62.78	47.49	318.20
	Income received (€)	5556.48	643.95	515.28	1992.22	8707.93
WITH COORDINATION	Electrical energy produced (MWh)	129.50	78.43	62.67	49.56	320.16
	Income received (€)	5556.48	643.95	505.31	2088.68	8794.42

Table 4.9 - Electrical energy produced and income received by each generator with and without coordination (day 5)

		GenA	GenB	GenC	GenD	TOTAL
WITHOUT COORDINATION	Electrical energy produced (MWh)	129.50	78.43	62.76	44.46	315.15
	Income received (€)	5556.48	643.95	515.12	1847.13	8562.68
WITH COORDINATION	Electrical energy produced (MWh)	129.50	78.43	62.58	49.56	320.07
	Income received (€)	5556.48	643.95	484.65	2088.68	8773.76

Day 3, Day 6

Without coordination

Figure 4.14 shows the output powers of the generators considering a winter load profile (day 3) and a summer load profile (day 6). The output powers of the generators are the same on both days.

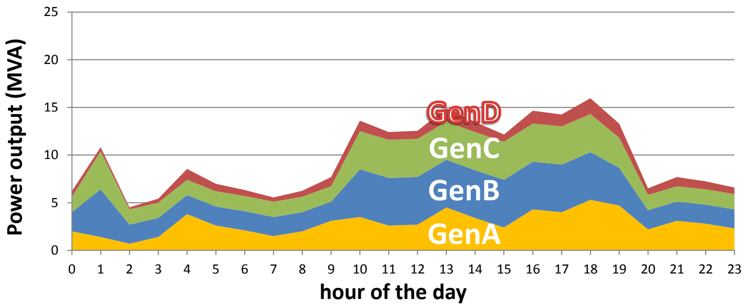

Figure 4.14 - Output powers of the generators on days 3 and 6 - no excess power observed in the distribution circuit

In days 3 and 6 there is no excess power in the distribution circuit. Therefore, the generators produce according to their anticipated outputs and the Aggregator takes no further action.

4.4.3.1 – Considering different costs of operation of GenC

The influence of the costs of operation of GenC in the coordination of generators is investigated. The coordination is evaluated on the selected period of operation considering five different costs of fuel: 25, 30, 35 (the value used in the previous simulations), 40 and 45 € per MWh. The start-up cost is kept at 100€ per start-up. Figure 4.15 shows the additional income obtained in each day with the different costs of fuel of GenC. Points A (day 4, fuel cost= 30 €/MWh) and B (day 5, fuel cost= 45 €/MWh) are indicated for further analysis.

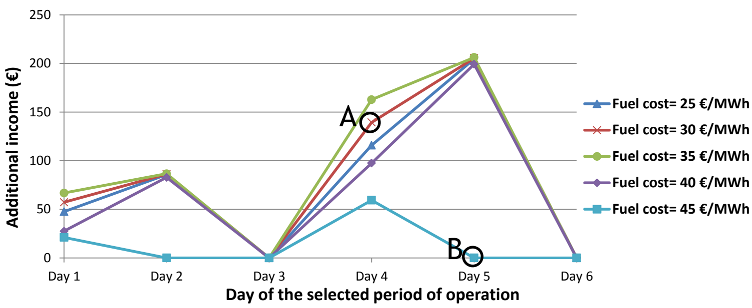

Figure 4.15 - Additional income obtained on each day with different costs of fuel of GenC

Figure 4.16 shows the coordinated output powers of the generators in day 4, when the cost of fuel is 30€/MWh → point A.

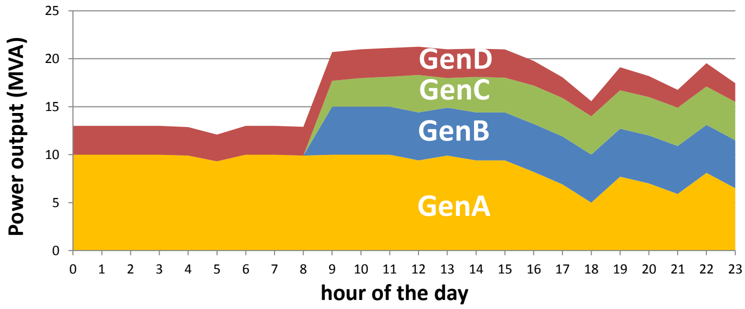

Figure 4.16 - Coordinated output powers of the generators in point A

The output power of the generators is the same as shown in Figure 4.9, when the cost of fuel is 35 €/MWh. However, the additional income obtained is inferior: 140€. This is explained by the reduction in the difference of the costs of fuel of GenC and GenD, which diminishes the additional income.

Figure 4.17 shows the output power of the generators on day 5, when the cost of fuel is 45€/MWh → point B.

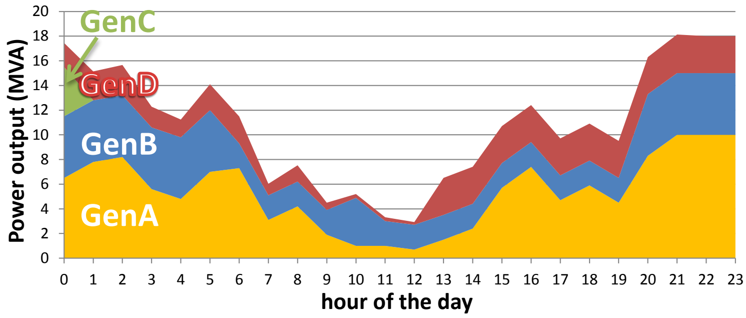

Figure 4.17 - Output powers of the generators in point B

There is no excess power in the distribution circuit in this case. The cost of fuel of GenC is higher than the price of electrical energy almost all day, except in hours 0, 21 and 22. GenC produces in hour 0 because it is was already operating before (no start-up cost). GenC does not produce in hours 21 and 22 because the income received would be inferior to the start-up cost. As the output powers of the generators do not exceed the distribution circuit rating, there is no coordination and the additional income is nil.

Figure 4.18 shows the additional income obtained on the selected week of operation with the different costs of fuel of GenC.

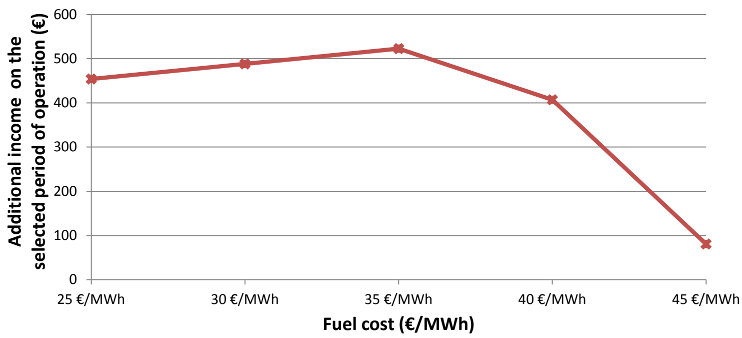

Figure 4.18 - Additional income obtained on the selected week of operation with different costs of fuel of GenC

Figure 4.18 shows that, for this two-busbar distribution network and with the data and assumptions considered, the coordination of distributed generators has greater value when the cost of fuel of GenC is 35 €/MWh.

4.4.4 - Allocation of the additional income to the generators

The income of the generators is higher when they coordinate their output powers, in comparison to “last-in, first-off” operation. However, if the income received by each generator came directly from its electrical energy produced: GenA and GenB would receive the same as in “last-in, first-off” operation; GenC would receive less; and GenD would receive more. GenA and GenB would have no economic incentive to provide their anticipated outputs to the Aggregator. This way, GenA, GenB and GenC would prefer to maintain “last-in, first-off” operation.

Then, the additional income obtained in coordination is allocated using a cooperative game with transferable utility. The technology coefficients used are the ones used in Portugal for the remuneration of renewable generators [122]. The formula to remunerate renewable generators contains a coefficient that differentiates the type of generation. The technology coefficients used are shown in Table 4.10.

Table 4.10 - Technology coefficients used in the income-sharing mechanism [122]

	GenA	GenB	GenC	GenD
Technology coefficient	4.6	8.2	8.2	4.6
Technology	Wind	Non-CHP biomass (forestry residues)	Non-CHP biomass (forestry residues)	Wind

The allocations of the additional income chosen by the Aggregator for each day, using equations (4.11) to (4.14), are given in Figures 4.19 to 4.22. The income received by each generator with the income-sharing mechanism (equation (4.15)) is given in Tables 4.11 to 4.14. A comparison with the income received by each generator in “last-in, first-off” operation is also provided.

Day 1

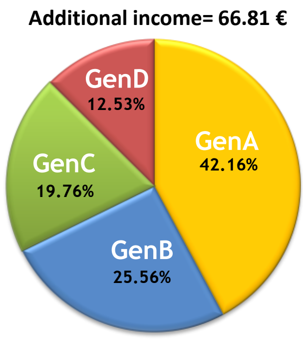

Figure 4.19 - Sharing of the additional income obtained on day 1 (66.87€)

Table 4.11 - Income received by each generator without coordination and with the income-sharing mechanism (day 1)

		GenA	GenB	GenC	GenD	TOTAL
WITHOUT COORDINATION	Income received (€)	7511.63	1211.71	948.89	2153.94	11826.17
WITH COORDINATION (income-sharing mechanism)	Income received (€)	7539.80	1228.78	962.09	2162.31	11892.98
Variation		(+28.17€, +0.37%)	(+17.07€, +1.41%)	(+13.20€, +1.39%)	(+8.37€, +0.39%)	(+66.81€, +0.56%)

Day 2

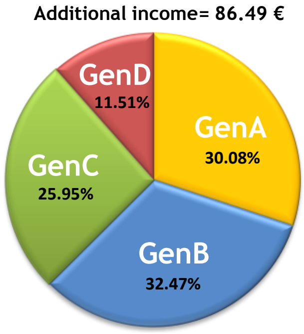

Figure 4.20 - Sharing of the additional income obtained on day 2 (86.49€)

Table 4.12 - Income received by each generator without coordination and with the income-sharing mechanism (day 2)

		GenA	GenB	GenC	GenD	TOTAL
WITHOUT COORDINATION	Income received (€)	5556.48	643.95	515.28	1992.22	8707.93
WITH COORDINATION (income-sharing mechanism)	Income received (€)	5582.50	672.02	537.72	2002.18	8794.42
Variation		(+26.01€, +0.47%)	(+28.07€, +4.36%)	(+22.44€, +4.36%)	(+9.96€, 0.50 %)	(+86.49€, +0.99%)

Day 4

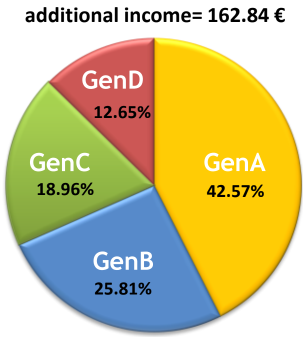

Figure 4.21 - Sharing of the additional income obtained on day 4 (162.84€)

Table 4.13 - Income received by each generator without coordination and with the income-sharing mechanism (day 4)

		GenA	GenB	GenC	GenD	TOTAL
WITHOUT COORDINATION	Income received (€)	7511.63	1211.71	948.89	2039.11	11711.33
WITH COORDINATION (income-sharing mechanism)	Income received (€)	7580.95	1253.74	979.77	2059.72	11874.17
Variation		(+69.32€, +0.92%)	(+42.03€, +3.47%)	(+30.88€, +3.25%)	(+20.61€, +1.01%)	(+162.84€, +1.39%)

Day 5

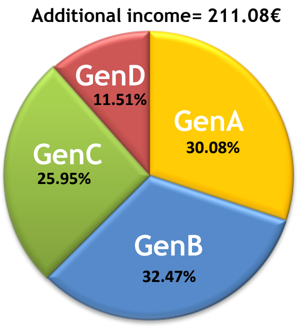

Figure 4.22 - Sharing of the additional income obtained on day 5 (211.08€)

Table 4.14 - Income received by each generator without coordination and with the income-sharing mechanism (day 5)

		GenA	GenB	GenC	GenD	TOTAL
WITHOUT COORDINATION	Income received (€)	5556.48	643.95	515.12	1847.13	8562.68
WITH COORDINATION (income-sharing mechanism)	Income received (€)	5619.99	712.51	569.83	1871.43	8773.76
Variation		(+63.51€, +1.14%)	(+68.56€, +10.65%)	(+54.71, +10.62%)	(+24.30€, +1.32%)	(+211.08€, +2.47%)

All generators increase their income when the income-sharing mechanism is used. The generators connected with firm access rights, GenA and GenB, increase their income despite not being scheduled. This is because the other generators cannot be scheduled without information about the anticipated outputs of GenA and GenB. So, GenA and GenB are rewarded for communicating their anticipated outputs to the Aggregator.

4.4.4.1 – Willingness of the dispatchable generators to participate in the coordination

The effect in the additional income of GenC of its marginal decrease in production (-1 MWh) to allow a marginal increase in the production of GenD (+1 MWh) in day 1 is evaluated. GenC is not able to schedule its production in other hours of that day because the price of electrical energy is lower than its costs of operation. The output power of the other dispatchable generator (GenB) is not altered.

Figure 4.23 shows the additional income received by GenC when its production is reduced to allow the production of the same amount of electricity by GenD. The reference point of the *x*-axis (PC, PD) is the output power of the two generators in coordination as reported in Table 4.6 (P_C= 55.88 MWh, P_D= 63.16 MWh). In Figure 4.23 is also shown how the additional income varies with different sets of technology coefficients. The sets of technology coefficients considered are:

- The coefficients defined in the Portuguese legislation (same as adopted in section 4.4.4 and shown in Table 4.10);
- Coefficients of the same value for all generators (no distinction);
- Coefficients of the dispatchable generators are three times the non-dispatchable generators' ($coef_B$= $coef_C$= 3.$coef_A$= 3.$coef_D$);
- Coefficients of the non-dispatchable generators are three times the dispatchable generators' ($coef_A$= $coef_D$= 3.$coef_B$= 3.$coef_C$);

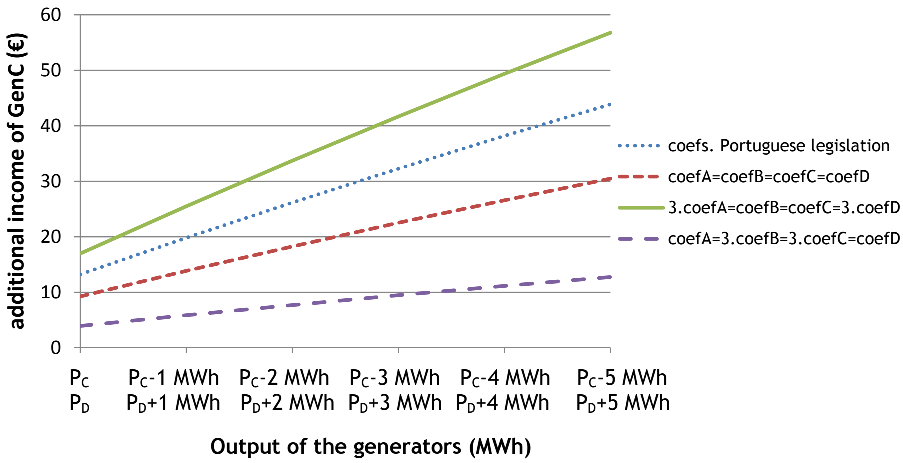

Figure 4.23 - Effect in the additional income of GenC of its reduction to allow GenD to produce, considering different technology coefficients

The additional income of GenC increases when its production is reduced to allow GenD to produce. This increase occurs with every set of technology coefficients considered. Thus, all other generators are willing to participate in the coordination.

4.5 - Summary

The coordination of independent distributed generators has been evaluated. The evaluation has been performed on a two-busbar distribution network. A period of operation was selected, representing different cases of wind power, price of electrical energy and load consumption.

The coordination allows generators to maximise their income without exceeding the power limit of the distribution circuit. The allocation of the additional income allows all generators to increase their income. The additional income is greater when the dispatchable generators reduce their output to allow the non-dispatchable generators to operate and are able to schedule their production in other hours. In some hours the dispatchable generators are not able to schedule all their production to allow the non-dispatchable generators to produce. This is because then their costs of operation are higher than the price of electricity.

The share of additional income received by each generator is added to what they would receive in “last-in first-off” operation (i.e., without coordination). Generators with firm access rights receive more and thus have an incentive to be operated in a coordinated manner. Generators without firm access rights are able to increase their income when compared to “last-in, first-off” operation. Therefore, considering different costs of operation and allocations of the additional income, all generators are able to improve the return of their projects when compared to the return they would have if “last-in, first-off” operation were in place.

Chapter 5 - Coordinating generators and controllable load

5.1 - Introduction

The coordination of generators and controllable load aims to maximise the income of the generators. A controllable load has flexibility to shift at least part of its consumption. The Aggregator shifts the consumption of the controllable load to allow the generators to maximise their production. Additional income is obtained from: i) the additional energy that the generators are able to produce; ii) the change of production to hours with a higher price of electrical energy. The additional income is allocated to the generators and the controllable load. A bargaining approach of game theory is used to set this allocation. The coordination of generators and controllable load is evaluated considering different cases of load flexibility and capacity.

5.2 - Integration of a controllable load in the coordination

The objective of the coordination of generators and controllable load is to maximise the income of the generators. In the coordination of independent distributed generators described in Chapter 4, load was considered not to be controllable. Thus, generators produced up to the limit of the distribution circuit and the load was considered to be determined. In the coordination of generators and controllable load, the controllable load is asked to shift its consumption to: i) allow generators to produce additional electricity; ii) allow generators to change their production to hours of higher price of electrical energy. The operation of the Aggregator in the coordination of generators and controllable load has two stages (see Figure 5.1):

- first, generators are scheduled as if load was determined (as described in Chapter 4);
- second, if the production of the generators is not maximised, the Aggregator operates the coordination of generators and controllable load.

The additional income obtained is allocated so that both generators and the load have an economic incentive to be operated in a coordinated manner.

5.2.1 - Assumptions and limitations

The coordination of generators and controllable load is formulated considering the following assumptions and limitations:

- The controllable load is not owned by any of the generators;
- Without coordination with the generators, the controllable load schedules its flexible consumption in the hours of lower price;
- Only the energy component is considered in the price paid by the load for buying electricity. Transmission/distribution charges, VAT and other costs are not considered.

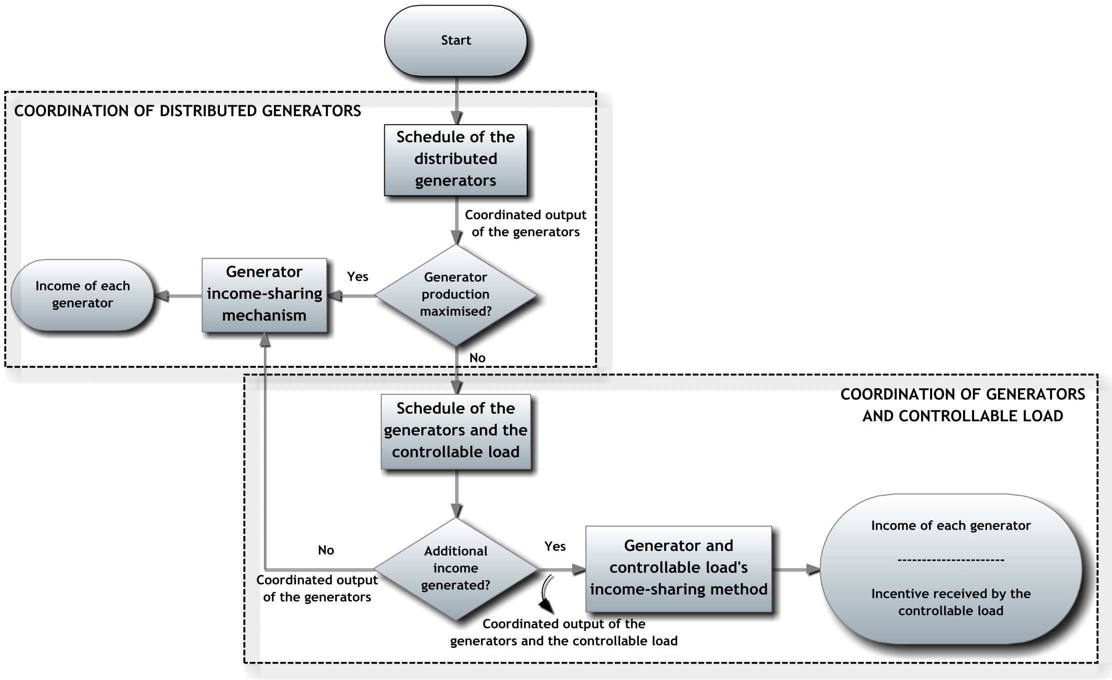

Figure 5.1 - Operation of the Aggregator with the integration of a controllable load in the coordination

5.2.2 - Operation of the Aggregator with the integration of the controllable load

The Aggregator has an additional input and two additional parameters (marked with *) in the coordination of generators and controllable load, see Figure 5.2.

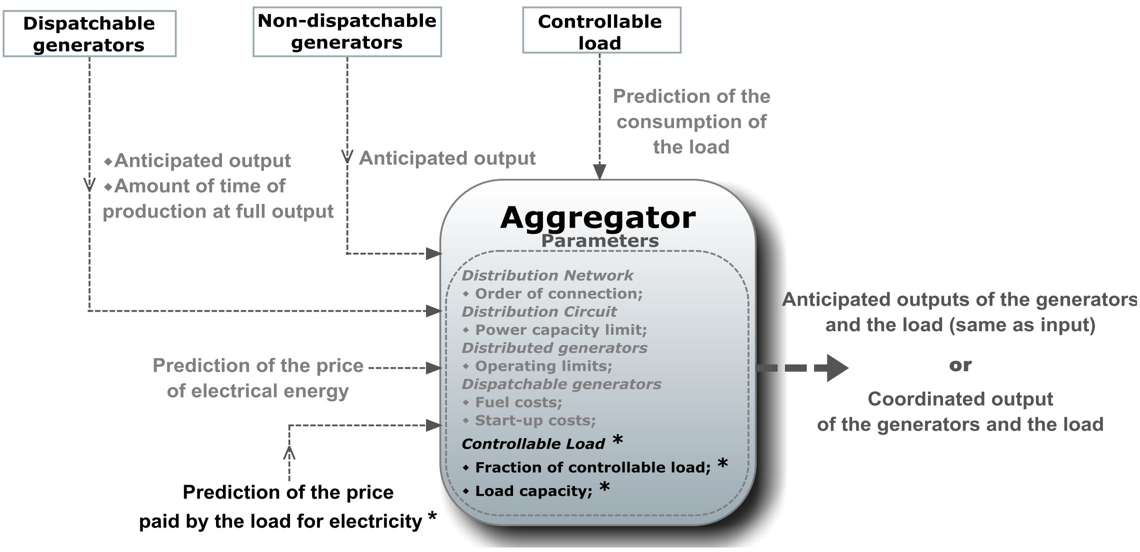

Figure 5.2 - Inputs, parameters and outcomes of the Aggregator in the coordination of generators and controllable load

The objective function maximises the income of the generators (INC_DIS for the dispatchable generators and INC_N_DIS for the non-dispatchable generators) considering the cost of shifting the consumption of the controllable load, $COST\_L$ (see equations (5.1) to (5.4)).

Maximise the income of the generators considering the cost of shifting the load

$$\max\ SINC\_new = INC\_DIS + INC\_N\_DIS - COST\_L \quad (5.1)$$

Being:

$$INC\_DIS = \sum_{d=1}^{DIS}\sum_{h=1}^{H}\left(\rho^{h}\cdot u\_new_{d}^{h}\cdot P\_new_{d}^{h} - Fuel\_new_{d}^{h} - Start\_new_{d}^{h}\right) \quad (5.2)$$

$$INC\_N\_DIS = \sum_{n\_d=1}^{N\_DIS}\sum_{h=1}^{H}\rho^{h}\cdot P\_new_{n\_d}^{h} \quad (5.3)$$

$$COST\_L = \sum_{h=1}^{H}\rho_{L}^{h}\cdot\left(Sload\_new^{h} - Sload\_no\_coord^{h}\right) \quad (5.4)$$

The suffix $\_new$ updates the value of the variables introduced in Chapter 4 to the coordination of generators and controllable load. The decision variables are u_new_d, P_new_d, $P\_new_{n\_d}$ and $Sload\_new$. The new fuel and start-up costs of each dispatchable generator *d* are given in equations (5.5) and (5.6), respectively:

$$Fuel\_new_{d}^{h} = u\_new_{d}^{h}\cdot fc_{d}\cdot P\_new_{d}^{h} \quad (5.5)$$

$$Start\_new_{d}^{h} = \max\left(0;\ su_{d}\cdot\left(u\_new_{d}^{h} - u\_new_{d}^{h-1}\right)\right) \quad (5.6)$$

Variable $Sload\_new$ is the consumption schedule of the controllable load after the coordination with the generators. ρ_L is the price paid by the controllable load for buying electricity. $Sload\_no\_coord$ is the consumption schedule of the controllable load if there was no coordination with the generators. There are no weights in equation (5.1) to enforce the order of access to the network when the costs of operation of the generators are the same. When the costs of operation are the same, the Aggregator adjusts the generation schedule after the optimisation to enforce the order of connection of the generators.

The maximisation presented in equation (5.1) is subject to the apparent power limit of the distribution circuit (constraint (5.7)), the reactive power requirements of the generators (equations (5.8) and (5.9)), the operating limits of the generators (constraints (5.10) and (5.11)), the amount of electrical energy that the dispatchable generators are able to produce (constraint (5.12)), the power factor of the controllable load (equation (5.13)), the upper and lower bounds of flexible consumption (constraints (5.14) and (5.15)) and the maintenance of the same amount of consumption before and after the coordination with the generators (equation (5.16)).

Apparent power limit of the distribution circuit

$$\sqrt{\left(\sum_{d=1}^{DIS}P\_new_{d}^{h} + \sum_{n\_d=1}^{N\_DIS}P\_new_{n\_d}^{h} - Pload\_new^{h}\right)^{2} + \left(\sum_{d=1}^{DIS}Q\_new_{d}^{h} + \sum_{n\_d=1}^{N\_DIS}Q\_new_{n\_d}^{h} - Qload\_new^{h}\right)^{2}} \le Scircuit, \forall h \in H \quad (5.7)$$

Reactive power requirements of the generators

$$\begin{cases} Q\_new_{d}^{i} = \tan\varphi\cdot P\_new_{d}^{i}, \forall i \in I \subseteq H, \forall d \in DIS \\ Q\_new_{n\_d}^{i} = \tan\varphi\cdot P\_new_{n\_d}^{i}, \forall i \in I \subseteq H, \forall n\_d \in N\_DIS \end{cases} \quad (5.8)$$

$$\begin{cases} Q\_new_d^j = 0, \forall j \in J \subseteq H \setminus \{I\}, \forall d \in DIS \\ Q\_new_{n\_d}^j = 0, \forall j \in J \subseteq H \setminus \{I\}, \forall n\_d \in N\_DIS \end{cases} \tag{5.9}$$

Operating limits of the generators

Dispatchable generators

$$S\_\min_d \leq S\_new_d^h \leq S\_\max_d, \forall d \in DIS, \forall h \in H \tag{5.10}$$

Non-dispatchable generators

$$S\_\min_{n\_d} \leq S\_new_{n\_d}^h \leq S\_ant_{n\_d}^h, \forall n\_d \in N\_DIS, \forall h \in H \tag{5.11}$$

Amount of electrical energy that the dispatchable generators can produce

$$\sum_{h=1}^{H} \left(u\_new_d^h \cdot S\_new_d^h\right) - \left(TFull_d \cdot S\_\max_d\right) \leq 0, \forall d \in DIS \tag{5.12}$$

Power factor of the controllable load

$$Pload^h = Sload^h \cdot \cos\varphi \tag{5.13}$$

Upper and lower bounds of flexible consumption

$$Sload\_lbound^h \leq Sload\_new^h \leq Sload\_ubound^h, \forall h \in H \tag{5.14}$$

$$\begin{cases} Sload\_lbound^h = Sload^h \cdot (1 - flex\_fraction) \\ Sload\_ubound^h = \min\left(Sload\_\max; Sload^h \cdot (1 + flex\_fraction)\right) \end{cases} \tag{5.15}$$

Same consumption before and after the coordination

$$\sum_{h=1}^{H} Sload\_new^h = \sum_{h=1}^{H} Sload^h \tag{5.16}$$

$flex\_fraction$ is the fraction of controllable load (value between 0 and 1) and $Sload\_max$ is the capacity of the controllable load.

5.3 - Allocation of the additional income obtained with the coordination of generators and controllable load

The coordination leads to an additional income when changing the production of the generators provides an income higher than the cost of changing the consumption of the load. The additional income obtained, δ_new, is given by equation (5.17).

$$\delta\_new = SINC\_new - SINC \tag{5.17}$$

$SINC\_new$ is the income obtained with the coordination of generators and controllable load (equation (5.1)) and *SINC* is the income obtained with the coordination of distributed generators (equation (4.11)).

The allocation of the additional income δ_new is made considering the coordination of generators and controllable load as a problem of Rubinstein bargaining [123]. Rubinstein bargaining is a non-cooperative game theory approach that addresses the negotiation between two players (in this case, the generators and the controllable load) that make alternating offers for sharing of a certain amount until one player accepts an offer. The offers made by each player are the allocation of the additional income δ_new. According to the Rubinstein bargaining model, the generators and the controllable load should share the additional income δ_new in equal parts (50% for each player) if:

- There is no devaluation of the amount to be shared after each round of negotiation. The negotiation occurs for a limited amount of time;
- No player has interest in deliberately delaying the negotiation. Both have equal interest in the success of it;
- The bargaining power of the players is equal, because they do not share privileged information. The Aggregator collects the parameters and inputs of the system without disclosing them to any of the players.

