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Andrianesis, Panagiotis and Liberopoulos, George and Sakellaris, Kostis and Vlachos, Andreas

University of Thessaly, Department of Mechanical Industrial Engineering, Regulatory Authority for Energy, Greece, Athens University of Economics and Business, Department of Economics

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Panagiotis Andrianesis [a], George Liberopoulos [a],
Kostis Sakellaris [b,c], Andreas Vlachos [b]

[a] Department of Mechanical & Industrial Engineering, University of Thessaly, Volos, Greece (corresponding author: Panagiotis Andrianesis)
[b] Regulatory Authority for Energy, Athens, Greece
[c] Athens University of Economics and Business

Tel: +30-24210-74043
Fax: +30-24210-74059
e-mail: andrianesis@uth.gr

Address
Department of Mechanical & Industrial Engineering, University of Thessaly,
Pedion Areos, 38334, Volos, Greece

Abstract: We sketch the main aspects of Greece's electricity system from a market-based point of view. First, we provide data concerning the mix of generating units, the system load and the frequency-related ancillary services. Then, we formulate a simplified model of Greece's Day-Ahead Scheduling (DAS) problem that constitutes the basis for our analysis. We examine various cases concerning the format of the objective function as well as the pricing and compensation schemes. An illustrative example is used to indicate the impact of reserve and fixed (start-up, shut-down, and minimum-load) costs on the resulting dispatching of units and on clearing prices, under the different cases. Our analysis aims at unveiling the impact of cost components other than energy offers on the DAS problem, and provide the grounds for future research on the design of the electricity market.

Keywords: Electricity Market, Day-Ahead Scheduling

1. Introduction

In 1996, European Directive 96/92/EC set as a goal the liberalization and the integration of the national electricity markets, leading to fundamental changes in the organization of the electricity sector, with new companies entering the wholesale or retail electricity markets and the creation of transmission and distribution system operators. As these entities are needed to function in a non-discriminatory and transparent way, significant emphasis was given to the wholesale market rules governing the scheduling of the generating units and the energy that they are called to produce.

In Greece, the electricity wholesale market was first introduced with Law 2773/1999, followed by a subsequent electricity Law (no. 3175/2003) and a Grid Control and Power Exchange Code for Electricity (Regulatory Authority for Energy, 2005) providing the details for the development of a centrally organized daily wholesale market, through which all electricity generated and consumed in Greece would be transacted. The Code is progressively being put in force over a transitory period extending from October 2005 till the middle of 2009.

The Greek wholesale market is designed as a pure mandatory pool consisting of:

(a) The Day-Ahead (DA) market, where the scheduling and clearing of the total energy produced and consumed in Greece, as well as imports and exports, takes place ('mandatory' pool).
(b) The Real Time Dispatch operation.
(c) The Imbalances Settlement, which includes the settlement of energy deviations from the DA program and the settlement of the services required for the balancing of the system.
(d) The Capacity Assurance Mechanism, through which part of the fixed costs of the production capacity are covered.

The basis for the wholesale electricity market operation is the Day-Ahead Scheduling (DAS) program, which minimizes the overall cost of serving energy load for the next day, under conditions of reliable system operation, while ensuring adequate reserves. In other words, the DAS program is a security-constrained unit commitment program, co-optimizing energy and reserves.

2. Greece's Electricity System

Greece has a variety of generating units: lignite, natural gas, oil, hydro plants, renewable energy sources (RES) such as wind parks, small hydros, biomass, photovoltaic, and cogeneration. The vast majority of thermal plants and all hydro plants belong to the Public Power Corporation (PPC). Only one Combined Cycle Gas Turbine (CCGT) unit of 390 MW and one small Gas Turbine (GT) unit belong to private producers. Wind parks are also privately-owned for the most part. It is obvious that the market is highly concentrated, as PPC holds about 95% of the market share. However, one more CCGT unit of 350 MW is in the process of entering the market by the end of October 2008, while construction has begun for at least two more CCGT units.

