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COMMITMENT TECHNIQUES FOR COMBINED-CYCLE GENERATING UNITS

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ABSTRACT

The purpose of this document is to present the optimization methodologies that are currently suggested to solve the Security Constrained Unit Commitment (SCUC) problem, and the ways of considering combined-cycle units when using those methodologies.

The report summarizes the major techniques used for the SCUC, including Lagrangian Relaxation, Bender Decomposition and Mixed Integer-Linear programming. A summary of operating characteristics of the combined-cycle generating units (CCGU) is presented. A literature review on modeling of CCGUs is included in the report together with a review of the commercial software products that can be used for modeling of these units.

The report contains a numerical example involving two combined-cycle units in a small system composed of five generators. Detailed analysis of a dispatch of such units under various bidding scenarios is provided.

Keywords:
Combined-cycle generating units, unit commitment, security-constrained unit commitment, dispatch optimization methods.

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EXECUTIVE SUMMARY

The basic formulation of the Unit Commitment problem assumes that in each time interval each generating unit may be in one of two states: on or off. Experience with the solution procedures showed that the two-state model, along with the use of constraints, was the most effective approach.

The first part of this report reviews the unit commitment methods currently applied in practice. The emphasis is placed on the Lagrangian relaxation method that found most frequent application in the unit dispatch programs currently used by electric utilities. Other methods are also reviewed; in particular the Mixed Integer-Linear Programming approach is introduced since it shows the greatest potential for addressing the unit commitment problem in the presence of combined cycle units.

Combined Cycle Generating Units (CCGUs), also referred to as Combined Cycle Units (CCUs), have intrinsically different operating modes, even without considering minimum up and down time constraints. These types of units became very popular in the last decade as they present several advantages when compared with other types of generating units, namely high efficiency, fast response, shorter installation time, abundance of gas and environmental friendliness. The purpose of this document is to present the characteristics and constraints of combined-cycle generating units. These are the characteristics and constraints that improvements in modeling or changes in market rules, if any, must address.

A combined-cycle generating station consists of one or more combustion turbines (CT), each with a heat recovery steam generator (HRSG). Steam produced by each HRSG is used to drive a steam turbine (ST). The steam turbine and each combustion turbine have an electrical generator that produces electricity. Typical configurations contain one, two, or three combustion turbines, each with a HRSG and a single steam turbine. The combined-cycle generating station can be operated in one of several states. The station's characteristics differ from one state to another, and the transition from one state to another may have a significant cost. The single-shaft plant is much less common. It has a CT and ST on a single shaft driving a common generator.

After a description of the operating characteristics of the CCGUs, a literature review is offered. This review focuses on the publications that address an issue of modeling the start-up characteristics and transitions between the operating states of a CCGU. These characteristics play an important role in the unit commitment and dispatch and are analyzed in detail in chapter 5 of this report. Figure (i) below shows an example of a transition diagram of a CCGU with one steam turbine and two combustion turbines.

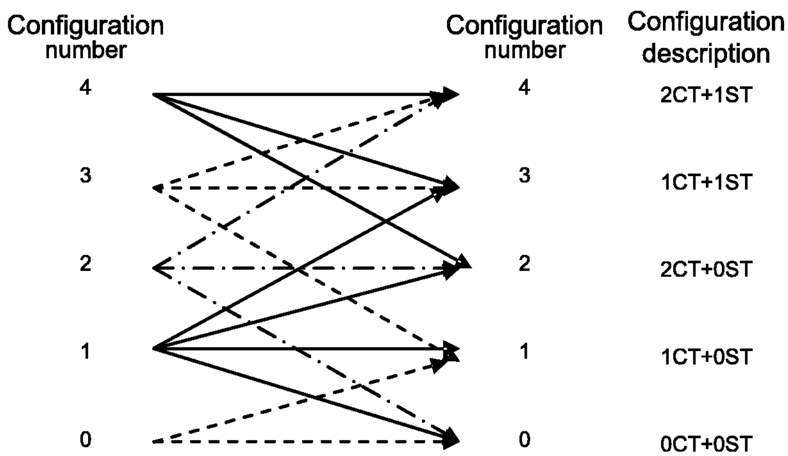

Figure (i) Example of a state space diagram for a combined-cycle unit

Chapter 6 gives an example of the commitment and dispatch of two combined cycle units in a small generating system. Figure (ii) shows an example of a dispatch of a CCGU analyzed in this chapter.

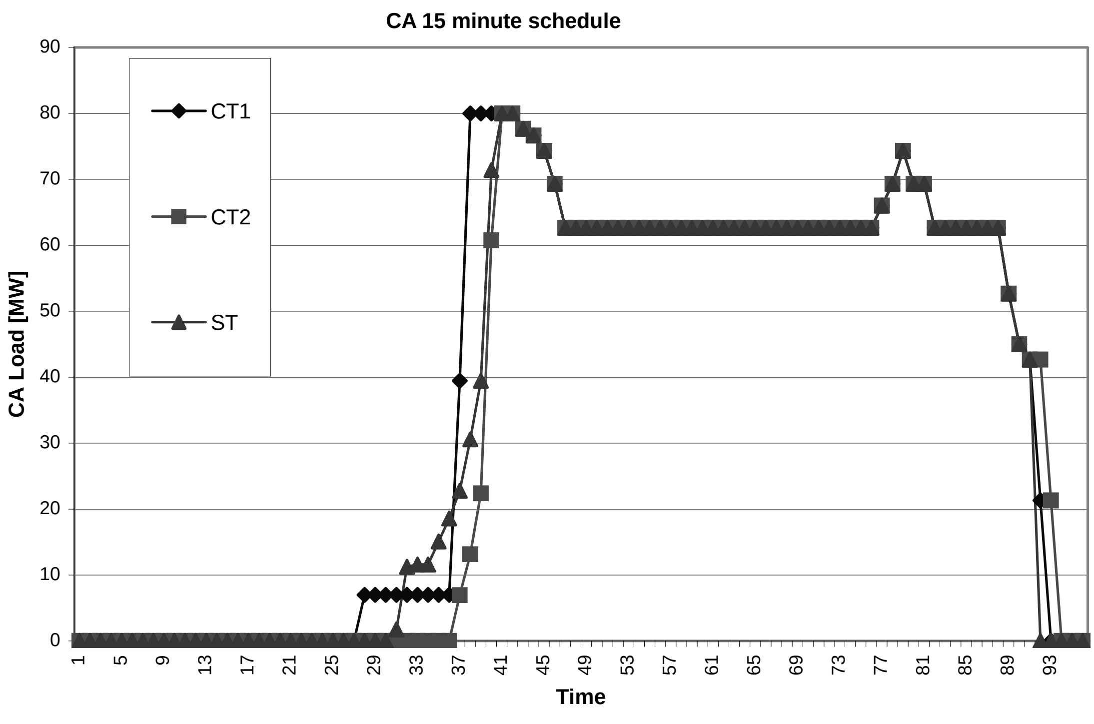

Figure (ii) Load of the CCGT unit in 15-minute intervals

From our experience, it appears that an application of the Mixed Integer Programming (MIP) with some metaheuristics in the case of a convergence problem would be the method best suited for the solution of the unit commitment and dispatch with CCGT units. The report contains a detailed discussion of modeling such units in the context of the present SCUC methodologies implemented in the NYISO. The examples analyzed in Chapter 6 confirm that it is possible to adequately model the CCGT units with the MIP algorithm.

In Appendix A, a brief review of the computer programs available on the market that include modeling of the CCGUs is offered. Appendix B contains a description of the optimization tools currently applied for the unit commitment problem and appendix C gives details of the MIP approach. A real-life example involving a large power system that applies the MIP for the unit commitment is presented in Appendix D.

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1.0 INTRODUCTION

The purpose of this document is to present the optimization methodologies that are currently suggested to solve the Security Constrained Unit Commitment (SCUC) problem, and the ways of considering combined-cycle units when using those methodologies.

The SCUC is a variant of a central problem arising in short-term planning of electric power production: the Unit Commitment Problem (UCP). In its classical form, it is the problem of deciding which electric generators must be committed/decommitted over a planning horizon (lasting from 1 day to 2 weeks, generally split in periods of 1 hour), and the production levels at which they must be operating, so that costs are minimized. The committed units must satisfy the forecasted system load and reserve requirements, subject to a large set of other system and technological constraints. The classical thermal UCP model considers that the power units are centrally managed in a global way, and aims at minimizing the total production cost, over the planning horizon, expressed as the sum of fuel, start-up and shutdown costs.

Being a hard and challenging problem, and due to its economic importance (large operational costs are involved), the problem has long been a matter of concern for electric utility companies, and with the advent of integrated wholesale electricity markets, is also the concern of the Independent System Operators that administer those markets. As a result, an effort has been made to develop faster and more effective optimization tools, and to improve the base model by including information that has become important for the more effective management of power production. These concerns have naturally led to the design of several variants of the classical thermal formulation and models, considering fuel and/or multi-area constraints have been studied. The increasing importance of environmental issues also gave rise to models that include emissions constraints (or objectives aiming at minimizing the emissions).

Another issue of current discussion has to do with the deregulation of the power industry sector. As a result of deregulation, the restructured power companies have additional needs that lead to a new set of modeling requirements and market design challenges. Many electric utilities have sold their fleet of generators or have placed them in an autonomous subsidiary. These power generator companies (GENCO) are concerned with optimizing the use of their generating assets.

Finally, for the quest of a secure management of the power grid, concerns on security and transmission constraints are now reflected in some problem formulations. This particular problem usually referred to as Security Constrained Unit Commitment, will be given particular attention in this document.

Other variants to the base thermal problem handle different types of generating units rather than thermal. Recently, due to its interesting characteristics (high efficiency, fast response, shorter installation time, etc.) combined-cycle units (CCU) have been given special attention. Combined-cycle units typically consist of one or more combustion turbines (CT) with one or more steam turbines (ST). The waste heat from the CTs is used to generate steam to drive the STs. In some cases a quantity of the steam is also used for an external process (cogeneration) or injected into the CTs. The CT can be operated with or without the ST [see (COHEN96)]. Based on different combinations of CTs and STs, a combined-cycle unit can operate at multiple configurations, according to its operating limits.

This document is structured as follows. It starts by introducing the base thermal UCP problem, its most well-known variants and the methodologies that are suggested to solve such problems. Given the increasing impact of deregulation on these models, the section proceeds with a reference to some important issues within deregulated environments. Section 3 is devoted to Security Constrained Unit Commitment methods, and Section 4 discusses possible approaches to solve the SCUC, with CCUs. Finally, we present our perspective on the issues discussed in this document. Sections 5 and 6 contain a detailed discussion of the modeling of the combined-cycle generating units (CCGUs) and a numerical example showing dispatch of CCU thermal units in a sample small system.

A reference to some commercial software solutions for SCUC with CCU, discussing the modeling issues and optimization techniques used can be found in Appendix A. Appendix B refers to the methodologies used to solve the problems introduced in Section 2 and Appendix C describes in more detail Mixed Integer Programming (MIP) algorithm, which we propose as the best solution for the CCGU commitment problem. A practical application of the MIP algorithm to a real-life system is described in Appendix D. Finally, Appendix E provides a short overview of metaheuristic techniques and presents a recent work where metaheuristics were used to solve the Unit Commitment with success, when compared to other techniques.

2.0 BASIC THERMAL PROBLEM

2.1 Problem Features and Solution Approaches

The Unit Commitment Problem (UCP) is the on/off problem of selecting which power generating units are to be in service, and deciding for how long will they remain in that state, for a given planning horizon. The committed units must satisfy the forecasted system load and reserve requirements, at minimum operating cost, subject to a large set of other constraints. Given that operating costs depend on the load assigned to each generator, the problem of committing units is directly connected to the additional problem of (roughly) assigning the load demand to the units that are on (known as the "Pre-Dispatch" problem).

This leads to a two-phase resolution method (Figure 1). First, for each period of time, it must be decided which units will be on/off. Secondly, the problem is decoupled into T subproblems, T being the size of the planning horizon, and for each subproblem (i.e., for each period of time) the production level of each unit that is on is calculated. The definition of the production level of each unit is a non-linear problem, that can be easily solved by using, e.g., the λ-iteration method based on the Kuhn-Tucker conditions (WOOD96). However, the on/off decision problem is a combinatorial, non-linear and non-convex optimization problem (RUDOLF99) that is NP-hard.

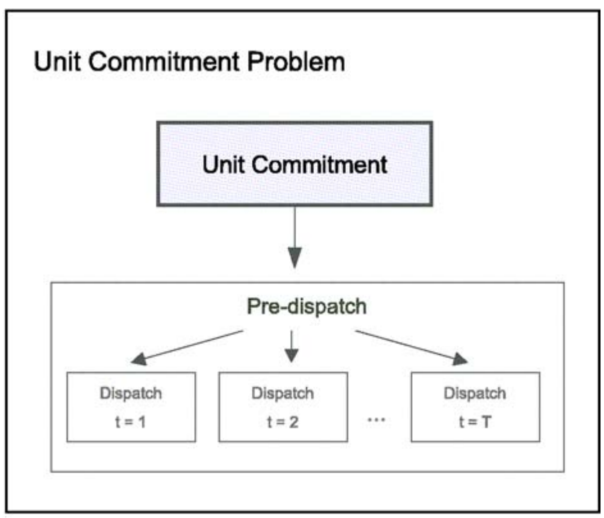


Figure 1 The Unit Commitment Problem

Being a combinatorial true multi-period problem (due to important start-up and shutdown costs) the UCP is in general very hard to solve as it is not possible to perform a separate optimization for each time interval. Except for very small size problems, exact methods such as Dynamic Programming and Branch-and-Bound proved to be inefficient and, in general, unable to find a solution within useful time. Thus, during the last decades, research efforts have concentrated on developing heuristic approaches, capable of efficiently finding satisfactory (not necessarily optimal) solutions for real size problems. Several heuristic approaches based on exact methods have been used, e.g., Branch-and-Bound (COH83), as well as methods based on priority-lists (LEE88) and Lagrangian

Relaxation (BER83; MER83; AOK87) or, more recently, Neural Networks (SAS92; OUY92; HUA97) and metaheuristics [e.g., Genetic Algorithms (DASGUPTA94; KAZARLIS96), GRASP (VIANA03), Simulated Annealing (ZHUANG90; MANTAWY98; WAWONG98) or Tabu Search (MANTAWY98a)]. More recently, a new search strategy [Constraint Oriented Neighborhoods – CON (VIANA05)] has been applied with success. The results obtained with CON have systematically outperformed those presented in the literature, both in terms of efficiency, quality of the solution and robustness of the algorithm.

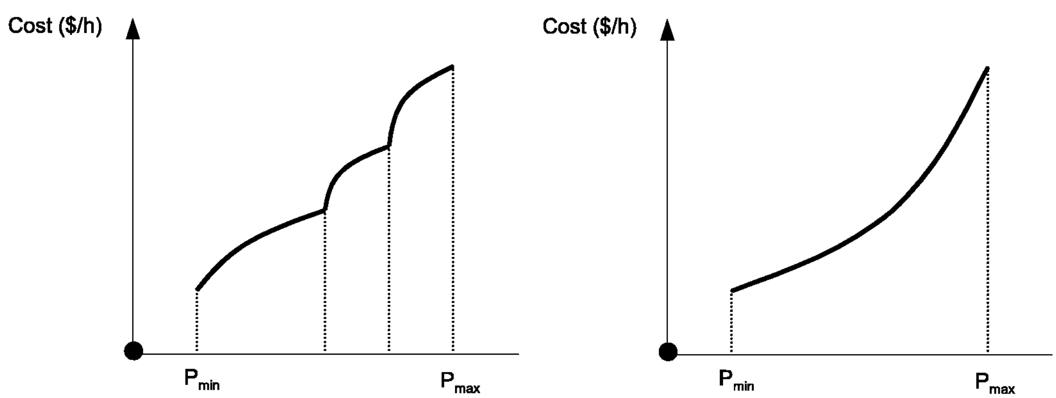
2.1.1 *Objective and Constraints*

Usually, the basic thermal UCP is modeled as a single objective problem that aims at minimizing total operation costs. Other objectives such as reduction of emissions or maximization of feasibility and system security, though less frequent, are also referred to in the literature (SEN98). In this section, unless otherwise stated, the minimization of total operation costs, expressed as the sum of fuel, start-up and shutdown costs, is considered.

2.1.2 *Fuel Costs*

Fuel costs are related to the fuel consumption of each unit and depend on its production level in each period of time, and on the type of unit under study (coal, fuel-oil, nuclear, etc.) Most often, however, the incremental fuel cost is used in the UC.

Although the functions that describe these incremental costs are, in general, non-continuous and non-convex [see Figure 2 a)], as the non-convexity of such functions prevents conventional optimization techniques from being used, approximate polynomial functions, as the one depicted in Figure 2 b), are generally used in practice.



a) Input/Output Function b) Polynomial approximation of Incremental

Figure 2 Incremental fuel cost function

2.1.3 *Start-up Costs*

Every time a unit is off, bringing it back into operation leads to an extra cost due to fuel used during the controlled heating of the unit, wear and tear on the unit and the extra maintenance that this will ultimately cause. Besides, frequent start-ups are undesirable from a social as well as a technical point of view: not only are they stressful to operators, but thermal units also undergo a heating and cooling cycle, coupled with pressurization and decompression of boilers, turbine chambers, etc., that lead to a reduction in the effective life of the generating units. Furthermore, the emission of pollutants like CO2, SOx and NOx is particularly high during the transient period of start-up and shutdown.

Start-up cost functions (S_x) should, in a certain way, reflect these concerns in the decision process. The costs depend on the latest period the unit was operating and, for steam units, they also depend on whether the boiler was kept hot, or not, while off. If it was not kept hot (i.e., if it has gone through a cooling process), start-up costs can be modeled by an exponential function as that in expression (1), where b_0 ($) is the fixed start-up cost and b_1 ($) is the cold start-up cost. τ is the cooling constant and OFF (h) the number of consecutive periods that the unit remained off.

$$S_x = b_1\left(1 - e^{-\frac{OFF}{\tau}}\right) + b_0 \tag{1}$$

As an alternative, several authors do also consider a two-step function, as the one in expression (2).

$$S_x = \begin{cases} S_h & \text{if OFF} \le t^{cold} \\ S_c & \text{otherwise} \end{cases} \tag{2}$$

In expression (2), S_h and S_c are the costs incurred for a hot and a cold start-up, respectively. t^{cold} is a unit parameter that indicates the number of hours that the boiler needs to cool down.

If the boiler temperature and pressure levels are maintained (banking), start-up costs can be represented by a linear function as that depicted in expression (3), where C ($/h) is the cost incurred by fuel consumption, to keep the boiler warm.

$$S_x = b_0 + C \times t \tag{3}$$

A graphical representation of these alternatives is given in Figure 3.

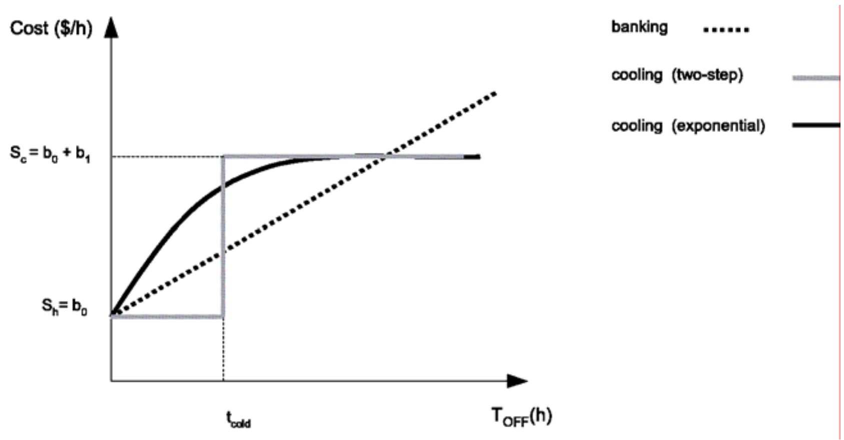


Figure 3 Start-up cost functions

Note that, although the cooling scheme could be a matter of optimization, it is generally predefined.

2.1.4 *Shutdown Costs*

Shutdown costs are typically represented by a constant (ORERO99). In a certain way, they measure the labor cost of decoupling units and are usually much lower than the start-up costs. Often shutdown costs are not considered in the UC problem since they can be lumped in with the start-up costs.

2.1.5 *Constraints*

The following constraints, modeling system and technical aspects of the generating units are considered.

- *System power balance*
  These constraints state that, in each period, the committed units must satisfy the total load demand.

- *Regulation requirements*
  Regulation constraints are aimed at maintaining system frequency and regional energy transfers. Regulation constraints assure that the system has the ability to compensate for the short-term fluctuations in load and power production.

- *Spinning reserve requirements*
  Reserve constraints are related to reliability and quality of service. They aim at supplying surplus power in the event of a contingency (e.g., due to a unit failure), or to compensate for possible differences between forecasted and current load demand. If such an event occurs, a quick system response can only be obtained by using units that are synchronized with the electrical power grid, i.e., that do not need any preliminary operations to be connected to the grid. The *spinning reserve* refers to the power that the generating system should be able to quickly supply and is given by the difference between the total amount of quick generation available in the system, and the current load demand. According to the Union for the Coordination of Transmission of Electricity (UCTE) system deviations must be fully deployed within 15 minutes.

- *Unit minimum up and down times*

  If a unit is off, it must remain off for at least T^{off} periods of time. In the same way, if a unit is on it must remain on for at least T^{on} periods of time. T^{off} and T^{on} are the unit minimum down and up time, respectively.

- *Unit generation limits*

  Thermal units are not technically capable of producing below a minimum production level, nor above a maximum. According to (WOOD96) the minimum production level has to do with fuel combustion stability and steam generator design constraints. This value is typically between 10% and 30% of the maximum production level, for gas or oil firing units, and between 20% and 50% of the maximum production level, for coal firing units. Maximum production levels are bounded by the unit design characteristics.

- *Unit ramp rate limits*

  Thermal units cannot drastically change their production levels in consecutive periods of time. Minimum up (down) rate constraints specify the maximum increase (decrease) that a unit may have in its production level, in consecutive periods of time.

2.2 Variants to the Base Problem

The base thermal UCP is based on minimization of the total system costs, subject to system and generating units' constraints, but other models including more information can be found in the literature. This section introduces some of those models (that tackle emissions, fuel and multi-area constraints), providing references to different modeling alternatives for each of the three variants. Given the importance of SCUC to this work, it will be introduced in a separate section.

2.2.1 Emission Constrained Unit Commitment

Among the few papers on the subject, there are two distinct lines of research to handle environmental concerns: one where emissions are explicitly stated and modeled as constraints (GJE96; MAN01; WAN95), and another where they are somehow included in the objective function (SRI97; KUL92).

In the first line of research we highlight the model presented in (GJE96) that seems particularly accurate. As fossil fired power plants pollute the air differently during normal, start-up and shutdown operations, this model evaluates emissions with different functions, depending on whether the units are in steady-state operation or in transition states. Except for the case of NOx, the functions that measure emissions are, in general, similar to those related to operating costs. SO_2 and CO_2 emissions are directly related to the fuel consumed and can be represented as a function of the unit fuel input/output equation and an emission factor. Start-up emissions depend on the latest period that a unit was operating and may be represented by a two-step or an exponential function similar to (2) or (1). Shutdown emissions are generally represented by a constant. Finally, NOx emissions are combustion-process dependent and, in general, cannot be described using the unit fuel input/output equation. However, they can be expressed as a function of the power output similar to the input/output curve.

Emission constraints may limit a single unit, a group of units or the entire system. The emission limits may be given for a single period of time or for a number of intervals.

In a parallel line of research, (KUL92) and (SRI97) model emissions as an objective (or part of an objective) to be minimized.

The work by (KUL92) considers two objective functions: the traditional total operating cost function, and the total emissions of the system. However, the two functions are aggregated into a single one and the problem is tackled accordingly. A constraint concerning emission limits is also included in this model.

In (SRI97), the aim is also to minimize total operating costs and emissions, and the problem is solved as a truly multi-objective problem without aggregating the two objectives. SO_2 emissions are measured as a function of a unit fuel input/output equation, as in (GJE96), regarding also the transition effects. CO_2, NOx and particulate emissions are evaluated by other second order functions that are not strictly related to the input/output equation.

2.2.2 *Fuel Constrained Unit Commitment*

In a generating company where thermal production is dominant, fuel costs are an important slice in the total operating costs and, therefore, a correct management of fuel becomes a major point of concern in daily operation planning. Fuel management may be constrained by several factors, e.g., fuel contracts, that usually specify a minimum/maximum consumption requirement for a given time duration, congestion in the fuel delivery system, limited storage facilities, etc., and naturally influences the production decisions involved in the UCP (e.g., the decision of keeping a unit on over the entire planning horizon may not be possible in case there is not enough fuel available). The inclusion of fuel management in short-term production planning is addressed by the Fuel Constrained Unit Commitment Problem.

In its general form, the problem is rather complex. However, several authors consider some assumptions that drastically reduce the level of complexity (LEE91). These are: 1) each thermal unit can be supplied by only one type of fuel, and/or 2) each thermal unit can burn up to two types of fuel, one constrained and the other unconstrained. In such cases, there is no correlation of fuels and the fuel coordination problem no longer exists. In (AOK87), (AOK89), (LEE89) and (TON90) the simplification assumptions prevail when defining the mathematical model.

LEE89 in (LEE89) addresses a model developed for Oklahoma Gas & Electric Co. (OG&E) that considers constraints on gas consumption and gas delivery. Gas is traded by take-or-pay contracts where a minimum trading quantity (of fuel or other resource) is defined for each period. In this type of contract, if the consumption of that resource does not reach the minimum quantity, the defined amount still has to be paid. Therefore, some constraints define a minimum level of gas consumption among all gas-fired units, for each period. A target for gas consumption over the entire Unit Commitment horizon is also defined. Constraints on gas delivery include minimum hourly gas take, to prevent the build-up of pipeline pressure (which can cause the shutdown of gas wells), maximum hourly gas deliverability and maximum daily gas take turn-up ratio, reflecting the dynamic characteristics of the gas delivery system.

Take-or-pay contracts are also considered in (WON96), but they are modeled in a different way from that which is proposed in (LEE89). They are included in the objective function, by making a distinction between non-fuel constrained and fuel constrained units.

In (AOK87) and (AOK89), the evaluation of fuel consumption differs, depending on whether the generator is in steady-state operation or starting-up.

In contrast with the previous models, some authors studied the problem where multiple types of fuel can supply the same unit. In (COH87) and in (LEE91), each contract for fuel supply has a lower and upper limit, the total fuel consumption over the planning horizon being expressed as a function of generation levels that cannot go above or below those limits. In (VEM92), minimum and maximum limits on contracts are also specified, and there are no restrictions on the number of constrained fuels for each unit. Moreover, the model considers that a contract can supply several units and a unit can be supplied by several contracts. The model differs from the previous one because minimum and maximum limits on contracts are defined on an hourly, daily and planning horizon basis.

As will be seen when CCU are introduced, the fuel constrained UC problem is somewhat similar to the commitment of CCU as, for the former, multiple generating modes are also considered, according to the type of fuel that is selected.

2.2.3 *Multi-Area Unit Commitment*

The objective of a multi-area UCP is to determine the optimal (or near optimal) commitment strategy for units located in distinct areas, connected through tie-lines. A main specific feature of this UCP variant is that the import and export of power from/to each area is allowed and, as a consequence, the local generation (i.e., the generation within a single area) is not necessarily balanced with the local demand. Still, the total system generation must be equal to the total load demand.

This is probably the variant of the UC problem that introduces more changes in the base model.

2.2.4 *"Hybrid" Models*

Naturally, there is not a strict border between the sets of problems just described and it is possible to find research work where two, or more, of those subjects are considered in a single formulation.

In (BAI97), for example, the authors introduce a UCP with fuel and emission constraints. (AGT98) present a hydrothermal problem with environment concerns, where fly ash emission of NOx and SO_2 are constrained to an upper value. The model presented in (KUL92) tackles the thermal UCP, considering emission, fuel and multi-area constraints, its emission concerns having been described in Section 2.2.1. Fuel consumption is limited to a minimum and maximum value and multi-area constraints limit inter-area power exchange and influence each area's spinning reserve requirements.

2.3 From Regulated to Deregulated Markets

The new conjecture related to deregulated markets leads to the emergence of new optimization requirements and several models have been built trying to capture the new reality of competitive markets. As the performance of each company may be highly affected by the decisions of other market participants, these models are inevitably associated to more or less elaborate strategic studies. Furthermore, they are naturally dependent on the market structure that may vary. Some aspects to consider are:

- *The number and type of products traded*
  In a market environment one must provide consumers with other services, and not only with the energy required, usually related to reliability and quality of service. Those services, ancillary services [or supportive services, according to (SHEBLE99)] may be traded within the same or different pools.

- *The bidding process*
  At the beginning, energy markets only allowed supply-side bidding for energy and certain ancillary services, but later demand-side bidding was also allowed in some markets. The structure of the bids may vary in the number of cost components and in the technical parameters that are provided. When including several price components (e.g., start-up costs, minimum-load and energy bid prices), they are called multi-part bids. A bid with a single price component is a single-part bid. Still, in both cases, it may include several energy price segments depending on the amount of energy.

- *The scheduling process*
  When the market is based on single-part bids, a simple clearing process based on the intersection of supply and demand bid curves may be sufficient to determine the winning bids and production schedules for each hour. However, if it is based on multi-part bids, unit commitment software may be needed.

- *Market clearing and settlement systems*
  These are the procedures that determine the quantities to be both produced and consumed, who pays, and who gets paid. When multiple markets are considered (e.g., energy, ancillary services and transmission products), two basic ways are provided to clear each market – sequential or simultaneous. In general, sequential auction markets clear each product separately in a sequence, even though several of the products may represent alternative uses of the same generator. In contrast, a simultaneous auction clears the relevant markets at the same time, minimizing the joint bid cost of providing energy and ancillary services.

2.3.1 New UC Models

Several new UC models have been studied lately to respond to the new challenges that competitive markets are creating. These models are inherently connected to other strategic studies, related to the bidding process and, depending on the characteristics of the energy market, can vary in form, according to the type of auction mechanism that is implemented, the kind of energy transactions that are allowed, etc. The independent operator of an integrated electricity market is still concerned with minimizing overall (as-bid) production cost, though technically, when demand-side bidding is permitted, the objective of the UC is more correctly described as maximizing the social welfare. The objective of the GENCO is no longer to minimize operating costs but rather to maximize the company's profit. Even so, they do in general share some common computational issues.

In this section, we address some of the issues that have received particular attention when developing/adapting UC models to deregulated markets. They are: the concern on integrating bidding and scheduling, consumer payment minimization and the inclusion of bilateral contracts.

2.3.2 *Integrating Bidding and Scheduling*

Although the price of electricity in regulated markets is pre-determined and fixed, when it comes to deregulated environments, it is no longer pre-determined and is set by the bids of each participant. As making a bid implies defining an operation schedule for generating units, integrated bidding and scheduling models have been developed, to provide the Decision Maker with a supporting tool that tries to anticipate market clearing price (MCP) values. They may consider the influence of the bids of other GENCO on the company's performance, by simulating some of their possible behaviors or, alternatively, and supposing that one knows in advance the competitors' bids, simulating the results that one may obtain by making a specific bid.

Guan et al. in (GUA01) present a model of integrated bidding and scheduling within a perfect market (i.e., when the MCP is not affected by any single bid). The aim is to select bid curves for individual units, maximizing the profit and reducing the risk. Due to minimum up and down time constraints, the bid curves (and, consequently, the MCP) are constrained.

In (LI99) the bidding strategy aims at determining the optimal bid curve for the generation supplier, so that maximum return is reached satisfying some given goals for revenue adequacy. These constraints are necessary, since the maximum return criterion does not imply that revenue adequacy is guaranteed for every supplier. After some bid price scenarios are built, one has to determine the suppliers' bid curve for each scenario through a centralized UC, finding a "reliable" MCP. The bid curve that maximizes the objective is the one selected.

Integrated bidding and scheduling is also studied by (HAO00), (NI04), (BORG03) and (BAI01).

Hao in (HAO00) studied the bidding strategies in a clearing price auction and drew the conclusion that, for this type of auction, the market participants have incentives to mark up their bids above their production cost, the amount of mark up depending on the probability of winning the bid.

Ni et al. in (NI04) present a unified optimization algorithm for the bidding strategy problem given a mix of hydro, thermal and pumped storage units. Their algorithm manages bidding risk and self-scheduling requirements.

Borghetti in (BORG03) investigates how traditional cost-based unit commitment tools, already available to generating companies, can be used in the competitive electricity market to assist bidding strategy decisions in a day-ahead electricity pool market.

In (BAI01) the set of constraints representing the generation facilities in a traditional UC are replaced by a set of hourly constraints, which define the firm's hourly revenue as a function of its energy output. In their example, the authors include a set of hourly minimum market share constraints to obtain a generation schedule similar to the traditional one. If no strategic constraints were used, the model would blindly follow all the short-term opportunities and the resulting operation would lead to an extremely inefficient dynamic performance of the generating units.

Other work on bidding and scheduling is that by (RIC98) and (RIC99).

2.3.3 *Demand-Side Bidding (DSB)*

In some markets, the consumers do not directly influence the market price definition as they are not allowed to submit bids (GRO00). There are, however, other markets where in order to play a proactive rule in the price determination process, consumers are allowed to submit bids not only for load requirements but also for load reduction in specific periods. Large industrial consumers, for example, may directly offer to the pool their ability to reduce load and receive a payment for that reduction.

As a natural evolution of the work presented in (GRO00), a model that considers explicit DSB with load reduction is presented in (BORG01). The supply-side must still specify the technical characteristics of each bidding unit (e.g., minimum and maximum output, minimum up and down time, etc.), the bid price and offered capacity, while the demand-side must specify the subset of the load reduction periods settled by the operator (the subset of the periods in which a bidder may undertake load reduction); the minimum and maximum demand that can be reduced by a bid, the subset of the load recovery periods settled by the operator (the subset in which a bidder may undertake a load recovery), and load recovery within a period, that is related to all the load reductions in each reduction period.

2.3.4 *Consumer Payment Minimization*

The solution that minimizes a generator's cost (the sum of the products of the hourly load demand and the hourly MCP, over the entire scheduling period) may not result in minimum cost to consumers. This is discussed in (JAC97) which shows that under uniform pricing rules, minimizing generation costs and consumer payments is different.

Hao et al. in (HAO98) present an approach for calculating optimal generation schedules that minimize energy payments by power pool consumers, within the framework of centralized optimization. The model assumes the use of a uniform pricing rule, i.e., all participants are paid the same, and considers an additional constraint, here referred to as a payment adequacy constraint, to ensure that all units winning in the auction will recover their start-up, no load and energy production costs, as implied by their bids.

Ren and Galiana in (REN02) discuss pricing methods with the objective of scheduling generators in such a way that the costumers obtain the lowest price for electricity, while the GENCO do at least cover their offered costs.

Consumer payment minimization will result in reduced social welfare, when compared to the social welfare maximization adopted by the majority of electricity markets around the world.

2.3.5 *Bilateral Contracts*

Within the pool-bilateral model followed by some markets of energy, two types of power generation and demand are considered during the commitment process: one related to bilateral transactions and another for trading in the pool. Bilateral transactions in the integrated energy markets such as ISO NE, NYISO and PJM are purely financial and do not influence the UCP. However, the integrated market model still allows generators to self-schedule, a process that does affect the UCP.

In analyzing the pool-bilateral model, Valenzuela and Mazumdar in (VAL01) consider bilateral contracts and transactions in the power pool and assume that the GENCO is a price-taker (i.e., if at a particular hour the power supplier decides to switch on one unit, it will be willing to take the price due at that hour).

2.4 New Trends

Several improvements may still be done in optimization techniques and problem modeling to reach more effective results in the everyday planning of energy production.

Problem modeling is a central point of current research, with the new paradigms and challenges introduced by the market restructuring process. In what concerns optimization techniques, an area for further research is on developing techniques that are capable of correctly tackling all the non-linearities that this problem presents and also on developing techniques capable of correctly handling more than one objective, for the same problem. We will highlight here three topics that, in our opinion, are extremely important and deserve further attention and research: strategy and multi-objective modeling, and optimization tools.

2.4.1 *Strategy and Multi-Objective Modeling*

The power industry restructuring is an ever evolving process, far too complex and involving many strategic agents. As the behavior and decisions of each of these market participants are uncontrollable and may strongly affect the performance of any single agent, such an agent may therefore need to develop its own strategies to reduce the impact of the other market participants on its own performance. Some of the models described in Section 2.3.1 do already reflect concerns on studying alternatives, given the predicted behavior of competitors. Even so, they should evolve to a higher stage, where both tactical and strategic decisions are also made and should probably be interconnected with elaborated strategy methodologies (e.g., Game Theory).

Concerning the number of objectives, except for one or two situations, the UCP has until now been modeled as a single objective problem. Although that may have been acceptable in the past, and represented the real problem in a satisfactory way, nowadays several other objectives are also important for ISO or a GENCO and should, therefore, be considered when making the operational production decisions. Several examples of multiobjective problems may be given. Within energy markets, for example, sellers and buyers are competitive participants with contradictory objectives – sellers seeking for the maximization of their profit, and buyers trying to buy electricity at the lowest possible cost. Another example is those markets where different commodities are traded in different auctions, each auction having its own objectives and operation rules that may interact with those of other auctions. The same reasoning applies if the influence of intra-day markets is considered in the evaluation of the overall performance of a company. One may find it strategically advisable to reduce the offers (and consequently the income) in the daily market, to be able to bid in intra-day markets at a more advantageous price. The applications are therefore vast and the subject deserves further attention.

2.4.2 Optimization Tools

A major problem of the conventional optimization tools provided by commercial software packages is that they require that the highly non-linear and non-convex information related to the hydro and thermal plants is represented by piecewise linear or polynomial approximations of monotonically increasing nature. However, such an approximation may lead to a suboptimal solution, resulting in a considerable inefficiency (increased production cost) over time. Thus the solution for such a problem demands more robust and versatile techniques.

Metaheuristics may prove to be an interesting choice as they do not place any restrictions on the shape of the cost curves and on other problem nonlinearities.

Furthermore, some attention should also be given to the development of techniques capable of "optimizing" more than one objective simultaneously. Given the potential that multiobjective metaheuristics have already proven to have at solving some combinatorial optimization problems, they should also be considered as a topic for further research.

3.0 THE SECURITY CONSTRAINED UNIT COMMITMENT PROBLEM

Except for the multi-area case, the problems referred to in the previous section do not reflect any concerns on security and transmission constraints. However, this is a critical issue for generation companies as the non-consideration of such constraints may lead to an overload of transmission lines. This may result in rescheduling some generators and may incur significant costs.

The Security Constrained Unit Commitment Problem (SCUC), an extension of the model presented in Section 2, reflects those concerns. The following section briefly describes the constraints that may be considered in this new model.

3.1 Description of Additional Constraints

Besides the prevailing constraints (such as load balance, system spinning reserve, ramp rate limits, and minimum up and down time limits) considered by traditional unit commitment formulations, SCUC incorporates network flow constraints in the unit commitment formulation. This has been done in several alternative ways, as follows.

Transmission constraints are represented in (SHA95) and (TSENG99) as linear constraints based on a DC power flow model. These constraints force generation to be distributed throughout the system, preventing transmission lines from being overloaded. They are modeled as a DC model, as follows:

$$-\overline{F}_l \le F_{lt} \le \overline{F}_l \tag{4}$$

Where

$$F_{lt} = \sum_{i=1}^{I} \Gamma_{li} P_{it} - \sum_{k=1}^{K} \Gamma_{lk} D_{kt} \tag{5}$$

F_{lt} represents the power flow in line l, in period t. $\overline{F}_l$ is the power flow limit of transmission line l, Γ_{li} is a sensitivity matrix relating generator's i output to power flow in transmission line l, and D_{kt} is the forecasted demand in node k, in period t.

The work by (LU2005) presents a model that sets upper and lower limits of voltage in each bus.

Upper and lower limits in tap changing and in phase shifting transformers' settings, as well as transmission flow and bus voltage constraints, are considered in (FU2005).

Using again the DC power flow model, the formulation in (XIA00) considers constraints on active power balance, voltage and power transmission line capacity.

Finally, the work by (COHEN99) considers branch-flow constraints, to insure that for selected lines and interfaces thermal limits are satisfied (for steady-state operating conditions), for the forecasted network configuration and for the configuration with a specified set of network and generator outages; and import and export constraints limiting the generation from specified generators and loads.

3.2 SCUC Within Market Environments: The Security Constrained Price-Based Unit Commitment

Within market environments new issues arise and several questions must be asked prior to the model definition. For example, are ancillary services optimized separately from energy services, or are the two services optimized jointly? GENCO may ask whether the objective of the optimization should be the minimization of production cost, or will one prefer to maximize a GENCO's bidding strategy, maximizing the profit, without a strict necessity of satisfying load demand? What type of market structure do we have?

In some of the deregulated markets (e.g., NYISO, ISO-NE, and PJM), the ISO commits generating units in much the same way as system operators did in the vertically integrated structure. The ISO uses bid-in costs submitted by GENCOs for each generating unit (multi-part bids that reflect start-up costs, minimum generation costs, running costs, etc.) to maximize the social welfare, determine which units will be committed and calculate the corresponding market clearing prices (MCPs) while the system security is retained. The ISO also obtains information from Transmission Companies (TRANSCO) on transmission line capability and availability.

In other deregulated markets (e.g., Australia), the responsibility for unit commitment is on each individual GENCO that maximizes its own profit. This unit commitment has a different objective than that of the base UC problem and is referred to as Price-Based UC (PBUC). In PBUC, satisfying load is no longer an obligation and the objective is to maximize the profit. Thus, GENCO run their own price-based unit commitment to maximize their individual profit, regardless of the system's overall social welfare. Each energy supplier is responsible for its own decision on what and how to bid on energy to supply load and reserves markets. GENCOs submit single-part bids to the ISO that aggregates them and determines the MCP. The ISO's objective will be maximizing social welfare while maintaining the system security. The GENCO's objective will be to maximize its own profit.

When security constraints are included in the PBUC problem, the new formulation is referred to as Security Constrained Price-Based Unit Commitment (SCPBUC). The objective of SCPBUC is to coordinate GENCO and ISO decisions (YAM02) by scheduling units based on generation bids to maximize GENCO revenue while ensuring the transmission flow security in steady-state and n-1 contingency cases. The model is appropriate for markets where GENCOs are taking the risk of committing their units, while the ISO is responsible for the system security.

Another important issue is transmission congestion. Although transmission constraints could be included explicitly in SCUC, it is impractical to assume transmission network information in PBUC since that information is unavailable to GENCOs. Since transmission congestion would incur price differences among different regions, it is suggested that transmission congestion should be incorporated through LMPs in (SC)PBUC.

An example of an SCPBUC is presented in (YAM04). As opposed to previous formulations, where cost-based models were developed for vertically integrated power systems, this model is price-based for GENCOs in restructured power markets. Therefore, the objective function is to maximize the GENCO's profit (revenue minus production cost), rather than minimizing the ISO's cost of supplying load. Transmission flow limits from bus k to bus m are rewritten in terms of steady state and contingency constraints, as follows:

$$-\overline{P}_{km} \le P_{km}^{t} = \sum_{i=1}^{I} A_{km}^{i}\left(P_{it} + P_{\phi it} - P_{dit}\right) \le \overline{P}_{km} \qquad t = 1,\ldots,T \tag{6}$$

$$-\overline{P}_{km} \le P_{km}^{jt} = \sum_{i=1}^{I} E_{km}^{i}(j)\left(P_{it} + P_{\phi it} - P_{dit}\right) \le \overline{P}_{km} \qquad \text{j=1,...,nc} \quad t = 1,\ldots,T \tag{7}$$

Where *nc* is the number of possible line outages in a contingency, *A* is a sensitivity coefficient matrix of steady state transmission constraints, *E(j)* is a sensitivity coefficient matrix of contingency transmission constraints for line outage *j*, $P_{\phi it}$ is the equivalent power injection from phase shifter, and P_{dit} is the forecasted demand.

3.2.1 The Case of the NYISO SCUC

The NYISO follows a number of interrelated processes until (and after) the SCUC is performed. These processes that consider planning horizons of different length are represented in Figure 4. As this document is focused on day-ahead and real-time commitment, no reference will be made to the other processes.

The objective of the day-ahead SCUC performed by the ISO is to minimize the total bid production cost of meeting all purchasers' bids, provide enough ancillary services, commit enough capacity to meet the load forecast, and meet all bilateral transactions (including imports and exports) submitted to the ISO. The SCUC considers current generating units' operating status, constraints on the minimum up and down time of the generators, generation and start-up bid prices, minimum and maximum generation constraints, generation and reserve requirements, maintenance and de-rating schedules, transmission constraints, phase angle regulator settings, and transaction bids (HIR01). The optimization is set to secure the next 24-hour period.

In terms of methodological approach, the SCUC performs an initial unit commitment to meet the required load at minimum total cost, disregarding security constraints. This schedule is used to produce a set of 24 base-case load flows, one for each hour. For each hourly load flow, the entire set of contingencies to be considered is checked for violations. The constraints derived from this process are then used as constraints in another invocation of the Lagrangian Relaxation-based unit commitment engine to modify the solution to solve for these violations. The process is repeated until no new violations are created, or a user defined maximum iteration count is reached (NYISO05).

SCUC results include hourly schedules for energy and ancillary services as well as hourly locational prices for energy, prices for the reserve services for three zones, and aggregate prices for regulation. The energy prices include the costs of marginal losses and transmission congestion. Generators are paid for their output on the basis of nodal prices, while loads pay for power on the basis of zonal prices.

Generators' inputs to SCUC include up to 11 constant-cost segments of an energy curve, as well as a minimum generation cost ($/hr), start-up bid ($), and start-up and shutdown constraints (the number of times that a unit can be stopped each day). The SCUC results, in terms of scheduled quantities and prices, represent binding financial contracts. Any deviations between schedules and real-time generator outputs or consumer loads are settled in the real-time market.

In real-time, the New York ISO relies on two components, the Real-Time Commitment (RTC) and the Real-Time Dispatch (RTD). RTC should perform a security-constrained unit commitment every 15 minutes, aiming at allowing adjustments to interchange schedules on the basis of expected prices; and at providing start-up and shutdown decisions for combustion turbines that can start within 30 minutes. In this way, the intra-day unit-commitment program supplements the day-ahead scheduling performed by SCUC, which focuses on the larger steam units that require more time to start-up and shutdown.

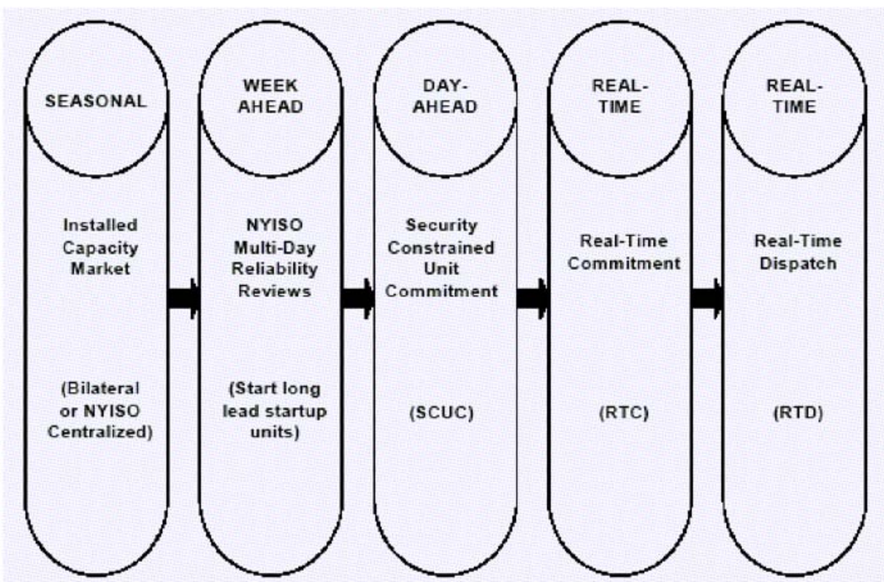


Figure 4 NYISO Market Process [Source: (NYISO05)]

The day-ahead UC is performed twice. The two UCs vary by the amount of load that is represented. The first SCUC execution considers only the load that buyers wish to purchase day ahead. The second SCUC execution uses a forecast of the next day's load and is used to ensure that adequate resources will be available the next day, regardless of the amount of energy transacted in the day-ahead market. The second SCUC execution retains the generators committed during the first SCUC execution. It then commits the units that are necessary to meet the additional load. Those generators are dispatched to the first settlement load level in each hour of the next day. Results of the dispatch are used to produce the day-ahead LMPs and schedules for the first settlement forward contracts.

After the day-ahead schedule is published and no later than 75 minutes before each hour, customers may submit hourly real-time bids into the Real-Time Commitment (RTC) program for real-time evaluation. RTC will make binding unit commitment and de-commitment decisions for the periods beginning 15 minutes (in the case of resources that can respond in ten minutes) and 30 minutes (in the case of resources that can respond in thirty minutes) after the scheduled posting time of each RTC run; provide advisory commitment information for the remainder of the two and a half hour optimization period; and produce binding schedules for external transactions to begin at the start of each hour. RTC co-optimizes to solve simultaneously for all load, operating reserves and regulation service requirements and to minimize the total as-bid production costs over its optimization timeframe. RTC will consider SCUC's resource commitment for the day; load and loss forecasts that RTC itself will produce each quarter hour; binding transmission constraints; and all real-time bids and bid parameters (NYISO05).

