MASTER EMIN

RAMP-BASED SCHEDULING VS. ENERGY-BLOCK SCHEDULING IN DAY-AHEAD MARKET (DAM)

Master's Thesis

Presented by:

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This master thesis aims at comparing two different unit commitment approaches for market clearing, one that is based on power trajectories, and the other based on traditional energy-block scheduling.

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The story of writing this thesis is quite a unique one. I was slightly anxious when I decided to go to the United States to develop my thesis. Although the whole immigrant procedure went well, it took me quite a while. Due to this VISA delay, I arrived late and my time left to accomplish the master thesis is shortened, and in the end, I need to come back to Spain in order to work more efficiently. Yet, this entire experience is educational and rewarding. It would not have been possible without the help and support of many.

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Abstract

It has been recently reported that conventional unit commitment approach, which is based on energy-block, may not be capable of guaranteeing that the resulting energy schedule is feasible for dispatch [1, 2, 33, 41, 65-67]. Moreover, due to some underlying accepted assumptions widely used in Unit Commitment (UC) formulations, inefficient deployment of resources and ramp constraint violations could take place, with resulting increases in system operational costs; furthermore, security of the entire power system could even be jeopardized.

Thus, this thesis has applied a newly proposed UC formulation proposed by Germán in [1, 2], which draws a clear distinction between power and energy, trying to identify the benefits of using power-based UC scheduling, instead of energy-blocks scheduled on an hourly basis. Piecewise-linear power trajectories are used for modeling both demand and generation. Moreover, startup and shutdown power trajectories are also taken into account, to obtain more efficient scheduling.

A realistic system — ERCOT is used as a case study to conduct experiments. Between power-based UC scheduling and traditional UC formulation, lots of comparisons are made in the thesis. A brief introduction and literature review about unit commitment and short term planning is given at the beginning of this thesis. The differences between the two UC formulations are presented afterwards. Finally, numerical results and tables, along with discussions and comparisons are shown at the end, giving conclusions as evidential support.

1.0 Introduction

1.1 Background

In an electric power system, consumption and production need to be balanced at each time. Demand varies rather predictably throughout the day, nevertheless, it can also fluctuate significantly in real time. Therefore, operating models are highly useful analytical tools, for which, hierarchy is usually defined in terms of the time scope of decision variables, ranging from several years to just few seconds. For example, as shown in the **Figure 1** below, long-term (from one year or above) planning would include nuclear fuel cycle and the use of multi-annual reservoirs;

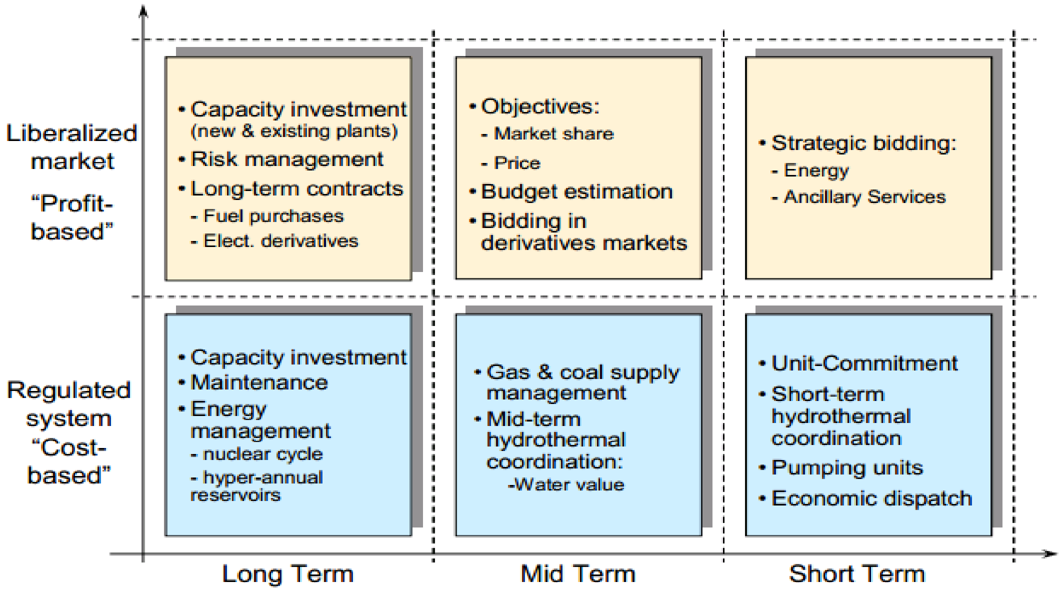


Figure 1 Functions of different operating models Source: [18]

whereas in short-term planning, decision maker would face daily or weekly thermal set startups and shutdowns, to ensure the balance between demand and supply, different combinations of generators, i.e., on/off scheduling, need to be determined to meet varying load. This is known as Unit Commitment (UC) [3].

With careful planning (daily on/off scheduling of generators) taking into account sets of complicated constraints (load and reserve requirements, as well as generator constrains), the most cost effective generation profile could be achieved. To be more specific, when load increases, system operators have to decide in advance if additional units need to be committed and which unit or unit should be dispatched to follow the load; on the other hand, when load decreases, operators need to know which unit(s) ought to be shut down. In addition, transmission network constraints are taken into account in the security-constrained unit commitment (SCUC). It determines an optimal schedule, and also ensures that delivery of that schedule is physically feasible based on the constraints of the network.

Clear distinction need to be made between day-ahead planning and real time operation. Obviously, sustained wind power penetration increases uncertainty in a power system by increasing the fluctuations and decreasing the predictability of the net load; that is, the difference between load a renewable production. Although wind can be forecasted, real time fluctuation, i.e., shortage and surplus, due to forecasting errors, need to be absorbed by operating reserves to maintain system reliability. These system resources must then be scheduled in advance, usually day-ahead, by solving the UC problem.

1.2 MOTIVATION

A power system can consist of thousands of nodes with hundreds of generating units subject to a variety of technical constraints. Due to its scale and the important role it plays in balancing demand and supply, unit commitment has become a major research area in the past few decades [3]. Techniques and tools for UC have changed and been updated over the years.

UC aims to find the optimal solution to meet forecasted load and reserve requirements, subject to both generator and transmission constraints. In general, it makes decisions for a time horizon of one day to one week, and it determines which generators will be operating during which hours taking into account inter-temporal parameters such as minimum down time, minimum up time, ramping limits, etc. [3].

A market should be carefully designed in order to bring economic efficiency, as well as reliability. Without doubt, more operating reserve better protects the system as a whole from unforeseen events, yet greater reserve levels implies more operation costs and deployment of resources at lower capacity factors. For example, many units could be maintained in the synchronized, however they may never be used above their minimum production levels [2, 4, 5]. To achieve economic efficiency, a procedure is adopted to schedule units to avoid possible ad-hoc interventions, such as startup of extra units, unnecessary load shedding, and in order to handle unexpected events using scheduled reserves [2, 6]. Therefore, UC-based market clearing (MC) formulations are becoming more and more popular nowadays as they bring technical constraints into consideration, which represents the real operation of the power system [2, 6-8].

As seen in [1], UC formulation with conventional representation of hourly energy block, instead of staircase energy functions utilizing piecewise linear hourly power trajectories representing instantaneous demand and supply, can be a source of inefficient and sometimes even infeasible operations; although UC-based MC formulations are recognized as the most appropriate approaches to schedule units. That is to say, a more efficient energy and reserve schedule can be obtained via ramp-based scheduling.

1.2.1 SOME WORDS ABOUT MARKET CLEARING (MC)

Unlike other commodities, electricity cannot be stored for later use, which implies that demand needs to be balanced with supply at all time. It is a very complex product, not only is its production subject to inter-temporal constraints, but also to a number of non-convex costs [10]. Electricity markets are organized as a sequence of auctions. There have been discussions about several proposed and implemented auction models; however, day-ahead markets are typically organized as a day-ahead auction determining quantities and prices for each hour of the following day [9]. That is to say, market prices and schedules are decided in one round, after receiving bids from generators and demand day-ahead. Within the single daily auction model, the main format of submitted bids can be described around two extremes: simple and complex.

In simple bids format, only pairs of price and quantity are involved. Both supply curves and demand curves are built for each hour based on generator offers and consumers demand bids respectively. Market is cleared at the intersection of the two aggregated curves [9]. On the one hand, simple bids provide transparency to the markets as by simple comparison between market clearing price and bided price, it is obvious and easy to make choices among offers, and in this way, responsibility is transfer to market participants; on the other hand, the simple format cannot guarantee feasibility with respect to various technical constraints, therefore, reschedules need to be done, for example, through intra-day markets [2, 9].

While complex bids allow more information on the technical characteristics to represent the power system in a more realistic way, so that the resulting schedules are closer to feasible profiles. Correspondingly, market clearing process is more complicated [2, 9-11]. In extreme cases, complex bidding can lead to the use of traditional centralized unit commitment optimization model [11].

Semi-complex bid is a hybrid product combining above two bidding formats. It has been in place in Spain since 1998 [11, 12]. This approach aims at introducing a few constraints to simple bids, without unduly complicating the market clearing process

[10]. More details about semi-complex bids can be found in [10] and [11].

1.3 OBJECTIVE

Within the electricity market, transactions are made based on energy blocks due to introduction of competition. However, [2] stated that, "Operating reserves have been highly deployed in order to match the energy-blocks schedule with the smooth demand, instead of ideally dealing with uncertainties." In addition, this type of paradigm sometimes even puts the system security in danger and increases the operational costs. More discussions about these two scheduling methodologies are covered in the following section. Thereby, a new paradigm, which is ramp-based scheduling paradigm, is proposed in [2].

The primary purpose of this thesis is to make a case study, experimenting on the given deterministic 24 hour UC-based Market-Clearing model. And it can be broken down into following sub-objectives:

1) Familiarize with and apprehend the given ramp-based UC model proposed in [1], which is developed in GAMS
2) Collect data, for both generators and network, that is needed about the Electric Reliability Council of Texas (ERCOT) in order to perform experiment. In the cases that data are not available, sensible estimation need to be created based on limited existing information.
3) Compare and analyze results obtained from energy scheduling and ramp/power scheduling under the deterministic context

Entire experiment consists of two stages which are scheduling stage and simulation stage. That is meant to see while in real time, what day-ahead scheduling could better prepare the system.

When collecting data about ERCOT system, two key underlying difficulties are limitation access to informants or information and lack or weakness of data. To be more specific: 1) Power system facts are highly relevant to national security, therefore it could be fairly difficult for one to gather regarding information; 2) In certain cases, needed information is nowhere to find, as there couldn't have been paid enough attention to. Therefore, lots of reading is required to make realistic estimations. Moreover, erroneous or misinterpreted data, poor documentation, disorganized data base format, etc. could all be barriers for data collection.

2.0 Ramp-Based Scheduling Vs. Energy Block Scheduling

2.1 THEORETICAL BACKGROUND

This section provides a basic review of the theoretical background of this master thesis. It starts with an introduction to the short-term system operation, and then presents problems of traditional UC leading to the new proposed formulation in Section **2.2.3**.

2.1.1 SHORT-TERM PLANNING

More and more wind generation has been implemented in power systems nowadays, increasing the difficulties of operating the system reliably. Typically, uncertainties can be classified as continuous and discrete. Continuous disturbances are mostly result from stochasticity of demand and some renewable resources, while on the other hand, discrete disturbances are mainly due to transmission, generation and load outages.