The total capacity installed by unit type is listed in Table 1, while the yearly load profile for 2007 is shown in Figure 1, where the hourly load has been ordered from highest to lowest.

Table 1. Installed capacity by unit type

Unit type	Number of units	Capacity (MW)
Lignite	22	4808.10
Oil	4	718.00
Combined Cycle	5	1962.10
Natural Gas	3	486.80
Small Thermal	2	116.10
Hydro	39	3016.50
RES/Cogeneration	>100	889.94
Total Capacity:		11997.54
Total Capacity (w/o RES/Cogen.):		11107.60
Total Capacity (thermal plants):		8091.10

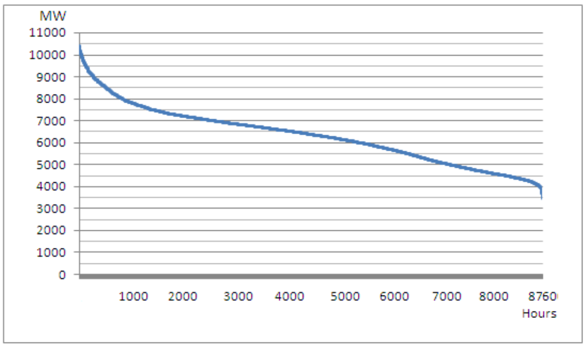

Figure 1. Yearly load profile for 2007

Greece is a UCTE (Union for Coordination of Transmission of Electricity) member and is interconnected with Albania, FYROM and Bulgaria in the North, and Italy in the North-West. The north interconnections have a net transfer capacity of about 600 MW and the interconnection with Italy 500 MW.

The frequency-related ancillary services are primary, secondary and tertiary reserve based on the timeframe each service is provided. The primary reserve requirement is set at 80 MW, the secondary reserve requirement is set at 150-300 MW for secondary up and 50-150 MW for secondary down; 50 MW of both up and down should be fast secondary reserve. Tertiary reserve requirement is set at 300-600 MW. In this paper, by the term "reserves" we mean only the frequency-related ancillary services.

Greece has a particularity concerning the location of generation and consumption. While most of the power plants are located in the North, the majority of the energy consumption takes place in the South. As a result, in case of high load, a transmission constraint is activated, prohibiting the transfer of the desired amount of energy from the North to the South. The amount of energy that can be transferred is about 3200 MW. To deal with this particularity of excess capacity in the North, Greece is divided in two operational zones (North – South) and producers are paid at different prices (Marginal Generating Prices) when the above transmission constraint is activated. Suppliers, however, face a uniform price, the System Marginal Price (SMP) regardless of their location. Andrianesis et al. (2007) state this two-zone model and show the incentives that it provides for the installation of new generation near consumption.

3. Day-Ahead Scheduling Problem

The DAS problem is solved every day, simultaneously for all 24 hours of the next day. The objective is to minimize the cost of matching the energy to be absorbed with the energy to be injected in the system, under the transmission constraints, the generation units' technical constraints and the reserve requirements. The DAS problem defines how each unit should operate in each hour, so that the social welfare of the electricity market is maximized. It also determines the clearing prices of the energy and primary and secondary reserve markets. Currently, tertiary reserve is not remunerated, but the relative requirement enters the DAS program as a constraint.

The producers submit energy offers for each hour of the following day, as a stepwise function of price-quantity pairs, with successive prices being strictly non-decreasing. They also submit primary and secondary reserve bids as price-quantity pairs, and shut-down costs that are considered equal to their warm start-up costs. The technical characteristics of the generation units that constitute the constraints of the DAS problem include the technical minimum and maximum output, the maximum reserve availability, the minimum up and down times, and the ramp up and down limits.

Demand for energy and reserve requirements are exogenously determined by the Hellenic Transmission System Operator (HTSO), and are therefore considered as parameters of the optimization problem.

The DAS problem, as is explicitly defined in the grid code, is a very complicated mixed integer programming model which requires significant effort in order to be implemented. For the purpose of this paper, we developed a simpler version of the model that allows us to focus mainly on the impact of reserve offers and fixed costs. For simplicity, this reduced model is being referred as the DAS problem.