3.3 Solution Methodologies

The methodologies that have been receiving more attention in recent years and that have been considered to be the most adequate ones to solve the SCUC problem are those based on Lagrangian Relaxation (LR) and Benders' Decomposition.

LR-based methods may be applied in two distinct ways, generally referred to as direct and indirect methods. Direct methods include the security constraints in the objective function, when optimizing the dual problem, with additional Lagrange multipliers. A consequence of the increase in the number of Lagrange multipliers is that the convergence of the dual optimization may be hampered. Indirect methods ignore the security constraints when solving the dual problem, reintroducing them when attempting to find a feasible primal solution. It is pointed out in (SHA95) that these methods can lead to severely suboptimal results. As they do not provide the dual optimization with any information on how to distribute generation through a transmission grid, the dual solutions that are produced may lead to worse starting points to construct primal feasible solutions. However, there seems to be some major motivations to apply indirect approaches: they speed up the dual optimization and allow the simulation of power market structures, such as the British Power Pool, where an initial UC does not consider transmission constraints that are only considered in modifying this initial commitment (TSENG99).

Other methodologies that were proposed to solve the SCUC are Mixed Integer Programming, Dynamic Programming (PAN81) and heuristic techniques based on unit decommitment (XIA00).

3.3.1 SCUC – Lagrangian Relaxation and Benders' Decomposition

Algorithmically, most LR-based approaches are alike. First, one obtains the dual problem, where demand, spinning reserve and security constraints are relaxed. This problem is shown to be separable into N subproblems (one for each of the N system units), each of them being solved with Dynamic Programming. As the solution obtained by the dual problem does not usually lead to a primal feasible solution, a feasibility recovering phase is then required to obtain a primal feasible solution. Generally, this phase detects which constraints have been violated and, accordingly, updates the multipliers (increasing or decreasing their value) that are related to those constraints in the dual problem. The feasibility phase is what mostly distinguishes different LR approaches and is heuristic.

To conclude the optimization process, one may add a post-processing method to the previous optimization algorithm. (TSENG99) suggests a unit decommitment method to be applied to each bus. This work considers a three-phase algorithmic scheme including dual optimization, a feasibility phase and unit decommitment. It is suggested in (TSENG97) that unit decommitment not only improves solution quality, but also mitigates unpredictable effects due to heuristics in the first two phases.

In (LU2005) the SCUC problem is decomposed into two coordinated problems, based on Benders' Decomposition, including a master problem that optimizes the UC and a subproblem for minimizing network violations. The master problem is solved through Augmented Lagrangian Relaxation, each dual problem being solved by Dynamic Programming. Augmented Lagrangian Relaxation is used to improve the convexity of the problem and, consequently, the convergence of the algorithm.

Similarly, Benders' Decomposition is also applied in (FU2005). Again, the master problem is solved with Augmented Lagrangian Relaxation. Then, AC network security constraints are checked for each subproblem. If there is any constraints' violation, appropriate Benders cuts are defined and added to the master problem in the next optimization step. The iterative process proceeds until AC violations are eliminated and convergence is reached. More details on Benders' Decomposition may be found in (LU2005).

3.3.2 *SCPBUC – Lagrangian Relaxation and Benders' Decomposition*

In (YAM02) the SCPBUC problem is decomposed into a master problem (that captures GENCO concerns) and a subproblem (reflecting the ISO concerns). The master problem solves a PBUC with all unit constraints. Then GENCOs submit their bids to the ISO that receives the transmission information from TRANSCOs. Accordingly, the ISO will try to reduce possible line flow violations by minimizing the cost of generation based on GENCOs submitted generation and adjustment bids. If violations persist, the ISO will execute an optimization to minimize flow violations and create Benders cuts that represent the flow violations that were detected. Benders cuts are added to the PBUC that is solved again by GENCOs to provide a new schedule. Independently of the GENCOs losses, if the bids that are resubmitted are not able to ensure a secure system operation, the ISO will take further actions to secure the system. This procedure is summarized in Figure 5.

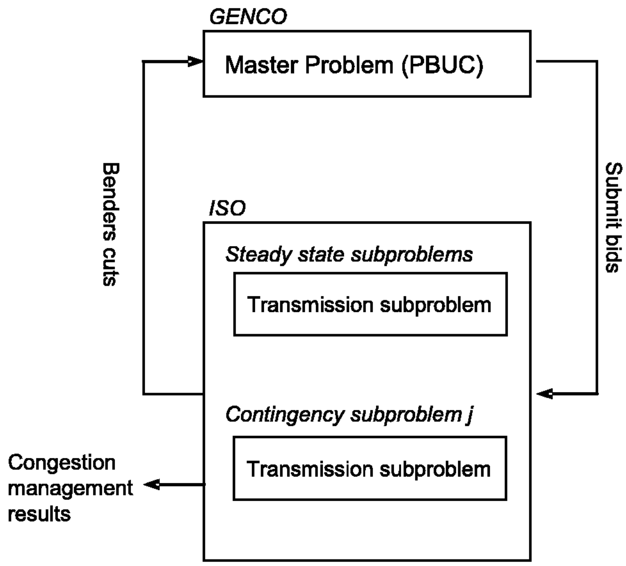


Figure 5 SCPBUC procedure [Source: (YAM02)]

The previous idea is further refined in (YAM04). Here it is mentioned that the master problem solves the GENCO's problem by an Interior Point Method. The solution of this problem maximizes the GENCO's profit based on the forecasted market price for energy and on the GENCO's prevailing constraints. Afterwards, and given the generation schedule, the subproblems are solved by examining the feasibility of the GENCO's proposed generation schedule in a transmission constrained system. Possible transmission overflows are minimized at steady state and n-1 contingency cases by adjusting phase shifters and utilizing adjustment bids based on the GENCO's original dispatch. If the GENCO's solution is not feasible at the subproblem level, Benders cuts are generated for re-calculating the GENCO's optimal generation.

4.0 INCLUSION OF COMBINED-CYCLE UNITS

The basic formulation of the Unit Commitment problem assumes that in each time interval each generating unit may be in one of two states: on or off. This is, naturally, an approximation of the real case. In fact, if we take into account minimum up and down time constraints, multiple on and off states should be considered, with different situations regarding possible transitions and different start-up costs in the off states. But experience with the solution procedures showed that the two-state model, along with the use of constraints, was the most effective approach.

However, there are units that intrinsically have different operating modes, even without considering minimum up and down time constraints. The most salient case regards combined-cycle units (CCU). These kinds of units became very popular in the last decade as they present several advantages when compared with other types of generating units, namely high efficiency, fast response, shorter installation time, abundance of gas and environmental friendliness (LU2004). The following section gives an overview of CCU operation.

4.1 Operating Characteristics of Combined-Cycle Units

4.1.1 Introduction

The purpose of this section is to present the characteristics and constraints of combined-cycle generating units (CCGUs). These are the characteristics and constraints that improvements in modeling or changes in market rules, if any, must address. This description is based on the document (NYISO2005).

A combined-cycle generating station consists of one or more combustion turbines (CT), each with a heat recovery steam generator (HRSG). Steam produced by each HRSG is used to drive a steam turbine (ST). The steam turbine and each combustion turbine have an electrical generator that produces electricity. Typical configurations contain one, two, or three combustion turbines, each with a HRSG and a single steam turbine. The combined-cycle generating station can be operated in one of several states. The station's characteristics differ from one state to another, and the transition from one state to another may have a significant cost. The single-shaft plant is much less common. It has a CT and ST on a single shaft driving a common generator.

4.1.2 Terminology

Term	Description
1-on-1	Combined-cycle plant with one CT-HRSG and one ST-COND
2-on-1	Combined-cycle plant with two CT-HRSGs and one ST-COND
3-on-1	Combined-cycle plant with three CT-HRSGs and one ST-COND
COND	Condenser
CT	Combustion turbine, also referred to as a gas turbine
HRSG	Heat recovery steam generator
MW	Megawatt – energy production rate, also used to describe capacity of a generator, which is its maximum or rated energy production rate
MWH	Megawatt Hour – unit of energy
PTS	Performance tracking system
RTC	Real-time unit commitment
ST	Steam turbine
SCUC	Security-constrained unit commitment

A review of combined-cycle characteristics and constraints, including a review of pertinent literature and discussions with several owners of combined-cycle plants, has highlighted the following areas where the operation of the combined-cycle plant differs markedly from traditional steam generating plant or simple-cycle CTs (NYISO2005):

- Start-up of a CT, warming of its HRSG, and possible warming of the ST;
- Transitions among operating states with one, two, or three CTs.

In many instances this document provides characteristics and constraints typical of combined-cycle plants. Significant variations can exist among the components of a combined-cycle plant. These variations may be a result of design, size, age, manufacturer, state of repair, etc. While these variations may be important in determining marginal costs, duration of heat-soak periods, etc., they are not important in identifying the characteristics and constraints relevant to improved modeling, commitment, and performance tracking of combined-cycle plants.

4.1.3 Typical Plant Configurations

The two building blocks of most combined-cycle power plants are (i) the combustion turbine (CT) combined with a heat recovery steam generator (HRSG) shown in Figure 6, and (ii) the steam turbine (ST) combined with a condenser (COND) shown in Figure 7. The typical combined-cycle power plant is made up of one or more of the CT-HRSG blocks and a single ST-COND block.

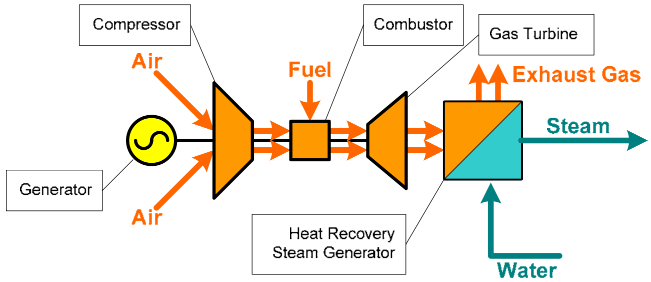


Figure 6 Combustion Turbine & Heat Recovery Steam Generator

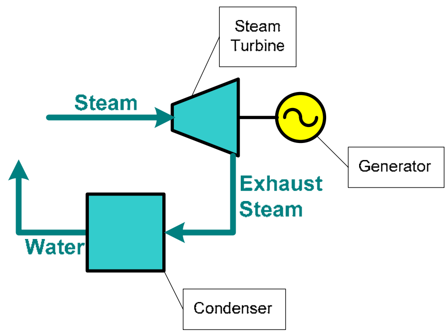


Figure 7 Steam Turbine & Condenser

Figure 8 illustrates typical configurations of combined-cycle plants. These contain one, two, or three CT-HRSG blocks and a single ST-COND block. Respectively, these plants are referred to as 1-on-1, 2-on-1, and 3-on-1 and have two, three, or four electrical generators.

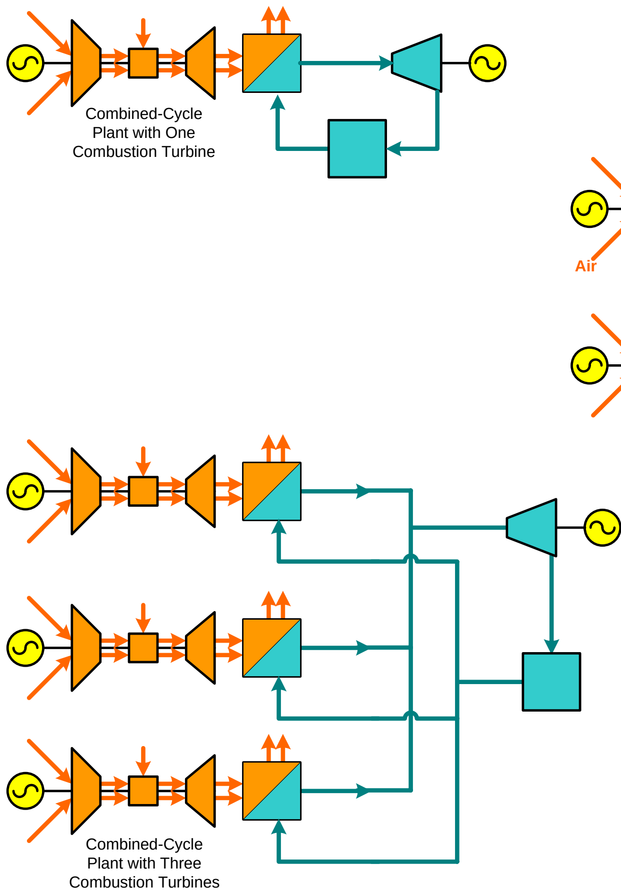


Figure 8 Typical Combined-Cycle Plant Configurations

The capacity of a plant's ST is roughly half that of the plant's CTs. That is, a 1-on-1 plant with an 80 MW CT will support a 40 MW ST with a full-load plant output of 120 MW. The same sized CTs in a 2-on-1 plant will support an 80 MW ST for a full-load plant output of 240 MW. Similarly, a 3-on-1 plant with three 80 MW CTs will support a 120 MW ST with a full-load plant output of 360 MW.

4.1.4 *Significant Variations*

There are many variations in the components of a combined-cycle plant. Many of these variations impact only the efficiency of the plant but have little impact on the capacity or responsiveness of the plant. The four variations that have an impact on the plant's participation in the wholesale electric markets are:

- Presence of a gas bypass system;
- Ability to duct fire;
- Dual fuel capability;
- Cogeneration.

4.1.4.1 Gas Bypass

Gas bypass gives a combined-cycle plant the ability to divert the hot CT exhaust to the atmosphere rather than to the HRSG. This provides extra operating flexibility by permitting the CT to operate in simple-cycle mode, albeit at a greatly reduced efficiency. Very few of the combined-cycle plants in New York have a gas bypass.

4.1.4.2 Duct Firing

Duct firing, or supplemental firing, is a way of increasing plant output by injecting and burning fuel in the HRSG. With duct firing, both the hot exhaust of the CT and heat from additional fuel is used to make steam in the HRSG. Overall plant efficiency decreases when duct firing is used. Many, but not all, of the combined-cycle plants in New York have duct firing capability. One plant reported an increased output of 10%.

4.1.4.3 Dual Fuel

Some combined-cycle plants may be fired with natural gas or with a high-quality fuel oil such as kerosene or jet fuel. Some plants can be fired using a mix of gas and oil. As of this writing, natural gas is the preferred fuel for most of the combined-cycle plants as fuel oil is more costly than natural gas. Many plants report a reduced ability to follow a control signal when burning fuel oil. One plant has reported that it is impossible to follow a control signal when a mix of fuels is burned.

4.1.4.4 Cogeneration

Cogeneration means the simultaneous production of electrical and thermal energy in the same power plant. The thermal energy is usually in the form of steam or hot water that is used for an industrial process, district heating, or some other purpose. Most often, the thermal needs of the external process determine the plant's operating point and the electrical output of the plant.

4.1.5 Start-up

During start-up, the combined-cycle plant has little ability to follow an external control signal. Plant output, while fairly predictable, does not increase smoothly from minimum load to maximum load. Instead, output during start-up is characterized by extended holds, where plant output does not change, periods where plant output increases slowly, and periods where plant output increases rapidly.

The cold start-up of a typical 2-on-1 combined-cycle plant is illustrated in Figure 9 and Figure 10. These figures show component speed and load respectively. The figures also illustrate the transition from operation with one CT to operation with two CTs. The start-up of a 1-on-1 plant takes less time; the start-up of a 3-on-1 plant takes more time. Time to full load for a cold plant takes roughly three hours for a 1-on-1 plant, four hours for a 2-on-1 plant, and five hours for a 3-on-1 plant. These times can grow significantly if significant chemical processing of the condensate is required. The start-up of a warm or hot plant takes less time than the start-up of a cold plant. The start-up time is also a function of the age and size of the gas turbine. Older, low tech, smaller gas turbines can start faster than newer, high tech, higher efficiency, larger gas turbines. Representative start-up times are tabulated below.

Plant Type	Representative Cold Start	Representative Hot Start
1-on-1	3 hours	1 hour
2-on-1	4 hours	1½ hours
3-on-1	5 hours	2 hours

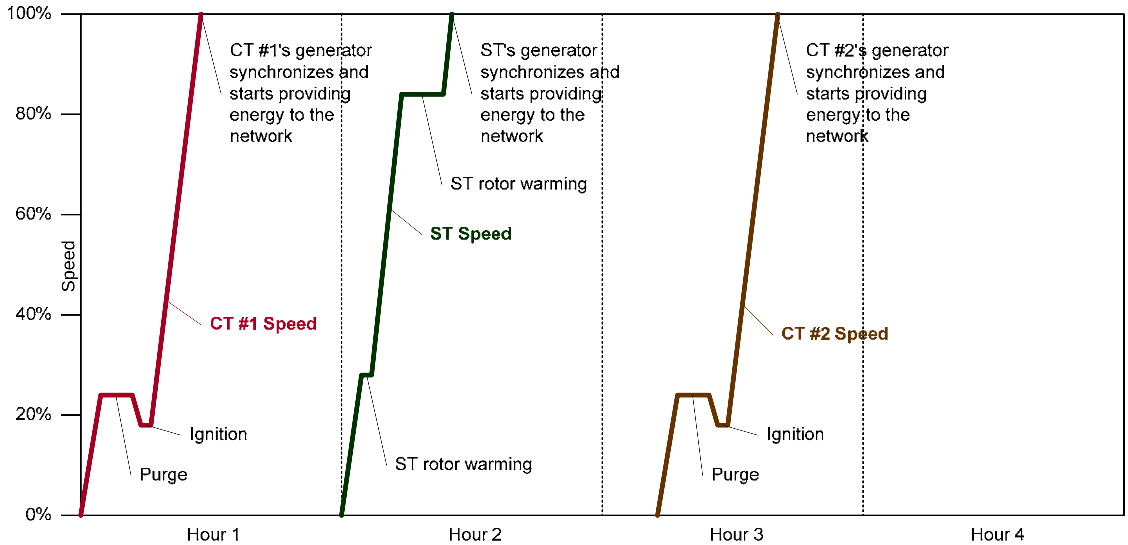


Figure 9 Component Speeds – Representative Cold Start

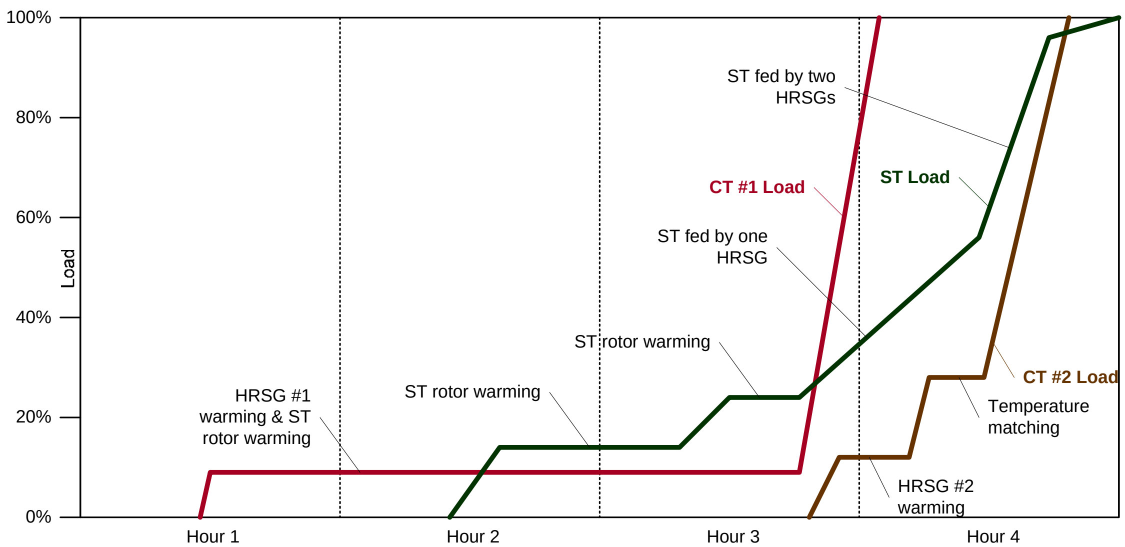


Figure 10 Component Loadings – Representative Cold Start

Typical steps in the start-up of a combined-cycle plant are explained in the sections that follow.

4.1.5.1 Start-up and Synchronization of First CT

As illustrated in Figure 9, the start-up and synchronization of a CT takes roughly 20-30 minutes. Roughly half of this time is used to purge the HRSG of combustible gases prior to firing the CT. Upon synchronization of the CT's generator, the CT is loaded to approximately 10% of its capacity.

4.1.5.2 Warming of HRSG

The HRSG must be warmed to the point of producing steam. This takes approximately half an hour for a cold HRSG. Initially steam produced by the HRSG bypasses the ST and is sent directly to the condenser.

4.1.5.3 Start-up, Warming, and Synchronization of ST

Before steam can be introduced into the ST, the turbine's steam seals must be put into operation and the condenser must be evacuated. The ST, like the HRSG, must be warmed slowly. Steam from the steam seals warms the ST before it rolls. Warming continues while the ST is being brought up to speed. At several points, the ST is held at constant speed (typically 1000 rpm, 3000 rpm, and 3600 rpm) for additional warming. These hold periods can be seen as flat spots in the ST speed of Figure 9. The duration of the holds for warming are longer for a cold ST than for a hot ST. A cold ST takes approximately half an hour to get to full speed. Once at full speed (3600 rpm), the ST's generator is synchronized to the network.

4.1.5.4 Loading of ST

Warming of the ST continues after it is at full speed and its generator has been synchronized to the network. At several points, the ST is held at a constant load for additional warming. These hold periods can be seen as flat spots in the ST load of Figure 10. It may take an hour or more for an ST to be fully warmed from the time it reaches full speed.

4.1.5.5 Start-up and Synchronization of the Second CT

The second CT in a combined-cycle plant is started after the ST has been fully warmed. Like the first CT, and as illustrated in Figure 9, the start-up and synchronization of the second CT takes about 20-30 minutes. Roughly half of this time is used to purge the CT and HRSG of combustible gases prior to firing the CT. Upon synchronization of the CT's generator, the CT is loaded to approximately 10% of its capacity.

4.1.5.6 Warming of the Second HRSG

The HRSG must be warmed to the point of producing steam. This takes approximately half an hour for a cold HRSG and can be seen as the first flat spot in the CT#2 load of Figure 9. Initially steam produced by the HRSG bypasses the ST and is sent directly to the condenser. It takes an additional half hour or so to match steam temperature of the second HRSG with that of the first HRSG and combine their outputs. This can be seen as the second flat spot in the CT#2 load of Figure 10. Once steam temperatures are reasonably matched, steam of the second HRSG is combined with that of the first HRSG and sent through the ST. The second CT is brought up to full load after steam from the two HRSGs is combined.

The third CT, if it exists, is typically started after the second CT is fully loaded. The steps in starting the third CT and the warming of the third CT's HRSG are very much like those of the second CT and its HRSG.

4.1.6 Normal Operation

The normal operating range of a combined-cycle plant is typically 70% to 100% of rated output. In this range the plant usually has excellent control characteristics and should be able to provide spinning reserve or regulation service when natural gas is used as a fuel. Some combined-cycle owners report reduced flexibility when a combined-cycle plant is fired with a petroleum fuel. Such reduced flexibility can be reflected in a lower ramp rate. Some combined-cycle owners report that all load following capability is lost when a combination of natural gas and petroleum fuels are burned simultaneously.

A 2-on-1 plant can also be operated in a 1-on-1 configuration with a corresponding decrease in capacity and response rate. A 3-on-1 plant can also be operated in a 2-on-1 or 1-on-1 configuration, also with a corresponding decrease in capacity and response rate. Capacity and control ranges for combined-cycle plants operating in various configurations are tabulated below.

Plant Type	Operating Mode	Capacity	Control Range
1-on-1	1-on-1	100%	70% - 100%
2-on-1	2-on-1	100%	70% - 100%
	1-on-1	50%	35% - 50%
3-on-1	3-on-1	100%	70% - 100%
	2-on-1	67%	47% - 67%
	1-on-1	33%	23% - 33%

CTs can typically be controlled down to approximately 80% of rated capacity without significant loss of efficiency; there are environmental consequences however. Above 80% of rated load both fuel and inlet air flows are controlled together to achieve a proper mix and to maintain temperatures in the CT. Air flow cannot be reduced below about 80% and temperatures are depressed by excess air at low operating levels. This results in a decrease in efficiency of the CT at low operating levels. While the efficiency effects of low-load operation become noticeable below about 80% of rated load, for environmental reasons most CTs in combined-cycle plants are normally not permitted to operate below 70% of rated output, except during start-up and shutdown.

Nitrogen oxides (NOx) are reduced through the use of Dry Low NOx combustors, water or steam injection, and/or the use of a Selective Catalytic Reduction in the HRSG. For NOx control water up to 3% or steam up to 5% of the air flow is used. One plant reported using a combination of DLN combustors and SCR to attain 2 ppm. The SCR requires a gas inlet temperature of approximately 700°F which may not be attained at lower CT loads.

The efficiency of the HRSG is largely a function of inlet gas temperature. CT exhaust temperature, which is also HRSG inlet temperature, varies little above 80% load, hence the efficiency of the HRSG varies little in the permissible operating range. The efficiency of the ST is also relatively constant. ST efficiency is impacted by a control stage that regulates steam flow and by exhaust (condenser) pressure. The ST used in combined-cycle applications rarely has a control stage and condensers are often sized large enough that the ST exhaust pressure remains relatively constant. Efficiency of the overall plant, neglecting auxiliary devices such as pumps and fans, is fairly constant from 80% to 100% load.

Output and, to a lesser extent, heat rate of a gas turbine are affected by ambient conditions: air temperature, humidity, and atmospheric pressure. Absent duct firing, the performance of the combined-cycle plant follows the performance of its CTs. Reference conditions for gas turbines are typically 59°F (15°C), 14.7 PSIA (1.013 bar, 29.92 in Hg), and 60% relative humidity. These reference conditions are established by the International Standards Organization and are also referred to as ISO conditions. Both output and heat rate are taken to be 1.0 at standard conditions. The exact characteristics of any particular gas turbine depend on its cycle parameters and component efficiencies and will vary slightly from the typical results presented here. In summary, the output of a gas turbine may change by ±15% due to ambient conditions. Change in heat rate due to ambient conditions will be in the range of ±5%.

Under unusual (emergency) circumstances the output of some gas turbines can be increased through the use of steam injection, inlet cooling, or peak firing.

- Five percent steam injection can increase output by 16 percentage points. In standard conditions this would be an increase from 100% to 116%. Lower levels of steam injection have a correspondingly lower impact on output. Steam injection can only be used on gas turbines with a wide surge margin in the compressor, typically found in aero derivative gas turbines.

- The impact of inlet cooling by means of an evaporative cooler or inlet chiller is reflected in the adjustment curve for ambient temperature below. At most, a gas turbine could increase its output by 10 percentage points (from 90% of standard to 100% of standard, for example) with the use of inlet cooling. Inlet cooling is employed in an attempt to recover the capacity lost to high ambient temperatures.

- Peak firing is operation at a higher firing temperature than normal, putting the “pedal to the metal,” so to speak. An increased output is the result. Peak firing requires no peripheral equipment as do steam injection or inlet cooling, however, operation at peak conditions shortens the normal maintenance interval for the turbine. Peak firing can increase output by approximately 10%. Not all gas turbines have the ability to peak fire.

4.1.6.1 CT Ambient Pressure Adjustments

Air flow to the turbine is reduced in direct proportion to a reduction in atmospheric pressure (Figure 11). There is a corresponding, and linear, reduction in output. Heat rate is not affected. Atmospheric pressure is commonly expressed as inches of Mercury (inHg). Atmospheric pressure at sea level is generally in the range 28.0 inHg (13.76 PSIA) to 31.0 inHg (15.23 PSIA), which means that gas turbine output may be as low as 93% of standard during hurricane conditions or as high as 103.5% of standard during the spectacular weather associated with a Bermuda high.

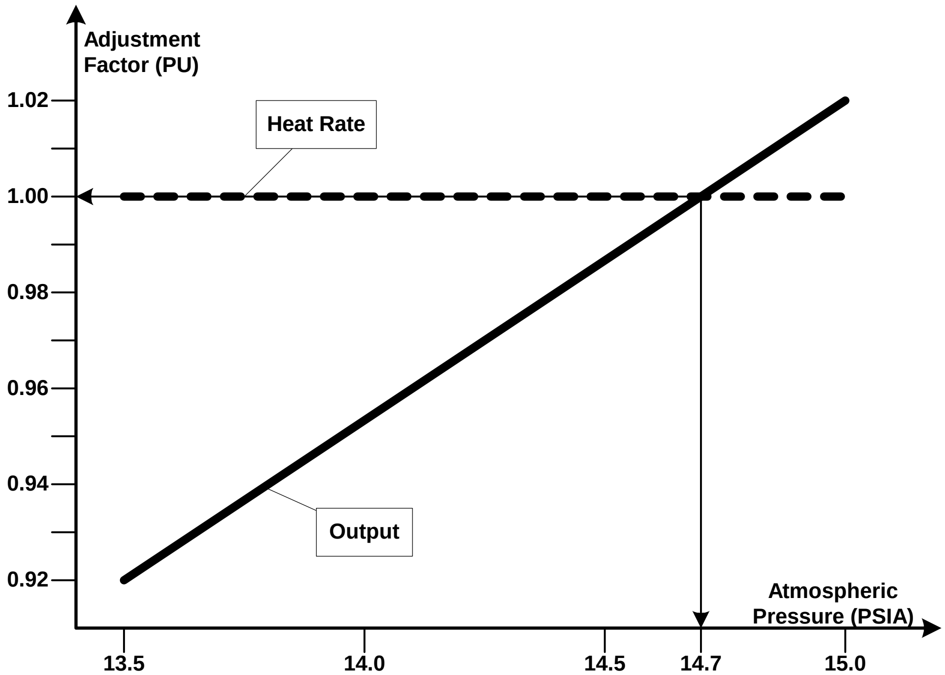


Figure 11 Adjustments for Atmospheric Pressure

4.1.6.2 CT Ambient Temperature Adjustments

The output of a gas turbine is quite sensitive to ambient air temperature (Figure 12). Output can be as high as 120% of standard on an extremely cold (0°F) day or as low as 86% of standard on an extremely hot (100°F) day. Ambient temperature has a smaller effect on heat rate. Heat rate increases slightly (net efficiency decreases) as temperature increases and decreases slightly (efficiency increases) as temperature decreases.

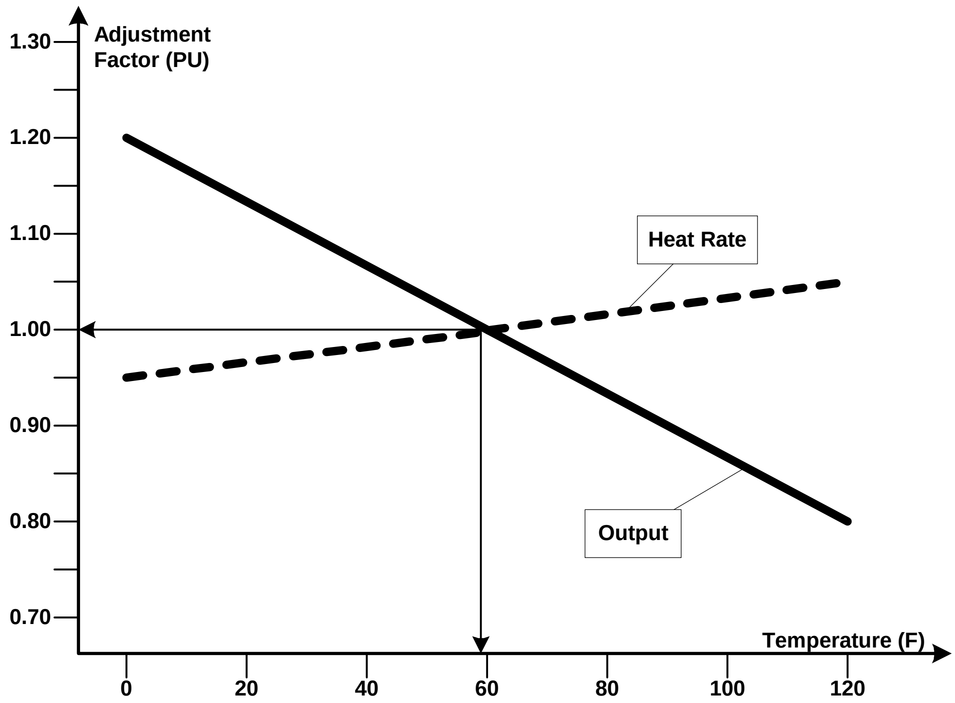


Figure 12 Adjustments for Ambient Temperature

4.1.6.3 CT Humidity Adjustments

Compared to adjustments for pressure and temperature, the adjustments for relative humidity are small; and the adjustment for humidity can be ignored for all practical purposes. Output of a gas turbine will increase slightly as relative humidity decreases. Output increases to approximately 100.1% of standard during periods of very low humidity and decreases to approximately 99.7% of standard at very high levels of humidity. Heat rate decreases (better efficiency) to approximately 99.7% of standard during periods of very low humidity and increases (poorer efficiency) to approximately 100.8% of standard at very high levels of humidity.

4.1.6.4 CT Combined Adjustment

An overall adjustment factor is obtained by multiplying the individual adjustment factors. For example, consider a day with an atmospheric pressure of 28.5 inHg (14.0 PSIA) and temperature of 90°F. Humidity is ignored. Output adjustment factors for pressure and temperature are 0.95 and 0.91 respectively. Expected output of the gas turbine will be $(0.95 \times 0.91) = 0.8645$ of standard – about 86.45% of standard. Under these conditions, a gas turbine that produces energy at a rate of 50 MW under standard conditions will produce energy at a rate of only 43.2 MW.

4.1.7 Shutdown

A combined-cycle plant can typically be shut down within 20 to 30 minutes when all CTs at the plant are unloaded and shut down simultaneously. The shutdown ramp rate is much larger than the ramp rate used during start-up or normal operation. The shutdown can be extended for plants that have multiple CTs by making a transition from operation with three to operation with two CTs, or from two CTs to one CT.

4.1.8 Transitions Between States

Based on different combinations of CTs and STs, a combined-cycle unit can operate at multiple configurations, according to its operating limits.

As the transition between configurations may be constrained (e.g., a direct transition between configuration A and configuration B may not be allowed), transition rules must be set. These rules are generally represented by state space diagrams that depend not only on the operation rules for individual configurations, but also on the relationship between configurations.

The operation rules for individual configurations are similar to minimum up/down time constraints [see (LU2004)]:

1. Combined-cycle units must operate for a specified time period using only the combustion turbines prior to generating using the ST.
2. There is usually a minimum required time to operate in each configuration.

Rules for transition between configurations are, for example:

1. The outward transition from a configuration will be from its top node;
2. The inward transition to a configuration will be to its bottom node;
3. To switch on a ST, at least one CT must be on;
4. To switch off a CT, all STs must be off;
5. Multiple CTs may be switched on/off simultaneously, but a CT and a ST cannot be switched on/off simultaneously.

Rules 1 and 2 consider that within a configuration there are different operating conditions (related to a unit's minimum up time, for example). We will further elaborate on this subject in Section 4.2 and also in Section 5.

4.1.9 Summary

Combined-cycle plants are built in a variety of configurations. Operation of a combined-cycle plant can be divided into three categories: start-up, normal operation, and shutdown.

- Start-up of a combined-cycle plant can take many hours. During most of this time at least one of the plant's generators is synchronized to the network and delivering electrical energy to the network. The plant's electrical output is reasonably predictable during start-up but the plant cannot arbitrarily adjust its output. A combined-cycle plant cannot respond to 5-minute dispatch signals during start-up.
- During normal operation, the combined-cycle plant can be quite responsive to external control signals and may, within a limited range, provide dispatch capability, reserve service, or regulation service.
- Shutdown of a combined-cycle plant can be accomplished quickly.

4.2 Review of Previous Studies

Lagrangian Relaxation is again the technique that deserves more attention when optimizing a SCUC with combined-cycle units. The approach has been used in (COHEN96), (LU2004) and (LU2005), among others, to commit and dispatch CCU.

(LU2004) introduced a method for establishing the state-space diagram of combined-cycle units. The method considered Dynamic Programming and Lagrangian Relaxation for the security constrained short-term scheduling problem. This study is generalized in (LU2005), where the SCUC algorithm considers the commitment and dispatch of generating units with flexible operating conditions for minimizing the cost of supplying the load while satisfying power flow, bus voltage, as well as generating unit constraints. The algorithm calculates the hourly state of generating units as well as the configuration of CCU. The SCUC algorithm decomposes the power system scheduling into a master problem (generating units) and a subproblem (network flow constrains) through Benders Decomposition [see Figure 13, from (LU2005)]. Lagrangian Relaxation is used to commit generating units in the master problem. Dynamic Programming is then used to solve a set of subproblems, one for each unit, based on state transition diagrams.

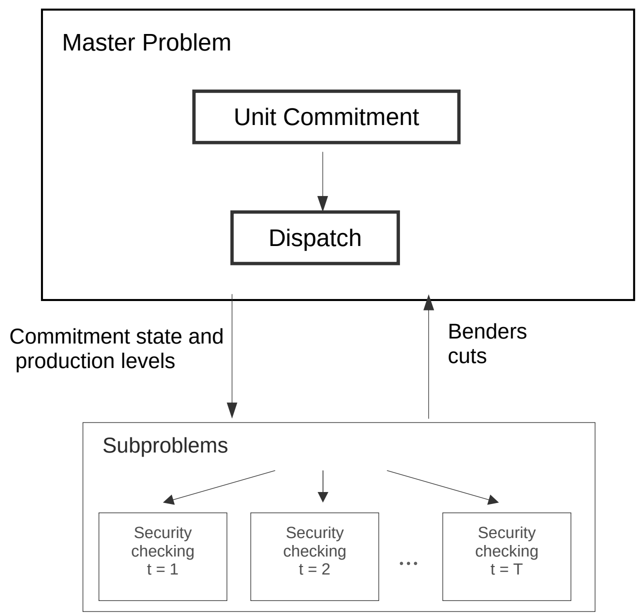


Figure 13 Benders' decomposition structure in SCUC

The algorithm that is proposed in (BJE2000) is based on the assumption that the thermal subsystem of a combined-cycle plant is modeled through input-output curves that are defined for all configurations and all steam load ranges. The paper discusses the application of a single combined-cycle plant Dynamic Programming algorithm to a plant's state space with restricted transitions.

4.2.1 *Combined-Cycle Unit Modeling Techniques*

This section presents, in increasing order of complexity, three alternative ways of modeling combined-cycle units. The first alternative considers an aggregate modeling of CC units, the second one considers a configuration-based modeling and the last one a physical modeling of each CC component.

a. Aggregated CC Modeling

The simplest way of modeling CC units is through an aggregation of all unit components into a single one, tackled in much the same way of thermal units, i.e., the decision made in each period of the planning horizon is to switch on/off the unit with no regard to the configuration state the unit will be operating in. This is the modeling approach currently in use in ISO NE, NYISO, MISO, and PJM.

As the CC components are hidden from the market operator, the determination of the CC configuration is left with the plant operator. This brings several problems to the plant operator, since unit technical constraints cannot be correctly captured using an aggregate representation. Therefore, alternative modeling approaches should be considered.

b. Configuration-Based CC modeling

Based on possible CT and ST combinations, a combined-cycle unit can operate in multiple configuration modes. For a 2 CT – 1 ST, for example, the possible configurations are 0 CT – 0 ST, 1 CT – 0 ST, 1 CT – 1 ST, 2 CT – 0 ST, and 2 CT – 1 ST. Each configuration is associated a number (0, 1, 2, …) and is characterized by, e.g., minimum up and down times, minimum and maximum production levels, etc., as well as by a correct representation of start-up and shutdown costs. No physical CC components are modeled.

As a direct transition between two configurations may not be allowed, a state-space diagram is drawn, to represent the transitions that are allowed. These transitions, as well as the forbidden ones, are represented in the mathematical model through a set of constraints. Thus the state space for a combined-cycle unit must be set according to the operation rules for individual configurations, as well as to those constraining the transition between the configurations. This is the commonly adopted approach, and can be found in many publications, e.g., (LU2004, 2005), (COHEN96) and (BJE2000).

Much of the discussion on this modeling approach and on how to create the state-space diagram in combined-cycle units is presented in Section 4.2.2.

c. Physical Unit-Based CC Modeling

Finally, one can go into further detail and consider a physical unit-based CC modeling where, instead of representing the possible unit modes, each physical component of the units is fully described, having all the standard unit constraints, i.e., each CT and each ST can have its own start-up cost, minimum up/down time, cost curves etc. Minimum times between start-ups for all CTs in a CC unit may also be represented.

Not much attention has been devoted to this model, probably due to the complexity of the state-transition diagram associated to this modeling approach. Even so, this is the approach that better reflects the reality of CC units. As so, a methodological approach that considers this model will be proposed in Section 5.

4.2.2 *Solution Techniques for UC with CC units*

Several optimization techniques have been used to solve the SCUC with CC units, the ones seeming to having received more attention in the recent past being those based on Lagrangian Relaxation. Even so, we may think of other techniques, such as those based on MIP and DP. Due to the computational complexity of this problem, none of the latter techniques can be used in their exact form, and must be subject to cuts. Therefore, the resulting solution is not guaranteed to be optimal.

In our opinion, the adequacy of each optimization technique when different modeling approaches are considered varies, mainly for those techniques where DP is used. This is due to the increase in the state transition diagram that guides the search in DP-based approaches. Therefore, we devise that the application of DP to the last modeling approach that is suggested would result in a very time consuming and complex algorithm. The same conclusion lasts for LR, if DP is used to solve the dual problem.

The technique that would be generally suited is that which is based on MIP. Other approaches, normally referred to as metaheuristics, might also be considered of interest. The main reason for that being the capability of metaheuristics to handle the non-linearities of the problem.

More general considerations on the pros and cons of these techniques will be given in Section 4.3.3..

4.2.3 *SCUC with Combined Cycle Units*

The inclusion of CCU in SCUC models does not drastically change the problem structure, nor does it prevent the techniques referred to in Section 3.3 from being used. As explained in the literature, it is only required that each CCU is modeled as a different unit for each of its possible configurations and that the transition rules between configurations (or inside a configuration) are modeled as constraints. Once these steps are concluded, one may consider LR, or any other optimization technique to solve the problem. Once again, and without surprise as the same arguments referred to for the SCUC hold for this choice, LR is the technique that prevails.

4.2.3.1 Literature review of the modeling techniques

Cohen and Ostrowski 1996 paper

LR is used in (COHEN96) to schedule the unit configurations. Recall that the LR method solves the unit commitment problem by decomposing it into a set of single unit problems where the system constraints are relaxed and included in the objective function with Lagrange multipliers. The single unit problems minimize the dual cost (that includes generation cost and start-up costs, and terms containing the Lagrange multipliers), subject to constraints on unit generation, minimum up and down time, and ramp rates. Dynamic Programming is used to solve the single unit problems. This requires the definition of the possible states that the unit can be in at each time point and of the transitions that are allowed between states, i.e., the state transition diagram.

The CC units are modeled by allowing each unit to have multiple configurations where each configuration has its own set of unit parameters. The authors use the nomenclature "unit mod" or simply "mod" to denote one of the unit's configurations. The authors define two types of unit mods: dependent and exclusive. A unit mod is dependent if it can operate only if another specified mod is operating. An example of a dependent mod is the overfire operation of a unit; the unit cannot be in overfire mode unless the base unit is scheduled. Exclusive mods are mutually exclusive, that is, only one of the mods of the unit can operate at a time. An example of exclusive mods is the different configurations of a combined-cycle unit. A dependent mod may be dependent on an exclusive mod; that is, the dependent mod may operate only if the specified exclusive mod is operating.

The remainder of this section describes the modeling of the dependent and exclusive mods. Unless otherwise stated, all data related to a unit is defined at the level of the unit mod. Therefore each mod has its own unit limits, reserve parameters, ramp rates, startup and shutdown profile, heat rates, etc. Fixed generation, maintenance and deratings also apply to unit mods.

<u>DEPENDENT MODS</u>

In addition to a full set of unit data, dependent mods also need to specify:

<u>base mod</u> – the unit or unit mod that must be on for this mod to be on.

<u>minimum on time of base mod</u> – the number of hours the base mod must be tip before the dependent mod can be started.

<u>EXCLUSIVE MODS</u>

Exclusive modes are defined by the allowed transitions between the mods and the allowed transitions between the modes and the off state. Also, the unit corresponding to the exclusive mods is assumed to have a single minimum downtime, that is, the time the unit must be down is independent of how the unit operated before it is down or will operate after it starts. The minimum up time of the mod corresponds to the time the mod must be on prior to the transition from the mod to the off state.

Additional data associated with an exclusive mod are:

- Startup flag – indicates if the unit can start-up from off into this mod;
- Shutdown flag – indicates if the unit can shut down from this mod;
- For each allowed transition:
  - Prior Mod – the mode on prior to the transition.
  - After Mod – the mode on after the transition.
  - Minimum up time – the time the mod operates prior to the transition.
  - Low and high operating limits prior to the transition.
  - Low and high operating limits after this transition.
  - Transition time – the number of hours it takes to transition between the mod and the associated after mod.
  - Transition ramp – the ramp rate MWh/hour during the transition.
  - Transition cost – the cost of the transition in $/transition.

The generation during the transitions is constrained as follows. If the transition time is greater than 0, then the transitioned limits are governed by the limits before and after this transition and the transition ramp rate. The unit data corresponding to the prior or after mod with the larger capability are used to define all other data (e.g., heat rate, reserve parameters) during the transition period. This choice, though somewhat arbitrary, is made because the reason the transitions occur is to provide the increased capability.

Bjelogrlic 2000 paper

In (BJE2000), by application of the LR technique, the optimization problem is decomposed in each iteration into a master problem and a sequence of subproblems. The solution to the master problem consists of adjusting the values of the Lagrange multipliers in order to satisfy the coupling constraints. All subproblems are solved for given values of the Lagrange multipliers at each iteration. The multipliers are then updated using a sub-gradient technique in which the change in the value of each multiplier is proportional to the violation of its associated coupling constraint. In order to improve the convexity of the problem, the Augmented Lagrangian Relaxation technique is applied and quadric penalty terms associated with the system demand requirements are added to the objective function. By application of Augmented Lagrangian Relaxation, the thermal subsystem commitment optimization problem is decomposed into the sequence of a study period single thermal unit's optimization subproblems and a single combined-cycle plant's optimization subproblem. These subproblems are solved by the application of Dynamic Programming. To apply DP, a state space transition diagram is defined for each unit, taking into account the unit's minimum and maximum power limits, minimum up and down times, ramp up and ramp down rates, start-up time, and other local constraints.

Mathematical formulation of the unit commitment problem is similar to the general expression given in equation 11 later in this report.

<u>State Space Model for Combined-Cycle Plants</u>

Construction of the state space model for the combined-cycle plants is illustrated in the paper according to principles similar those Lu and Shahidehpour discuss below. In addition to the base case, the start-up and shutdown constraints, and/or power constraints are modeled by introducing some additional states.

The state space for combined-cycle plants is composed of the state space of distinct configurations. There is only one independent configuration with one CT in operation; despite how many CTs with the same characteristics belonging to the combined-cycle plant. The same is true for combinations of two CTs with the same characteristics, for the combined-cycle plants with more then two CTs. A priority can be easily added to the preferred configuration, in order to manage and keep a track of the number of working hours, number of startups and shutdowns for such configurations. Aggregation of state spaces of different configurations is done according to the following steps:

- Combined-cycle configurations are ordered according to the user's predefined order (it can be the usual start-up order to reach the maximum power of a combined-cycle plant, or ordered according to the configuration's maximum power);
- State space for the first configuration is put at the bottom of the graph representing combined-cycle plant state space;

- State space for each of the following configurations is added to the latest state space of the combined-cycle plant from the previous step according to the user's predefined order;
- Base transitions, that are defined as transitions from the last state of the previous configuration to the first state of the current configuration are added;
- Non-adjacent transitions or transition jumps are incorporated on the final state space.

For each distinct configuration, the input data is organized as for classic thermal units. Start-up and shutdown costs of the first configuration are equal to the costs associated to the combustion turbine and associated generator that usually start first. Start-up and shutdown costs of the second and other configurations, are the start-up and shutdown costs of the unit that had to be added to the previous configuration to form the current one, according to the user predefined start-up order. In case such a transition is not allowed, an artificial high cost is added to prevent that transition in the optimization process.

For non adjacent transitions, the separate input that defines those transitions and associated costs is formed. The input has the following form: configuration-from, configuration-to, maximum-power-from, maximum- power-to, transition-costs.

The construction of the state space for a combined-cycle plant with two CT-HRSG pairs and one ST is depicted in Figure 17 below.

Lu and Shahidehpour 2004 and 2005 papers

The work by (LU2004) calculates the optimal generation schedule based on the decomposition of a SCUC problem (with network constraints) into a master problem (generating units) and a subproblem (network constraints). Again, LR is applied and the relaxed problem is decomposed into a set of simple subproblems for each individual unit. The individual subproblems are solved using Dynamic Programming to obtain the optimal commitment at all periods based on state transition diagrams. As the inclusion of temporal constraints such as ramping in Dynamic Programming may lead to suboptimal results, ramping constraints are handled by discretizing the generation capacity range in each configuration and extending the state-space diagram accordingly. Once the combined-cycle units are committed, the ramping between configurations and within a configuration is considered as part of the economic dispatch so that the final results satisfy the prevailing constraints.