Therefore, operating reserve, which is essentially generating capacity available to the system operator (SO) within a short interval of time is desired in case of disturbances. To be more specific, in order to absorb system-wise unpredictable disturbances causing imbalance between demand and supply, power system resources that are available and ready to be deployed in real time are needed. By solving UC problem, usually day-ahead (but in some cases hour-ahead), sufficient system resources are ensured.

In most cases, Market Operator (MO) or Independent System Operator (ISO) performs market clearing to determine the quantities and prices to be used in the transactions [33]. These transactions are organized around a sequence of successive markets. The overall trading timetables range from months to years before a trade is realized, then to the "gate closure", even further to the moment the transaction is to take place (real time). By then, generation and load parties shall notify SO about their expected physical position in real time [10, 11]. One way of splitting the market sequences is into the following categories [11]:

- long-term markets,
- day-ahead markets (DAM) and

- intraday plus balancing markets in the EU or real-time markets (RTM) in the USA

This thesis is built based on a case study of ERCOT, which is the ISO in charge of the assigned area. More details regarding ERCOT system can be found in [32].

2.1.2 DISADVANTAGES OF CONVENTIONAL UC

Two problems need to be addressed here: infeasible power supply and overlook of startup and shutdown trajectories.

Conventional formulations might fail to deliver scheduled energy because ramping capabilities are not dealt with in an appropriate way. For instance, as shown in the **Figure 2** below, which is an example taken from [33]. A generator with a minimum and a maximum output of 100MW and 300MW, has a ramp limit of 200MW/h. Based on traditional energy scheduling, the unit is not able to reach a desired 300MW output until the end of the second hour. Consequently, the system's ramp availability is misestimated due to the energy block representation which could cause difficulties when facing real-time uncertainties. It has been proved that it may be infeasible to deliver energy resulting from energy scheduling [41, 42]. Thus, in fact, infinite ramp limit is required to guarantee that energy schedules can always be used [1, 2, 16, 61].

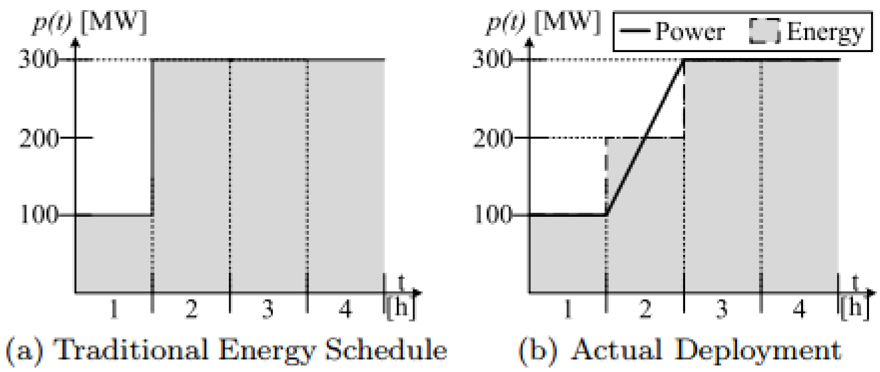


Figure 2 Scheduling Vs. Deployment Source: [33]

Moreover, most of conventional day-ahead UC models consider generating units to startup or shutdown at their minimum production level, while ignoring power trajectories completely [1, 2, 16, 33, 43]. This results in non-allocated energy (and ramp) during the startup and shutdown processes, and due to penetration of variable generation, thermal units startup and shutdown more and more frequently [44].

Let us consider one simple illustrative example from [33]:

Two identical power units are used to meet a required demand. They are both of 100MW minimum output and 300MW maximum output, as well as 100MW/h maximum up/down ramping capability. 2 hours are needed to achieve the minimum output after synchronization, which is a process of matching the speed and frequency of a generator or other source to the network. In the **Figure 3** below, instant power meets the demand at the beginning of each period, nevertheless, energy cannot be satisfied because of discontinuities introduced by startup process.

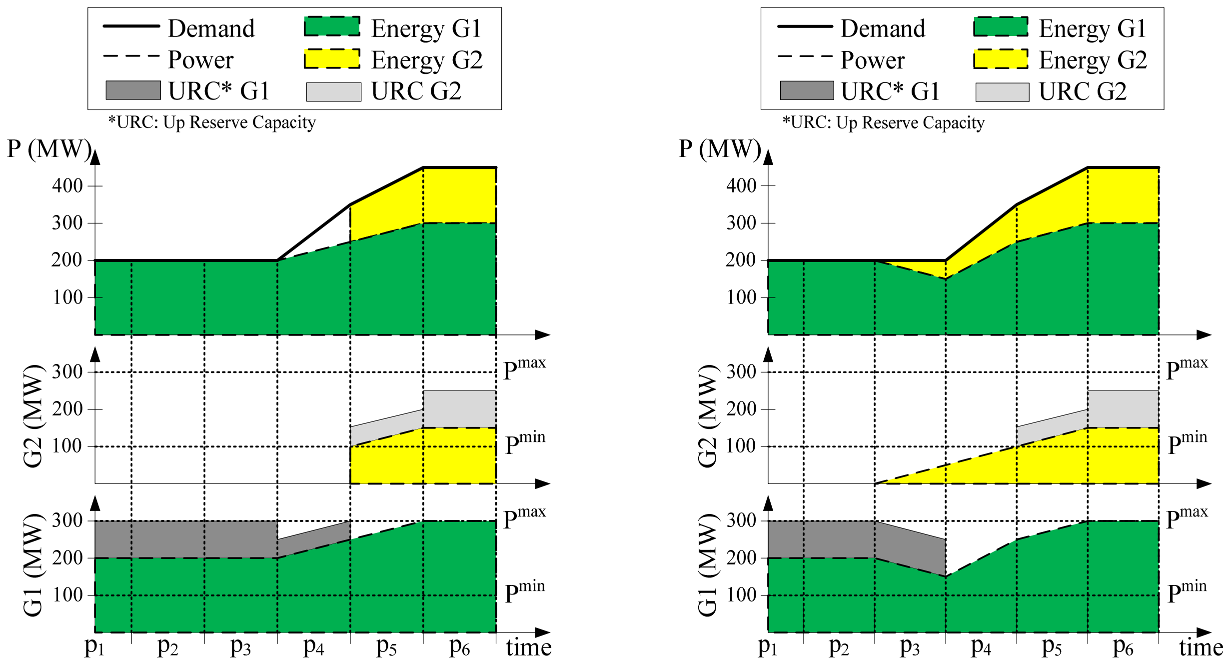


Figure 3 (a) Generation scheduling (b) Actual generation deployment

Source: [33]
From the bottom to the top, power output of unit G1, power output of unit G2, and power output of G1 and G2 matching the electric demand.

In the actual deployment stage, G2 needs to start to synchronize at the end of p2 in order to produce at the minimum level at the end of p4. Furthermore, in order to match demand and supply all the time, G1 has to utilize its downward reserve to accommodate G2's startup trajectory. If not taking into account the startup and shutdown power trajectories, from scheduling result, up reserve capacity is expected to be 50MW for [p4, p5] and 100MW elsewhere. Likewise, down reserves is expected to be 100MW for [p1, p4] and 150MW for p5 and p6: 100MW that G1 can provide all the time and 50MW that G2 can provide for p5 and p6.

From the above, one need to notice that: 1) downward reserves were used in p3 and p4, which was unexpected from scheduling; 2) in p4, the system run out of up reserves as G1 needs to ramp down at its maximum capability to accommodate the startup of G2, which implies insufficient resources are deployed in the day-ahead schedule to secure system reliability. Yet this situation can be coped with by including power trajectories in the UC based market clearing formulation, obtaining better commitment decisions (**Figure 4** below), which thereby decreases operational costs [16].

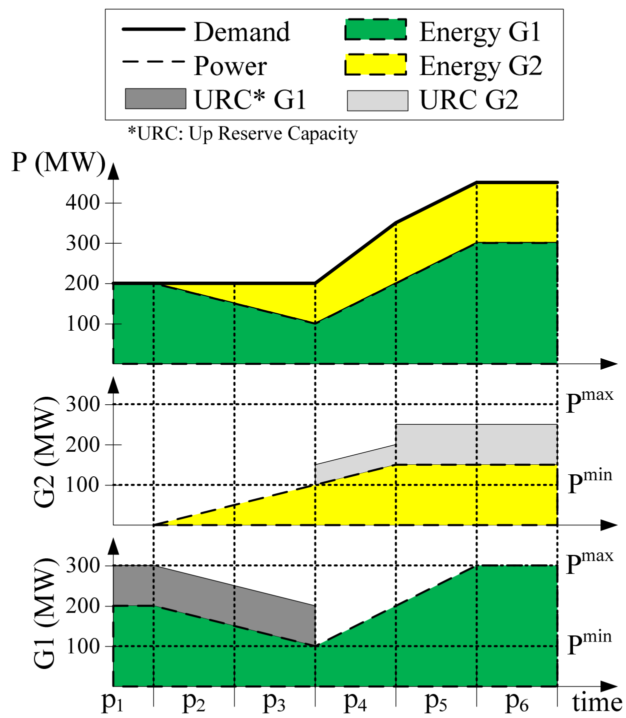


Figure 4 Scheduling considering the startup and shutdown power trajectories

Source: [33]

Although the importance of including power trajectories is emphasized in UC problems [1, 16, 33, 45, 46] and models are proposed accordingly [33, 47, 48], these power trajectories continue being overlooked because the resulting model would have considerably increases complexity leading to substantial computational intensity [33]

2.2 Model Formulation

2.2.1 Nomenclature

Definitions

online Unit is synchronized with the system

offline Unit is not synchronized with the system

up Unit is producing above its minimum output. During the *up* state, the unit output is controllable

down Unit is producing above below its minimum output. When *offline*, starting up or shutting down

Indexes and Sets

$g \in \mathcal{G}$ Generating units, running from 1 to G

$\ell \in L_g$ Startup intervals, running form 1 (hottest) to N_{Lg}

$t \in \mathcal{T}$ Hourly periods in the time horizon, running from 1 to N_T hours

Unit's Parameters

C_g^{NL} No-load cost of unig g [$/h]

C_g^{LV} Linear variable cost of unit g [$/MWh]

$C_{g,l}^{SU}$ Cost of the interval ℓ of the stepwise startup cost function of unit g [$]

C_g^{SD} Shutdown cost of unit g [$]

RU_g Ramp up capability of unit g [MW/h]

RD_g Ramp down capability of unit g [MW/h]

SD_g Startup capability of unit g [MW/h]

SU_g Shutdown capability of unit g [MW/h]

TU_g Minimum up time of unit g [h]

TD_g Minimum down time of unit g [h]

$\underline{P_g}$ Minimum power output of unit g [MW]

$\overline{P_g}$ Maximum power output of unit g [MW]

SU_g^D Duration of the startup process of unit g [h]

SD_g^D Duration of the shutdown process of unit g [h]

$\mathrm{P_i^{SD}}$ Power output at the beginning of the i^{th} interval of the shutdown ramp process [MW]

$\mathrm{P_i^{SU}}$ Power output at the beginning of the i^{th} interval of the startup ramp process [MW]

Decision Variables

e_{gt} Energy output above minimum output for hour t of unit g [MWh]

$\widehat{e_{gt}}$ Total energy output at the end of hour t, including startup and shutdown trajectories of unit g [MWh]

p_{gt} Power output above minimum output for hour t of unit g [MW]

$\widehat{p_{gt}}$ Total power output at the end of hour t, including startup and shutdown trajectories of unit g [MW]

$\mathrm{v_{gt}}$ Binary variable which takes the value of 1 if the unit startup and 0 otherwise

$\mathrm{u_{gt}}$ Binary variable which is equal to 1 if the unit is producing above minimum output and 0 otherwise

$\mathrm{w_{gt}}$ Binary variable which takes the value of 1 if the unit shuts down and 0 otherwise

2.2.2 GENERIC ENERGY-BLOCK FORMULATION OF UC

In order to find an optimal hourly scheduling (startup and shutdown decisions of thermal units, to meet demand at the minimum cost) in the short term, i.e., in intervals ranging from one day to one week, one needs to solve the problem named Unit Commitment (UC). Chronological electricity demand curve usually cycles weekly which results in periodic unit commitment decisions.