The DAS problem can be formulated as a mixed integer linear programming problem (MILP) as follows:

$$\min_{\mathbf{x}_{u,h},\mathbf{z}_{u,h}} f_{DAS} = \{\sum_{u,h} \mathbf{c}_{u,h}^{\mathrm{T}} \cdot \mathbf{x}_{u,h} + \sum_{u,h} \mathbf{d}_u^{\mathrm{T}} \cdot \mathbf{z}_{u,h}\} \quad (1)$$

subject to:

$$\sum_u \mathbf{A_1} \cdot \mathbf{x}_{u,h} + \sum_u \mathbf{A_2} \cdot \mathbf{z}_{u,h} \geq \mathbf{a}_h \qquad \forall h \quad (2)$$

$$\mathbf{B}_{\mathbf{1}u,h} \cdot \mathbf{x}_{u,h} + \mathbf{B}_{\mathbf{2}u,h} \cdot \mathbf{z}_{u,h} \geq \mathbf{b}_{u,h} \qquad \forall u,h \quad (3)$$

$$\mathbf{x}_{u,0} = \mathbf{x}_u^0, \qquad \mathbf{z}_{u,0} = \mathbf{z}_u^0 \qquad \forall u \quad (4)$$

with $\mathbf{x}_{u,h} \geq \mathbf{0}$ and $\mathbf{z}_{u,h}$ integer, $\forall u,h$.

The objective function (1) aims at minimizing a cost function that can include the cost for providing energy and reserves as well as fixed costs. The vector $\mathbf{x}_{u,h}$ represents the commodities of the electricity market, such as energy and reserves. The vector $\mathbf{z}_{u,h}$ represents the status of the generating units and other auxiliary variables, such as start-up and shut-down signals. Vectors $\mathbf{c}_{u,h}$ and $\mathbf{d}_u$ are the cost coefficients for the commodities of energy and reserves, i.e., the price part of the energy and reserves offers, and the fixed costs, which can include the start-up, shut-down and minimum-load cost, respectively.

Constraint (2) is the market-clearing constraint, i.e., the energy balance and the reserve requirements. Constraint (3) represents the generating units' technical constraints, such as the technical minimum, technical maximum and the reserve availability constraint. Equality (4) states the initial conditions of the units.

Assuming that each unit submits a single price-quantity offer in each hour, the vectors and matrices in (1) - (4) can be written as follows, using the notation in the Appendix:

$$\mathbf{x}_{u,h} = \begin{bmatrix} G_{u,h} & R_{u,h} \end{bmatrix}^{\mathrm{T}}, \ \mathbf{z}_{u,h} = \begin{bmatrix} ST_{u,h} & Y_{u,h} & V_{u,h} \end{bmatrix}^{\mathrm{T}}$$

$$\mathbf{c}_{u,h} = \begin{bmatrix} P_{u,h}^g & P_{u,h}^r \end{bmatrix}^{\mathrm{T}}, \ \mathbf{d}_u = \begin{bmatrix} MLC_u & SUC_u & SDC_u \end{bmatrix}^{\mathrm{T}}$$

$$\mathbf{A_1} = \begin{bmatrix} 1 & 0 \\ 0 & 1 \end{bmatrix}, \ \mathbf{A_2} = \begin{bmatrix} 0 & 0 & 0 \\ 0 & 0 & 0 \end{bmatrix}, \ \mathbf{a}_h = \begin{bmatrix} D_h \\ R_h^{req} \end{bmatrix}$$

$$\mathbf{B}_{\mathbf{1}u,h} = \begin{bmatrix} 1 & 0 \\ -1 & -1 \\ 0 & -1 \end{bmatrix}, \ \mathbf{B}_{\mathbf{2}u,h} = \begin{bmatrix} -Q_u^{\min} & 0 & 0 \\ Q_u^{\max} & 0 & 0 \\ R_u^{bid} & 0 & 0 \end{bmatrix}, \ \mathbf{b}_{u,h} = \begin{bmatrix} 0 \\ 0 \\ 0 \end{bmatrix}$$

In the above, we assumed that only one type of reserve is addressed. To deal with all types of frequency-related ancillary services, the reserve requirement constraint has to be applied at every type, taking into consideration the substitutability of lower quality services by higher quality ones. The general formulation of constraint (2) is applicable to all types of constraints; nevertheless, the purpose of this paper is served even by addressing only one type of reserve.