LR is also used in (LU2005) to solve the SCUC with CCU. In the combined-cycle unit subproblem, each configuration is considered as a pseudo unit with constraints that are similar to those of thermal units. However, because configurations of a combined-cycle unit are mutually exclusive, they are considered simultaneously for commitment, given the Lagrangian multipliers. According to the dispatch solution, the Lagrangian multipliers are updated and sent back to each subproblem to re-schedule the units. This process continues until the final solution is achieved.

The optimization problem is formulated in this paper is given by equations 10 and 11 later in this report. In the combined-cycle unit subproblem, each configuration is considered as a pseudo unit with constraints that are similar to those of thermal units. However, because configurations of a combined-cycle unit are mutually exclusive, the authors consider them simultaneously for commitment, given the Lagrangian multipliers. Once the commitment of a combined-cycle unit is scheduled, they treat its unit configurations as a set of pseudo units with associated commitments and incorporate them into economic dispatch. According to the dispatch solution, they update the Lagrangian multipliers. The multipliers are sent back to each subproblem to re-schedule the units. This process is built into the existing SCUC algorithm, which includes other types of units. Such iterations will continue until the final solution is achieved.

Consideration of transitions between the states

Lu and Shahidehpour suggest that the state space for a combined-cycle unit must be set up according to the operation rules for individual configurations as well as those governing the relationship between the configurations. First, they define the operating rules for individual configurations.

The number of nodes in the state space of each configuration is equal to the minimum operation time of the configuration. The OFF state of a combined-cycle unit is Configuration 0 and the minimum OFF time of the unit is the minimum operation time of Configuration 0. In Figure 14, if the minimum OFF time of a combined-cycle unit is 3 hr, the number of states for the Configuration 0 will be three.

Accordingly, state transitions for a configuration are as follows:

$$X(i,t+1) = \begin{cases} X(i,t)+1, & X(i,t)+1 < T_{\min} \\ T_{\min}, & X(i,t)+1 \geq T_{\min} \end{cases}$$

Where

X(i, t) duration of time that unit *i* has been in a given configuration at time *t*
Tmin minimum time for unit *i* to stay in a configuration

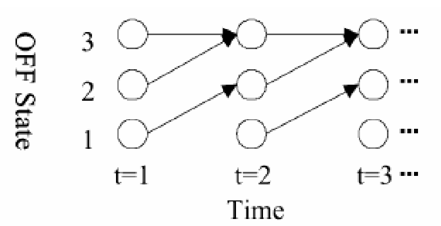


Figure 14 State transition diagram for OFF state

Next, they define the transition rules between configurations. The following rules are established accordingly.

- The outward transition from a configuration will be from its top node.
- The inward transition to a configuration will be to its bottom node.
- Since the ST operation relies on the exhaust gas emitted by CT, they choose the “first CT, then ST” rule for turning a unit ON. So a combined-cycle unit with two CTs and one ST is represented by the configurations listed in the following table.

Configuration Number	Components
1	1CT + 0ST
2	2CT + 0ST
3	1CT + 1ST
4	2CT + 1ST

The authors consider Configuration 0 at the bottom of the state-space diagram for a combined-cycle unit. Figures 15 and 16 are the upward and downward state transitions for a combined-cycle unit with configurations listed in the above table. We should point out that an outward transition could be either upward or downward. The outward transition represents the departure from the top state of a configuration; an inward transition must arrive at the bottom state of the configuration.

The conditions for establishing the state transition between configurations are discussed as follows.

- Ignore a state transition between the same configurations, which follows the representation in Figure 15.
- Multiple CTs can be turned ON/OFF simultaneously, but a CT and a ST cannot be turned ON/OFF simultaneously.
- The transition cost between two configurations is associated with the changes in the number of CTs and STs.

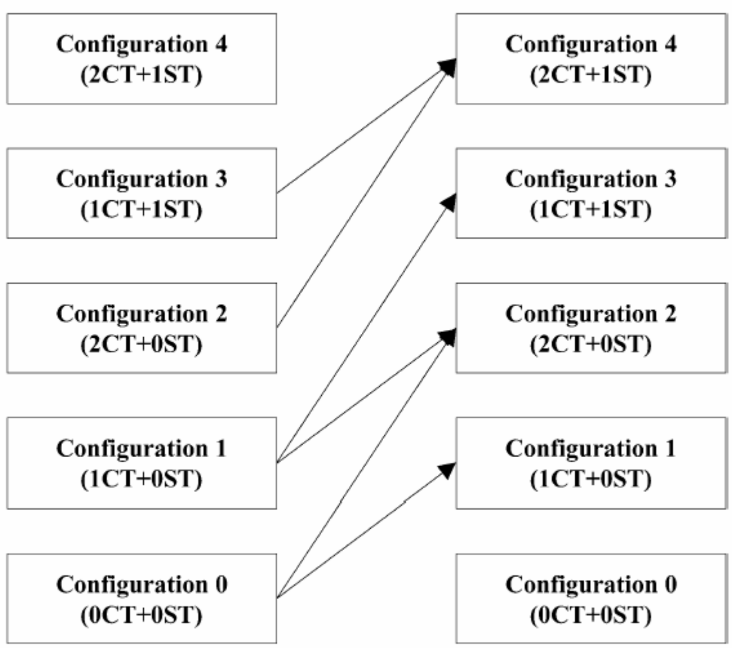


Figure 15 Upward state transition diagram

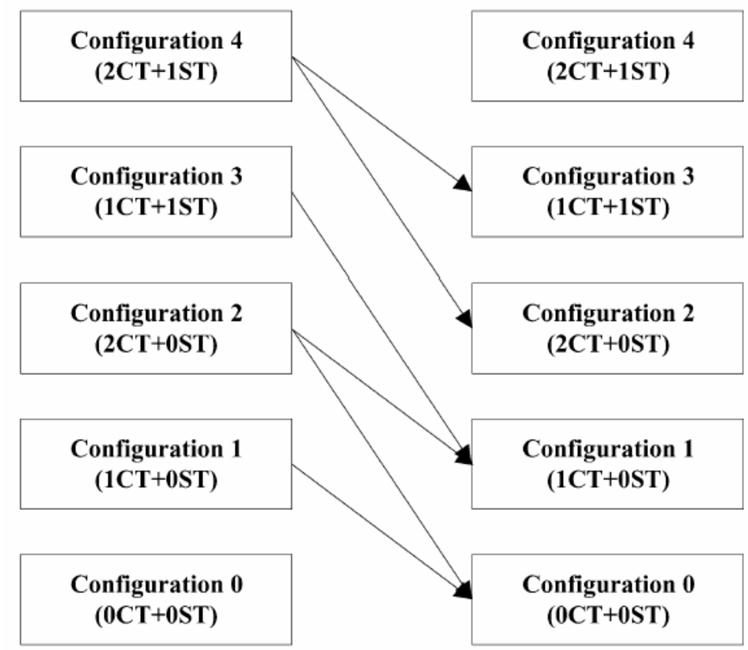


Figure 16 Downward state transition diagram

Other publications

A large stream of research in the power systems area focuses on this problem. The usual paradigm is to recast the economic optimization into the minimization of a cost minus revenues function and to account for the physical model of the plant through suitably defined constraints. The results available in the literature differ both in the features of the CCU modeled and in the scope of optimization.

In (MOSL1991), (BON1991), (FR1996) and (MOSS2000) the CCU is assumed in a standard operating condition and optimal scheduling of the resources is performed via non linear programming techniques. The main limitation is that the possibility of turning on/off the turbines is not considered and therefore it is not possible to determine the optimal switching strategy. The discrete features of a CCU (i.e., the fact that turbines can be turned on/off, the start-up dynamics, the minimum up and down time constraints and the priority constraints in start-up sequences) can be captured by using binary decision variables along with continuous valued variables describing physical quantities (e.g., mass, energy and flow rates).

In (MANO1997) binary variables are introduced to model the on/off status of the devices and the corresponding optimization problem is solved through the use of genetic algorithms. The same modeling feature is considered in (ITO1995) where the automatic computation of the optimal on/off input commands (also fulfilling operational priority constraints) is accomplished through Mixed Integer Linear Programming (MILP). However, in both papers the modeling of the CCU is done in an ad-hoc fashion and the generalization to plants with different topologies and/or specifications seems difficult. Moreover, other important features such as minimum up and down times or the behavior during start-up are neglected.

A fairly complete model of a thermal unit, using integer variables for describing minimum up/down time constraints, ramp constraints and different start-up procedures, is given in (AR2000). The behavior of the unit is then optimized by solving MILP problems. Even if this approach could be adapted for modeling a single turbine of a CCU, no methodological way for describing the coordination between different turbines is provided.

The paper (FR2002) shows how both the tasks of modeling and optimization of CCUs can be efficiently solved by resorting to hybrid system methodologies[1]. The authors use discrete-time hybrid systems in the Mixed Logical Dynamical (MLD) form to provide a general framework for modeling many discrete features of CCUs, including the coordination and prioritization between different devices. The drawback of this excellent paper is that it considers only one CT working with one ST unit. The papers by Lu and Shahidehpour reviewed above can be viewed as an extension of this paper.

Summary

The subject of modeling of combined-cycle units has been attracting increasing attention among power system researchers. The majority of the models published in the literature use the same basic formulation as described by equations 10 and 11 below. The CC units are modeled so that the CTs and STs are represented as separate physical units with some limitations on the state space transitions. The majority of successful applications use Mixed Integer and Linear programming approach as an optimization method of choice. Some approaches use the Lagrangian relaxation technique.

4.3 Suggested Methodologies to Solve the SCUC with CCU

This section discusses four distinct approaches to solving the SCUC problem with CCU. The first approach is based on mixed integer programming (MIP), the second is a hybrid of LR and metaheuristics, the third is a hybrid of MIP and metaheuristics, and the fourth and final one is a pure metaheuristic approach. The adequacy of each approach to solve the problem will however require a deeper knowledge of some problem details, namely its dimension. Other aspects are related to what the decision maker requirements for the supporting tool are.

Before introducing the methodologies, some considerations on how to model combined-cycle units, so that each technique may be applied, will be made. This will be followed by a more detailed description of the proposed approach using MIP with several numerical examples.

4.3.1 Modeling Combined Cycle Units

This section discusses some issues related to the mathematical modeling of combined-cycle units and how this may affect the utilization of standard optimization techniques, such as MIP and LR. Besides, it also presents a possible coding solution for this problem, if metaheuristics are to be applied. All considerations that will be made may be generalized to other types of units with multiple configurations (e.g., fuel switching and over-fired units).

[1] In the nomenclature of this paper, a hybrid system is one that employs both continuous and discrete variables.

(LU2004) suggest that CCU could be split into a set of "sub-units," each of them representing one of the possible configurations of that unit. Mathematically, the state of each configuration would be represented by a binary variable which would take the value 1 if the unit was in that configuration, and the value 0, otherwise.

We suggest a slightly different approach, by considering a binary variable with three indexes, rather than two, as follows:

$$u_{ijt} = \begin{cases} 1 & \text{if unit } i \text{ is in configuration } j \text{ in period } t \\ 0 & \text{otherwise} \end{cases}$$

In terms of constraints, each unit must be assigned a set of constraints similar to conventional thermal units. Furthermore, constraints related to the transitions that are allowed between configurations must also be considered. They will map the set of rules represented in state transition diagrams, indicating which transitions may be done. Furthermore, as configurations are mutually exclusive, one will have to guarantee that each CCU is in a single configuration mode, in each period of time. These constraints will be represented by equations similar to (8), where the transition from configuration *j* to configuration *k* is not allowed for unit *i*, and to (9), that guarantees that, in each period of time, one unit cannot be in more than one configuration.

$$u_{ijt} + u_{ik(t+1)} \leq 1 \quad \forall t \tag{8}$$

$$\sum_j u_{ijt} = 1 \quad \forall i \forall t \tag{9}$$

If this notation is used, once the state space and transition constraints are defined, both LR and MIP can be used. The LR method for optimizing exclusive modes is identical to the standard LR method, except for the inclusion in the Lagrangian function of a new term related to CCU. The remainder of the methodology, using Dynamic Programming, can be used to solve the single unit problems in much the same way as for regular problems, with an increase in the number of states.

Concerning MIP-based methods, as far as the state transition diagrams are appropriately reflected in the problem formulation through a set of adequate constraints, they may also be used with no further considerations.

Another possible representation of the state of each CCU would be to consider an integer variable where each value would represent one possible configuration of a combined-cycle unit, e.g., u_{it} would equal 0, if the unit was off, 1 if it was in a 1 CT + 0 ST configuration, 2 if it was in a 2 CT + 0 ST configuration, etc. Although this may not be the most adequate representation, if we think of standard techniques based on Mixed Integer Programming, it is our opinion that it might be suitable if a metaheuristic approach was chosen. Therefore, this may be an alternative to consider in a future implementation.

4.3.2 State Transitions and Related Constraints

State transition diagrams for a combined-cycle unit are more difficult to design than those for other units with flexible operating conditions, due to their multiple configurations. Typically, a combined-cycle plant consists of several CTs and a set of STs. Based on possible CT and ST combinations, a combined-cycle unit can operate at multiple configurations according to its operating limits. So the state space for a combined-cycle unit must be set according to the operation rules for individual configurations, as well as to those constraining the transition between the configurations. Much of the discussion for creating the state-space diagram in combined-cycle units is presented in (LU2004).

An example of a state space diagram for a CCU with two CTs and one ST is depicted in Figure 17, assuming that minimum and maximum power levels may be reached within a time period. It is assumed that transitions between some configurations are not allowed (e.g., between configurations 2 and 3). In practical terms, for DP to consider these constraints, it would only be required that a large value be assigned to the transition costs between these two states.

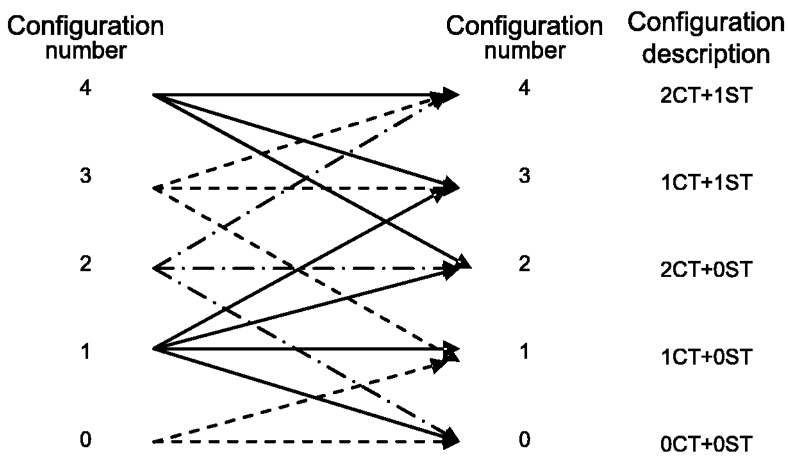


Figure 17 State space diagram for a combined-cycle unit

This type of diagram may also represent minimum up time constraints, by replicating each configuration as many times as the value assigned to the minimum up time. Suppose that a minimum up time of 2 was assigned to configuration 2, in the previous example. This constraint might be represented by dividing configuration 2 into two possible sub-configurations (2.1 and 2.2), one for each hour that the unit was operating in that configuration. The resulting state space diagram is depicted in Figure 18. For simplification purposes, only transitions within state 2 and from state 2 are presented.

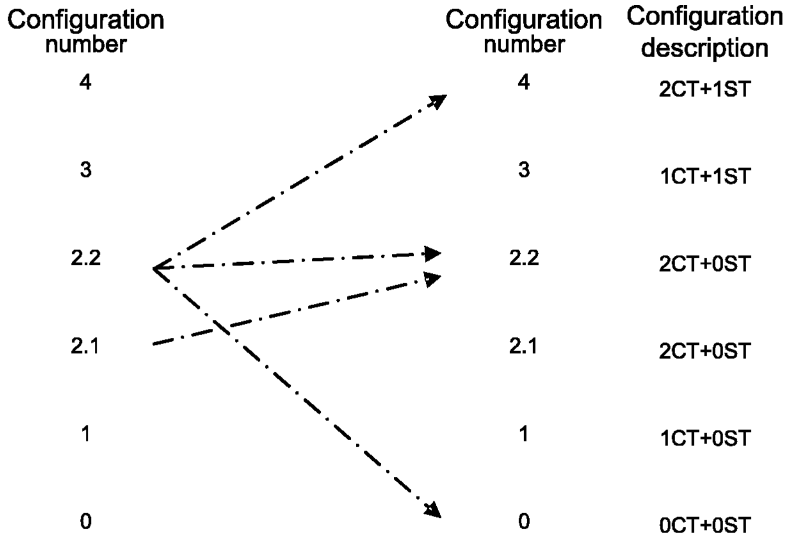


Figure 18 State space diagram for a combined-cycle unit with minimum up times

If ramp rates are introduced in the problem modeling, the above state space diagram will not be affected, as long as there are no technical constraints preventing one unit from moving from one configuration to another before a certain production level has been reached.

4.3.3 *Suggested Approaches*

We suggest four distinct approaches to solve the SCUC with combined-cycle units: MIP LR with metaheuristics, MIP with metaheuristics and pure metaheuristics. The practicability of each approach is constrained by several factors, namely the dimension of the problem to solve. Therefore, several considerations are made for each of the approaches that are proposed.

4.3.3.1 Mixed Integer Programming (MIP)

A MIP approach would be the most straightforward way of solving this problem. It would require a thorough mathematical formulation of the problem that would include the standard constraints used to model thermal units plus constraints of the type referred in Section 4.2.1, to forbid some transitions and prevent more than one configuration being assigned to one CCU. The model would then be introduced in a solver that, depending on the problem's dimension, might solve it to optimality.

The problem formulation presents some "interesting" characteristics that may allow a more efficient search. Constraint (9), for example, is of particular interest in MIP optimization as it allows a reduction in the search space (if the appropriate mechanisms are made available) and, consequently, the computational time required to obtain a solution is also lower. Solvers like CPLEX by ILOG have those mechanisms and correctly handle these types of constraints. Even so, this particularity of the formulation may not be sufficient to allow optimal solutions for real size problems to be obtained. Therefore, some previous testing is required to study the capability of the solver to reach the optimal solution. If this pre-testing leads to the conclusion that optimal solutions are not achievable, then it will be necessary to implement an approximate method still based on MIP but with cuts in the search space. This approach is illustrated in the numerical example below.

4.3.3.2 LR and Metaheuristics
It is well known that what is regarded as a major advantage of LR by Decision Makers is that it provides a lower bound on the cost of the best possible schedule. However, this also presents drawbacks that may be if metaheuristics are also considered, namely, the lack of convergence for some problems. Therefore, the second option considers a hybrid approach based on LR and metaheuristics.

We suggest a two-step approach to solve the problem. In the first step, the standard LR would be used for a pre-specified number of iterations (or computational time) providing a feasible solution and a lower bound on the cost of the best possible schedule. Afterwards, metaheuristics would try to improve the resulting solution.

To apply LR if we originally have a Lagrangian function as the one in equation (10), the inclusion of CCU will originate a new equation, as the one represented in equation (11).

$$L = \sum_{t=1}^{T} \left\{ \sum_{i=1}^{I} C\left((P_{it}, u_{it}\right) \right\} - \lambda_t \left[\sum_{i=1}^{I} P_{it} - P_t^d \right] - \mu_t \left[\sum_{i=1}^{I} \overline{P}_i u_{it} - P_t^d - R_t \right] \tag{10}$$

$$L_{CC} = L + L_{CCU} = L + \sum_{t=1}^{T} \left\{ \sum_{c=1}^{C} \sum_{j=1}^{J} \left[C\left((P_{cjt}, u_{cjt}\right)\right] \right\} - \lambda_t \left[\sum_{c=1}^{C} \sum_{j=1}^{J} P_{cjt} \right] - \mu_t \left[\sum_{c=1}^{C} \sum_{i=1}^{I} \overline{P}_{cj} u_{cjt} - P_t^d - R_t \right] \tag{11}$$

λ_t is the Lagrangian multiplier for the load balance constraint in time t; μ_t is the Lagrangian multiplier for the spinning reserve constraint in time t; L_{CCU} is the Lagrangian function for combined-cycle units, I and C are the number of thermal and combined-cycle units, respectively; P_{cjt} is the production level of unit c in configuration j and P_{cj} is the maximum production of unit c in configuration j.

We do have some concerns regarding the increase of the state space in Dynamic Programming. In fact, we move from a situation where only two states were considered in each stage of the DP process, to a situation where several other states will have to be considered. This may result in a drastic increase in the search space and DP may become inefficient. If this happens, a solution that would consider some simplifications, and therefore might lead to suboptimal results, would have to be implemented. Even so, no final conclusions may be drawn before some testing is performed.

4.3.3.3 MIP and Metaheuristics
The third option is a hybrid solution based on MIP and metaheuristics that should only be considered when MIP is not able to find the optimal solution due to time constraints. Again, we would have a two-step approach to solving the problem. In the first step, an MIP optimization would be performed, for a pre-specified number of iterations (or computational time) providing a

feasible solution and a lower bound on the cost of the best possible schedule. Afterwards, metaheuristics would try to improve the resulting solution.

Compared to the previous approach, this one has the advantage of being able to optimize any objective function, even if it is not separable.

4.3.3.4 Metaheuristics

The last option regards a pure metaheuristics implementation. Metaheuristics have been used to solve the UC problem before, and presented very good results when compared to techniques such as LR, both in terms of efficiency and quality of the results (VIANA05).

An advantage of these techniques, when compared to LR and MIP, is that they are able to tackle the non-linearities of the problem, while the others cannot correctly reflect them. A (possible) drawback is that they do not provide any information on how far the current solution is from the optimal. Furthermore, as they are non-deterministic methods, they may provide quite different results in successive runs. Therefore, a study on the consistency of the results should be performed.

If metaheuristics are to be applied, a solution representation similar to the one used when thermal units are modeled, might be used. We would therefore consider a matrix, where each row represents the operation schedule of one unit over the planning horizon and each element of a row represents the state/configuration of that unit in a given period of time. Once an initial feasible solution was built, through a set of simple priority rules, it would be subject to "self-contained" changes that would try to improve it. Further details on the approach may be found in Appendix E.

5.0 PROPOSED APPLICATION OF THE MIP FOR THE COMMITMENT AND DISPATCH OF CCG UNITS

The proposed MIP approach to the commitment and dispatch of generating units has several advantages over other approaches currently used, in particular the Lagrangian relaxation. In our opinion there are two powerful methods that can be used for the commitment and dispatch:

- Dynamic programming (DP);
- Mix Integer (& Linear) Programming (MIP).

The first method, DP, is very general and can be used in processes that have linear and nonlinear characteristics. However, DP requires a large amount of computing resources due to its two-stage optimization, and long computing time is also required to obtain any solution. In our practice, we were never able to obtain practical results from the DP application for a system larger than 20-30 units.

The MIP is not as universal as the DP methodology as it requires linearization of nonlinear characteristics. However, this problem can be easily overcome by a piece-wise linear approximation of a nonlinear characteristic. It increases the number of variables but it does not cause difficulties in obtaining of a solution. For example, the nonlinear (step function) of the bid is modeled by assigning a variable to each band of the bid. If a bid consists of 10 bands, it is represented by 10 variables.

A practical application of the MIP requires mainly modeling of the commitment and dispatch problems as shown below. There are several powerful engines which can successfully solve the linear optimization problems with integer variables. We have practical experience with XPRESS, the engine produced by Dash Corp. in the UK. This engine uses a simplex matrix for performing linear optimization and a cut method to find the solution among binary variables. One long-running practical implementation models over 100 generating units using 25,000 linear variables, 2,500 binary variables and 50,000 pseudo-variables (constraints). The simplex matrix has the size 25,000 by 75,000 with over 2,000,000 non-zero elements.

5.1 Modeling Units for Commitment and Dispatch

5.1.1 The Objective Function

The objective function of the commitment and dispatch problem is formulated as the sum of the three major cost components. Additional complexities arise if reserve and/or regulation services are considered. The three components are:

- Cost of energy due to the prices provided in the balancing bids;
- Cost of the start-up, if it happens;
- Cost of the unit shutdown, if it happens.

$$\min\ C_{GENERATION} = \min \sum_{\text{Periods}} \sum_{\text{Generators}} (C_{BIDS} + C_{START-UP} + C_{SHUT-DOWN}) \tag{12}$$

Where

$C_{GENERATION}$	Total cost of the energy dispatched
C_{BIDS}	The cost of energy purchased from the balancing bids
$C_{START\text{-}UP}$	The cost of start-up
$C_{SHUT\text{-}DOWN}$	The cost of shutdown

5.1.2 *Balancing Demand*

The energy dispatch must in each calculation period balance the given dispatch.

$$Energy_{Period} = \sum_{\text{Generators}} (Energy_{BIDS} + Energy_{START-UP} + Energy_{SHUT-DOWN}) \geq Demand_{Period} \tag{13}$$

We may change (13) to an equality constraint.

Where

$Energy_{period}$	The total energy dispatch in each calculation period
$Energy_{BIDS}$	The energy purchased from the balancing bids
$Energy_{START\text{-}UP}$	The energy produced during start-up
$Energy_{SHUT\text{-}DOWN}$	The energy produced during shutdown

5.1.3 *The Cost of Energy Purchased from the Balancing Bids*

This cost is calculated as the product of the price from the given band of the balancing bids and the energy purchased from this band of the balancing bid.

$$C_{BIDS}(i) = \sum_{\substack{i \in bids \\ accepted\ set}} Bids\ Price(i) * Bids\ Energy(i) \tag{14}$$

Where

C_{BIDS} *(i)*	The cost of energy purchased from the balancing bids
Bids Price(i)	The price in the selected band of the balancing bid
Bids Energy(i)	The energy purchased from the selected band of the balancing bid

5.1.4 *Cost of Energy During Shutdown*

The shutdown of any unit depends on its characteristics. For example, if the CCGT unit consists of three units, the shutdown characteristic can be constructed as shown in Table 1

Table 1 Characteristic of shutdown

15-minute period	h	h+1	h+2	h+3
CT1	60	30	0	0
CT2	60	60	30	0
ST	60	0	0	0
Total	**180**	**90**	**30**	**0**

When the shutdown process is initiated, the variables representing the load of particular units have to satisfy the pattern of the shutdown characteristic as follows.

If Shut_Down = 1 then

If i=h then $P_{CT1}^{i} = P_{CT1}^{\min}$ $P_{CT2}^{i} = P_{CT2}^{\min}$ $P_{ST}^{i} = P_{St}^{\min}$ $P_{CCGT}^{i} = P_{Ct1}^{i} + P_{CT2}^{i} + P_{ST}^{i}$

If i=h+1 then $P_{CT1}^{i} = 0.5 * P_{CT1}^{\min}$ $P_{CT2}^{i} = P_{CT2}^{\min}$ $P_{ST}^{i} = 0$ $P_{CCGT}^{i} = P_{Ct1}^{i} + P_{CT2}^{i} + P_{ST}^{i}$

If I=h+2 then $P_{CT1}^{i} = 0$ $P_{CT2}^{i} = 0.5 * P_{CT2}^{\min}$ $P_{ST}^{i} = 0$ $P_{CCGT}^{i} = P_{Ct1}^{i} + P_{CT2}^{i} + P_{ST}^{i}$

If I=h+3 then $P_{CT1}^{i} = 0$ $P_{CT2}^{i} = 0$ $P_{ST}^{i} = 0$ $P_{CCGT}^{i} = P_{Ct1}^{i} + P_{CT2}^{i} + P_{ST}^{i}$

End if

There are two possible options to price the energy produced during the shutdown process:

- Energy is priced based on the prices in the balancing bids $C_{CCGT}^{Shut\_Down}(i) = P_{CCGT}^{i} * c_{CCGT}^{j}$, where "j" denotes the appropriate band in the balancing bids.
- Energy is priced using the special price submitted separately or located in a special way in the balancing bids. For example, in the 10-band balancing bids, bands 10 and 9 can be assigned as the start-up price and shutdown price, respectively $C_{CCGT}^{Shut\_Down}(i) = P_{CCGT}^{i} * c_{CCGT}^{Shut\_Down}$

5.1.5 *Cost During the Start-up Process*

The start-up of any CCGT unit is described by the characteristics of the particular unit and the relation between the energy generated by the CCGT components. For the unit characteristics provided by the NYISO, the characteristics are summarized in Table 2 and shown graphically in Figure 19.

Table 2 The start-up characteristics of CCGTU

	CT1	CT2	ST	CCGT
h	2.3	0.0	0.0	2.3
h+1	7.0	0.0	0.0	7.0
h+2	7.0	0.0	0.0	7.0
h+3	7.0	0.0	0.0	7.0
h+4	7.0	0.0	1.8	8.8
h+5	7.0	0.0	11.2	18.2
h+6	7.0	0.0	11.6	18.6
h+7	7.0	0.0	11.6	18.6
h+8	7.0	0.0	15.1	22.1
h+9	7.0	0.0	18.6	25.6
h+10	39.4	6.9	22.8	69.1
h+11	80.0	13.2	30.6	123.7
h+12	80.0	22.4	39.5	141.9
h+13	80.0	60.8	71.4	212.2
h+14	80.0	80.0	80.0	240.0

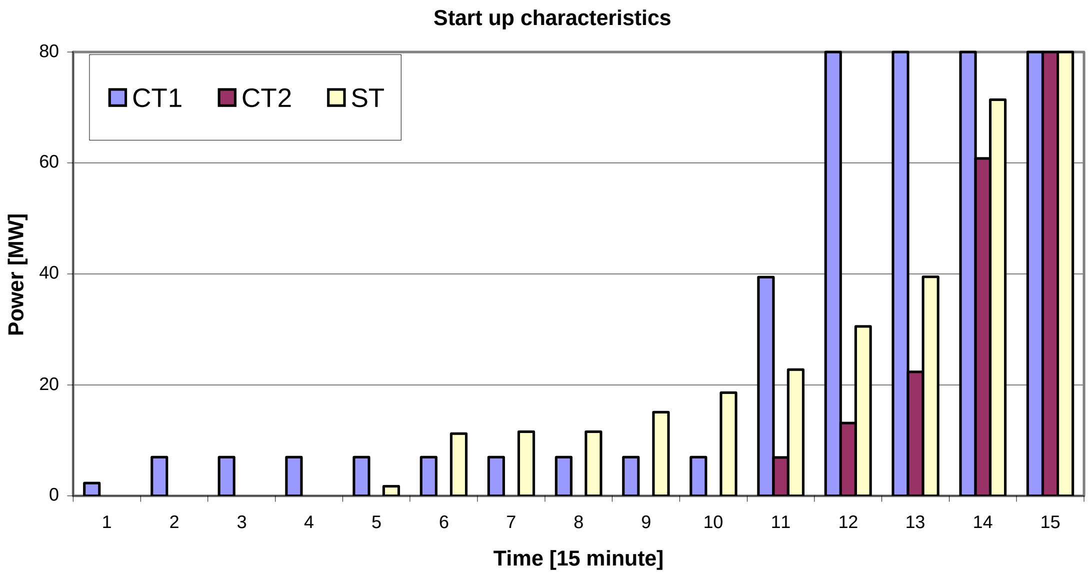


Figure 19 The start-up characteristics of a CCGT unit (based on the data from the NYISO)

Similarly to the shutdown process, the start-up characteristics can be described as a set of variables with the appropriate relations between them.

Also here, there are two possible options to price the energy produced during the start-up process:

- Energy is priced based on the prices in the balancing bids $C_{CCGT}^{Shut\_Down}(i) = P_{CCGT}^{i} * c_{CCGT}^{j}$, where "j" denotes the appropriate band in the balancing bid.
- Energy is priced using the special price submitted separately or located in a special way in the balancing bids. For example, in the 10-band balancing bids, bands 10 and 9 can be assigned as the start-up price and shutdown price respectively $C_{CCGT}^{Start\_up}(i) = P_{CCGT}^{i} * c_{CCGT}^{Start\_up}$

5.2 Commitment and Dispatch

Figure 20 shows a diagram describing the commitment and dispatch.

The power generating units provide to the ISO the following information:

- Balancing bids;
- Technical data.

The balancing bids can be of various forms, for example:

- Balancing bids with 10 or more bands;
- Balancing bids can be submitted for the entire day, for each hour or for every 15 minutes.

It is also possible to submit the default bids which are used by ISO if the update does not arrive.

The technical data submitted by the power generation units can contain:

- Maximum and minimum power;
- Ramp rates;
- Start-up characteristics;
- Shutdown characteristics;
- Information of inflexible start time;
- Information on inflexible generation.

It is also possible to submit the default technical data which is used by the ISO if the update does not arrive.

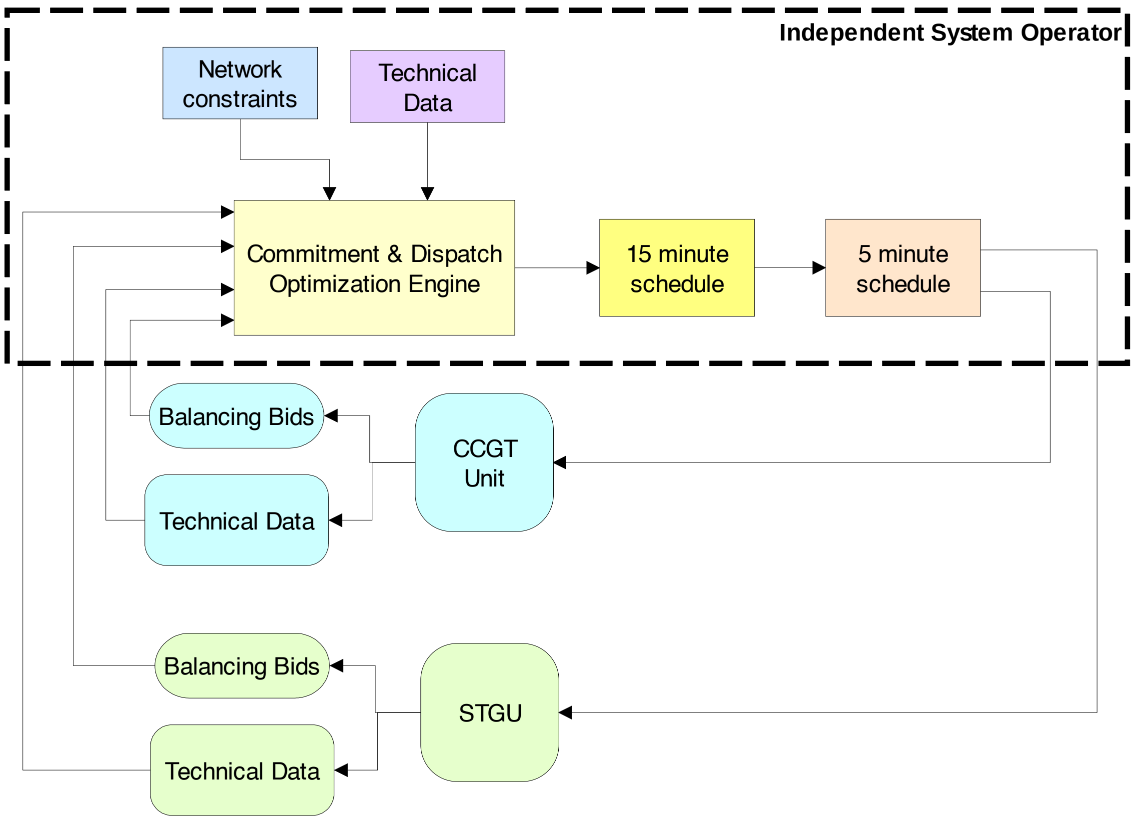


Figure 20 Diagram showing the relations between the ISO and power generating units

The optimization engine generates a commitment and dispatch schedule in 15-minute time intervals. This schedule is split into 5-minute control signals to be sent to power generating units.

It is also possible to recalculate the 15-minute schedule into power signals and transfer to power generating units for each time interval: the initial power and a ramp rate.

5.3 The Traditional Approach

In one approach (COH96), the CCGT unit is modeled with the application of operating states (modes) and transitions between these modes. The example of this modeling is shown in Figure 21.

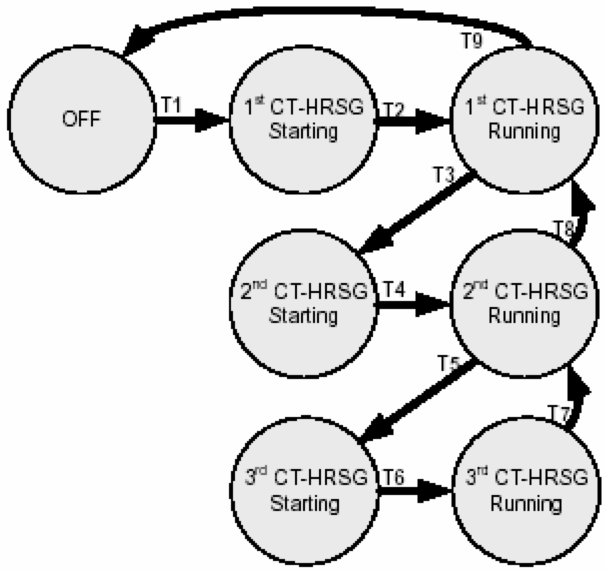


Figure 21 Mode and Transition Model of a Three-on-One Combined-Cycle Modeling [Source: Combined-Cycle Modeling, Draft, NYISO]

This approach leads to a complicated system of transitions which are difficult to predict and control. This subject is discussed in more detail Section 4.1.

5.4 A New Approach

A new approach is based on the following assumptions:

- Each CCGT unit is divided into a number of component modes. Components of a CCGT are the Combustion Turbines (CT), Heat Recovery Steam Generator (HRSG), and Steam Turbines (ST). The CT and HRSG can usually be thought of as a single component.
- Each component mode is described by the states defining the energy produced by a given component in a given 15-minute period.

  The relations between states of particular component modes are defined in the Relation Matrix and can be used for commitment and dispatch of the entire CCGT unit.

5.4.1 Main Working Modes of a CCGT

A CCGT unit can be in four main modes:

- Start-up;
- Regulating Up;

- Regulating Down;
- Shutdown.

In some cases, the two modes "Regulating Up" and "Regulating Down" can be considered as one "Regulating Mode." If needed, one can also consider the regulating mode split into two regions: regulating up/down – low range, and regulating up/down – high range. Some CC units have a 50% lower operating limit. The low range is approximately 50% - 80%. The high range is approximately 80% - 100%. The low range has a higher incremental cost than the high range.

This can be described mathematically as

$$CA(m) = \{CA_S,\ \ CA_{UP}^R\ \ \ CA_{Down}^R,\ \ CA_{Down}\} \tag{15}$$

Where

m = one of four main modes

Each of these modes can be described as a set of possible states.

5.4.2 Setting Modes

The variables defining the modes and states during the start-up period are defined as follows:

CCGT Start-up mode

$$CA_S = \{\begin{Bmatrix} 0 \ \ before \\ 1 \ \ during \\ 2 \ \ completed \end{Bmatrix} \tag{16}$$

CCGT regulation mode (up)

$$CA_{UP}^R = \begin{Bmatrix} 0 \ \ notactive \\ 1 \ \ active \end{Bmatrix} \tag{17}$$

CCGT regulation mode (down)

$$CA_{Down}^R = \begin{Bmatrix} 0 \ \ notactive \\ 1 \ \ active \end{Bmatrix} \tag{18}$$

CCGT shutdown mode

$$CA_{\mathrm{Down}} = \{\begin{Bmatrix} 0 \ \ before \\ 1 \ \ during \\ 2 \ \ completed \end{Bmatrix} \tag{19}$$

It is worth mentioning that two modes "Regulating Up" and "Regulating Down" are expressed by two values {0, 1} as they can follow each other without a need for a delay in time. The "Start-up" mode is expressed by three values as the information about the end of this mode is required to allow for Regulating modes. Moreover, the unit cannot come back to the starting mode without passing "Shutdown" mode.

A flow chart of the commitment of a CCGT unit is shown in Figure 22. The logic is that if CAs=1, it means that the system can start the start-up process. The logical variable CAs=1 when the start-up process is continued. When the start-up process is completed, then CAs changes its value to 2 and the unit goes to the regulation mode.

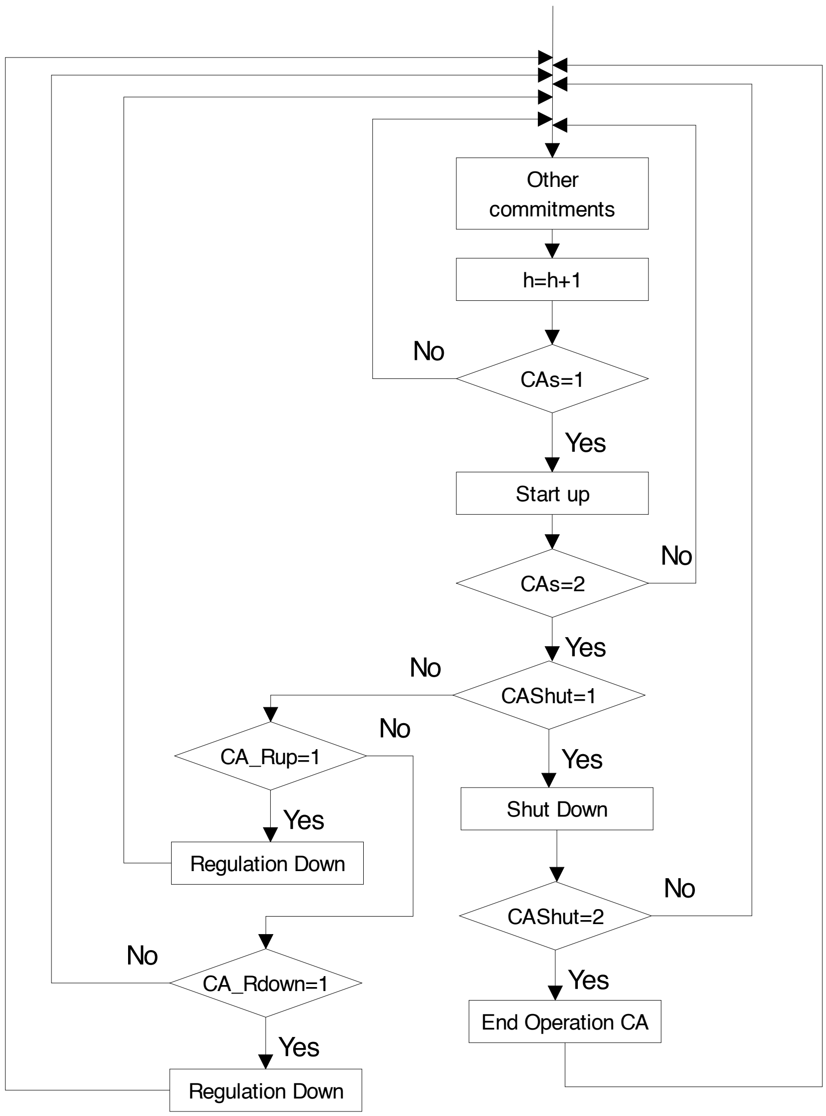


Figure 22 Flow chart of commitment of a CCGT unit

5.4.3 *Start-up Characteristics*

Assuming that CCGT unit comprises two gas turbines and one steam turbine, their start-up characteristics are as presented in Figure 23.

Each dot in this figure defines one state of the starting mode of any CCGT unit component. The state is the value of energy generated by a particular component in a 15-minute period.

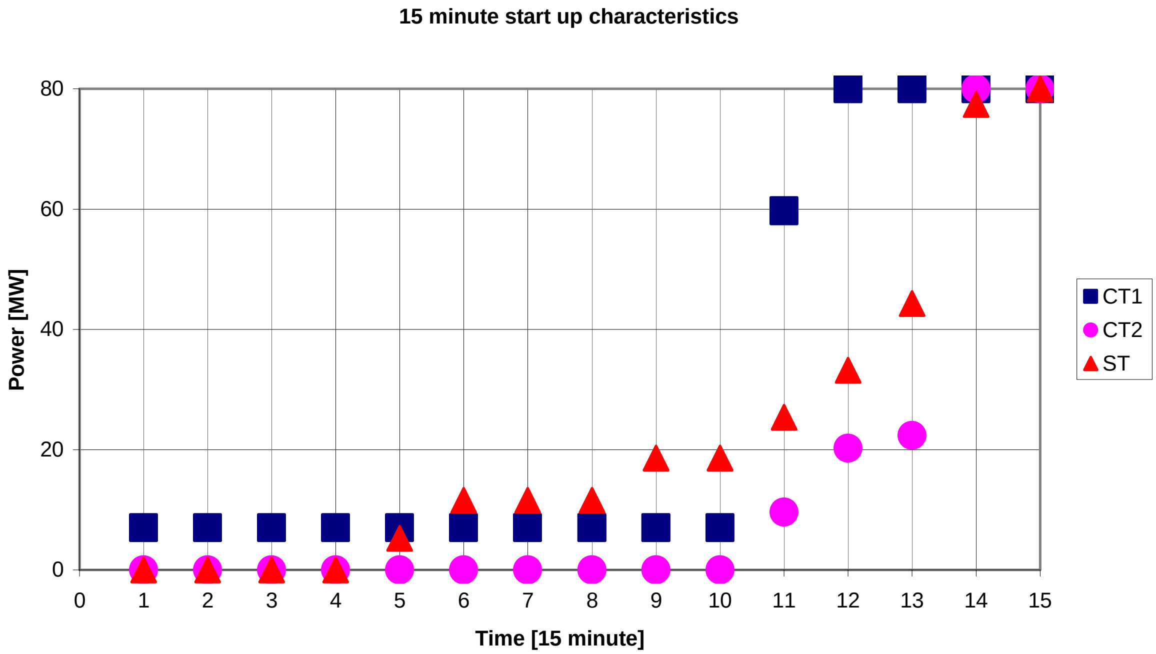


Figure 23 The states of CCGT components during start-up

5.4.3.1 CT1 start-up states

The gas turbine denoted as CT1 can have several start-up states as shown in Figure 24.

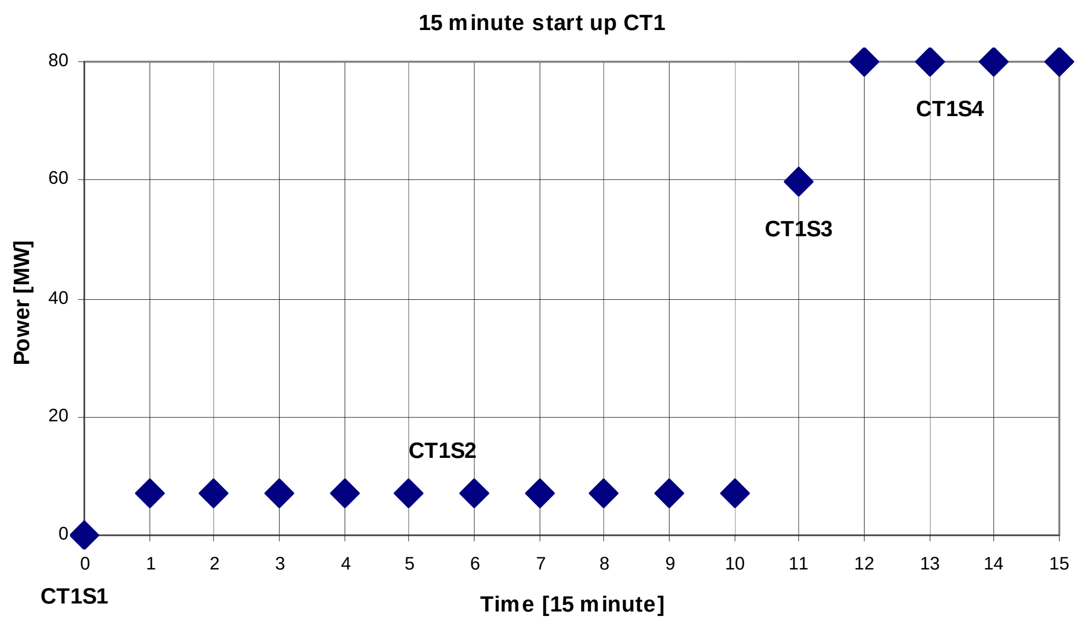


Figure 24 Start-up characteristic of CT1

The possible states of CT1 during start-up can be described mathematically as follows.

$$CT1_S = \{CT1S1,\ CT1S2,\ CT1S3,\ CT1S4\} \tag{21}$$

5.4.3.2 ST start-up states

The heat recovery steam turbine denoted as ST can have several modes as shown in Figure 25 when a CCGT unit operates in the "2-on-1" configuration.