Generally, the formulation covers four aspects: objective function, unit limitations, various cost functions, as well as complexity constraints such as logic constraint between commitment, startup and shutdown. One generic formulation [39, 40, 56] is briefly presented in this subsection.

Objective function

$$\min \sum_{g \in G} \sum_{t \in T} [C_g^{NL} * u_{gt} + C_g^{LV} * \widehat{e_{gt}} + C_{g,t}^{SU} * v_{gt} + C_g^{SD} * w_{gt}]$$

Objective function is formulated as the summation of no-load cost C_g^{NL}, linear variable cost C_g^{LV}, startup/shutdown cost, $C_{g,t}^{SU}/C_g^{SD}$ and energy non-served penalty. Among which, C_g^{NL} and C_g^{LV} (**Figure 5** below) are related with α_t and β_t terms shown in the **Appendix B**. The entire cost function is approximated as a straight line, i.e., linearly.

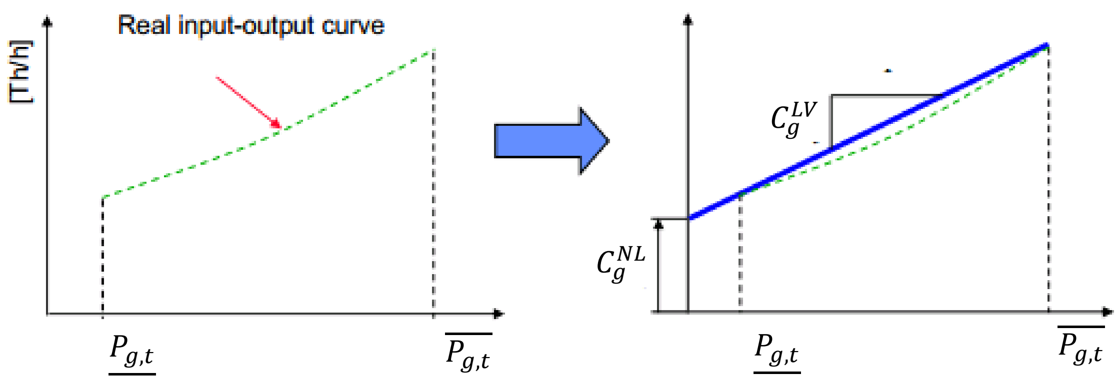


Figure 5 Fuel Cost Approximation Source: modified from [18]

To be more specific, C_g^{NL} is essentially fuel cost to sustain zero net output MW at synchronous generator speed in the unit of $/h, therefore, it is counted whenever the unit is committed, i.e., $u_{gt} = 1$. And C_g^{LV} is unit production cost for producing an extra MWh energy, which consists of fuel and variable O&M[1] costs.

While $C_{g,t}^{SU}$ representing the stepwise startup cost, is slightly differently defined in the ramp-based formulation in which, they are distinguished only as hot and cold startup (presented in the later section). Startup costs are counted when there is a startup of a unit, i.e., $v_{gt} = 1$. v_{gt} and w_{gt} are binary variables, standing for startup and shutdown decisions.

Unit limitations

Minimum Up and Down time

$$\sum_{i=t-TU_g+1}^{p} v_{gi} \leq u_{gt} \qquad \forall g, t \in [TU_g, N_T]$$

$$\sum_{i=t-TD_g+1}^{p} w_{gi} \leq 1 - u_{gt} \qquad \forall g, t \in [TD_g, N_T]$$

where TU_g and TD_g are minimum up and down time of unit g respectively. Summing up startup (shutdown) decisions in the pre-defined periods and forcing it less than or equal to commitment decisions (the complementary of commitment decisions) in period t have guaranteed that units are up and down for a minimum of periods of time. As explained in the later Section **3.2.6**, they are usually used to represent the minimum amount of time to release thermal stresses in the equipment which could otherwise arise.

[1] O&M: Acronym for "Operation and Maintenance"

Unit Ramp Limits

$$e_{gt} - e_{g(t-1)} \leq RU_g * u_{g(t-1)} + SU_g * v_{gt} \qquad \forall g, t$$

$$e_{g(t-1)} - e_{gt} \leq RD_g * u_{gt} + SD_g * w_{gt} \qquad \forall g, t$$

Units cannot ramp up or ramp down over a limit. Therefore, difference between energy produced in two consecutive periods "$e_{gt} - e_{g(t-1)}$" or "$e_{g(t-1)} - e_{gt}$" shall not either exceed upward ramp limits "RU_g" or downward ramp limits "RD_g" if the unit is committed, i.e., $u_{gt} = 1$; or exceed its startup "SU_g" or shutdown "SD_g" capability if the unit is starting up or shutting down, i.e., $v_{gt} = 1$ or $w_{gt} = 1$.

Capacity Limit

$$u_{gt} * \underline{P_g} \leq p_{gt} \leq u_{gt} * \overline{P_g} \qquad \forall g, t$$

Logical constraint between commitment, startup and shutdown

$$u_{gt} - u_{g(t-1)} = v_{gt} - w_{gt}$$

This constraint maintains the consistency between binary decision variables. With v_{gt} and w_{gt} denoting startup and shutdown decisions of unit g at the beginning of period t respectively: a unit that is already connected cannot startup concurrently, but it may be shut down. Conversely, a unit that is off cannot be shut down but it can be started up. Notice that given formulation allows start up and shut down simultaneously in certain period, i.e., $v_{gt} = w_{gt} = 1$. However, since both these decisions are associated with costs, the avoidance of such a situation is intrinsic to the meaning of optimization.

Cost functions (MILP stair-wise startup costs)

$$C_{g,t}^{SU} \geq C_{g,k}^{SU'} * \left(u_{gt} - \sum_{i=1}^{k} u_{g(t-i)} \right) \qquad \forall g, t, k \in [1, T_{N_{Lg}}^{SU}]$$

where $C_{g,k}^{SU'}$ is the cost of turning on the unit g after being offline for k time periods. $C_{g,k}^{SU'}$ is defined as:

$$C_{g,k}^{SU'} \begin{cases} C_{g,1}^{SU} & if\ k < T_{g,2}^{SU} & \forall g \\ C_{g,l}^{SU} & if\ k < [T_{g,l}^{SU}, T_{g,l+1}^{SU}) & \forall g, l \in (1, N_{Lg}) \\ C_{g,N_{Lg}}^{SU} & if\ k = T_{g,N_{Lg}}^{SU} & \forall g \end{cases}$$

System-wide constraints

Demand Balance Constraint

$$\sum_g e_{gt} + W_t = D_t$$

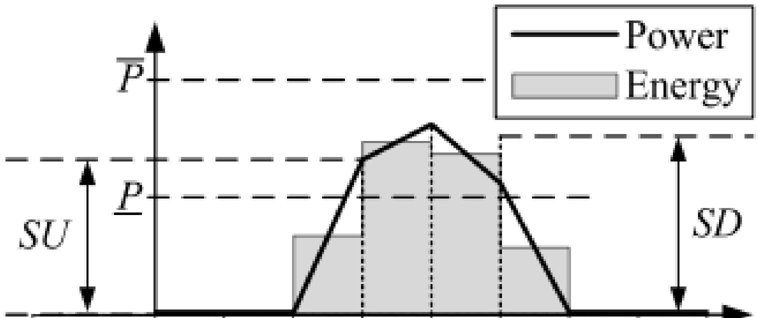
Here W_t and D_t denote wind production and demand at each period t respectively.

Different conventions are used in [39, 40, 56], nevertheless, problem formulations are equivalent in the three references. The next subsection shows a different formulation for unit commitment which deals with infeasible power delivery and startup and shutdown trajectories mentioned in Section **2.1.2**.

2.2.3 RAMP-BASED SCHEDULING FORMULATION

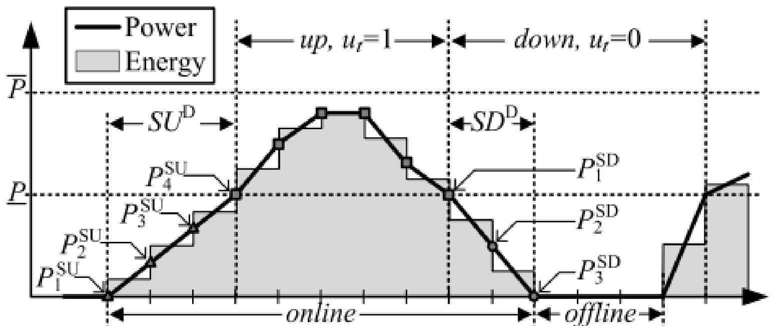
In one word, a more precise and accurate UC model is needed for MC, in order to bring greater efficiency to electricity markets [16, 17]. Formulation appears in this section is taken from [2, 33].

All units fall into two categories, quick-start units, referring to their capabilities of ramping up from 0 to minimum output within one period; and slow-start units, which need more than one period to reach minimum output level. **Figure 6** and **Figure 7** show the basic operations for quick-start and slow-start units. Up and down states are distinguished from online and offline states [16, 61].



u_t	0	0	0	1	1	0	0	0
v_t	0	0	0	1	0	0	0	0
w_t	0	0	0	0	0	1	0	0

Figure 6 Startup and shutdown capabilities for quick-start units Source: [33]



t [h]	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
u_t	0	0	0	0	1	1	1	1	1	0	0	0	0	0	0	1
v_t	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	1
w_t	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0

Figure 7 Operating states, including power trajectories for slow-start units Source: [33]

For both types of units, they can follow any power trajectory between minimum and maximum outputs during the up periods ($u_t = 1$). Nevertheless, when the unit is starting up or shutting down, a predefined power trajectory will be followed. And for quick-start units, their start-up and shutdown power trajectories are defined by their startup (SU) and shutdown (SD) capabilities.