As the aforementioned conditions are met, the additional income received by the generators, δ_gen, is given by equation (5.18):

$$\delta\_gen = \delta + (0.5 \cdot \delta\_new) \tag{5.18}$$

δ is the additional income obtained in the coordination of distributed generators, see equation (4.12). The new allocation of the additional income to each generator is given in equation (5.19).

$$\begin{cases} alloc\_new_d = \dfrac{\sum_{h=1}^{H} coef_d \cdot u\_new_d^h \cdot P\_new_d^h}{\sum_{d=1}^{DIS}\sum_{h=1}^{H} coef_d \cdot u\_new_d^h \cdot P\_new_d^h + \sum_{n\_d=1}^{N\_DIS}\sum_{h=1}^{H} coef_{n\_d} \cdot P\_new_{n\_d}^h}, \forall d \in DIS \\ alloc\_new_{n\_d} = \dfrac{\sum_{h=1}^{H} coef_{n\_d} \cdot P\_new_{n\_d}^h}{\sum_{d=1}^{DIS}\sum_{h=1}^{H} coef_d \cdot u\_new_d^h \cdot P\_new_d^h + \sum_{n\_d=1}^{N\_DIS}\sum_{h=1}^{H} coef_{n\_d} \cdot P\_new_{n\_d}^h}, \forall n\_d \in N\_DIS \\ 0 \le alloc\_new_d, alloc\_new_{n\_d} \le 1, \forall d \in DIS, \forall n\_d \in N\_DIS \\ \sum_{d=1}^{DIS} alloc\_new_d + \sum_{n\_d=1}^{N\_DIS} alloc\_new_{n\_d} = 1 \end{cases} \tag{5.19}$$

The income received by the generators is given in equation (5.20), which is an update of equation (4.15) to include the terms $alloc\_new$ and δ_gen.

$$\begin{cases} income\_new_d = \sum_{h=1}^{H} \left(\rho^h \cdot P\_lifo_d^h - Fuel\_lifo_d^h - Start\_lifo_d^h\right) + \left(alloc\_new_d \cdot \delta\_gen\right), \forall d \in DIS \\ income\_new_{n\_d} = \sum_{h=1}^{H} \left(\rho^h \cdot P\_lifo_{n\_d}^h\right) + \left(alloc\_new_{n\_d} \cdot \delta\_gen\right), \forall n\_d \in N\_DIS \end{cases} \tag{5.20}$$

The income received by the controllable load after the coordination with the generators is given in equation (5.21).

$$income_L = COST\_L + (0.5 \cdot \delta\_new) \tag{5.21}$$

The first term in equation (5.21), $COST\_L$, allows the load to cover the cost of changing its consumption. $COST\_L$ is given by equation (5.4). The second term, $(0.5 \cdot \delta\_new)$, represents the incentive of the load for its operation in a coordinated manner.

5.4 - Example of the coordination with a controllable load on the two-busbar distribution network

The coordination of generators and controllable load is evaluated on the two-busbar distribution network introduced in Chapter 4. The load connected to the distribution network is now considered to have flexible consumption. Different fractions of controllable load and load capacities are evaluated. The evaluation is performed on the same selected period of operation. This period of operation represents a set of extreme cases of price of electrical energy, wind power and load consumption. The additional income obtained is quantified and the incentives for both generators and the load are reported.

5.4.1 - Description of the price paid by the controllable load for buying electricity

The price paid by the controllable load for buying electricity is different from the price of electrical energy. In each day of the period of operation, the load pays for electricity the price of electrical energy plus a margin of 6%, which corresponds to the supplier's net margin[1] (see Figures 5.3 to 5.5).

Day 1, Day 4

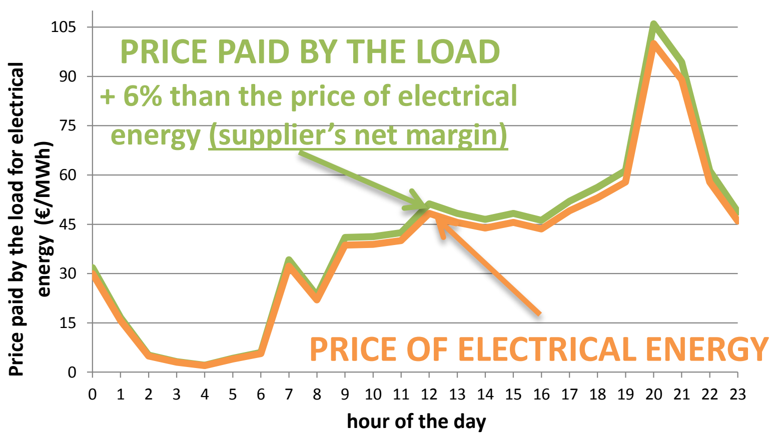

Figure 5.3 - Price paid by the controllable load for buying electricity on days 1 and 4

Day 2, Day 5

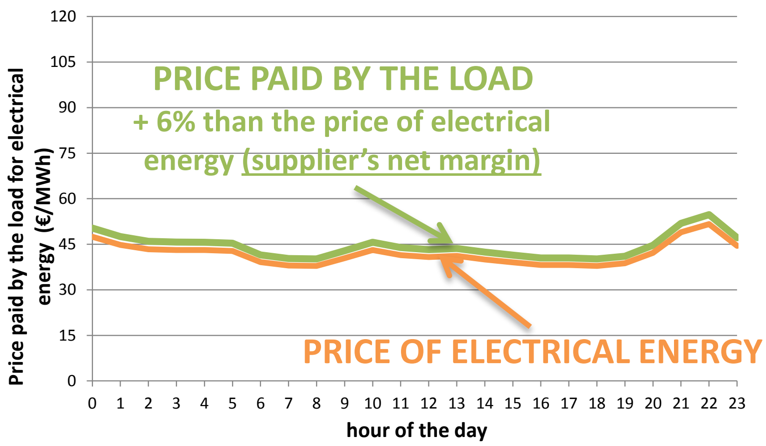

Figure 5.4 - Price paid by the controllable load for buying electricity on days 2 and 5

[1] Value obtained from Ofgem (UK) for electricity consumers, September 2012 (available online: https://www.ofgem.gov.uk/ofgem-publications/39751/electricity-and-gas-supply-market-indicators-5-september-2012.pdf – last accessed on 04/12/2012)

Day 3, Day 6

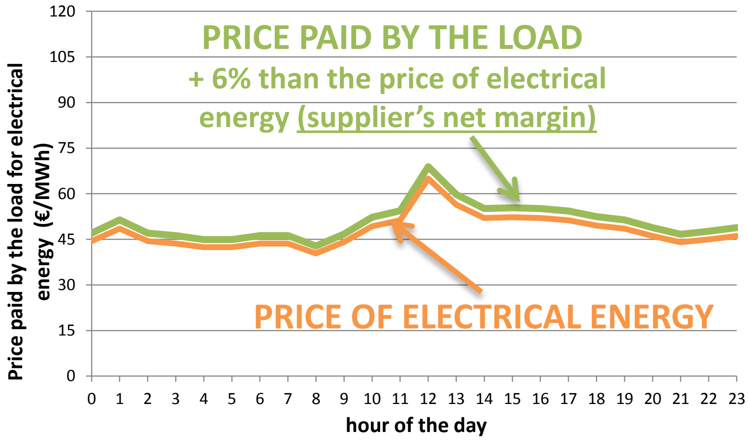

Figure 5.5 - Price paid by the controllable load for buying electricity on days 3 and 6

5.4.2 - Assessment on the selected period of operation

The coordination is evaluated on the selected period of operation considering:

- fractions of ±10% and ±100% load flexibility, considering a load capacity of 7.3 MVA with a power factor of 0.95;
- fractions of ±10% and ±100% load flexibility considering different load capacities (from no load to two times the installed capacities of the generators connected without firm access rights, *GenC* and *GenD*).

The generation and consumption schedules determined by the Aggregator in each day of operation are provided in Appendix E. Generation and consumption schedules without coordination are also given.

5.4.2.1 – Considering a ±10% fraction of load flexibility

Day 1

<u>Without coordination of generators and controllable load</u>

The controllable load schedules its flexible consumption in the hours of lower price. Considering the price for buying electricity shown in Figure 5.3, the controllable load schedules its consumption as illustrated in Figure 5.6.

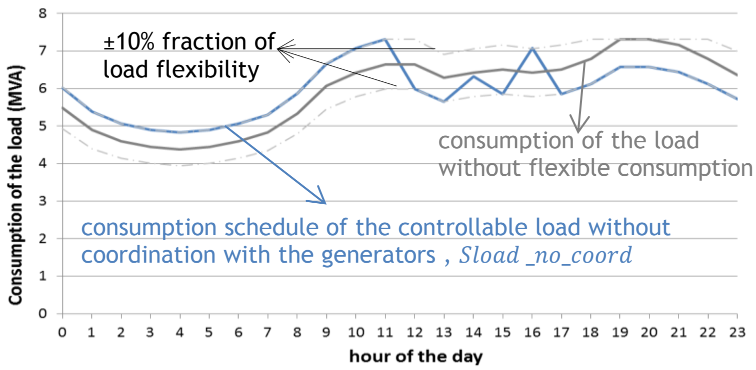

Figure 5.6 - Consumption schedule of the controllable load with a ±10% fraction of load flexibility on day 1 (no coordination with the generators)

The Aggregator schedules the generators but GenC is unable to produce all its available production in hours 9, 12, 13 and 15 (see the shaded areas in

Figure 5.7). This is because the distribution circuit limit was reached and GenC could not schedule its available production in hours 0 to 8. This is because the price of electrical energy then is lower than the operation costs of GenC.

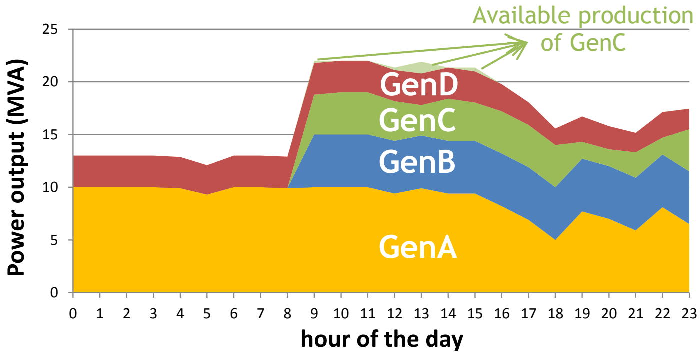

Figure 5.7 - Coordinated output of the generators with a ±10% fraction of load flexibility on day 1 (without coordination with the controllable load)

With coordination of generators and controllable load

The Aggregator operates the coordination by changing the consumption of the controllable load to allow GenC to produce, see Figure 5.8. GenC still does not produce all its available production because the load is already at its maximum consumption in hour 9.

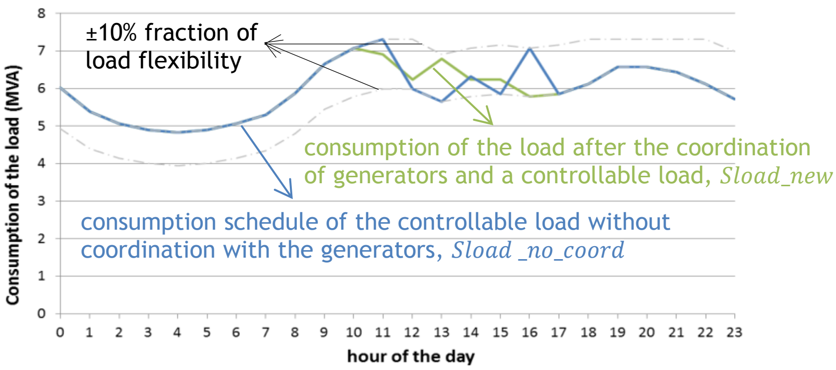

Figure 5.8 - Consumption of the controllable load after the operation of the coordination of generators and controllable load, with a ±10% fraction of load flexibility on day 1

The additional income obtained with the coordination, δ_new, considering a ±10% fraction of flexible consumption on day 1 is given in Table 5.1.

Table 5.1 - Additional income obtained with the coordination, with a ±10% fraction of load flexibility on day 1

Income of the additional production of GenC (€)	Increase of the electricity bill of the load, $COST\_L$ (€)	Additional income δ_new (€)
18.34	5.90	12.44

Days 2 to 6

On days 2 to 6, the additional income obtained is given in Table 5.2.

Table 5.2 - Additional income obtained with the coordination, with a ±10% fraction of load flexibility on days 2 to 6

Day	Day 2	Day 3	Day 4	Day 5	Day 6
Additional income δ_new (€)	0	0	8.90	0	0

On all days except day 4, the production of the generators is maximised after the operation of the coordination of distributed generators. Therefore, the coordination of generators and controllable load is not operated in those days.

5.4.2.2 – Considering a ±100% fraction of load flexibility

Day 1

Without coordination of generators and controllable load

The controllable load schedules its flexible consumption in the hours of lower price. Considering the price for buying electricity shown in Figure 5.3, the load schedules its consumption as illustrated in Figure 5.9.

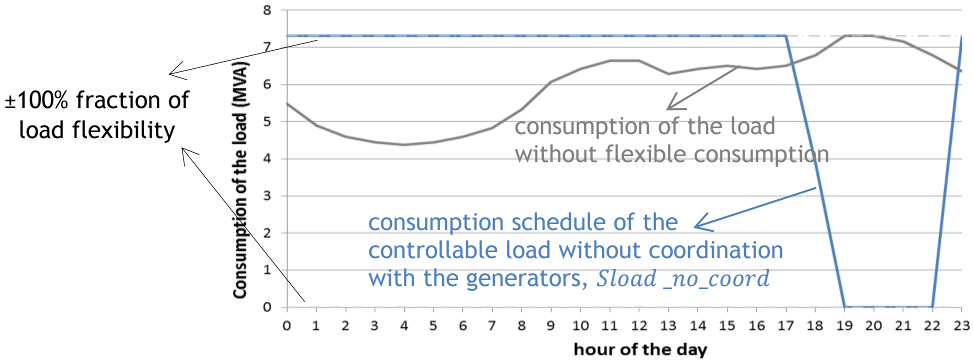

Figure 5.9 - Consumption schedule of the controllable load with a ±100% fraction of load flexibility on day 1 (no coordination with the generators)

The Aggregator schedules the generators, but GenB and GenC are unable to produce all their available production between hours 19 and 22 (see the shaded area in Figure 5.10). This is because the distribution circuit limit was reached and both GenB and GenC could not schedule their available production in hours 0 to 8. The price of electrical energy then is lower than the operation costs of GenB and GenC.

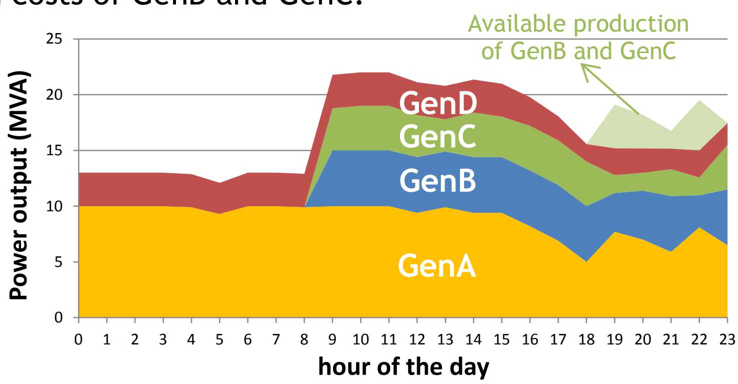

Figure 5.10 - Coordinated output of the generators with a ±100% fraction of load flexibility on day 1 (without coordination with the controllable load)

With coordination of generators and controllable load

The Aggregator operates the coordination by changing the consumption of the controllable load to allow GenB and GenC to produce, see Figure 5.11.

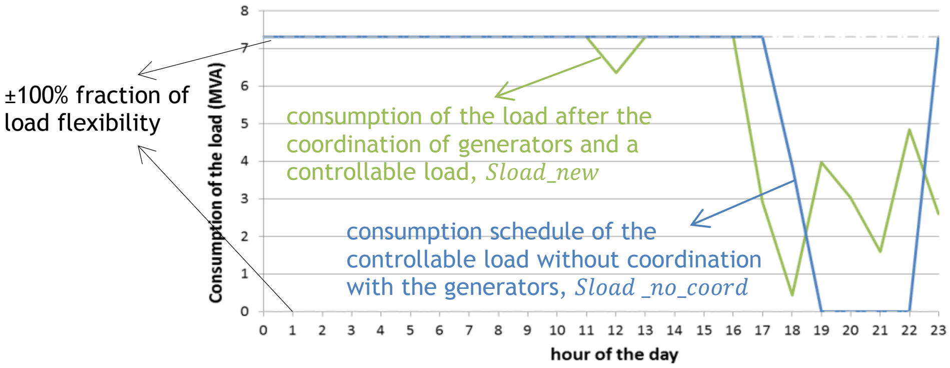

Figure 5.11 - Consumption of the controllable load after the operation of the coordination of generators and controllable load, with a ±100% fraction of load flexibility on day 1

The consumption profile of the controllable load in coordination allows the generators to maximise their production. The additional income obtained with the coordination of generators and controllable load, δ_new, considering a ±100% fraction of flexible consumption in day 1 is shown in Table 5.3.

Table 5.3 - Additional income obtained with the coordination of generators and controllable load, with a ±100% fraction of load flexibility on day 1

Income of the additional production of GenB and GenC (€)	Increase of the electricity bill of the load, $COST\_L$ (€)	Additional income δ_new (€)
461.17	315.66	145.51

Day 2

<u>Without coordination of generators and controllable load</u>

The controllable load schedules its flexible consumption in the hours of lower price. Considering the price for buying electricity shown in Figure 5.4, the load schedules its consumption as illustrated in Figure 5.12.

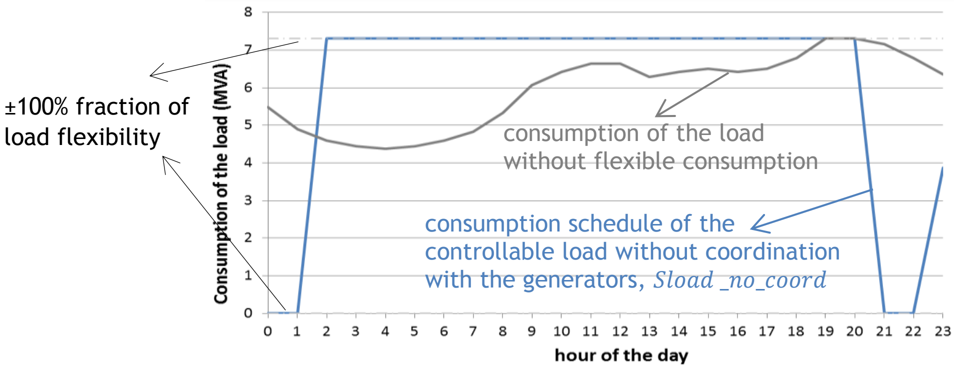

Figure 5.12 - Consumption schedule of the controllable load with a ±100% fraction of load flexibility on day 2 (no coordination with the generators)

The Aggregator schedules the generators and they produce all their available production. However, GenC had to be turned off in hours 21 and 22 to allow GenD to produce (see Figure 5.13). This leads to a start-up cost, which reduces the income obtained by the generators.

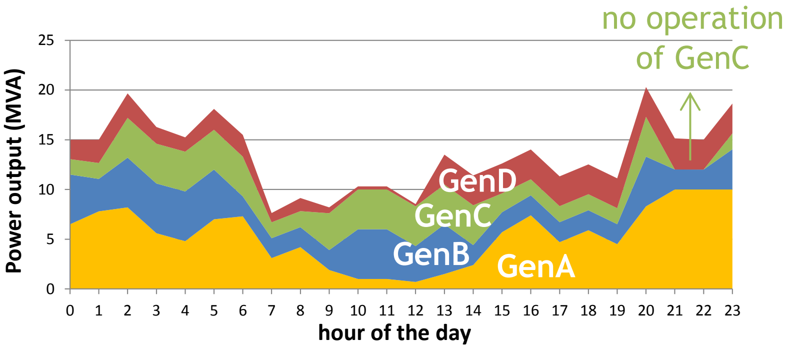

Figure 5.13 - Coordinated output of the generators with a ±100% fraction of load flexibility on day 1 (without coordination with the controllable load)

<u>With coordination of generators and controllable load</u>

The Aggregator operates the coordination by changing the consumption of the controllable load to maximise the production of the generators, see Figure 5.14.

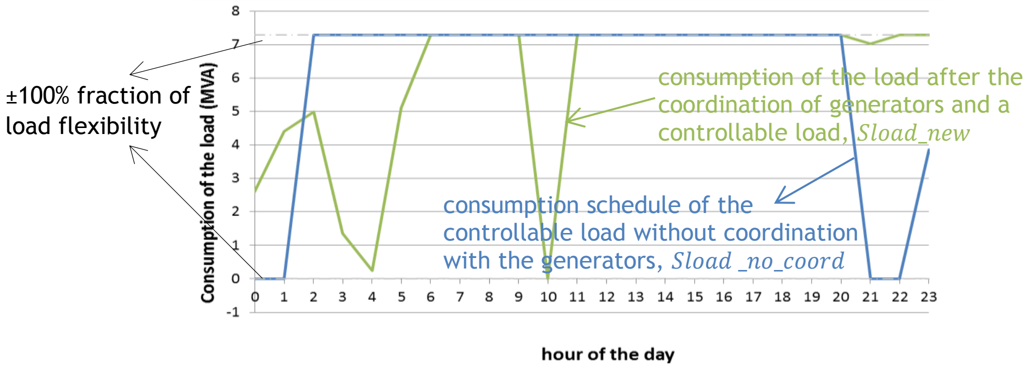

Figure 5.14 - Consumption of the controllable load after the operation of the coordination of generators and controllable load, with a ±100% fraction of load flexibility on day 2

The generation schedule after the coordination with the controllable load is shown in Figure 5.15. GenB is able to produce in the hours with higher price of electrical energy. GenC is not turned off at any time but still has to schedule part of its production off the hours with higher price of electrical energy.

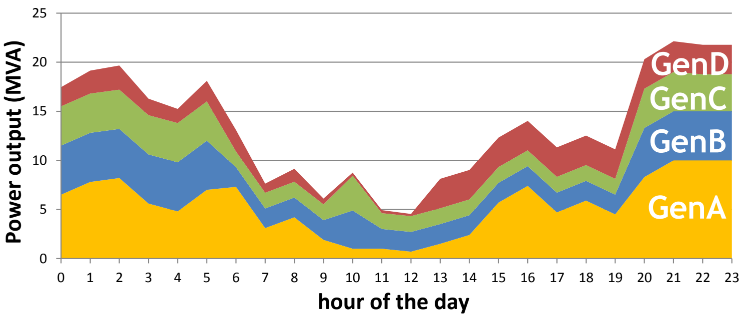

Figure 5.15 - Output powers of the generators after the coordination with the controllable load, with a ±100% fraction of load flexibility on day 2

The additional income obtained with the coordination, δ_new, considering a ±100% fraction of flexible consumption on day 2 is given in Table 5.4.

Table 5.4 - Additional income obtained with the coordination of generators and controllable load, with a ±100% fraction of load flexibility on day 2

Income for the rescheduling of GenB and GenC (€)	Increase of the electricity bill of the load, $COST\_L$ (€)	Additional income δ_new (€)
274.12	135.18	138.94

Day 3

On day 3, the production of the generators is maximised after the operation of the coordination of distributed generators. Therefore, the coordination of generators with a controllable load is not operated.

Days 4 to 6

On days 4 to 6, the additional income obtained with the coordination is given in Table 5.5. In day 4, generators are not able to produce all their available production. This is because the cost of changing further consumption of the load was higher than the income originated by further increase in production. In day 5, GenC has still to schedule part of its production off the hours of higher price of electrical energy. In day 6, as in day 3, there is no operation of the coordination of generators and controllable load.

Table 5.5 - Additional income obtained with the coordination of generators and controllable load, with a ±100% fraction of load flexibility on days 4 to 6

Day	Day 4	Day 5	Day 6
Additional income δ_new (€)	83.13	138.17	0

5.4.2.3 – Considering different load capacities

Figure 5.16 shows the additional income obtained with the coordination, δ_new, considering different load capacities during the selected period of operation. Load capacities are presented in relation to the sum of the installed capacities of GenC and GenD, $(GenC + GenD) = 7\ MVA$. Load capacity $Sload\_max$ varies from zero to the double of $GenC + GenD$. This is because the value of the coordination varies with the amount of generation capacity connected without firm access rights. Two fractions of load flexibility, ±10% and ±100%, are considered.

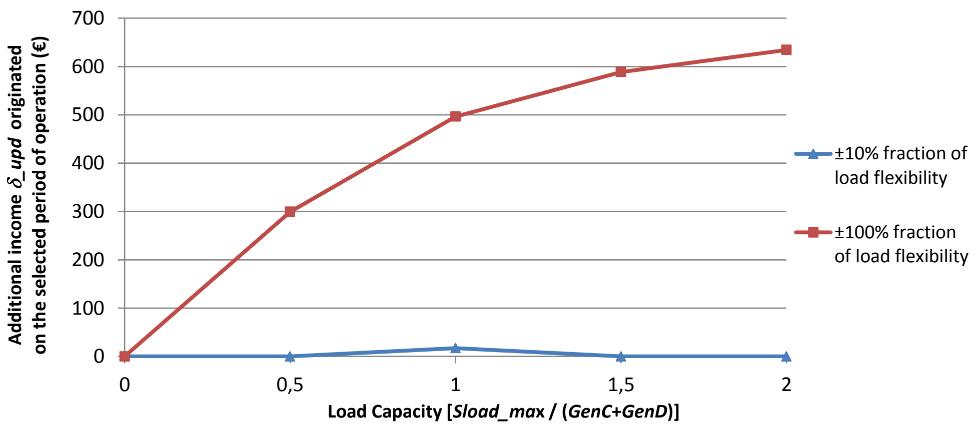

Figure 5.16 - Additional income obtained with the coordination considering different fractions of controllable load and load capacities

With a ±10% fraction of load flexibility, there is additional income only when the load capacity is equal to the sum of the installed capacities of GenC and GenD. With a ±100% fraction of load flexibility, the additional income increases with the increase in load capacity.

5.4.3 - Sharing the additional income obtained with the coordination of the generators and the controllable load

The allocation of the additional income in days 1 and 2 are shown as follows. A ±100% fraction of load flexibility is considered.

5.4.3.1 – Economic incentive for the generators

<u>Day 1, ±100% fraction of load flexibility</u>

The additional income received by the generators, δ_gen, is:

$$\delta\_gen = \delta + (0.5 \cdot \delta\_new) = 298.04 + (0.5 \cdot 145.51) = 370.80 \text{ €}$$

The income received each generator, as defined by equations (5.19) and (5.20), is given in Table 5.6. A comparison with the results of “last-in, first-off” operation and the coordination of distributed generators (without coordination with a controllable load) is provided.

Table 5.6 – Income received by each generator considering a ±100% fraction of load flexibility on day 1, considering: “last-in, first-off” operation; coordination of distributed generators; coordination of generators and controllable load

	Income of GenA (€)	Income of GenB (€)	Income of GenC (€)	Income of GenD (€)	TOTAL (€)
LAST-IN, FIRST-OFF OPERATION (no coordination)	7511.63	1211.71	810.16	1610.97	11144.47
WITH COORDINATION (coordination of distributed generators)	7642.27	1286.27	864.17	1649.80	11442.51
WITH COORDINATION (coordination of generators and controllable load)	7666.89	1305.83	885.43	1657.12	11515.27

<u>Day 2, ±100% fraction of load flexibility</u>

The additional income received by the generators, δ_gen, is:

$$\delta\_gen = \delta + (0.5 \cdot \delta\_new) = 542.48 + (0.5 \cdot 138.94) = 611.95 \text{ €}$$

The income received by each generator is given in Table 5.7. A comparison with the results of “last-in, first-off” operation and the coordination of distributed generators (without coordination with a controllable load) is provided.

Table 5.7 - Income received by each generator considering a ±100% fraction of load flexibility on day 2, considering: "last-in, first-off" operation; coordination of distributed generators; coordination of generators and controllable load

	Income of GenA (€)	Income of GenB (€)	Income of GenC (€)	Income of GenD (€)	TOTAL (€)
LAST-IN, FIRST-OFF OPERATION (no coordination)	5556.48	643.94	328.96	1462.17	7991.55
WITH COORDINATION (coordination of distributed generators)	5719.93	819.89	469.33	1524.88	8534.03
WITH COORDINATION (coordination of generators and controllable load)	5740.42	842.53	487.81	1532.74	8603.50

5.4.3.2 – Economic incentive for the controllable load

Day 1, ±100% fraction of load flexibility

The income received by the controllable load on day 1 after the coordination with the generators is:

$$income_L = COST\_L + (0.5 \cdot \delta\_new) = 315.66 + (0.5 \cdot 145.51) = 388.42€$$

Day 2, ±100% fraction of load flexibility

The income received by the controllable load on day 2 after the coordination with the generators is:

$$income_L = COST\_L + (0.5 \cdot \delta\_new) = 135.18 + (0.5 \cdot 138.94) = 204.65€$$

5.5 - Summary

The coordination of generators and controllable load has been evaluated on the two-busbar distribution network. The evaluation considered different load flexibility and capacity amounts during the selected period of operation.

Results show limited benefit of the coordination when the load flexibility is small. The coordination has better results when the load is entirely flexible. Also, the value of the coordination increases with the increase in load capacity. The additional income obtained with the coordination is allocated to the generators and the controllable load. All generators receive a greater income if they coordinate with the controllable load. The controllable load is able to cover the increase of its electricity bill. In addition, it receives part of the additional income to incentivise its operation in a coordinated manner.

Chapter 6 - Coordinating non-dispatchable generators and energy storage systems

6.1 - Introduction

The coordination of independent non-dispatchable generators and energy storage systems connected to the same circuit is presented. The coordination aims to maximise the income received by the generators without exceeding the power limit of the circuit. The energy storage systems are asked to change their schedule to allow the generators to maximise their production. The coordination is operated by an Aggregator. Additional income is obtained from the coordination for the additional energy produced. This additional income is allocated to the generators and the energy storage systems using a bargaining approach of game theory – Rubinstein bargaining.

6.2 - Coordination with energy storage systems

The coordination of independent non-dispatchable generators and energy storage systems aims to maximise the income of the generators. The coordination is operated by an Aggregator, run by the generators and the energy storage systems. The operation of the Aggregator is summarised as follows:

- The charging of the energy storage systems is scheduled to allow the generators to operate;
- The discharging of the energy storage systems is operated in hours of reduced output of the generators;
- The generators are curtailed when the circuit rating limit is still exceeded, on a “last-in, first-off” basis;
- Additional income is obtained from additional energy production. The additional income obtained is allocated so that both generators and energy storage systems have an economic incentive to be operated in a coordinated manner.

6.2.1 – Assumptions and limitations

The coordination is formulated according to the same assumptions and limitations set in Chapter 4, with the exception of the following:

Related to the distributed generators

- Only non-dispatchable generators are considered;
- The generators operate with unity power factor;

Related to the energy storage systems

- The energy storage systems are not owned by any of the generators;
- Charging and discharging is performed according to the price of electrical energy;
- The output of the energy storage systems can range from zero to the respective installed capacities;
- Round-trip storage efficiency is considered to be 100%;

Related to the optimisation

- The generators and energy storage systems are price takers;
- The forecasts considered (available power of the non-dispatchable generators and price of electrical energy) are entirely reliable;
- The non-dispatchable generators and the energy storage systems do not have costs of operation;

6.2.2 – Operation of the Aggregator

The Aggregator uses the following parameters for the coordination (see Figure 6.1): the order of connection to the network; the distribution circuit power capacity limit; operating limits of the generators and energy storage systems; the energy capacity and maximum number of daily charge/discharge cycles of each storage system.