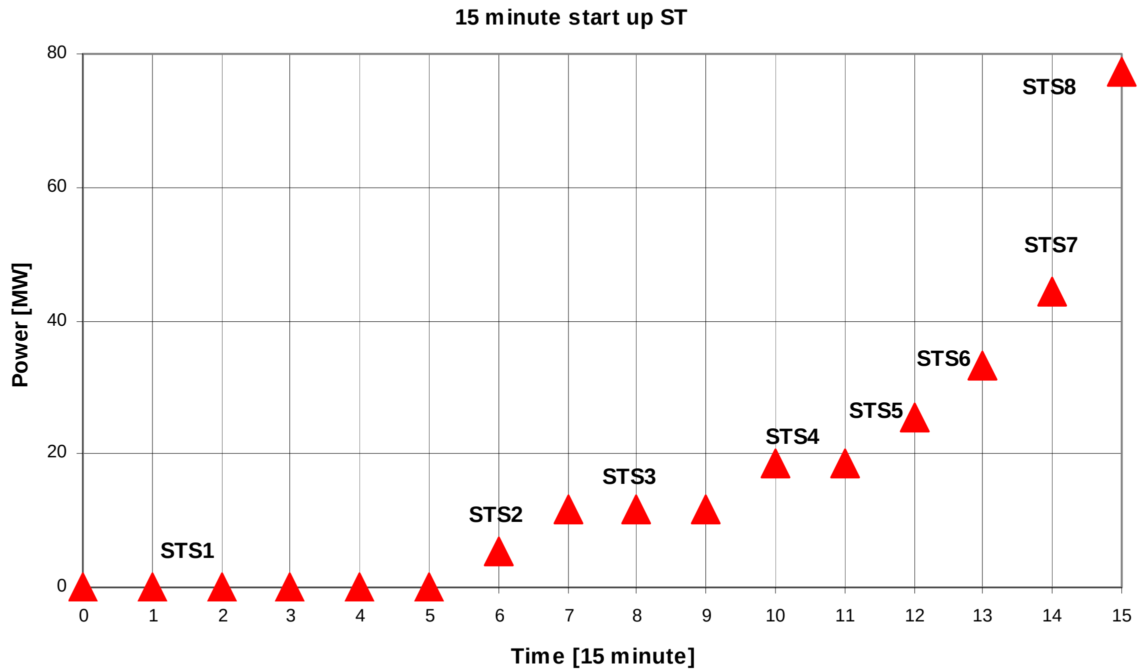


Figure 25 The states of start-up characteristic of ST when operating in the "2-on-1" configuration

The possible states of ST during start-up can be described mathematically as

$$ST_S = \{STS1,\ STS2,\ STS3,\ STS4,\ STS5,\ STS6,\ STS7,\ STS8,\}$$

5.4.3.3 CT2 start-up states

The gas turbine denoted as CT2 can have several modes as shown in Figure 26. The characteristic relates to the configuration "2-on-1" when CT2 starts as the second gas turbine.

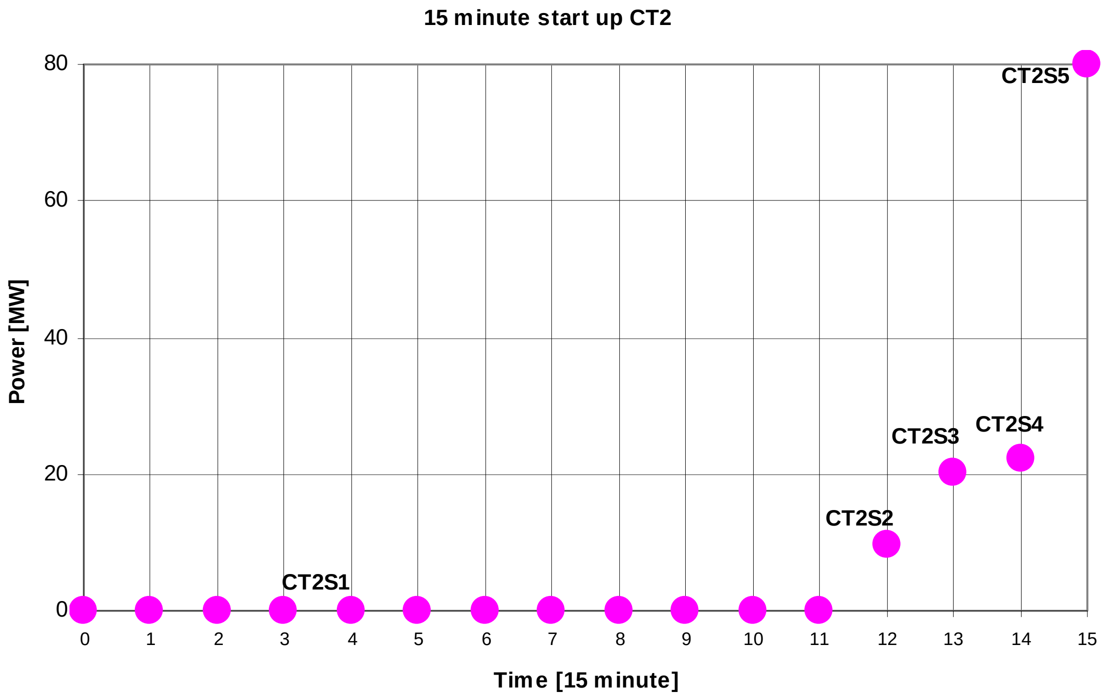


Figure 26 Start-up characteristic of CT2

The possible states of CT2 during start-up can be described mathematically as

$$CT2_S = \{CT2S1,\ CT2S2,\ CT2S3,\ CT2S4,\ \ ST2S5\}$$

5.4.3.4 Start-up state logical values

The start-up process can be described by logical variables, as shown below. Each of the logical variable can take two values {0, 1} depending on whether the CCGT unit component is in a given state or not.

$$CA_S = \{CT1_S,\ CT2_S,\ ST_S\}$$

Possible states of the CCGT components are as follows:

$$CT1_S = \{CT1S1,\ CT1S2,\ CT1S3,\ CT1S4\}$$

$$ST_S = \{STS1,\ STS2,\ STS3,\ STS4,\ STS5,\ STS6,\ STS7,\ STS8,\}$$

$$CT2_S = \{CT2S1,\ CT2S2,\ CT2S3,\ CT2S4,\ \ ST2S5\}$$

The transition matrix is shown in Table 3 for the operation in the "2-on-1" configuration. Table 4 demonstrates the transition matrix when the power generated in particular states is used in the matrix.

Tables 5 and 6 show the transition matrices when a CCGT unit operates in the "1-on-1" configuration.

Table 3 Logical transition matrix for the start-up process for the "2-on-1" configuration

Period	CT1S1	CT1S2	CT1S3	CT1S4	STS1	STS2	STS3	STS4	STS5	STS6	STS7	STS8	CT2S1	CT2S2	CT2S3	CT2S4	CT2S5
0	1	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
1	0	1	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
2	0	1	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
3	0	1	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
4	0	1	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
5	0	1	0	0	0	1	0	0	0	0	0	0	1	0	0	0	0
6	0	1	0	0	0	0	1	0	0	0	0	0	1	0	0	0	0
7	0	1	0	0	0	0	1	0	0	0	0	0	1	0	0	0	0
8	0	1	0	0	0	0	1	0	0	0	0	0	1	0	0	0	0
9	0	1	0	0	0	0	1	0	0	0	0	0	1	0	0	0	0
10	0	1	0	0	0	0	1	0	0	0	0	0	1	0	0	0	0
11	0	0	1	0	0	0	0	1	0	0	0	0	0	1	0	0	0
12	0	0	0	1	0	0	0	0	1	0	0	0	0	0	1	0	0
13	0	0	0	1	0	0	0	0	0	1	0	0	0	0	0	1	0
14	0	0	0	1	0	0	0	0	0	0	1	0	0	0	0	0	1
15	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	1

Table 4 Power values of the transition matrix for the start-up process for the "2-on-1" configuration

Period	CT1S1	CT1S2	CT1S3	CT1S4	STS1	STS2	STS3	STS4	STS5	STS6	STS7	STS8	CT2S1	CT2S2	CT2S3	CT2S4	CT2S5
0	$CT1S1^P$	0	0	0	$STS1^P$	0	0	0	0	0	0	0	$CT2S1^P$	0	0	0	0
1	0	$CT1S2^P$	0	0	$STS1^P$	0	0	0	0	0	0	0	$CT2S1^P$	0	0	0	0
2	0	$CT1S2^P$	0	0	$STS1^P$	0	0	0	0	0	0	0	$CT2S1^P$	0	0	0	0
3	0	$CT1S2^P$	0	0	$STS1^P$	0	0	0	0	0	0	0	$CT2S1^P$	0	0	0	0
4	0	$CT1S2^P$	0	0	$STS1^P$	0	0	0	0	0	0	0	$CT2S1^P$	0	0	0	0
5	0	$CT1S2^P$	0	0	0	$STS2^P$	0	0	0	0	0	0	$CT2S1^P$	0	0	0	0
6	0	$CT1S2^P$	0	0	0	0	$STS3^P$	0	0	0	0	0	$CT2S1^P$	0	0	0	0
7	0	$CT1S2^P$	0	0	0	0	$STS3^P$	0	0	0	0	0	$CT2S1^P$	0	0	0	0
8	0	$CT1S2^P$	0	0	0	0	$STS3^P$	0	0	0	0	0	$CT2S1^P$	0	0	0	0
9	0	$CT1S2^P$	0	0	0	0	$STS3^P$	0	0	0	0	0	$CT2S1^P$	0	0	0	0
10	0	$CT1S2^P$	0	0	0	0	$STS3^P$	0	0	0	0	0	$CT2S1^P$	0	0	0	0
11	0	0	$CT1S3^P$	0	0	0	0	$STS4^P$	0	0	0	0	0	$CT2S2^P$	0	0	0
12	0	0	0	$CT1S4^P$	0	0	0	0	$STS5^P$	0	0	0	0	0	$CT2S3^P$	0	0
13	0	0	0	$CT1S4^P$	0	0	0	0	0	$STS6^P$	0	0	0	0	0	$CT2S4^P$	0
14	0	0	0	$CT1S4^P$	0	0	0	0	0	0	$STS7^P$	0	0	0	0	0	$CT2S5^P$
15	0	0	0	$CT1S4^P$	0	0	0	0	0	0	0	$STS8^P$	0	0	0	0	$CT2S5^P$

Table 5 Logical transition matrix for the "1-on-1" configuration

Period	CT1S1	CT1S2	CT1S3	CT1S4	STS1	STS2	STS3	STS4	STS5
0	1	0	0	0	1	0	0	0	0
1	0	1	0	0	1	0	0	0	0
2	0	1	0	0	1	0	0	0	0
3	0	1	0	0	1	0	0	0	0
4	0	1	0	0	1	0	0	0	0
5	0	1	0	0	0	1	0	0	0
6	0	1	0	0	0	0	1	0	0
7	0	1	0	0	0	0	1	0	0
8	0	1	0	0	0	0	1	0	0
9	0	1	0	0	0	0	1	0	0
10	0	1	0	0	0	0	1	0	0
11	0	0	1	0	0	0	0	1	0
12	0	0	0	1	0	0	0	0	1

Table 6 Power transition matrix for the "1-on-1" configuration

Period	CT1S1	CT1S2	CT1S3	CT1S4	STS1	STS2	STS3	STS4	STS5
0	$CT1S1^P$	0	0	0	$STS1^P$	0	0	0	0
1	0	$CT1S2^P$	0	0	$STS1^P$	0	0	0	0
2	0	$CT1S2^P$	0	0	$STS1^P$	0	0	0	0
3	0	$CT1S2^P$	0	0	$STS1^P$	0	0	0	0
4	0	$CT1S2^P$	0	0	$STS1^P$	0	0	0	0
5	0	$CT1S2^P$	0	0	0	$STS2^P$	0	0	0
6	0	$CT1S2^P$	0	0	0	0		0	0
7	0	$CT1S2^P$	0	0	0	0	$STS3^P$	0	0
8	0	$CT1S2^P$	0	0	0	0	$STS3^P$	0	0
9	0	$CT1S2^P$	0	0	0	0	$STS3^P$	0	0
10	0	$CT1S2^P$	0	0	0	0	$STS3^P$	0	0
11	0	0	$CT1S3^P$	0	0	0	0	$STS4^P$	0
12	0	0	0	$CT1S4^P$	0	0	0	0	$STS5^P$

5.4.3.5 Moving between the states

When the procedure of the state assignment is executed, it results in the state transition as shown in Figure 27 for "2-on-1" CCGT unit configuration.

			New					Old	
Period		CT1	CT2	ST			CT1	CT2	ST
0							CT1=S1	CT2=S1	St=S1
1		CT1=S2	CT2=S1	St=S1			CT1=S2	CT2=S1	St=S1
5		CT1=S2	CT2=S1	St=S2			CT1=S2	CT2=S1	St=S2
6		CT1=S2	CT2=S1	St=S3			CT1=S2	CT2=S1	St=S3
11		CT1=S3	CT2=S2	St=S4			CT1=S3	CT2=S2	St=S4
12		CT1=S4	CT2=S3	St=S5			CT1=S4	CT2=S3	St=S6
13		CT1=S4	CT2=S4	St=S6			CT1=S4	CT2=S4	St=S6
14		CT1=S4	CT2=S5	St=S7			CT1=S4	CT2=S5	St=S7
15		CT1=S4	CT2=S5	St=S8					

Figure 27 Transition of between states for "2-on-1" configuration

It is possible to provide all transitions between different configurations, for example, from "1-on-1" to "2-on-1." While this example emphasizes the start-up and shutdown characteristics, a numerical example with the transition that does not involve the startup of a unit is presented in Section 6.7.6. The transitions between the states shown in Figure 27 are an example of a general procedure first introduced by Lu and Shahidehpour (LU2004) and described in more detail in Section 4.2.3.1.

5.4.4 *Selecting Characteristics*

- Typical constructions of CCGUs;
- Three gas turbines with one steam turbine;
- Two gas turbines with one steam turbine;
- One gas turbine with one steam turbine.

Such CCGT units can operate in different configurations. These configurations are normally described by the characteristics stored in the ISO database. The assumption is that one of the commitment parameters defines the configuration of a CCGT unit and based on the selected configuration an appropriate characteristic is used in the commitment process (see Figure 28).

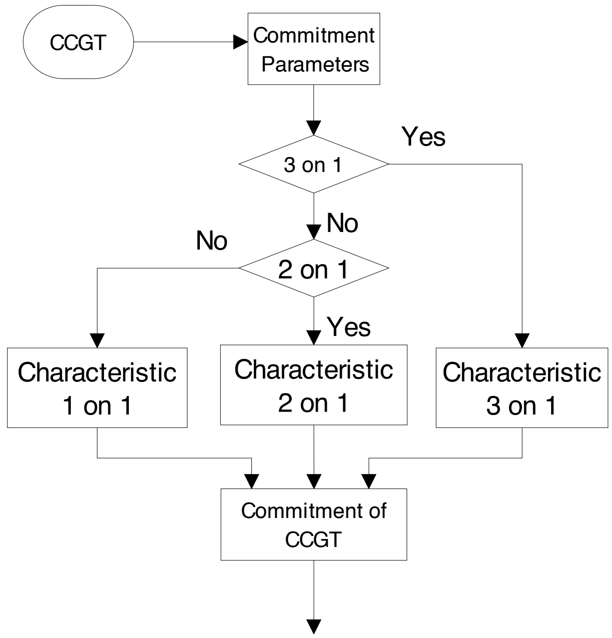


Figure 28 Selection of the CCGT unit configuration

5.4.5 *Day Ahead Commitment*

The day ahead commitment of the CCGU units is modeled with the use of:

- Configuration, which can take two options "2-on-1" or "1-on-1."
- Modes which can take four values: Start-up, Regulating Up, Regulating Down and Shutdown. It is also possible to consider only one regulating mode assuming the regulation in both directions.
- Shutdown mode.

For the purpose of a day ahead commitment it is assumed that a CCGT unit is scheduled in a given mode described by the following rules:

- In start-up mode the unit state (schedule) results from the start-up curve provided by a CCGT unit. It is also possible that such a curve is in the ISO data base with the possible access and update by MIS.
- In regulating modes the state (schedule) results from the optimization carried out by the SCUC module, taking into account the provided unit parameters.
- The shutdown mode can be executed in one hour so in the case of a one-hour schedule it does not require a shutdown curve.

5.4.5.1 States of start-up mode

The states of the start-up mode are obtained from the calculation of the energy generated in each hour of the start-up process for a given configuration of a CCGT unit. Figure 29 shows an example of the start-up states for "2-on-1" configuration of the CCGT unit components. Figure 30 demonstrates the states of the start-up characteristic for a "1-on-1" configuration of a CCGT unit.

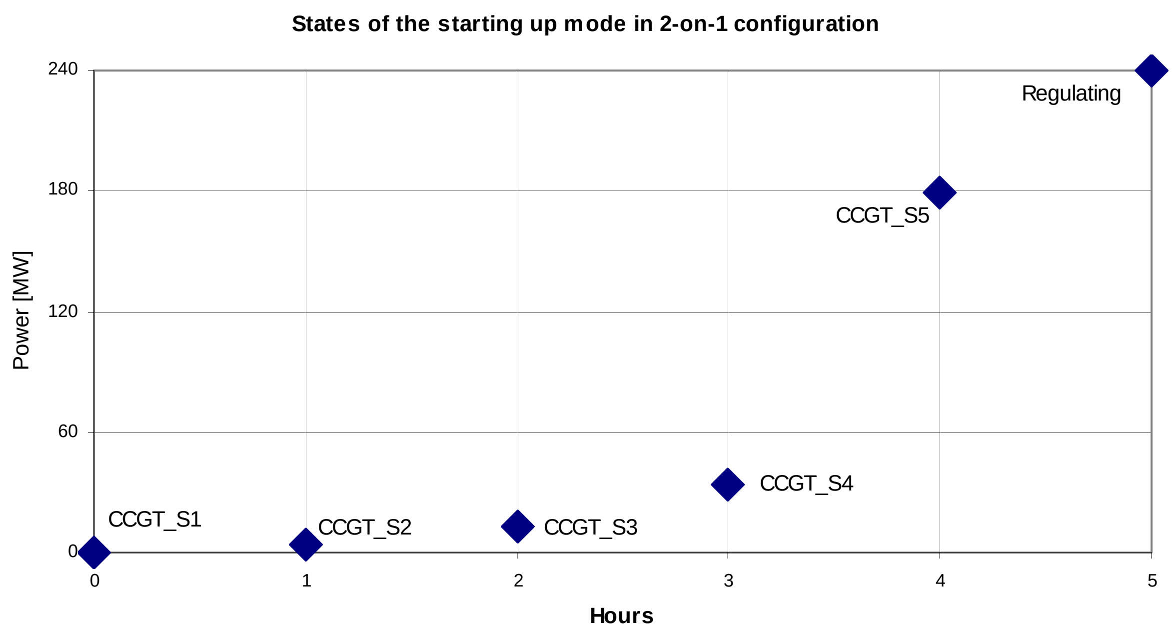


Figure 29 States of the start-up characteristics for "2-on-1" configuration

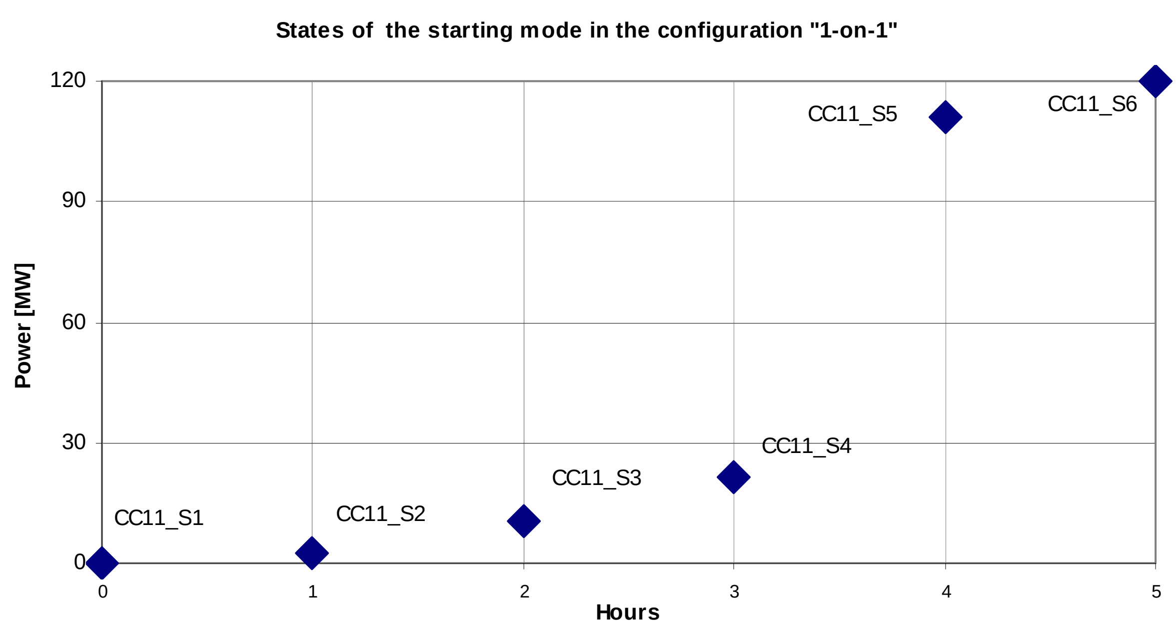


Figure 30 States of the start-up characteristics for "1-on-1" configuration

5.4.5.2 Possible commitment

The possible commitment in a day ahead scheduling is shown in Figure 31 for a "2-on-1" configuration. The unit is in the start-up mode for 4 hours when it reaches the operation mode. In this mode, power can be changed due to the parameters defining the operation range. The shutdown mode takes only one hour.

An example of possible commitment for a "1-on-1" configuration is shown in Figure 32. In this case, the entire CCGT unit reaches maximum generated power of 120 MW, and, starting from hour 4, can generate in the operation mode.

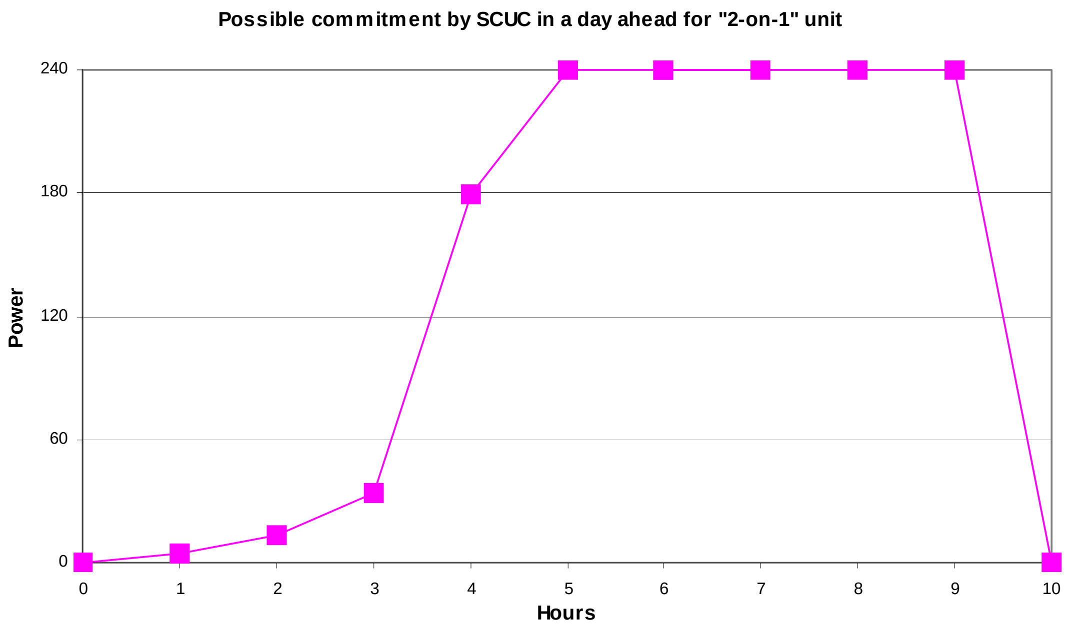


Figure 31 An example of dispatch of a CCGT unit in the "2-on-1" configuration

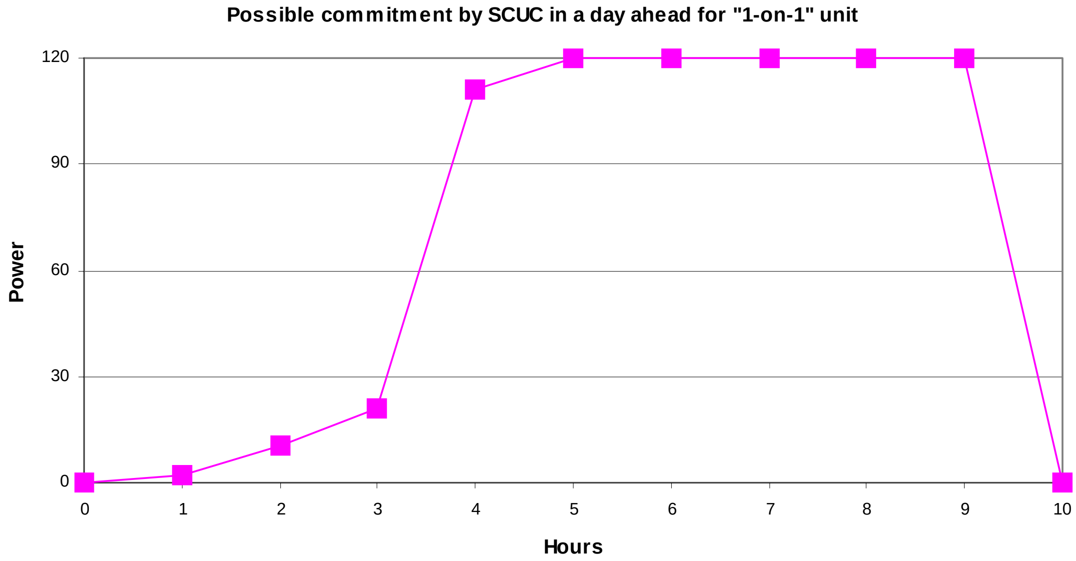


Figure 32 An example of dispatch of a CCGT unit in the "1-on-1" configuration

5.4.5.3 Configuration selection

In a day-a-head market, a CCGT unit submits, using the MIS information of the two possible configurations of a CCGT unit. If a CCGT unit has three combustion turbines it submits information on three possible configurations.

The method allows the selection of a configuration in the day-ahead market as in the intra-day market. A new configuration can be selected:

(i) Before the CCGT unit start-up;
(ii) When the CCGT unit reaches the regulation mode.

The only limitation is that a configuration cannot be changed in the start-up process since this could cause a technical problem with the heating of the ST unit.

Each configuration is treated as a separate generating unit. The authors of this report do not know exactly how the SCUC module incorporates various constraints but such a constraint can be easily implemented in any module.

Figure 33 shows the arrangement in a day-ahead market. The CCGU constraints are written in the form of a list of power generating units, in this case, C21 and C11 with the notation "LE 1" (less equal one), which means that only of two generating units can operate.

If a CCGT comprises three combustion turbines, there will be three generating units C31, C21 and C11 with the same constraint that only one of these units can operate in a day ahead schedule.

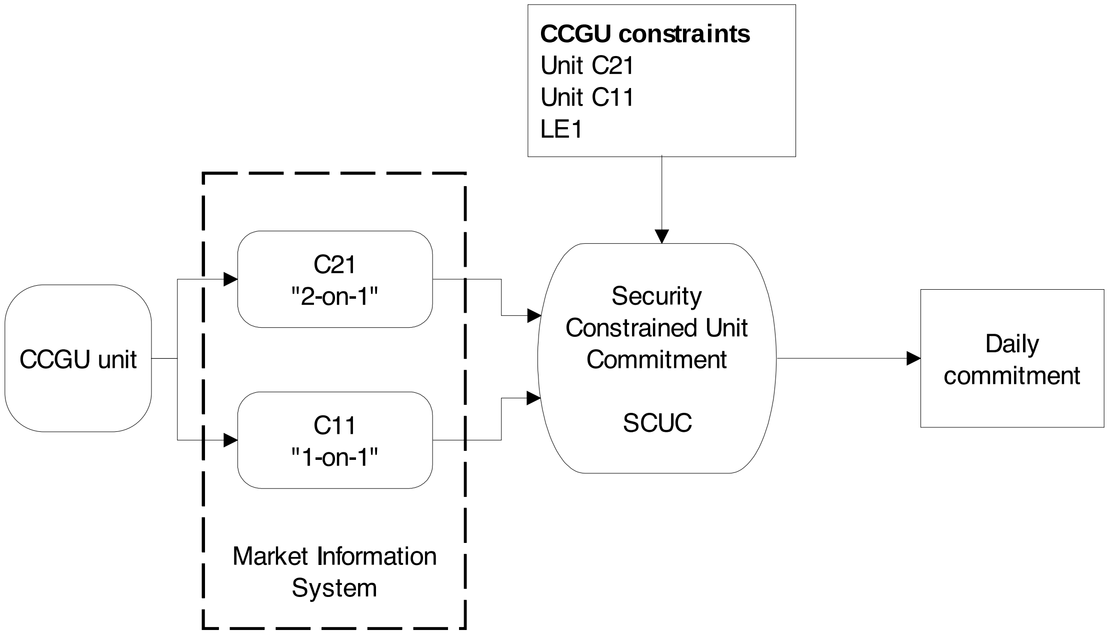


Figure 33 Arrangement in a day ahead market

5.4.6 *Data Provided by a CCGT Unit*

5.4.6.1 “2-on-1” Configuration

The unit denoted C21, “2-on-1” configuration, provides the information as shown in Table 7. It is worth noting that this table structure is exactly the same as currently used in the NY market. The only difference is one line in which a CCGT owner can declare starting up characteristic in terms of MW or in the pu system (see Table 8 and Table 9).

It is also possible not to extend Table 7 but locate the information on the start-up characteristic in the NYISO data base with the user access to correct or update the information using the MIS.

It is possible to provide the bids for each component, with energy paid based on the bid provided. In the simulation presented in the example, we have assumed, for simplicity, one bid for the entire unit because we focused our attention on modeling and not on the settlement. If the separate bids are provided for each component of the CCGT unit, the start-up process is the same as it is carried out based on the start-up characteristics. The component load in regulation mode can be different (if the different component bid is provided) but only to the degree allowed by the technical parameters.

Table 7 Information on the C21 unit

Symbol	Description	Units
FDgC21	Flag indicating whether generator “g” in the configuration C21 is dispatchable	Y/N
FRgC21	Flag indicating whether generator “g” in the configuration C21 is able to supply regulation	Y/N
FSgC21	Flag indicating whether generator “g” in the configuration C21 is able to supply spinning reserve	Y/N
gC21	Index of generator in the configuration C21	-
h	Index of hour of the day (0, 1, 2, 3, …)	0,1,2,…
IEg,hC21	Incremental energy offer curve of generator “g” in the configuration C21 for the hour beginning “h”	$/MWH vs. MW
MGCg,h,C21	Hourly cost for generator “g” in the configuration C21 to operate at its minimum generation level for the hour beginning “h”	$/hr
MGLg,h, C21	Minimum generation level of generator “g” in the configuration C21 for the hour beginning “h”	MW
MNDOWNg,C21	Minimum down time of generator “g” in the configuration C21	hr
MNRUNg, C21	Minimum run time of generator “g” in the configuration C21	hr
MWSg,h, C21	Self-scheduled MW of generator “g” in the configuration C21 for the hour beginning “h”	MW
MXSTOPg, C21	Maximum stops per day of generator “g” in the configuration C21	0,1,2,…
REg, C21	Emergency ramp rate of generator “g” in the configuration C21	MW/min
RNg, C21	Normal ramp rate of generator “g” in the configuration C21	MW/min
RRg, C21	Regulation ramp rate of generator “g” in the configuration C21	MW/min
SUCg,h, C21	Start-up cost of “g” in the configuration C21 for the hour beginning “h.” Start-up cost may be defined as a function of hours since the most recent shutdown.	$
STARTg, C21	Start-up energy curve in each hour for C21 configuration	MW/h(pu/h)
UOLEg,h,C21	Emergency upper operating limit of generator “g” in the configuration C21 for the hour beginning “h”	MW
UOLNg,h, C21	Normal upper operating limit of generator “g” in the configuration C21 for the hour beginning “h”	MW

The start-up energy curve can be arranged as a table in two possible options:

- States are provided directly as MW values – Table 8;
- States can be provided as pu values taking the maximum power as a base – Table 9.

Table 8 Start-up curve expressed in MW

Hour	1	2	3	4
Power	4.1	13.2	40	179

Table 9 Start-up curve expressed in pu

Hour	1	2	3	4
Power	0.017	0.055	0.141	0.748

5.4.6.2 "1-on-1" Configuration

The same information as was shown for the "2-on-1" configuration is submitted to the SCUC module for the "1-on-1" configuration: Tables 10, 11 and 12.

Table 10 Information on the C11 unit

Symbol	Description	Units
FDgC11	Flag indicating whether generator "g" in the configuration C11 is dispatchable	Y/N
FRgC11	Flag indicating whether generator "g" in the configuration C11 is able to supply regulation	Y/N
FSgC11	Flag indicating whether generator "g" in the configuration C11 is able to supply spinning reserve	Y/N
gC11	Index of generator in the configuration C11	-
h	Index of hour of the day (0, 1, 2, 3, …)	0,1,2,…
IEg,hC11	Incremental energy offer curve of generator "g" in the configuration C11 for the hour beginning "h"	$/MWH vs MW
MGCg,h,C11	Hourly cost for generator "g" in the configuration C11 to operate at its minimum generation level for the hour beginning "h"	$/hr
MGLg,h, C11	Minimum generation level of generator "g" in the configuration C11 for the hour beginning "h"	MW
MNDOWNg,C11	Minimum down time of generator "g" in the configuration C11	hr
MNRUNg, C11	Minimum run time of generator "g" in the configuration C11	hr
MWSg,h, C11	Self-scheduled MW of generator "g" in the configuration C11 for the hour beginning "h"	MW
MXSTOPg, C11	Maximum stops per day of generator "g" in the configuration C11	0,1,2,…
REg, C11	Emergency ramp rate of generator "g" in the configuration C11	MW/min
RNg, C11	Normal ramp rate of generator "g" in the configuration C11	MW/min
RRg, C11	Regulation ramp rate of generator "g" in the configuration C11	MW/min

SUCg,h, C11	Start-up cost of “g” in the configuration C11 for the hour beginning “h.” Start-up cost may be defined as a function of hours since the most recent shutdown.	$
STARTg, C11	Start-up energy curve in each hour for C11 configuration	MW/h(pu/h)
UOLEg,h,C11	Emergency upper operating limit of generator “g” in the configuration C11 for the hour beginning “h”	MW
UOLNg,h, C11	Normal upper operating limit of generator “g” in the configuration C11 for the hour beginning “h”	MW

Similarly, as for C21 configuration, the start-up curve can be expressed in terms of MW or pu taking the maximum power of this configuration as a base.

Table 11 Start-up curve expressed in MW

Hour	1	2	3	4
Power	2.3	10.3	21.2	110.9

Table 12 Start-up curve expressed in pu

Hour	1	2	3	4
Power	0.014	0.06	0.132	0.693

5.4.7 *Real-Time Commitment and Dispatch*

The real-time commitment module uses the information about the flexibility of the CCGT unit. It is assumed that any CCGT unit can have either Flexible or Fixed status. Fixed and Flexible refer to the ability of the CC to respond to 5-minute updates from the economic dispatch function, equivalent to Off/On dispatch. Flexible units can respond. Fixed units cannot respond. In NYISO’s current operation, the economic dispatch program calculates an operating point for Flexible units; Fixed units advise the ISO of their expected output.

The status results from the bids of the CCGT unit or from the optimization procedure carried out by the RTC module. The Fixed status means that the RTC module uses the 15-minute state characteristic of a CCGT unit. The Flexible status means that a CCGT unit base points result from the optimization procedure taking into account the maximum and the minimum range of such operation.

The example of the operation of a CCGT unit is shown in Figures 24 – 29. To adopt the proposal to the current operation arrangement of the RTC and the RTD modules it was assumed that the CCGT unit bids are locked for 60 minutes and they are read at the beginning of each hour. This is an auxiliary assumption, made for the illustration of the commitment and dispatch, not affecting the proposed methodology.

In the example shown, a CCGT unit is assigned to begin its operation in hour 10:00. Its start-up takes four hours so from hour 10:00 to hour 13:00 inclusive, the unit is in its start-up mode and its base point results from the 15-minute characteristics split into 5-minute intervals – Figures 34, 35, 36 and 37.

In hour 14:00 the CCGT unit is in its regulating mode, the status is Flexible and its base points result from the optimization procedure – Figure 38.

It was assumed that the unit is to shut down at hour 23:00 so its status becomes Fixed and the base point results from the states of the shutdown characteristic – Figure 39.

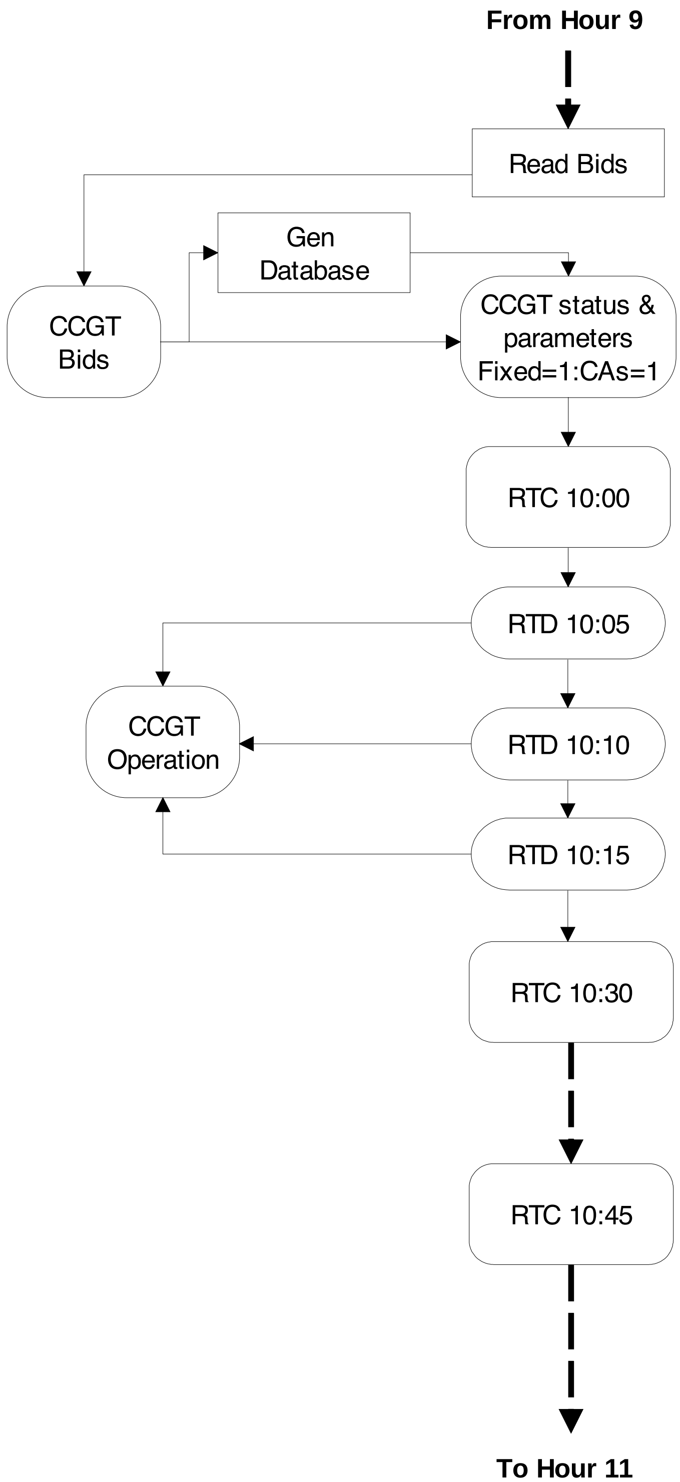


Figure 34 Start-up – Hour 10

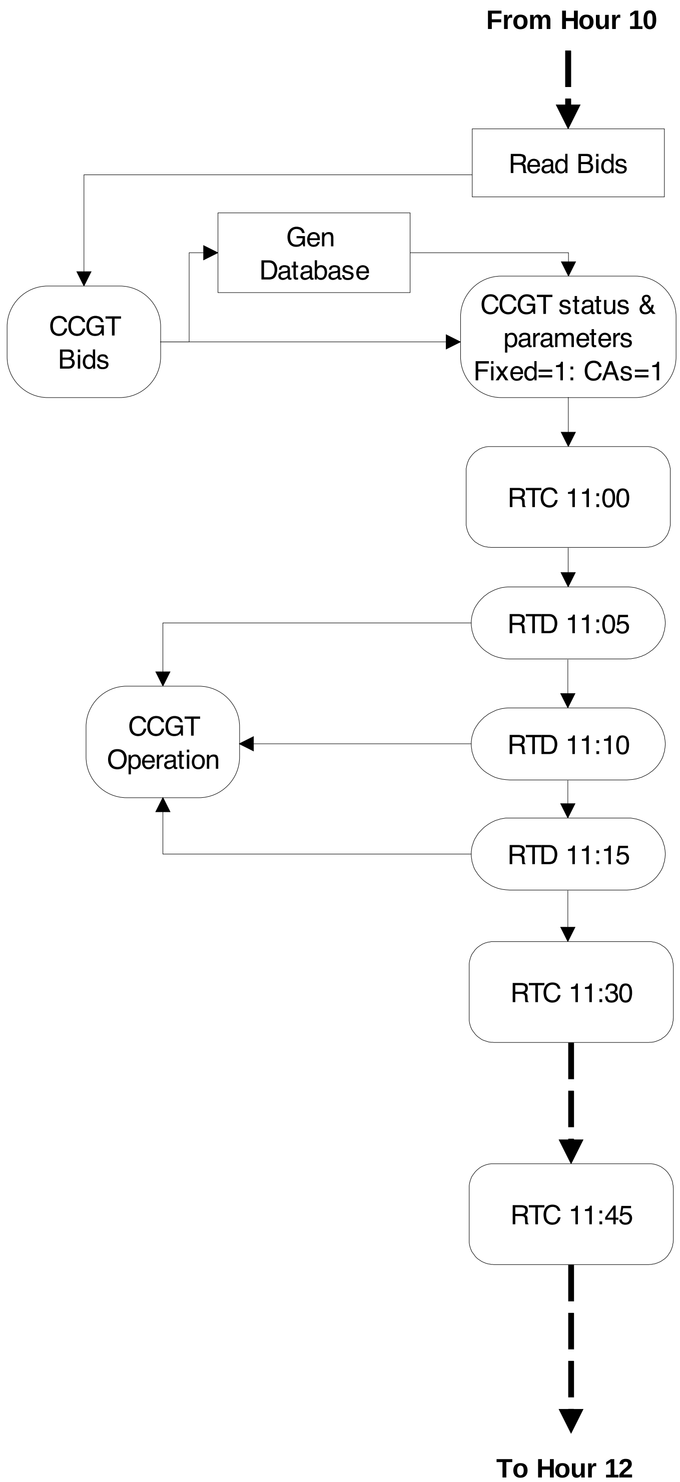


Figure 35 Start-up – Hour 11

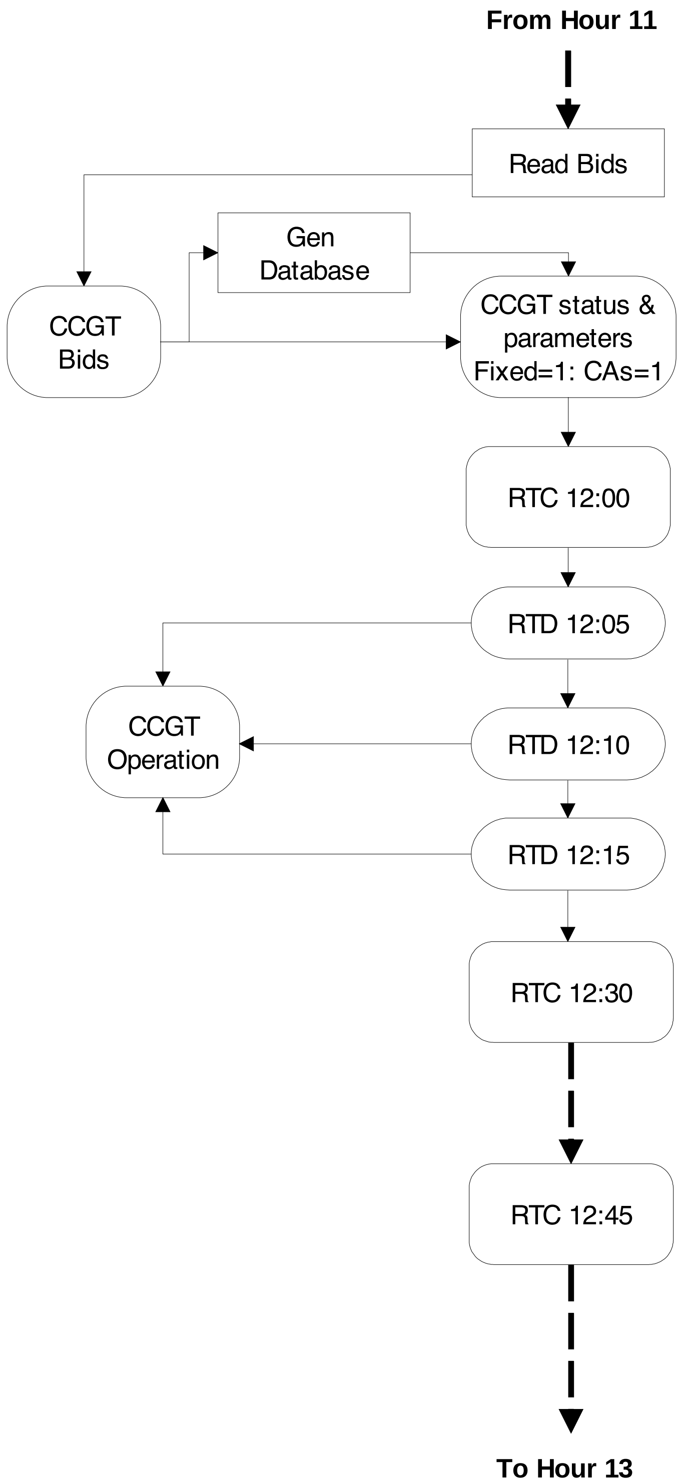


Figure 36 Start-up – Hour 12

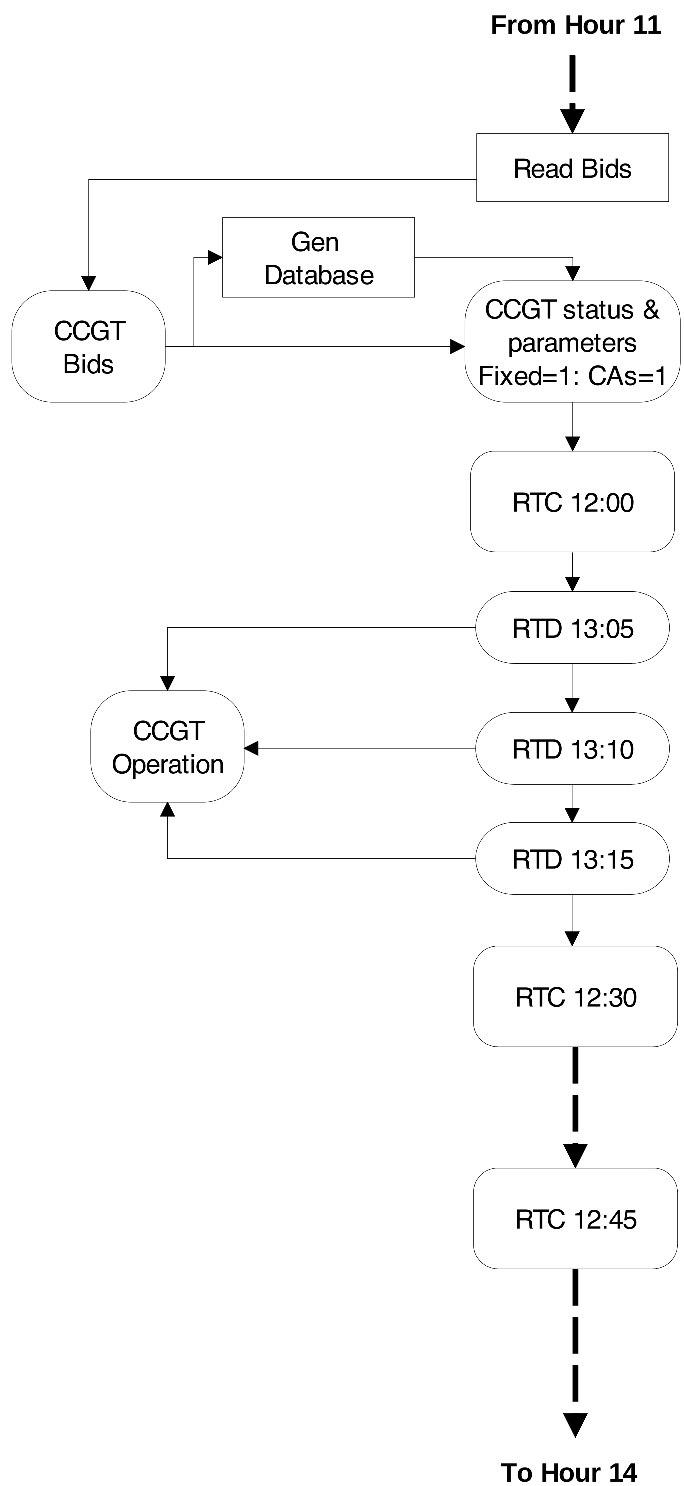


Figure 37 Start-up – Hour 12

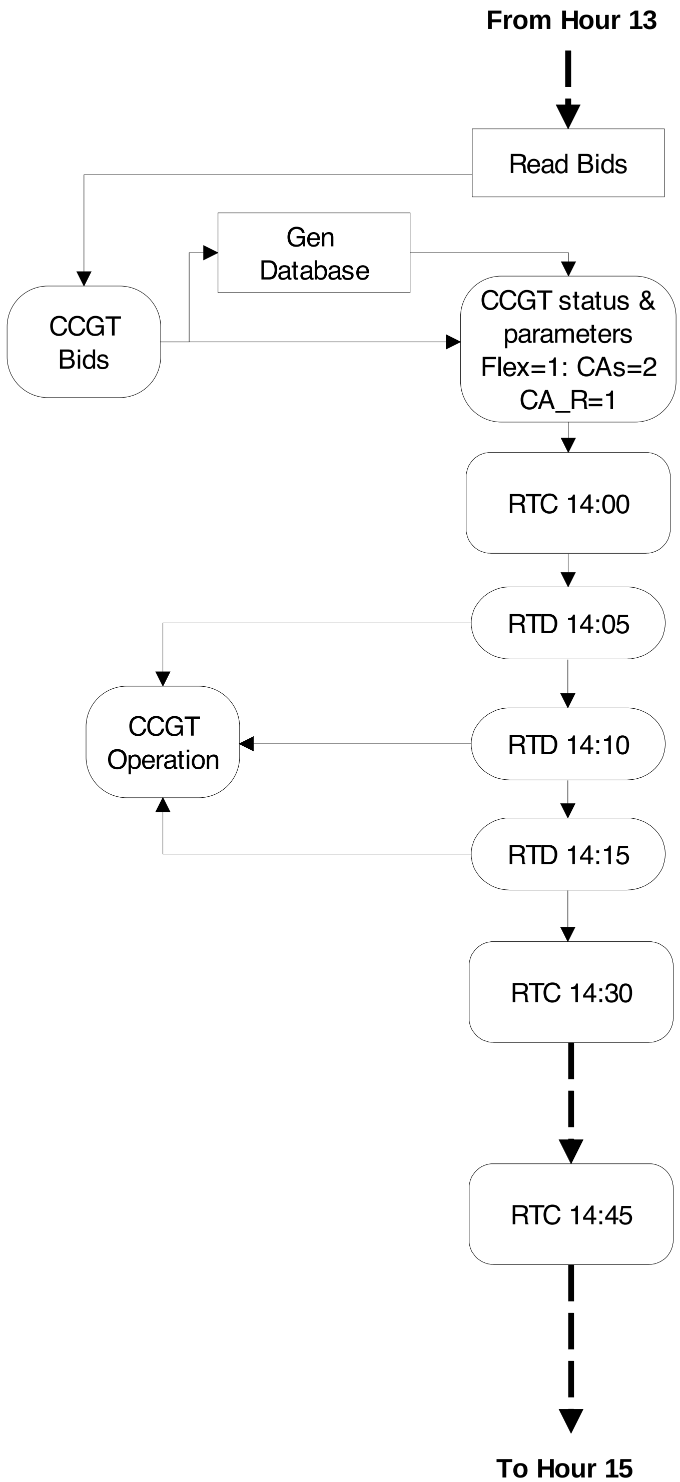


Figure 38 Regulating mode

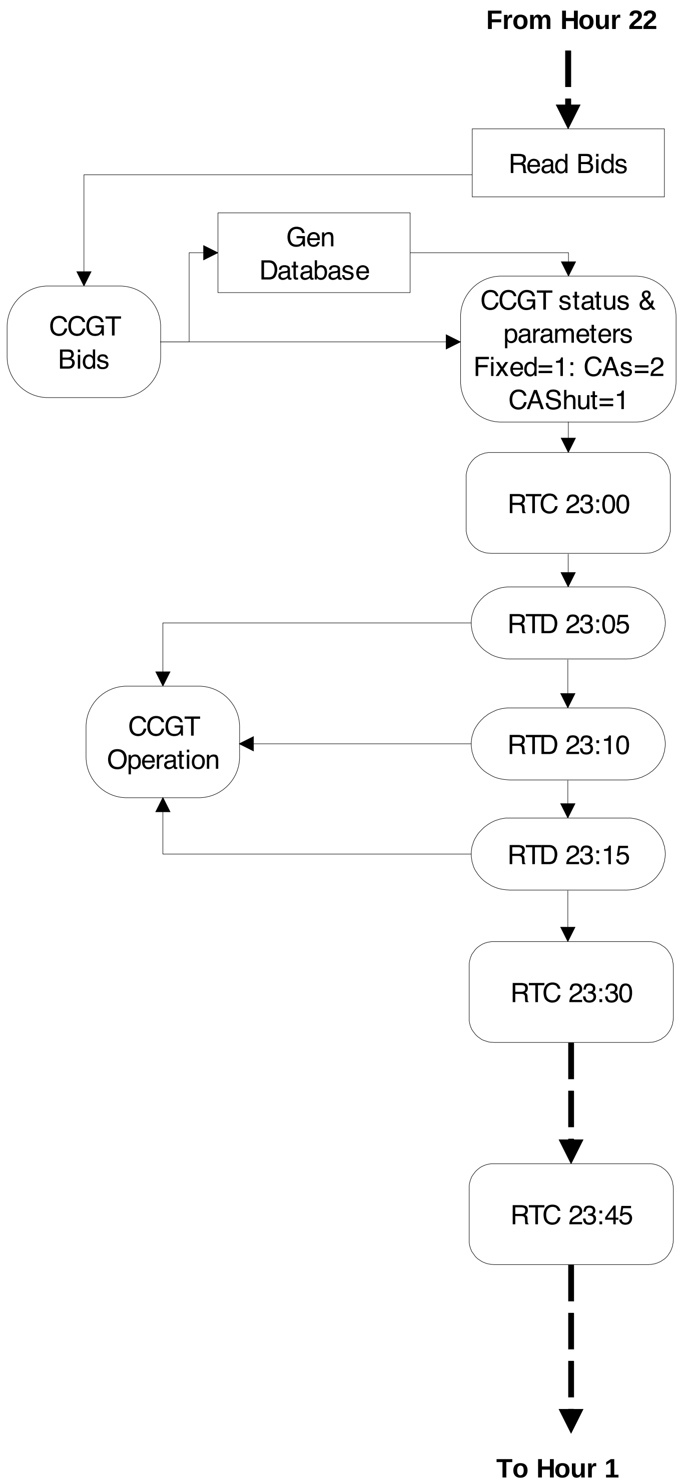


Figure 39 Shutdown mode

6.0 DESCRIPTION OF THE CASE STUDIES APPLYING THE MIP ALGORITHM

6.1 Simulated Power System

The power system used for the simulation is shown in Figure 40. The system has five generators and loads connected by six lines. In a general case, line constraints and generating unit constraints can be modeled by either the nodal constraints or by specific load flow equations. However, for the purpose of this study, there are no specific system constraints considered.