SU and SD capabilities are in the unit of MW. Assuming a unit is running from 1 to T hours, using t as the index for time. Basic operating constraints are defined as follows [61]:

$$p_{gt} \leq \left(\overline{P_g} - \underline{P_g}\right) * u_{gt} - \left(\overline{P_g} - SD_g\right) * w_{t+1} + \left(SU_g - \underline{P_g}\right) * v_{g(t+1)} \quad \forall g, t \in [1, T-1] \tag{1}$$

$$p_{gT} \leq \left(\overline{P_g} - \underline{P_g}\right) * u_{gT} \qquad \forall g \tag{2}$$

$$p_{gt} \geq 0 \qquad \forall g, t \tag{3}$$

Where $\overline{P_g}$ and $\underline{P_g}$ represent the maximum and minimum power output in MW; u_{gt}, v_{gt} and w_{gt} are *binary* decision variables indicating commitment status, startup status and shutdown status respectively; p_{gt} is the power output of the unit for period t, above the minimum load.

$$u_{gt} - u_{g(t-1)} = v_{gt} - w_{gt} \qquad \forall t \in [2, T] \tag{4}$$

$$\sum_{i=t-TU+1}^{t} v_{gi} \leq u_{gt} \qquad \forall t \in [TU+1, T] \tag{5}$$

$$\sum_{i=t-TD+1}^{t} w_{gi} \leq 1 - u_{gt} \qquad \forall t \in [TD+1, T] \tag{6}$$

$$0 \leq u_{gt} \leq 1 \qquad \forall t \tag{7}$$

$$0 \leq v_{gt} \leq 1, 0 \leq w_{gt} \leq 1 \qquad \forall t \in [2, T] \tag{8}$$

Where TU and TD are parameters, denoting the minimum up and down time for each unit. They are defined in the same way as in Section **2.2.2**. Equation ($u_{gt} - u_{g(t-1)} = v_{gt} - w_{gt} \quad \forall t \in [2, T]$ (**4**) guarantees the logical relation of startups and shutdowns to operational status. Minimum up and down times as in Equation ($\sum_{i=t-TU+1}^{t} v_{gi} \leq u_{gt} \quad \forall t \in [TU+1, T]$ (**5**) and ($\sum_{i=t-TD+1}^{t} w_{gi} \leq 1 - u_{gt} \quad \forall t \in [TD+1, T]$ (**6**) ensure that a unit would not startup and shutdown simultaneously [16].

Constraints ($p_{gt} \leq \left(\overline{P_g} - \underline{P_g}\right) * u_{gt} - \left(\overline{P_g} - SD_g\right) * w_{t+1} + \left(SU_g - \underline{P_g}\right) * v_{g(t+1)} \quad \forall g, t \in [1, T-1]$ (**1**) to ($0 \leq v_{gt} \leq 1, 0 \leq w_{gt} \leq 1 \quad \forall t \in [2, T]$ (**8**) are applicable to both quick-start and slow-start units, except when describing slow-start units, $SU_g = SD_g = \underline{P_g}$.

The total power output of a slow-start unit is given by:

$$\widehat{p_{gt}} = \sum_{i=1}^{SU^D} P_i^{SU} * v_{g(t-i+SU^D+2)} + \sum_{i=2}^{SD^D+1} P_i^{SD} * w_{g(t-i+2)} + \left\{\underline{P_g} * \left(u_{gt} + v_{g(t+1)}\right) + p_{gt}\right\} \quad \forall t \tag{9}$$

The first and second terms in the above equation are SU and SD trajectories, and the third term is unit output when the state is up. Similarly, the total energy production of a slow-start unit is:

$$e_{gt} = \underline{P_g} * u_{gt} + \frac{p_{gt}+p_{g(t-1)}}{2} + \sum_{i=1}^{SD^D} \frac{P_{i+1}^{SD}+P_i^{SD}}{2} * w_{g(t-i+1)} + \sum_{i=1}^{SU^D} \frac{P_{i+1}^{SU}+P_i^{SU}}{2} * v_{g(t-i+SU^D+1)} \qquad \forall t \tag{10}$$

For quick-start unit, the total power is given by:

$$\widehat{p_{gt}} = \underline{P_g} * \left(u_{gt} + v_{g(t+1)}\right) + p_{gt} \qquad \forall t \tag{11}$$

And the total energy production is:

$$\widehat{e_{gt}} = \frac{\underline{P_g} * \left(2u_{gt} + v_{g(t+1)} + w_{gt}\right) + p_{g(t-1)} + p_{gt}}{2} \qquad \forall t \tag{12}$$

For Equations ($\widehat{p_{gt}} = \sum_{i=1}^{SU^D} P_i^{SU} * v_{g(t-i+SU^D+2)} + \sum_{i=2}^{SD^D+1} P_i^{SD} * w_{g(t-i+2)} + \left\{\underline{P_g} * \left(u_{gt} + v_{g(t+1)}\right) + p_{gt}\right\} \quad \forall t$ (**9**) – ($\widehat{e_{gt}} = \frac{\underline{P_g} * \left(2u_{gt} + v_{g(t+1)} + w_{gt}\right) + p_{g(t-1)} + p_{gt}}{2} \quad \forall t$ (**12**), t is defined for all values, within and outside $[1, \mathrm{T}]$. When the sub index is $t < 1 \; or \; t > T$, those variables are considered to be zero.

The objective function of the UC problem is the total operational costs of each generator, and is defined as follows;

$$C = C_g^{NL} * \mathbf{u}_{\mathbf{gt}} + C_g^{LV} * \mathbf{e}_{\mathbf{gt}} + C_{g,l}^{SU'} * \mathbf{v}_{\mathbf{gt}} + C_g^{SD} * \mathbf{w}_{\mathbf{gt}} \tag{13}$$

$$\mathrm{C}_{\mathrm{g,l}}^{\mathrm{SU}'} = C_{g,l}^{SU} + C_g^{NL} * SU_g^D \tag{14}$$

$$\mathrm{C}_{\mathrm{g,l}}^{\mathrm{SD}'} = C_{g,l}^{SD} + C_g^{NL} * SD_g^D \tag{15}$$

Cg,lSU′=*Cg,lSU*+*CgNL*∗*SUgD* (14) and
Cg,lSD′=*Cg,lSD*+*CgNL*∗*SDgD* (15) redefine costs of startups and shutdowns, to take into account no-load costs during the startup and shutdown process. And $SU_g^D = SD_g^D = 1$ for quick-start units.

3.0 System Description and Parameter Derivation

3.1 ERCOT Facts and Test System Description

This section is dedicated to give a general overview of the ERCOT system, as well as a broad description of the test system. Originally, a system that is exactly the same as ERCOT is targeted. However, due to difficulties and problems encountered during data collection and processing, such system used for validation is not the exact same as the latest ERCOT system, but close to real. Therefore, it is safe to conclude that results and conclusions obtained from performed experiments make practical sense.

3.1.1 ERCOT Quick Facts

As the Independent System Operator of Texas area, it serves 24 million customers, representing 85 percent of the state's electric load and 75 percent of the Texas land area. It manages more than 41500 circuit miles of HV transmission line and over 550 generating units. Moreover, it also handles financial settlement for the competitive wholesale bulk-power market and administers customer switching for 6.7 million premises in competitive choice areas [49, 50]

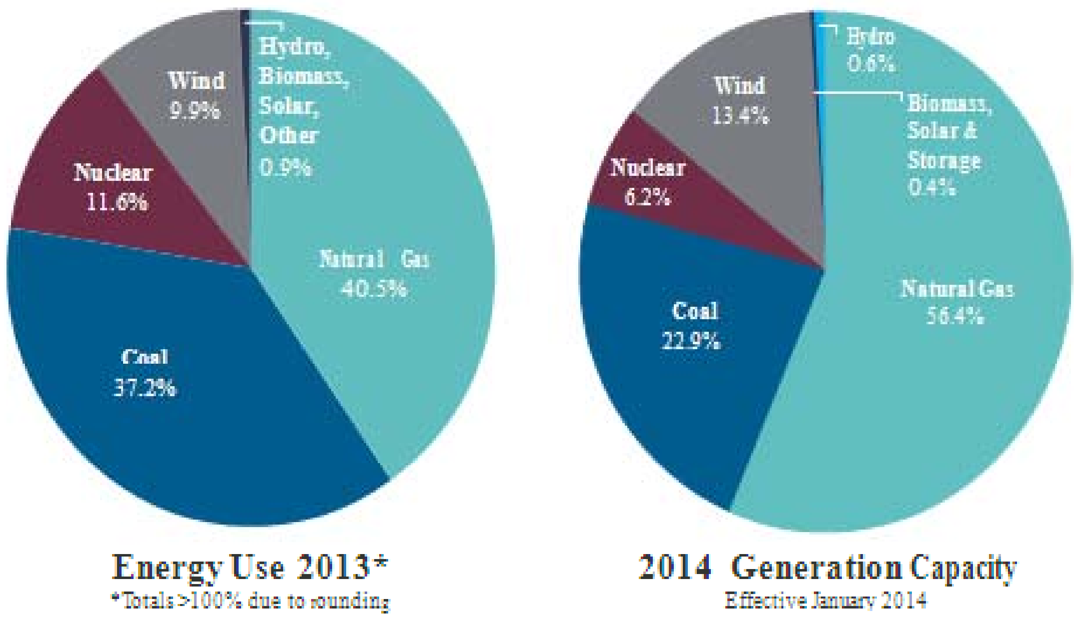


Figure 8 Energy Use in 2013 and Generation Capacity in 2014 of ERCOT system [49]

Note: Figure on the left, "Energy Use", referred to "Electrical Energy Production", indicates the percentage of electrical energy produced by each technology.

The highest peak demand occurred on Aug 3rd, 2011 [49]. Since the restructuring of the Texas electricity market by the Texas Legislature in 1999, there has been many big investments in transmission and generation. Wind generation has surpassed 10% of total generation capacity in 2014.

3.1.2 Some Remarks about ERCOT Operation

In DAM, market prices are calculated through solving a UC problem; while in RTM, a security-constrained economic dispatch (SCED) help to find the clearing prices and quantities with minimum cost using online units. ERCOT successfully transited from zonal market to nodal in 2010 and in the new wholesale market, a Reliability Unit Commitment (RUC) has been implemented [34] to ensure ERCOT System reliability. Practical operation is shown below in **Figure 9**. There are other ISOs that use similar procedures, typically performing Day-Ahead RUC (DRUC) after the DAM, and hourly RUC, namely (HRUC) [33, 35, 36]. On one hand, DRUC is responsible for ensuring that enough resources are committed at the right location as a result of DAM, to serve the forecasted load taking into account wind uncertainty. In the end, commitment schedule of DAM may be altered due to DRUC. On the other hand, HRUC is fed with updated demand and wind forecast and performances more frequently, providing extra information to secure the system further in real time [33].

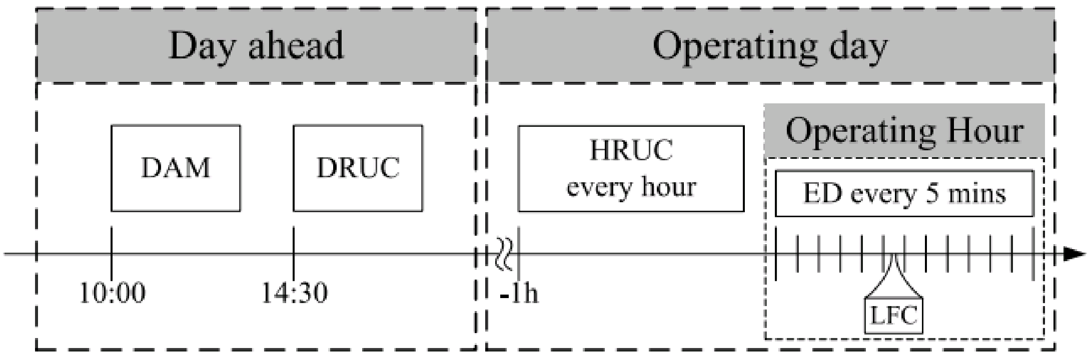


Figure 9 Practical Operation of power systems Source: [33]

According to current ERCOT nodal protocol, at least one DRUC (must be run after the close of the DAM) and one HRUC (before each hour of the Operating Day) need to be conducted. ERCOT, in its sole discretion, may conduct a RUC at any time to evaluate and resolve reliability issues. The RUC Study Period for DRUC is the next Operating Day and the RUC Study Period for HRUC is the balance of the current Operating Day. **Figure 10** below is a summary of RUC timeline.