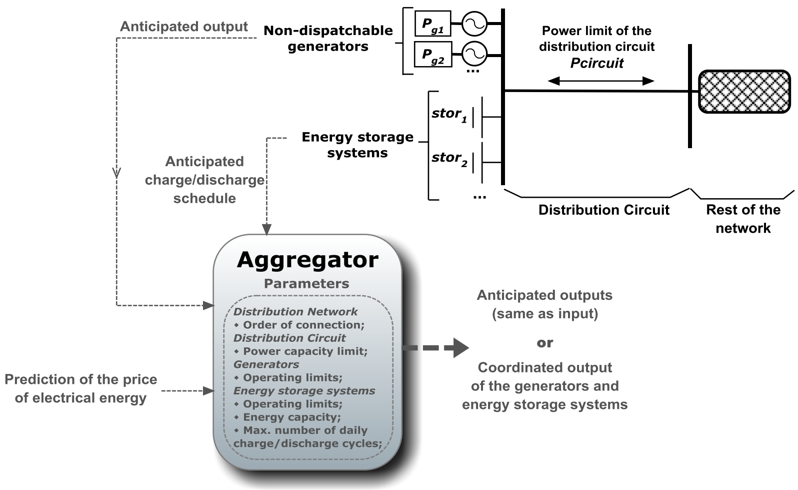

Figure 6.1 - The Aggregator operating the coordination of non-dispatchable generators and energy storage systems

The operation of the Aggregator is described as follows:

(1) The Aggregator receives from the generators their anticipated outputs and the anticipated charge/discharge schedule from the energy storage systems. Generators make their projections based on power forecasts. Energy storage systems make their projections considering the prediction of the price of electrical energy;

(2) The Aggregator assesses whether the circuit rating is exceeded by the anticipated outputs. If the limit is not exceeded, the Aggregator accepts the anticipated outputs and takes no further action. If the limit is exceeded, the Aggregator runs an optimisation algorithm to schedule the generators and the energy storage systems, as described in step (3).

(3) The optimisation algorithm has an objective function (Equation (6.1)) to maximise the income of the generators for producing electricity (variable *F*). The decision variables are the active power outputs of the generators and the energy storage systems in each time step *h* of the optimisation. *P* is the active power output of the generators. *St_dis* is the energy discharged by each energy storage system *stor*. *St_ch* is the energy charged by each energy storage system *stor*.

$$\max F = \underbrace{\sum_{g=1}^{G} w_g \cdot \sum_{h=1}^{H} \rho^h \cdot P_g^h}_{\text{Non-dispatchable generators}} + \underbrace{\sum_{stor=1}^{STOR} w_{stor} \cdot \left(\sum_{h=1}^{H} \rho^h \cdot \left(St\_dis_{stor}^h - St\_ch_{stor}^h \right) \right)}_{\text{Energy storage systems}} \quad (6.1)$$

The first term of Equation (6.1) is the income of the non-dispatchable generators and the second term is the income of the energy storage systems. *g* is the index of the non-dispatchable generators; *G* and *STOR* are the total number of generators and energy storage systems, respectively; *w* is a weight to enforce the order of access to the network and favour the production of the generators in detriment of the discharge of the energy storage systems; *H* is the time span of the optimisation; ρ is the price of electrical energy.

The constraints of the optimisation algorithm are: power limit of the distribution circuit (constraint (6.2)); operating limits of the generators (constraint (6.3)) and energy storage systems (constraints (6.4) and (6.5)); energy capacity limit of the energy storage systems (constraint (6.6)); limits for discharging (constraint (6.7)); and no charging and discharging in the same time step (constraint (6.8)). The discharge of the energy storage systems (given in constraint (6.5)) is limited by the operation of the generators: the generators are scheduled first, up to their anticipated power outputs, P_ant; then, the discharge of the energy storage systems is the minimum of the available capacity after scheduling the non-dispatchable generators and the maximum output power of the energy storage systems, $\overline{St}$. The maximization term *max* in constraint (6.5) prevents negative values in the discharge of the energy storage systems.

Power limit of the distribution circuit

$$\sum_{g=1}^{G} P_g^h + \sum_{stor=1}^{STOR} \left(St\_dis_{stor}^h - St\_ch_{stor}^h \right) \leq Pcircuit, \forall h \in H \quad (6.2)$$

Operating limits of the generators

$$\underline{P}_g \leq P_g^h \leq P\_ant_g^h, \forall g \in G, \forall h \in H \quad (6.3)$$

Operating limits of the energy storage systems

$$\underline{St}_{stor} \leq St\_ch_{stor}^h \leq \overline{St}_{stor}, \forall stor \in STOR, \forall h \in H \quad (6.4)$$

$$\underline{St}_{stor} \leq St\_dis_{stor}^h \leq \min \left[\underbrace{\max \left(Pcircuit - \sum_{g=1}^{G} P\_ant_g^h ; \underline{St}_{stor} \right)}_{\geq \underline{St}_{stor}} ; \overline{St}_{stor} \right], \forall stor \in STOR, \forall h \in H \quad (6.5)$$

Energy capacity limit of the energy storage systems

$$\sum_{h=1}^{H} St\_dis_{stor}^h \leq E\_cap_{stor} \cdot nC_{stor}, \forall stor \in STOR \quad (6.6)$$

Discharge does not exceed charging

$$\sum_{h=1}^{H} St\_dis_{stor}^h \leq \sum_{h=1}^{H} St\_ch_{stor}^h, \forall stor \in STOR \quad (6.7)$$

Charging and discharging not possible in the same time step

$$St\_dis_{stor}^i \cdot St\_ch_{stor}^j = 0, \forall i = j \in H, \forall stor \in STOR \quad (6.8)$$

$\underline{P}$ is the minimum output power of the non-dispatchable generator g; *P_ant* is the anticipated power output of g, based on the power forecast; $\underline{St}$ is the minimum output power of the energy storage system *stor*; $\overline{St}$ is the maximum output power of *stor*; *E_cap* is the energy capacity limit of *stor*; *nC* is the maximum number of daily charge/discharge cycles of *stor*.

(4) The outcome of the optimisation is the coordinated output of generators and energy storage systems that maximises the income of the generators and does not exceed the distribution circuit rating.

6.3 - Application of the coordination to a two-busbar distribution network

The coordination is evaluated on a two-busbar distribution network with two generators and an energy storage system connected. The evaluation is performed using a set of extreme cases of price of electrical energy and wind power. The impact on the additional income of different orders of connection to the network is analysed. Then, the evaluation is extended to a year of operation to assess the impact on the additional income of different installed capacities of the energy storage system.

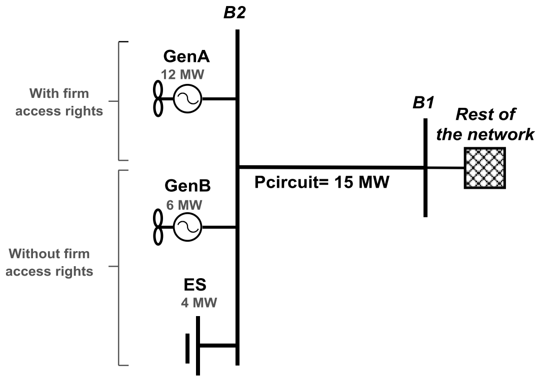

Figure 6.2 – Two-busbar distribution network used to evaluate the coordination

6.3.1 - Modelling of the distribution network

The two-busbar network used to evaluate the coordination is shown in Figure 6.2. Generator GenA is a wind generator connected with firm access rights. GenB is a wind generator connected without firm access rights. Energy storage system ES is connected without firm access rights. The installed capacities of the generators and energy storage system were determined following cost-benefit analyses. The parameters of the system are given in Table 6.1.

Table 6.1 - Parameters of the system

Parameter	Value	Unit
Power limit of the distribution circuit (*Pcircuit*)	15	MW
Minimum output power of *GenA* and *GenB* ($\underline{P}_A$, $\underline{P}_B$)	0	MW
Minimum charge/discharge limit of *ES* ($\underline{St}_{ES}$)	0	MW
Maximum charge/discharge limit of *ES* ($\overline{St}_{ES}$)	4	MW
Energy capacity of *ES* (E_cap_{ES})	5 [124]	MWh
Maximum number of daily charge/discharge cycles	1	

The weights w used on the objective function of the coordination are: $w_{GenA} = 3$; $w_{GenB} = 2$; $w_{ES} = 1$.

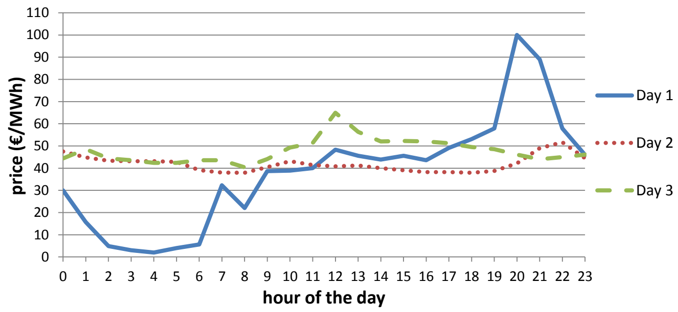

Figure 6.3 - Three profiles of one day of price of electrical energy [120]

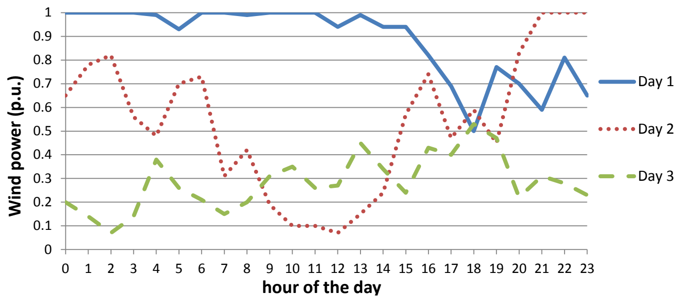

Figure 6.4 - Three profiles of one day of wind power

6.3.2 - Description of the set of extreme cases of price and wind power

The coordination is evaluated on a selected period of three days that represents extreme cases of price of electrical energy and wind power (see Table 6.2 and Figures 6.3 and 6.4).

Price data was obtained from the Iberian Electricity Market (Portuguese side) [120]. The wind power data was obtained from the wind speed data (10-minute average series) of a Portuguese wind farm. This wind speed data was applied to the power curve of wind turbine Vestas V80 [121]. Price and wind power data were not collected on the same days (no correlation).

Table 6.2 - Selected period of operation used for the evaluation of the coordination

Day	Price of electrical energy	Wind power
Day 1	Large variation of price	High wind power
Day 2	Medium magnitude of price	Medium wind power
Day 3	High magnitude of price	Low wind power

6.3.3 – Distribution network operation with extreme cases of price and wind power

"Last-in, first-off" and coordinated operation of the generators and energy storage system are presented as follows. Two different orders of connection to the network are considered: GenB is connected last; ES is connected last.

6.3.3.1 – "Last-in, first-off" operation

GenB is connected last

GenB is scheduled after *GenA* and *ES* have determined their anticipated outputs.

Days 1 and 2

The output powers of the generators and the energy storage system in days 1 and 2 are shown in Figures 6.5 and 6.6, respectively. *GenB* is curtailed when the power limit of the distribution circuit is exceeded.

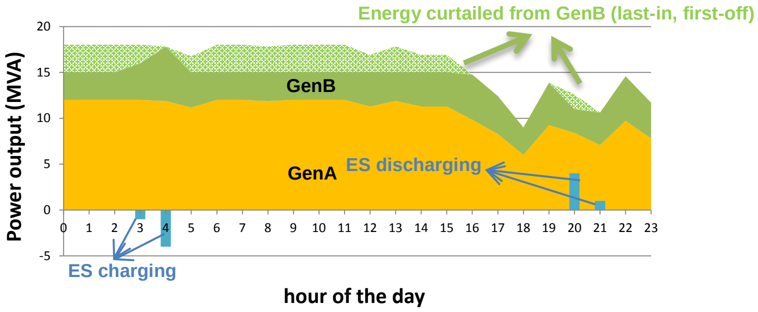

Figure 6.5 - Output powers of the generators and the energy storage system in "last-in, first-off operation" when *GenB* is connected last (day 1)

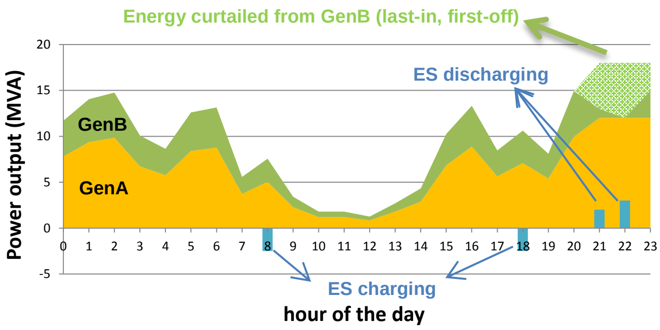

Figure 6.6 - Output powers of the generators and the energy storage system in "last-in, first-off operation" when GenB is connected last (day 2)

<u>Day 3</u>

The output powers of the generators and the energy storage system in day 3 are shown in Figure 6.7. The distribution circuit limit is not exceeded. There is no energy curtailment.

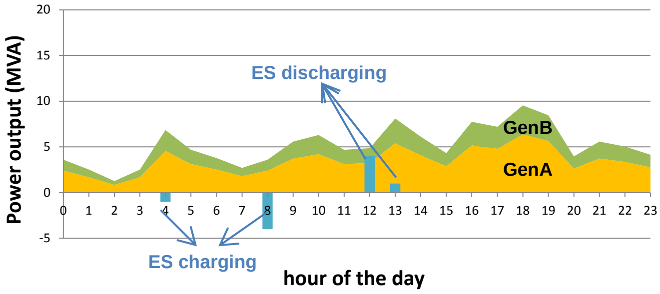

Figure 6.7 - Output powers of the generators and the energy storage system in "last-in, first-off operation" when *GenB* is connected last (day 3)

ES is connected last

ES is scheduled after *GenA* and *GenB* have determined their anticipated outputs.

<u>Days 1 and 2</u>

The output powers of the generators and the energy storage system in days 1 and 2 are shown in Figures 6.8 and 6.9, respectively. In day 2 (Figure 6.9) it is assumed that *ES* comes fully charged from the previous 24-hour period of operation. *GenB* is curtailed when the power limit of the distribution circuit is exceeded.

Day 3

The output powers of the generators and the energy storage system in day 3 are the same as shown in Figure 6.7. This is because the distribution circuit limit is not exceeded, as in the case when *GenB* is connected last.

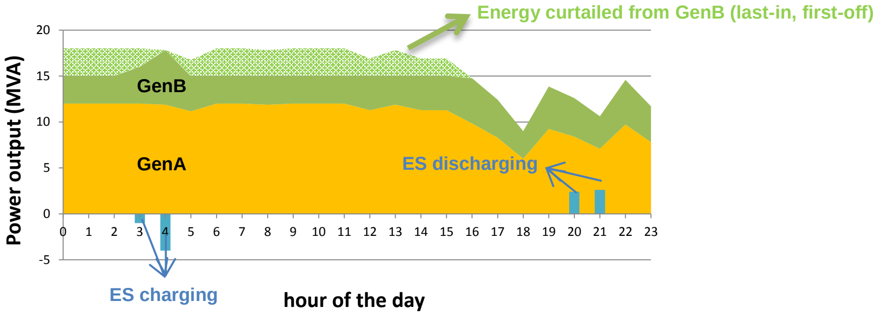

Figure 6.8 - Output powers of the generators and the energy storage system in “last-in, first-off operation” when *ES* connects last (day 1)

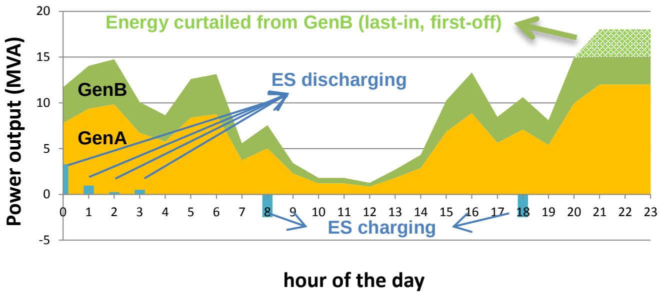

Figure 6.9 - Output powers of the generators and the energy storage system in “last-in, first-off operation” when *ES* is connected last (day 2)

6.3.3.2 – Coordinated operation of generators and energy storage systems

The Aggregator schedules the charging of *ES* to hours when *GenB* is curtailed. Hours of higher price are selected first for charging. The discharging is set to hours of reduced output of *GenA* and *GenB*. This leads to an additional income, due to the additional electricity produced by *GenB*.

Day 1

The output powers of the generators and the energy storage system in coordination in day 1 are shown in Figure 6.10. *ES* changes its charging from hours 3 and 4 to hours 12, 13 and 15. The new charging hours are the hours of higher price when *GenB* was curtailed in “last-in, first-off” operation. This allows *GenB* to produce more electricity and originates an additional income.

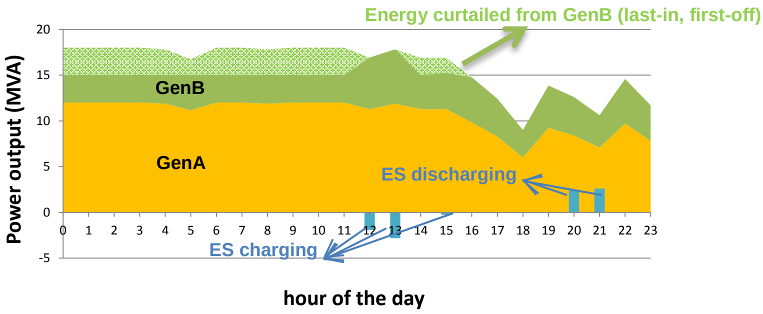

Figure 6.10 - Output powers of the generators and the energy storage system in coordination (day 1)

The electrical energy produced and the income of each generator and energy storage system in coordination in day 1 are presented in Table 6.3. Comparison with "last-in, first-off" operation is provided.

Table 6.3 - Electrical energy produced and income of each generator and energy storage system with coordination and in "last-in, first-off" operation (day 1)

			GenA	*GenB*	*ES*	TOTAL
WITH COORDINATION		Electrical energy produced (MWh)	255	89.54	5	349.54
		Income received (€)	9013	3645	238	12896
"LAST-IN, FIRST-OFF" OPERATION	*GenB* is connected last	Electrical energy produced (MWh)	255	86.76	5	346.76
		Income received (€)	9013	3260	478	12751
	ES is connected last	Electrical energy produced (MWh)	255	88.36	5	348.36
		Income received (€)	9013	3421	460	12894

Day 2

The output powers of the generators and the energy storage system in coordination in day 2 are shown in Fig. 6.11. The energy storage system changes its charging from hours 8 and 18 to hours 21 and 22. This is to allow GenB to produce in the hours of higher price when it was curtailed in "last-in, first-off" operation.

The electrical energy produced and the income of each generator and energy storage system in coordination is presented in Table 6.4. It is again assumed that *ES* comes fully charged from the previous 24-hour period of operation. The negative income of *ES* in coordination means that the cost of charging is greater than the income received for the discharge. *ES* would have no income if it was paid according to its charge/discharge schedule in coordination. Thus, the income received by generators and energy storage system in coordination is determined using a bargaining mechanism of game theory. This gives both generators and energy storage systems an economic incentive to operate in a coordinated manner.

Table 6.4 - Electrical energy produced and income of each generator and energy storage system with coordination and in "last-in, first-off" operation (day 2)

			GenA	*GenB*	*ES*	TOTAL
WITH COORDINATION		Electrical energy produced (MWh)	155.4	73.7	5	234.1
		Income received (€)	6668	3151	-21.31	9798
"LAST-IN, FIRST-OFF" OP.	*GenB* is connected last	Electrical energy produced (MWh)	155.4	63.7	5	224.1
		Income received (€)	6668	2645	63	9376
	ES is connected last	Electrical energy produced (MWh)	155.4	68.7	5	229.1
		Income received (€)	6668	2898	42	9608

6.4 - Allocation of additional income obtained in coordination

The coordination of independent non-dispatchable generators and energy storage systems originates an income (*INC*) given by Equation (6.9).

$$INC = \sum_{g=1}^{G}\sum_{h=1}^{H}\left(\rho^h \cdot P_g^h\right) + \sum_{stor=1}^{STOR}\sum_{h=1}^{H}\rho^h \cdot \left(St\_dis_{stor}^h - St\_ch_{stor}^h\right) \tag{6.9}$$

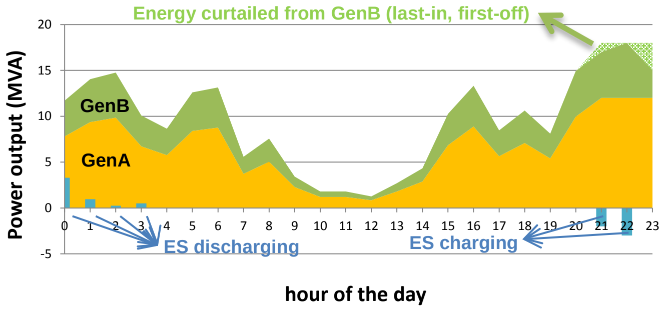

Figure 6.11 - Output powers of the generators and the energy storage system in coordination (day 2)

Income *INC* is greater than the income originated in "last-in, first-off" operation, *INC_lifo* (see Equation (6.10)).

$$INC\_lifo = \sum_{g=1}^{G}\sum_{h=1}^{H}\left(\rho^h \cdot P\_lifo_g^h\right) + \sum_{stor=1}^{STOR}\sum_{h=1}^{H}\rho^h \cdot \left(St\_dis\_lifo_{stor}^h - St\_ch\_lifo_{stor}^h\right) \tag{6.10}$$

Suffix *_lifo* in Equation (6.10) refers to "last-in, first-off" operation. The difference between *INC* and *INC_lifo* is the additional income obtained in coordination, δ, see Equation (6.11). This difference varies with the order of connection of the generators and energy storage systems in "last-in, first-off operation".

$$\delta = INC - INC\_lifo \tag{6.11}$$

The allocation of δ is made considering the coordination as a problem of Rubinstein bargaining [123], similarly as described in Chapter 5. In this case, the players are the sets of generators and energy storage systems. According to the Rubinstein bargaining model, the generators and energy storage systems share the additional income δ equally (50% for each player). The additional income to be allocated by the generators, δ_gen, and the energy storage systems, δ_st, is then given by Equation (6.12):

$$\delta\_gen = \delta\_st = 0.5 \cdot \delta \tag{6.12}$$

6.4.1 – Allocation amongst generators

The part of δ_gen received by each generator $g \in G$, δ_g, is determined in a similar manner as described in the coordination of independent distributed generators (Chapter 4, equation (4.14)), see equation (6.13).

$$\begin{cases} \delta_g = \dfrac{\sum_{h=1}^{H} coef_g \cdot P_g^h}{\sum_{g=1}^{G}\sum_{h=1}^{H} coef_g \cdot P_g^h} \cdot \delta\_gen, \forall g \in G \\ \sum_{g=1}^{G} \delta_g = \delta\_gen \end{cases} \tag{6.13}$$

6.4.2 – Allocation amongst energy storage systems

The part of δ_st received by each energy storage system $stor \in STOR$ is calculated *pro rata* to the absolute amount of energy changed in coordination, see Equation (6.14).

$$\begin{cases} \delta_{stor} = \dfrac{\sum_{h=1}^{H} \left| \left(St\_dis_{stor}^{h} - St\_ch_{stor}^{h}\right) - \left(St\_dis\_lifo_{stor}^{h} - St\_ch\_lifo_{stor}^{h}\right) \right|}{\sum_{stor=1}^{STOR} \sum_{h=1}^{H} \left| \left(St\_dis_{stor}^{h} - St\_ch_{stor}^{h}\right) - \left(St\_dis\_lifo_{stor}^{h} - St\_ch\_lifo_{stor}^{h}\right) \right|} \cdot \delta\_st \\ \sum_{stor=1}^{STOR} \delta_{stor} = \delta\_st \end{cases} \tag{6.14}$$

6.5 - Sharing the additional income on the two-busbar distribution network example

The coordination presented in section 6.3.3.2 originates an additional income in both days, as shown in Figure 6.12. The additional income is greater when *GenB* is connected last. This is because the amount of energy curtailed in "last-in, first-off" operation is greater than when *ES* is connected last.

The additional income obtained in coordination is allocated as described by Equations (6.13) and (6.14) and added to what the generators and the energy storage system would receive in "last in, first-off" operation. *GenA* receives a greater income for communicating its anticipated output to the Aggregator. The income received by the generators and the energy storage system in days 1 and 2 is given in Tables 6.5 to 6.8. Comparison with "last-in, first-off" operation is provided. As both generators are wind generators, they have the same technology coefficient *coef*.

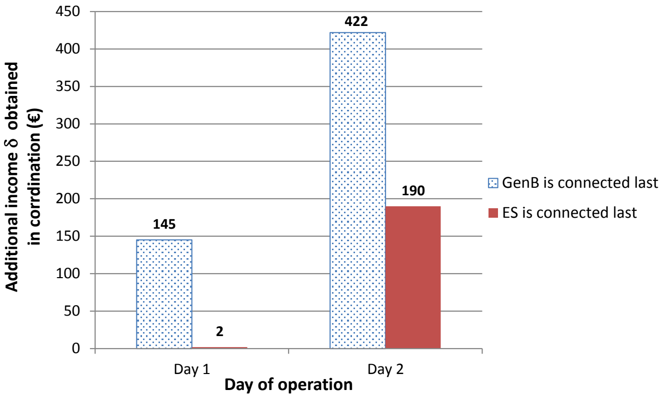

Figure 6.12 – Additional income δ obtained in days 1 and 2 when: i) *GenB* is connected last; ii) *ES* is connected last

Day 1

Table 6.5 - Income received by each generator and energy storage system as determined by Eqs. (6.13) and (6.14) when GenB is connected last (day 1)

	INCOME RECEIVED (€)			
GenB is connected last	*GenA*	*GenB*	*ES*	TOTAL
With coordination – Equations (6.13) and (6.14)	9066.65	3278.85	550.50	12896
"Last-in, first-off" operation	9013	3260	478	12751

Table 6.6 - Income received by each generator and energy storage system as determined by Equations (6.13) and (6.14) when ES is connected last (day 1)

	INCOME RECEIVED (€)			
ES is connected last	*GenA*	*GenB*	*ES*	TOTAL
With coordination – Equations (6.13) and (6.14)	9013.74	3421.26	461	12896
"Last-in, first-off" operation	9013	3421	460	12894

Day 2

Table 6.7 - Income received by each generator and energy storage system as determined by Equations (6.13) and (6.14) when GenB is connected last (day 2)

	INCOME RECEIVED (€)			
GenB is connected last	*GenA*	*GenB*	*ES*	TOTAL
With coordination - Equations (6.13) and (6.14)	6811.12	2712.88	274	9798
“Last-in, first-off” operation	6668	2645	63	9376

Table 6.8 - Income received by each generator and energy storage system as determined by Equations (6.13) and (6.14) when ES is connected last (day 2)

	INCOME RECEIVED (€)			
ES is connected last	*GenA*	*GenB*	*ES*	TOTAL
With coordination - Equations (6.13) and (6.14)	6732.44	2928.56	137	9798
“Last-in, first-off” operation	6668	2898	42	9608

6.5.1 – Additional income obtained during one year of operation

The coordination is operated during one year, in independent 24-hour periods with one hour time step.

6.5.1.1 – Impact of different orders of connection to the network

The additional income δ obtained in coordination during one year is presented in Figure 6.13. Wind power data from the same Portuguese wind farm is used. Price data used is obtained from the Iberian Electricity Market (Portuguese side) from May 2010 to April 2011 [125].

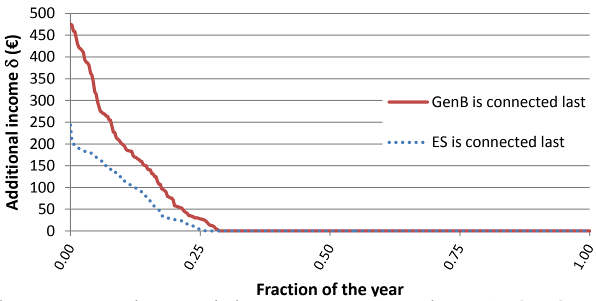

Figure 6.13 - Additional income δ obtained during one year when: i) *GenB* is connected last; ii) *ES* is connected last

The additional income obtained is greater when *GenB* is connected last. This is because of the greater amount of energy curtailed in “last-in, first-off” operation. In both orders of connection the coordination is operated approximately 25% of the year. The coordination is not operated in the rest of the year as the distribution circuit limit is not exceeded then.

The income received by the generators and the energy storage system in the year of operation considered is given in Table 6.9. The additional income δ during the year of operation is 18.03 k€ if *GenB* is connected last and 9.05 k€ if *ES* is connected last.

Table 6.9 - Income received by each generator and energy storage system with coordination and in “last-in, first-off” operation during the year of operation considered

		INCOME RECEIVED (k€)			
		GenA	*GenB*	*ES*	TOTAL
WITH COORDINATION - Equations (6.13) and (6.14)		1206.90	528.66	44.59	1780.15
“LAST-IN, FIRST-OFF” OPERATION	*GenB* is connected last	1203.78	516.63	41.71	1762.12
	ES is connected last	1203.78	527.26	40.06	1771.10

6.5.1.2 – Impact of different installed capacities of ES

The additional income δ obtained during one year of operation with different installed capacities of the energy storage system *ES* is shown in Figure 6.14. The energy capacity of *ES* is maintained as 5 MWh.

The additional income obtained increases as the installed capacity of *ES* grows. The additional income obtained stops to increase when the installed capacity of *ES* matches the installed capacity of *GenB* (6 MW).

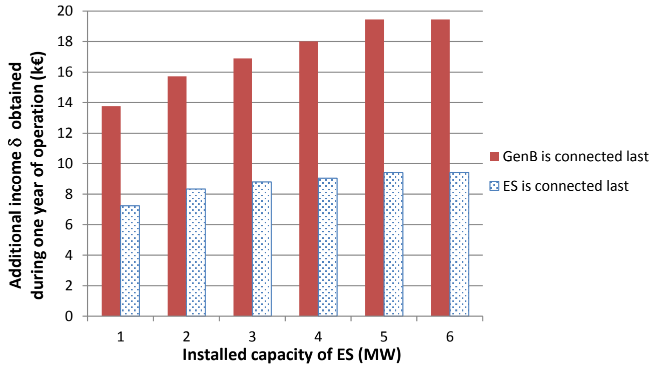

Figure 6.14 – Additional income δ obtained during one year with different installed capacities of *ES* when: i) *GenB* is connected last; ii) *ES* is connected last

6.6 - Conclusion

The coordination of independent non-dispatchable generators and energy storage systems allows generators to maximise their income without exceeding the power limit of the distribution circuit.

Additional income results of the change of the charge/discharge schedule of the energy storage systems to allow the non-dispatchable generators to operate. This additional income obtained is allocated to generators and energy storage systems. The energy storage systems receive part of the additional income to incentivise its operation in a coordinated manner.

The coordinated output of generators and energy storage systems does not depend on the order of connection to the network. However, the additional income obtained varies with the order of connection. The additional income is greater when a non-dispatchable generator is connected last. This is because the amount of energy curtailment in “last-in, first-off” operation is greater than when an energy storage system is connected last.

The additional income obtained increases with the growth of the installed capacity of the energy storage system. The additional income obtained stops to increase when the installed capacities of the energy storage system and the generator connected without firm access rights are equal.