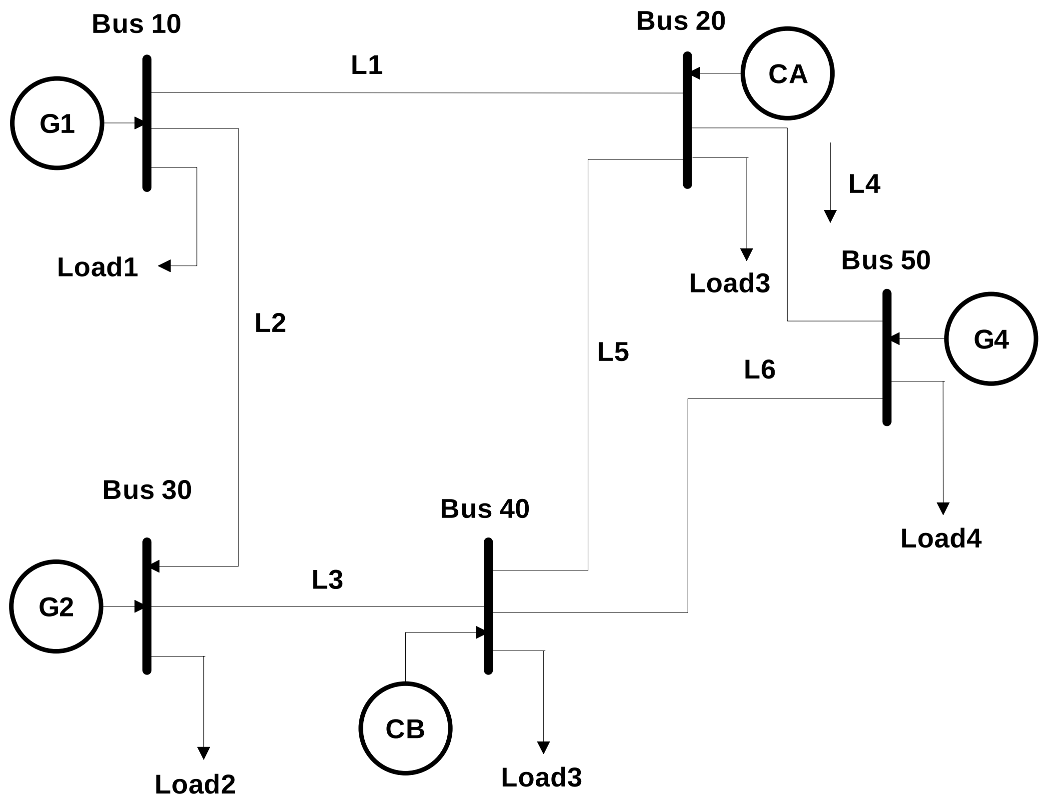


Figure 40 Simulated power system

6.2 Technical Data of Power Generating Units

The technical data of the units modeled are provided in Table 13.

Table 13 Generating unit technical data

Steam Turbine Generating Unit	Pmin	Pmax	Ramp_Up [MW/15min]	Ramp_Down [MW/15min]
G1	200	600	30	50
G2	200	500	20	50
G3	200	500	40	50
CA	0	250	30	40
CB	0	250	30	40

Three generating units denoted G1, G2 and G3 were modeled as typical steam turbine units. They have wide range of regulation from 200 MW to 500 MW. Such large regulation is necessary for modeling of a small system of five generating units. Two large combined-cycle gas turbine units are denoted as CA and CB. In the simulated system, a quick start-up of CCGT has to be compensated by a power reduction in the large steam units, therefore they must have a wider range of regulation. In a large real system, a quick injection of 240 MW can be compensated by a small decrease of power generation in many generating units.

6.3 Start-up Characteristics

The start-up characteristics of steam generating units can be modeled as discussed in the general description of the model. However, in the simulation scenarios discussed below we assumed that the steam units are already running and only start-ups of CCGUs will take place as they are the most interesting for the purpose of this study.

The start-up characteristics for CCGT units are presented in Figure 41. They have been taken from the information provided by the NYISO. For the purpose of the simulation study, we have assumed that both units CA and CB are 2-1 units with two gas turbines and one steam turbine. Thus, a CCGT unit consists of three parts: CT1 – gas turbine 1, CT2 – gas turbine 2, and ST – steam turbine.

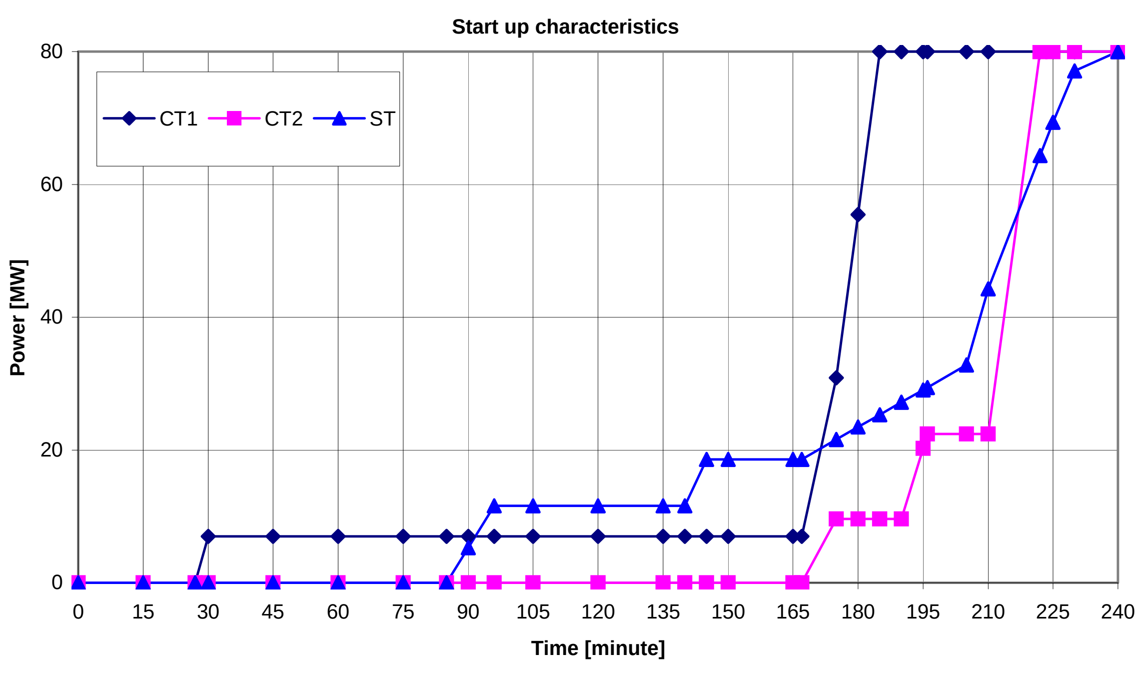


Figure 41 Start-up characteristics of the CCGT units

The characteristics shown in Figure 41 are obtained by reading the characteristics provided by the NYISO with the points identified in various time intervals so they are presented as a "point" with a "ramp" of increase. In practice, these are power modeling characteristics. Because the simulation and optimization process is carried out for energy and not for power, for the purpose of the simulation studies we have developed a one-minute model of start-up characteristics that is shown in Figure 42. This model allows the aggregation of the characteristics in 5 and 15 minute intervals.

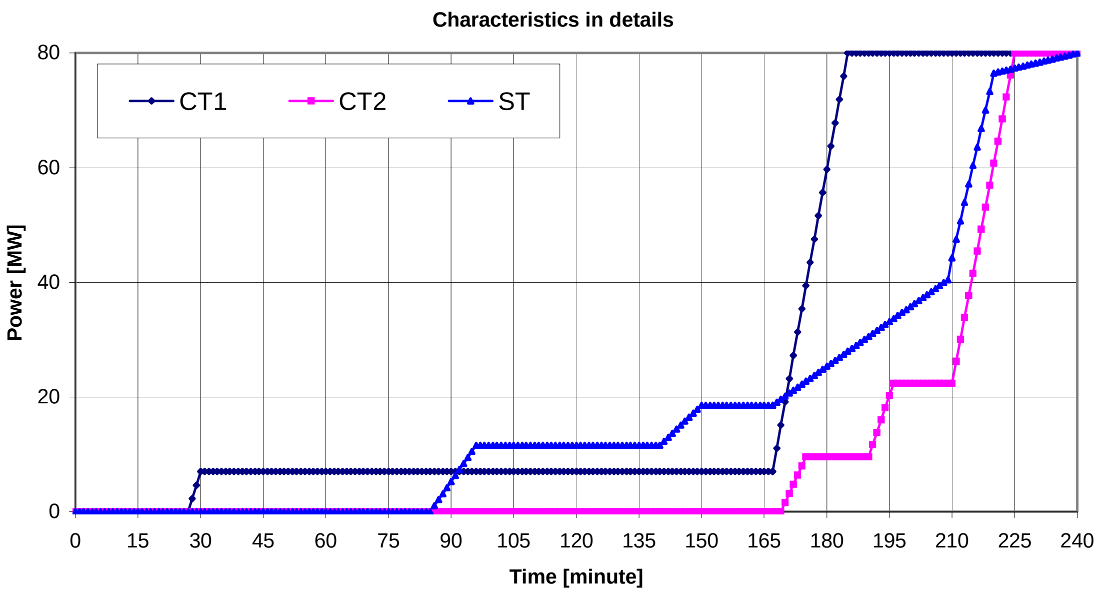


Figure 42 One-minute model of start-up characteristics

There were no special requirements specified related to the limitation of CCGT units in the regulating mode. For the purposes of the simulation, it was assumed that the speed of power regulation is limited by the ramp rate assigned to each generating unit.

There were no special requirements on the shutdown characteristics, so the characteristics from the literature were adapted as shown in Figure 43. It lead to the following sequence:

- When the power generated from the entire unit drops below 50% of the rated output, the steam turbine is shut down in the next 15-minute period.
- In the same 15-minute period, the first gas turbine output power drops to 50%.
- In the next 15-minute period, the second gas turbine power drops to 50% while the first gas turbine is shut down.
- In the next 15-minute period, the second gas turbine is shut down.

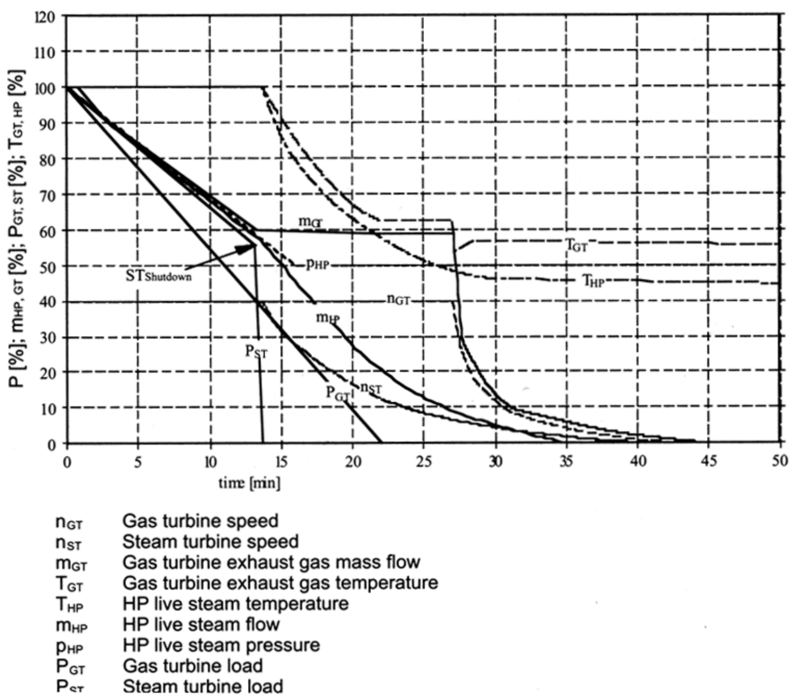


Figure 43 Shutdown characteristics
[Source: Combined-Cycle Gas Steam Turbine Power Plants by R. H. Kehlohofer, J. Warner, H. Nielsen, R. Bachmann published by PennWell, 1999]

6.4 Demand

In the simulated system, the total demand was assumed and a profile with one morning peak, a small decrease for the lunch time period, a small increase in demand when people are returning to work after lunchtime and the evening peak. The demand profile is shown in Figure 44.

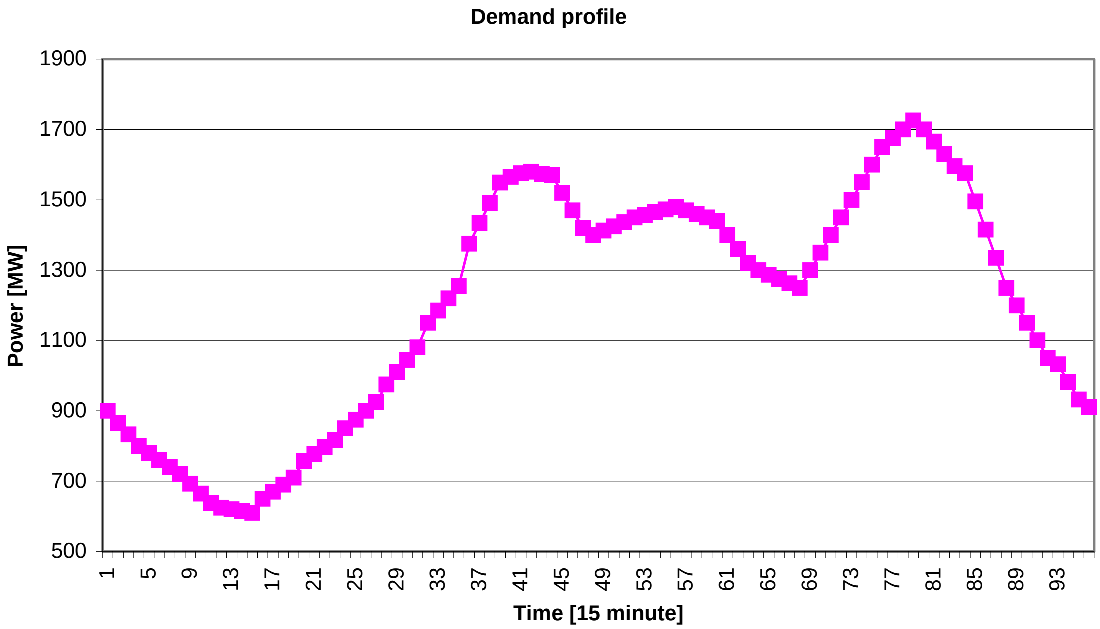


Figure 44 Demand profile

6.5 Initial States

It was assumed that before the simulation, the last 15-minute period in Day N-1, three steam generating units are working being loaded as shown in the Table 14. This assumption was made to simulate the start-up of CCGT units when power demand increases during the morning hours.

Table 14 Initial generator load

Unit Name	Initial Generation
STGU1	285
STGU2	300
STGU3	340
CCGU_A	0
CCGU_B	0
Sum	925

6.6 Balancing Bids

It was assumed that each generator provided balancing bids for every hour of the day as shown in Table 15. The prices are provided in USD per MWh for a given hour.

Table 15 Example of energy bids of five generating units

Hour1		1	2	3	4	5	6	7	8	9	10	Sum Power
G1	Price	15	16	35	40	42	44	51	60	75	300	
	Power	200	85	49	45	40	20	20	20	20	1	500
G2	Price	15,1	15,7	25	27	31	46	55	65	70	250	
	Power	200	120	40	30	27	22	20	20	20	1	500
G3	Price	15,2	15,5	40	50	55	60	65	66	67	230	
	Power	200	140	30	30	20	20	20	20	19	1	500
CA	Price	19	21	23	25	29	32	35	36	37	38	
	Power	27	41	30	30	30	20	20	20	20	2	240
CB	Price	300	304	308	312	316	320	324	328	332	336	
	Power	28	40	30	30	30	30	20	20	10	2	240

6.7 Simulation Cases

All simulations were carried out in 15-minute periods providing 15-minute dispatch for generating units. This dispatch was recalculated to 5-minute signals.

6.7.1 *Simulation – Case A*

The first simulation case was carried out with the assumption that only one CCGT unit (CA) will be operating. It was achieved by an appropriate construction of the balancing bids. The bids provided by CB were very expensive so the optimization procedure did not dispatch this unit.

The dispatch results of this case are shown in Figures 45 and 46. It happens that at the end of the day when demand was low the optimization procedure decided to shut down the unit CA. However, it was not shut down completely so it still generated a bit of power in the last 15-minute period.

The assumption for this study was to complete the entire start-up process. This means that the start-up characteristics were used until all units CT1, CT2 and ST have reached the full load. When the start-up process was completed, the start-up constraints were released and power was to be regulated constrained by the ramp rate.

As seen from Figure 47, after the start-up the unit CA was fully loaded for some time. There two reasons for that:

- Demand was high;
- Prices offered by the CCGT unit were more competitive in this load range than prices of other units.

However, the decreasing demand caused that power was reduced for some time but the anticipated high evening demand resulted again in the full load for this unit.

The load of CCGT as the sum of particular units is shown in Figure 48.

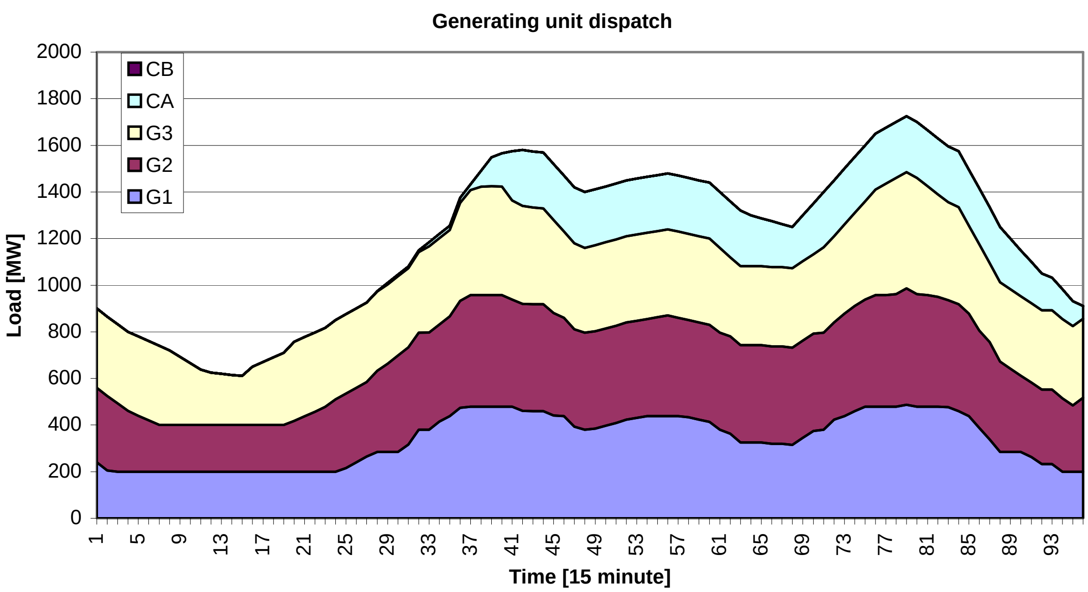


Figure 45 Dispatch of the generating units as the sum of the power produced

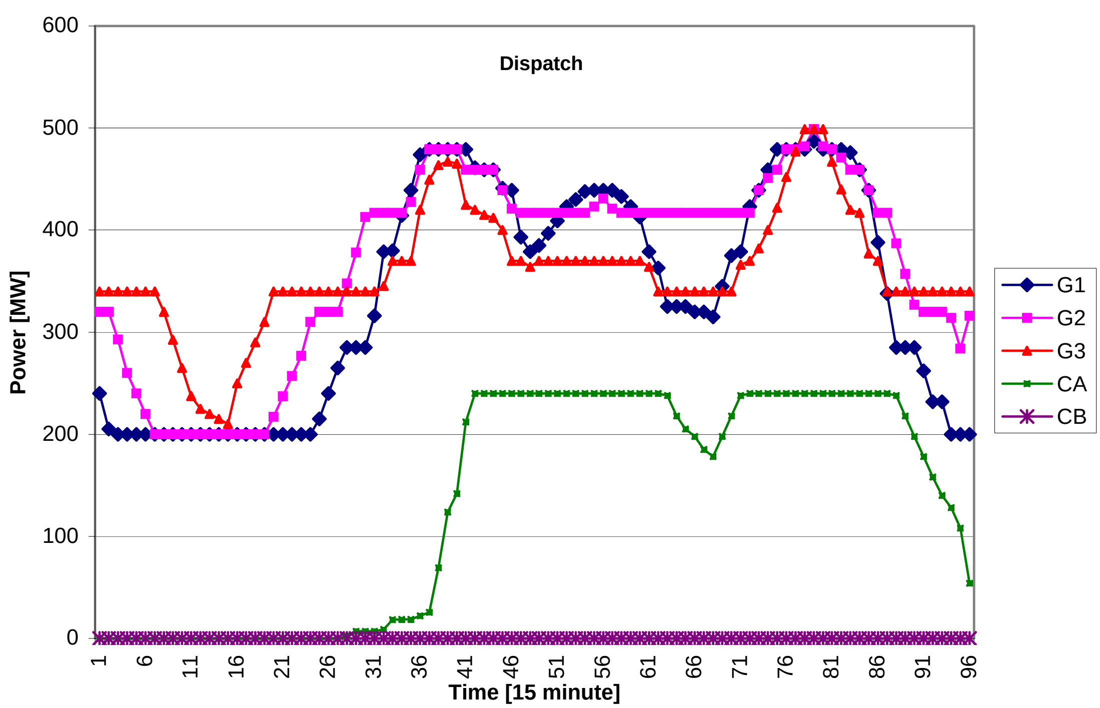


Figure 46 The dispatch of particular generating units

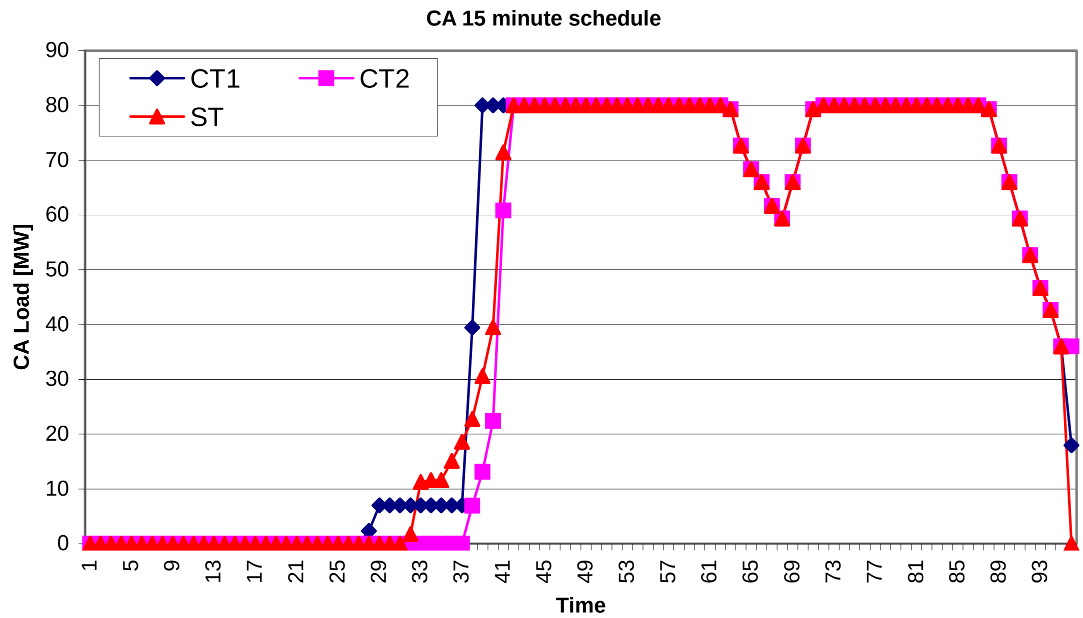


Figure 47 Dispatch of CT1, CT2 and ST in 15-minute periods

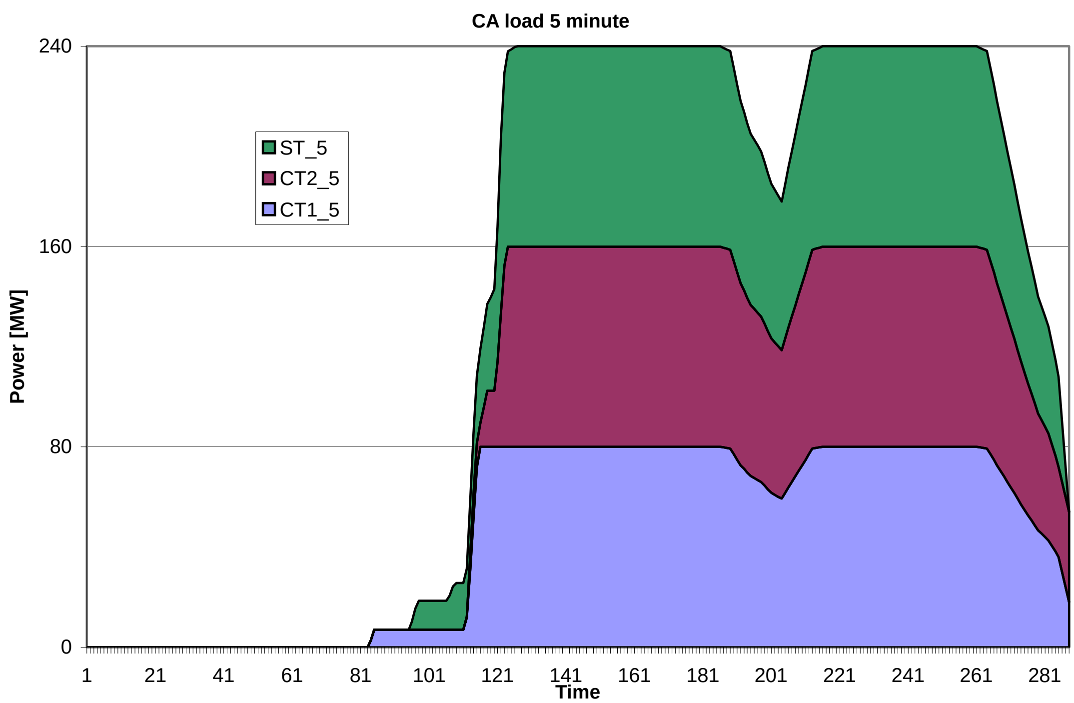


Figure 48 Load of particular CCGT units as sum of the generated powers

The analysis was carried out to investigate what would be the difference when the 15-minute dispatch periods were used as control signals for CCGT units. The differences between the exact characteristic and the 15-minute control signals are shown in Figures 49, 50 and 51 for particular generating units. These differences can be explained as follows.

The start-up characteristics are determined technically as power characteristics, i.e., points and ramp rates between the points. Many software packages for the generating unit control, for example, PROCONTROL, operate the same way. However, electricity markets operate using energy produced in the given period. The periods can be one-hour, 30-minute or 15-minute intervals. The only exception (as far as we can determine) is the English system where bids are given in power and they are subject to linear approximation by the TSO. The energy market, the commitment and dispatch have to be consistent with the trade carried out in terms soft energy. Also, power characteristics are recalculated in the terms of energy in a given period.

To carry out the simulation, we have to recalculate the power characteristics in terms of energy. In such a case it is obvious that the energy assigned to a given period can be slightly different when the length of the period is changed. We have shown that the differences between 15-minute and 5-minute periods are not large, so our energy assignment is justified.

Even though there are no large differences between 15-minute signals and characteristics, in the methodology we proposed that the 15-minute dispatch is split into 5-minute signals resulting in smaller differences.

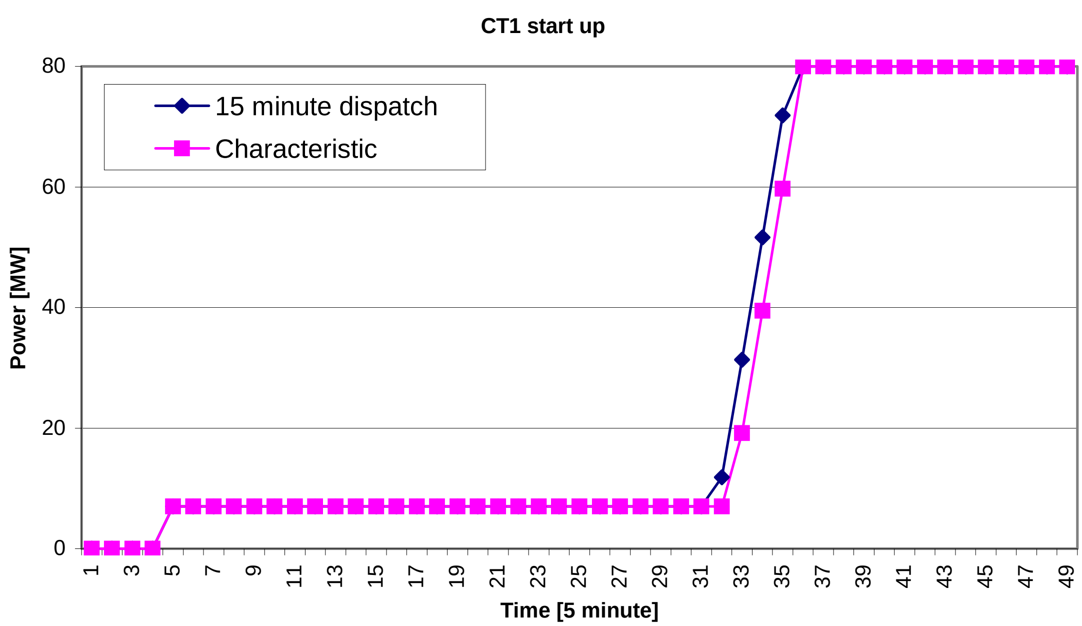


Figure 49 Characteristic of CT1 and 15-minute dispatch

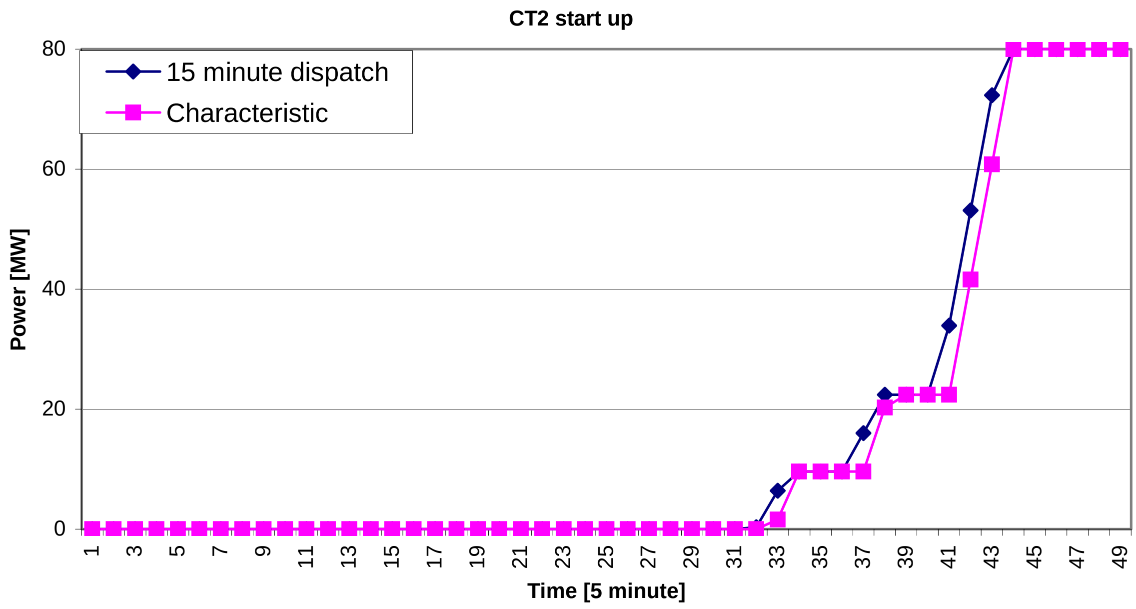


Figure 50 Characteristic of CT2 and 15-minute dispatch

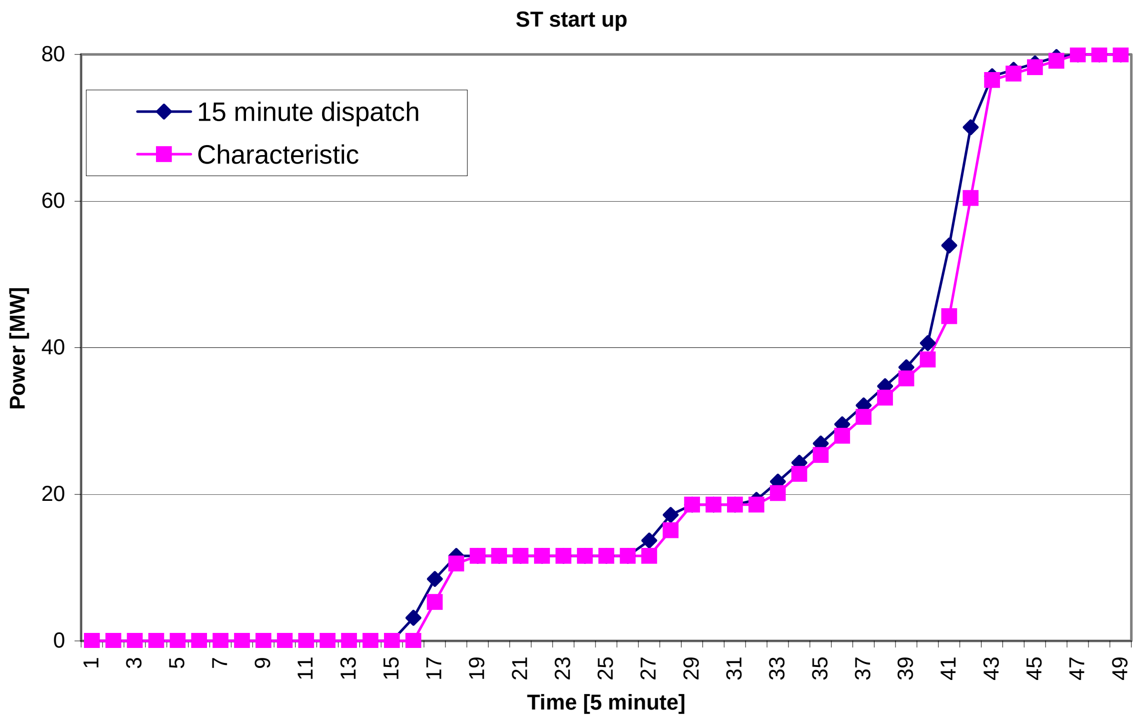


Figure 51 Characteristic of ST and 15-minute dispatch

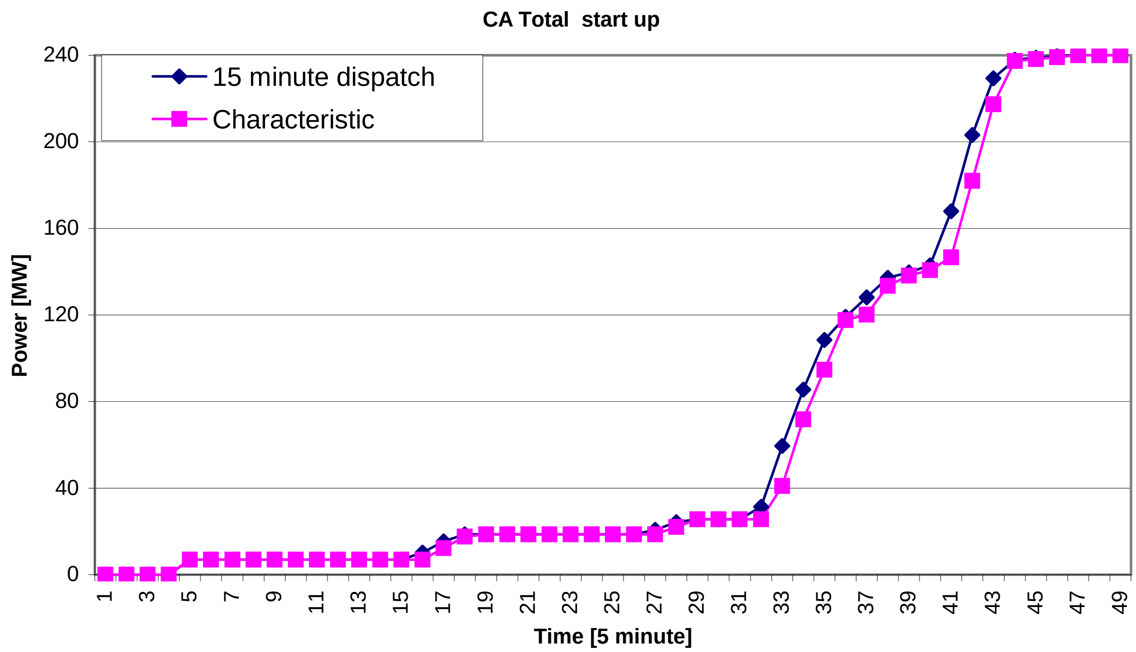


Figure 52 Characteristic of the entire CCGT and 15-minute dispatch

6.7.2 *Simulation – Case B*

For the Case B, the price profile was changed as shown in Figure 53. It was constructed to bid low prices of CCGT in the first six bands and band 10 and high prices in bands 7, 8 and 9. Such a construction of the balancing bids should result in a change in the use of CCGT units in power regulation by the optimization procedure.

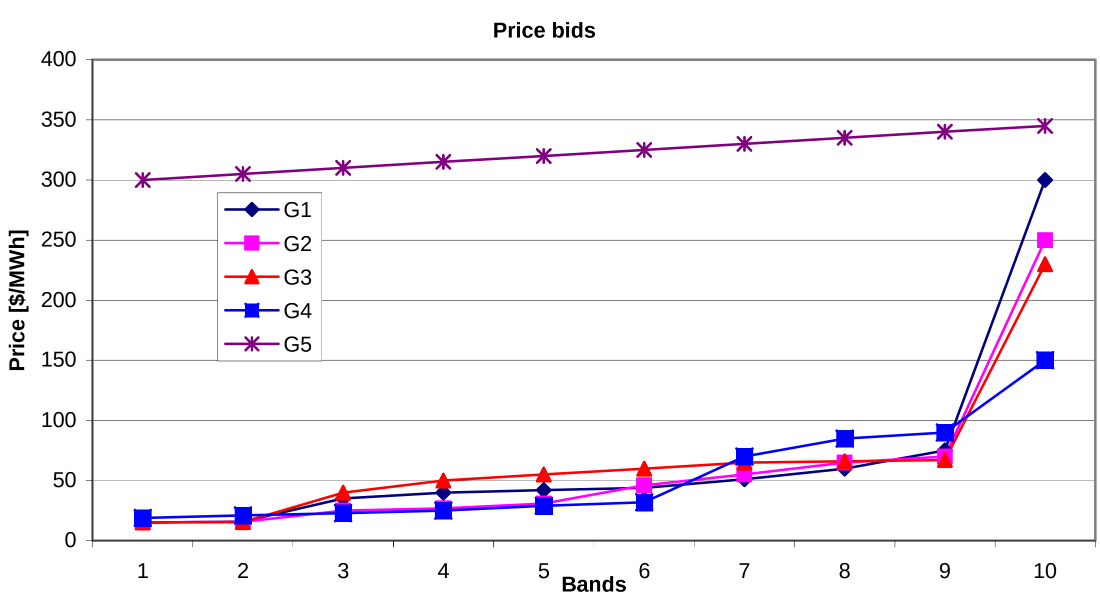


Figure 53 Price profiles in the balancing bids

The dispatch for Case B is shown in Figure 54 as the sum of power generated by all dispatched units and for particular units in Figure 55.

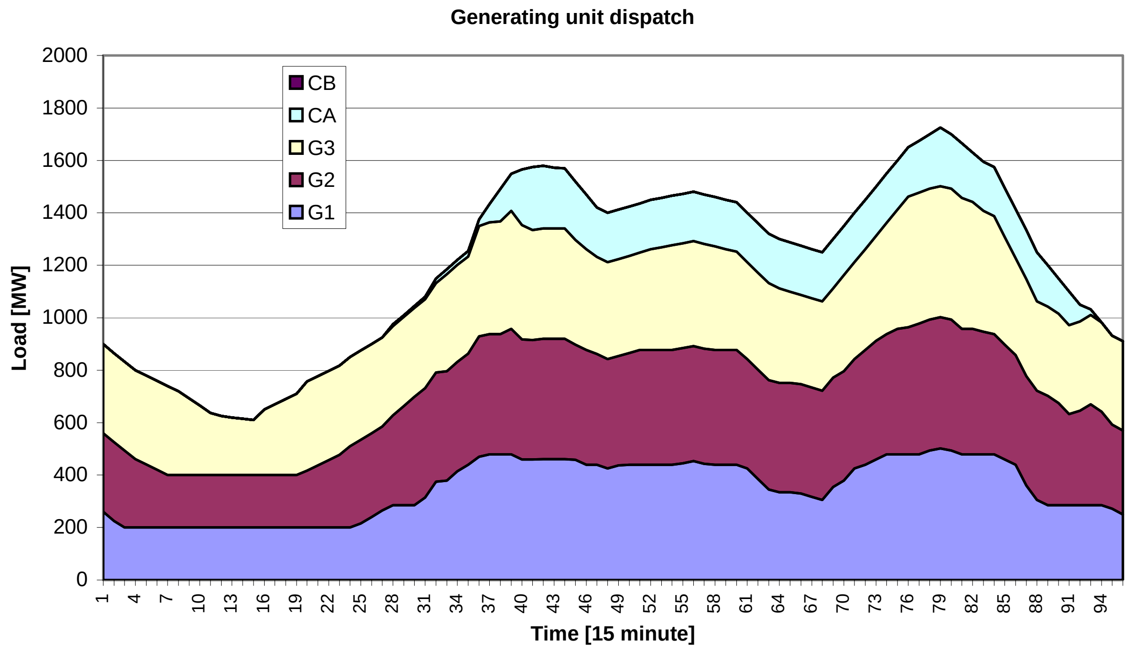


Figure 54 The dispatch for Case B

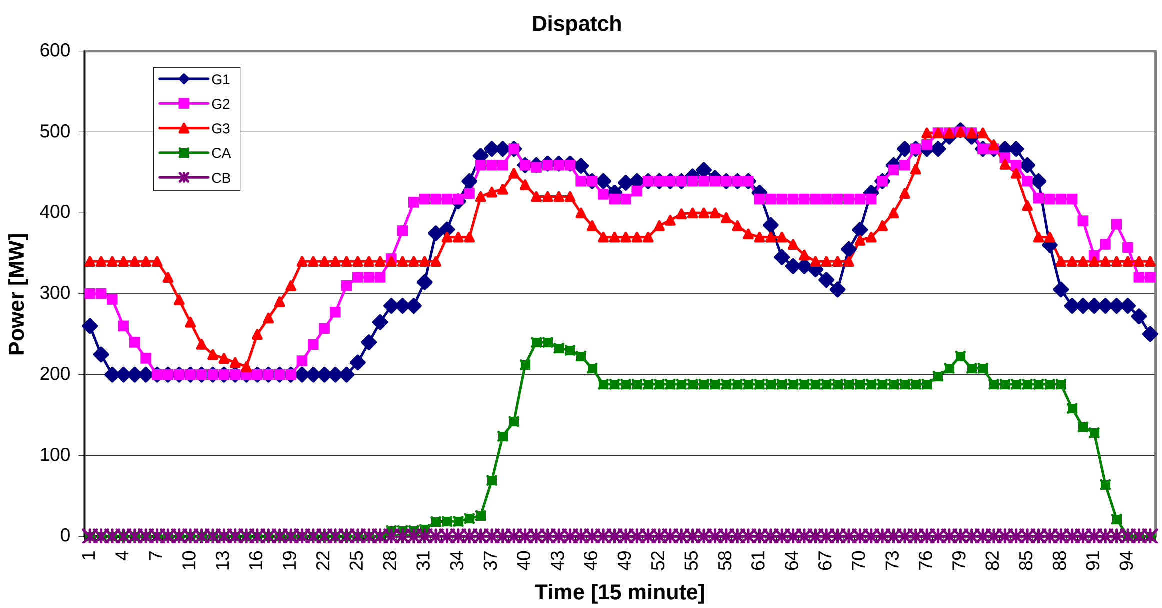


Figure 55 Dispatch of particular generating units – Case B

Figure 56 shows the 15-minute dispatch, while Figure 57 demonstrates the 5-minute dispatch.