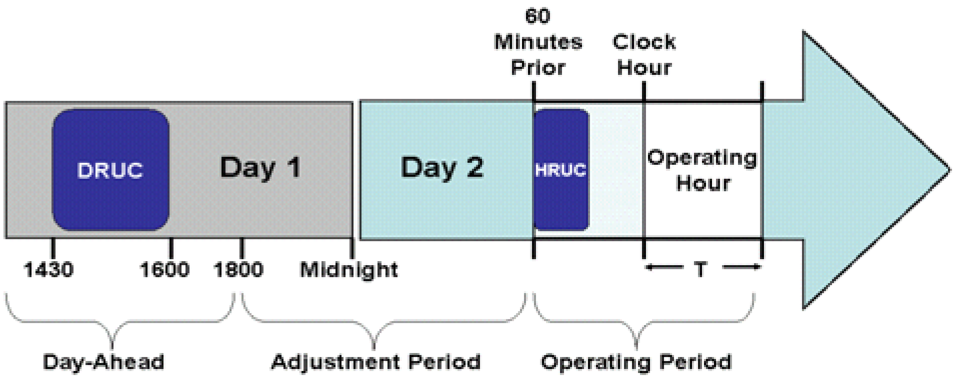


Figure 10 Summary of RUC Timeline Source: [35]

3.1.3 TEST SYSTEM DESCRIPTION

As stated in Section **1.3**, data are collected for both generators and network. However, this case study would ideally be conducted in two parts, with two sets of data: first considering only generators' characteristics, while treating the entire system as a single node system; then taking network data into account, repeating all experiments that were performed for the non-network system. We haven't been able to invert a matrix for computing the Power Transmission Distribution Factors (PTDF) that are required for solving the network-constrained UC. That is to say, system without network had been the focus of this thesis.

Single Node System

The system used for study, does not consider any reserve. Two different scheduling approaches are evaluated assuming that all information is known. It comprises 298 generators in total, all of them are thermal units except two, which are biomass units. Wind farms are considered separately. Because it is a 24 hours deterministic case study, power demand or net load (in MWh), which is the total demand excluding wind, is meant to be satisfied for 24 consecutive periods.

System with Network

Compared to the single node system, net load in this data set is distributed to individual nodes accordingly based on Load Distribution Factors (LDF). This is information extracted from a summer peak base case study of ERCOT given by [55].

A snapshot of reality was recorded, so to speak, instantaneous generation and demand at each bus are clearly documented. Therefore, LDF can be easily computed. In addition, line records are provided in this data set, with line parameters already converted in per unit, as well as line capacity in MW. There are a total of 6820 lines including double circuits. For double circuits, “Circuit ID” differentiates interconnections between the same nodes, by specifying them with different circuit ID numbers.

One thing worth to mention here, is to match generators with buses, i.e., to identify geographic locations for all counted units, as transmission network constraints would take place in this case. This is a quite time-consuming process. Looking through files obtained from ERCOT official site and [19], connections between “PSSE_BUS_NAME” and “PSSE_BUS_NUMBER” within generator profiles and network records were traced, thus most of the units are located successfully. However, units that are left, their sites were approximated by the closest substations that can be tracked, again with “PSSE_BUS_NAME” and “PSSE_BUS_NUMBER”.

3.2 DATA GATHERING & JUSTIFICATIONS

3.2.1 DATA RESOURCES AND DESCRIPTION

Generator characteristics are gathered mainly from ERCOT official website. In the case that required parameters are not available, reasonable estimations need to be created based on given limited information. In order to do so, lots of reading is required, a table of documents is listed below, from which all approximations are originated. Some detailed parameter derivations can be found in **Appendix A**.

Document Type	Reference No.	Reference Title
Protocol	[20]	ERCOT Protocols (2011)
	[31]	PJM Manual 15: Cost Development Guidelines
	[35]	ERCOT Current Protocols - Nodal
Report or Presentation	[21]	Quantifying the Value of Hydropower
	[23]	Cost and Performance Data for Power Generation Technologies
	[24]	Analysis of Wind Power Ramping Behavior in ERCOT
	[25]	Operating Flexibility of Power Plants with Carbon Capture and Storage (CCS)
	[26]	Power Plant Cycling Costs
	[27]	Power Plants: Characteristics and Costs
	[30]	Summary Report on Coal Plant Dynamic Performance Capability
	[32]	2012 State of the Market Report for The ERCOT Wholesale Electricity Market
Web Information	[28]	2 Combined cycle operating flexibility
	[29]	Energy resources compared - higher
Journal Paper or Dissertation	[34]	Reliability Unit Commitment in ERCOT Nodal Market
	[36]	Wind power forecasting in US electricity markets
	[37]	Reliability Assessment Unit Commitment with Uncertain Wind Power
Personal Communication	[19]	Julia Matevosyan
	[22]	Jared

Table 1 Data Resources List

Categories of necessary information to run the UC model are listed in **Table 2**. Data resources and justifications of estimated values are provided for each parameter in this section following.

Parameters [unit]	Definition
Generator	Generator name, can be defined in all ways
Bus number/ID	Bus ID, define the specific bus that generator is connected to
MaxProd [MW]	Maximum Production Level
MinProd [MW]	Minimum Production Level
IniProd [MW]	Initial Production Level
IniState [p]	Initial States, positive values stand for the unit has been on for certain periods, negative vice-versa
RampUp [MW/h]	Ramp up limit while the unit is up
RampDw [MW/h]	Ramp down limit while the unit is up
InterVarCost [€/h]	No-load cost
SlopVarCost [€/h]	Variable production cost
MinUpTime [p]	Minimum up time
MinDwTime [p]	Minimum down time
SDCost [€]	Shutdown cost
SDDuration [p]	Shutdown duration
SUHCost [€]	Hot start-up cost
SUHDuration [p]	Hot start-up duration, from synchronous to minimum output
SUCCost [€]	Cold start-up cost
SUCDuration [p]	Cold start-up duration, from synchronous to minimum output
Tcold [p]	Threshold to differentiate between cold start-up and hot start-up
SURamp [MW]	Startup capability
SDRamp [MW]	Shutdown capability

Table 2 Generator Characteristics

3.2.2 GENERATOR SELECTION & BUS NUMBER/ID

“Generators”: They are directly taken from ERCOT website market report named “60-Day SCED Disclosure”[2]

During the first stage data collection, units are categorized in the following way, following the convention of ERCOT:

ERCOT Abbreviations	Unit Types
NUC	Nuclear
CCGT90	Combined Cycle Greater than 90MW
CCLE90	Combined Cycle Less than or Equal to 90MW
CLLIG	Coal and Lignite
GSNONR	Gas-Steam Non-reheat or boiler without air-preheater
GSREH	Gas-Steam Reheat Boiler
GSSUP	Gas-Steam Supercritical Boiler
RENEW	Renewable Generations
SCGT90	Simple Cycle Greater than 90MW
SCLE90	Simply Cycle Less than or Equal to 90MW
DSL	Diesel
WIND	Wind units
HYDRO	Hydro units

Table 3 ERCOT Units Nomenclature

At the beginning, there were 433 units (in use at ERCOT at the time of starting writing this thesis), characteristics listed in **Table 2** are gathered for all of them. Hydro units are removed because they are of little importance in ERCOT and the model is not prepared to dispatch hydro power plants. Wind farms were introduced separately in another format, thereafter, impacts of high penetration of wind in a system can be more visible. Finally, 298 conventional thermal generators are left, constituting the generator set for experiments.

“Bus number/ID”: Each generator has a corresponding “RESOURCE_NODE”, which has a unique “ELECTRICAL_BUS” associated with it. They are listed in the

[2] ERCOT Webpage: http://www.ercot.com/mktinfo/reports/index.html.

section of "Day-Ahead Supporting Information" within "Market Information", located at: http://www.ercot.com/mktinfo/dam/index.html, named "Settlement Points List and Electrical Buses Mapping".

3.2.3 Maximum and Minimum Output

Minimum and maximum real power output limits for all the generators (hereafter referred to as "MaxProd" and "MinProd") were obtained from [19] and ERCOT. Certainly, unit production would not surpass its maximum value and it cannot go below the lower limits to ensure stable operations. This limit is usually given as a percentage of units' maximum production level.

3.2.4 Startup Costs & Shutdown Costs

Conventionally, units can either produce within its operational range (unit is online) or have no output at all (unit is offline). The transitions between the offline and online states are known as the startup and shutdown.

The first practical electricity generating system using a steam turbine was designed and made by Charles Parsons in 1885. Turbine design has hardly changed since then apart from size alternation [72]. Although during the past almost 130 years, various generating technologies have been introduced, steam turbines are still play the key role among all. Gas turbine, also known as a combustion turbine, is operated in a similar way to steam power plant, except air is used instead of water.

Taking startup of a unit using steam turbine as an example, essentially it is a process of heating up the unit to produce high pressure to drive the turbine, synchronizing, and then increasing production to at least the minimum stable level. To be more specific, first, steam is raised from primary energy such as fossil fuel sources, and then high pressure steam is fed to the turbine and passes along the machine axis through multiple rows of alternately fixed and moving blades. Stationary blades are connected to the casing while rotating blades are connected to the shaft.

Within ERCOT, "startup cost" is primarily fuel cost, which is calculated by multiplying "Startup fuel consumption rates (MMBtu/start)" with the relevant fuel price ($/MMBtu), adding "Startup Cost Adder" afterwards. Every entity must submit for all startup types. The following is a general description of startup costs per startup type [51]:

Hot Startup Cost

Hot startup cost is the expected cost to start a resource that is in the "hot" condition. Hot conditions vary unit by unit, but in general, a steam unit is hot through an overnight shutdown.

Intermediate Startup Cost

Intermediate startup cost is the expected cost to start a resource that has recently been online and for which neither hot nor cold conditions are applicable.

Cold Startup Cost

Cold startup cost is the expected cost to start a resource that is in the "cold" condition. Cold conditions vary unit by unit, but in general, a steam unit is cold after a two or three-day shutdown.

In this thesis, intermediate startup costs are omitted for simplicity, only “Hot Startup Cost” and “Cold startup Cost” are used in the study. Values are obtained either from [19] --- a long term transmission study for the Department of Energy or from the “60-Day SCED Disclosure” report on ERCOT website.

Furthermore, shutdown costs are not given information and conventionally they are treated as zero in modeling. Therefore, in the case study, shutdown costs are uniformly nil.

3.2.5 NO-LOAD COSTS AND VARIABLE COSTS

According to [31]: No-Load Fuel (MMBTU/hour) is the total fuel to sustain zero net output MW at synchronous generator speed.

No-load cost is the total fuel cost to sustain zero net output MW at synchronous generator speed. Whereas, variable cost, which can also be denoted as incremental cost, is the cost per hour to operate a unit assuming a start has already occurred.

Same definitions are applied here. No-load cost is referred as “InterVarCost” and variable cost is referred as “SlopVarCost” respectively in this case study. In my case, “SlopVarCost” is the cost per MWh ($/MWh) to produce energy above the economic minimum level (minimum generation level with the unit available for economic dispatch) [31].