Chapter 7 - Conclusions and future work

7.1 - Contribution of this research

The following was addressed:

- The limitations to the connection of generation capacity of the firm access connection policy were identified;
- The benefit of coordinating independent distributed generators to maximise their income was presented;
- The coordination of generators and independent controllable load was introduced to maximise the income of the generators;
- Economic incentives for both generators and controllable load to operate in a coordinated manner were analysed;
- The potential of coordinating non-dispatchable generation and energy storage systems was assessed.

7.2 - Connection of generation to distribution networks

The operation of a distribution network with the inclusion of independent distributed generators connected with and without firm access rights of connection was analysed. A representative of the distribution system of Northeast Portugal was used as an example.

7.2.1 - Operation of the distribution network with generators connected with firm access rights only

The distribution network was operated with acceptable voltages and currents in two extreme power flow cases.

By extending the operation of the distribution network to a period of 24 hours, the technical possibility of producing further electricity was identified. The export capacity of the distribution network is below its rated value during part of the 24 hours due to: (i) the non-operation of the dispatchable generator in certain hours because of its costs of operation, and; (ii) the reduced availability of wind in certain hours. However, no additional capacity could be connected with firm access rights.

7.2.2 - Operation of the distribution network with generators connected without firm access rights

Two generators agreed to connect to the distribution network on the basis of non-firm access. The minimum cost operation of the network could not be implemented because of firm access right privileges and the “last-in, first-off” policy. Different costs of operation and ability to be dispatched are not considered in “last-in, first-off” operation. Only the order of connection of the generators is considered when there is inadequate capacity in the distribution network. The economic value of the generators was not maximised, as a cheap generator was curtailed to allow a more expensive generator to produce.

7.3 - Coordination of independent distribution generators

The coordination of independent distributed generators maximises the income of the generators without exceeding the capacity limit of the network. In this research, the coordination is evaluated in a medium voltage distribution network. However, it can be applied to other network voltage levels.

The coordination of independent distributed generators leads to an additional income, in comparison to the income originated by “last-in, first-off” operation. The additional income is maximised when the non-dispatchable generators maximise their production and the dispatchable generators are able to schedule all their available production in other hours.

On some days, dispatchable generators are not able to schedule all their production in other hours because the price of electrical energy is lower than their costs of operation.

Non-dispatchable generators are curtailed when the cost of turning off dispatchable generators is higher than the income obtained by the additional production of the non-dispatchable generators.

The additional income originated will be limited when the connection of new generators does not provide additional production of electricity or the scheduling of more expensive generation in other hours.

7.3.1 - Sharing the additional income obtained in coordination

The additional income obtained in coordination is allocated to the generators. This is performed by an income-sharing mechanism based in cooperative game theory. All generators receive a greater income when compared to what they would have received in “last-in, first-off” operation. No generator can form partial coalitions with other generators to increase its income. This is because one generator would have to know the anticipated outputs of the generators outside the coalition and the estimation of load consumption to schedule its own production.

7.3.2 - Influence of different costs of operation on the additional income

The additional income obtained varies with the costs of operation of the dispatchable generator connected without firm access rights. This generator changes its production to allow the non-dispatchable generators to produce. In the example considered, the additional income was maximised when the cost of operation of this generator was 35 €/MWh. Below this cost of operation, the additional income obtained was lower as the difference between costs of operation of dispatchable and non-dispatchable generators was lower. Above this cost of operation, the price of electrical energy was lower than the costs of operation of the dispatchable generator in many hours. Thus, the dispatchable generator did not operate in those hours and the distribution capacity limit was not exceeded.

7.3.3 - Influence of different technology coefficients on the additional income received by each generator

The dispatchable generator connected without firm access rights receives a greater income in coordination. Its income increases with: i) the growth in the amount of production changed to allow the non-dispatchable generators to produce; ii) the increase in its allocation of the additional income, which is determined by the technology coefficients. Therefore, all other generators are also incentivised to operate in a coordinated manner.

7.4 - Coordinating generators and controllable load

The integration of controllable load in the coordination aims to maximise the income of the generators. Additional income is obtained from the additional energy that the generators are able to produce and the change of production to hours with a higher price of electrical energy.

The production of the generators is not maximised when the cost of changing consumption of the controllable load is higher than the income originated by the increase in their production.

The controllable load receives part of the additional income originated: i) to cover the costs of changing its consumption; ii) to incentivise its operation in a coordinated manner.

7.4.1 - Additional income considering a ±10% fraction of load flexibility

In the example considered, the coordination considering a ±10% fraction of controllable load had limited impact on the income of the generators. Results were limited by the small fraction of controllable load. The additional income obtained hardly would cover the operation costs of the coordination of generators and controllable load.

7.4.2 - Additional income considering a ±100% fraction of load flexibility

In the example considered, the coordination presented greater benefit with a ±100% fraction of load flexibility. The additional income obtained was significantly higher when compared to the case of ±10% fraction of load flexibility. However, a fraction of flexibility of ±100% is difficult to obtain.

7.4.3 - Additional income considering different load capacities

The additional income obtained had little variation with different load capacities when a ±10% fraction of controllable load was considered. For load capacities below the capacity of the generators without firm access rights, the coordination was not operated. This is because the cost of changing the controllable load was higher than the income originated by the increase in the production of the generators. For load capacities above the capacity of the generators without firm access rights, the coordination was not operated. The Aggregator could maximise the income of the generators without coordinating with controllable load.

In the case of a ±100% fraction of controllable load, the additional income obtained increased with the increase in load capacity. This happened as the controllable load was able to change its consumption with lower costs when its capacity increased.

7.4.4 - Sharing the additional income to the generators and the load

The additional income was allocated in equal parts by the generators and the controllable load. This allocation was determined using the Rubinstein bargaining model. The Aggregator set the income of the generators using the income-sharing mechanism described in the coordination of distributed generators. Both generators and controllable load have an economic incentive to be operated in a coordinated manner.

7.5 – Coordinating generators and energy storage systems

The coordination of independent non-dispatchable generators and energy storage systems allows generators to maximise their income without exceeding the power limit of the distribution circuit.

7.5.1 – Coordinated operation with extreme cases of price and wind power

The Aggregator schedules the charging of the energy storage systems to hours when the non-dispatchable generators are curtailed.

The coordinated output of generators and energy storage systems does not depend on the order of connection to the network.

7.5.2 – Sharing the additional income to the generators and energy storage systems

Comparison with “last-in, first-off” operation shows that energy storage systems would see their income reduced if they were paid according to their charge/discharge schedule in coordination. Thus, the income received by generators and energy storage system in coordination is determined using a bargaining mechanism of game theory – Rubinstein bargaining.

The part of the additional income received by each non-dispatchable generator is determined in a similar manner as described in the coordination of independent distributed generators (Chapter 4). The part of the additional income received by each energy storage system is calculated *pro rata* to the absolute amount of energy changed in coordination. Both generators and energy storage systems have an economic incentive to be operated in a coordinated manner.

7.5.3 – Additional income obtained during one year of operation

With different orders of connection to the network

The additional income obtained varies with the order of connection. The additional income is greater when a non-dispatchable generator is connected last. This is because the amount of energy curtailed in “last-in, first-off” operation is greater than when the energy storage system is connected last.

With different installed capacities

The additional income obtained increases with the growth of the installed capacity of the energy storage systems. The additional income obtained stops to increase when the installed capacities of the energy storage systems and the generators connected without firm access rights are equal.

7.6 - Future work

The following is indicated as further work to this research:

7.6.1 - Coordination of independent distribution generators

- Introduce losses in the coordination methodology;
    - Adopt a method to apportion the losses caused/avoided by each generator and respective income reconciliation (pay or be paid for losses caused/avoided);
- Develop a methodology to determine the limit when the connection of a new generator without firm access rights would not bring additional value to the coordination;
- Development of real-time mechanisms to adjust the output powers of the generators when changes in forecasted inputs occur;
    - These real-time mechanisms aim to maximise the income of the generators;
- Include the production of heat by thermal generators;
    - Maximisation of the income of thermal generators considering the need to produce both electricity and heat;
- Definition of the communication infrastructure to implement the coordination.
    - To allow the practical testing and implementation of the coordination of independent distributed generators.

7.6.2 - Coordinating generators and controllable load

- Inclusion of constraints to schedule certain amounts of consumption.
    - Incorporation of constraints for devices that must be operated during defined time slots (e.g., wet appliances, space heating).

7.6.3 - Coordinating non-dispatchable generators and energy storage systems

- Incorporation of dispatchable generators and controllable load in the coordination;
    - Establishment of a global methodology to maximise the production of the generators, providing an economic incentive for all to be operated in a coordinated manner;
- Consideration of losses in the energy storage systems (round-trip efficiency below 100%).

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Appendix A - Cost-benefit analyses to determine the installed capacities of generators GenC and GenD

The installed capacities of GenC and GenD are determined using cost/benefit analyses. The installed capacities chosen are the ones that provide a greater economic return for their producers at the end of their investments. These cost/benefit analyses have the following assumptions:

- One year of operation of the generators is considered;
- The generators schedule their production in periods of 24 hours;
- Only the active power production of the generators is considered;
- There is no load consumption;
- Generator GenA produces according to the availability of wind. One year of wind speed average time series (10-minute average series) from a Portuguese wind farm is considered, see Figure A1. Data were collected from May 2010 to May 2011.

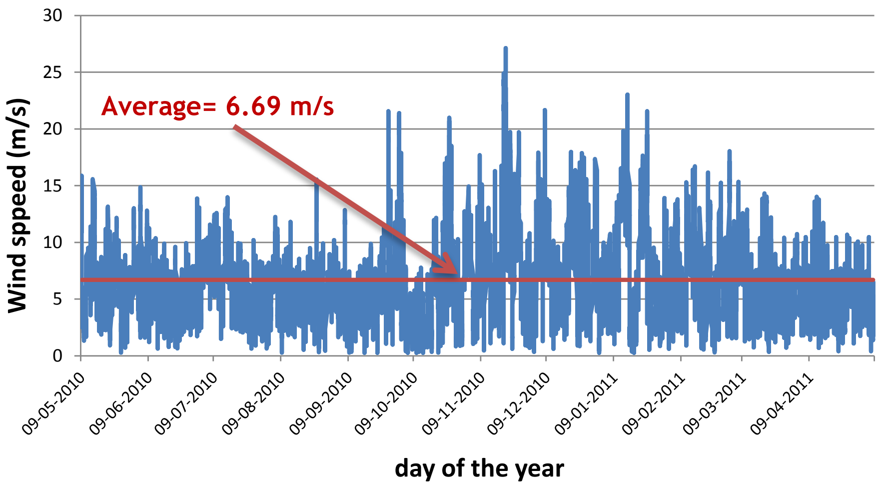

Figure A1 - Wind speed average time series from a Portuguese wind farm (May 2010-May 2011)

The power curve of wind turbine *Vestas V80* (shown in Figure A2 [121]) is linearized to determine the wind power produced by GenA during the year of operation.

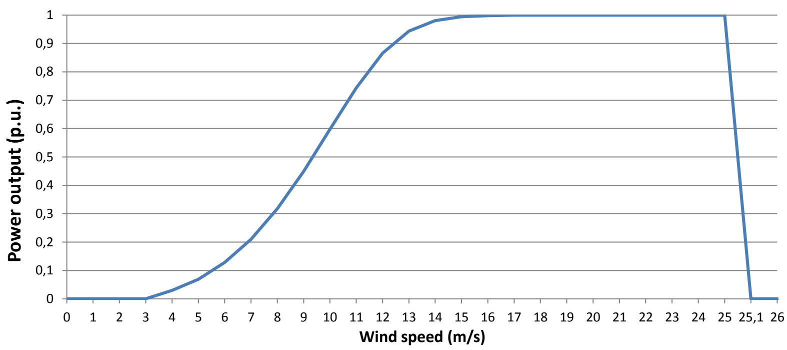

Figure A2 - Power curve of wind turbine *Vestas V80*

The available wind power during the year of operation is shown in the cumulative wind power curve of Figure A3.

Appendix A - Cost-benefit analyses to determine the installed capacities of generators GenC and GenD

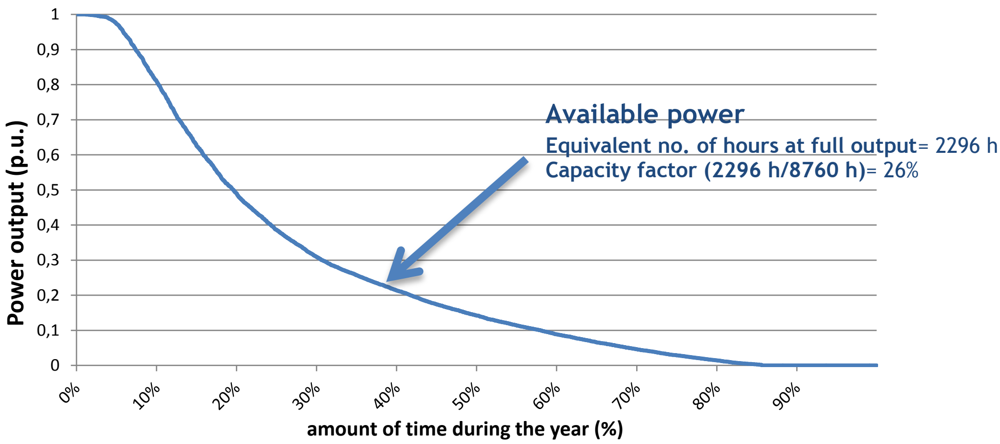

Figure A3 - Cumulative wind power curve from May 2010 to May 2011

- Generator GenB schedules its production according to the price of electrical energy. For this, the price of electrical energy of the Iberian Electricity Market (Portuguese side) during one year (May 2010 to May 2011) is used, see Figure A4.

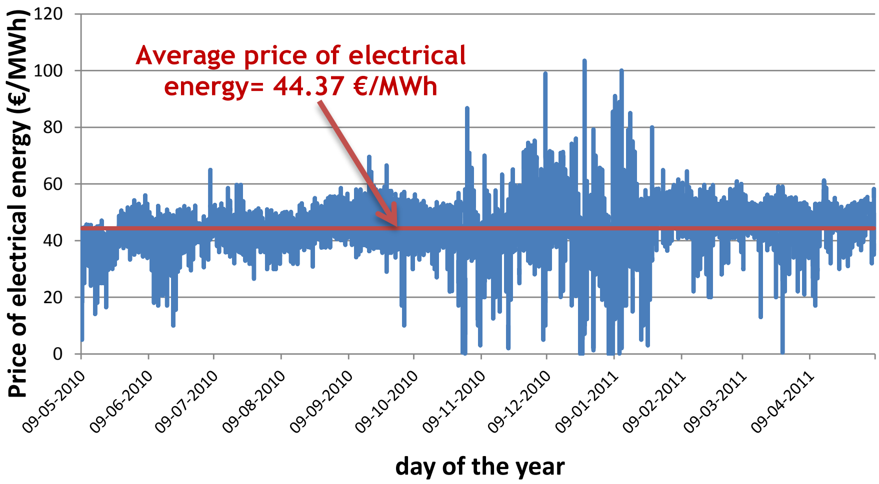

Figure A4 - Price of electrical energy of the Iberian Electricity Market (Portuguese side) during one year (May 2010 to May 2011)

- The parameters of the generators are presented in Table A1. S_max_C and S_max_D are the installed capacities of GenC and GenD, respectively.

Table A1 - Parameters of the generators

Parameter	Value	Unit
Minimum output power of GenA and GenD	0	MVA
Maximum power output of GenA	10	MVA
Operating limits of GenB	$[1.6;\ 5]$	MVA
Operating limits of GenC	$[40\% \cdot S\_max\_C;\ S\_max\_C]$	MVA
Maximum power output of GenD	S_max_D	MVA
Fuel costs of GenB and GenC (fc_B, fc_C)	35	€/MWh
Start-up costs of GenB and GenC (su_B, su_C)	100	€

The amount of electrical energy that GenB and GenC can produce per day is fixed (16 hours of full output power).

Appendix A – Cost-benefit analyses to determine the installed capacities of generators GenC and GenD

Cost-benefit analysis to determine the installed capacity of GenC

GenC operates when there is available capacity in the distribution circuit (after GenA and GenB have scheduled their output powers). GenC schedules its production according to the price profile given in Figure A4.

Ratings from 1 MW to 10 MW for GenC are evaluated. The initial investment considered is 1 M€ per MW installed [126]. The operation and maintenance costs are 2% of the initial investment per year during the lifespan of the investment [127]. Parameters for the financial analysis are shown in Table A2.

Table A2 – Parameters for the cost/benefit analysis of the rating of GenC

Lifespan of the investment (years)	25[2]
Discount rate of the investment	5%
Annual Consumer Price Index	3.8%[3]

The annual consumer price index is used to update the price profile given in Figure A4 for each year of the investment. Periods of unavailability of the generator are not taken into account. Taxes, risk premiums and loan/amortisation plans are also not considered.

The production of GenC and respective income generated during the year of operation with different ratings is presented in Table A3.

Table A3 – Production of GenC and respective income generated during the year of operation

Rating (MVA)	Production (MWh/year)	Income (€)
1	4979.99	56822.25
2	10387.15	121404.77
3	15767.88	185620.72
4	21228.67	250919.68
5	26335.52	311496.96
6	31254.54	372335.30
7	36162.60	429756.04
8	40850.33	484100.46
9	45294.35	530594.55
10	49324.84	571903.25

The net present value at the end of the investment is calculated using equation (A1).

$$NPV = \left[\frac{Income_1}{(1+d)^1} + \frac{Income_2}{(1+d)^2} + \ldots + \frac{Income_n}{(1+d)^n} \right] - Initial\ Investment \qquad \text{(A1)}$$

Where d is the discount rate of the investment, $Income$ is the income generated by GenC and n is the year of the investment.

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[2] Expected lifetime of a biomass generator, according to [111]

[3] Consumer Price Index in Portugal in the period May 2010-May 2011 (source: www.ine.pt)

Appendix A - Cost-benefit analyses to determine the installed capacities of generators GenC and GenD

The net present value (NPV) at the end of the investment for each possible rating of GenC is shown in Figure A5.

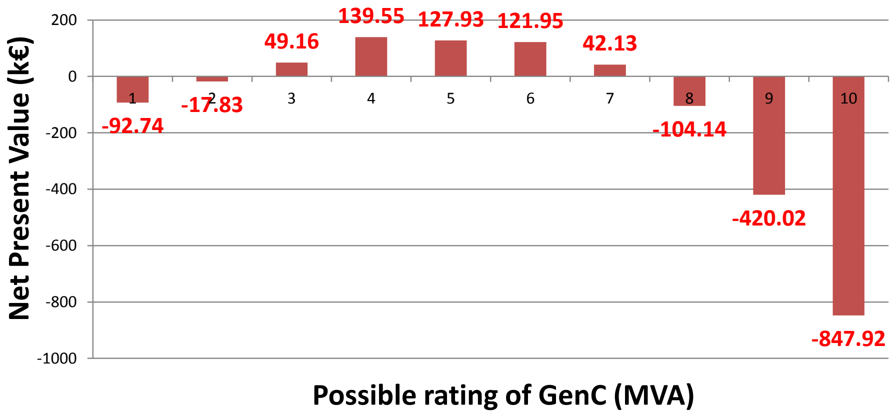

Figure A5 - Net Present Value at the end of the investment with different ratings of GenC

The return of the investment is greater being the rating of GenC equal to 4 MVA. The internal rate of return of the investment (rate above which one investment has positive NPV) with GenC equal to 4 MVA is 5.27%.

Cost-benefit analysis to determine the installed capacity of GenD

GenD produces according to the availability of wind shown in Figure A1. GenD operates when there is available capacity in the distribution circuit (after GenA, GenB and GenC have scheduled their output powers). GenD is curtailed when the distribution circuit rating is exceeded.

Ratings from 1 MW to 10 MW for GenD are evaluated. The initial investment considered is 1 M€ per MW installed [128]. This amount includes turbine, grid connection, electrical installation and civil engineering costs. The operation and maintenance costs are 12.5 € per MWh produced, an average over the lifespan of the investment [128]. Parameters for the financial analysis are shown in Table A4.

Table A4 - Parameters for the cost/benefit analysis of the rating of GenD

Lifespan of the investment (years)	20[4]
Discount rate of the investment	5%
Annual Consumer Price Index	3.8%

The annual consumer price index is used to update the price profile given in Figure A4 for each year of the investment. Wake effect and periods of unavailability of the generator are not taken into account. Taxes, risk premiums and loan/amortisation plans are also not considered.

The production of GenD and respective income generated during the year of operation with different ratings is presented in Table A5.

[4] Expected lifetime of a wind generator, according to [112]

Table A5 - Production of GenD and respective income generated during the year of operation

Rating (MVA)	Production (MWh/year)	Income (€)
1	2001.49	85465.93
2	3863.60	164156.38
3	5625.37	238018.72
4	7299.89	307737.48
5	8901.51	373934.55
6	10308.26	433152.84
7	11611.60	488353.33
8	12830.64	540303.43
9	13990.64	589867.92
10	15098.17	637268.43

The net present value at the end of the investment for each possible rating of GenD, calculated using equation (A1), is shown in Figure A6.

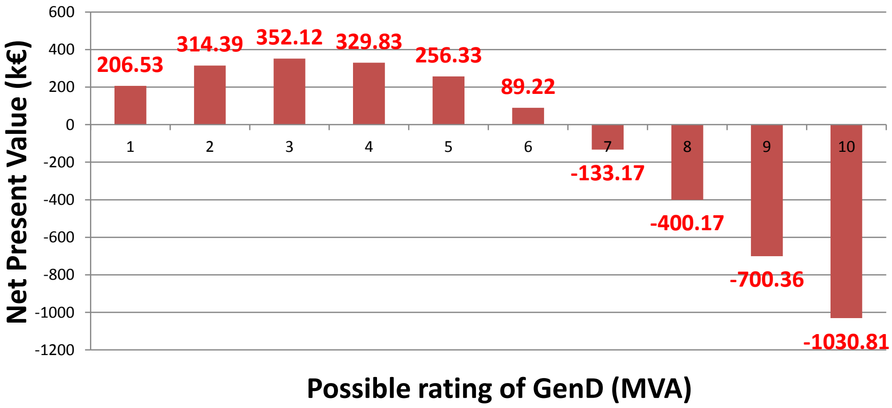

Figure A6 - Net Present Value at the end of the investment with different ratings of GenD

The return of the investment is greater being the rating of GenD equal to 3 MVA. The internal rate of return of the investment (rate above which one investment has positive NPV) with GenD equal to 3 MVA is 6.14%.

Appendix B - AC optimal power flow in the representative of the Portuguese MV distribution network

An AC optimal power flow (OPF) is run in the representative of the Portuguese MV distribution network introduced in Chapter 3, see Figure B1. The objective is to minimise the costs of producing active power. The AC OPF is run in the *Matlab*-based package *MATPOWER* [116].

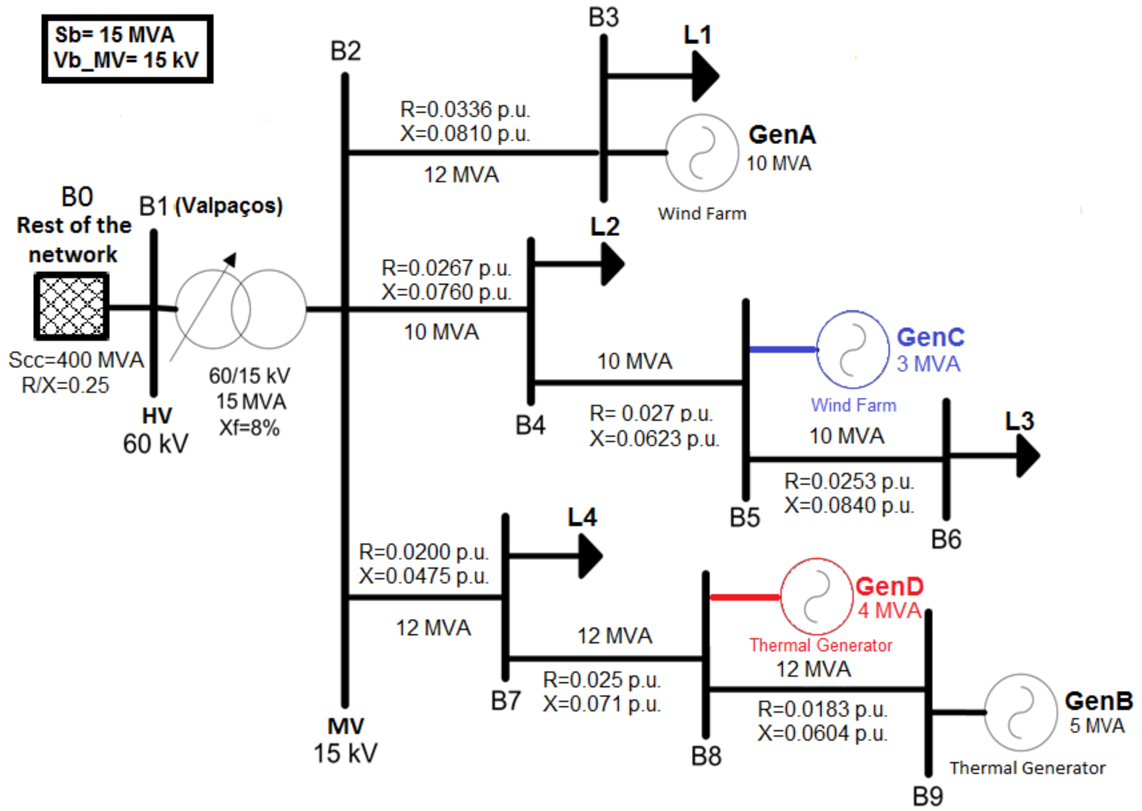

Figure B1 - Distribution network below Valpaços substation

Busbar B0 is introduced to represent the network connected upstream the *Valpaços* distribution substation, see Figure B1.

The operating limits of the generators in the AC OPF are given in Table B1:

Table B1 - Operating limits of the generators in the AC OPF

Generator	Operating limits	Unit
GenA	[0; 10]	MVA
GenB	[2; 5]	MVA
GenC	[1.6; 4]	MVA
GenD	[0; 3]	MVA

Generators GenA and GenD have no operation costs. The operation of GenB and GenC costs 35€ per MWh produced. No start-up costs are considered. The generators located upstream the *Valpaços* substation (busbar B0) have a cost function CF defined as follows: $CF(P_0) = 50 + 290 \cdot P_0 + 33 \cdot P_0^2 (€/MWh)$ (adapted of [129]). P_0 is the active output power of the generators located upstream the *Valpaços* substation.

Appendix B – AC optimal power flow in the representative of the Portuguese MV distribution network

The following taps were manually tested for the transformer connected between busbars B1 and B2: {0.94; 0.96; 0.98; 1; 1.02; 1.04; 1.06}.

The results of the AC OPF reported by *MATPOWER* are shown as follows. Power flows and busbar voltage data are presented. The objective function value is 558.4€. The cost of operation of the generators located upstream the *Valpaços* substation is $CF(0.75) = 50 + 290 \cdot 0.75 + 33 \cdot 0.75^2 = 286.1€$. Then, the cost of operating generators GenA, GenB, GenC and GenD is $558.4 - 286.1 = 272.3€$. This minimum cost of operating the distribution network is obtained being the transformer tap equal to 1.06.

Results of the AC OPF reported by *MATPOWER*

##

MATPOWER Version 4.1, 14-Dec-2011 -- AC Optimal Power Flow

MATLAB Interior Point Solver -- MIPS, Version 1.0, 07-Feb-2011

Converged!

Converged in 0.15 seconds

Objective Function Value = 558.4 €/hr

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| System Summary |

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How many?		How much?	P (MW)	Q (MVAr)
Buses	10	Total Gen Capacity	222.0	-300.0 to 300.0
Generators	5	On-line Capacity	222.0	-300.0 to 300.0
Committed Gens	5	Generation (actual)	21.5	4.8
Loads	5	Load	21.0	2.0
Fixed	5	Fixed	21.0	2.0
Dispatchable	0	Dispatchable	-0.0 of -0.0	0.0
Shunts	0	Shunt (inj)	-0.0	0.0
Branches	10	Losses (I^2 * Z)	0.49	2.81
Transformers	1	Branch Charging (inj)	–	0.0
Inter-ties	0	Total Inter-tie Flow	0.0	0.0
Areas	1			

	Minimum	Maximum
Voltage Magnitude	0.918 p.u. @ bus 6	1.000 p.u. @ bus 0
Voltage Angle	0.00 deg @ bus 0	12.05 deg @ bus 9
P Losses (I^2*R)	–	0.14 MW @ line 2-3
Q Losses (I^2*X)	–	1.35 MVAr @ line 1-2
Lambda P	35.00 €/MWh @ bus 9	339.54 €/MWh @ bus 0
Lambda Q	0.00 €/MWh @ bus 0	89.13 €/MWh @ bus 6

Appendix B – AC optimal power flow in the representative of the Portuguese MV distribution network

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| Bus Data |

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Bus #	Voltage Mag(pu)	Voltage Ang(deg)	Generation P (MW)	Generation Q (MVAr)	Load P (MW)	Load Q (MVAr)	Lambda(€/MVA-hr) P	Lambda(€/MVA-hr) Q
0	1.000	0.000*	0.75	4.79	15.00	0.00	339.539	-
1	0.998	2.153	-	-	-	-	333.865	3.056
2	0.921	7.232	-	-	-	-	51.915	87.474
3	0.932	10.012	10.00	0.00	2.65	0.87	42.128	89.118
4	0.919	7.651	-	-	1.16	0.38	50.690	88.396
5	0.922	8.290	3.00	0.00	-	-	48.379	88.735
6	0.918	7.999	-	-	0.85	0.28	49.547	89.126
7	0.927	8.639	-	-	1.38	0.45	47.024	88.560
8	0.939	11.064	4.00	0.00	-	-	38.421	89.066
9	0.944	12.047	3.78	0.00	-	-	35.000	89.125
	Total:		21.53	4.79	21.04	1.98		

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| Branch Data |

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Branch #	From Bus	To Bus	From Bus Injection P (MW)	From Bus Injection Q (MVAr)	To Bus Injection P (MW)	To Bus Injection Q (MVAr)	Loss (I^2 * Z) P (MW)	Loss (I^2 * Z) Q (MVAr)
1	0	1	-14.25	4.79	14.39	-4.25	0.137	0.55
2	1	2	-14.39	4.25	14.39	-2.89	0.000	1.35
3	2	3	-7.21	1.21	7.35	-0.87	0.141	0.34
4	2	4	-0.98	0.70	0.98	-0.69	0.003	0.01
5	2	7	-6.20	0.98	6.26	-0.84	0.062	0.15
6	4	5	-2.14	0.31	2.15	-0.29	0.010	0.02
7	5	6	0.85	0.29	-0.85	-0.28	0.002	0.01
8	7	8	-7.64	0.39	7.76	-0.06	0.112	0.32
9	8	9	-3.76	0.06	3.78	0.00	0.019	0.06
10	6	9	-0.00	0.00	0.00	-0.00	0.000	0.00
						Total:	0.486	2.81

##

Appendix C - Data of the selected period of operation

Data of the selected period of operation used to evaluate the coordination of independent distributed generators and the coordination of generators and controllable load are presented as follows. Tables C1 to C6 show the values of price of electrical energy, wind power and load consumption for each hour of six days of operation.