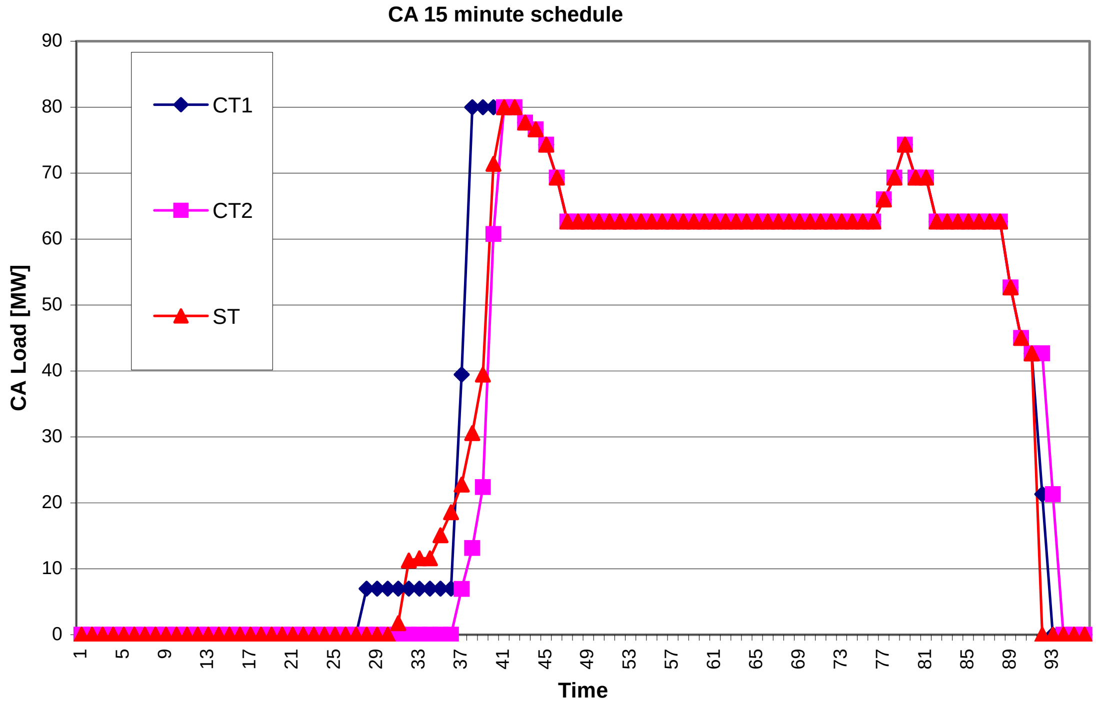


Figure 56 Load of the CCGT unit in 15-minute intervals

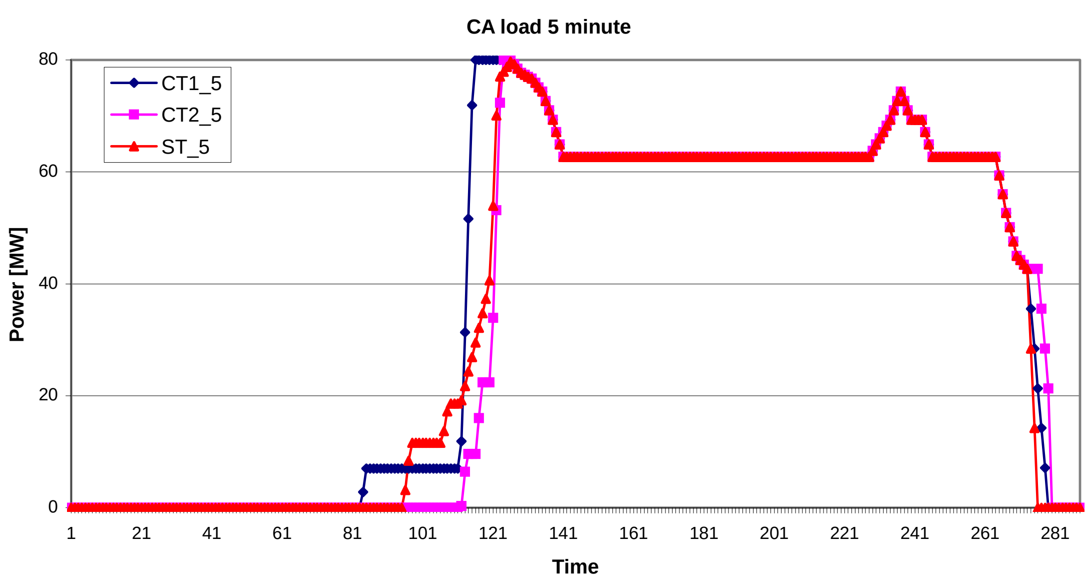


Figure 57 Load of the CCGT unit in 5-minute intervals

6.7.3 Simulation – Case C

In the case C it was assumed that the CCGT unit completed the start-up mode when:

- The power generated by CT1 is equal 80 MW;
- The power generated by ST is equal 40 MW;
- The power generated by CT2 is equal 24 MW.

The results are shown in Figures 58, 59 and 60.

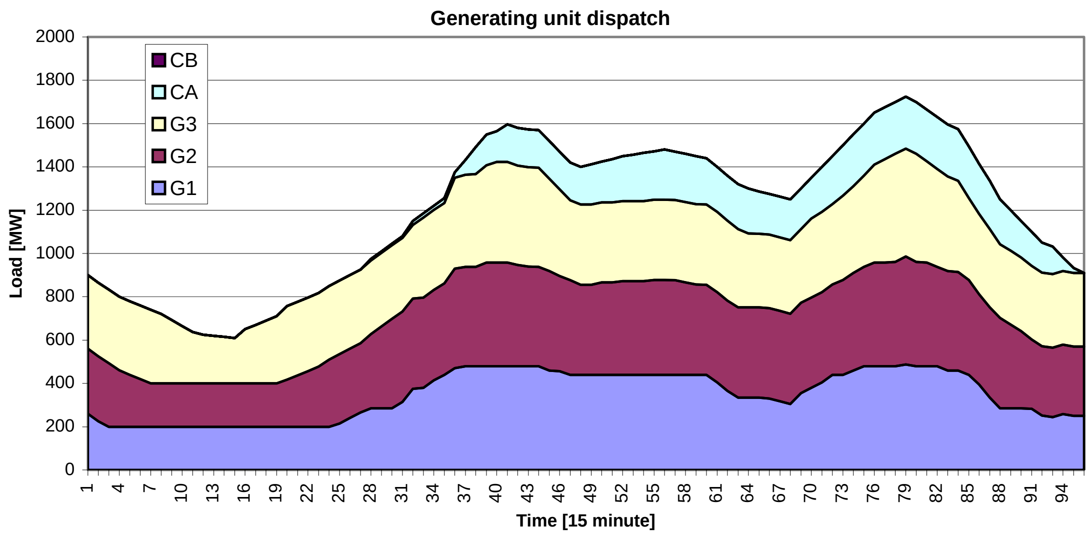


Figure 58 Dispatch of the generating units showing the sum of generated power – Case C

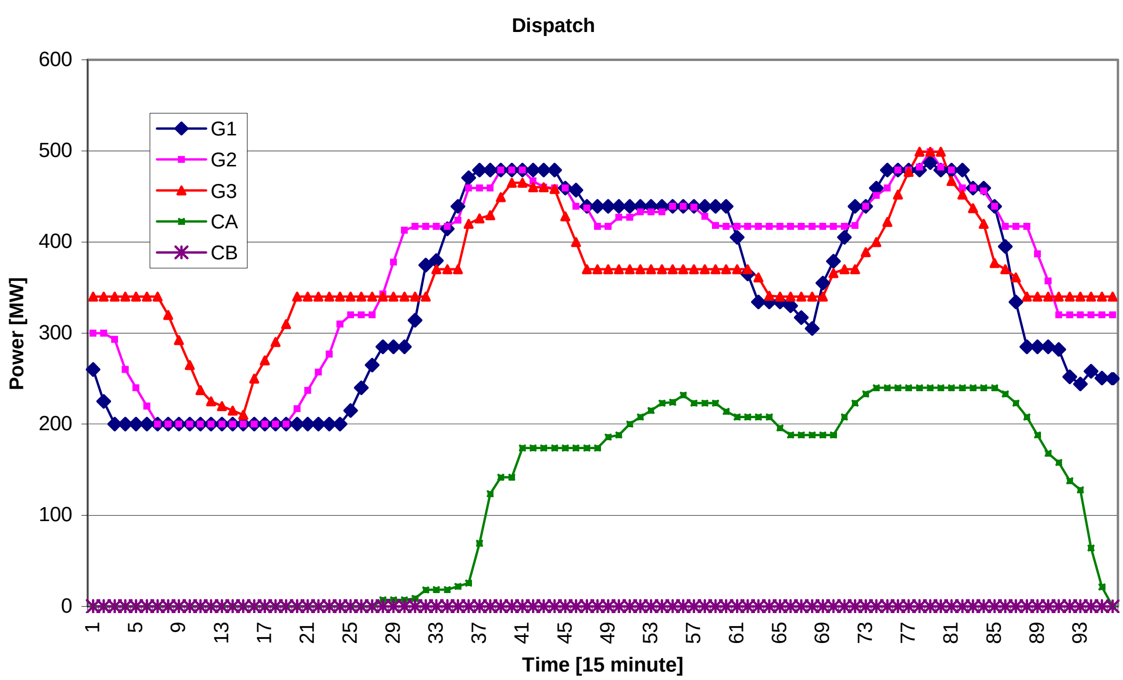


Figure 59 Dispatch of the particular generating units – Case C

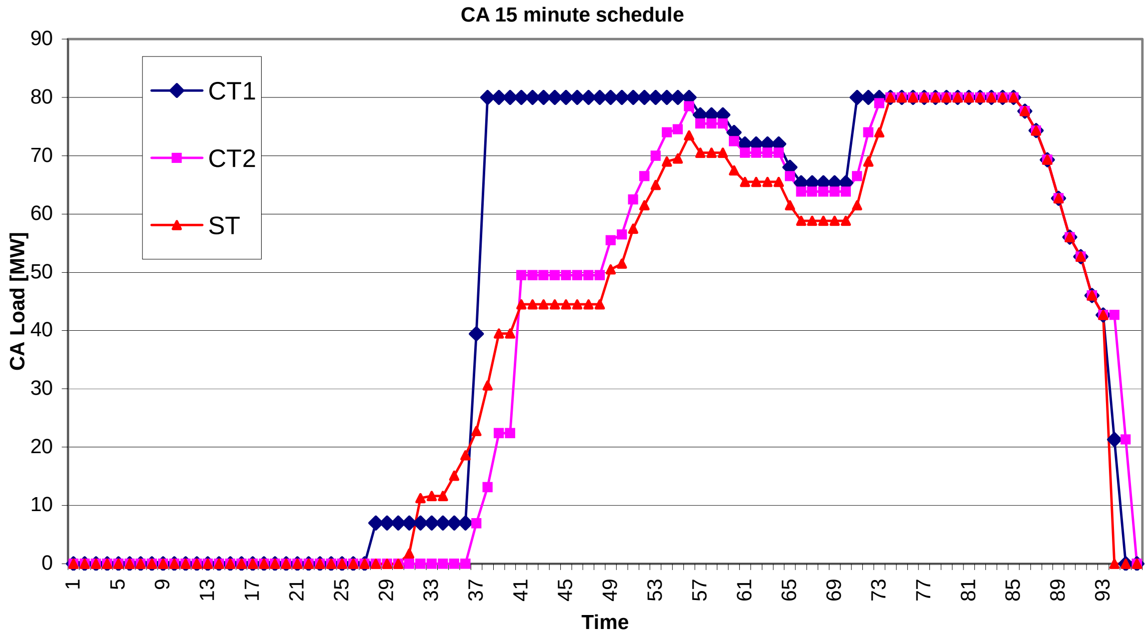


Figure 60 Dispatch of CCGT units – Case C

6.7.4 *Simulation – Case D*

In this case it was assumed that the start-up of CCGT would not depend on prices in the balancing bids and demand for power, but the start-up was set up for the assumed time of the day, earlier than when it was done by the optimization procedure.

The power dispatch for Case D is shown in Figures 61 and 62. Figure 63 shows the dispatch of CCGT units.

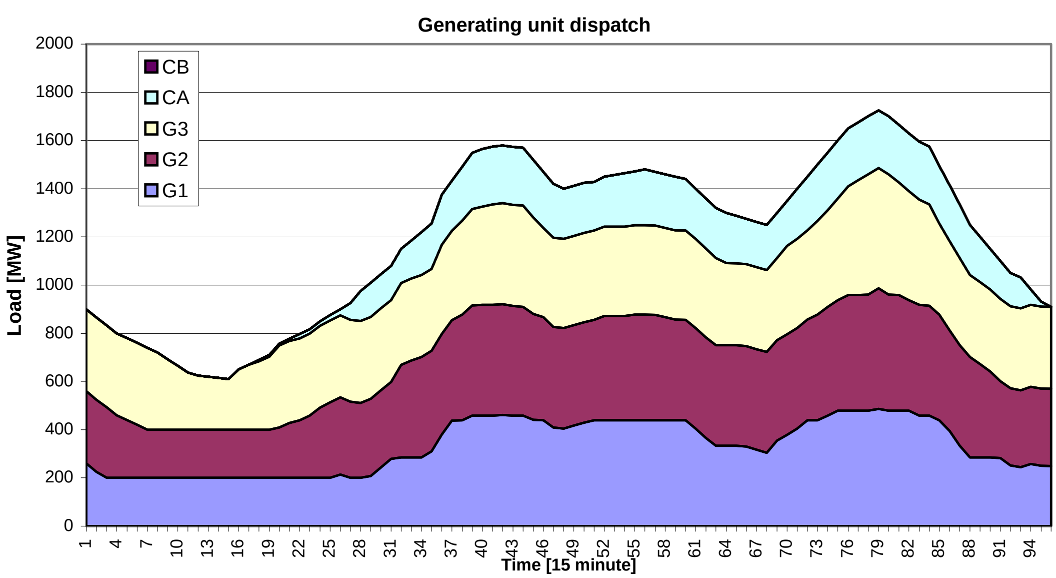


Figure 61 Dispatch as the sum of power generated by all units dispatched – Case D

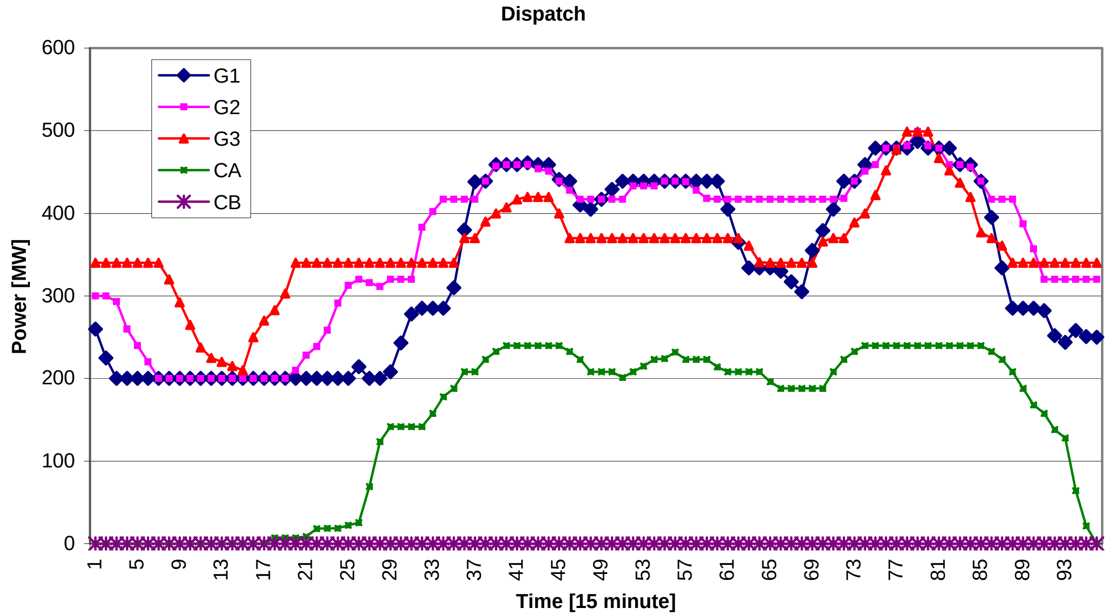


Figure 62 Dispatch power generated by all units dispatched – Case D

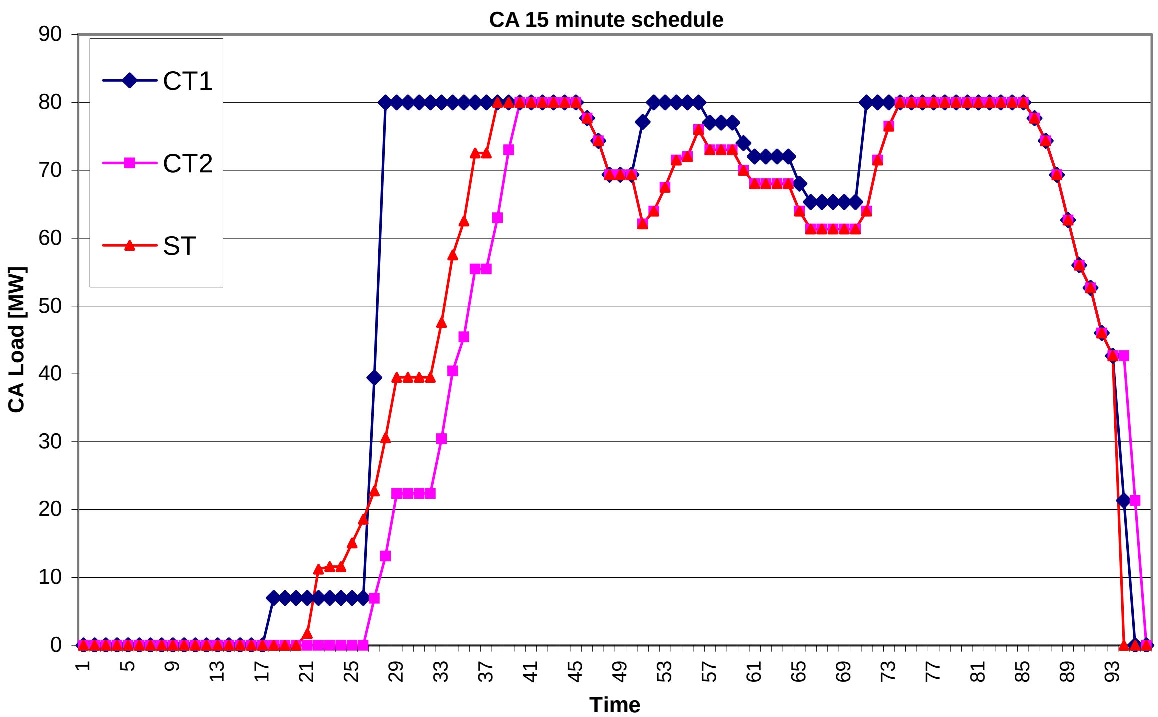


Figure 63 Dispatch of CCGT units – Case D

6.7.5 *Simulation – Case E*

In Case E, the balancing bids for unit CB were changed. In this case, prices are lower, resulting in the dispatch of the second CCGT unit.

The dispatch for Case E is shown in Figures 64 and 65.

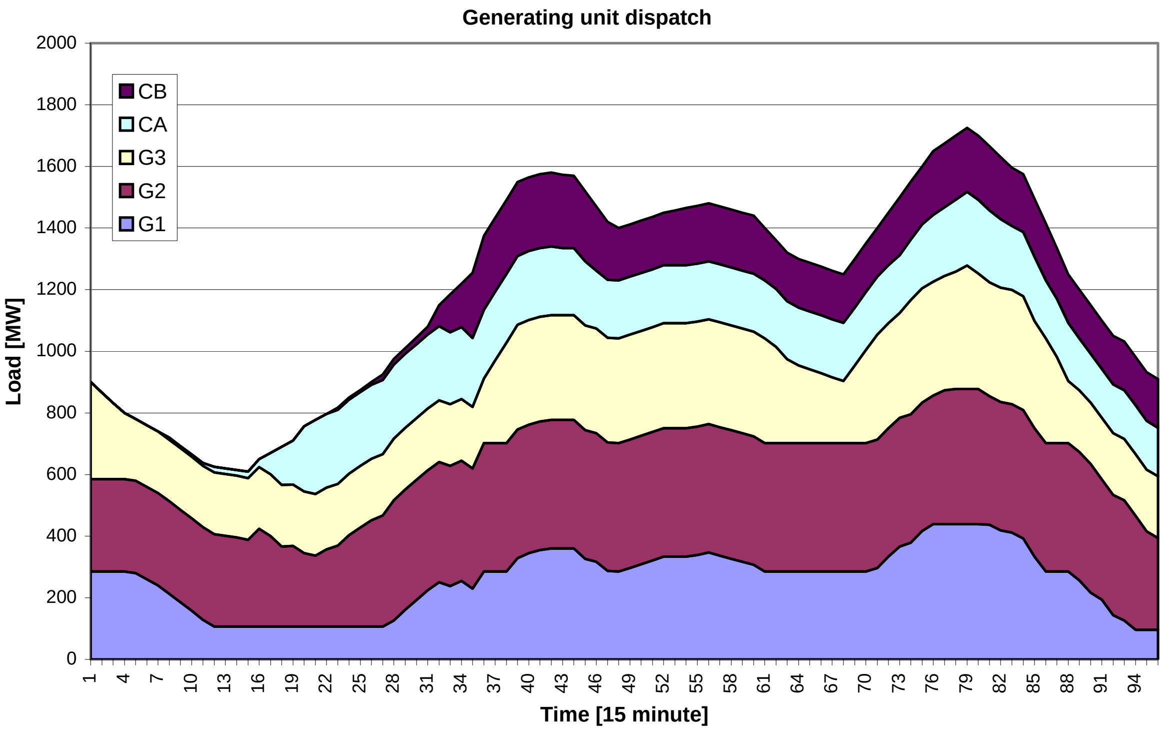


Figure 64 Dispatch as the sum of power generated by all units dispatched – Case E

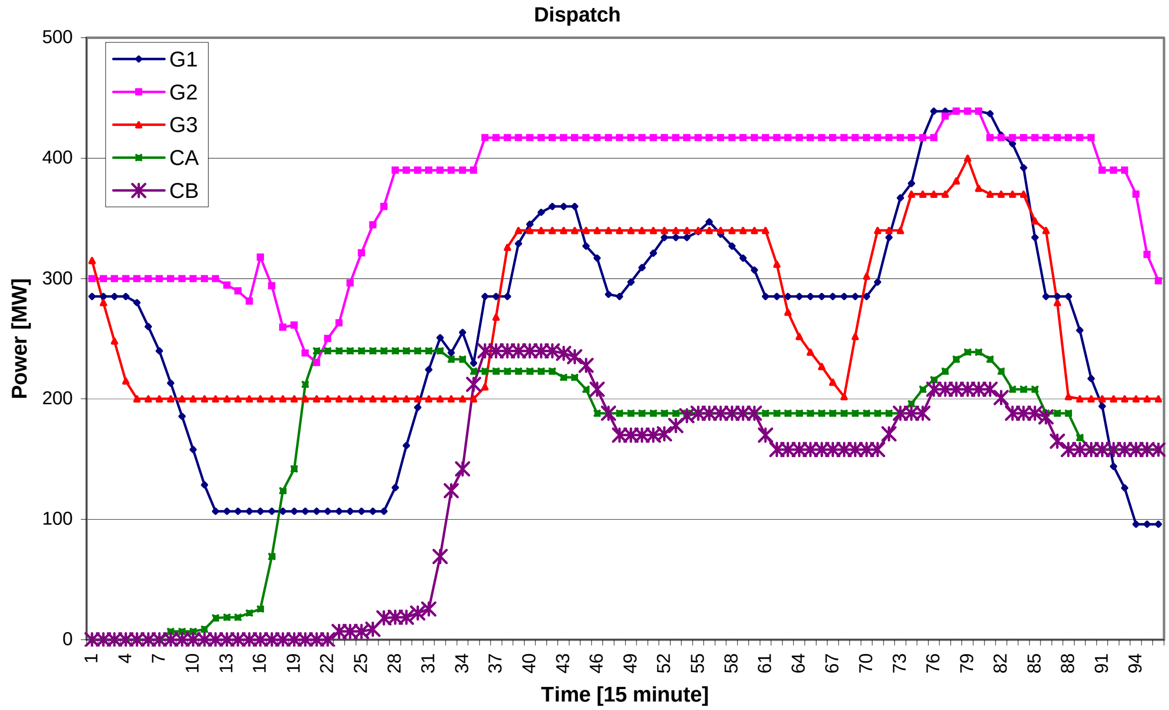


Figure 65 Dispatch as the power generated by all units dispatched – Case E

The 15-minute dispatch for CA and CB units are shown in Figures 66 and 67, respectively.

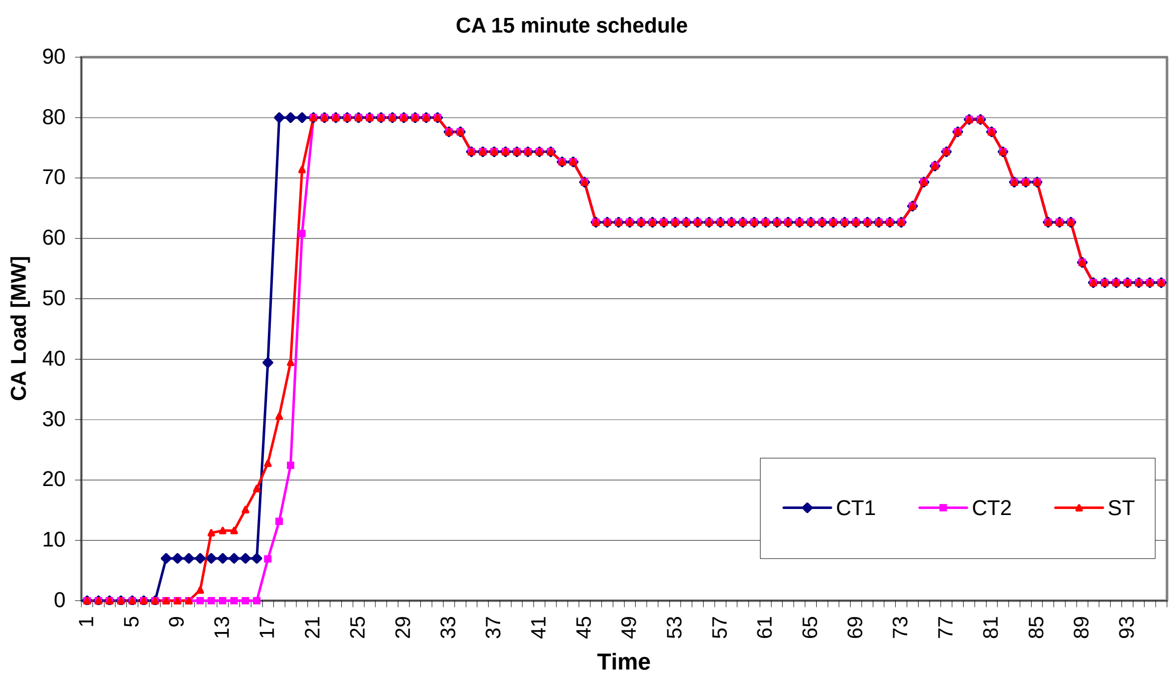


Figure 66 Dispatch of the CA unit – Case E

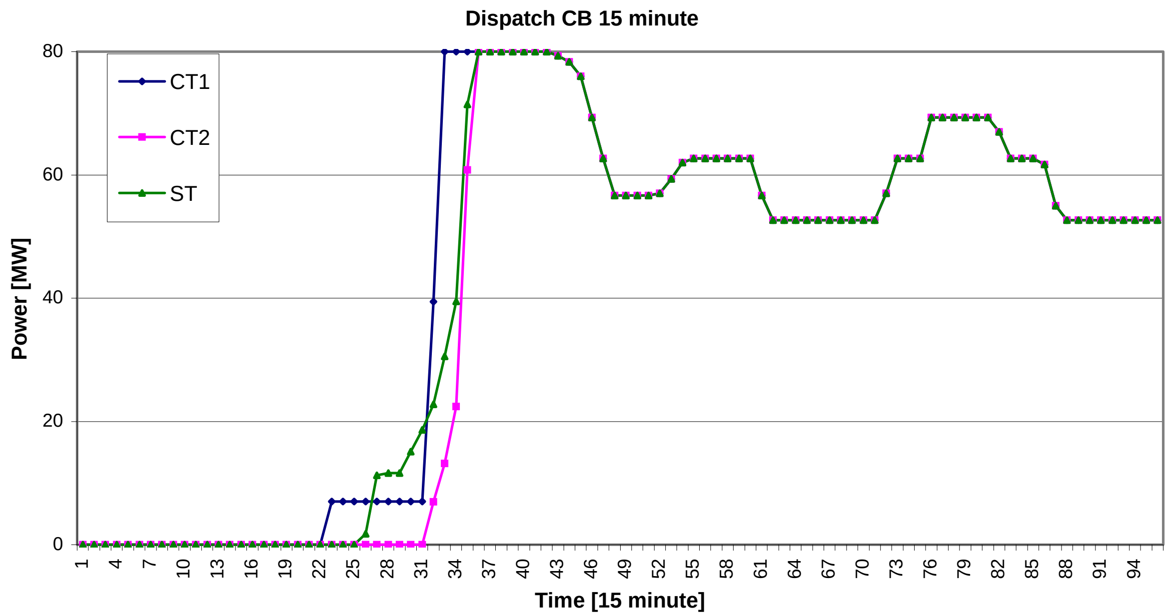


Figure 67 Dispatch of the CB unit – Case E

Figures 68 and 69 show 5-minute dispatch of CA and CB units, respectively.

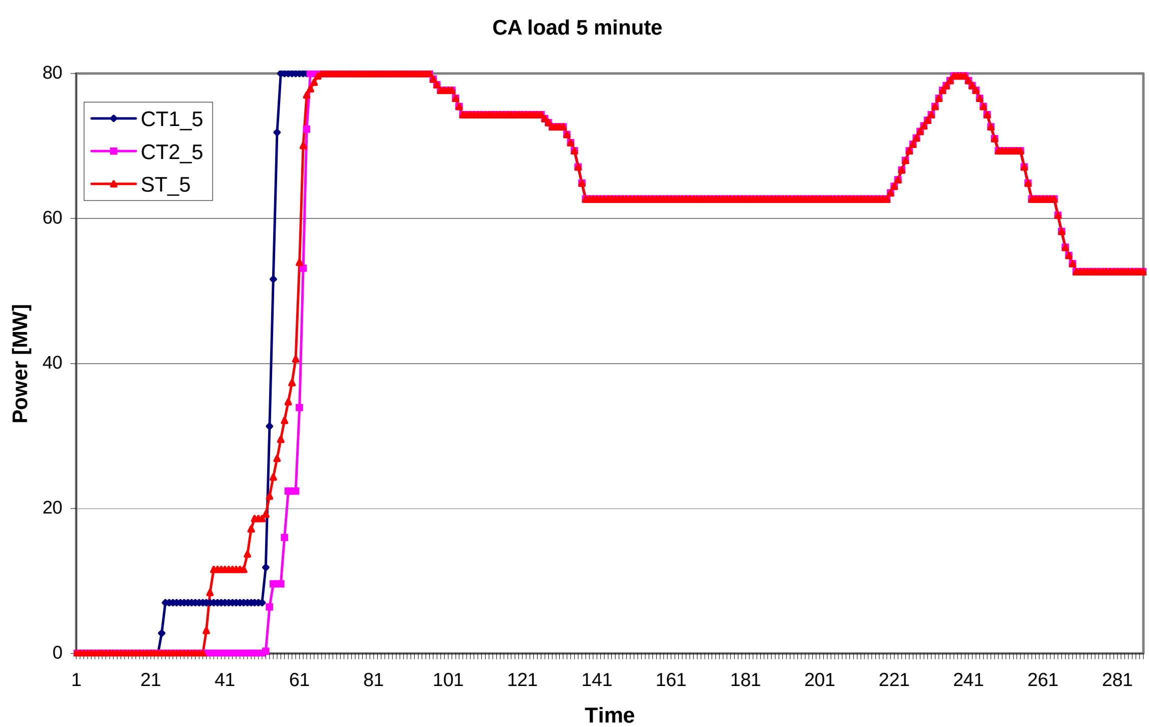


Figure 68 Plot of 5 minute dispatch of the CA unit – Case E

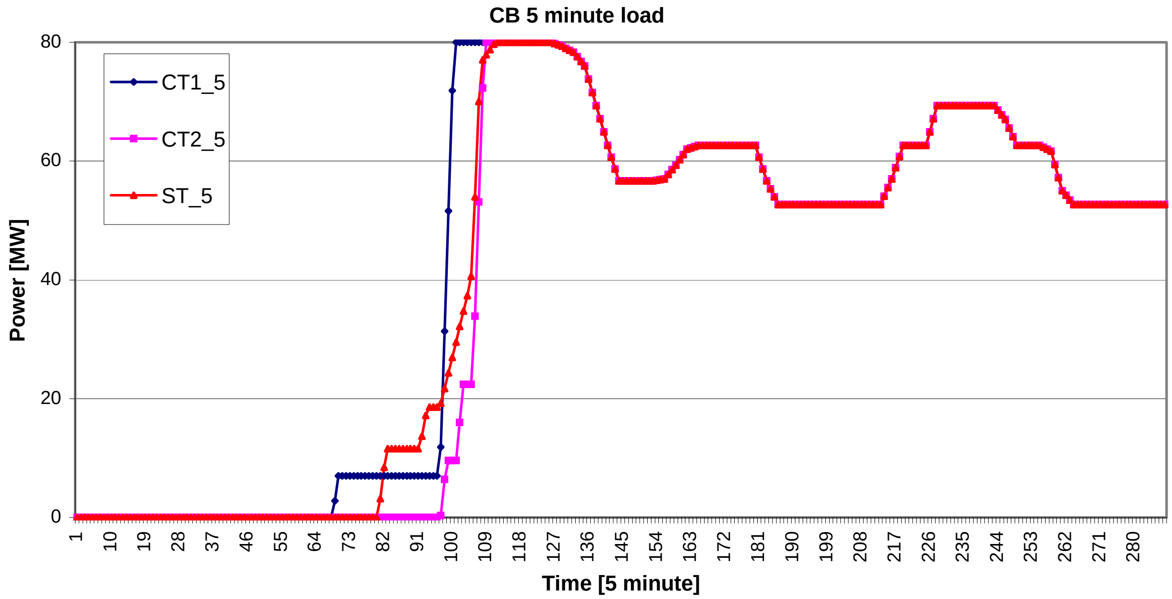


Figure 69 Plot of 5 minute dispatch of the CA unit – Case E

Figures 70, 71 and 72 show the dispatch of 15- and 5-minute for CB units. It is visible that 5-minute dispatch results in smooth control signals.

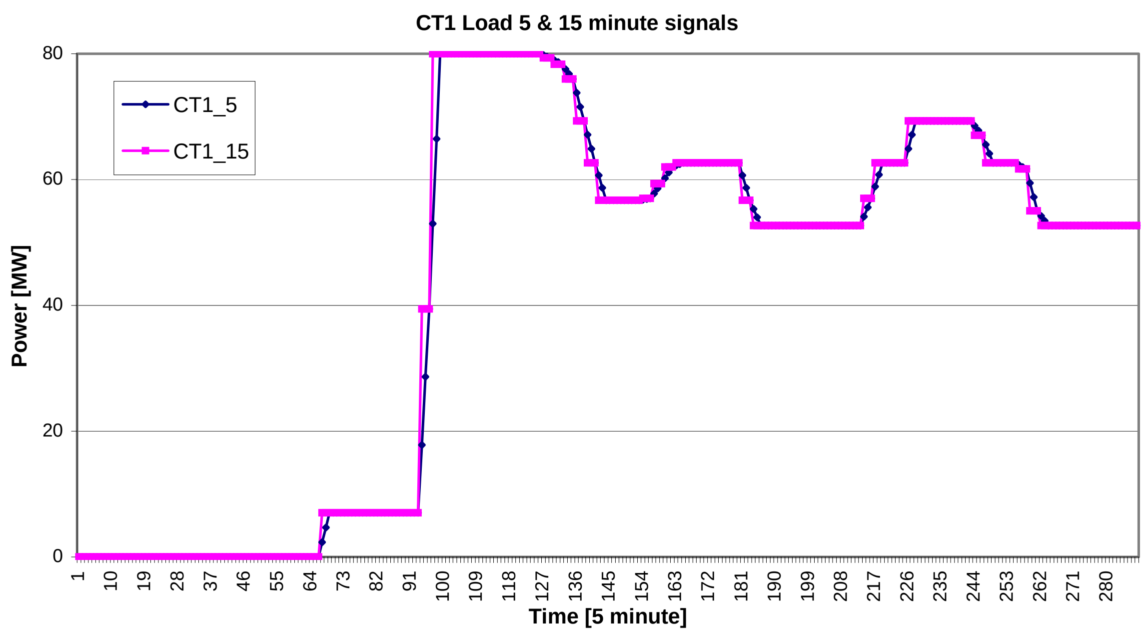


Figure 70 5- and 15-minute dispatch for unit CT1 of CB

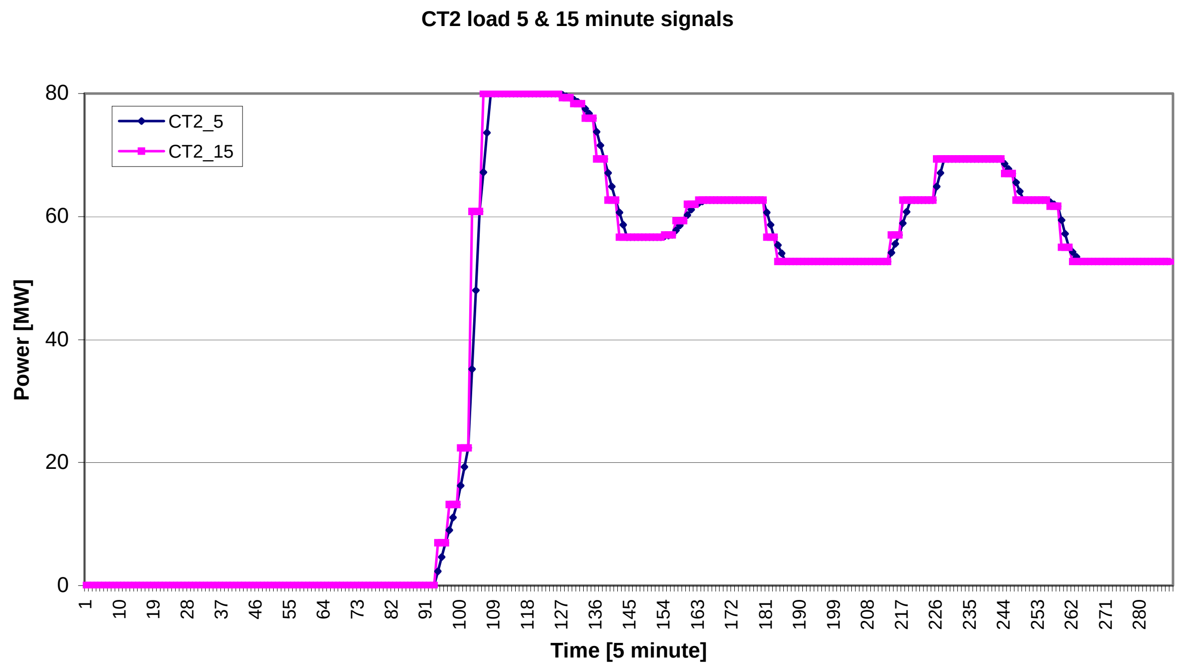


Figure 71 5- and 15-minute dispatch for unit CT2 of CB

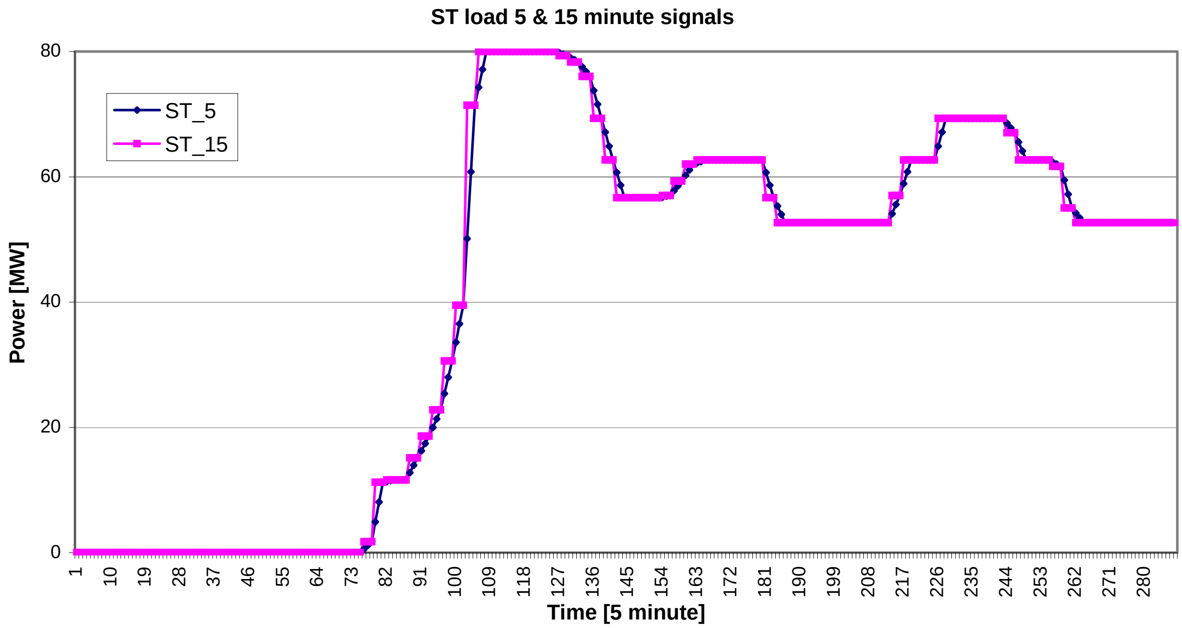


Figure 72 5- and 15-minute dispatch for unit ST of CB

6.7.6 Simulation – Case F

In case study F, the regulation of CCGT units was carried out due to the slopes of their characteristics when they end the start-up mode – Figures 73 and 74.

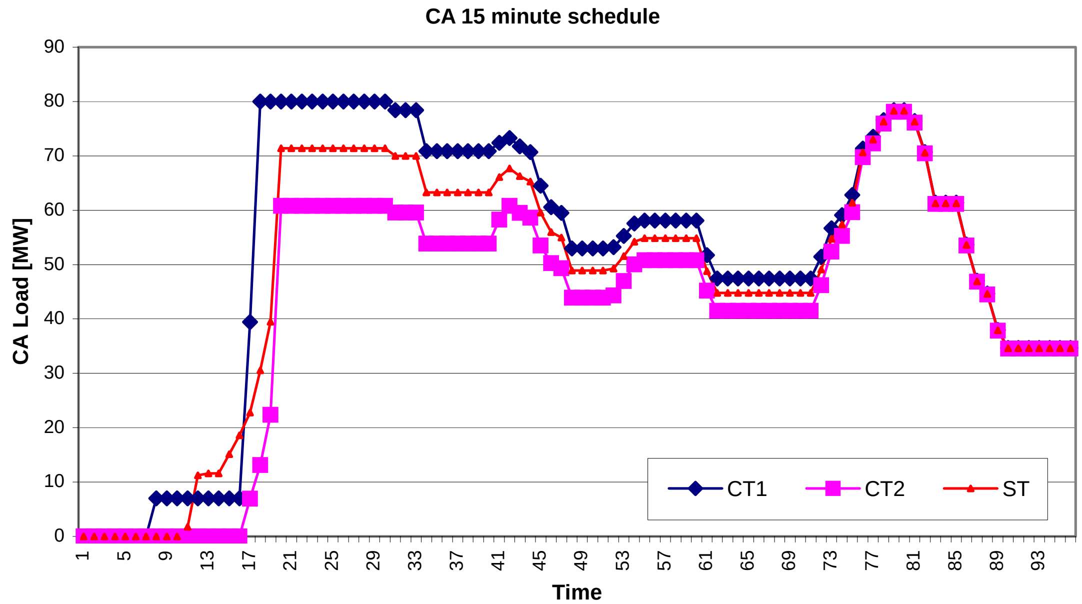


Figure 73 The 15-minute unit A schedules

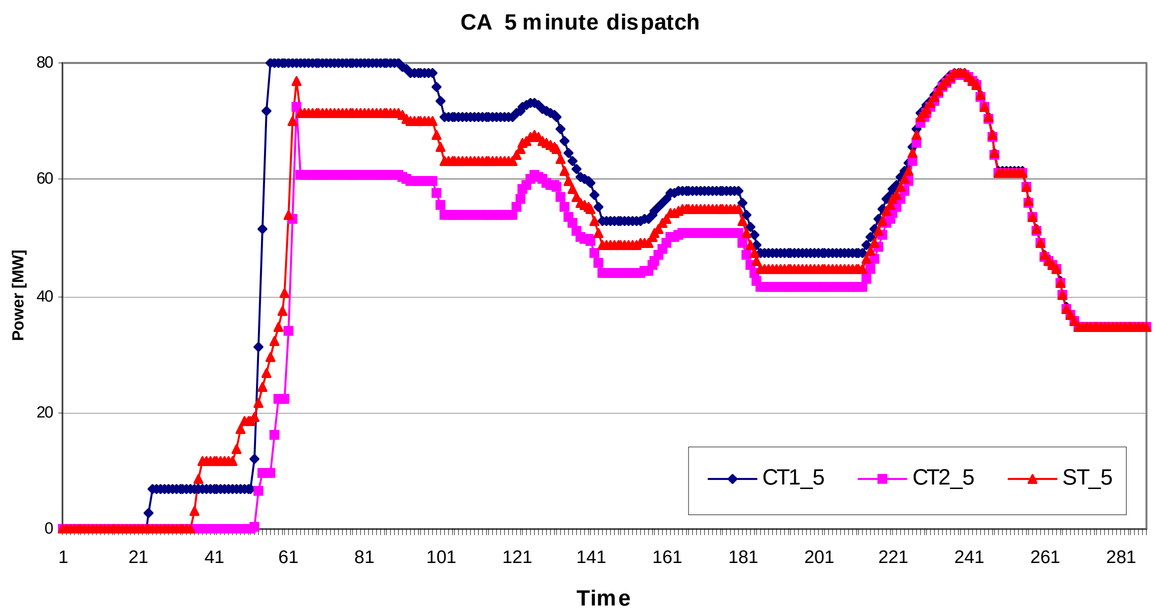


Figure 74 The 5-minute unit A schedules

6.7.7 Simulation – Case G

Case G illustrates the change of the configuration during the dispatch day. In period 46, the CCGT unit named CA changed the configuration from 2-on-1 to 1-on-1, switching off the component CT2 (the second gas turbine) and consequently reducing the output from the steam turbine component to a maximum of 50% of the CT1, i.e., 40 MW.

The further dispatch took into account only two components of the CCGT unit – see Figure 75.