No-load costs and variable costs are not direct information from ERCOT, they are calculated based on the formulas below and data provided by [19] and “60-Day SCED Disclosure” reports:

$$\text{SlopVarCost} = \text{Equivalet FIP(Fuel Index Price)} * \text{Heat Rate} + \text{Variable O}\&M$$

$$\text{InterVarCost} = \text{MinGenCost} * \text{LSL} - \text{SlopVarCost} * \text{LSL}$$

For certain technologies, no “SlopVarCost” can be found straightforwardly. Public records in [20], as well as FIP[3] of 2013 are used for approximations.

In a few cases, “InterVarCost” turns out to be negative. They are dealt with case by case, aligning with a unit that has the same technology and similar capacity, meanwhile factoring in its LSL (Low Sustained Limit: Established by QSE[4] to represent the minimum amount of available generation capacity in real time, similar to HSL[5]).

To illustrate better, a numerical example is shown below:

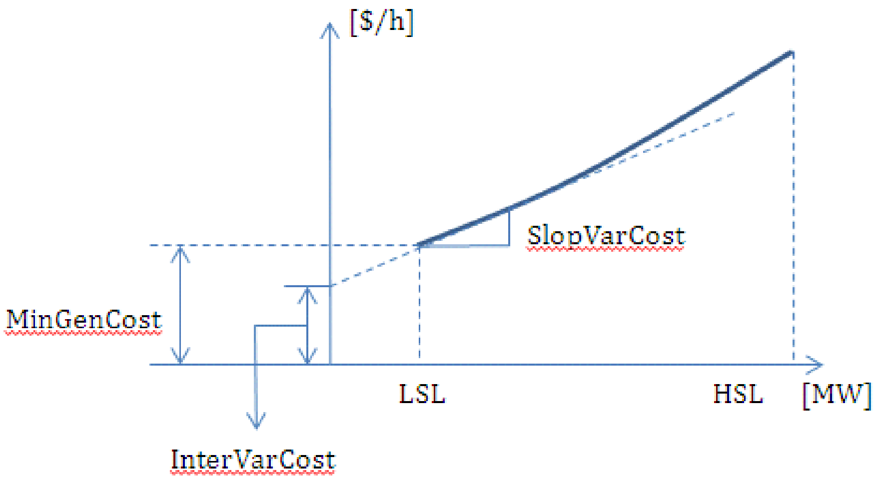


Figure 11 Approximation of "InterVarCost"

A unit of LSL=130MW, MinGenCost=36.37$/MWh and SlopVarCost=25.46$/MWh, its “InterVarCost” can be approximated by $(\mathbf{36.37 - 25.46}) * \mathbf{130} = \mathbf{1418.3}\ \$/\mathbf{h}$.

[3] FIP: Acronym for Fuel Index Price [51]
[4] QSE: Acronym for Qualified Scheduling Entity [51]
[5] HSL: Acronym for High Sustained Limit [51]

3.2.6 MINIMUM UP AND DOWN TIME

Minimum run time, also known as minimum on time (denoted as "MinUpTime" in this thesis), refers to the time the unit has to be on once it starts up and the minimum down time (denoted as "MinDwTime" hereafter) refers to the time the unit has to be off once it shuts down [3]. "MinDwTime" occurs due to intrinsic properties of generating units, for example: In the case of coal generators, units need to remain offline for a certain period of time to prevent boiler wear and damage [52]. For coal as well as for nuclear plants, a technically mandated minimum down time of 15-24 hours is imposed [53, 54]. They typically reflect the need to minimize thermal stresses in the equipment which could otherwise arise [54]. Both "MinUpTime" and "MinDwTime" can be obtained from [19] and "60-Day SCED Disclosure" reports on ERCOT official websites.

3.2.7 MAXIMUM RAMP UP AND RAMP DOWN

The maximum ramp up and ramp down limits are termed as "RampUp" and "RampDw" respectively in the case study. Increased maintenance costs can take place when there are rapid changes in temperature for thermal units. More importantly, there is a technical limitation for generating units that can safely attain when needed Therefore, proper ramp up and ramp down limits are provided by utilities for operation. As these two parameters are not readily reported, but are common across a given technology, values for all units are drawn from [19]. Note that these parameters are operating ramping rates, which are different from startup/shutdown ramping rates. In this thesis, startup/shutdown ramping rates are referred as startup and shutdown capabilities, regarding which, more details are following in Section **3.2.9**.

3.2.8 STARTUP & SHUTDOWN DURATIONS & TCOLD

Similarly to Section **3.2.4**, different startup types, implying different offline hours before new startup, result in different startup durations. Startup and shutdown durations are not considered explicit information. Therefore, generic data from [25, 27-30] are used to make sensible estimations.

Hot and Cold Startup Durations

In the case study, the two durations are referred to as “SUCDuration” and “SUHDuration”, which are defined as periods from synchronization to minimum production level for cold and hot start, respectively. The way in which final values are determined is, first to find out the time needed from synchronization to full load, then to scale it down in proportion with "$\boldsymbol{MinProd}/_{\boldsymbol{MaxProd}}$". For example, if a unit has a maximum production level of 300MW and a minimum production level of 100MW, and it needs 3 hours to *cold* startup from zero to full load, then its “SUCDuration” would be $3hr * (^{100MW}/_{300MW}) = 1hr$, suggesting this unit would need 1 hour to cold startup from producing 0MW to minimum production level.

Units are grouped by their technologies. Each technology would have quite different startup durations, while within the same technology category, each units’ startup durations are similar.

Due to previous proportional scale-down, values obtained are non-integer. On the other hand, integers are required to feed into the model, therefore, rounding off is needed as the last step.

Shutdown Durations

For shutdown durations, two methods are applied based on predefined unit types, namely “quick-start units” and “slow-start units”. Usually, units are able to shut down within a shorter period when compared to start up. As “SUHDuration” and “SUCDuration” are appropriately defined above, “SDDuration” is also easy to find.

For quick-start units,

$$\text{SDDuration} = \frac{SUHDuration+SUCDuration}{2};$$

whereas for slow-start units,

$$\text{SDDuration} = \text{SUHDuraion}.$$

"Tcold"

"Tcold" is a threshold, distinguishing hot from cold startup. If a unit were off for a period of time greater than "Tcold", then the next startup of such unit would be considered as a "cold startup", otherwise, it would be a "hot startup".

"Tcold" are different for all units. They are estimated based on two values, minimum down time and start up hot duration. In order to make sure that parameter "SUHCosts" are activated during optimization, "Tcold" needs to be greater or equal to the addition of these two values. If "Tcold" is smaller than "MinDwTime", then the unit will never have a hot startup. Therefore, for simplicity, "Tcold" are set to equal to the addition of "MinDwTime" and "SUHDuration".

3.2.9 STARTUP AND SHUTDOWN CAPABILITIES

As mentioned in the previous section, startup ramping rates are different from operating ramping rates. In this case study, they are referred to as startup and shutdown capabilities, denoted as "SURamp" and "SDRamp". These two parameters are relatively easy to find once "MaxProd", "MinProd" and hot startup durations (from 0 to full load) become known.

For units that are recognized as "quick-start" units, their startup and shutdown capabilities are simply:

$$\text{SURamp} = \text{SDRamp} = {}^{MaxProd}\!/_{HotStartupDurations(0\ to\ full\ load)};$$

for slow-start units, calculation is not even needed:

$$\text{SURamp} = \text{SDRamp} = \frac{\text{MinProd}}{one\ period}$$

In reality, SURamp and SDRamp are not readily defined. Nevertheless, this approach of deriving parameters is effective here due to inherent properties of the model used, i.e., all units are classified and modeled either as quick or slow.

3.2.10 INITIAL CONDITIONS

Two parameters in the data set, "IniProd" and "IniState" define the initial conditions for each unit. "IniProd" gives the initial production level and "IniState" represents periods that the unit has been on or off with positive and negative values correspondingly. In the case study, “IniProd” is obtained by following the procedure below:

1) As will be mentioned in the later section, two days among yearly data of 2012 are targeted which are 12th January and 25th December. Therefore, to find “IniProd”, previous days’ actual generation profiles (Please refer to Section **3.2.12** for details) are also needed which are 11th January and 24th December respectively.

2) Aggregate the two consecutive days’ actual generation (48 hours) and feed into the ramp-based UC scheduling model as demand to come up with unit commitment decisions in 48 hours. Besides, at this step, initial committed units and their production level are determined by matching quantities of each unit type to real cases (since actual generation are sorted by technology as seen in Section **3.2.12**)

3) Take commitment decisions and production level in hour 24 as “IniProd” and “IniState” for the case study.

3.2.11 Data Consistency

In general, data consistency is mostly about keeping information uniform. In the case study, the complete data are double checked to ensure coherence and logic, such that when running the optimization problem, all constraints are activated in the model.

For example, “IniProd” is smaller than or equal to the “MaxProd”, while “IniState” depends on “IniProd”, one cannot have non-zero initial production level while “IniState” suggests that the unit has been off for quite a while, i.e., with negative values. Moreover, “SlopVarCost” shall follow a logical and conventional merit order, which would imply the sequence of unit startups.

3.2.12 Energy Demand and Wind Data

Because the case study is built based on certainty, that is to say, hourly demand is also needed to run the optimization problem. Hourly generation sorted by technology are obtained for the entire 2012 year from [22]. Therefore, total demand is known and the actual wind production can be easily isolated for study. Furthermore, all wind generation is aggregated and treated as a single wind farm. That is to say, wind injection for each period is determined.

3.2.13 TRANSMISSION NETWORK

The full transmission network is built based on 2007 ERCOT network data which includes line impedances (in p.u.), shunt impedances (in p.u.) and line capacity (in MW). By matching “PSSE_Bus_number”, all generators are successfully located to individual nodes. Although, the nomenclature has changed multiple times during these years, PSSE bus numbers do not vary that much and with the help from [19], a realistic network is established.

4.0 Model Assessment

4.1 SCHEDULING AND SIMULATION STAGES

The entire case study using the proposed model consists of two stages, as shown in the **Figure 12** below. At the scheduling stage, both ramp-based unit commitment models would run, for all the three power demand profiles, as well as energy-based model would run for energy demand profile. As a result, four sets of hourly commitment decisions would be obtained. Subsequently, simulations are performed with each of these obtained commitment decisions, by solving a 5 minute dispatch problem[6]. Various numerical values can be acquired for consequential analysis.

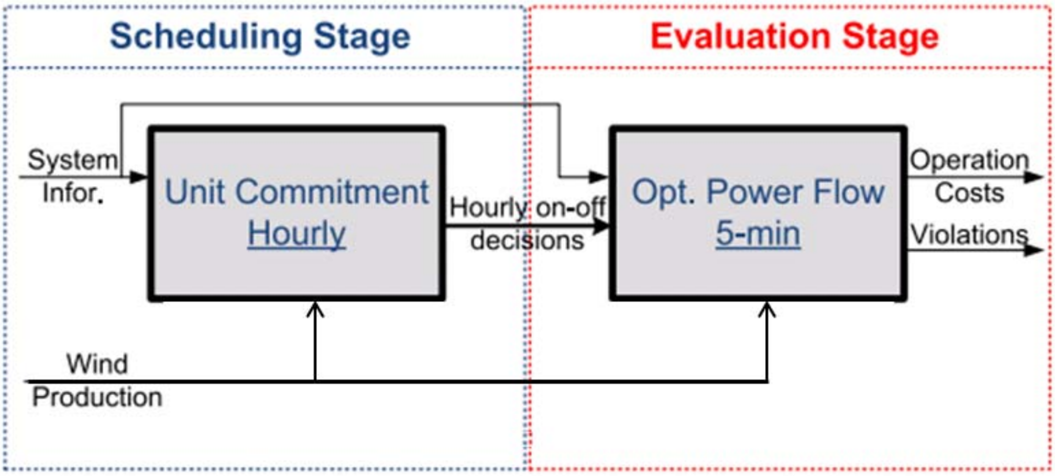


Figure 12 Scheduling and Evaluation Stages

Source: modified from [33]

Penalty costs for violations of constraints are introduced in the 5 minute economic dispatch for the purpose of imitating the high costs due to corrective actions in practical operation. A value of 10,000$/MWh is assumed to be the penalty cost for demand-balance violations. These values are also suggested in [33, 56].