Price data was obtained from the Iberian Electricity Market (Portuguese side) [120]. Wind power data was obtained from the wind speed data (10 minute average series) of a Portuguese wind farm. This wind speed data was applied to the power curve of the wind turbine *Vestas V80*. Wind power and price data were not collected on the same days (there is no correlation between data). Load data corresponds to the average consumption profiles of a working day in Portugal from 2004 to 2007, provided by the Portuguese Energy Services Regulator [114]. The load profiles were normalised by the maximum value observed in the winter load profile.

Day 1 – Large variation of price, high wind power, winter load profile

Table C1 – Values of price of electrical energy, wind power and load consumption on day 1

Hour	Price of electrical energy (€/MWh)	Wind power (p.u. of rated power)	Load consumption (p.u. of maximum consumption)
0	30	1	0.75
1	15.69	1	0.67
2	4.90	1	0.63
3	3	1	0.61
4	2	0.99	0.60
5	4	0.93	0.61
6	5.65	1	0.63
7	32.28	1	0.66
8	22	0.99	0.73
9	38.67	1	0.83
10	38.89	1	0.88
11	40.01	1	0.91
12	48.33	0.94	0.91
13	45.59	0.99	0.86
14	43.85	0.94	0.88
15	45.59	0.94	0.89
16	43.57	0.82	0.88
17	49.11	0.69	0.89
18	53.06	0.50	0.93
19	57.87	0.77	1
20	100	0.70	1
21	89	0.59	0.98
22	57.87	0.81	0.93
23	45.95	0.65	0.87

Day 2 – Medium magnitude of price, medium wind power, winter load profile

Table C2 – Values of price of electrical energy, wind power and load consumption on day 2

Hour	Price of electrical energy (€/MWh)	Wind power (p.u. of rated power)	Load consumption (p.u. of maximum consumption)
0	47.48	0.65	0.75
1	44.82	0.78	0.67
2	43.38	0.82	0.63
3	43.13	0.56	0.61
4	43.10	0.48	0.60
5	42.80	0.70	0.61
6	39.14	0.73	0.63
7	38.02	0.31	0.66
8	37.90	0.42	0.73
9	40.45	0.19	0.83
10	43.10	0.10	0.88
11	41.45	0.10	0.91
12	40.82	0.07	0.91
13	41.16	0.15	0.86
14	40	0.24	0.88
15	39.07	0.57	0.89
16	38.20	0.74	0.88
17	38.20	0.47	0.89
18	37.90	0.59	0.93
19	38.73	0.45	1
20	42.15	0.83	1
21	48.98	1	0.98
22	51.68	1	0.93
23	44.48	1	0.87

Day 3 – High magnitude of price, low wind power, winter load profile

Table C3 – Values of price of electrical energy, wind power and load consumption on day 3

Hour	Price of electrical energy (€/MWh)	Wind power (p.u. of rated power)	Load consumption (p.u. of maximum consumption)
0	44.40	0.20	0.75
1	48.51	0.14	0.67
2	44.40	0.07	0.63
3	43.59	0.14	0.61
4	42.40	0.38	0.60
5	42.40	0.26	0.61
6	43.59	0.21	0.63
7	43.59	0.15	0.66
8	40.38	0.20	0.73
9	44.08	0.31	0.83
10	49.30	0.35	0.88
11	51.30	0.26	0.91
12	64.99	0.27	0.91
13	56.38	0.45	0.86
14	52.01	0.34	0.88
15	52.27	0.24	0.89
16	52.01	0.43	0.88
17	51.25	0.40	0.89
18	49.51	0.53	0.93
19	48.51	0.47	1
20	46.10	0.22	1
21	44.02	0.31	0.98
22	44.99	0.28	0.93
23	46.10	0.23	0.87

Day 4 – Large variation of price, high wind power, summer load profile

Table C4 – Values of price of electrical energy, wind power and load consumption on day 4

Hour	Price of electrical energy (€/MWh)	Wind power (p.u. of rated power)	Load consumption (p.u. of maximum consumption)
0	30	1	0.66
1	15.69	1	0.62
2	4.90	1	0.58
3	3	1	0.56
4	2	0.99	0.54
5	4	0.93	0.55
6	5.65	1	0.56
7	32.28	1	0.58
8	22	0.99	0.65
9	38.67	1	0.76
10	38.89	1	0.80
11	40.01	1	0.82
12	48.33	0.94	0.84
13	45.59	0.99	0.80
14	43.85	0.94	0.81
15	45.59	0.94	0.80
16	43.57	0.82	0.80
17	49.11	0.69	0.78
18	53.06	0.50	0.77
19	57.87	0.77	0.77
20	100	0.70	0.80
21	89	0.59	0.82
22	57.87	0.81	0.80
23	45.95	0.65	0.75

Day 5 – Medium magnitude of price, medium wind power, summer load profile

Table C5 – Values of price of electrical energy, wind power and load consumption on day 5

Hour	Price of electrical energy (€/MWh)	Wind power (p.u. of rated power)	Load consumption (p.u. of maximum consumption)
0	47.48	0.65	0.66
1	44.82	0.78	0.62
2	43.38	0.82	0.58
3	43.13	0.56	0.56
4	43.10	0.48	0.54
5	42.80	0.70	0.55
6	39.14	0.73	0.56
7	38.02	0.31	0.58
8	37.90	0.42	0.65
9	40.45	0.19	0.76
10	43.10	0.10	0.80
11	41.45	0.10	0.82
12	40.82	0.07	0.84
13	41.16	0.15	0.80
14	40	0.24	0.81
15	39.07	0.57	0.80
16	38.20	0.74	0.80
17	38.20	0.47	0.78
18	37.90	0.59	0.77
19	38.73	0.45	0.77
20	42.15	0.83	0.80
21	48.98	1	0.82
22	51.68	1	0.80
23	44.48	1	0.75

Day 6 – High magnitude of price, low wind power, summer load profile

Table C6 – Values of price of electrical energy, wind power and load consumption on day 6

Hour	Price of electrical energy (€/MWh)	Wind power (p.u. of rated power)	Load consumption (p.u. of maximum consumption)
0	44.40	0.20	0.66
1	48.51	0.14	0.62
2	44.40	0.07	0.58
3	43.59	0.14	0.56
4	42.40	0.38	0.54
5	42.40	0.26	0.55
6	43.59	0.21	0.56
7	43.59	0.15	0.58
8	40.38	0.20	0.65
9	44.08	0.31	0.76
10	49.30	0.35	0.80
11	51.30	0.26	0.82
12	64.99	0.27	0.84
13	56.38	0.45	0.80
14	52.01	0.34	0.81
15	52.27	0.24	0.80
16	52.01	0.43	0.80
17	51.25	0.40	0.78
18	49.51	0.53	0.77
19	48.51	0.47	0.77
20	46.10	0.22	0.80
21	44.02	0.31	0.82
22	44.99	0.28	0.80
23	46.10	0.23	0.75

Appendix D - Output powers of the generators without and with the coordination of independent distributed generators

The output powers of the generators without and with the coordination of independent distributed generators for each day of the selected period of operation are presented as follows. Load consumption is also presented (columns “Load (MW)”, “Load (MVar)” and “Load (MVA)”). Column “Distr. Circuit (MVA)” shows the utilisation of the distribution circuit. The utilisation of the distribution circuit is presented in absolute value. Column “Circuit limit (MVA)” shows the distribution circuit limit. The output powers of GenD with asterisk (*) in Tables D1, D3, D6 and D8 refer to curtailed outputs.

Appendix D – Output powers of the generators without and with the coordination of independent distributed generators

DAY 1

Without coordination

Table D1 - Output powers of the generators without coordination on day 1

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Load (MW)	Load (MVar)	Load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	10	0	10	0	0	0	0	0	0	3	0	3	5.19	1.71	5.46	8	15
1	10	0	10	0	0	0	0	0	0	3	0	3	4.68	1.54	4.93	8.46	15
2	10	0	10	0	0	0	0	0	0	3	0	3	4.40	1.44	4.63	8.72	15
3	10	0	10	0	0	0	0	0	0	3	0	3	4.23	1.40	4.46	8.88	15
4	9.90	0	9.90	0	0	0	0	0	0	2.97	0	2.97	4.18	1.36	4.40	8.80	15
5	9.30	0	9.30	0	0	0	0	0	0	2.79	0	2.79	4.23	1.40	4.46	7.98	15
6	10	0	10	0	0	0	0	0	0	3	0	3	4.34	1.44	4.57	8.78	15
7	10	0	10	0	0	0	0	0	0	3	0	3	4.56	1.50	4.80	8.57	15
8	9.90	0	9.90	0	0	0	0	0	0	2.87	0.86	3	5.08	1.66	5.34	7.73	15
9	10	0	10	4.79	1.44	5	3.83	1.15	4	2.09 *	0.63 *	2.18 *	5.75	1.89	6.05	15.00	15
10	10	0	10	4.79	1.44	5	3.83	1.15	4	2.43 *	0.73 *	2.54 *	6.10	2.01	6.42	15.00	15
11	10	0	10	4.79	1.44	5	3.83	1.15	4	2.65 *	0.8 *	2.77 *	6.32	2.07	6.65	15.00	15
12	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.32	2.07	6.65	14.58	15
13	9.90	0	9.90	4.79	1.44	5	3.83	1.15	4	2.4 *	0.72 *	2.51 *	5.97	1.97	6.29	15.00	15
14	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.10	2.01	6.42	14.81	15
15	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.15	2.02	6.47	14.76	15
16	8.20	0	8.20	4.79	1.44	5	3.83	1.15	4	2.46	0.74	2.57	6.10	2.01	6.42	13.25	15
17	6.90	0	6.90	4.79	1.44	5	3.83	1.15	4	2.07	0.62	2.16	6.15	2.02	6.47	11.5	15
18	5	0	5	4.79	1.44	5	3.83	1.15	4	1.50	0.45	1.57	6.49	2.14	6.83	8.68	15
19	7.70	0	7.70	4.79	1.44	5	3.83	1.15	4	2.31	0.69	2.41	6.93	2.28	7.3	11.74	15
20	7	0	7	4.79	1.44	5	3.83	1.15	4	2.10	0.63	2.19	6.93	2.28	7.3	10.83	15
21	5.90	0	5.90	4.79	1.44	5	3.83	1.15	4	1.77	0.53	1.85	6.77	2.23	7.13	9.56	15
22	8.10	0	8.10	5	0	5	4	0	4	2.43	0	2.43	6.49	2.14	6.83	13.21	15
23	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	6.04	1.98	6.36	11.58	15
TOTAL	**212.5**	**0**	**212.5**	**72.27**	**18.72**	**75**	**57.79**	**14.95**	**60**	**61.25**	**9.95**	**62.74**	**135.5**	**44.57**	**142.64**		

	GenA	**GenB**	**GenC**	**GenD**	**TOTAL**
INCOME (€)	7511.63	1211.71	948.89	2153.94	11826.17

Appendix D – Output powers of the generators without and with the coordination of independent distributed generators

With coordination

Table D2 - Output powers of the generators with coordination on day 1

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Load (MW)	Load (MVar)	Load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	10	0	10	0	0	0	0	0	0	3	0	3	5.19	1.71	5.46	8	15
1	10	0	10	0	0	0	0	0	0	3	0	3	4.68	1.54	4.93	8.46	15
2	10	0	10	0	0	0	0	0	0	3	0	3	4.40	1.44	4.63	8.72	15
3	10	0	10	0	0	0	0	0	0	3	0	3	4.23	1.40	4.46	8.88	15
4	9.90	0	9.90	0	0	0	0	0	0	2.97	0	2.97	4.18	1.36	4.40	8.80	15
5	9.30	0	9.30	0	0	0	0	0	0	2.79	0	2.79	4.23	1.40	4.46	7.98	15
6	10	0	10	0	0	0	0	0	0	3	0	3	4.34	1.44	4.57	8.78	15
7	10	0	10	0	0	0	0	0	0	3	0	3	4.56	1.50	4.80	8.57	15
8	9.90	0	9.90	0	0	0	0	0	0	2.87	0.86	3	5.08	1.66	5.34	7.73	15
9	10	0	10	4.79	1.44	5	3.04	0.91	3.17	2.87	0.86	3	5.75	1.89	6.05	15.00	15
10	10	0	10	4.79	1.44	5	3.39	1.02	3.54	2.87	0.86	3	6.10	2.01	6.42	15.00	15
11	10	0	10	4.79	1.44	5	3.61	1.08	3.77	2.87	0.86	3	6.32	2.07	6.65	15.00	15
12	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.32	2.07	6.65	14.58	15
13	9.90	0	9.90	4.79	1.44	5	3.36	1.01	3.51	2.87	0.86	3	5.97	1.97	6.29	15.00	15
14	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.10	2.01	6.42	14.81	15
15	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.15	2.02	6.47	14.76	15
16	8.20	0	8.20	4.79	1.44	5	3.83	1.15	4	2.46	0.74	2.57	6.10	2.01	6.42	13.25	15
17	6.90	0	6.90	4.79	1.44	5	3.83	1.15	4	2.07	0.62	2.16	6.15	2.02	6.47	11.5	15
18	5	0	5	4.79	1.44	5	3.83	1.15	4	1.50	0.45	1.57	6.49	2.14	6.83	8.68	15
19	7.70	0	7.70	4.79	1.44	5	3.83	1.15	4	2.31	0.69	2.41	6.93	2.28	7.3	11.74	15
20	7	0	7	4.79	1.44	5	3.83	1.15	4	2.10	0.63	2.19	6.93	2.28	7.3	10.83	15
21	5.90	0	5.90	4.79	1.44	5	3.83	1.15	4	1.77	0.53	1.85	6.77	2.23	7.13	9.56	15
22	8.10	0	8.10	5	0	5	4	0	4	2.43	0	2.43	6.49	2.14	6.83	13.21	15
23	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	6.04	1.98	6.36	11.58	15
TOTAL	**212.5**	**0**	**212.5**	**72.27**	**18.72**	**75**	**55.87**	**14.37**	**57.99**	**63.16**	**10.51**	**64.74**	**135.5**	**44.57**	**142.64**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME BEFORE INCOME SHARING (€)	7511.63	1211.71	938.20	2231.45	11892.98
INCOME AFTER INCOME SHARING (€)	**7539.80**	**1228.78**	**962.09**	**2162.31**	**11892.98**

Appendix D – Output powers of the generators without and with the coordination of independent distributed generators

DAY 2

Without coordination

Table D3 - Output powers of the generators without coordination on day 2

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Load (MW)	Load (MVar)	Load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	5.19	1.71	5.46	12.38	15
1	7.80	0	7.80	5	0	5	4	0	4	2.34	0	2.34	4.68	1.54	4.93	14.54	15
2	8.20	0	8.20	5	0	5	4	0	4	2.13 *	0 *	2.13 *	4.40	1.44	4.63	15.00	15
3	5.60	0	5.60	5	0	5	4	0	4	1.68	0	1.68	4.23	1.40	4.46	12.13	15
4	4.80	0	4.80	5	0	5	4	0	4	1.44	0	1.44	4.18	1.36	4.40	11.14	15
5	7	0	7	5	0	5	4	0	4	2.1	0	2.1	4.23	1.40	4.46	13.94	15
6	7.30	0	7.30	2	0	2	1.60	0	1.60	2.19	0	2.19	4.34	1.44	4.57	8.87	15
7	3.10	0	3.10	2	0	2	1.60	0	1.60	0.93	0	0.93	4.56	1.50	4.80	3.42	15
8	4.20	0	4.20	1.92	0.58	2.01	1.54	0.46	1.61	1.26	0.38	1.32	5.08	1.66	5.34	3.85	15
9	1.90	0	1.90	1.92	0.58	2.01	1.54	0.46	1.61	0.57	0.17	0.59	5.75	1.89	6.05	0.70	15
10	1	0	1	3.73	1.12	3.89	2.96	0.89	3.09	0.30	0.09	0.31	6.10	2.01	6.42	1.91	15
11	1	0	1	1.92	0.58	2.01	1.54	0.46	1.61	0.30	0.09	0.31	6.32	2.07	6.65	1.82	15
12	0.70	0	0.70	1.92	0.58	2.01	1.54	0.46	1.61	0.21	0.06	0.22	6.32	2.07	6.65	2.18	15
13	1.50	0	1.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.97	1.97	6.29	1.86	15
14	2.40	0	2.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.10	2.01	6.42	2.63	15
15	5.70	0	5.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.15	2.02	6.47	5.88	15
16	7.40	0	7.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.10	2.01	6.42	7.63	15
17	4.70	0	4.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.15	2.02	6.47	4.88	15
18	5.90	0	5.90	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.49	2.14	6.83	5.75	15
19	4.50	0	4.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.93	2.28	7.3	3.92	15
20	8.30	0	8.30	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.93	2.28	7.3	12.91	15
21	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.77	2.23	7.13	14.77	15
22	10	0	10	5	0	5	4	0	4	2.34 *	0 *	2.34 *	6.49	2.14	6.83	15.00	15
23	10	0	10	5	0	5	4	0	4	1.92 *	0 *	1.92 *	6.04	1.98	6.36	15.00	15
TOTAL	**129.5**	**0**	**129.5**	**78.43**	**10.38**	**80**	**62.76**	**8.25**	**64.00**	**47.49**	**8.53**	**48.77**	**135.5**	**44.57**	**142.64**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	5556.48	643.95	515.28	1992.22	8707.93

Appendix D – Output powers of the generators without and with the coordination of independent distributed generators

With coordination

Table D4 - Output powers of the generators with coordination on day 2

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Load (MW)	Load (MVar)	Load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	5.19	1.71	5.46	12.38	15
1	7.80	0	7.80	5	0	5	4	0	4	2.34	0	2.34	4.68	1.54	4.93	14.54	15
2	8.20	0	8.20	5	0	5	3.67	0	3.67	2.46	0	2.46	4.40	1.44	4.63	15.00	15
3	5.60	0	5.60	5	0	5	4	0	4	1.68	0	1.68	4.23	1.40	4.46	12.13	15
4	4.80	0	4.80	5	0	5	4	0	4	1.44	0	1.44	4.18	1.36	4.40	11.14	15
5	7	0	7	5	0	5	4	0	4	2.10	0	2.10	4.23	1.40	4.46	13.94	15
6	7.30	0	7.30	2	0	2	1.60	0	1.60	2.19	0	2.19	4.34	1.44	4.57	8.87	15
7	3.10	0	3.10	2	0	2	1.60	0	1.60	0.93	0	0.93	4.56	1.50	4.80	3.42	15
8	4.20	0	4.20	1.92	0.58	2.01	1.54	0.46	1.61	1.26	0.38	1.32	5.08	1.66	5.34	3.85	15
9	1.90	0	1.90	1.92	0.58	2.01	1.54	0.46	1.61	0.57	0.17	0.59	5.75	1.89	6.05	0.70	15
10	1	0	1	3.73	1.12	3.89	3.83	1.15	4	0.30	0.09	0.31	6.10	2.01	6.42	1.91	15
11	1	0	1	1.92	0.58	2.01	2.65	0.8	2.77	0.30	0.09	0.31	6.32	2.07	6.65	1.82	15
12	0.70	0	0.70	1.92	0.58	2.01	1.54	0.46	1.61	0.21	0.06	0.22	6.32	2.07	6.65	2.18	15
13	1.50	0	1.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.97	1.97	6.29	1.86	15
14	2.40	0	2.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.10	2.01	6.42	2.63	15
15	5.70	0	5.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.15	2.02	6.47	5.88	15
16	7.40	0	7.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.10	2.01	6.42	7.63	15
17	4.70	0	4.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.15	2.02	6.47	4.88	15
18	5.90	0	5.90	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.49	2.14	6.83	5.75	15
19	4.50	0	4.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.93	2.28	7.3	3.92	15
20	8.30	0	8.30	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.93	2.28	7.3	12.91	15
21	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.77	2.23	7.13	14.90	15
22	10	0	10	5	0	5	3.34	0	3.34	3	0	3	6.49	2.14	6.83	15.00	15
23	10	0	10	5	0	5	2.92	0	2.92	3	0	3	6.04	1.98	6.36	15.00	15
TOTAL	**129.5**	**0**	**129.5**	**78.43**	**10.38**	**80**	**62.67**	**8.85**	**64**	**49.56**	**8.53**	**50.84**	**135.5**	**44.57**	**142.64**		

	GenA	**GenB**	**GenC**	**GenD**	**TOTAL**
INCOME BEFORE INCOME SHARING (€)	5556.48	643.95	505.31	2088.68	8794.42
INCOME AFTER INCOME SHARING (€)	**5582.49**	**672.03**	**537.72**	**2002.18**	**8794.42**

Appendix D - Output powers of the generators without and with the coordination of independent distributed generators

DAY 3

Without coordination

Table D5 - Output powers of the generators without coordination on day 3

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Load (MW)	Load (MVar)	Load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	2	0	2	2	0	2	1.60	0	1.60	0.60	0	0.60	5.19	1.71	5.46	1.99	15
1	1.40	0	1.40	5	0	5	4	0	4	0.42	0	0.42	4.68	1.54	4.93	6.33	15
2	0.70	0	0.70	2	0	2	1.60	0	1.60	0.21	0	0.21	4.40	1.44	4.63	1.44	15
3	1.40	0	1.40	2	0	2	1.60	0	1.60	0.42	0	0.42	4.23	1.40	4.46	1.84	15
4	3.80	0	3.80	2	0	2	1.60	0	1.60	1.14	0	1.14	4.18	1.36	4.40	4.57	15
5	2.60	0	2.60	2	0	2	1.60	0	1.60	0.78	0	0.78	4.23	1.40	4.46	3.09	15
6	2.10	0	2.10	2	0	2	1.60	0	1.60	0.63	0	0.63	4.34	1.44	4.57	2.46	15
7	1.50	0	1.50	2	0	2	1.60	0	1.60	0.45	0	0.45	4.56	1.50	4.80	1.80	15
8	2	0	2	1.92	0.58	2.01	1.54	0.46	1.61	0.60	0.18	0.63	5.08	1.66	5.34	1.07	15
9	3.10	0	3.10	1.92	0.58	2.01	1.54	0.46	1.61	0.93	0.28	0.97	5.75	1.89	6.05	1.83	15
10	3.50	0	3.50	4.79	1.44	5	3.83	1.15	4	1.05	0.32	1.10	6.10	2.01	6.42	7.13	15
11	2.60	0	2.60	4.79	1.44	5	3.83	1.15	4	0.78	0.23	0.81	6.32	2.07	6.65	5.73	15
12	2.70	0	2.70	4.79	1.44	5	3.83	1.15	4	0.81	0.24	0.84	6.32	2.07	6.65	5.86	15
13	4.50	0	4.50	4.79	1.44	5	3.83	1.15	4	1.35	0.41	1.41	5.97	1.97	6.29	8.56	15
14	3.40	0	3.40	4.79	1.44	5	3.83	1.15	4	1.02	0.31	1.07	6.10	2.01	6.42	7	15
15	2.40	0	2.40	4.79	1.44	5	3.83	1.15	4	0.72	0.22	0.75	6.15	2.02	6.47	5.65	15
16	4.30	0	4.30	4.79	1.44	5	3.83	1.15	4	1.29	0.39	1.35	6.10	2.01	6.42	8.17	15
17	4	0	4	4.79	1.44	5	3.83	1.15	4	1.20	0.36	1.25	6.15	2.02	6.47	7.73	15
18	5.30	0	5.30	4.79	1.44	5	3.83	1.15	4	1.59	0.48	1.66	6.49	2.14	6.83	9.07	15
19	4.70	0	4.70	3.79	1.14	3.96	3.03	0.91	3.16	1.41	0.42	1.47	6.93	2.28	7.3	6	15
20	2.20	0	2.20	1.92	0.58	2.01	1.54	0.46	1.61	0.66	0.2	0.69	6.93	2.28	7.3	1.21	15
21	3.10	0	3.10	1.92	0.58	2.01	1.54	0.46	1.61	0.93	0.28	0.97	6.77	2.23	7.13	1.16	15
22	2.80	0	2.80	2	0	2	1.60	0	1.60	0.84	0	0.84	6.49	2.14	6.83	2.27	15
23	2.30	0	2.30	2	0	2	1.60	0	1.60	0.69	0	0.69	6.04	1.98	6.36	2.05	15
TOTAL	**68.40**	**0**	**68.40**	**77.58**	**16.42**	**80**	**62.06**	**13.1**	**64**	**20.52**	**4.32**	**21.15**	**135.5**	**44.57**	**142.64**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	3320.83	1131.72	905.16	996.25	6353.97

Appendix D - Output powers of the generators without and with the coordination of independent distributed generators

DAY 4

Without coordination

Table D6 - Output powers of the generators without coordination on day 4

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Load (MW)	Load (MVar)	Load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	10	0	10	0	0	0	0	0	0	3	0	3	4.58	1.51	4.82	8.55	15
1	10	0	10	0	0	0	0	0	0	3	0	3	4.30	1.41	4.53	8.81	15
2	10	0	10	0	0	0	0	0	0	3	0	3	4.02	1.32	4.23	9.08	15
3	10	0	10	0	0	0	0	0	0	3	0	3	3.89	1.28	4.10	9.20	15
4	9.90	0	9.90	0	0	0	0	0	0	2.97	0	2.97	3.75	1.23	3.95	9.20	15
5	9.30	0	9.30	0	0	0	0	0	0	2.79	0	2.79	3.82	1.25	4.02	8.36	15
6	10	0	10	0	0	0	0	0	0	3	0	3	3.89	1.28	4.10	9.20	15
7	10	0	10	0	0	0	0	0	0	3	0	3	4.02	1.32	4.23	9.08	15
8	9.90	0	9.90	0	0	0	0	0	0	2.87	0.86	3	4.51	1.48	4.75	8.28	15
9	10	0	10	4.79	1.44	5	3.83	1.15	4	1.62 *	0.49 *	1.69 *	5.27	1.73	5.55	15.00	15
10	10	0	10	4.79	1.44	5	3.83	1.15	4	1.90 *	0.57 *	1.98 *	5.55	1.82	5.84	15.00	15
11	10	0	10	4.79	1.44	5	3.83	1.15	4	2.03 *	0.61 *	2.12 *	5.69	1.87	5.99	15.00	15
12	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.74 *	0.82 *	2.86 *	5.83	1.92	6.14	15.00	15
13	9.90	0	9.90	4.79	1.44	5	3.83	1.15	4	1.99 *	0.60 *	2.08 *	5.55	1.82	5.84	15.00	15
14	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.54 *	0.76 *	2.65 *	5.62	1.85	5.92	15.00	15
15	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.46 *	0.74 *	2.57 *	5.55	1.82	5.84	15.00	15
16	8.20	0	8.20	4.79	1.44	5	3.83	1.15	4	2.46	0.74	2.57	5.55	1.82	5.84	13.81	15
17	6.90	0	6.90	4.79	1.44	5	3.83	1.15	4	2.07	0.62	2.16	5.41	1.78	5.70	12.26	15
18	5	0	5	4.79	1.44	5	3.83	1.15	4	1.50	0.45	1.57	5.34	1.76	5.62	9.86	15
19	7.70	0	7.70	4.79	1.44	5	3.83	1.15	4	2.31	0.69	2.41	5.34	1.76	5.62	13.38	15
20	7	0	7	4.79	1.44	5	3.83	1.15	4	2.10	0.63	2.19	5.55	1.82	5.84	12.25	15
21	5.90	0	5.90	4.79	1.44	5	3.83	1.15	4	1.77	0.53	1.85	5.69	1.87	5.99	10.67	15
22	8.10	0	8.10	5	0	5	4	0	4	2.43	0	2.43	5.55	1.82	5.84	14.10	15
23	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	5.2	1.71	5.47	12.37	15
TOTAL	**212.5**	**0**	**212.5**	**72.27**	**18.72**	**75**	**57.79**	**14.95**	**60**	**58.5**	**9.11**	**59.84**	**119.47**	**39.25**	**125.77**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	7511.63	1211.71	948.89	2039.11	11711.33

Appendix D – Output powers of the generators without and with the coordination of independent distributed generators

With coordination

Table D7 - Output powers of the generators with coordination on day 4

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Load (MW)	Load (MVar)	Load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	10	0	10	0	0	0	0	0	0	3	0	3	4.58	1.51	4.82	8.55	15
1	10	0	10	0	0	0	0	0	0	3	0	3	4.30	1.41	4.53	8.81	15
2	10	0	10	0	0	0	0	0	0	3	0	3	4.02	1.32	4.23	9.08	15
3	10	0	10	0	0	0	0	0	0	3	0	3	3.89	1.28	4.10	9.20	15
4	9.90	0	9.90	0	0	0	0	0	0	2.97	0	2.97	3.75	1.23	3.95	9.20	15
5	9.30	0	9.30	0	0	0	0	0	0	2.79	0	2.79	3.82	1.25	4.02	8.36	15
6	10	0	10	0	0	0	0	0	0	3	0	3	3.89	1.28	4.10	9.20	15
7	10	0	10	0	0	0	0	0	0	3	0	3	4.02	1.32	4.23	9.08	15
8	9.90	0	9.90	0	0	0	0	0	0	2.87	0.86	3	4.51	1.48	4.75	8.28	15
9	10	0	10	4.79	1.44	5	2.58	0.77	2.69	2.87	0.86	3	5.27	1.73	5.55	15.00	15
10	10	0	10	4.79	1.44	5	2.85	0.86	2.98	2.87	0.86	3	5.55	1.82	5.84	15.00	15
11	10	0	10	4.79	1.44	5	2.99	0.9	3.12	2.87	0.86	3	5.69	1.87	5.99	15.00	15
12	9.40	0	9.40	4.79	1.44	5	3.74	1.12	3.9	2.82	0.85	2.95	5.83	1.92	6.14	15.00	15
13	9.90	0	9.90	4.79	1.44	5	2.95	0.89	3.08	2.87	0.86	3	5.55	1.82	5.84	15.00	15
14	9.40	0	9.40	4.79	1.44	5	3.54	1.06	3.7	2.82	0.85	2.95	5.62	1.85	5.92	15.00	15
15	9.40	0	9.40	4.79	1.44	5	3.47	1.04	3.62	2.82	0.85	2.95	5.55	1.82	5.84	15.00	15
16	8.20	0	8.20	4.79	1.44	5	3.83	1.15	4	2.46	0.74	2.57	5.55	1.82	5.84	13.81	15
17	6.90	0	6.90	4.79	1.44	5	3.83	1.15	4	2.07	0.62	2.16	5.41	1.78	5.70	12.26	15
18	5	0	5	4.79	1.44	5	3.83	1.15	4	1.50	0.45	1.57	5.34	1.76	5.62	9.86	15
19	7.70	0	7.70	4.79	1.44	5	3.83	1.15	4	2.31	0.69	2.41	5.34	1.76	5.62	13.38	15
20	7	0	7	4.79	1.44	5	3.83	1.15	4	2.10	0.63	2.19	5.55	1.82	5.84	12.25	15
21	5.90	0	5.90	4.79	1.44	5	3.83	1.15	4	1.77	0.53	1.85	5.69	1.87	5.99	10.67	15
22	8.10	0	8.10	5	0	5	4	0	4	2.43	0	2.43	5.55	1.82	5.84	14.10	15
23	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	5.2	1.71	5.47	12.37	15
TOTAL	**212.5**	**0**	**212.5**	**72.27**	**18.72**	**75**	**53.1**	**13.54**	**55.09**	**63.16**	**10.51**	**64.74**	**119.47**	**39.25**	**125.77**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME BEFORE INCOME SHARING (€)	7511.63	1211.71	919.38	2231.45	11874.17
INCOME AFTER INCOME SHARING (€)	**7580.96**	**1253.73**	**979.77**	**2059.71**	**11874.17**