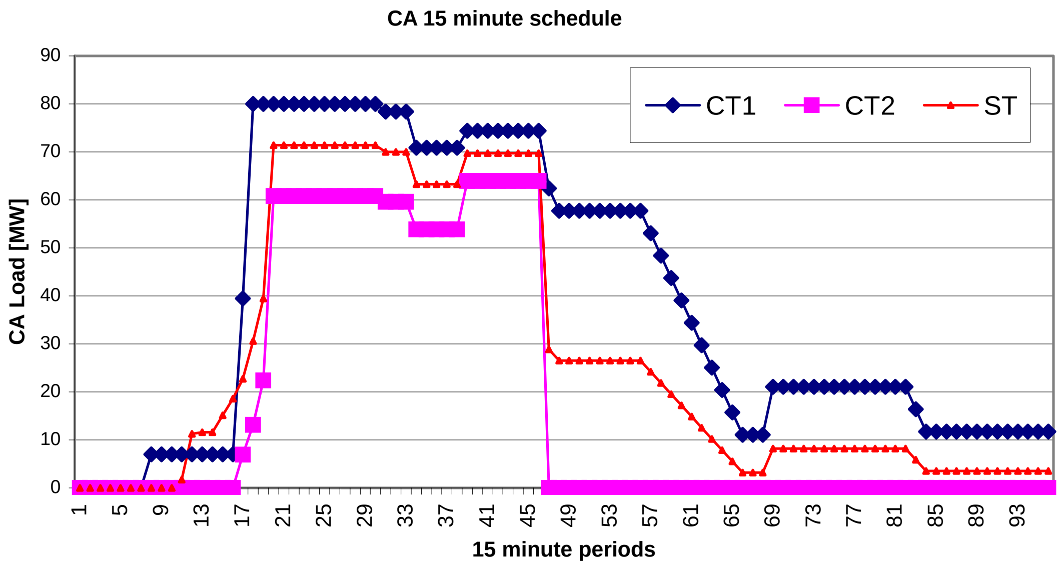


Figure 75 Change of the configuration of the CA unit during the dispatch day

7.0 CONCLUDING REMARKS

This document introduces the base thermal UCP problem, its most well-known variants and the methodologies that are suggested to solve such problems. It then reviews a state-of-the-art, concerning Security Constrained Unit Commitment methods discusses possible approaches to solve the SCUC with the CCUs. References to some commercial software solutions for a SCUC with CCU modeling are discussed in Appendix A. A short overview of metaheuristic techniques and a recent work where metaheuristics were used to solve the Unit Commitment with success are also presented in Appendix E.

Four possible approaches are discussed to solve the SCUC, when combined-cycle units are considered. They are based on MIP, a hybrid of LR and metaheuristics, MIP and metaheuristics, and a pure metaheuristics implementation. As explained in the text, the suitability of each approach to the problem under study depends on multiple factors. We made some comments on the advantages, drawbacks and problems of each approach.

From our experience, it appears that an application of the Mixed Integer Programming with some metaheuristics in the case of a convergence problem would be the method best suited for the solution of the unit commitment and dispatch with CCGT units. The report contains a detailed discussion of modeling such units in the context of the present SCUC methodologies implemented in the NYISO. We have also presented a numerical example with five different situations involving modeling of the start-up scenarios for two such units in a five-unit, 10-line sample system. The examples confirm that it is possible to model adequately the CCGT units with the MIP algorithm.

APPENDIX A. COMMERCIAL SOFTWARE FOR SCUC WITH COMBINED-CYCLE UNITS

A.1 Reviewed products

Best practices available today incorporate security-constrained unit commitment and security constrained economic dispatch with detailed generating unit operating characteristics and system transmission representation. A complete set of transmission contingencies must simultaneously be considered when committing and dispatching the system.

The purpose of this Appendix is to refer to commercial software solutions capable of handling the SCUC problem with combined-cycle units. In particular, and when the information is available, we make a reference to the security constraints that are modeled, to CCU and to the optimization techniques that are provided.

The solutions that were assessed are summarized in Table A1, along with the name of the company that provides them, and a link to their web page. Details on the SCUC software provided by ABB are described in (COHEN99).

Table A1 Reviewed products

Product	Provider	Web page
COMET	Nexant Inc.	www.nexant.com
Siemens PowerCC	Siemens	www.powergeneration.siemens.com
PCI GENTRADER	PCI	www.powercosts.com
PowerOp	Power Optimization	www.powerop.co.uk
e-terracommit	Areva	www.areva-td.com
U-PLAN	LCG Consulting	http://www.energyonline.com/products/uplane.asp
PowrSym3	Operation Simulation Associates	www.comax.com
HNLO	Energy Supply Chain Technologies	www.clinchain.com
Dayzer	Cambridge Energy Solutions	www.ces-us.com

A.2 Some Software Features

COMET

COMET is available in three forms: as a stand-alone package; as a calculation engine, to be integrated into any environment; or as an integrated web-based SCUC system for ISO/RTO use. It supports both generator price and/or cost offer bids, models multiple energy markets, spinning and operating reserve markets. It also models load shedding contracts based on price bids, bilateral contracts and multiple load forecast zones.

Siemens PowerCC

PowerCC SCUC functionality supports full co-optimization of energy and ancillary services, cascading prices of ancillary services, modeling of energy limited resources, modeling of piece-wise linear price curves, optimization of energy lost opportunity costs, price sensitive interruptible loads, and integrated preventive/corrective contingency constrained modeling.

The daily unit commitment optimization provides an operating schedule for the next 24 hours. In a second step, an instantaneous unit commitment optimization is performed every 30 minutes based on current energy consumption for heat and power. The instantaneous load distribution is compared with the results of this optimization. Any cost differences are determined and serve as decision making criteria for implementing corrective actions.

PCI GENTRADER

PCI GENTRADER provides unit commitment and resource scheduling to either maximize profits or minimize costs. It has multi-area market definitions with both path quantity and price/tariff inputs that can vary on an hourly basis. Ancillary Service markets with forward and option contracts can be added for spin, non-spin, regulation up or down, balancing down and replacement reserve.

The GENTRADER model is used to model over half of all the generation capacity in the United States.

PowerOp

PowerOp allows the minimization of the total fuel costs over the study period whilst satisfying the appropriate constraints. Alternatively, it maximizes profit, defined as the total revenue from electricity sales minus fuel costs. The study period, divided into half-hourly time intervals, can be from a single half-hour up to eight days.

An electricity contract with another company can be modeled as a pseudo-generating unit or as a "demand" unit.

For the British electricity market, the software also has an option for the direct modeling of the electricity contracts which are offered on power exchanges or by electricity brokers. Electricity contracts may be of type buy or sell, and they are characterized by a price per megawatt-hour, upper and lower MW limits, and a contract start-time and duration. There is also an option to specify a block size for each contract, for example, a contract may be for 50, 100 or 150 MW but not for intermediate values. Contracts may optionally be grouped, so that if one contract in a group is accepted then all the other contracts in that group must be accepted. This direct modeling of electricity contracts allows the software to consider a larger number of such contracts than if they were modeled as pseudo-generating units.

The software also has an option to meet a particular demand pattern using electricity contracts only. This option could be used, for example, by an electricity trading company that has no generation of its own. Furthermore, it has an option to minimize changes from a previously calculated schedule, while taking account of any changes in demand and plant availability that have occurred since the previous run of the software. This can be useful if circumstances change suddenly, but the system operator does not wish to change many of the previously issued instructions to the power stations.

U-PLAN

U-PLAN software is mostly used in investment and maintenance planning, as well as for monitoring purposes. Even so, they do also have a SCUC module that covers the topic of this section.

A.3 Which Security Constraints are Considered?

COMET

COMET models networks in explicit bus-branch model form. Limits are represented for both pre- and post-outage ("n-1" security constrained) on all monitored network facilities, such as lines, transformers and interfaces. All facilities can have up to three limit sets and all have maintenance schedules.

A flexible range of network models is offered: a full nonlinear AC network model, both in the pre- and post-contingency states and a DC network model, representing only MW control devices. Intermediate models allow, for example, AC pre-outage modeling and limits, with incremental DC post-outage modeling.

PowerOp

The software does not provide a security assessment of the transmission network because it does not contain a detailed model of the transmission network.

e-terracommit

The SCUC program optimizes the scheduled generation and price-sensitive load while satisfying generation, reserve requirements, transmission constraints, and generator operating constraints such as minimum up and down times. The transmission constraints that are modeled are of two types: branch-flow constraints, insuring that line and interface thermal limits are satisfied (for steady-state operating conditions) for the forecasted network configuration and for the configuration with a specified set of network and generator outages; import and export constraints limiting the generation from specified generators and loads. The latter constraints, which can be used to model voltage and dynamic security constraints, are developed using off-line analysis and are inputs to the program.

U-PLAN

Day-ahead schedules meet forecasted energy and ancillary services requirements, while taking into account region-specific operating protocols as well as transmission constraints. OPF simulation is used to ensure that the final unit commitment can obey to all transmission constraints including line contingencies, flow gates, thermal limits, phase shifters and generator outages. It performs a DC commitment and an AC (or DC) dispatch.

PowrSym3

The system may be divided into geographic areas for electric loads. The load areas may have different spinning and operating reserve requirements. Reserve requirements may also be applied to area groups. Transport limits between the geographic areas, along with losses and wheeling charges, may be applied to power transfer between the areas.

Dayzer

Dayzer considers first contingency or multiple contingency transmission constraints, locational operating reserves, second contingency generation and transmission constraints/operating procedures.

A.4 How are Combined-Cycle Units Modeled?

COMET

The following unit specifications are considered: generation limits, quick start capacities, incremental heat rate curves, minimum up and down times, ramp up and down rates, start-up cost characteristics for each CT/ST configuration, multiple emission constraints, multiple fuel constraints, must on/off, maintenance schedules and other operating constraints.

PCI GENTRADER

For CC units, the software can handle up to 10 unique CC states or stages. It commits each stage and indicates the optimal MW loading within each stage. Unit hours, starts, fuel burn, etc., are tracked for each stage of the CC. Typically, they describe a CC unit such as a 2x1 such that it can operate in 1x1 fashion, 2x1 fashion. If it has duct-firing, that state can also be described.

PowerOp

Combined-cycle units can be modeled in two different ways. One version of the software models each combined-cycle station as a single equivalent generating unit, but it allows the user to specify a multi-segment piecewise-linear incremental heat rate curve for each generating unit. The incremental heat rates do not have to be monotonically increasing as the power output increases, which means this approach can model step-changes in thermal efficiency when another turbine starts up. Another version of the software models each individual mode of operation as a pseudo-generating unit. The software contains some logic which prevents incompatible modes of operation from being used in the same half-hour.

U-PLAN

There are two options to model CC units: as a single unit with multiple configuration modes (1x0, 1x1, 2x1 and so forth); and by representing each component such as the CT and heat recovery unit as individual units and using a built-in integer program option.

PowrSym3

Combined-cycle units may have up to three states with minimum transition times and incremental start costs between the states. Each state may have different heat rate curves.

HNLO

Modeling of CTs includes hourly temperature/humidity forecast as an input, maximum and minimum operating levels, ramp rates (this will vary across the loading range and is also dependent on the configuration currently running), minimum up and down times, no-load zones (vibration zones to stay out of, etc.), models and optimizes between the available transitions between various CC configurations, handles combined-cycle configurations 1x1, 2x1, 3x1, 4x1, 2x2, 3x2, 4x2. Emission curves are modeled as individual I/O curves for the individual units of a combined-cycle plant and not by a simplification by treating them as a single I/O curve for the aggregate CC unit.

Dayzer

Dayzer assumes a fixed state for combined-cycle units running either in combined-cycle mode with corresponding heat rate or in simple cycle mode with corresponding heat rate and shape.

A.5 Which Optimization Techniques are Used?

COMET

COMET employs a combination of Mixed-Integer Programming, Augmented Lagrangian Relaxation, Benders' Decomposition and, where appropriate, parallel computing.

Siemens PowerCC

PowerCC SCUC considers Mixed Integer Programming (MIP) techniques combined with a Separable Sequential Quadratic Interior Point Method.

PCI GENTRADER

The optimization logic is based on Sequential Bidding.

e-terracommit

e-terracommit uses Lagrangian Relaxation and MIP. Users may choose between the new MIP algorithm and the standard Lagrangian Relaxation algorithm. The optimization approach is fully described in (COHEN99).

U-PLAN

U-PLAN uses proprietary decomposition algorithms. The principle of the methodology may be found in (WOOD96), Chapter 13.4.1 Linear Programming Method with Only Real Power Variables and Chapter 13.4.2 Linear Programming with AC Power Flow Variables and Detailed Cost Functions.

PowrSym3

A Dynamic Programming optimization with proprietary branch trimming and sorting techniques is used for the unit commitment. Additional algorithms create branches and allow base load units to be fixed and peaking units to respond to needs only.

Another feature of their DP is that it can be given an initial commit scheme as input (or develop the initial scheme using a traditional algorithm) and then search a window about that scheme finding improvements if it can. Any branches that do not meet security constraints are penalized proportional to the constraint violation in the DP objective function.

HNLO

The optimization model encompasses multiple mathematical solutions including Linear Programming, Mixed Integer Programming, Heuristics and Expert system rules.

Dayzer

Mixed Integer nonlinear programming techniques are used.

A.6 Clients

Optimal technologies – AEMPFAST

Constellation, Lawrence Berkeley National Laboratory, the California Energy Commission, the California ISO, New Power Technologies, Pacific Gas and Electric, and Enron.

Siemens PowerCC

Generation companies currently using Spectrum PowerCC GM are EW Obwalden in Switzerland; EDP in Portugal; SaarEnergie in Germany; Power IT in Finland; Fuji Matsumoto Factory in Japan; and Alliance RTO (ASP) in the United States.

PCI GENTRADER

GENTRADER is used by a number of energy companies participating in the deregulated Texan electricity market, e.g., Reliant Energy, TXU and Calpine Corp.

PowerOp

One version of the unit commitment software, developed for Northern Ireland Electricity (NIE), has been used every day since December 1996 to schedule the generating units in the Northern Ireland power system. Other versions of the unit commitment software are being used for self-scheduling by a number of generating companies under the New Electricity Trading Arrangements (NETA) in the England and Wales electricity market. They will also be appropriate for use under the proposed British Electricity Trading and Transmission Arrangements (BETTA). Each version is customized to the individual requirements of the user.

e-terracommit

ISO NE, MISO, ERCOT, and PJM.

U-PLAN

All major companies in New York and Texas use U-PLAN for planning purposes. It is also present in PJM and ERCOTT.

APPENDIX B. SOLUTION METHODOLOGIES FOR THE BASE THERMAL PROBLEM

The first studies on the UCP date back to the 40's (LI97a) and since then several methodologies ranging from very straightforward to more complicated methods have been proposed. Initially, methods for unit commitment based on relative cost priority lists dominated the power industry in this area. During the 60's and 70's Dynamic Programming (DP) approaches have been suggested and since the 70's Lagrangian Relaxation (LR)-based unit commitment methods have been successfully applied in Energy Management Systems (EMS). Later, methods based on Artificial Intelligence and on metaheuristics were also proposed. However, as far as the authors of this report are aware, there is no commercial software that provides the latter techniques.

In this section we give an overview of solution methodologies, from the first attempts to the state-of-the-art techniques. Due to their historical importance, Dynamic Programming and Priority List-based methods are introduced first. The section proceeds with a reference to Lagrangian Relaxation, to constructive methods and to Metaheuristics and Evolutionary Algorithms. It concludes with a summary of other techniques that, though not so frequently, have received some attention in the literature. Additional information on the UCP and on its solution methodologies can be found in the surveys by (SHEBLE94), (SEN98) and (YAM04).

B.1 Priority List-Based Methods

Priority List-based methods rank all units in the system according to a merit function and, based on this ranking and for each time interval, the units are switched on (or off) until load and spinning reserve constraints are fulfilled. The commitment priority order may be determined by, e.g., the Average Full Load Cost (AFLC) (expression B.1) or, alternatively, by the Commitment Utilization Factor (CUF) of each unit (expression B.2).

$$AFLC = \frac{\text{working cost at maximum production level}}{\text{maximum production level}} \tag{B.1}$$

$$CUF = \frac{\text{reserve requirements}}{\text{total commited output - load}} \tag{B.2}$$

Although these methods are particularly appealing, due to their implementation simplicity the quality of the solutions is normally weak. This is due to the difficulty in correctly ascertaining the relative efficiency of the units, as important system information is neglected in these functions. Even so, this is still a popular approach in commercial software packages and now also in market environments, where suppliers are ordered according to their bid prices and selected, in that order, until (inelastic) load demand is satisfied.

B.2 Dynamic Programming

Each stage of DP represents a particular time period and, in every stage, the corresponding states represent different combinations of commitment states (on/off) for the generating units in that specific period. This approach is particularly interesting, because it maintains solution feasibility. However, it suffers from the "curse of dimensionality" and is not directly applicable to real size problems in its standard form (HOBB88). To reduce problem dimensionality, different strategies that truncate the hourly state space have been developed, e.g., DP-Sequential Combination, DP-Truncated Combination, etc. Additional heuristic procedures have also been combined with DP to achieve a further reduction of the searching space and to speed up the execution. In (OUY92), for example, DP is combined with neural networks. The results obtained are, naturally, suboptimal but the computation times are considerably smaller.

B.3 Lagrangian Relaxation

Lagrangian Relaxation was first used to solve the UCP nearly three decades ago by (MUC77) and since then it has been widely applied to the problem, as it can be confirmed by the huge number of publications in this area, e.g., (BER83; MER83; AOK87; BARD88; ZHUANG88; AOK89; TON90; BAL95; GJE96; TAK00; BORG01). The basic idea of the approach is to relax system constraints by using Lagrangian multipliers. The resulting problem is dualized and decomposed into a set of smaller problems, one for each generator, which can be solved more easily. Once the values of multipliers have been fixed, each separated subproblem is solved with the constraints that represent the operating characteristics of the corresponding unit. The entire solution procedure is an iterative process that successively solves subproblems and adjusts the multipliers, according to the extent of violation of system constraints.

A major drawback of LR is the difficulty in obtaining feasible solutions, due to the dual nature of the algorithm. To overcome this difficulty, an Augmented Lagrangian Relaxation (ALR) has been developed and used in e.g., (WAN95), (BAT92) and (BEL02). ALR is a combination of penalty and LR methods where quadratic penalty terms, associated to power demand, are added to the objective function. A major advantage of this approach is that it may obtain a feasible primal solution in cases where the classical Lagrangian Relaxation presents a duality gap. Furthermore, the dual function associated to the Augmented Lagrangian function is differentiable in cases where the LR presents a non-differentiable dual function. However, when solving non-convex problems, as it is the case with the UCP, the ALR method may reach a local optimum, and give no information on its relative quality. Lately, LR has also been successfully used in conjunction with other methodologies. In (CHENG00) a joint approach of Lagrangian Relaxation and Genetic Algorithms (GA) is presented. GA is incorporated in LR, to update the Lagrangian multipliers and improve the performance of LR. In (VAL02) LR is used to obtain good initial solutions to build the initial population of a numeric algorithm.

Within the framework of deregulated energy markets, the LR technique has been receiving particular attention, as it gives “price signals” to the generator companies.

B.4 Constructive Heuristics

Several constructive heuristics, different from the priority list-based ones, have been designed to solve the UCP. One such heuristic is the Unit Decommitment method, presented in (TSENG97). The method can work alone or serve as a post-processing tool to improve the solution quality of other methods used for the UCP. It works as follows: Given an initial feasible solution, where all the available units are committed over the planning horizon, the method uses DP to determine an “optimal” strategy to decommit overcommitted units, according to some specified economic criteria.

The decommitment process is concluded when no further reduction in the total cost is possible, or the unit schedules of two consecutive iterations over the time period remain unchanged, without any violation of the spinning reserve constraint. In (TSENG00) the authors extend the method to a more general formulation. They also show that it may be viewed as an approximate implementation of the LR approach and that the number of iterations that it requires is bounded by the number of units.

The approach presented in (SEN98a) reduces the number of units in the power system to the lowest possible number, according to their fuel/generation cost characteristics. The reduced system is solved through modified DP.

Other problem-specific heuristics can be found in, e.g., (TON91), (LEE88) and (SHEBLE90).

B.5 Metaheuristics and Evolutionary Algorithms

More recently, metaheuristics and evolutionary algorithms have also been regarded as interesting tools to tackle the UCP, a literature review showing that approaches based on GA prevail: (SHEBLE94; MA95; KAZARLIS96; MAIFELD96; SHEBLE96; YANG96; SWA03). Nevertheless, other approaches based on, e.g., Simulated Annealing, Tabu Search or hybridizations of these methods, have also been developed.

Mainly to reduce the computational time of GA approaches, some authors have designed additional tools to include in the base algorithm. (ORERO97a; ORERO97) consider a hybrid GA approach where the solution obtained with a priority list method is part of its initial population. By doing so, they reach better results than the standard GA method presented in (ORERO96).

In (VAL02), the authors study a GA with Local Search. In each generation, Local Search with two distinct neighborhood operators is applied to the best solution of the new generation if, and only if, the solution is better than the best solution found so far. A modified version, where LR is first used to obtain an initial solution, is compared to the base version leading to better results for large size instances.

(YANG97) increases the search speed through a parallel implementation.

Other Evolutionary and Immune Algorithm approaches can be found in (DUO99) and in (HUA99), respectively.

(MANTAWY99) develop a hybrid method, the core of the algorithm based on GA. Tabu Search is used to generate offspring in the reproduction phase of GA, and Simulated Annealing is used to accelerate its convergence.

Concerning Local Search-based metaheuristics, the work by (ZHUANG90) was probably the first attempt to solve the UCP through Simulated Annealing (SA). Other approaches are those by (MANTAWY98) and by (WAWONG98). Tabu Search approaches can be found in (MANTAWY98a) and (BORG01). An implementation based on GRASP is presented in (VIANA03).

More recently a new search strategy for Local Search-based metaheuristics was proposed by (VIANA05). This strategy, Constraint Oriented Neighborhoods (or CON), was tested in a set of problem instances from the literature, and the computational did consistently lead to better results than others previously obtained, while the required CPU time has been drastically decreased.

Other paradigms such as Neural Networks, Expert Systems, Fuzzy Logic and Constraint Logic Programming have also been considered.

APPENDIX C. DETAILS OF THE MIXED INTEGER PROGRAMMING (OR MIXED INTEGER LINEAR PROGRAMMING) METHOD

General linear programming is a linear program with additional constraint in the form of:

$$\begin{aligned} &\min \mathbf{c}^T\mathbf{x} \\ &\text{subject to: } \mathbf{Ax}\begin{Bmatrix} \le \\ = \\ \ge \end{Bmatrix}\mathbf{b} \\ &\mathbf{x} \in \mathbb{Z}^{n-p} \times \mathbb{R}^p \end{aligned} \tag{C.1}$$

With $\mathbf{A} \in \mathbb{R}^{(m \times n)}$, $\mathbf{b} \in \mathbb{R}^m$, $\mathbf{c} \in \mathbb{R}^n$, $p \in \{1, \ \ldots, \ n\}$.

If, in above formulas:

$p=n$	We have a linear problem
$p=0$	We have an integer problem
$0<p<n$	We have (general) mixed integer problem (or mixed integer linear problem)

The linear programming solution is an upper bound on the integer programming solution. If the linear programming is infeasible, then the integer programming is infeasible. If the linear programming solution is integral (all variables have integer values), it is also the integer programming solution.

Some linear programming problems (e.g., transportation problems, assignment problems, min-cost network flow) will always have integer solutions. These can be classified as problems with a unimodular matrix **A**. (unimodular =>$det\mathbf{A}$ = 0,1 or -1).

Other linear programming problems have real solutions that must be rounded to the nearest integer. This can violate constraints, however, as well as being non-optimal. It is good enough if integer values take on large values or the accuracy of constraints is questionable. You can also pre-process problems and add constraints to make the solutions come out closer to integers.

C.1 Search Techniques

C.1.1 Branch and Bound Method

Branch and bound is a general search method. Suppose we wish to minimize a function f(x), where x is restricted to some feasible region (defined, e.g., by explicit mathematical constraints). To apply branch and bound, one must have the means to compute a lower bound on an instance of the optimization problem and the means to divide the feasible region of a problem to create smaller subproblems. There must also be a way to compute an upper bound (feasible solution) for at least some instances; for practical purposes, it should be possible to compute upper bounds for some set of nontrivial feasible regions.

The method starts by considering the original problem with the complete feasible region, which is called the root problem. The lower-bounding and upper-bounding procedures are applied to the root problem. If the bounds match, then an optimal solution has been found and the procedure terminates. Otherwise, the feasible region is divided into two or more regions, each strict subregions of the original, which together cover the whole feasible region; ideally, these subproblems partition the feasible region. These subproblems become the children of the root search node. The algorithm is applied recursively to the subproblems, generating a tree of subproblems. If an optimal solution is found to a subproblem, it is a feasible solution to the full problem, but not necessarily globally optimal. Since it is feasible, it can be used to prune the rest of the tree: if the lower bound for a node exceeds the best known feasible solution, no globally optimal solution can exist in the subspace of the feasible region represented by the node. Therefore, the node can be removed from consideration. The search proceeds until all nodes have been solved or pruned, or until some specified threshold is met between the best solution found and the lower bounds on all unsolved subproblems.

The branch and bound method is a systematic scheme for implicitly enumerating the many finitely feasible solutions to integer linear programming. Although, theoretically the size of the enumeration tree is exponential in the problem parameters, in most cases, the method eliminates a large number of feasible solutions. The key features of the branch and bound method are:

- Selection/Removal of one or more problems from a candidate list of problems.
- Relaxation of the selected problem so as to obtain a lower bound (on a minimization problem) on the optimal objective function value for the selected problem.
- Fathoming, if possible, of the selected problem.
- Branching Strategy: If the selected problem is not fathomed, branching creates sub-problems which are added to the candidate list of problems.

The above four steps are repeated until the candidate list is empty. The branch and bound method sequentially examines problems that are added and removed from a candidate list of problems.

C.1.2 Procedure of Branch and Bound Method:

0: Initialize:

Given the problem (3.1) $\Rightarrow$ (**P**). Let F(**P**) denote the feasible region of (**P**) and z(**P**) denote the optimal objective function value of (**P**). For any $\overline{\mathbf{x}}$ in F(**P**), let $z_P(\overline{\mathbf{x}}) = \mathbf{c}\overline{\mathbf{x}}$. The corresponding objective function value is denoted as z_I. The incumbent value z_I is obtained by applying some heuristic (if a feasible solution to (**P**) is not available, set $z_I = +\infty$). Initialize the candidate list $\mathbf{C} \leftarrow \{(\mathbf{P})\}$.

1: Optimality:

If $\mathbf{C}=\varnothing$ and $z_I = +\infty$, then (**P**) is infeasible, **STOP**. Stop also if $\mathbf{C}=\varnothing$ and $z_I < +\infty$, the incumbent is an optimal solution to (**P**).

2: Selection:

Using some candidate selection rule, select and remove a candidate problem (CP)$\in$C.

3: Bound:

Obtain a lower bound for (**CP**) by either solving a relaxation (**CP**$_R$) of (**CP**) or by applying some ad-hoc rules. If (**CP**$_R$) is infeasible, return to **Step 1**. Else, let x_R be an optimal solution of (**CP**$_R$) .

4: Fathom:

If $z(\mathbf{CP}_R) > z_I$, return to **Step 1**. Else if x_R is feasible in (**CP**) and $z(\mathbf{CP}) < z_I$, set $z_I \leftarrow z(\mathbf{CP})$, update the incumbent as x_R and return to **Step 1**. Finally, if x_R is feasible in (**CP**) but $z(\mathbf{CP}) > z_I$, return to **Step 1**.

5: Separation:

Using some separation or branching rule, separate (**CP**) into ($\mathbf{CP}_i$), $i= 1, 2, \ldots, q$ and set $\mathbf{C} \leftarrow \mathbf{C} \cup \{(\mathbf{CP}_1), (\mathbf{CP}_2), \ldots, (\mathbf{CP}_q)\}$ and return to **Step 1**.

6: End Procedure.

Although the branch and bound method is easy to understand, the implementation of this scheme for a particular integer linear programming is a nontrivial task requiring:

- a relaxation strategy with efficient procedures for solving these relaxations;
- efficient data-structures for handling the rather complicated book-keeping of the candidate list;
- clever strategies for selecting promising candidate problems; and
- separation or branching strategies that could effectively prune the enumeration tree.

A key problem is that of devising a relaxation strategy, i.e., to find "good relaxations" which are significantly easier to solve than the original problems and tend to give sharp lower bounds. Since these two are conflicting, one has to find a reasonable trade-off.

C.1.3 Branch and Cut Method

For branch and cut, the lower bound is again provided by the linear-programming (LP) relaxation of the integer program. The optimal solution to this linear program is at a corner of the polytope which represents the feasible region (the set of all variable settings which satisfy the constraints). If the optimal solution to the LP is not integral, this algorithm searches for a constraint which is violated by this solution, but is not violated by any optimal integer solutions. This constraint is called a cutting plane. When this constraint is added to the LP, the old optimal solution is no longer valid, and so the new optimal will be different, potentially providing a better lower bound. The cutting planes are iteratively until either an integral solution is found or it becomes impossible or too expensive to find another cutting plane. In the latter case, a traditional branch operation is performed and the search for cutting planes continues on the subproblems.

The branch and cut method incorporates the features of both the branch and bound method presented above and the cutting plane method presented in the previous section. The main difference between the branch and cut method and the general branch and bound scheme is in the bound step (**Step 3**) (see Section C.1.2).

A distinguishing feature of the branch and cut method is that the relaxation ($\mathbf{CP}_R$) of the candidate problem (**CP**) is a linear programming problem and instead of merely solving ($\mathbf{CP}_R$), an attempt is made to solve (**CP**) by using cutting planes to tighten the relaxation. If ($\mathbf{CP}_R$) contains inequalities that are valid for (**CP**) but not for the given integer linear problem, then the Gomory-Chvátal rounding procedure may generate inequalities that are valid for (**CP**) but not for the integer linear problem. In the branch and cut method, the inequalities that are generated are always valid for the integer linear problem, and hence, can be used globally in the enumeration tree.

Another feature of the branch and cut method is that often heuristic methods are used to convert some of the fractional solutions, encountered during the cutting plane phase, into feasible solutions of the (**CP**) or more generally of the given integer linear problem. Such feasible solutions naturally provide the upper bounds for the integer linear problem. Some of these upper bounds may be better than the previously identified best upper bound and if so, the current incumbent is updated accordingly.

We thus obtain the branch and cut method by replacing the bound step (**Step 3**) of the branch and bound method by Steps 3(a) and 3(b), and also by replacing the fathom step (**Step 4**) by Steps 4(a) and 4(b) given below:

3(a): Bound:

Let ($\mathbf{CP}_R$) be the linear programming relaxation of (**CP**). Attempt to solve (**CP**) by a cutting plane method which generates valid inequalities for (**P**). Update the constraint system of (**P**) and incumbent it.

Update the constraint system of (**P**) to include all the generated inequalities. The constraints for all the problems in the candidate list are also to be updated.

During the cutting plane phase, apply heuristic methods to convert some of the identified fractional solutions into feasible solutions to (**P**). If a feasible solution, $\bar{\mathbf{x}}$, to (**P**), is obtained such that $\mathbf{c}\bar{\mathbf{x}} < z_I$, update the incumbent to $\bar{\mathbf{x}}$ and z_I to $\mathbf{c}\bar{\mathbf{x}}$. Hence the remaining changes to the procedure of the branch and bound method are as follows:

3(b) Decide on the next step

If (**CP**) is solved go to **Step 4(a)**. Else, let $\bar{\mathbf{x}}$ be the solution obtained when the cutting plane phase is terminated, (we are unable to identify a valid inequality of (**P**) that is violated by $\bar{\mathbf{x}}$) go to **Step 4(b)**.

4(a) Fathom by Optimality:

Let **x*** be an optimal solution to (**CP**). If $z(\mathbf{CP}) < z_I$, set $x_I \leftarrow z(\mathbf{CP})$ and update the incumbent as **x***. Return to **Step 1**.

4(b) Fathom by Bound:

If $\mathbf{c}\bar{\mathbf{x}} > z_I$, return to **Step 1**. Else go to **Step 5**.

C.2 Branch and Price Method

This is essentially branch and bound combined with column generation. This method is used to solve integer programs where there are too many variables to represent the problem explicitly. Thus, only the active set of variables is maintained and columns are generated as needed during the solution of the linear program.

The basic idea is simple. Leave most columns out of the linear problem relaxation because there are too many columns to handle efficiently; most of them will have their associated variable equal to zero in an optimal solution anyway. Then, as in column generation for linear programming, to check the optimality of a linear problem solution, a subproblem, called the *pricing problem*, is solved to try to identify columns to enter the basis. If such columns are found, the linear problem is reoptimized; if not, we are done. To solve the linear problem relaxation of the set-partitioning formulation of the problem, pricing or column generation is done by solving n knapsack problems.

Obviously, the linear problem relaxation may not have an integral optimal solution and then we have to branch. However, applying a standard branch-and-bound procedure over the existing columns is unlikely to find an optimal (or even good or even feasible) solution to the original problem. Therefore, it may be necessary to generate additional columns in order to solve the linear problem relaxations at non-root nodes of the search tree. Branch-and-bound algorithms in which the linear problem relaxations at nodes of the search tree are solved by column generation are called **branch-and-price** algorithms. There are two fundamental difficulties in applying column generation techniques to solve the linear programs occurring at the nodes of the search tree:

- Conventional integer programming branching on variables may not be effective because fixing variables can destroy the structure of the pricing problem.
- Solving these linear problems and the subproblems to optimality may not be efficient, in which case different rules will apply for managing the search tree.

C.3 Conclusions

- Mixed Integer Programming Methods are very effective to solve (C1) problems.
- Mixed Integer Programming Methods can be applied to solve the large and very large problems.
- Mixed Integer Programming Methods are well suited to implementation on multiprocessors computers (parallel programming).

APPENDIX D. DESCRIPTION OF AN IMPLEMENTATION OF MIP IN A LARGE POWER SYSTEM

This appendix describes an implementation of the MIP algorithm in a large power system. The system operated by Polskie Sieci Energetyczne (PSE) in Poland is selected for demonstration purposes because it was entirely developed by one of the persons working on this report. It shows a successful application of the MIP approach and, in our view, could be easily adopted to include Combined-Cycle Generating Units (CCGU) as illustrated in Section 5 of this report.

A successful application of the Mixed Integer Linear Programming is demonstrated by the operation of the Polish Balancing Market. The system for commitment and dispatch based on balancing bids was introduced on September 1, 2001 and it is still operating successfully. During its time of operation, despite severe network conditions, the system for the commitment and dispatch called LPD was able to provide the schedules for the generating units.

The simplex matrix used in this system contains over 25,000 independent variables, which are modeled as columns and over 50,000 pseudo-variables, which are used to model various constraints. The minimum power of thermal generating unit is modeled as binary variables. There are over 2,500 binary variables in the optimization task.

The LPD is supported by the GMOS module which contains network and power station constraints modeled as nodal constraints of seven categories. The XPRESS module provided by Dash Corp., is used as the calculation engine.

The optimization procedure is carried out for over 100 generating units with one-hour intervals for one day ahead (24 hours). The hourly commitment and dispatch is split into 15-minute control signals, which are transmitted to power stations. The entire optimization procedure for time horizon of 24 hours takes about 2-3 minutes with the use of PC4 (1MHz).

The LPD system should be seen not only as a specific module providing commitment and dispatch but as a kind of methodology allowing for many other applications.

D.1 Historical Background

When the electricity market structure was approved in 1999 in Poland, there was pressure to quickly implement the electricity market. The Power Exchange was established in June 2000, however, the balancing market was not ready for operation until September 2001.

The balancing market operation required new computer software which would be able to prepare commitment and dispatch using balancing bids submitted by generating units, taking into account the network constraints and the technical characteristics of over 100 generating units.

Two systems: LPD and GMOS were designed and constructed in 2000 for a day ahead balancing market. However, their implementation had to wait for the development of telecommunication infrastructure. The balancing market started its operation with new systems for commitment and dispatch on September 1, 2001. It has been working successfully ever since.

The power operation planning is based on two systems. The first one, Linear Programming Dispatch is the software for linear-binary optimization based on the balancing bids submitted by generating units. The second one, GMOS is the data base for the network constraints represented by nodal constraints.

The operation of the balancing market includes several stages. First, it verifies the consistency of contract positions and the bids submitted. Secondly, using the balancing bids and information about technical constraints, the TSO computes commitment and dispatch for the generating units. The calculation results in the one-hour interval generation schedule for Day N. However, one-hour intervals used for energy trading are too large for generating unit control, due to large variations in daily electricity demand. The TSO recalculates the one-hour interval schedule to a 15-minute interval schedule in order to provide adequate control signals. It is assumed that the average values of four 15-minute signals in a given hour are equal to the energy in this hour set by the one-hour interval generation schedule.

The linear-binary programming has been applied to solve commitment and dispatch problems. The LP engine XPRESS provided by Dash Associates Limited was implemented to find the minimum of the objective function subjected to network constraints.

There are some similarities between the Polish balancing market and the NETA, but the solutions implemented in the Polish balancing market are simpler, allowing for a transparent balancing mechanism with less complicated procedures. In contrast to the NETA, which employs power bids with linear approximation for final notifications, the Polish balancing market uses energy for bids, commitment and dispatch. This makes the Polish balancing market more consistent with the energy trade.

D.2 Structure of the Polish Electricity Market

The Polish electricity market, with a total annual production of about 153 TWh, operates as a bilateral market with the Power Exchange, which is an independent party, and the Balancing Market managed by the Transmission System Operator (TSO). Currently the TSO is PSE-Operator.

When the electricity market was introduced there were 33 distribution generating units, with a capacity of over 100 MW, which are centrally dispatched by the TSO. They are called Centrally Dispatched Generating Units (CDGU) and are obliged to be equipped with second and minute reserve. The CDGU units have to submit the balancing bids to the day ahead balancing market and follow the instruction from the TSO on electricity volume generated.

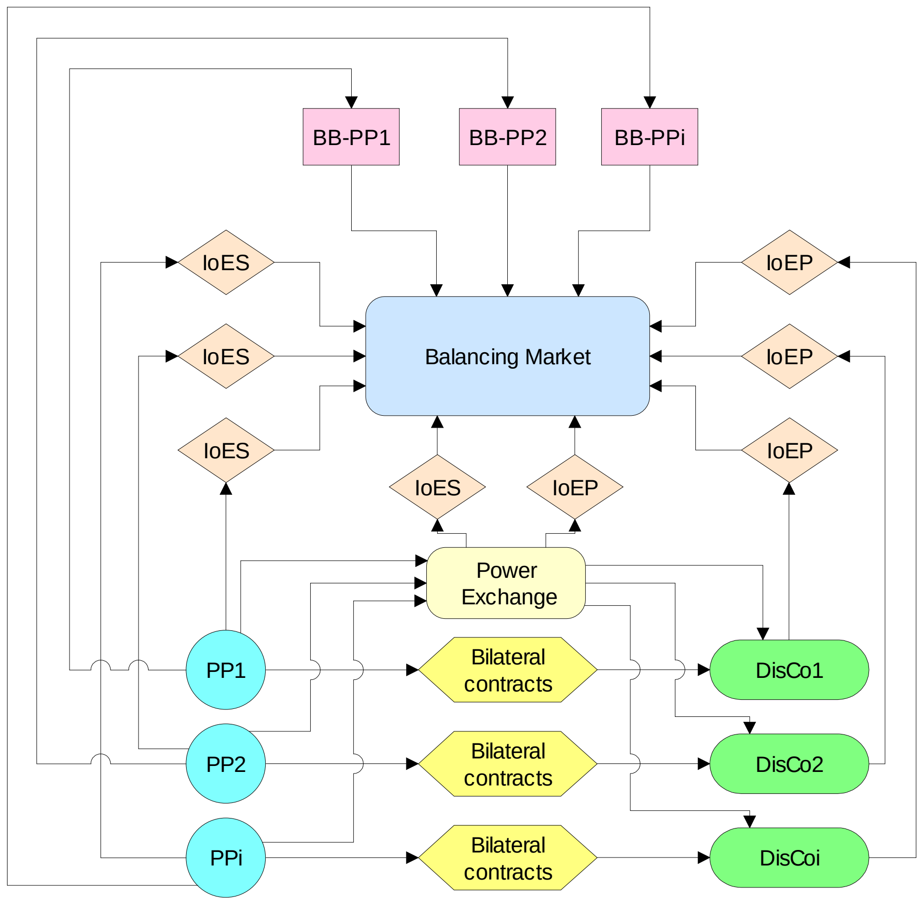


Figure D.1 Structure of a day ahead balancing market

Figure D.1 depicts the structure of the Polish electricity market. Power Producers (PP) enter bilateral contracts with Distribution Companies (DisCo) and some large industrial users – not shown on this figure. The bilateral trade of various forms covers over 95% of the electricity in the wholesale market including electrical energy in long term contracts, which is traded with the involvement of PSE SA and Minimum Energy Take (MET) imposed on distributors. The Power Exchange turnover is about 2% and the balancing market volume turnover comprises of about 2% of the total electricity produced.

Participants in the wholesale market have to send Information on Energy Sold (IoES) and Information on Energy Purchased (IoEP) to the TSO. The same obligation is imposed on the Power Exchange and energy trades. The information on energy sold and purchased has to relate to each generating unit in one hour intervals for one day ahead. Power generating units also have to submit balancing bids for each generating unit in one-hour intervals. Balancing bids from energy users and distributors are not allowed in this stage of the market development.

D.3 Energy Assigned to Generating Units

The TSO forced the obligation to assign the energy traded to each generating unit. The reason behind this solution is the presence of the long term contracts between power stations and PSE SA, which is the parent company of PSE-Operator. Long term contracts relate to the individual generating units. The information on energy sold from each generating unit facilitates the settlement of long term contracts, which is carried out outside of the balancing market. However such allocation of the energy sold has several drawbacks.

Electrical energy is traded between power stations and distributors or other energy users as legal entities, so there is no need to specify which generating unit is used to produce electricity as this product has uniform physical features. The TSO does not also need to know which generating unit is assigned to which specific trade party in the purchase contracts when several generating units are connected to a network node. From the network operation point of view, the amount of energy injected in a specific node and the number of working and standby units is sufficient information.

Before the introduction of the balancing market some power stations had installed local optimization software to assign power production to the most efficient unit, preserving volume of energy flowing to the network node on the prescribed level. These power stations were forced by these market rules to shut down their local optimization.

Electricity trade in the Power Exchange is carried out by clearing supply and demand bids submitted by power companies as legal entities and members of the Power Exchange. The balancing market rules, which require an energy purchase party to be assigned to each generating unit, forced several operation cycles in Power Exchange. First the clearing price is calculated using bids submitted by the Power Exchange participants and the information on the volume traded is sent back to power producers. Secondly, power producers assign the electricity sold in Power Exchange transactions to individual generating units and transmit this information to the Power Exchange, which passes the information obtained to TSO.

Moreover, such balancing market rules allow for market gaming by power producers. From the information received from TSO, power station traders know the nodal constraints required to preserve some level of power production as well as the number of operating units in a network node. They can easily foresee which generating units have to operate due to network constraints. It allows them to assign the energy traded to power generating units which are not required for secure network operation, not assigning energy to the generating units necessary for network operation.

The TSO is forced to purchase energy from some generating units and reduce the amount of energy offered by other generating units that are not necessary for the network operation. This switching of energy between generating units brings extra income to power stations despite the price cap on energy purchases forced by the network condition.

The future solution should aim at splitting system operation from energy trade. In such a case, the balancing market participants will only provide the information on energy sold as legal entities. The TSO should be able to assign power generating units based on network constraints without the need for a trade off between particular generating units. Another solution is to impose on power producers the requirement to provide generating programs complying with all network constraints. This is more difficult to implement in a weak transmission network with many constraints.

D.4 Demand for Electrical Energy

The total demand for electric power in Poland reaches over 23,000 MW. However, demand covered by CDGU is smaller. It varies from about 8,000 MW during low night demand – demand valley – to near 20,000 MW during maximum demand period – demand peak. Figure 2 shows the demand to be covered by CDGU in September computed as average values in hours of the days along a 30-day period.

The energy volume in the balancing market is small, reaching about 5,000-6,000 MWh per day. Figure D.2 shows average values calculated for specific hours of the day in two weeks in March 2005.

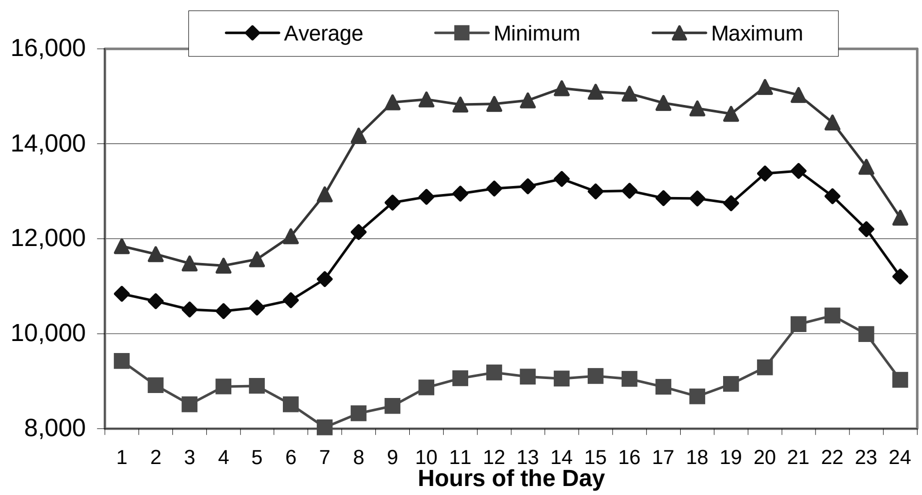


Figure D.2 Demand for electrical energy to cover by CDGU.

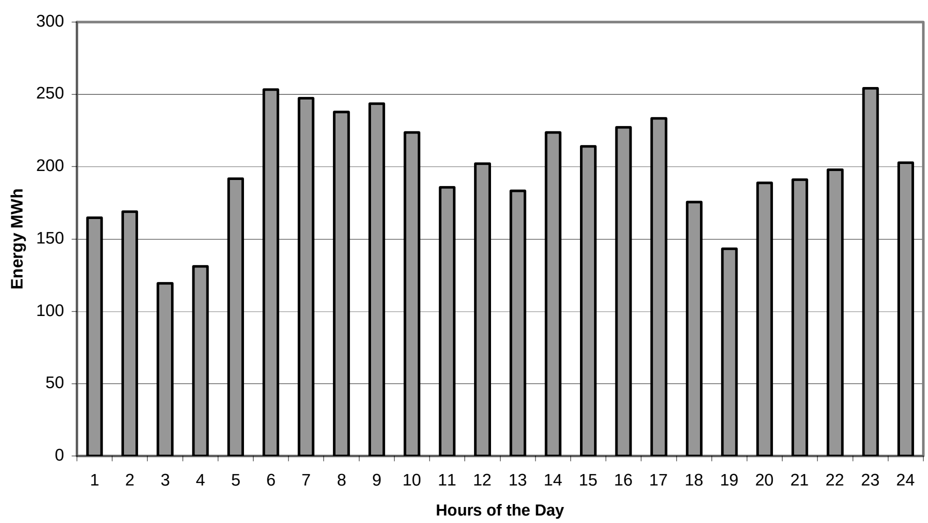


Figure D.3 Energy volume in the balancing market in March 2005.

The demand for electrical energy to be covered by CDGU is calculated by the TSO as the difference between the total demand forecasted, international flows, the production in cogeneration, industrial facilities, small hydro power stations and energy used for water pumping as well as the energy produced by large pumping water power stations – Figure D.4.

The largest portion of energy production outside the large thermal power station relates to cogeneration. Large cogeneration facility produces nearly 20 TWh electrical energy which counts for about 15% of the total domestic electricity production. The largest share of cogeneration appears in spring when co-generating facilities are fully loaded and the total demand is decreasing. This creates danger for secure network operation. It happens that during the demand valley when the total demand is low, the demand to be covered by CDGU is small due to high production from cogeneration. It happens that production required by network constraints is larger than the portion of demand to be covered by CDGU.

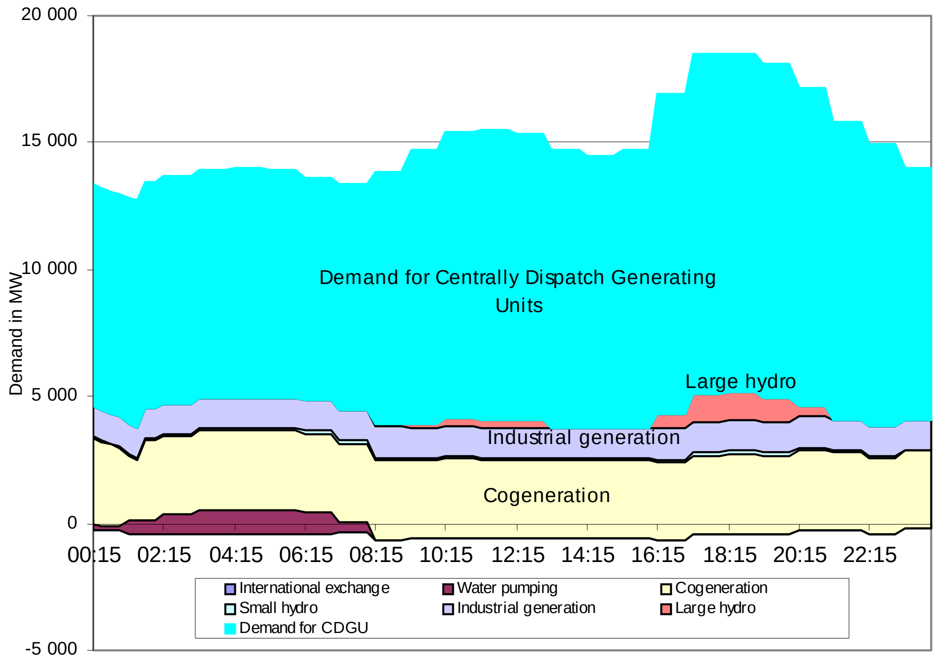


Figure D.4 Calculation of demand for CDGU

D.5 Market Schedule

As the balancing market operates as a day ahead market, a day before energy delivery (Day N-1), market participants submit information on energy that they purchased or they sold and submit balancing bids of power generating units. In the beginning of the balancing market operation, the TSO closed the gate at 10:00 am. After one year of operation the gate closure was shifted to 11:00 am.