The model used to perform the 5-minute dispatch is not an exact, but an approximation of the real world [33, 35, 59]. In reality, a security-constrained economic dispatch (SCED) is performed every 5 minutes to ensure system balance.

[6] Note: 5 minutes power and energy demand can all be obtained easily once hourly power and energy demand is known.

Following is a brief description of its operation in ERCOT: at first, a snapshot of the current system state taken 1 minute prior to the next 5 minutes interval is considered as the previous generation base point. Then a SCED would run and suggest what the next base point would be. Afterwards, the system has 4 minutes to adjust and adapt to the new position, and then is required to maintain at that position for 1 minute while a new snapshot would be taken [33]. Nevertheless, in the model used for case study, generators are dispatched and ramping in a linear manner from one base point to another for simplicity, see **Figure 13**, dashed line.

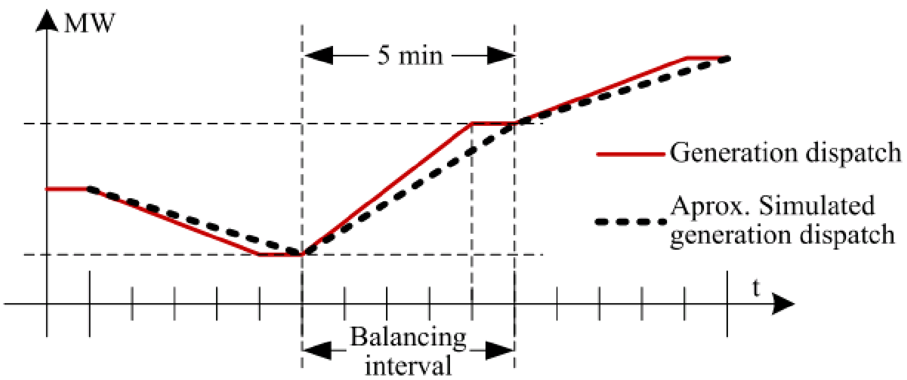


Figure 13 Generation dispatch in the Simulation Stage Vs. Reality Source: [33]

4.2 Evaluation Factors

In order to compare performance of different UC approaches, five features are looked into and compared. Two of them are with respect to the scheduling stage while three of them are related to the simulation stage. Each of them is concisely introduced as follows.

Within the scheduling stage, both 1) fixed production costs (Fixed Cost [G$]), which include no-load costs and startup/shutdown costs, and 2) number of startups (# SU) are examined. These are indicators of commitment decisions, which tell what needs to be done to prepare the system for real-time operation.

As for simulation stage, UC decisions made in the previous step are utilized. 3) dispatch costs (Dispatch Cost [G$]); 4) number of violations (# Tot) and 5) total energy that cannot be supplied or demand-balance violations (GWh), are the three main aspects examined.

5.0 Results and Analysis

In Chapter **2.0**, we have briefly introduced the two approaches and the power system used for study is presented in Chapter **3.0**. The current chapter aims at presenting results and comparisons between the traditional energy-block scheduling and ramp-based scheduling proposed in [1, 33] for UC problems.

To perform experiments with the 24 hours deterministic UC model, a whole year's actual hourly generation (hereafter, referred to as demand) is carefully examined, among which, two days are chosen eventually: one is 12th January, which is the winter peaking day with the maximum energy demand; another is 25th December, which is a day of highest wind production through the year. **Figure 14** shows the total demand and wind injection on day 12th January

One thing worth to mention here is that, instead of power demand, demand provided by ERCOT is energy demand, in the unit of MWh. Therefore, certain approximation is made to cope with that.

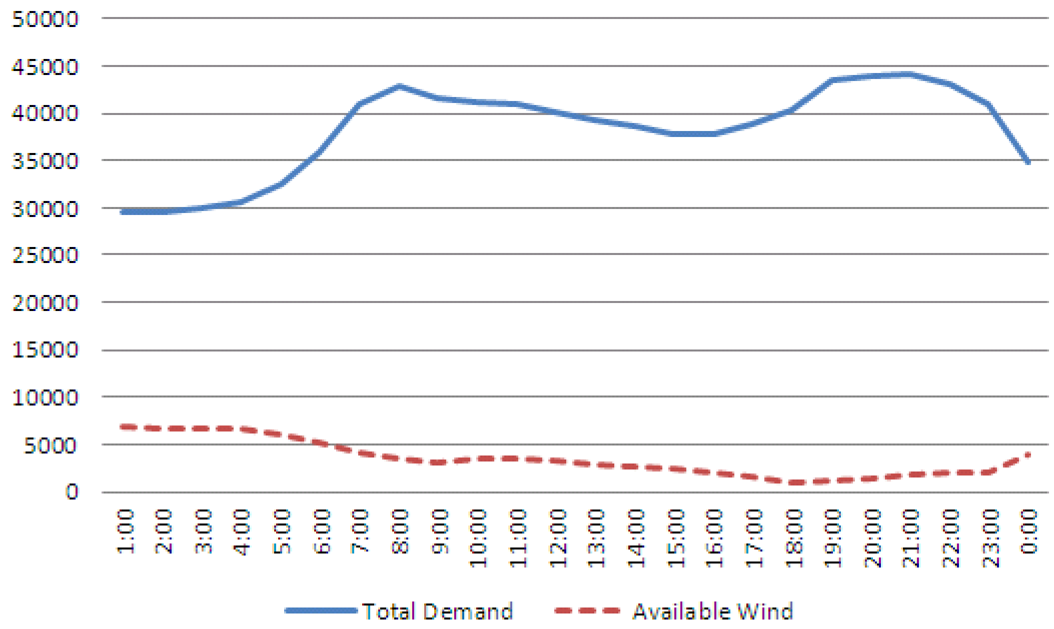


Figure 14 Total Demand and Wind Production on 12th January

Notice the difference between total demand and net demand[7].

[7] Net Demand = Total Demand – Available Wind Power

Base Case Building

Hour	0
D^{P2}	33799.59

Hour	1	2	3	4	5	6	7	8
D^{P2}	32944.17	33063.66	33563.22	34315.69	36282.31	40084.15	45785.66	47844.30
D^{E}	33371.88	33003.91	33313.44	33939.45	35299.00	38183.23	42934.90	46814.98
Hour	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**
D^{P2}	46573.54	46136.10	45905.66	44930.09	43972.22	43140.51	42377.07	42235.36
D^{E}	47208.92	46354.82	46020.88	45417.87	44451.16	43556.37	42758.79	42306.21
Hour	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
D^{P2}	43359.79	45210.30	48713.29	49235.19	49281.50	48126.29	45832.66	43665.39
D^{E}	42797.57	44285.04	46961.79	48974.24	49258.34	48703.89	46979.47	44749.02

Table 4 Power and Energy Demand of D^{P2} on Day 12th January

For both days, treating one hour as one period, a base case is built based on actual generation given by ERCOT. Power demand is not given information, and was not available as data. Therefore, energy demand, as mentioned in Section **3.2.12**, is used directly as power demand profile (hereafter, referred to as "*P2*", representing the real case), then a new energy demand profile can be created. Using the last hour of the previous day's "power demand" as initial condition, there is a total of 25 values. Power demand is considered at the end of the hour. By taking the average of two consecutive periods' power, energy demands in 24 periods are generated. See **Table 4** for an example. More details regarding data arrangement and some actual data can be found in **Appendix C**.

Now, with fixed energy demand profile, by varying the initial condition of "*P2*", two other different power demand profiles are created: one (referred to as "*P1*" hereafter) is of small initial power demand than *P2*; another has a greater initial value than *P2*, referred to as "*P3*" afterwards. In the end, with one energy demand profile, there are three totally different power demand profiles. "*P1*" and "*P3*" are shown below respectively (**Table 5** and **Table 6**).

Hour	0
D^{P1}	33684.37

Hour	1	2	3	4	5	6	7	8
D^{P1}	33059.39	32948.44	33678.44	34200.47	36397.53	39968.93	45900.88	47729.08
D^{E}	33371.88	33003.91	33313.44	33939.45	35299.00	38183.23	42934.90	46814.98
Hour	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**
D^{P1}	46688.76	46020.88	46020.88	44814.87	44087.44	43025.29	42492.29	42120.14
D^{E}	47208.92	46354.82	46020.88	45417.87	44451.16	43556.37	42758.79	42306.21
Hour	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
D^{P1}	43475.01	45095.08	48828.51	49119.97	49396.72	48011.07	45947.88	43550.17
D^{E}	42797.57	44285.04	46961.79	48974.24	49258.34	48703.89	46979.47	44749.02

Table 5 Power and Energy Demand of D^{P1} on Day 12th January

Hour	0
D^{P1}	34018.31

Hour	1	2	3	4	5	6	7	8
D^{P1}	32725.45	33282.38	33344.5	34534.41	36063.59	40302.87	45566.93	48063.02
D^{E}	33371.88	33003.91	33313.44	33939.45	35299.00	38183.23	42934.90	46814.98
Hour	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**
D^{P1}	46688.76	46020.88	46020.88	44814.87	44087.44	43025.29	42492.29	42120.14
D^{E}	46354.82	46354.82	45686.94	45148.81	43753.5	43359.23	42158.35	42454.08
Hour	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
D^{P1}	43475.01	45095.08	48828.51	49119.97	49396.72	48011.07	45947.88	43550.17
D^{E}	43141.07	45429.02	48494.57	49453.91	49062.78	48345.01	45613.94	43884.11

Table 6 Power and Energy Demand of D^{P3} on Day 12th January

Wind inputs for 25 periods (24 periods in one day plus initial condition) remain the same for all three power profiles. However, for the purpose of seeing some curtailment, wind generations for 25th December are scaled up to 1.2 times prior to all tests. Example of wind input can be found in **Appendix C**.

5.1 Results Presentation

Two scheduling approaches are applied to the system for comparison: the conventional energy-block scheduling, and the ramp-based scheduling. Traditionally, UC models aim at meeting an energy demand profile at minimum cost, and in this case study, formulation in [56] is used which is quite typical in the literature [6, 17, 33, 40, 57]. The formulation implicitly makes the power constant in each period, with jumps in power levels between periods. In contrast, ramp-based scheduling proposed in [1] draws a clear distinction between power and energy [33]. Both demand and generation are modeled by instantaneous power trajectories with hourly piecewise linear functions. Consequently, demand and therefore power output of generating units is no longer a staircase which result in power discontinuities in between periods, but is instead a smoother function that respects all ramp constraints.

5.1.1 Single Node System with Certain Wind

As mentioned in an earlier chapter, this thesis focuses on the single node system. Meanwhile, two fixed wind profiles are provided for the chosen days. That is to say, there will be no uncertainties present. Therefore, operating reserves are neither needed nor considered. The purpose is to discover, which UC strategy minimizes costs and demand violations. Hereafter, the two approaches of scheduling are entitled as "*RmpUC*" for ramp-based scheduling and "*EngUC*" for energy block scheduling correspondingly.