Moreover, we have to note that the start-up and shut-down signal variables $Y_{u,h}$ and $V_{u,h}$ are dependent variables and are defined by the status variables $ST_{u,h}$ and $ST_{u,h-1}$. For example, the start-up variable $Y_{u,h}$ is defined by the following equality:

$$Y_{u,h} = ST_{u,h}(1 - ST_{u,h-1}) \quad \forall u,h \quad (5)$$

To avoid the non-linear term $ST_{u,h} \cdot ST_{u,h-1}$, we can replace (5) by the following two inequalities:

$$Y_{u,h} \geq ST_{u,h} - ST_{u,h-1} \quad \forall u,h \quad (6)$$

$$ST_{u,h} - ST_{u,h-1} + 1.1(1 - Y_{u,h}) \geq 0.1 \quad \forall u,h \quad (7)$$

For simplicity we did not include these inter-temporal constraints in the formulation, as this would result in more complex **B** matrices. It is left to the interested reader to reform the matrices so as to include these constraints.

To make things clearer, we can rewrite the DAS problem, in its simple version, as follows:

$$\min_{G_{u,h},R_{u,h},ST_{u,h},Y_{u,h},V_{u,h}} f_{DAS} = \{\sum_{u,h} P_{u,h}^g \cdot G_{u,h} + \sum_{u,h} P_{u,h}^r \cdot R_{u,h} + \\ + \sum_{u,h} ST_{u,h} \cdot MLC_u + \sum_{u,h} Y_{u,h} \cdot SUC_u + \sum_{u,h} V_{u,h} \cdot SDC_u\} \quad (8)$$

subject to:

$$\sum_u G_{u,h} = D_h \qquad \forall h \qquad (p_h^G) \quad (9)$$

$$\sum_u R_{u,h} \geq R_h^{req} \qquad \forall h \qquad (p_h^R) \quad (10)$$

$$G_{u,h} - ST_{u,h} \cdot Q_u^{\min} \geq 0 \qquad \forall u,h \qquad (\lambda_{u,h}) \quad (11)$$

$$-G_{u,h} - R_{u,h} + ST_{u,h} \cdot Q_u^{\max} \geq 0 \qquad \forall u,h \qquad (\theta_{u,h}) \quad (12)$$

$$-R_{u,h} + ST_{u,h} \cdot R_u^{bid} \geq 0 \qquad \forall u,h \qquad (\varepsilon_{u,h}) \quad (13)$$

To complete the above formulation we must add the constraints that define dependent variables, e.g., equality (5) or the equivalent inequalities (6)-(7), as well as any other constraint that we wish to take into account, such as units' minimum up and down times. In this case, some additional integer variables such as time counters and auxiliary variables need to be added to sort out for nonlinearities. Once the complete MILP problem is stated, it can be solved using any commercial MILP solver available. Note that the dual variables (shadow prices) that appear in parentheses next to constraints (9)-(13) refer to the resulting LP problem when the integer variables are fixed at their optimal values.

3.1 Impact of Reserve Offers

The formulation of the DAS problem gives rise to numerous market design issues and questions concerning the reserves. Does it make sense to price reserves as a separate commodity? Should the producers submit priced offers for reserves or not? What pricing scheme should be used? How do reserve bids influence the generation unit scheduling? What rules should apply for these bids (price caps, rules against price reversals, etc.)? How should the reserve offers be included in the objective function? Should all reserves be treated in the same way? These and other questions arise from the various market designs applied all over the world, but answering them is not straightforward.