The Power Exchange closes the gate at 8:00 am and finalizes energy trade by 9:00 am. This allows the market participants 2 hours to adjust information on energy traded and prepare balancing bids – Figure D.5.

The information on the energy traded and balancing bids submitted to TSO before 11:00 am is verified until 13:00 – 14:00, when the commitment and dispatch computation has to be processed. It requires about 1-2 hours to prepare and verify the commitment and dispatch for a day ahead in one-hour intervals. The next step is the completion, before 18:00, the 15-minute schedule in which dispatch in one-hour intervals is split into 15-minute periods.

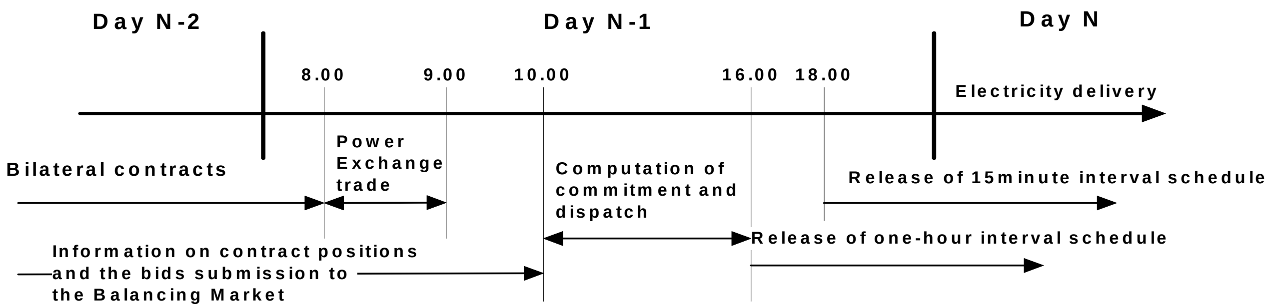


Figure D.5 The schedule of the Polish electricity market

D.6 Information on Bilateral and Power Exchange Transactions

After receiving the information on the energy traded TSO starts the procedure of the data verification. The principles of the balancing market operation require that the data submitted should be consistent and the volume of energy sold should be equal to the volume of energy purchased.

Despite the support of computer software in the data preparation, it happens that the data submitted is not consistent. In such cases the TSO has to precede with the verification procedures. When a mistake is clearly visible, the TSO can ask a balancing market participant to correct and submit the information again. However, in most cases it is difficult to contact participants to point out the errors made. TSO has to adjust the information provided to achieve the balance between energy sold and energy purchased.

The adjustment procedures arrange balancing market participants into priority levels. The highest level is assigned to the Power Exchange as its contract position is always closed, i.e., the energy sold is equal to the energy purchased. The second level is given to power producers as they are limited by technical constraints. The third level is assigned to energy buyers. The verification procedure starts from the information submitted by the Power Exchange (PX) assuming that such information is correct. If any of the market participants' information on their trade in the power exchange transaction is not consistent with the date from the PX, their energy volume traded is adjusted to the volume submitted by the PX. The next step involves the information submitted by power producers. If the information from distributors on the energy purchased is not consistent with the power producers' data, the volumes submitted by distributors are adjusted to the values provided by power producers.

Currently, power traders have to have closed contract positions so the verification of their information is carried out in the same way as the information from the PX.

Table D.1 Information on energy traded, submitted by power producers for one of their generating units for one hour for a day ahead

Contract partner	DisCo 1	DisCo 2	Energy Trader A	Energy Trader B	Power Exchange	Sum=Contract position
Energy in MWh	30	65	100	50	20	265

Table D.2 Information on energy traded, submitted by power buyers for one hour for a day ahead

Contract partner	Generating Unit X1	Generating Unit X2	Generating Unit X3	Energy Trader B	Power Exchange	Sum=Contract position
Energy in MWh	100	150	120	70	30	470

D.7 Balancing Bid

Balancing bids are provided by power producers for each of their generating units for every hour, one day ahead. The balancing bid has a very complex structure allowing for the accommodation of various types of information – Table D.3.

- There are 10 bands providing power producers with a large scope of flexibility to accommodate the energy traded and additional energy offered for production.

- The bands are split into two categories: “R” bands accommodate the energy sold in various bilateral contracts and power exchange transactions, “P” bands allow for the allocation of energy offered to the TSO for production.

- The sum of energy allocated in “R” bands is equal to the volume of the energy traded, i.e., to the contract position.

- Energy in balancing bids is displayed as net and gross values. It allows power producers to determine the volume of energy required for the operation of the power generating units. This duality is the result of the difference between operational procedures and trade. The commitment and dispatch is carried out using gross energy production while energy trade uses net energy, i.e., energy injected into the transmission system.

- Prices in bands noted “R” indicate how much a power producer is ready to accept from the TSO when their production is reduced below their contract position.

- Prices in bands noted “P” indicate how much a power producer is ready to accept from the TSO for additional power production above their contract position.

- The energy volume in the first band must be equal to the minimum power generated by the bid submitting unit. When this generating unit provides second or minute reserve or both, the energy volume in the first band must include Psec+ and Pmin+ values – Figure 7.

- The sum of energy in all bands cannot be larger than Pmax. If a generating unit provides second or minute reserve or both, the energy in the balancing bid should be reduced, taking into account the values of Psec- and Pmin-.

- Price in the band proceeding must be larger by at least in 0.01 PLN than the price in the preceding band. This allows for a uniform increase of bid prices.

- The minimum energy offered in any band is 1 MWh.

- The last band (numbered as 10) is reserved for the price of the energy produced by a starting up unit. Such energy must have a price assigned. The use of one band in the balancing bid for energy of a starting up unit creates a convenient channel to gain such information from power producers.

- Minimum price is 70 PLN/MWh, while the maximum price is equal to 1,500 PLN/MWh.

Table D.3 shows an example of a balancing bid. The electricity traded in the form of bilateral contracts and power exchange transactions is equal to 370 MWh = 300 + 40 + 30. This energy is allocated in three "R" bands. The gross production relating to the energy sold accounts for 396 MWh = 312 + 42 + 33. The additional energy production offered to the TSO is equal 95 MWh = 40 + 15 + 10 + 10 + 10 +10 and is allocated in six "P" bands. The last band price equal to 1,449 PLN/MWh indicates the energy produced by starting-up generating unit.

The structure of balancing bids allows a large degree of flexibility for power producers. They can split the energy contracted into several "R" bands with various energy amounts and prices. This reduces the risk of being entirely excluded from the schedule when the TSO cannot realize the contract positions declared. Power producers can also offer additional amounts of energy to the TSO if it requires more generation to balance energy demand.

Table D.3 Example of a balancing bid submitted for a given generating unit

Band	1	2	3	4	5	6	7	8	9	10
Price (PLN/MWh)	70	75	80	100	105	110	120	130	150	1499
Energy net (MWh)	300	40	30	40	15	10	10	10	10	1
Energy gross (MWh)	312	42	33	42	16	11	11	11	11	1
Band category	R	R	R	P	P	P	P	P	P	P

D.8 Modelling Balancing Bid

Balancing bids submitted by power stations in the form of tables which have a graphical representation as a step function – Figure D.6. The approximation of such a function by a high order polynomial is not acceptable by market participants as the approximation error would affect their income from the balancing market trade. Moreover, the use of a high order polynomial would involve the implementation of optimization procedures, which are able to cope with high order nonlinearity. Such procedures provide only local minima dependent on the algorithm starting point.

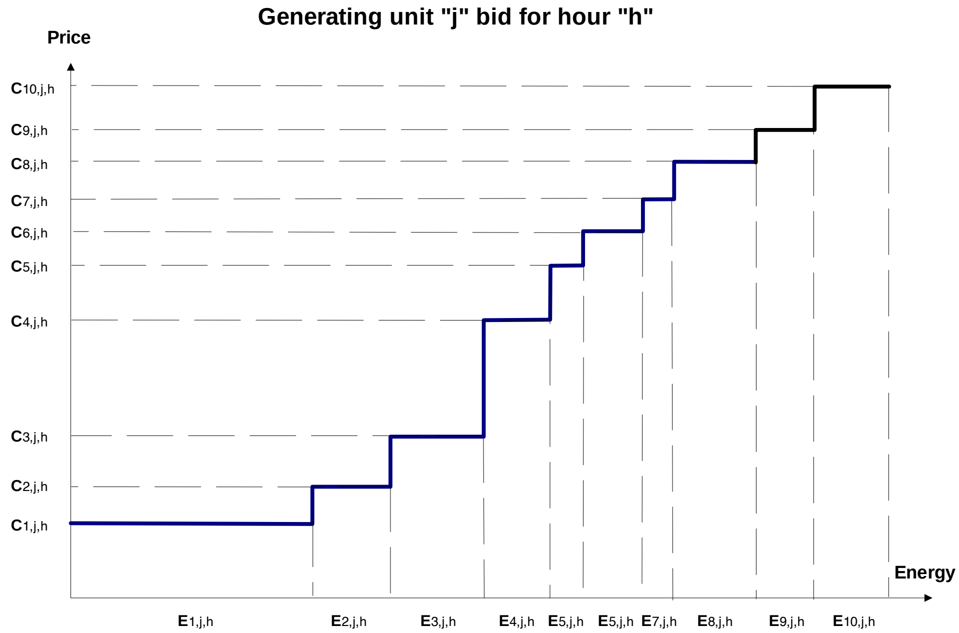


Figure D.6 Graphical representation of a balancing bid

The algorithm used for commitment and dispatch should compute the global minimum independently on a calculation starting point. This can be achieved by the implementation of Linear Programming. However, the representation of the minimum power of a generating unit in the first band and the condition that a unit cannot be dispatched below this level leads to the application of binary representation for the first band.

The balancing bid is modeled in the following way:

- The energy in the first band is modeled as a binary value multiplied by energy denoted as, where "1" relates to the band number, "j" denotes a generating unit and "k" is the hour of the day for which the bid is submitted.
- The energy in the second band is modeled as a real variable and can take any value within constraints.
- The energy in other bands is modeled in a similar way as in band 2.

Such an approach increases the number of variables as any balancing bid submitted by a generating unit is modeled by 10 variables. However, the modeling is very simple and allows the application of linear constraints. When over 100 generating units are dispatched for a day ahead the optimization problem includes over 24,000 variables = 100 generating units x 10 variables x 24 hours.

D.9 Second and Minute Reserves

Planning power generation for a day ahead the TSO has to ensure an adequate level of second and minute reserve. The value of second reserve for each TSO is determined by UCTE requirements. The value of secondary reserve is set by the TSO to about 400 MW.

The TSO buys second and minute reserve once a year in a tendering procedure. There are two components to this Ancillary Service: a stand-by component and a working component. The latter is paid to all power stations contracted. They have to preserve the equipment ready for services. Two days before energy generation the TSO sends the information to power stations on how much second and minute reserve will be required. The power stations are obliged to accommodate the second and minute reserve in balancing bids.

When a generating unit is to provide both services, the energy allocated in the first band should be equal to minimum power increased by two components, i.e., $E_1 = (P_{\min} + P_{\sec-} + P_{\min-}) * 1hour$ –Figure D.7. If a generating unit does not provide second and minute reserve the energy in the first band should be equal to the minimum power, i.e., $E_1 = P_{\min} * 1hour$. Similarly the sum of energy offered in a balancing bid when a generating unit provides both services should exclude power required for second and minute reserve, i.e., $E = \sum_{i=1}^{10} E_i \le (P_{\max} - P_{\sec+} - P_{\min+}) * 1hour$ – Figure D.7. If a generating unit does not provide any services, the sum of energy offered in a balancing bid can reach maximum power $E = \sum_{i=1}^{10} E_i \le P_{\max} * 1hour$.

This very simple system of implementation of second and minute reserve in the balancing bid was implemented as a compromise between the short time given for the software development and the flexibility of reserve optimization. However, the methodology used is able to include the second and minute reserve in the optimization process carried out by LPD.

D.10 Modeling Start-Up Characteristics

There are three characteristics used in commitment and dispatch of generating units representing the start-up processes from three states: hot, warm and cold. Each characteristic is represented by four points determining the power generated after the given time period. The last point represents the minimum power offered in a balancing bid. Because the value of this power depends on second and minute reserve served, the modeling of start-up characteristics should take into account these Ancillary Services provided by a generating units – Figure D.8.

There are three possible combinations of Ancillary Services relating to second and minute reserve:

- Unit does not provide second and minute reserve;
- Unit provides only second reserve;
- Unit provides only minute reserve;
- Unit provides both second and minute reserve.

The combination of possible Ancillary Services and three thermal states leads to twelve start-up characteristics to be used in modeling generating units.

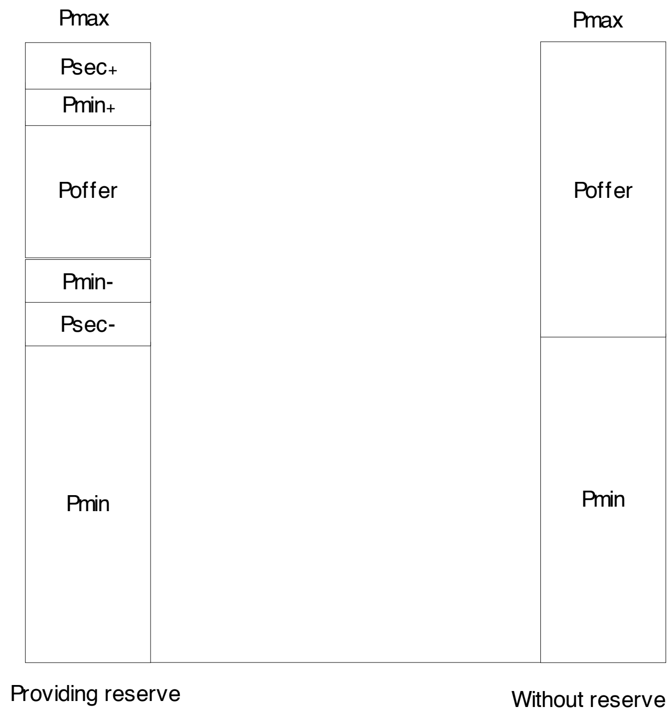


Figure D.7 Including reserve in balancing bid

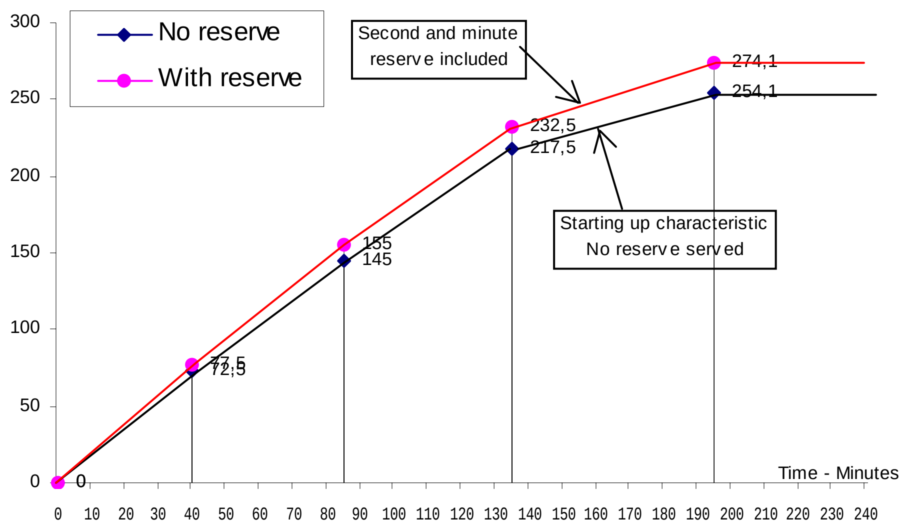


Figure D.8 Start-up characteristics of a generating unit

Another problem to solve is the allocation of start-up intervals determined in minutes into one-hour intervals in commitment and dispatch in a day ahead market. If it is assumed that a generating unit begins its start-up process in the first minute of a one-hour interval, the process would be completed somewhere in the middle of the one-hour period. In an example shown in Figure D.9, the start-up process is completed after 195 minutes, just 15 minutes after the beginning of Hour 4. If such a solution is implemented the energy generated in Hour 4 should be split into the start-up energy (E4a) and the energy generated after completion of start-up (E4b).

To avoid such problems, the modeling of start-ups assumes that each start-up characteristic is shifted to the end of the one-hour dispatch interval – Figure D.10. This results in the competition of any start-up process in the last minute of a one-hour interval.

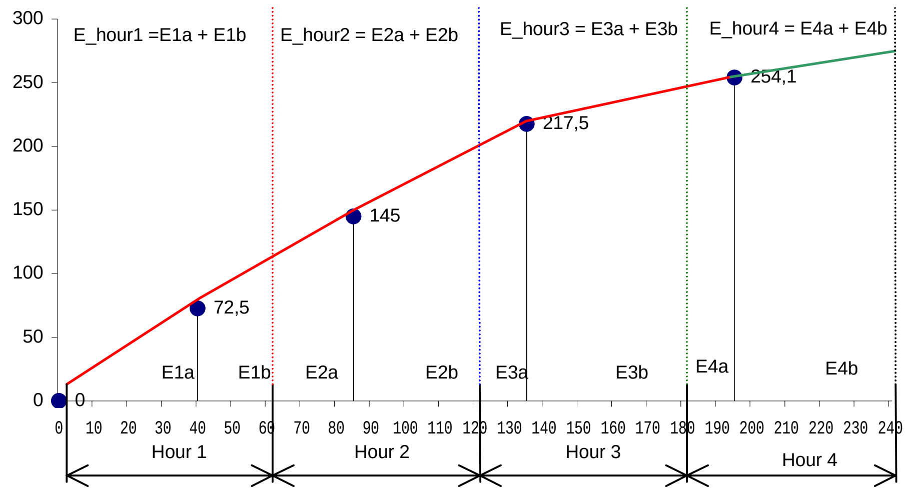


Figure D.9 Start-up periods and one-hour dispatch intervals

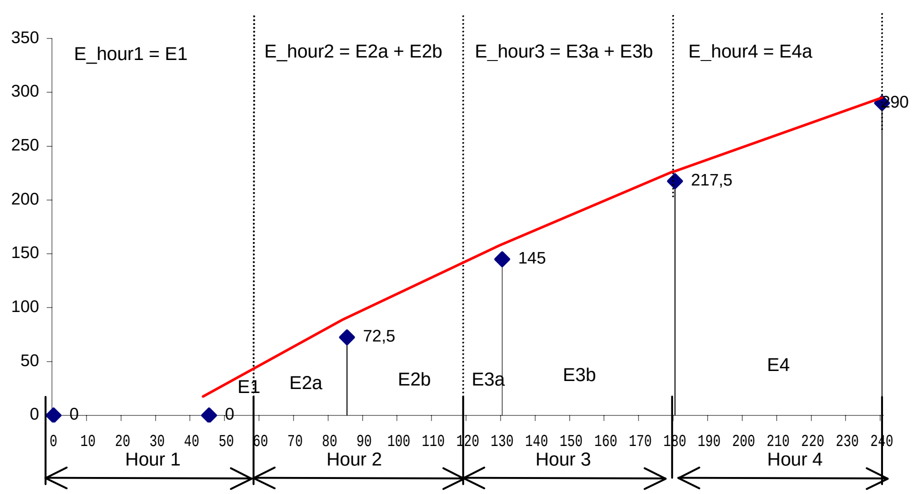


Figure D.10 Allocation of start-up characteristic in one-hour intervals

D.11 Allocation of Energy in Balancing Bids

The balancing market rules tie up the energy trade with individual generating units forcing the power producers to allocate the energy traded into generating units and include this information in a balancing bid. Before submitting a balancing bid to the TSO a power producer has to allocate the energy traded and the additional energy that can be produced into a balancing bid. Figure D.11 shows an example of such allocation.

Four bilateral contracts and the Power Exchange transaction have been allocated to one generating unit. The sum of contracts and the transaction allocated set the contract position of this generating unit. There is also the additional energy that can be produced by this unit. The energy traded and energy possible for production has to be accommodated into a balancing bid with ten bands and several constraints.

In this example a power station trader has decided to assign three "R" bands to energy resulting from the contract position. In the first band the trader has allocated energy relating to the minimum power. The rest of energy traded is split into two "R" bands.

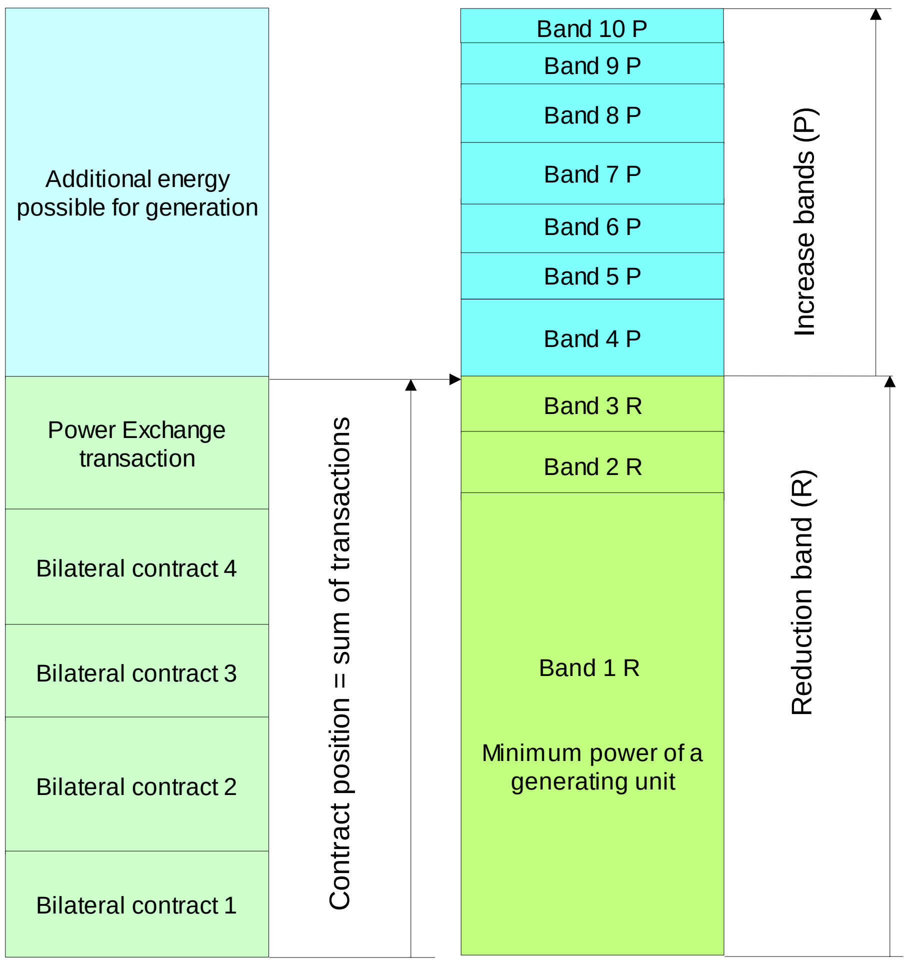


Figure D.11 Relation between energy traded and a balancing bid

The additional energy offered to the balancing market is split into several "P" bands denoted from 4 to 10, taking into account that the price in band no. 10 is used to valuate energy produced during a start-up process

D.12 Objective Function

The objective function is formulated as the sum of the products of the bid prices and the energy in the balancing bids. This embraces nine bands. The last band is used to bid on the start-up price. This price is not paid to generators; however, it is used in commitment and dispatch computations. Setting the tenth band as the start-up price allows for the flexibility of balancing bids as a bid provider can express his willingness to be committed by setting a low start-up price.

The objective function has the following form (D.1).

$$F_{objective} = \min\left\{\sum_{h=1}^{Hk}\sum_{j=1}^{N_j}\sum_{i=1}^{9} c_{h,j,i} * E_{h,j,i} + c_{h,j,10} * E_{h,j}^{start\_up}\right\} \tag{D.1}$$

Where

$E_{h,j,i}$ – dispatch in hour "h," generating unit "j," energy from band "i"

$c_{h,j,i}$ – bid price in hour "h," generating unit "j," in band "i"

$E_{h,j}^{start\_up}$ – start-up energy in hour "h," generating unit "j" resulting from one of three starting unit characteristics

N – number of generating units which have submitted the bids

Hk – time horizon equal to 24 hours.

D.13 Including Reserve

The information on the required level of primary and secondary reserve is distributed to market participants by the TSO two days before energy generation. The contracts for Ancillary Services bind generating units to include power relating to primary and secondary reserve directly to a balancing bid.

A tertiary reserve (hour reserve) is included into the algorithm as a constraint. This means that the difference between the energy offered by all committed units and the energy dispatched in all committed units should be larger than the assumed level of the tertiary reserve.

$$\sum_{j=1}^{N_j}\sum_{i=1_j}^{m} E_{h,j,i} - \sum_{j=1}^{N_j}\sum_{i=m=1_j}^{9} E_{h,j,i} \geq P_{Tertiary}^{reserve}(h) * t \tag{D.2}$$

for $h = 1....24$

The spinning reserve allowing for the reduction of energy generation is set up in a similar way. The assumed system allows for the setting of tertiary reserve values to increase the electricity production and to decrease it for each hour of a day ahead.

D.14 Input and Output Data

The module LPD receives the information on network constraints from the module called GMOS in the form of linear constraints. Additionally, it receives the load forecast for each hour of a day ahead.

The operator sets up the level of tertiary reserve and supplies the balancing bids submitted by power stations – Figure D.12.

The computations are carried out four times:

- For the load forecasted to prepare the basic commitment and dispatch;
- For the load lower than forecasted, usually about 2,000 MW;
- For the load higher than forecasted, usually about 2,000 MW;
- For the merit order of balancing bids without constraints.

The differences between the basic dispatch for the load forecasted and dispatch for lower and higher load allows the preparation of priority lists of uploading generating units and downloading these units when the real demand for electricity is different than forecasted. Each priority list is split into two parts. The first one relates to the increase or decrease of the energy generated using the spinning reserve. The second one contains the units that should be started up when demand increases or shut down when demand decreases. The priority lists are sent together with the dispatch to power stations.

Each computation of commitment and dispatch takes about 2.5-3 minutes.

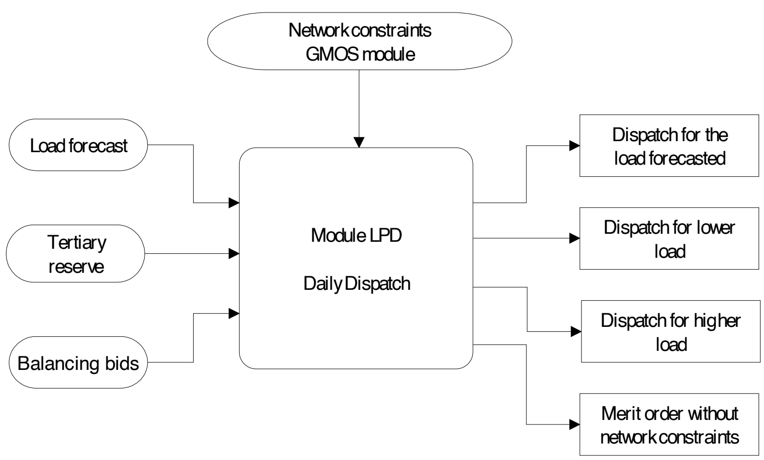


Figure D.12 Input and output module for LPD program

D.15 Evaluation of Commitment

Despite the high reliability of the module computing commitment and dispatch, the operation procedure contains the evaluation by experts as the basic element of planning for a day ahead market. There are over 100 generating units submitting balancing bids and about 70-80 generating units are dispatched every day.

To facilitate the evaluation procedure, a special evaluation sheet has been designed – Figure 13. The evaluation table contains 25 columns representing 24 hours of a day ahead and the last hour of the day before noted as 24 in brackets. The names of generating units are located in table rows. The system of notation is as follows. If a table cell is filled up with three dashes it means that a generating unit operates in a given hour. If a cell is empty a unit does not operate in a given hour. When a cell contains three asterisks this means that a unit is starting up. In the example shown in Figure 13, the united noted BEL 2-01 (unit no. 1 in Belchatow power station connected to 220 kV) starts up in hours 13, 14 and 15 and generates electricity during the rest of this day. The unit noted BEL 2-02 operates along 24 hours, while the unit noted BEL 4-09 does not operate on a given day.

The evaluation tables allow the graphical representation of the commitment for about 100 generating units using only 2 pages in A4 format. The evaluation takes place after the first run of computation. If for any reason the commitment is not accepted by a dispatcher they can introduce additional constraints and carry out the computation again.

```
#==================================================================================================================
#Power station: Bełchatów
#Unit name |<24>| 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10| 11| 12| 13| 14| 15| 16| 17| 18| 19| 20| 21| 22| 23| 24|
BEL 2-01   |    |   |   |   |   |   |   |   |   |   |   |   |   |***|***|***|---|---|---|---|---|---|---|---|---|
BEL 2-02   |----|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
BEL 2-03   |----|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
BEL 2-04   |----|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
BEL 2-05   |----|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|   |   |
BEL 4-06   |    |   |   |   |***|***|***|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
BEL 4-07   |    |   |   |   |   |***|***|***|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
BEL 4-08   |----|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
BEL 4-09   |    |   |   |   |   |   |   |   |   |   |   |   |   |   |   |   |   |   |   |   |   |   |   |   |   |
BEL 4-10   |----|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
BEL 4-11   |----|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
BEL 4-12   |----|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
#==================================================================================================================
```

Figure D.13 Commitment evaluation table

D.16 Hourly Commitment and Dispatch

The results of the calculation of commitment and dispatch of generating units in a day ahead balancing market are shown in Figure D.14 for one selected power station. As seen, two generating units start-up and are shut down during one day.

The electrical energy in the Polish power system is generated mostly by thermal power stations. The demand for second and minute reserve limits tertiary spinning reserve. Large changes in demand during night hours (demand valley) and demand peaks force the system operator to start-up and shut down several generating units every day.

To limit the number of starting up units during the day and during any hour, the LPD module is equipped with additional constraints allowing a dispatcher to set up a number of start-ups for a day and also during one hour. However, this requires a flexible approach as the introduction of a small number of starting up units often leads to unsolvable optimization problems and the LPD module cannot generate the commitment and dispatch.

The second tool with which a dispatcher is equipped is the reduction of the number of starting up units by a penalty function. A dispatcher has three buttons noted Number of Start ups: “Small,” “Medium” and “Large.” The selection of any button results in the assignment of the prescribed penalty function leading to the increase of the cost of energy generated during start-up. The advantage of this tool is that it does not create an over-constrained problem as the previous one.

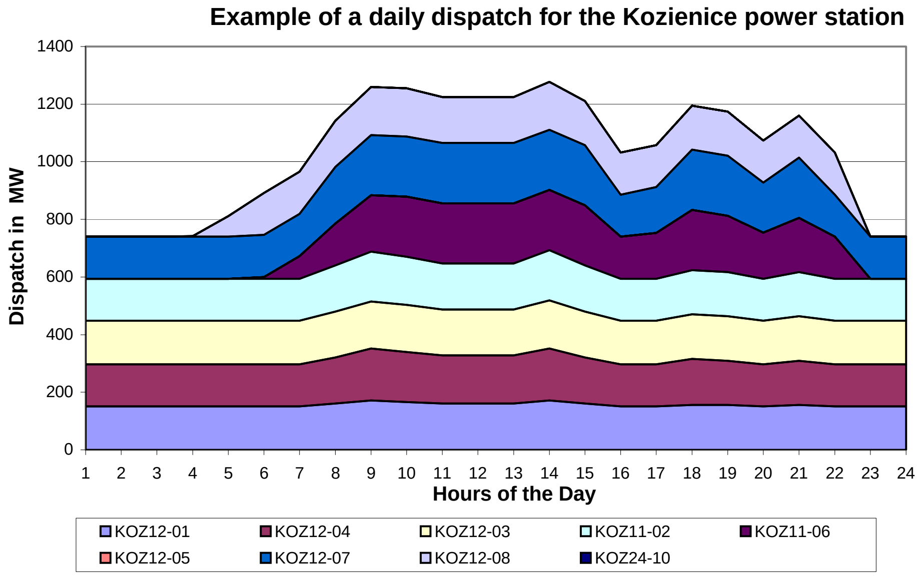


Figure D.14 Example of unit commitment and dispatch for one of the Polish power station.

D.17 Spinning Reserve

The level of spinning reserve represents the possibility to adjust the generation to the load using the units operating. The minimum level of spinning reserve is set up by a dispatcher who is in charge of the LPD module. The real value of spinning reserve depends on the balancing bids and the energy planned for generation.

An example of the spinning reserve values in hours of a day ahead is shown in Figure D.15. It is seen that negative spinning reserve is very small during night hours. This results from the network and security constraints required for a specific number of generating units to be operated in order to keep voltage levels and ensure reliability criteria. To satisfy network constraints the LPD module reduces load on generating units to preserve the required minimum number of units to stay in operation. Figure D.16 shows the range in which the generation can be adjusted using spinning reserve.

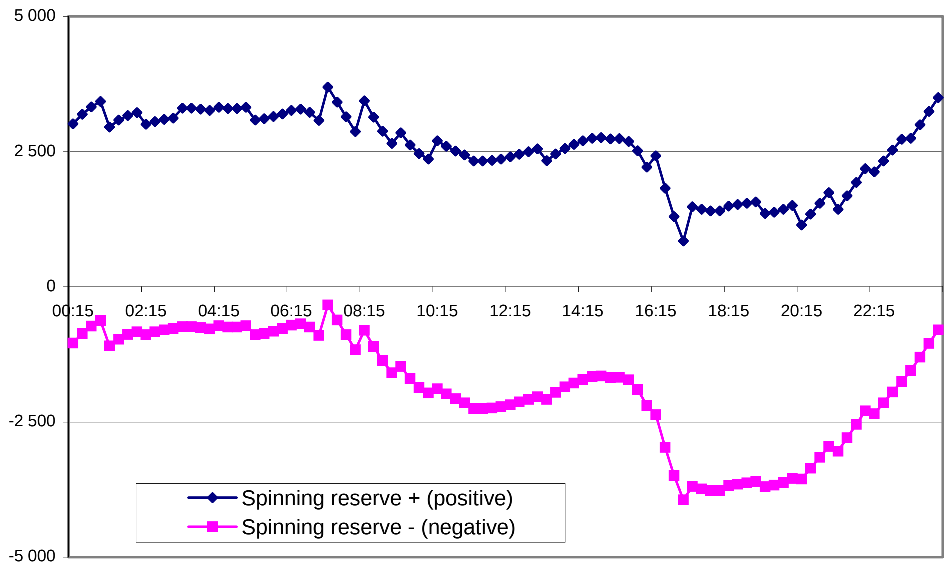


Figure D.15 Spinning reserve in hours of the day.

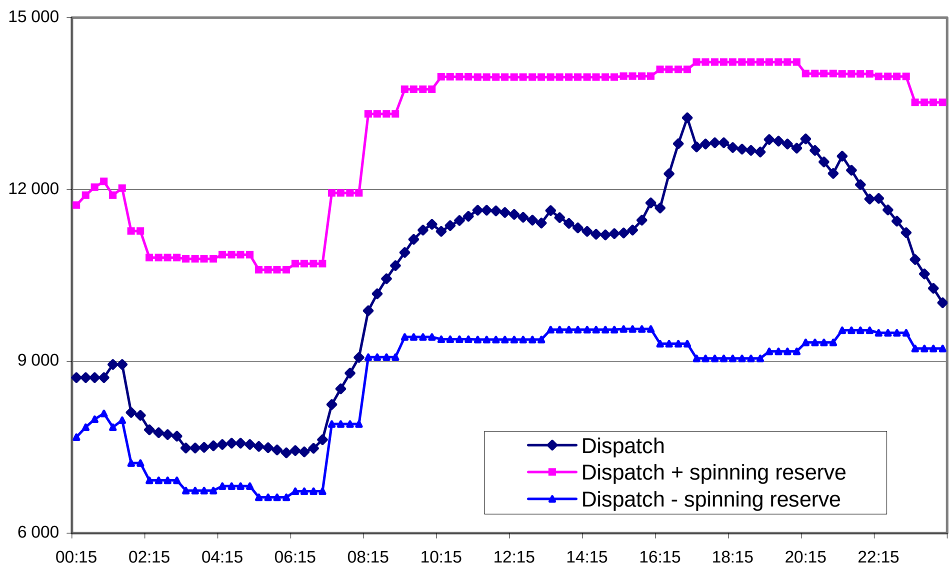


Figure D.16 Dispatch and spinning reserve in hours of the day.

D.18 Conclusions

A successful application of the Mixed Integer Linear Programming is shown in the operation of the Polish Balancing Market. The system for commitment and dispatch based on balancing bids was introduced on September 1, 2001 and it is still operating successfully. During its time of operation despite the severe network condition the system for the commitment and dispatch called LPD was able to provide the schedules of the generating units.

The simplex matrix used in this system contains over 25,000 independent variables, which are modeled as columns and over 50,000 pseudo-variables, which are used to model various constraints.

The minimum power of thermal generating unit is modeled as binary variables. There are over 2,500 binary variables in the optimization task.

The LPD is supported by the GMOS module which contains network and power station constraints modeled as nodal constraints of seven categories. The XPRESS module provided by Dash Corp. is used in the calculation engine.

The optimization procedure is carried out for over 100 generating units with one-hour intervals for one day ahead (24 hours). The hourly commitment and dispatch is split into 15-minute control signals, which are transmitted to power stations. The entire optimization procedure for a time horizon of 24 hours takes about 2-3 minutes with the use of PC4 (1 MHz).

The LPD system should be seen not only as a specific module providing commitment and dispatch but as a kind of methodology allowing for many other applications including modeling of the combined-cycle generating units.

APPENDIX E. A SHORT OVERVIEW OF METAHEURISTICS

The increasing dimension and complexity of problems found in practice lead frequently to a situation where exact optimization algorithms (from now on simply referred to as exact algorithms) are not able to find a solution within a reasonable amount of time, i.e., in a way that is useful for the decision making process under consideration. In such cases, approximation algorithms (heuristics) are an essential tool and, sometimes, the only applicable one to provide good quality solutions within the time available for making a decision. These techniques are based on the implementation of more or less elaborate "rules of thumb" that try to explore the solution space in an appropriate manner. However, these rules are usually tightly related to specific problem characteristics (constraints or objectives) and, due to that, the heuristic tends to become very problem dependent – small changes in the problem characteristics may result in drastic changes in the heuristic rules. While trying to overcome this problem, increasing attention has been given in the last two decades to metaheuristics – general heuristics that can be applied to different optimization problems, needing relatively few modifications to become adapted to a specific problem.

An area where metaheuristics have received particular attention is in combinatorial optimization problems. These problems are usually rather complex to solve and, despite the fast evolution of computer technology, it is still very challenging (if not impossible) to find exact solutions for many such problems. On the other hand, the ever changing scenarios that one must face nowadays do not make traditional heuristic techniques particularly appealing if they are too problem dependent and the problem characteristics are frequently changing.

The number of different metaheuristics described in the literature is getting so large that it becomes difficult to present a complete survey on such methods, always facing the risk of omitting a specific one or, given the similarity of some of them, referring to two different metaheuristics as if they were the same. Such a thorough survey is not the aim of this section and the reader is reported to (LAP96; GLO03), for additional information on the subject. The purpose of this section is solely to introduce those metaheuristics that have set the ground for the tremendous development of this area, namely Simulated Annealing, Tabu Search and Genetic Algorithms, and those that are somehow related to the work of this thesis, GRASP and VNS.

E.1 Simulated Annealing

Simulated Annealing (SA) was first proposed in (KIRK83). It is a randomized local search procedure where, at each iteration, the current solution X is modified by randomly selecting a move that leads to a neighbor solution. If the new solution Y is better, it is automatically accepted and becomes the new current solution. Otherwise, the new solution is accepted according to the Metropolis distribution (equation E1) where the probability of acceptance is related to the magnitude of quality reduction and to a parameter called the temperature (T). Basically, a move is more likely to be accepted if the temperature is high and the decrease in quality is low.

The temperature parameter is progressively lowered, according to some pre-defined cooling schedule, and a certain number of iterations are performed at each temperature level. When the temperature is sufficiently low, only improving moves are accepted and the method stops at a local optimum. So, to achieve diversification, the algorithm starts with a high temperature to perform a wide search of the solution space. The temperature is then gradually reduced to focus on a specific region, allowing a correct search intensification.

$$P_{accept}(X,Y,T) = \begin{cases} 1 & \text{if } f(Y) < f(X) \\ e^{\frac{f(X)-f(Y)}{T}} & \text{otherwise} \end{cases} \tag{E1}$$

Under certain neighborhood structures and depending on the way in which the temperature is decreased, it is possible to prove that SA asymptotically converges to the global optimum. The proof is based on Markov chains. If: 1) the neighborhood is connected, i.e., if it is possible to move from each solution via a sequence of neighbored solutions to any other solution, and 2) the temperature does not decrease too quickly to 0, SA converges to a globally optimal solution with probability 1 (LAA87). However, this result is mainly of theoretical interest as each real implementation of SA is still a heuristic method, since it only runs a finite number of iterations. Furthermore, the above result does not give a rate of convergence. Thus, no bounds on the quality of the solution after a finite number of steps are known.

The SA procedure is outlined in Figure E.1. X* stands for the best solution found so far, and nT stands for the number of iterations that shall be performed at the same temperature level.

```
Algorithm SA

i = 0
Generate initial solution X_i
X* = X_i
Set initial temperature value (T)
Set n_T
While stopping criterion not met
    n = 0
    While n < n_T
        Explore neighbourhood of X_i and generate candidate solution Y
        if f (Y) < f (X_i)
            X_i+1 = Y
        else
            Calculate P_accept(X_i, Y, T)
            if P_accept(X_i, Y, T) > random[0,1]
                X_i+1 = Y
            else
                X_i+1 = X_i
        if f(X_i+1) < f(X*)
            X* = X_i+1
        n = n + 1
    Update temperature value (T)
    i = i + 1
Return X*
```

Figure E.1 Simulated Annealing

The reader is addressed to (VID93; REEVES95; RAY96) or (AZE92; AAR97; AAR02; HEN03), for additional information on this algorithm.

E.2 Tabu Search

Tabu Search (TS) ideas were introduced by (GLOV86) and also by a parallel and independent work developed by (HAN86) named the Steepest Ascent/Mildest Descent method. It is a deterministic local search strategy that, in each iteration, moves to the best admissible neighbor, even if this leads to a solution that is worse than the current one. As this acceptance criterion may lead to cycling (i.e., returning to solutions recently visited), in order to prevent this, a list of forbidden moves (the Tabu List), is considered. The Tabu List stores the last k moves (or some attributes of the moves), where k is a parameter of the method. Whenever a new move is accepted as the new current solution, the oldest one is discarded.

Storing attributes rather than the complete solutions may prevent the method from achieving some interesting solutions. An aspiration criterion is normally used to avoid this problem. The most straightforward aspiration criterion considers that if for a solution X a move leads to a better solution, the new solution is accepted as the new current one, regardless of its Tabu status.

Like in Simulated Annealing, a Tabu Search procedure may stop either when the number of iterations (or CPU time) reaches a given value, or when a solution is not improved after a pre-specified number of consecutive iterations. An outline of this procedure is given in Figure E.2.

Algorithm TS

```
i = 0
Generate initial solution X_i
X* = X_i
Initialise Tabu List
Set aspiration criterion
While stopping criterion not met
    Generate n neighbours of X_i
    Choose best neighbour of  X_i, Y, that is not in the Tabu List
    or that reaches the aspiration criterion
    if f (Y) < f (X*)
        X* = Y
    Update Tabu List
    i = i + 1
Return X*
```

Figure E.2 Tabu Search

Starting from the simple Tabu Search method just described, a number of developments and refinements have been proposed over the years. The reader is referred to (GLOV86; GOL89; GLOV90; GLOV93; GLOLAG97; GLO02; GEN02; GEN03), for additional information on these developments.

E.3 Genetic Algorithms

Genetic Algorithms (GA) were first introduced by (HOL75). The main point of distinction between these algorithms and others previously reported is that they are population-based algorithms, i.e., they consider several solutions in parallel and exchange "information" between each solution, aiming at obtaining better quality results. The algorithms are inspired by models of the natural evolution of species and their reasoning relies on the principle of natural selection, which favors stronger individuals that are more apt at surviving and reproducing.

Three main operators are used to correctly exploit the space: selection, crossover and mutation. Selection gives to individuals (solutions) with a higher fitness score, a higher priority of being chosen for the next generation and for the application of the remaining operators. The genetic material of two individuals, also called parents, is recombined by means of a crossover operator to generate new individuals, called offsprings. The idea of crossover is to exchange useful information between two individuals and in this way to generate a hopefully better offspring. Mutation is understood as a background operator, which introduces small random modifications to an individual.

A sketch of a GA algorithm is presented in Figure E.3 (note, however, that numerous variations of this basic scheme can be considered). The algorithm considers a set Xi of N individuals. In each iteration 2m elements are selected from Xi (according to their fitness score), pairwise crossover is applied and the offspring solutions are stored in Zi. Mutation is then applied to each element of this set, with a given probability. Finally, 2m elements are selected from Xi (a higher probability of selection being given to worse elements) and replaced by Zi. At the end, the best solution found so far is updated.

Algorithm GA

$i = 0$
Generate initial population of solutions $X_i = \{x_{i1}, x_{i2}, \ldots, x_{iN}\}$
Set $F^* = \min \{F(x_{ij}), j = 1, \ldots, n\}$
Set $x^* = \arg\min \{F(x_{ij}), j = 1, \ldots, n\}$
While stopping criterion not met
  Y_i = Select 2m elements from X_i
  $Z_i = \{\}$
  For k = 1 to m
    $Z_i = Z_i \cup \text{Crossover}(y_{i,2k-1}, y_{i,2k})$
  Mutation(Z_i)
  Replace(X_i, Z_i)
  if ($\min \{F(x_{ij}), j = 1, \ldots, n\} < F^*$)
    $F^* = \min \{F(x_{ij}), j = 1, \ldots, n\}$
    $x^* = \arg\min \{F(x_{ij}), j = 1, \ldots, n\}$
  $i = i + 1$
Return x^*

Figure E.3 Genetic Algorithms

For additional information on GA the reader is addressed to (GOL89), (MIC94), or (REEVES95).

E.4 GRASP

The first references to GRASP (Greedy Randomized Adaptive Search Procedure) appear in (FeoRes89), motivated by the work of (HAR87). GRASP is a multi-start metaheuristic composed of two main phases: a Construction Phase and a Local Search Phase. In the Construction Phase, an initial feasible solution is iteratively built following an adaptive reasoning, i.e., the decisions taken in previous iterations influence the decision taken in the current iteration. Then, the neighborhood of that solution is explored, using a Local Search procedure, and if the solution (X) that is obtained is better than the best solution found in previous runs of the algorithm (X*) it is kept. The procedure is outlined in Figure E.4, where n stands for the number of initial solutions that shall be generated.

```
Algorithm GRASP

n = 0
Set n_S
While n < n_S
    Generate new solution X_n
    X = Local Search(X_n)
    if n = 0
      X* = X
    else
       if f(X) < f(X*)
           X* = X
    n = n + 1
Return X*
```

Figure E.4 Greedy Randomized Adaptive Search Procedure

To obtain an initial feasible solution, at each iteration of the Construction Phase all elements (decisions that can be taken) in a set of possible candidates are ranked according to a greedy function that evaluates the contribution to the objective function obtained by choosing that particular element. If the elements in the ranked list reach a given threshold, they are accepted for future decisions and stored in a Restricted Candidate List (RCL). The decisions taken in each iteration of the Construction Phase are then randomly selected among those in the RCL. By following this reasoning, at each GRASP iteration a different initial solution is obtained and, hopefully, different regions of the search space are explored by the Local Search procedure. Finally, at the end of each iteration, the greedy function is adapted, so that in the following iterations it will take into account the decisions previously taken.

E.5 Variable Neighborhood Search (VNS)

VNS was presented in the late 90's by (HAN97). The aim of this metaheuristic is to avoid poor local optima by defining alternative neighborhood movements (N) that are systematically changed to explore an increasingly larger region of the solution space.

Given a set of neighborhood structures, K, a solution is randomly generated in the first neighborhood of the current solution, from which a local descent is performed. If the local optimum obtained is not better than the current best one, the procedure is repeated with the next neighborhood. The search restarts from the first neighborhood when a better solution is found (Figure E.5).

Additional information on VNS can be found in (HAN99; HAN01; HAN01a; HAN01b; HAN02; HAN03).

Algorithm VNS

Set K
Generate initial solution X
For k = 0 to K
    Set N_k
While k < K
    Y = Local Search(X,N_k)
    if f (Y) < f (X)
        X = Y
        k = 0
    else
        k = k + 1
Return X

Figure E.5 Variable Neighborhood Search

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