Appendix D - Output powers of the generators without and with the coordination of independent distributed generators

DAY 5

Without coordination

Table D8 - Output powers of the generators without coordination on day 5

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Load (MW)	Load (MVar)	Load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	4.58	1.51	4.82	12.96	15
1	7.80	0	7.80	5	0	5	4	0	4	2.34	0	2.34	4.30	1.41	4.53	14.91	15
2	8.20	0	8.20	5	0	5	4	0	4	1.76 *	0	1.76 *	4.02	1.32	4.23	15.00	15
3	5.60	0	5.60	5	0	5	4	0	4	1.68	0	1.68	3.89	1.28	4.10	12.46	15
4	4.80	0	4.80	5	0	5	4	0	4	1.44	0	1.44	3.75	1.23	3.95	11.56	15
5	7	0	7	5	0	5	4	0	4	2.10	0	2.10	3.82	1.25	4.02	14.33	15
6	7.30	0	7.30	2	0	2	1.60	0	1.60	2.19	0	2.19	3.89	1.28	4.10	9.29	15
7	3.10	0	3.10	2	0	2	1.60	0	1.60	0.93	0	0.93	4.02	1.32	4.23	3.84	15
8	4.20	0	4.20	1.92	0.58	2.01	1.54	0.46	1.61	1.26	0.38	1.32	4.51	1.48	4.75	4.41	15
9	1.90	0	1.90	1.92	0.58	2.01	1.54	0.46	1.61	0.57	0.17	0.59	5.27	1.73	5.55	0.84	15
10	1	0	1	3.73	1.12	3.89	2.96	0.89	3.09	0.30	0.09	0.31	5.55	1.82	5.84	2.46	15
11	1	0	1	1.92	0.58	2.01	1.54	0.46	1.61	0.30	0.09	0.31	5.69	1.87	5.99	1.19	15
12	0.70	0	0.70	1.92	0.58	2.01	1.54	0.46	1.61	0.21	0.06	0.22	5.83	1.92	6.14	1.67	15
13	1.50	0	1.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.55	1.82	5.84	2.28	15
14	2.40	0	2.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.62	1.85	5.92	3.11	15
15	5.70	0	5.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.55	1.82	5.84	6.48	15
16	7.40	0	7.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.55	1.82	5.84	8.18	15
17	4.70	0	4.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.41	1.78	5.70	5.62	15
18	5.90	0	5.90	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.34	1.76	5.62	6.89	15
19	4.50	0	4.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.34	1.76	5.62	5.49	15
20	8.30	0	8.30	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	5.55	1.82	5.84	14.33	15
21	10	0	10	4.79	1.44	5	3.83	1.15	4	1.91 *	0.57	1.99 *	5.69	1.87	5.99	15.00	15
22	10	0	10	5	0	5	4	0	4	1.45 *	0	1.45 *	5.55	1.82	5.84	15.00	15
23	10	0	10	5	0	5	4	0	4	1.11 *	0	1.11 *	5.2	1.71	5.47	15.00	15
TOTAL	**129.5**	**0**	**129.5**	**78.43**	**10.38**	**80**	**62.76**	**8.25**	**64**	**44.46**	**8.24**	**45.69**	**119.47**	**39.25**	**125.77**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	5556.48	643.95	515.12	1847.13	8562.68

Appendix D – Output powers of the generators without and with the coordination of independent distributed generators

With coordination

Table D9 - Output powers of the generators with coordination on day 5

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Load (MW)	Load (MVar)	Load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	4.58	1.51	4.82	12.96	15
1	7.80	0	7.80	5	0	5	4	0	4	2.34	0	2.34	4.30	1.41	4.53	14.91	15
2	8.20	0	8.20	5	0	5	3.30	0	3.30	2.46	0	2.46	4.02	1.32	4.23	15.00	15
3	5.60	0	5.60	5	0	5	4	0	4	1.68	0	1.68	3.89	1.28	4.10	12.46	15
4	4.80	0	4.80	5	0	5	4	0	4	1.44	0	1.44	3.75	1.23	3.95	11.56	15
5	7	0	7	5	0	5	4	0	4	2.10	0	2.10	3.82	1.25	4.02	14.33	15
6	7.30	0	7.30	2	0	2	1.60	0	1.60	2.19	0	2.19	3.89	1.28	4.10	9.29	15
7	3.10	0	3.10	2	0	2	1.60	0	1.60	0.93	0	0.93	4.02	1.32	4.23	3.84	15
8	4.20	0	4.20	1.92	0.58	2.01	1.54	0.46	1.61	1.26	0.38	1.32	4.51	1.48	4.75	4.41	15
9	1.90	0	1.90	1.92	0.58	2.01	1.54	0.46	1.61	0.57	0.17	0.59	5.27	1.73	5.55	0.84	15
10	1	0	1	3.73	1.12	3.89	3.83	1.15	4	0.30	0.09	0.31	5.55	1.82	5.84	2.48	15
11	1	0	1	1.92	0.58	2.01	3.83	1.15	4	0.30	0.09	0.31	5.69	1.87	5.99	1.19	15
12	0.70	0	0.70	1.92	0.58	2.01	1.54	0.46	1.61	0.21	0.06	0.22	5.83	1.92	6.14	1.67	15
13	1.50	0	1.50	1.92	0.58	2.01	3.31	0.99	3.45	2.87	0.86	3	5.55	1.82	5.84	2.28	15
14	2.40	0	2.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.62	1.85	5.92	3.11	15
15	5.70	0	5.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.55	1.82	5.84	6.48	15
16	7.40	0	7.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.55	1.82	5.84	8.18	15
17	4.70	0	4.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.41	1.78	5.70	5.62	15
18	5.90	0	5.90	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.34	1.76	5.62	6.89	15
19	4.50	0	4.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.34	1.76	5.62	5.49	15
20	8.30	0	8.30	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	5.55	1.82	5.84	14.33	15
21	10	0	10	4.79	1.44	5	2.86	0.86	2.99	2.87	0.86	3	5.69	1.87	5.99	15.00	15
22	10	0	10	5	0	5	2.45	0	2.45	3	0	3	5.55	1.82	5.84	15.00	15
23	10	0	10	5	0	5	2.11	0	2.11	3	0	3	5.20	1.71	5.47	15.00	15
TOTAL	**129.5**	**0**	**129.5**	**78.43**	**10.38**	**80**	**62.58**	**9.44**	**63.99**	**49.56**	**8.53**	**50.84**	**119.47**	**39.25**	**125.77**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME BEFORE INCOME SHARING (€)	5556.48	643.95	484.65	2088.68	8773.76
INCOME AFTER INCOME SHARING (€)	**5619.99**	**712.51**	**569.82**	**1871.44**	**8773.76**

Appendix D - Output powers of the generators without and with the coordination of independent distributed generators

DAY 6

Without coordination

Table D10 - Output powers of the generators without coordination on day 6

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Load (MW)	Load (MVar)	Load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	2	0	2	2	0	2	1.60	0	1.60	0.60	0	0.60	4.58	1.51	4.82	2.21	15
1	1.40	0	1.40	5	0	5	4	0	4	0.42	0	0.42	4.30	1.41	4.53	6.67	15
2	0.70	0	0.70	2	0	2	1.60	0	1.60	0.21	0	0.21	4.02	1.32	4.23	1.41	15
3	1.40	0	1.40	2	0	2	1.60	0	1.60	0.42	0	0.42	3.89	1.28	4.10	1.99	15
4	3.80	0	3.80	2	0	2	1.60	0	1.60	1.14	0	1.14	3.75	1.23	3.95	4.95	15
5	2.60	0	2.60	2	0	2	1.60	0	1.60	0.78	0	0.78	3.82	1.25	4.02	3.40	15
6	2.10	0	2.10	2	0	2	1.60	0	1.60	0.63	0	0.63	3.89	1.28	4.10	2.76	15
7	1.50	0	1.50	2	0	2	1.60	0	1.60	0.45	0	0.45	4.02	1.32	4.23	2.02	15
8	2	0	2	1.92	0.58	2.01	1.54	0.46	1.61	0.60	0.18	0.63	4.51	1.48	4.75	1.57	15
9	3.10	0	3.10	1.92	0.58	2.01	1.54	0.46	1.61	0.93	0.28	0.97	5.27	1.73	5.55	2.26	15
10	3.50	0	3.50	4.79	1.44	5	3.83	1.15	4	1.05	0.32	1.10	5.55	1.82	5.84	7.70	15
11	2.60	0	2.60	4.79	1.44	5	3.83	1.15	4	0.78	0.23	0.81	5.69	1.87	5.99	6.38	15
12	2.70	0	2.70	4.79	1.44	5	3.83	1.15	4	0.81	0.24	0.84	5.83	1.92	6.14	6.37	15
13	4.50	0	4.50	4.79	1.44	5	3.83	1.15	4	1.35	0.41	1.41	5.55	1.82	5.84	9	15
14	3.40	0	3.40	4.79	1.44	5	3.83	1.15	4	1.02	0.31	1.07	5.62	1.85	5.92	7.49	15
15	2.40	0	2.40	4.79	1.44	5	3.83	1.15	4	0.72	0.22	0.75	5.55	1.82	5.84	6.27	15
16	4.30	0	4.30	4.79	1.44	5	3.83	1.15	4	1.29	0.39	1.35	5.55	1.82	5.84	8.74	15
17	4	0	4	4.79	1.44	5	3.83	1.15	4	1.20	0.36	1.25	5.41	1.78	5.70	8.49	15
18	5.30	0	5.30	4.79	1.44	5	3.83	1.15	4	1.59	0.48	1.66	5.34	1.76	5.62	10.25	15
19	4.70	0	4.70	3.79	1.14	3.96	3.03	0.91	3.16	1.41	0.42	1.47	5.34	1.76	5.62	7.62	15
20	2.20	0	2.20	1.92	0.58	2.01	1.54	0.46	1.61	0.66	0.2	0.69	5.55	1.82	5.84	0.96	15
21	3.10	0	3.10	1.92	0.58	2.01	1.54	0.46	1.61	0.93	0.28	0.97	5.69	1.87	5.99	1.88	15
22	2.80	0	2.80	2	0	2	1.60	0	1.60	0.84	0	0.84	5.55	1.82	5.84	2.48	15
23	2.30	0	2.30	2	0	2	1.60	0	1.60	0.69	0	0.69	5.20	1.71	5.47	2.20	15
TOTAL	**68.40**	**0**	**68.40**	**77.58**	**16.42**	**80**	**62.06**	**13.1**	**64**	**20.52**	**4.32**	**21.15**	**119.47**	**39.25**	**125.77**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	3320.83	1131.72	905.16	996.25	6353.97

Appendix E - Generation and consumption schedules without and with the coordination of distributed generators and controllable load

The generation and consumption schedules without and with the coordination are presented as follows. Cases of ±10% and ±100% of load flexibility for each day are shown. Load consumption is presented in columns “Contr. load (MW)”, “Contr. load (MVar)” and “Contr. load (MVA)”. Column “Distr. Circuit (MVA)” shows the utilisation of the distribution circuit. The utilisation of the distribution circuit is presented in absolute value. Column “Circuit limit (MVA)” shows the distribution circuit limit. The output powers of GenD with asterisk (*) in Tables E1, E4, E7, E10, E13, E16, E20 and E23 refer to curtailed outputs.

Appendix E – Generation and consumption schedules without and with the coordination of distributed generators and controllable load

DAY 1: ±10% fraction of load flexibility

Without coordination

Table E1 - Output powers of the generators and the controllable load without coordination on day 1 (±10% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	10	0	10	0	0	0	0	0	0	3	0	3	5.72	1.88	6.02	7.52	15
1	10	0	10	0	0	0	0	0	0	3	0	3	5.11	1.68	5.38	8.07	15
2	10	0	10	0	0	0	0	0	0	3	0	3	4.81	1.57	5.06	8.34	15
3	10	0	10	0	0	0	0	0	0	3	0	3	4.66	1.51	4.90	8.48	15
4	9.90	0	9.90	0	0	0	0	0	0	2.97	0	2.97	4.58	1.50	4.82	8.42	15
5	9.30	0	9.30	0	0	0	0	0	0	2.79	0	2.79	4.66	1.51	4.90	7.58	15
6	10	0	10	0	0	0	0	0	0	3	0	3	4.81	1.57	5.06	8.34	15
7	10	0	10	0	0	0	0	0	0	3	0	3	5.04	1.64	5.30	8.13	15
8	9.90	0	9.90	0	0	0	0	0	0	2.87	0.86	3	5.57	1.82	5.86	7.26	15
9	10	0	10	4.79	1.44	5	3.83	1.15	4	2.65 *	0.80 *	2.77 *	6.33	2.07	6.66	15	15
10	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.72	2.20	7.07	14.82	15
11	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
12	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.58 *	0.77 *	2.69 *	5.68	1.87	5.98	14.99	15
13	9.90	0	9.90	4.79	1.44	5	3.83	1.15	4	1.79 *	0.54 *	1.87 *	5.37	1.76	5.65	15	15
14	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.00	1.98	6.32	14.91	15
15	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.46 *	0.74 *	2.57 *	5.56	1.82	5.85	15	15
16	8.20	0	8.20	4.79	1.44	5	3.83	1.15	4	2.46	0.74	2.57	6.72	2.20	7.07	12.61	15
17	6.90	0	6.90	4.79	1.44	5	3.83	1.15	4	2.07	0.62	2.16	5.56	1.82	5.85	12.11	15
18	5	0	5	4.79	1.44	5	3.83	1.15	4	1.5	0.45	1.57	5.80	1.92	6.11	9.39	15
19	7.70	0	7.70	4.79	1.44	5	3.83	1.15	4	2.31	0.69	2.41	6.24	2.06	6.57	12.45	15
20	7	0	7	4.79	1.44	5	3.83	1.15	4	2.1	0.63	2.19	6.24	2.06	6.57	11.54	15
21	5.90	0	5.90	4.79	1.44	5	3.83	1.15	4	1.77	0.53	1.85	6.12	2.00	6.44	10.23	15
22	8.10	0	8.10	5	0	5	4	0	4	2.43	0	2.43	5.80	1.92	6.11	13.86	15
23	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	5.43	1.80	5.72	12.15	15
TOTAL	**212.5**	**0**	**212.5**	**72.27**	**18.72**	**75**	**57.79**	**14.95**	**60**	**61.26**	**9.94**	**62.74**	**135.5**	**44.42**	**142.64**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	7511.63	1211.71	948.89	2145.69	11817.92

Appendix E - Generation and consumption schedules without and with the coordination of distributed generators and controllable load

With coordination (coordination of distributed generators)

Table E2 - Output powers of the generators and the controllable load (coordination of distributed generators, no coordination with the controllable load) on day 1 (±10% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	10	0	10	0	0	0	0	0	0	3	0	3	5.72	1.88	6.02	7.52	15
1	10	0	10	0	0	0	0	0	0	3	0	3	5.11	1.68	5.38	8.07	15
2	10	0	10	0	0	0	0	0	0	3	0	3	4.81	1.57	5.06	8.34	15
3	10	0	10	0	0	0	0	0	0	3	0	3	4.66	1.51	4.90	8.48	15
4	9.90	0	9.90	0	0	0	0	0	0	2.97	0	2.97	4.58	1.50	4.82	8.42	15
5	9.30	0	9.30	0	0	0	0	0	0	2.79	0	2.79	4.66	1.51	4.90	7.58	15
6	10	0	10	0	0	0	0	0	0	3	0	3	4.81	1.57	5.06	8.34	15
7	10	0	10	0	0	0	0	0	0	3	0	3	5.04	1.64	5.30	8.13	15
8	9.90	0	9.90	0	0	0	0	0	0	2.87	0.86	3	5.57	1.82	5.86	7.26	15
9	10	0	10	4.79	1.44	5	3.61	1.08	3.77	2.87	0.86	3	6.33	2.07	6.66	15	15
10	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.72	2.20	7.07	14.82	15
11	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
12	9.40	0	9.40	4.79	1.44	5	3.59	1.08	3.75	2.82	0.85	2.95	5.68	1.87	5.98	15	15
13	9.90	0	9.90	4.79	1.44	5	2.75	0.83	2.87	2.87	0.86	3	5.37	1.76	5.65	15	15
14	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.00	1.98	6.32	14.91	15
15	9.40	0	9.40	4.79	1.44	5	3.47	1.04	3.62	2.82	0.85	2.95	5.56	1.82	5.85	15	15
16	8.20	0	8.20	4.79	1.44	5	3.83	1.15	4	2.46	0.74	2.57	6.72	2.20	7.07	12.61	15
17	6.90	0	6.90	4.79	1.44	5	3.83	1.15	4	2.07	0.62	2.16	5.56	1.82	5.85	12.11	15
18	5	0	5	4.79	1.44	5	3.83	1.15	4	1.50	0.45	1.57	5.80	1.92	6.11	9.39	15
19	7.70	0	7.70	4.79	1.44	5	3.83	1.15	4	2.31	0.69	2.41	6.24	2.06	6.57	12.45	15
20	7	0	7	4.79	1.44	5	3.83	1.15	4	2.10	0.63	2.19	6.24	2.06	6.57	11.54	15
21	5.90	0	5.90	4.79	1.44	5	3.83	1.15	4	1.77	0.53	1.85	6.12	2.00	6.44	10.23	15
22	8.10	0	8.10	5	0	5	4	0	4	2.43	0	2.43	5.80	1.92	6.11	13.86	15
23	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	5.43	1.80	5.72	12.15	15
TOTAL	**212.5**	**0**	**212.5**	**72.27**	**18.72**	**75**	**55.89**	**14.38**	**58.01**	**63.16**	**10.51**	**64.74**	**135.5**	**44.42**	**142.64**		

	GenA	GenB	GenC	GenD	TOTAL		Contr. load
INCOME (€)	7511.63	1211.71	929.63	2231.45	11884.42	**COST (€)**	6067.03

Appendix E - Generation and consumption schedules without and with the coordination of distributed generators and controllable load

With coordination (coordination of generators and controllable load)

Table E3 - Output powers of the generators and the controllable load with coordination on day 1 (±10% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	10	0	10	0	0	0	0	0	0	3	0	3	5.72	1.88	6.02	7.52	15
1	10	0	10	0	0	0	0	0	0	3	0	3	5.11	1.68	5.38	8.07	15
2	10	0	10	0	0	0	0	0	0	3	0	3	4.81	1.57	5.06	8.34	15
3	10	0	10	0	0	0	0	0	0	3	0	3	4.66	1.51	4.90	8.48	15
4	9.90	0	9.90	0	0	0	0	0	0	2.97	0	2.97	4.58	1.50	4.82	8.42	15
5	9.30	0	9.30	0	0	0	0	0	0	2.79	0	2.79	4.66	1.51	4.90	7.58	15
6	10	0	10	0	0	0	0	0	0	3	0	3	4.81	1.57	5.06	8.34	15
7	10	0	10	0	0	0	0	0	0	3	0	3	5.04	1.64	5.30	8.13	15
8	9.90	0	9.90	0	0	0	0	0	0	2.87	0.86	3	5.57	1.82	5.86	7.26	15
9	10	0	10	4.79	1.44	5	3.61	1.08	3.77	2.87	0.86	3	6.33	2.07	6.66	15	15
10	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.72	2.20	7.07	14.82	15
11	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.57	2.17	6.92	14.60	15
12	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	5.92	1.94	6.23	15	15
13	9.90	0	9.90	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.45	2.12	6.79	15	15
14	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	5.92	1.94	6.23	14.91	15
15	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	5.91	1.94	6.22	15	15
16	8.20	0	8.20	4.79	1.44	5	3.83	1.15	4	2.46	0.74	2.57	5.49	1.81	5.78	12.61	15
17	6.90	0	6.90	4.79	1.44	5	3.83	1.15	4	2.07	0.62	2.16	5.56	1.82	5.85	12.11	15
18	5	0	5	4.79	1.44	5	3.83	1.15	4	1.50	0.45	1.57	5.8	1.92	6.11	9.39	15
19	7.70	0	7.70	4.79	1.44	5	3.83	1.15	4	2.31	0.69	2.41	6.24	2.06	6.57	12.45	15
20	7	0	7	4.79	1.44	5	3.83	1.15	4	2.10	0.63	2.19	6.24	2.06	6.57	11.54	15
21	5.90	0	5.90	4.79	1.44	5	3.83	1.15	4	1.77	0.53	1.85	6.12	2	6.44	10.23	15
22	8.10	0	8.10	5	0	5	4	0	4	2.43	0	2.43	5.8	1.92	6.11	13.86	15
23	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	5.43	1.80	5.72	12.15	15
TOTAL	**212.5**	**0**	**212.5**	**72.27**	**18.72**	**75**	**57.56**	**14.88**	**59.76**	**63.16**	**10.51**	**64.74**	**135.5**	**44.45**	**142.64**		

	GenA	GenB	GenC	GenD	TOTAL		Contr. load
INCOME (€)	7511.63	1211.71	948.08	2231.45	11902.87	**COST (€)**	6072.93

Appendix E – Generation and consumption schedules without and with the coordination of distributed generators and controllable load

DAY 2: ±10% fraction of load flexibility

Without coordination

Table E4 - Output powers of the generators and the controllable load without coordination on day 2 (±10% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	4.66	1.55	4.91	12.88	15
1	7.80	0	7.80	5	0	5	4	0	4	2.34	0	2.34	4.22	1.38	4.44	14.98	15
2	8.20	0	8.20	5	0	5	4	0	4	1.70 *	0 *	1.70 *	3.96	1.31	4.17	15	15
3	5.60	0	5.60	5	0	5	4	0	4	1.68	0	1.68	3.81	1.25	4.01	12.53	15
4	4.80	0	4.80	5	0	5	4	0	4	1.44	0	1.44	3.76	1.24	3.96	11.55	15
5	7	0	7	5	0	5	4	0	4	2.10	0	2.10	3.81	1.25	4.01	14.34	15
6	7.30	0	7.30	2	0	2	1.60	0	1.60	2.19	0	2.19	4.78	1.57	5.03	8.46	15
7	3.10	0	3.10	2	0	2	1.60	0	1.60	0.93	0	0.93	5.02	1.64	5.28	3.08	15
8	4.20	0	4.20	1.92	0.58	2.01	1.54	0.46	1.61	1.26	0.38	1.32	5.58	1.82	5.87	3.36	15
9	1.90	0	1.90	1.92	0.58	2.01	1.54	0.46	1.61	0.57	0.17	0.59	6.33	2.07	6.66	0.95	15
10	1	0	1	3.73	1.12	3.89	2.96	0.89	3.09	0.30	0.09	0.31	5.49	1.81	5.78	2.52	15
11	1	0	1	1.92	0.58	2.01	1.54	0.46	1.61	0.30	0.09	0.31	6.16	2.01	6.48	1.65	15
12	0.70	0	0.70	1.92	0.58	2.01	1.54	0.46	1.61	0.21	0.06	0.22	6.94	2.26	7.30	2.82	15
13	1.50	0	1.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.57	2.17	6.92	1.29	15
14	2.40	0	2.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.71	2.2	7.06	2.04	15
15	5.70	0	5.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.76	2.24	7.12	5.28	15
16	7.40	0	7.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.71	2.2	7.06	7.03	15
17	4.70	0	4.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.76	2.24	7.12	4.28	15
18	5.90	0	5.90	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	5.3	15
19	4.50	0	4.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	3.91	15
20	8.30	0	8.30	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.24	2.06	6.57	13.62	15
21	10	0	10	4.79	1.44	5	3.83	1.15	4	2.42 *	0.73 *	2.53 *	6.10	2	6.42	15	15
22	10	0	10	5	0	5	4	0	4	1.72 *	0 *	1.72 *	5.84	1.93	6.15	15	15
23	10	0	10	5	0	5	4	0	4	1.32 *	0 *	1.32 *	5.43	1.80	5.72	15	15
TOTAL	**129.5**	**0**	**129.5**	**78.43**	**10.38**	**80**	**62.76**	**8.25**	**64**	**45.39**	**8.4**	**46.65**	**135.5**	**44.52**	**142.64**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	5556.48	643.94	515.12	1892.80	8608.34

Appendix E – Generation and consumption schedules without and with the coordination of distributed generators and controllable load

With coordination (coordination of distributed generators)

Table E5 - Output powers of the generators and the controllable load (coordination of distributed generators, no coordination with the controllable load) on day 2 (±10% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	4.66	1.55	4.91	12.88	15
1	7.80	0	7.80	5	0	5	4	0	4	2.34	0	2.34	4.22	1.38	4.44	14.98	15
2	8.20	0	8.20	5	0	5	3.24	0	3.24	2.46	0	2.46	3.96	1.31	4.17	15	15
3	5.60	0	5.60	5	0	5	4	0	4	1.68	0	1.68	3.81	1.25	4.01	12.53	15
4	4.80	0	4.80	5	0	5	4	0	4	1.44	0	1.44	3.76	1.24	3.96	11.55	15
5	7	0	7	5	0	5	4	0	4	2.10	0	2.10	3.81	1.25	4.01	14.34	15
6	7.30	0	7.30	2	0	2	1.60	0	1.60	2.19	0	2.19	4.78	1.57	5.03	8.46	15
7	3.10	0	3.10	2	0	2	1.60	0	1.60	0.93	0	0.93	5.02	1.64	5.28	3.08	15
8	4.20	0	4.20	1.92	0.58	2.01	1.54	0.46	1.61	1.26	0.38	1.32	5.58	1.82	5.87	3.36	15
9	1.90	0	1.90	1.92	0.58	2.01	1.54	0.46	1.61	0.57	0.17	0.59	6.33	2.07	6.66	0.95	15
10	1	0	1	3.73	1.12	3.89	3.83	1.15	4	0.30	0.09	0.31	5.49	1.81	5.78	3.41	15
11	1	0	1	1.92	0.58	2.01	3.83	1.15	4	0.30	0.09	0.31	6.16	2.01	6.48	0.91	15
12	0.70	0	0.70	1.92	0.58	2.01	1.54	0.46	1.61	0.21	0.06	0.22	6.94	2.26	7.30	2.82	15
13	1.50	0	1.50	1.92	0.58	2.01	2.39	0.72	2.50	2.87	0.86	3	6.57	2.17	6.92	2.11	15
14	2.40	0	2.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.71	2.2	7.06	2.04	15
15	5.70	0	5.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.76	2.24	7.12	5.28	15
16	7.40	0	7.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.71	2.2	7.06	7.03	15
17	4.70	0	4.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.76	2.24	7.12	4.28	15
18	5.90	0	5.90	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	5.30	15
19	4.50	0	4.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	3.91	15
20	8.30	0	8.30	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.24	2.06	6.57	13.62	15
21	10	0	10	4.79	1.44	5	3.38	1.01	3.53	2.87	0.86	3	6.1	2	6.42	15	15
22	10	0	10	5	0	5	2.72	0	2.72	3	0	3	5.84	1.93	6.15	15	15
23	10	0	10	5	0	5	2.32	0	2.32	3	0	3	5.43	1.80	5.72	15	15
TOTAL	**129.5**	**0**	**129.5**	**78.43**	**10.38**	**80**	**62.60**	**9.32**	**64**	**49.56**	**8.53**	**50.84**	**135.5**	**44.52**	**142.64**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	5556.48	643.94	492.23	2088.68	8781.34

Appendix E - Generation and consumption schedules without and with the coordination of distributed generators and controllable load

DAY 3: ±10% fraction of load flexibility

Without coordination

Table E6 - Output powers of the generators and the controllable load without coordination on day 3 (±10% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	2	0	2	2	0	2	1.60	0	1.60	0.60	0	0.60	5.71	1.88	6.01	1.94	15
1	1.40	0	1.40	5	0	5	4	0	4	0.42	0	0.42	4.82	1.57	5.07	6.20	15
2	0.70	0	0.70	2	0	2	1.60	0	1.60	0.21	0	0.21	4.84	1.58	5.09	1.61	15
3	1.40	0	1.40	2	0	2	1.60	0	1.60	0.42	0	0.42	4.66	1.55	4.91	1.73	15
4	3.80	0	3.80	2	0	2	1.60	0	1.60	1.14	0	1.14	4.60	1.51	4.84	4.22	15
5	2.60	0	2.60	2	0	2	1.60	0	1.60	0.78	0	0.78	4.66	1.55	4.91	2.79	15
6	2.10	0	2.10	2	0	2	1.60	0	1.60	0.63	0	0.63	4.78	1.57	5.03	2.21	15
7	1.50	0	1.50	2	0	2	1.60	0	1.60	0.45	0	0.45	5.02	1.64	5.28	1.72	15
8	2	0	2	1.92	0.58	2.01	1.54	0.46	1.61	0.60	0.18	0.63	5.58	1.82	5.87	0.77	15
9	3.10	0	3.10	1.92	0.58	2.01	1.54	0.46	1.61	0.93	0.28	0.97	6.33	2.07	6.66	1.38	15
10	3.50	0	3.50	4.79	1.44	5	3.83	1.15	4	1.05	0.32	1.10	5.49	1.81	5.78	7.76	15
11	2.60	0	2.60	4.79	1.44	5	3.83	1.15	4	0.78	0.23	0.81	5.69	1.87	5.99	6.38	15
12	2.70	0	2.70	4.79	1.44	5	3.83	1.15	4	0.81	0.24	0.84	5.69	1.87	5.99	6.51	15
13	4.50	0	4.50	4.79	1.44	5	3.83	1.15	4	1.35	0.41	1.41	5.38	1.76	5.66	9.17	15
14	3.40	0	3.40	4.79	1.44	5	3.83	1.15	4	1.02	0.31	1.07	5.49	1.81	5.78	7.63	15
15	2.40	0	2.40	4.79	1.44	5	3.83	1.15	4	0.72	0.22	0.75	5.53	1.81	5.82	6.29	15
16	4.30	0	4.30	4.79	1.44	5	3.83	1.15	4	1.29	0.39	1.35	5.49	1.81	5.78	8.80	15
17	4	0	4	4.79	1.44	5	3.83	1.15	4	1.20	0.36	1.25	5.53	1.81	5.82	8.37	15
18	5.30	0	5.30	4.79	1.44	5	3.83	1.15	4	1.59	0.48	1.66	5.84	1.93	6.15	9.74	15
19	4.70	0	4.70	3.79	1.14	3.96	3.03	0.91	3.16	1.41	0.42	1.47	6.94	2.26	7.30	5.99	15
20	2.20	0	2.20	1.92	0.58	2.01	1.54	0.46	1.61	0.66	0.20	0.69	6.94	2.26	7.30	1.19	15
21	3.10	0	3.10	1.92	0.58	2.01	1.54	0.46	1.61	0.93	0.28	0.97	6.94	2.26	7.30	1.09	15
22	2.80	0	2.80	2	0	2	1.60	0	1.60	0.84	0	0.84	6.94	2.26	7.30	2.28	15
23	2.30	0	2.30	2	0	2	1.60	0	1.60	0.69	0	0.69	6.65	2.19	7.00	2.19	15
TOTAL	**68.40**	**0**	**68.40**	**77.58**	**16.42**	**80**	**62.06**	**13.1**	**64**	**20.52**	**4.32**	**21.15**	**135.5**	**44.45**	**142.64**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	3320.83	1131.72	905.16	996.25	6353.97