In this paper, we will assume that producers submit offers for reserves and examine some of the most often implemented pricing schemes for reserves. In the following, we list the pricing schemes, which we will examine in section 4:

1. Scheme based on shadow price:
   a. Non-priced reserves bids (sorting rule based on energy bids)
   b. Priced reserves bids included in the objective function
2. Scheme based on the highest bid accepted:
   a. Reserves bids not included in the objective function (sorting rule based on reserve bids)
   b. Reserves bids included in the objective function
3. Pay-as-bid scheme:
   a. Reserves bids not included in the objective function (sorting rule based on reserves bids)
   b. Reserve bids included in the objective function

The shadow price approach is based on the dual variable of the reserve requirements constraint. The producer may submit priced or non-priced reserves bids. If non-priced bids are submitted, a sorting rule has to be applied to deal with multiple solutions of the DAS problem, i.e., to allocate the reserve; such a rule could be based on the energy bids. In case of priced reserves bids, which are included as a cost in the objective function, under marginal pricing theory (Sshweppe et al., 1988), there exists a strong energy-reserve interaction. Andrianesis et al. (2008) show this interaction in detail and explain its origin by addressing the coupling effect between energy and reserve.

The highest bid accepted scheme compensates all units with a uniform price that is set at the highest reserve bid that is included in the DAS. The reserves bids may or may not be included in the objective function.

The pay-as-bid scheme sets different reserve prices for producers, with every unit being paid their bid if chosen to provide the corresponding service. As in the previous cases, the reserves bids may or may not be included in the objective function.

3.2 Impact of Fixed Costs

Fixed costs introduce non-convexities in the problem. O' Neill et al. (2005) address this issue and show the non existence of equilibrium prices in a Walrasian auction. Their analysis was motivated by electricity markets, and the non-convexities that appear there are due to the generation units' characteristics. Their basic contribution is that they value the activities that are associated with the integer variables through shadow prices in such a way that the market is cleared. In a parallel work, Hogan and Ring (2003) present a minimum uplift pricing approach that focuses on non-convexities, taking into account the technical minimum and maximum constraints and the start-up costs. Bjørndal and Jörnsten (2004) address the same issue, proposing a methodology based on the generation of a separating valid inequality that supports the optimal resource allocation.

In the DAS problem, the introduction of a fixed cost component in the objective function can be interpreted as a means for preventing frequent start-ups and shut-downs, rather than as an incentive for the units to bid their true costs, as is the usual case. Thus, the units have to incorporate somehow the minimum load and start-up and shut-down costs in their energy offers, because there is no bid or cost recovery mechanism. This in turn means that the SMP will reflect these costs, distorting the energy price. In a recent amendment in Greece's Grid and Market Operations Code in May 2008, a cost recovery clause was added for the transitory period, allowing for marginal cost but not full cost recovery.

At this point, we should clarify what we mean by the term "minimum-load cost." As is implied by its name, it is a €/hour value reflecting the cost of a unit operating at its technical minimum. A similar cost component is the no-load cost, which is used in some markets to represent the hourly cost of a unit that is online but does not produce. It is believed by some market designers that such a cost component should be addressed directly, so that the units will not have to incorporate it in their stepwise energy offers. However, nowadays, in most markets, the usual practice is to apply the minimum-load cost but not the no-load cost. In any case, either approach results in an hourly cost that should be included in the DAS provided that the unit is online.

In the example that follows, we will also examine the impact of including or excluding the fixed costs from the biddings and the DAS problem.

4. Illustrative Example

In this section, we present some results from solving the DAS problem described above on an illustrative case. The input data to the DAS problem are listed in Tables 2 and 3. The demand data are shown in Figure 2. Quantities are given in MW and prices for energy and reserve bids in €/MWh. The bids are considered to be the same for all 24 hours. Minimum up and down times are given in hours and start-up, shut-down and minimum-load costs are in €. The reserve requirement is set at 600 MW for all 24 hours.

Table 2. Units' energy and reserve offers

Unit	Q_u^{max}	Q_u^{min}	$P_{u,h}^{g}$	R_u^{bid}	$P_{u,h}^{r}$
u1	4000	2500	35	300	10
u2	450	250	80	50	5
u3	476	144	72	150	4
u4	300	150	110	80	4.5
u5	550	155	75	150	6
u6	389	240	70	149	3.5
u7	389	240	85	149	3
u8	141	0	150	141	2

Table 3. Units' data

Unit	$MU_u = MD_u$	$SUC_u = SDC_u$	MLC_u	$ST_{u,0}$
u1	24	1000000	-	1
u2	8	40000	800	0
u3	8	16000	550	1
u4	16	30000	1000	0
u5	5	24000	700	1
u6	3	14000	500	1
u7	3	14000	600	0
u8	0	5000	200	0

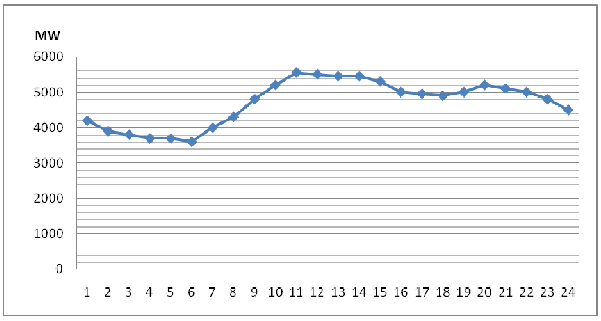

Figure 2. Demand data (load curve)

Unit u1 is an aggregate representation of all lignite units available for producing. This unit corresponds to about 80% of the installed lignite units, assuming that the rest 20% is not available due to scheduled maintenance or outages. Unit u2 is an aggregate representation of the available oil units. Units u3-u7 represent existing gas units, and unit u8 is a gas turbine that can provide all its capacity for reserve. Hydro plants are subject to different rules and scheduling and are therefore not included in this example. The demand has been adjusted to take into account the hydros' contribution as well as renewables, imports and exports.

As we consider only one block for energy offers, parameter MLC_u is treated as an additive hourly cost. Had we considered stepwise offers, it would be more appropriate to include the cost for providing energy at the minimum output in the minimum-load cost component; energy offers would then start from the technical minimum to avoid double counting.

We used the mathematical programming language AMPL (Fourer et al. 1993) to model the DAS problem, and the ILOG CPLEX 9.0 optimization software package to solve it.

The results for the hourly SMP and Reserve Price (RP) under the different pricing schemes defined in section 3.1 are shown in Figure 3.

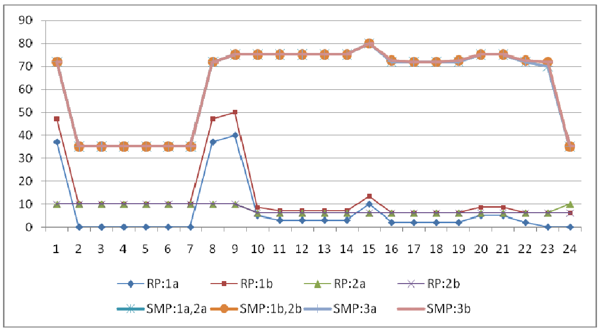

Figure 3. SMPs and RPs for different pricing schemes

The SMP does not exhibit significantly different behavior under the different cases and generally follows the load. The RP, as is expected, is much more sensitive to the pricing scheme. High RP spikes are observed under the shadow price approach (1a and 1b), which are due to reserve shortages. The highest bid accepted schemes (2a and 2b) have a less volatile behavior. Reserve prices in pay-as-bid schemes cannot be shown in the same figure, as they are not uniform for all units.

Assuming that the units are paid the SMP for energy, RP for reserve and their fixed costs, their net profits for the various pricing schemes are presented in Table 4.

The same results are shown in Table 5, but in €/MWh, i.e., each unit's net profits are divided by the daily production of the unit, as this is scheduled by the DAS solution. This representation can be more indicative of the units' net profits allowing for comparisons to be made among units. An interesting direction for further research would be to take into account these values and try to reform the bids so as to eliminate losses. However, this is beyond the scope of this paper.