DAY 4: ±10% fraction of load flexibility

Without coordination

Table E7 - Output powers of the generators and the controllable load without coordination on day 4 (±10% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	10	0	10	0	0	0	0	0	0	3	0	3	5.04	1.64	5.30	8.13	15
1	10	0	10	0	0	0	0	0	0	3	0	3	4.73	1.56	4.98	8.42	15
2	10	0	10	0	0	0	0	0	0	3	0	3	4.43	1.45	4.66	8.69	15
3	10	0	10	0	0	0	0	0	0	3	0	3	4.28	1.39	4.50	8.83	15
4	9.90	0	9.90	0	0	0	0	0	0	2.97	0	2.97	4.12	1.36	4.34	8.86	15
5	9.30	0	9.30	0	0	0	0	0	0	2.79	0	2.79	4.20	1.38	4.42	8.01	15
6	10	0	10	0	0	0	0	0	0	3	0	3	4.28	1.39	4.50	8.83	15
7	10	0	10	0	0	0	0	0	0	3	0	3	4.43	1.45	4.66	8.71	15
8	9.90	0	9.90	0	0	0	0	0	0	2.87	0.86	3	4.96	1.63	5.22	7.85	15
9	10	0	10	4.79	1.44	5	3.83	1.15	4	2.12 *	0.64 *	2.21 *	5.8	1.89	6.10	15	15
10	10	0	10	4.79	1.44	5	3.83	1.15	4	2.42 *	0.73 *	2.53 *	6.10	2	6.42	15	15
11	10	0	10	4.79	1.44	5	3.83	1.15	4	2.57 *	0.77 *	2.68 *	6.25	2.06	6.58	15	15
12	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.14 *	0.64 *	2.23 *	5.24	1.74	5.52	14.99	15
13	9.90	0	9.90	4.79	1.44	5	3.83	1.15	4	1.42 *	0.43 *	1.48 *	5	1.63	5.26	15	15
14	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.11 *	0.63 *	2.20 *	5.21	1.72	5.49	15	15
15	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	1.90 *	0.57 *	1.98 *	5	1.63	5.26	15	15
16	8.20	0	8.20	4.79	1.44	5	3.83	1.15	4	2.46	0.74	2.57	6.10	2	6.42	14.38	15
17	6.90	0	6.90	4.79	1.44	5	3.83	1.15	4	2.07	0.62	2.16	4.86	1.61	5.12	12.83	15
18	5	0	5	4.79	1.44	5	3.83	1.15	4	1.50	0.45	1.57	4.81	1.57	5.06	10.41	15
19	7.70	0	7.70	4.79	1.44	5	3.83	1.15	4	2.31	0.69	2.41	4.81	1.57	5.06	13.93	15
20	7	0	7	4.79	1.44	5	3.83	1.15	4	2.10	0.63	2.19	5	1.63	5.26	12.82	15
21	5.90	0	5.90	4.79	1.44	5	3.83	1.15	4	1.77	0.53	1.85	5.12	1.68	5.39	11.26	15
22	8.10	0	8.10	5	0	5	4	0	4	2.43	0	2.43	5	1.63	5.26	14.62	15
23	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	4.68	1.55	4.93	12.86	15
TOTAL	**212.5**	**0**	**212.5**	**72.27**	**18.72**	**75**	**57.79**	**14.95**	**60**	**59.02**	**9.27**	**60.38**	**119.5**	**39.16**	**125.77**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	7511.63	1211.71	948.89	2000.89	11673.12

Appendix E – Generation and consumption schedules without and with the coordination of distributed generators and controllable load

With coordination (coordination of distributed generators)

Table E8 - Output powers of the generators and the controllable load (coordination of distributed generators, no coordination with the controllable load) on day 4 (±10% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	10	0	10	0	0	0	0	0	0	3	0	3	5.04	1.64	5.30	8.13	15
1	10	0	10	0	0	0	0	0	0	3	0	3	4.73	1.56	4.98	8.42	15
2	10	0	10	0	0	0	0	0	0	3	0	3	4.43	1.45	4.66	8.69	15
3	10	0	10	0	0	0	0	0	0	3	0	3	4.28	1.39	4.50	8.83	15
4	9.90	0	9.90	0	0	0	0	0	0	2.97	0	2.97	4.12	1.36	4.34	8.86	15
5	9.30	0	9.30	0	0	0	0	0	0	2.79	0	2.79	4.20	1.38	4.42	8.01	15
6	10	0	10	0	0	0	0	0	0	3	0	3	4.28	1.39	4.50	8.83	15
7	10	0	10	0	0	0	0	0	0	3	0	3	4.43	1.45	4.66	8.69	15
8	9.90	0	9.90	0	0	0	0	0	0	2.87	0.86	3	4.96	1.63	5.22	7.85	15
9	10	0	10	4.79	1.44	5	3.08	0.92	3.21	2.87	0.86	3	5.80	1.89	6.10	15	15
10	10	0	10	4.79	1.44	5	3.38	1.01	3.53	2.87	0.86	3	6.10	2	6.42	15	15
11	10	0	10	4.79	1.44	5	3.53	1.06	3.69	2.87	0.86	3	6.25	2.06	6.58	15	15
12	9.40	0	9.40	4.79	1.44	5	3.15	0.95	3.29	2.82	0.85	2.95	5.24	1.74	5.52	15	15
13	9.90	0	9.90	4.79	1.44	5	2.38	0.71	2.48	2.87	0.86	3	5	1.63	5.26	15	15
14	9.40	0	9.40	4.79	1.44	5	3.12	0.94	3.26	2.82	0.85	2.95	5.21	1.72	5.49	15	15
15	9.40	0	9.40	4.79	1.44	5	2.91	0.87	3.04	2.82	0.85	2.95	5	1.63	5.26	15	15
16	8.20	0	8.20	4.79	1.44	5	3.83	1.15	4	2.46	0.74	2.57	6.10	2	6.42	13.25	15
17	6.90	0	6.90	4.79	1.44	5	3.83	1.15	4	2.07	0.62	2.16	4.86	1.61	5.12	12.83	15
18	5	0	5	4.79	1.44	5	3.83	1.15	4	1.50	0.45	1.57	4.81	1.57	5.06	10.41	15
19	7.70	0	7.70	4.79	1.44	5	3.83	1.15	4	2.31	0.69	2.41	4.81	1.57	5.06	13.93	15
20	7	0	7	4.79	1.44	5	3.83	1.15	4	2.10	0.63	2.19	5	1.63	5.26	12.82	15
21	5.90	0	5.90	4.79	1.44	5	3.83	1.15	4	1.77	0.53	1.85	5.12	1.68	5.39	11.26	15
22	8.10	0	8.10	5	0	5	4	0	4	2.43	0	2.43	5	1.63	5.26	14.62	15
23	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	4.68	1.55	4.93	12.86	15
TOTAL	**212.5**	**0**	**212.5**	**72.27**	**18.72**	**75**	**53.65**	**13.7**	**55.68**	**63.16**	**10.51**	**64.74**	**119.5**	**39.16**	**125.77**		

	GenA	GenB	GenC	GenD	TOTAL		Contr. load
INCOME (€)	7511.63	1211.71	902.44	2231.45	11857.22	**COST (€)**	5252.73

Appendix E - Generation and consumption schedules without and with the coordination of distributed generators and controllable load

With coordination (coordination of generators and controllable load)

Table E9 - Output powers of the generators and the controllable load with coordination on day 4 (±10% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	10	0	10	0	0	0	0	0	0	3	0	3	5.04	1.64	5.30	8.13	15
1	10	0	10	0	0	0	0	0	0	3	0	3	4.73	1.56	4.98	8.42	15
2	10	0	10	0	0	0	0	0	0	3	0	3	4.43	1.45	4.66	8.69	15
3	10	0	10	0	0	0	0	0	0	3	0	3	4.28	1.39	4.50	8.83	15
4	9.90	0	9.90	0	0	0	0	0	0	2.97	0	2.97	4.12	1.36	4.34	8.86	15
5	9.30	0	9.30	0	0	0	0	0	0	2.79	0	2.79	4.20	1.38	4.42	8.01	15
6	10	0	10	0	0	0	0	0	0	3	0	3	4.28	1.39	4.50	8.83	15
7	10	0	10	0	0	0	0	0	0	3	0	3	4.41	1.44	4.64	8.71	15
8	9.90	0	9.90	0	0	0	0	0	0	2.87	0.86	3	4.96	1.63	5.22	7.85	15
9	10	0	10	4.79	1.44	5	3.08	0.92	3.21	2.87	0.86	3	5.80	1.89	6.10	15	15
10	10	0	10	4.79	1.44	5	3.38	1.01	3.53	2.87	0.86	3	6.10	2	6.42	15	15
11	10	0	10	4.79	1.44	5	3.53	1.06	3.69	2.87	0.86	3	6.25	2.06	6.58	15	15
12	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	5.92	1.94	6.23	15	15
13	9.90	0	9.90	4.79	1.44	5	2.82	0.85	2.95	2.87	0.86	3	5.44	1.80	5.73	15	15
14	9.40	0	9.40	4.79	1.44	5	3.12	0.94	3.26	2.82	0.85	2.95	5.21	1.72	5.49	15	15
15	9.40	0	9.40	4.79	1.44	5	2.91	0.87	3.04	2.82	0.85	2.95	5	1.63	5.26	15	15
16	8.20	0	8.20	4.79	1.44	5	3.83	1.15	4	2.46	0.74	2.57	5	1.63	5.26	14.38	15
17	6.90	0	6.90	4.79	1.44	5	3.83	1.15	4	2.07	0.62	2.16	4.86	1.61	5.12	12.83	15
18	5	0	5	4.79	1.44	5	3.83	1.15	4	1.50	0.45	1.57	4.81	1.57	5.06	10.41	15
19	7.70	0	7.70	4.79	1.44	5	3.83	1.15	4	2.31	0.69	2.41	4.81	1.57	5.06	13.93	15
20	7	0	7	4.79	1.44	5	3.83	1.15	4	2.10	0.63	2.19	5	1.63	5.26	12.82	15
21	5.90	0	5.90	4.79	1.44	5	3.83	1.15	4	1.77	0.53	1.85	5.12	1.68	5.39	11.26	15
22	8.10	0	8.10	5	0	5	4	0	4	2.43	0	2.43	5	1.63	5.26	14.62	15
23	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	4.68	1.55	4.93	12.86	15
TOTAL	**212.5**	**0**	**212.5**	**72.27**	**18.72**	**75**	**53.65**	**13.7**	**55.68**	**63.16**	**10.51**	**64.74**	**119.5**	**39.15**	**125.77**		

	GenA	GenB	GenC	GenD	TOTAL		Contr. load
INCOME (€)	7511.63	1211.71	916.16	2231.45	11870.95	**COST (€)**	5257.56

DAY 5: ±10% fraction of load flexibility

Without coordination

Table E10 - Output powers of the generators and the controllable load without coordination on day 5 (±10% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	4.12	1.36	4.34	13.4	15
1	7.80	0	7.80	5	0	5	4	0	4	2.02 *	0 *	2.02 *	3.87	1.26	4.07	15	15
2	8.20	0	8.20	5	0	5	4	0	4	1.37 *	0 *	1.37 *	3.62	1.19	3.81	15	15
3	5.60	0	5.60	5	0	5	4	0	4	1.68	0	1.68	3.50	1.14	3.68	12.83	15
4	4.80	0	4.80	5	0	5	4	0	4	1.44	0	1.44	3.37	1.12	3.55	11.92	15
5	7	0	7	5	0	5	4	0	4	2.10	0	2.10	3.43	1.13	3.61	14.71	15
6	7.30	0	7.30	2	0	2	1.60	0	1.60	2.19	0	2.19	4.28	1.39	4.50	8.92	15
7	3.10	0	3.10	2	0	2	1.60	0	1.60	0.93	0	0.93	4.43	1.45	4.66	3.51	15
8	4.20	0	4.20	1.92	0.58	2.01	1.54	0.46	1.61	1.26	0.38	1.32	4.96	1.63	5.22	3.97	15
9	1.90	0	1.90	1.92	0.58	2.01	1.54	0.46	1.61	0.57	0.17	0.59	5.80	1.89	6.10	0.69	15
10	1	0	1	3.73	1.12	3.89	2.96	0.89	3.09	0.3	0.09	0.31	5.00	1.63	5.26	3.03	15
11	1	0	1	1.92	0.58	2.01	1.54	0.46	1.61	0.3	0.09	0.31	5.12	1.68	5.39	0.66	15
12	0.70	0	0.70	1.92	0.58	2.01	1.54	0.46	1.61	0.21	0.06	0.22	6.41	2.12	6.75	2.28	15
13	1.50	0	1.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.73	1.88	6.03	2.10	15
14	2.40	0	2.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.18	2.01	6.50	2.55	15
15	5.70	0	5.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.10	2.00	6.42	5.93	15
16	7.40	0	7.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.10	2.00	6.42	7.63	15
17	4.70	0	4.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.95	1.95	6.26	5.08	15
18	5.90	0	5.90	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.87	1.93	6.18	6.36	15
19	4.50	0	4.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.87	1.93	6.18	4.96	15
20	8.30	0	8.30	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	5.00	1.63	5.26	14.90	15
21	10	0	10	4.79	1.44	5	3.83	1.15	4	1.44 *	0.40 *	1.50 *	5.12	1.68	5.39	15	15
22	10	0	10	5	0	5	4	0	4	0.91 *	0 *	0.91 *	5.00	1.63	5.26	15	15
23	10	0	10	5	0	5	4	0	4	0.60 *	0 *	0.60 *	4.68	1.55	4.93	15	15
TOTAL	129.5	0	129.5	78.43	10.38	80	62.76	8.25	64	42.23	8.1	43.44	119.5	39.18	125.77		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	5556.48	643.94	515.12	1790.87	8506.41

Appendix E – Generation and consumption schedules without and with the coordination of distributed generators and controllable load

With coordination (coordination of distributed generators)

Table E11 - Output powers of the generators and the controllable load (coordination of distributed generators, no coordination with the controllable load) on day 5 (±10% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	4.12	1.36	4.34	13.4	15
1	7.80	0	7.80	5	0	5	3.68	0	3.68	2.34	0	2.34	3.87	1.26	4.07	15	15
2	8.20	0	8.20	5	0	5	2.91	0	2.91	2.46	0	2.46	3.62	1.19	3.81	15	15
3	5.60	0	5.60	5	0	5	4	0	4	1.68	0	1.68	3.50	1.14	3.68	12.83	15
4	4.80	0	4.80	5	0	5	4	0	4	1.44	0	1.44	3.37	1.12	3.55	11.92	15
5	7	0	7	5	0	5	4	0	4	2.10	0	2.10	3.43	1.13	3.61	14.71	15
6	7.30	0	7.30	2	0	2	1.60	0	1.60	2.19	0	2.19	4.28	1.39	4.50	8.92	15
7	3.10	0	3.10	2	0	2	1.60	0	1.60	0.93	0	0.93	4.43	1.45	4.66	3.51	15
8	4.20	0	4.20	1.92	0.58	2.01	1.54	0.46	1.61	1.26	0.38	1.32	4.96	1.63	5.22	3.97	15
9	1.90	0	1.90	1.92	0.58	2.01	1.54	0.46	1.61	0.57	0.17	0.59	5.80	1.89	6.10	0.69	15
10	1	0	1	3.73	1.12	3.89	3.83	1.15	4	0.30	0.09	0.31	5.00	1.63	5.26	3.93	15
11	1	0	1	1.92	0.58	2.01	3.83	1.15	4	0.30	0.09	0.31	5.12	1.68	5.39	1.94	15
12	0.70	0	0.70	1.92	0.58	2.01	3.17	0.95	3.31	0.21	0.06	0.22	6.41	2.12	6.75	0.67	15
13	1.50	0	1.50	1.92	0.58	2.01	3.83	1.15	4	2.87	0.86	3	5.73	1.88	6.03	4.45	15
14	2.40	0	2.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.18	2.01	6.50	2.55	15
15	5.70	0	5.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.10	2.00	6.42	5.93	15
16	7.40	0	7.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.10	2.00	6.42	7.63	15
17	4.70	0	4.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.95	1.95	6.26	5.08	15
18	5.90	0	5.90	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.87	1.93	6.18	6.36	15
19	4.50	0	4.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	5.87	1.93	6.18	4.96	15
20	8.30	0	8.30	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	5.00	1.63	5.26	14.90	15
21	10	0	10	4.79	1.44	5	2.40	0.72	2.51	2.87	0.86	3	5.12	1.68	5.39	15	15
22	10	0	10	5	0	5	1.91	0	1.91	3	0	3	5.00	1.63	5.26	15	15
23	10	0	10	5	0	5	1.60	0	1.60	3	0	3	4.68	1.55	4.93	15	15
TOTAL	**129.5**	**0**	**129.5**	**78.43**	**10.38**	**80**	**62.51**	**9.95**	**64**	**49.56**	**8.53**	**50.84**	**119.5**	**39.18**	**125.77**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	5556.48	643.94	470.64	2088.68	8759.76

Appendix E – Generation and consumption schedules without and with the coordination of distributed generators and controllable load

DAY 6: ±10% fraction of load flexibility

Without coordination

Table E12 - Output powers of the generators and the controllable load without coordination on day 6 (±10% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	2	0	2	2	0	2	1.60	0	1.60	0.60	0	0.60	5.03	1.67	5.30	2.04	15
1	1.40	0	1.40	5	0	5	4	0	4	0.42	0	0.42	3.88	1.26	4.08	7.05	15
2	0.70	0	0.70	2	0	2	1.60	0	1.60	0.21	0	0.21	4.42	1.44	4.65	1.44	15
3	1.40	0	1.40	2	0	2	1.60	0	1.60	0.42	0	0.42	4.28	1.42	4.51	1.82	15
4	3.80	0	3.80	2	0	2	1.60	0	1.60	1.14	0	1.14	4.13	1.37	4.35	4.62	15
5	2.60	0	2.60	2	0	2	1.60	0	1.60	0.78	0	0.78	4.20	1.38	4.42	3.10	15
6	2.10	0	2.10	2	0	2	1.60	0	1.60	0.63	0	0.63	4.28	1.42	4.51	2.49	15
7	1.50	0	1.50	2	0	2	1.60	0	1.60	0.45	0	0.45	4.42	1.44	4.65	1.83	15
8	2	0	2	1.92	0.58	2.01	1.54	0.46	1.61	0.60	0.18	0.63	4.97	1.63	5.23	1.16	15
9	3.10	0	3.10	1.92	0.58	2.01	1.54	0.46	1.61	0.93	0.28	0.97	5.80	1.92	6.11	1.79	15
10	3.50	0	3.50	4.79	1.44	5	3.83	1.15	4	1.05	0.32	1.10	5	1.63	5.26	8.27	15
11	2.60	0	2.60	4.79	1.44	5	3.83	1.15	4	0.78	0.23	0.81	5.12	1.68	5.39	6.97	15
12	2.70	0	2.70	4.79	1.44	5	3.83	1.15	4	0.81	0.24	0.84	5.25	1.74	5.53	6.97	15
13	4.50	0	4.50	4.79	1.44	5	3.83	1.15	4	1.35	0.41	1.41	5	1.63	5.26	9.57	15
14	3.40	0	3.40	4.79	1.44	5	3.83	1.15	4	1.02	0.31	1.07	5.06	1.67	5.33	8.07	15
15	2.40	0	2.40	4.79	1.44	5	3.83	1.15	4	0.72	0.22	0.75	5	1.63	5.26	6.84	15
16	4.30	0	4.30	4.79	1.44	5	3.83	1.15	4	1.29	0.39	1.35	5	1.63	5.26	9.31	15
17	4	0	4	4.79	1.44	5	3.83	1.15	4	1.20	0.36	1.25	4.87	1.61	5.13	9.05	15
18	5.30	0	5.30	4.79	1.44	5	3.83	1.15	4	1.59	0.48	1.66	4.81	1.57	5.06	10.80	15
19	4.70	0	4.70	3.79	1.14	3.96	3.03	0.91	3.16	1.41	0.42	1.47	4.81	1.57	5.06	8.17	15
20	2.20	0	2.20	1.92	0.58	2.01	1.54	0.46	1.61	0.66	0.20	0.69	6.07	2	6.39	0.80	15
21	3.10	0	3.10	1.92	0.58	2.01	1.54	0.46	1.61	0.93	0.28	0.97	6.26	2.06	6.59	1.44	15
22	2.80	0	2.80	2	0	2	1.6	0	1.6	0.84	0	0.84	6.10	2	6.42	2.30	15
23	2.30	0	2.30	2	0	2	1.6	0	1.6	0.69	0	0.69	5.72	1.88	6.02	2.07	15
TOTAL	**68.40**	**0**	**68.40**	**77.58**	**16.42**	**80**	**62.06**	**13.1**	**64**	**20.52**	**4.32**	**21.15**	**119.5**	**39.25**	**125.77**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	3320.83	1131.72	905.16	996.25	6353.97

Appendix E – Generation and consumption schedules without and with the coordination of distributed generators and controllable load

DAY 1: ±100% fraction of load flexibility

Without coordination

Table E13 - Output powers of the generators and the controllable load without coordination on day 1 (±100% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
1	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
2	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
3	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
4	9.90	0	9.90	0	0	0	0	0	0	2.97	0	2.97	6.94	2.26	7.30	6.35	15
5	9.30	0	9.30	0	0	0	0	0	0	2.79	0	2.79	6.94	2.26	7.30	5.62	15
6	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
7	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
8	9.90	0	9.90	0	0	0	0	0	0	2.87	0.86	3	6.94	2.26	7.30	6	15
9	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
10	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
11	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
12	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.94	2.26	7.30	13.95	15
13	9.90	0	9.90	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.50	15
14	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.94	2.26	7.30	13.95	15
15	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.94	2.26	7.30	13.95	15
16	8.20	0	8.20	4.79	1.44	5	3.83	1.15	4	2.46	0.74	2.57	6.94	2.26	7.30	12.39	15
17	6.90	0	6.90	4.79	1.44	5	3.83	1.15	4	2.07	0.62	2.16	6.94	2.26	7.30	10.69	15
18	5	0	5	4.79	1.44	5	3.83	1.15	4	1.50	0.45	1.57	3.68	1.19	3.87	11.59	15
19	7.70	0	7.70	4.79	1.44	5	2.28	1.15	2.55	0 *	0 *	0 *	0	0	0	15	15
20	7	0	7	4.79	1.44	5	2.98	1.15	3.19	0 *	0 *	0 *	0	0	0	15	15
21	5.90	0	5.90	4.79	1.44	5	3.83	1.15	4	0.24 *	0.07 *	0.25 *	0	0	0	15	15
22	8.10	0	8.10	5	0	5	1.90	0	1.90	0 *	0 *	0 *	0	0	0	15	15
23	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	6.94	2.26	7.30	10.75	15
TOTAL	**212.5**	**0**	**212.5**	**72.27**	**18.72**	**75**	**53.29**	**14.95**	**55.64**	**54.79**	**8.73**	**56.11**	**135.5**	**44.13**	**142.64**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	7511.63	1211.71	810.16	1610.97	11144.47

Appendix E - Generation and consumption schedules without and with the coordination of distributed generators and controllable load

With coordination (coordination of distributed generators)

Table E14 - Output powers of the generators and the controllable load (coordination of distributed generators, no coordination with the controllable load) on day 1 (±100% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
1	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
2	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
3	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
4	9.90	0	9.90	0	0	0	0	0	0	2.97	0	2.97	6.94	2.26	7.30	6.35	15
5	9.30	0	9.30	0	0	0	0	0	0	2.79	0	2.79	6.94	2.26	7.30	5.62	15
6	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
7	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
8	9.90	0	9.90	0	0	0	0	0	0	2.87	0.86	3	6.94	2.26	7.30	6	15
9	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
10	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
11	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
12	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.94	2.26	7.30	13.95	15
13	9.90	0	9.90	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.50	15
14	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.94	2.26	7.30	13.95	15
15	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.94	2.26	7.30	13.95	15
16	8.20	0	8.20	4.79	1.44	5	3.83	1.15	4	2.46	0.74	2.57	6.94	2.26	7.30	12.39	15
17	6.90	0	6.90	4.79	1.44	5	3.83	1.15	4	2.07	0.62	2.16	6.94	2.26	7.30	10.69	15
18	5	0	5	4.79	1.44	5	3.83	1.15	4	1.50	0.45	1.57	3.68	1.19	3.87	11.59	15
19	7.70	0	7.70	3.30	0.99	3.45	1.54	0.46	1.61	2.31	0.69	2.41	0	0	0	15	15
20	7	0	7	4.18	1.25	4.36	1.54	0.46	1.61	2.10	0.63	2.19	0	0	0	15	15
21	5.90	0	5.90	4.79	1.44	5	2.30	0.69	2.40	1.77	0.53	1.85	0	0	0	15	15
22	8.10	0	8.10	2.87	0	2.87	1.60	0	1.60	2.43	0	2.43	0	0	0	15	15
23	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	6.94	2.26	7.30	10.75	15
TOTAL	**212.5**	**0**	**212.5**	**68.04**	**18.08**	**70.68**	**49.28**	**13.11**	**51.22**	**63.16**	**10.51**	**64.74**	**135.5**	**44.13**	**142.64**		

	GenA	GenB	GenC	GenD	TOTAL		Contr. load
INCOME (€)	7511.63	1089.26	610.16	2231.45	11442.50	**COST (€)**	4543.77

Appendix E - Generation and consumption schedules without and with the coordination of distributed generators and controllable load

With coordination (coordination of generators and controllable load)

Table E15 - Output powers of the generators and the controllable load with coordination on day 1 (±10% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
1	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
2	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
3	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
4	9.90	0	9.90	0	0	0	0	0	0	2.97	0	2.97	6.94	2.26	7.30	6.35	15
5	9.30	0	9.30	0	0	0	0	0	0	2.79	0	2.79	6.94	2.26	7.30	5.62	15
6	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
7	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
8	9.90	0	9.90	0	0	0	0	0	0	2.87	0.86	3	6.94	2.26	7.30	6	15
9	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
10	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
11	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
12	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.04	1.99	6.36	14.87	15
13	9.90	0	9.90	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.50	15
14	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.94	2.26	7.30	13.95	15
15	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.94	2.26	7.30	13.95	15
16	8.20	0	8.20	4.79	1.44	5	3.83	1.15	4	2.46	0.74	2.57	6.94	2.26	7.30	12.39	15
17	6.90	0	6.90	4.79	1.44	5	3.83	1.15	4	2.07	0.62	2.16	2.77	0.92	2.92	15	15
18	5	0	5	4.79	1.44	5	3.83	1.15	4	1.50	0.45	1.57	0.41	0.13	0.43	15	15
19	7.70	0	7.70	4.79	1.44	5	3.83	1.15	4	2.31	0.69	2.41	3.77	1.24	3.97	15	15
20	7	0	7	4.79	1.44	5	3.83	1.15	4	2.10	0.63	2.19	2.89	0.94	3.04	15	15
21	5.90	0	5.90	4.79	1.44	5	3.83	1.15	4	1.77	0.53	1.85	1.52	0.5	1.60	15	15
22	8.10	0	8.10	5	0	5	4	0	4	2.43	0	2.43	4.61	1.51	4.85	15	15
23	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	2.47	0.81	2.60	15	15
TOTAL	**212.5**	**0**	**212.5**	**72.27**	**18.72**	**75**	**57.79**	**14.95**	**60**	**63.16**	**10.51**	**64.74**	**135.5**	**44.20**	**142.64**		

	GenA	GenB	GenC	GenD	TOTAL		Contr. load
INCOME (€)	7511.63	1211.71	948.89	2231.45	11903.67	**COST (€)**	4859.43

Appendix E - Generation and consumption schedules without and with the coordination of distributed generators and controllable load

DAY 2: ±100% fraction of load flexibility

Without coordination

Table E16 - Output powers of the generators and the controllable load without coordination on day 2 (±100% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	6.50	0	6.50	5	0	5	3.50	0	3.50	0 *	0 *	0 *	0	0	0	15	15
1	7.80	0	7.80	5	0	5	2.20	0	2.20	0 *	0 *	0 *	0	0	0	15	15
2	8.20	0	8.20	5	0	5	4	0	4	2.46	0	2.46	6.94	2.26	7.30	12.92	15
3	5.60	0	5.60	5	0	5	4	0	4	1.68	0	1.68	6.94	2.26	7.30	9.61	15
4	4.80	0	4.80	5	0	5	4	0	4	1.44	0	1.44	6.94	2.26	7.30	8.60	15
5	7	0	7	5	0	5	4	0	4	2.10	0	2.10	6.94	2.26	7.30	11.39	15
6	7.30	0	7.30	2	0	2	1.80	0	1.80	2.19	0	2.19	6.94	2.26	7.30	6.74	15
7	3.10	0	3.10	2	0	2	1.60	0	1.60	0.93	0	0.93	6.94	2.26	7.30	2.36	15
8	4.20	0	4.20	1.92	0.58	2.01	1.54	0.46	1.61	1.26	0.38	1.32	6.94	2.26	7.30	2.15	15
9	1.90	0	1.90	1.92	0.58	2.01	1.54	0.46	1.61	0.57	0.17	0.59	6.94	2.26	7.30	1.46	15
10	1	0	1	3.73	1.12	3.89	3.83	1.15	4	0.30	0.09	0.31	6.94	2.26	7.30	1.92	15
11	1	0	1	1.92	0.58	2.01	3.83	1.15	4	0.30	0.09	0.31	6.94	2.26	7.30	0.45	15
12	0.70	0	0.70	1.92	0.58	2.01	3.83	1.15	4	0.21	0.06	0.22	6.94	2.26	7.30	0.55	15
13	1.50	0	1.50	1.92	0.58	2.01	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	3.20	15
14	2.40	0	2.40	1.92	0.58	2.01	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	4.09	15
15	5.70	0	5.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	5.10	15
16	7.40	0	7.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	6.80	15
17	4.70	0	4.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	4.11	15
18	5.90	0	5.90	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	5.30	15
19	4.50	0	4.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	3.91	15
20	8.30	0	8.30	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	12.90	15
21	10	0	10	4.79	1.44	5	0	0	0	0 *	0 *	0 *	0	0	0	14.86	15
22	10	0	10	5	0	5	0	0	0	0 *	0 *	0 *	0	0	0	15	15
23	10	0	10	5	0	5	3.63	0	3.63	0 *	0 *	0 *	3.68	1.19	3.87	15	15
TOTAL	**129.5**	**0**	**129.5**	**78.43**	**10.38**	**80**	**62.49**	**10.12**	**64**	**36.40**	**7.67**	**37.55**	**135.5**	**44.13**	**142.64**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	5556.48	643.94	328.96	1462.17	7991.17