Table 4. Units' net profits in €

Unit	Case 1a	Case 1b	Case 2a	Case 2b	Case 3a	Case 3b
u1	2636000	2662820	2647990	2650650	2636660	2650650
u2	-30150	-26175	-28300	-27125	-28750	-27875
u3	-3002	19935	-32	145	-12912	-12135
u4	-	-	-	-	-	-
u5	-21280	905	-19210	-19045	-24244	-24446
u6	20155	28475	20074	20880	15340	16431
u7	-7812	-5428	-6024	-6024	-7812	-7812
u8	22701	44133	15910	25380	6768	6768

Table 5. Units' net profits in €/MWh

Unit	Case 1a	Case 1b	Case 2a	Case 2b	Case 3a	Case 3b
u1	28.562	28.853	28.692	28.721	28.570	28.721
u2	-7.947	-6.899	-7.459	-7.149	-7.578	-7.347
u3	-0.486	3.163	-0.005	0.023	-2.090	-1.925
u4	-	-	-	-	-	-
u5	-4.369	0.186	-3.944	-3.910	-4.977	-5.019
u6	4.193	6.080	4.176	4.459	3.191	3.509
u7	-8.138	-5.654	-6.275	-6.275	-8.138	-8.138
u8	N/A[1]	N/A	N/A	N/A	N/A	N/A

The results in Tables 4 and 5 show that the generation units may incur losses by participating in the DAS, unless a compensation mechanism is applied. Although we assumed that they are compensated for their fixed costs, the fact that units may produce at their minimum output for some hours, means that they cannot directly influence the SMP at those hours. Thus, the SMP at which they are paid for energy is less than their bid and in some cases substantially less than their variable cost. For instance, at hours when the lignite units are the marginal units and set the SMP, the gas units are extra-marginal and produce energy at a cost far exceeding the price that they will get paid for energy.

A possible compensation scheme could be, e.g., to remunerate these units on a variable cost basis for those hours. Such a scheme, combined with full fixed cost compensation would eliminate losses for units. Another scheme, which is commonly implemented in practice as part of bid/cost recovery mechanisms, is the comparison on a daily (24-hour) basis of the market revenue versus the relevant bid/cost of the unit. If the second value is greater, then the unit is compensated for the difference. Both of these compensation mechanisms are incentive compatible, as they give the proper incentives to the units to bid their true costs. Opportunities for making profit through their participation in the DAS would then appear at hours when units are infra-marginal, i.e., their offers are below the SMP. The reserve payments could also be used as a mean for units to cover their losses.

[1] N/A: Not applicable. Unit u8 is included in the DAS only for reserve.

To get an idea of the magnitude of energy and reserve payments under the cases that have been discussed earlier, we provide the relative data in Table 6.

Table 6. Overall payments

Case	Overall Energy Payments	Overall Reserve Payments	Overall Fixed Costs SUC	SDC	MLC
1a	7281950	96600	73000	28000	57200
1b	7299050	187800	(as 1a)	(as 1a)	(as 1a)
2a	(as 1a)	110400	(as 1a)	(as 1a)	(as 1a)
2b	(as 1b)	108000	(as 1a)	(as 1a)	(as 1a)
3a	(as 1a)	65032	(as 1a)	(as 1a)	(as 1a)
3b	(as 1b)	64722	(as 1a)	(as 1a)	(as 1a)

We also listed the overall fixed costs by type, which are the same for all cases, as, in our example, the unit commitment does not change under the different pricing schemes for reserves. However, this may not always be the case. In fact, when we examine the impact of the fixed costs, we see that the unit commitment may change. To show the impact of including or excluding fixed costs in the objective function, we list the statuses of the units for all the above mentioned pricing schemes in Table 7.

Table 7. Unit commitment

Unit	Fixed costs included	Fixed costs excluded	
	Cases 1a,1b,2a,2b,3a,3c	Cases 1a,1b,2a,2b,3b	Case 3a
u1	1-24	1-24	1-24
u2	10-24	10-22	10-24
u3	1-24	1-24	1-24
u4	-	-	-
u5	1-24	1-24	1-24
u6	9-24	9-24	9-24
u7	11-14	11-14	11-14
u8	1-24	1-24	1-24

We observe a change for unit u2, which in most cases shuts down at hour 22, when the fixed costs are excluded from the objective function.