Appendix E - Generation and consumption schedules without and with the coordination of distributed generators and controllable load

With coordination (coordination of distributed generators)

Table E17 - Output powers of the generators and the controllable load (coordination of distributed generators, no coordination with the controllable load) on day 2 (±100% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	6.50	0	6.50	4.95	0	4.95	1.60	0	1.60	1.95	0	1.95	0	0	0	15	15
1	7.80	0	7.80	3.26	0	3.26	1.60	0	1.60	2.34	0	2.34	0	0	0	15	15
2	8.20	0	8.20	5	0	5	4	0	4	2.46	0	2.46	6.94	2.26	7.30	12.92	15
3	5.60	0	5.60	5	0	5	4	0	4	1.68	0	1.68	6.94	2.26	7.30	9.61	15
4	4.80	0	4.80	5	0	5	4	0	4	1.44	0	1.44	6.94	2.26	7.30	8.60	15
5	7	0	7	5	0	5	4	0	4	2.10	0	2.10	6.94	2.26	7.30	11.39	15
6	7.30	0	7.30	2	0	2	3.94	0	3.94	2.19	0	2.19	6.94	2.26	7.30	8.79	15
7	3.10	0	3.10	2	0	2	1.60	0	1.60	0.93	0	0.93	6.94	2.26	7.30	2.36	15
8	4.20	0	4.20	1.92	0.58	2.01	1.54	0.46	1.61	1.26	0.38	1.32	6.94	2.26	7.30	2.15	15
9	1.90	0	1.90	1.92	0.58	2.01	3.83	1.15	4	0.57	0.17	0.59	6.94	2.26	7.30	1.33	15
10	1	0	1	4.79	1.44	5	3.83	1.15	4	0.30	0.09	0.31	6.94	2.26	7.30	3.01	15
11	1	0	1	4.79	1.44	5	3.83	1.15	4	0.30	0.09	0.31	6.94	2.26	7.30	3.01	15
12	0.70	0	0.70	3.51	1.05	3.66	3.83	1.15	4	0.21	0.06	0.22	6.94	2.26	7.30	1.31	15
13	1.50	0	1.50	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	6.17	15
14	2.40	0	2.40	1.92	0.58	2.01	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	4.09	15
15	5.70	0	5.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	5.10	15
16	7.40	0	7.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	6.80	15
17	4.70	0	4.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	4.11	15
18	5.90	0	5.90	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	5.30	15
19	4.50	0	4.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	3.91	15
20	8.30	0	8.30	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	12.90	15
21	10	0	10	1.93	0.58	2.02	0	0	0	2.87	0.86	3	0	0	0	14.87	15
22	10	0	10	2	0	2	0	0	0	3	0	3	0	0	0	15	15
23	10	0	10	4.03	0	4.03	1.60	0	1.60	3	0	3	3.68	1.19	3.87	15	15
TOTAL	**129.5**	**0**	**129.5**	**78.20**	**12.03**	**80**	**62.39**	**10.81**	**64**	**49.56**	**8.53**	**50.84**	**135.5**	**44.13**	**142.64**		

	GenA	GenB	GenC	GenD	TOTAL		Contr. load
INCOME (€)	5556.48	581.05	301.45	2088.68	8527.66	**COST (€)**	6130.62

Appendix E - Generation and consumption schedules without and with the coordination of distributed generators and controllable load

With coordination (coordination of generators and controllable load)

Table E18 - Output powers of the generators and the controllable load with coordination on day 2 (±100% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	2.47	0.81	2.60	15	15
1	7.80	0	7.80	5	0	5	4	0	4	2.34	0	2.34	4.20	1.38	4.42	15	15
2	8.20	0	8.20	5	0	5	4	0	4	2.46	0	2.46	4.74	1.56	4.99	15	15
3	5.60	0	5.60	5	0	5	4	0	4	1.68	0	1.68	1.29	0.43	1.36	15	15
4	4.80	0	4.80	5	0	5	4	0	4	1.44	0	1.44	0.24	0.07	0.25	15	15
5	7	0	7	5	0	5	4	0	4	2.10	0	2.10	4.86	1.61	5.12	13.34	15
6	7.30	0	7.30	2	0	2	1.60	0	1.60	2.19	0	2.19	6.94	2.26	7.30	6.55	15
7	3.10	0	3.10	2	0	2	1.60	0	1.60	0.93	0	0.93	6.94	2.26	7.30	2.36	15
8	4.20	0	4.20	1.92	0.58	2.01	1.54	0.46	1.61	1.26	0.38	1.32	6.94	2.26	7.30	2.15	15
9	1.90	0	1.90	1.92	0.58	2.01	1.54	0.46	1.61	0.57	0.17	0.59	6.94	2.26	7.30	1.46	15
10	1	0	1	3.73	1.12	3.89	3.40	1.02	3.55	0.30	0.09	0.31	0	0	0	8.72	15
11	1	0	1	1.92	0.58	2.01	1.54	0.46	1.61	0.30	0.09	0.31	6.94	2.26	7.30	2.46	15
12	0.70	0	0.70	1.92	0.58	2.01	1.54	0.46	1.61	0.21	0.06	0.22	6.94	2.26	7.30	2.82	15
13	1.50	0	1.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	0.96	15
14	2.40	0	2.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	1.83	15
15	5.70	0	5.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	5.10	15
16	7.40	0	7.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	6.80	15
17	4.70	0	4.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	4.11	15
18	5.90	0	5.90	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	5.30	15
19	4.50	0	4.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	3.91	15
20	8.30	0	8.30	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	12.90	15
21	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.68	2.19	7.03	14.86	15
22	10	0	10	5	0	5	3.77	0	3.77	3	0	3	6.94	2.26	7.30	15	15
23	10	0	10	5	0	5	3.77	0	3.77	3	0	3	6.94	2.26	7.30	15	15
TOTAL	129.5	0	129.5	78.43	10.38	80	62.74	8.38	64	49.56	8.53	50.84	135.5	44.21	142.64		

	GenA	GenB	GenC	GenD	TOTAL		Contr. load
INCOME (€)	5556.48	643.95	512.66	2088.68	8801.77	COST (€)	6265.80

Appendix E – Generation and consumption schedules without and with the coordination of distributed generators and controllable load

DAY 3: ±100% fraction of load flexibility

Without coordination

Table E19 - Output powers of the generators and the controllable load without coordination on day 3 (±100% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	2	0	2	2	0	2	1.60	0	1.60	0.60	0	0.60	6.93	2.29	7.30	2.40	15
1	1.40	0	1.40	5	0	5	4	0	4	0.42	0	0.42	6.94	2.26	7.30	4.49	15
2	0.70	0	0.70	2	0	2	1.60	0	1.60	0.21	0	0.21	6.94	2.26	7.30	3.32	15
3	1.40	0	1.40	2	0	2	1.60	0	1.60	0.42	0	0.42	6.94	2.26	7.30	2.72	15
4	3.80	0	3.80	2	0	2	1.60	0	1.60	1.14	0	1.14	6.94	2.26	7.30	2.77	15
5	2.60	0	2.60	2	0	2	1.60	0	1.60	0.78	0	0.78	6.94	2.26	7.30	2.26	15
6	2.10	0	2.10	2	0	2	1.60	0	1.60	0.63	0	0.63	6.94	2.26	7.30	2.34	15
7	1.50	0	1.50	2	0	2	1.60	0	1.60	0.45	0	0.45	6.94	2.26	7.30	2.65	15
8	2	0	2	1.92	0.58	2.01	1.54	0.46	1.61	0.60	0.18	0.63	6.94	2.26	7.30	1.36	15
9	3.10	0	3.10	1.92	0.58	2.01	1.54	0.46	1.61	0.93	0.28	0.97	6.94	2.26	7.30	1.09	15
10	3.50	0	3.50	4.79	1.44	5	3.83	1.15	4	1.05	0.32	1.10	6.94	2.26	7.30	6.26	15
11	2.60	0	2.60	4.79	1.44	5	3.83	1.15	4	0.78	0.23	0.81	6.94	2.26	7.30	5.09	15
12	2.70	0	2.70	4.79	1.44	5	3.83	1.15	4	0.81	0.24	0.84	0	0	0	12.46	15
13	4.50	0	4.50	4.79	1.44	5	3.83	1.15	4	1.35	0.41	1.41	0	0	0	14.78	15
14	3.40	0	3.40	4.79	1.44	5	3.83	1.15	4	1.02	0.31	1.07	0	0	0	13.36	15
15	2.40	0	2.40	4.79	1.44	5	3.83	1.15	4	0.72	0.22	0.75	0	0	0	12.07	15
16	4.30	0	4.30	4.79	1.44	5	3.83	1.15	4	1.29	0.39	1.35	3.74	1.24	3.94	10.61	15
17	4	0	4	4.79	1.44	5	3.83	1.15	4	1.20	0.36	1.25	6.94	2.26	7.30	6.91	15
18	5.30	0	5.30	4.79	1.44	5	3.83	1.15	4	1.59	0.48	1.66	6.94	2.26	7.30	8.61	15
19	4.70	0	4.70	3.79	1.14	3.96	3.03	0.91	3.16	1.41	0.42	1.47	6.93	2.29	7.30	5.99	15
20	2.20	0	2.20	1.92	0.58	2.01	1.54	0.46	1.61	0.66	0.20	0.69	6.94	2.26	7.30	1.19	15
21	3.10	0	3.10	1.92	0.58	2.01	1.54	0.46	1.61	0.93	0.28	0.97	6.94	2.26	7.30	1.09	15
22	2.80	0	2.80	2	0	2	1.6	0	1.6	0.84	0	0.84	6.94	2.26	7.30	2.28	15
23	2.30	0	2.30	2	0	2	1.6	0	1.6	0.69	0	0.69	6.94	2.26	7.30	2.29	15
TOTAL	**68.40**	**0**	**68.40**	**77.58**	**16.42**	**80**	**62.06**	**13.1**	**64**	**20.52**	**4.32**	**21.15**	**135.6**	**44.24**	**142.64**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	3320.83	1131.72	905.16	996.25	6353.97

Appendix E - Generation and consumption schedules without and with the coordination of distributed generators and controllable load

DAY 4: ±100% fraction of load flexibility

Without coordination

Table E20 - Output powers of the generators and the controllable load without coordination on day 4 (±100% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
1	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
2	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
3	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
4	9.90	0	9.90	0	0	0	0	0	0	2.97	0	2.97	6.94	2.26	7.30	6.35	15
5	9.30	0	9.30	0	0	0	0	0	0	2.79	0	2.79	6.94	2.26	7.30	5.62	15
6	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
7	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
8	9.90	0	9.90	0	0	0	0	0	0	2.87	0.86	3	6.94	2.26	7.30	6	15
9	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
10	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
11	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
12	9.40	0	9.40	4.79	1.44	5	2.25	0.68	2.35	0 *	0 *	0 *	1.53	0.50	1.61	15	15
13	9.90	0	9.90	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.50	15
14	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.94	2.26	7.30	13.95	15
15	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.94	2.26	7.30	13.95	15
16	8.20	0	8.20	4.79	1.44	5	3.83	1.15	4	2.46	0.74	2.57	6.94	2.26	7.30	12.39	15
17	6.90	0	6.90	4.79	1.44	5	3.12	0.94	3.26	0 *	0 *	0 *	0	0	0	15	15
18	5	0	5	4.79	1.44	5	3.83	1.15	4	1.09 *	0.33 *	1.14 *	0	0	0	15	15
19	7.70	0	7.70	4.79	1.44	5	2.36	0.71	2.46	0 *	0 *	0 *	0	0	0	15	15
20	7	0	7	4.79	1.44	5	3.02	0.91	3.15	0 *	0 *	0 *	0	0	0	15	15
21	5.90	0	5.90	4.79	1.44	5	3.83	1.15	4	0.24 *	0.07 *	0.25 *	0	0	0	15	15
22	8.10	0	8.10	5	0	5	1.9	0	1.9	0 *	0 *	0 *	0	0	0	15	15
23	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	6.94	2.26	7.30	10.75	15
TOTAL	**212.5**	**0**	**212.5**	**72.27**	**18.72**	**75**	**51.12**	**13.59**	**53.12**	**49.49**	**7.14**	**50.57**	**119.5**	**38.91**	**125.77**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	7511.63	1211.71	783.51	1351.27	10858.12

Appendix E - Generation and consumption schedules without and with the coordination of distributed generators and controllable load

With coordination (coordination of distributed generators)

Table E21 - Output powers of the generators and the controllable load (coordination of distributed generators, no coordination with the controllable load) on day 1 (±100% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
1	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
2	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
3	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
4	9.90	0	9.90	0	0	0	0	0	0	2.97	0	2.97	6.94	2.26	7.30	6.35	15
5	9.30	0	9.30	0	0	0	0	0	0	2.79	0	2.79	6.94	2.26	7.30	5.62	15
6	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
7	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
8	9.90	0	9.90	0	0	0	0	0	0	2.87	0.86	3	6.94	2.26	7.30	6	15
9	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
10	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
11	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
12	9.40	0	9.40	2.61	0.78	2.72	1.54	0.46	1.61	2.82	0.85	2.95	1.53	0.50	1.61	14.93	15
13	9.90	0	9.90	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.50	15
14	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.94	2.26	7.30	13.95	15
15	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.94	2.26	7.30	13.95	15
16	8.20	0	8.20	4.79	1.44	5	3.83	1.15	4	2.46	0.74	2.57	6.94	2.26	7.30	12.39	15
17	6.90	0	6.90	4.3	1.29	4.49	1.54	0.46	1.61	2.07	0.62	2.16	0	0	0	15	15
18	5	0	5	4.79	1.44	5	3.42	1.03	3.57	1.50	0.45	1.57	0	0	0	15	15
19	7.70	0	7.70	3.3	0.99	3.45	1.54	0.46	1.61	2.31	0.69	2.41	0	0	0	15	15
20	7	0	7	4.18	1.25	4.36	1.54	0.46	1.61	2.10	0.63	2.19	0	0	0	15	15
21	5.90	0	5.90	4.79	1.44	5	2.30	0.69	2.40	1.77	0.53	1.85	0	0	0	15	15
22	8.10	0	8.10	2.87	0	2.87	1.60	0	1.60	2.43	0	2.43	0	0	0	15	15
23	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	6.94	2.26	7.30	10.75	15
TOTAL	**212.5**	**0**	**212.5**	**65.37**	**17.27**	**67.89**	**44.29**	**11.61**	**46.01**	**63.16**	**10.51**	**64.74**	**119.5**	**38.91**	**125.77**		

	GenA	GenB	GenC	GenD	TOTAL		Contr. load
INCOME (€)	7511.63	1053.29	539.92	2231.45	11336.29	**COST (€)**	3654.44

Appendix E - Generation and consumption schedules without and with the coordination of distributed generators and controllable load

With coordination (coordination of generators and controllable load)

Table E22 - Output powers of the generators and the controllable load with coordination on day 1 (±10% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
1	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
2	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
3	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
4	9.90	0	9.90	0	0	0	0	0	0	2.97	0	2.97	6.94	2.26	7.30	6.35	15
5	9.30	0	9.30	0	0	0	0	0	0	2.79	0	2.79	6.94	2.26	7.30	5.62	15
6	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
7	10	0	10	0	0	0	0	0	0	3	0	3	6.94	2.26	7.30	6.47	15
8	9.90	0	9.90	0	0	0	0	0	0	2.87	0.86	3	6.94	2.26	7.30	6	15
9	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
10	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
11	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	14.60	15
12	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	5.92	1.94	6.23	15	15
13	9.90	0	9.90	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.45	2.12	6.79	15	15
14	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	6.94	2.26	7.30	13.95	15
15	9.40	0	9.40	4.79	1.44	5	3.83	1.15	4	2.82	0.85	2.95	5.92	1.94	6.23	15	15
16	8.20	0	8.20	4.79	1.44	5	3.83	1.15	4	2.46	0.74	2.57	4.4	1.44	4.63	15	15
17	6.90	0	6.90	4.79	1.44	5	3.83	1.15	4	2.07	0.62	2.16	2.77	0.92	2.92	15	15
18	5	0	5	4.79	1.44	5	3.83	1.15	4	1.50	0.45	1.57	0.41	0.13	0.43	15	15
19	7.70	0	7.70	4.23	1.27	4.42	1.54	0.46	1.61	2.31	0.69	2.41	0.93	0.3	0.98	15	15
20	7	0	7	4.18	1.25	4.36	1.54	0.46	1.61	2.10	0.63	2.19	0	0	0	15	15
21	5.90	0	5.90	4.79	1.44	5	2.3	0.69	2.4	1.77	0.53	1.85	0	0	0	15	15
22	8.10	0	8.10	2.87	0	2.87	1.6	0	1.6	2.43	0	2.43	0	0	0	15	15
23	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	2.47	0.81	2.60	15	15
TOTAL	**212.5**	**0**	**212.5**	**68.97**	**18.36**	**71.65**	**49.28**	**13.11**	**51.22**	**63.16**	**10.51**	**64.74**	**119.5**	**38.98**	**125.77**		

	GenA	GenB	GenC	GenD	TOTAL		Contr. load
INCOME (€)	7511.63	1110.54	610.16	2231.45	11463.77	**COST (€)**	3698.80

Appendix E – Generation and consumption schedules without and with the coordination of distributed generators and controllable load

DAY 5: ±100% fraction of load flexibility

Without coordination

Table E23 - Output powers of the generators and the controllable load without coordination on day 5 (±100% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	6.50	0	6.50	5	0	5	3.50	0	3.50	0 *	0 *	0 *	0	0	0	15	15
1	7.80	0	7.80	5	0	5	2.20	0	2.20	0 *	0 *	0 *	0	0	0	15	15
2	8.20	0	8.20	5	0	5	1.80	0	1.80	0 *	0 *	0 *	0	0	0	15	15
3	5.60	0	5.60	5	0	5	4	0	4	1.68	0	1.68	1.53	0.49	1.61	14.76	15
4	4.80	0	4.80	5	0	5	4	0	4	1.44	0	1.44	6.94	2.26	7.30	8.60	15
5	7	0	7	5	0	5	4	0	4	2.10	0	2.10	6.94	2.26	7.30	11.39	15
6	7.30	0	7.30	2	0	2	1.60	0	1.60	2.19	0	2.19	6.94	2.26	7.30	6.55	15
7	3.10	0	3.10	2	0	2	1.60	0	1.60	0.93	0	0.93	6.94	2.26	7.30	2.36	15
8	4.20	0	4.20	1.92	0.58	2.01	1.54	0.46	1.61	1.26	0.38	1.32	6.94	2.26	7.30	2.15	15
9	1.90	0	1.90	1.92	0.58	2.01	1.54	0.46	1.61	0.57	0.17	0.59	6.94	2.26	7.30	1.46	15
10	1	0	1	3.73	1.12	3.89	2.96	0.89	3.09	0.30	0.09	0.31	6.94	2.26	7.30	1.06	15
11	1	0	1	1.92	0.58	2.01	1.54	0.46	1.61	0.30	0.09	0.31	6.94	2.26	7.30	2.46	15
12	0.70	0	0.70	1.92	0.58	2.01	1.54	0.46	1.61	0.21	0.06	0.22	6.94	2.26	7.30	2.82	15
13	1.50	0	1.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	0.96	15
14	2.40	0	2.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	1.83	15
15	5.70	0	5.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	5.10	15
16	7.40	0	7.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	6.80	15
17	4.70	0	4.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	4.11	15
18	5.90	0	5.90	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	5.30	15
19	4.50	0	4.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	3.91	15
20	8.30	0	8.30	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	12.90	15
21	10	0	10	4.79	1.44	5	0	0	0	0 *	0 *	0 *	0	0	0	14.86	15
22	10	0	10	5	0	5	0	0	0	0 *	0 *	0 *	0	0	0	15	15
23	10	0	10	5	0	5	0	0	0	0 *	0 *	0 *	0	0	0	15	15
TOTAL	**129.5**	**0**	**129.5**	**78.43**	**10.38**	**80**	**46.43**	**7.1**	**47.50**	**33.94**	**7.67**	**35.09**	**119.5**	**38.91**	**125.77**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	5556.48	643.94	314.58	1355.45	7870.45

Appendix E - Generation and consumption schedules without and with the coordination of distributed generators and controllable load

With coordination (coordination of distributed generators)

Table E24 - Output powers of the generators and the controllable load (coordination of distributed generators, no coordination with the controllable load) on day 5 (±100% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	6.50	0	6.50	5	0	5	1.55	0	1.55	1.95	0	1.95	0	0	0	15	15
1	7.80	0	7.80	3.26	0	3.26	1.60	0	1.60	2.34	0	2.34	0	0	0	15	15
2	8.20	0	8.20	2.74	0	2.74	1.60	0	1.60	2.46	0	2.46	0	0	0	15	15
3	5.60	0	5.60	5	0	5	4	0	4	1.68	0	1.68	1.53	0.49	1.61	14.76	15
4	4.80	0	4.80	5	0	5	4	0	4	1.44	0	1.44	6.94	2.26	7.30	8.60	15
5	7	0	7	5	0	5	4	0	4	2.10	0	2.10	6.94	2.26	7.30	11.39	15
6	7.30	0	7.30	2	0	2	3.83	0	3.83	2.19	0	2.19	6.94	2.26	7.30	8.68	15
7	3.10	0	3.10	2	0	2	3.37	0	3.37	0.93	0	0.93	6.94	2.26	7.30	3.34	15
8	4.20	0	4.20	1.92	0.58	2.01	1.54	0.46	1.61	1.26	0.38	1.32	6.94	2.26	7.30	2.15	15
9	1.90	0	1.90	4.7	1.41	4.91	3.83	1.15	4	0.57	0.17	0.59	6.94	2.26	7.30	4.09	15
10	1	0	1	4.79	1.44	5	3.83	1.15	4	0.30	0.09	0.31	6.94	2.26	7.30	3.01	15
11	1	0	1	4.79	1.44	5	3.83	1.15	4	0.30	0.09	0.31	6.94	2.26	7.30	3.01	15
12	0.70	0	0.70	4.79	1.44	5	3.83	1.15	4	0.21	0.06	0.22	6.94	2.26	7.30	2.62	15
13	1.50	0	1.50	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	6.17	15
14	2.40	0	2.40	1.92	0.58	2.01	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	4.09	15
15	5.70	0	5.70	1.92	0.58	2.01	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	7.39	15
16	7.40	0	7.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	6.80	15
17	4.70	0	4.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	4.11	15
18	5.90	0	5.90	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	5.30	15
19	4.50	0	4.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.30	3.91	15
20	8.30	0	8.30	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.30	12.90	15
21	10	0	10	1.93	0.58	2.02	0	0	0	2.87	0.86	3	0	0	0	14.87	15
22	10	0	10	2	0	2	0	0	0	3	0	3	0	0	0	15	15
23	10	0	10	2	0	2	0	0	0	3	0	3	0	0	0	15	15
TOTAL	**129.5**	**0**	**129.5**	**78.02**	**13.25**	**80**	**62.29**	**11.5**	**64**	**49.56**	**8.53**	**50.84**	**119.5**	**38.91**	**125.77**		

	GenA	GenB	GenC	GenD	TOTAL		Contr. load
INCOME (€)	5556.48	566.09	279.76	2088.68	8491.01	**COST (€)**	5352.21

Appendix E - Generation and consumption schedules without and with the coordination of distributed generators and controllable load

With coordination (coordination of generators and controllable load)

Table E25 - Output powers of the generators and the controllable load with coordination on day 5 (±100% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	6.50	0	6.50	5	0	5	4	0	4	1.95	0	1.95	2.47	0.81	2.6	15	15
1	7.80	0	7.80	5	0	5	4	0	4	2.34	0	2.34	4.2	1.38	4.42	15	15
2	8.20	0	8.20	5	0	5	4	0	4	2.46	0	2.46	4.74	1.56	4.99	15	15
3	5.60	0	5.60	5	0	5	4	0	4	1.68	0	1.68	1.29	0.43	1.36	15	15
4	4.80	0	4.80	5	0	5	4	0	4	1.44	0	1.44	0.24	0.07	0.25	15	15
5	7	0	7	5	0	5	4	0	4	2.10	0	2.10	3.13	1.01	3.29	15	15
6	7.30	0	7.30	2	0	2	1.60	0	1.60	2.19	0	2.19	6.94	2.26	7.3	6.55	15
7	3.10	0	3.10	2	0	2	1.60	0	1.60	0.93	0	0.93	6.94	2.26	7.3	2.36	15
8	4.20	0	4.20	1.92	0.58	2.01	1.54	0.46	1.61	1.26	0.38	1.32	6.94	2.26	7.3	2.15	15
9	1.90	0	1.90	1.92	0.58	2.01	1.54	0.46	1.61	0.57	0.17	0.59	6.94	2.26	7.3	1.46	15
10	1	0	1	3.73	1.12	3.89	3.40	1.02	3.55	0.30	0.09	0.31	0	0	0	8.72	15
11	1	0	1	1.92	0.58	2.01	1.54	0.46	1.61	0.30	0.09	0.31	0	0	0	4.89	15
12	0.70	0	0.70	1.92	0.58	2.01	1.54	0.46	1.61	0.21	0.06	0.22	6.52	2.15	6.87	2.39	15
13	1.50	0	1.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	0	0	0	8.06	15
14	2.40	0	2.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.3	1.83	15
15	5.70	0	5.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.3	5.10	15
16	7.40	0	7.40	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.3	6.80	15
17	4.70	0	4.70	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.3	4.11	15
18	5.90	0	5.90	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.3	5.30	15
19	4.50	0	4.50	1.92	0.58	2.01	1.54	0.46	1.61	2.87	0.86	3	6.94	2.26	7.3	3.91	15
20	8.30	0	8.30	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.94	2.26	7.3	12.90	15
21	10	0	10	4.79	1.44	5	3.83	1.15	4	2.87	0.86	3	6.68	2.19	7.03	14.86	15
22	10	0	10	5	0	5	3.77	0	3.77	3	0	3	6.94	2.26	7.3	15	15
23	10	0	10	5	0	5	3.77	0	3.77	3	0	3	6.94	2.26	7.3	15	15
TOTAL	129.5	0	129.5	78.43	10.38	80	62.74	8.38	64	49.56	8.53	50.84	119.5	38.98	125.77		

	GenA	GenB	GenC	GenD	TOTAL		Contr. load
INCOME (€)	5556.48	643.95	512.66	2088.68	8801.77	COST (€)	5524.80

DAY 6: ±100% fraction of load flexibility

Without coordination

Table E26 - Output powers of the generators and the controllable load without coordination on day 6 (±100% load flexibility)

hour	GenA (MW)	GenA (MVar)	GenA (MVA)	GenB (MW)	GenB (MVar)	GenB (MVA)	GenC (MW)	GenC (MVar)	GenC (MVA)	GenD (MW)	GenD (MVar)	GenD (MVA)	Contr. load (MW)	Contr. load (MVar)	Contr. load (MVA)	Distr. circuit (MVA)	Circuit limit (MVA)
0	2	0	2	2	0	2	1.60	0	1.60	0.60	0	0.60	6.94	2.26	7.30	2.38	15
1	1.40	0	1.40	5	0	5	4	0	4	0.42	0	0.42	6.94	2.26	7.30	4.49	15
2	0.70	0	0.70	2	0	2	1.60	0	1.60	0.21	0	0.21	6.94	2.26	7.30	3.32	15
3	1.40	0	1.40	2	0	2	1.60	0	1.60	0.42	0	0.42	6.94	2.26	7.30	2.72	15
4	3.80	0	3.80	2	0	2	1.60	0	1.60	1.14	0	1.14	6.94	2.26	7.30	2.77	15
5	2.60	0	2.60	2	0	2	1.60	0	1.60	0.78	0	0.78	6.94	2.26	7.30	2.26	15
6	2.10	0	2.10	2	0	2	1.60	0	1.60	0.63	0	0.63	6.94	2.26	7.30	2.34	15
7	1.50	0	1.50	2	0	2	1.60	0	1.60	0.45	0	0.45	6.94	2.26	7.30	2.65	15
8	2	0	2	1.92	0.58	2.01	1.54	0.46	1.61	0.60	0.18	0.63	6.94	2.26	7.30	1.36	15
9	3.10	0	3.10	1.92	0.58	2.01	1.54	0.46	1.61	0.93	0.28	0.97	6.94	2.26	7.30	1.09	15
10	3.50	0	3.50	4.79	1.44	5	3.83	1.15	4	1.05	0.32	1.10	6.94	2.26	7.30	6.26	15
11	2.60	0	2.60	4.79	1.44	5	3.83	1.15	4	0.78	0.23	0.81	0	0	0	12.33	15
12	2.70	0	2.70	4.79	1.44	5	3.83	1.15	4	0.81	0.24	0.84	0	0	0	12.46	15
13	4.50	0	4.50	4.79	1.44	5	3.83	1.15	4	1.35	0.41	1.41	0	0	0	14.78	15
14	3.40	0	3.40	4.79	1.44	5	3.83	1.15	4	1.02	0.31	1.07	0	0	0	13.36	15
15	2.40	0	2.40	4.79	1.44	5	3.83	1.15	4	0.72	0.22	0.75	0	0	0	12.07	15
16	4.30	0	4.30	4.79	1.44	5	3.83	1.15	4	1.29	0.39	1.35	0	0	0	14.52	15
17	4	0	4	4.79	1.44	5	3.83	1.15	4	1.20	0.36	1.25	1.59	0.51	1.67	12.47	15
18	5.30	0	5.30	4.79	1.44	5	3.83	1.15	4	1.59	0.48	1.66	6.94	2.26	7.30	8.61	15
19	4.70	0	4.70	3.79	1.14	3.96	3.03	0.91	3.16	1.41	0.42	1.47	6.94	2.26	7.30	5.99	15
20	2.20	0	2.20	1.92	0.58	2.01	1.54	0.46	1.61	0.66	0.20	0.69	6.94	2.26	7.30	1.19	15
21	3.10	0	3.10	1.92	0.58	2.01	1.54	0.46	1.61	0.93	0.28	0.97	6.94	2.26	7.30	1.09	15
22	2.80	0	2.80	2	0	2	1.60	0	1.60	0.84	0	0.84	6.94	2.26	7.30	2.28	15
23	2.30	0	2.30	2	0	2	1.60	0	1.60	0.69	0	0.69	6.94	2.26	7.30	2.29	15
TOTAL	**68.40**	**0**	**68.40**	**77.58**	**16.42**	**80**	**62.06**	**13.1**	**64**	**20.52**	**4.32**	**21.15**	**119.6**	**38.93**	**125.77**		

	GenA	GenB	GenC	GenD	TOTAL
INCOME (€)	3320.83	1131.72	905.16	996.25	6353.97