We have to note that the input to the DAS was the same regardless of whether the fixed costs were included in the objective function or not. However, this assumption is not very realistic, because, if the fixed costs are not included in the DAS, the units will not get paid for them. This would mean that they would have to internalize these costs in their offers, which in turn would cause a deviation of the SMP from the marginal cost for energy.

5. Conclusions

In the previous sections we presented a sketch of Greece's electricity system and formulated a simplified model of the DAS problem. The emphasis of our analysis was placed on frequency-related ancillary services and fixed costs, namely start-up, shut-down and minimum-load cost. We stated various cases concerning the format of the objective function as well as the reserve pricing schemes. Shadow price, highest bid accepted and pay-as-bid approaches were discussed for reserve, and the impact on unit commitment was shown when the fixed costs were either included or excluded from the objective function. An 8-unit example was used to illustrate the results under the various cases and provide the magnitude order for payments and clearing prices.

It was shown that if units submit truthful bids and are compensated with SMP for energy and RP for reserve, and even if they are remunerated for all their fixed costs, they may incur losses. Unless we want the units to bid over their true costs, as a response to such a market design, a compensation mechanism is needed to deal with this fact. The reserve payments can also contribute to the same direction, as we can assume that no direct costs are associated with their provision. However, although opportunity costs from holding capacity for reserve have not been addressed in our analysis, such costs do exist and must be taken into account. These issues combined with the strong interaction between the energy and reserve commodities, and the non-convexities that fixed costs introduce, make the DAS a very difficult and complicated problem. Careful and mostly incentive-compatible design is needed, in order to provide the right economic signs in the electricity market.

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Appendix

Notation

u	Generation unit
h	Time period (hour: 1..24)
$\mathbf{x}_{u,h}$	Vector of commodities for unit u, hour h
$\mathbf{z}_{u,h}$	Vector of integer variables for unit u, hour h
$\mathbf{c}_{u,h}$	Vector of cost coefficients of commodities for unit u, hour h
$\mathbf{d}_u$	Vector of fixed costs for unit u
$\mathbf{x}_u^0$	Initial condition for unit u (commodities)
$\mathbf{z}_u^0$	Initial condition for unit u (integer variables)
$\mathbf{A}_1, \mathbf{A}_2$	Matrices of market-clearing constraints

$\mathbf{a}_h$	Vector. Right hand side of market clearing constraints (requirements) for hour h
$\mathbf{B}_{\mathbf{1}u,h}, \mathbf{B}_{\mathbf{2}u,h}$	Matrices of technical constraints for unit u, hour h
$\mathbf{b}_{u,h}$	Vector. Right hand side of technical constraints for unit u, hour h
$G_{u,h}$	Total generation (output) for unit u, hour h
$R_{u,h}$	Reserve included in DAS for unit u, hour h
$ST_{u,h}$	Status (condition) for unit u, hour h. Binary variable. 1:On(line), 0:Off(line)
$Y_{u,h}$	Start-up signal for unit u, hour h. Dependent binary variable. 1: Start-up
$V_{u,h}$	Shut-down signal for unit u, hour h. Dependent binary variable. 1: Shut-down
$P_{u,h}^{g}$	Price of energy offer for unit u, hour h
$P_{u,h}^{r}$	Price of reserve offer for unit u, hour h
MLC_u	Minimum-load cost for unit u
SUC_u	Start-up cost for unit u
SDC_u	Shut-down cost for unit u
D_h	Demand (load) for hour h
R_h^{req}	Reserve requirement for hour h
$Q_u^{\min}$	Technical minimum for unit u
$Q_u^{\max}$	Technical maximum for unit u
R_u^{bid}	Maximum reserve availability for unit u
MU_u	Minimum up time for unit u
MD_u	Minimum down time for unit u