Table 7 and **Table 8** show the hourly power and energy demand for both days. Three different power profiles are all consistent with a unique energy demand profile. To illustrate better, **Figure 15 - Figure 18** are first shown to give a general description.

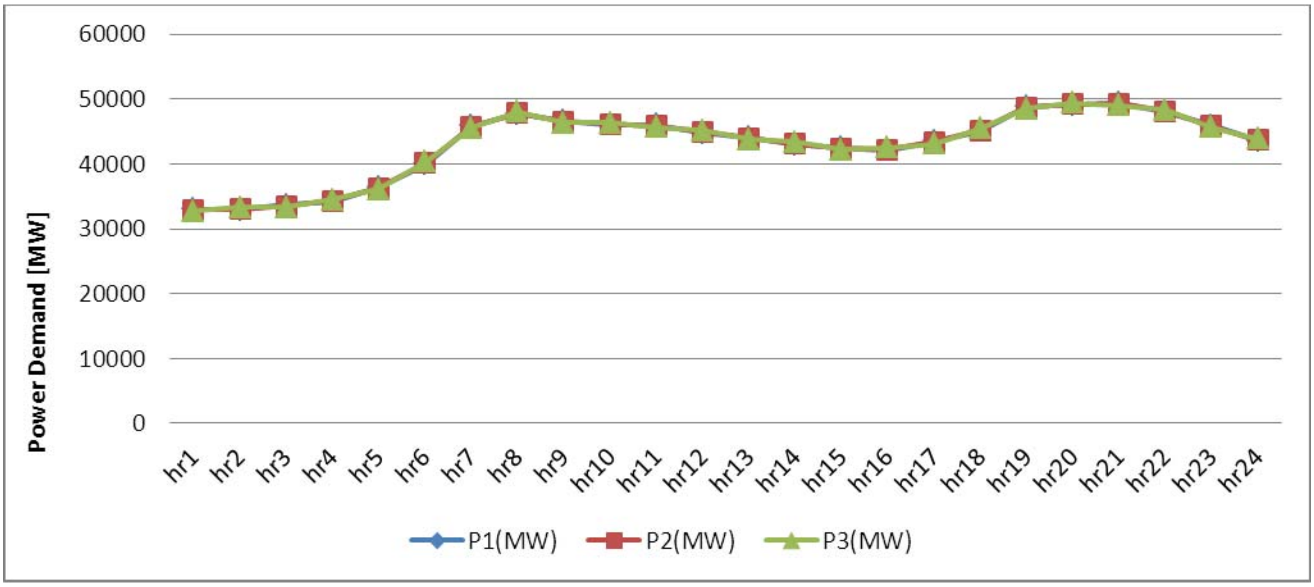


Figure 15 Power Demand Profiles of Day 12th January

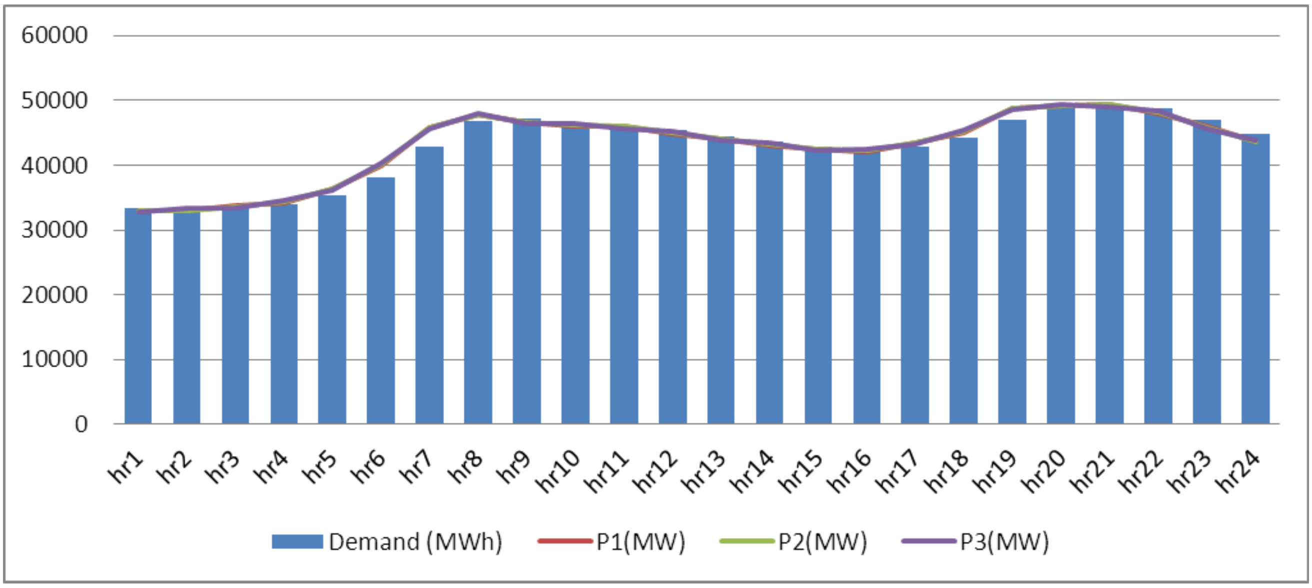


Figure 16 Power and Energy Demand Profiles of Day 12th January

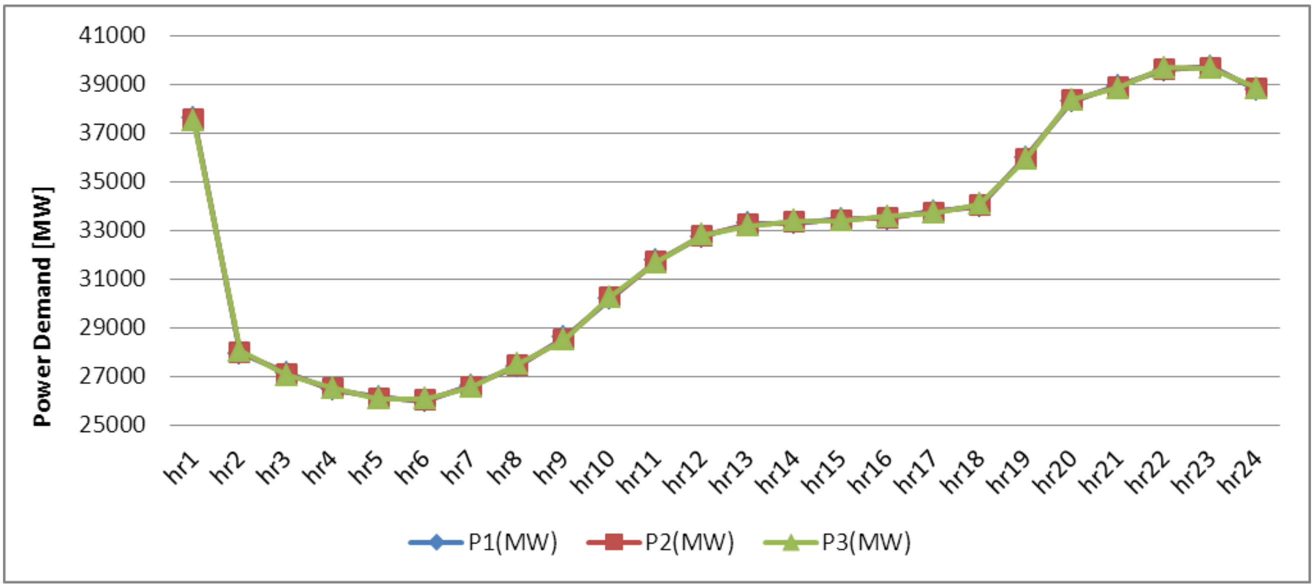


Figure 18 Power Demand Profile of Day 25th December

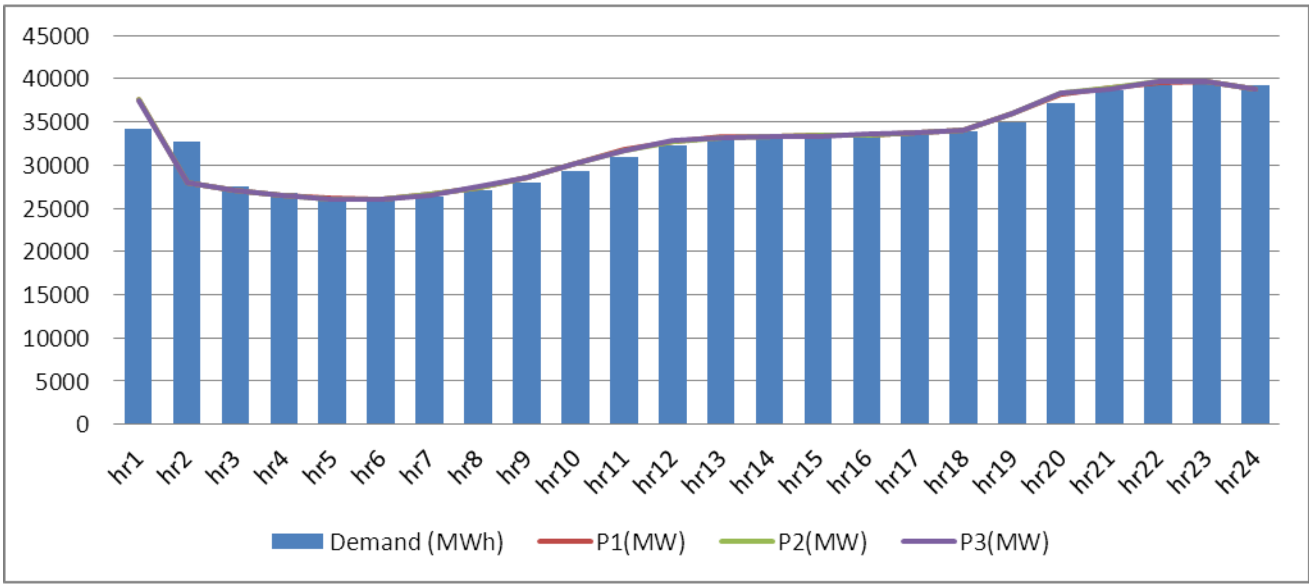


Figure 18 Power and Energy Demand Profiles of Day 25th December

5.1.2 Some Minor Contribution

Author would like to highlight a little contribution that was made in the case study before looking into the results in this section.

When doing experiments with the original model developed in [2], it was discovered that *ramp scarcity* (See end of Section **5.1.3**) would never happen as ramp availability that provided by committed units, which is a parameter can be computed from the model, is always greater than what is needed. Therefore, questions were raised.

By looking through relevant codes, a small defect was found: Instead of summing up all available ramping capability that can be provide by committed units, original code simply summed up all ramping limits of all committed units. Therefore, changes were made to the original formulas. As a result, *ramp scarcity* is observed, as seen in the next Section.

5.1.3 Discussions and Comparisons

Table 9 – **Table 16** presented following in this section are obtained by solving UC problem using *RmpUC* and *EngUC* approaches respectively and performing simulations upon acquired commitment decisions.

Hour	1	2	3	4	5	6	7	8	9	10	11	12
D^{P1}	33059	32948	33678	34200	36398	39969	45901	47729	46689	46021	46021	44815
D^{P2}	32944	33064	33563	34316	36282	40084	45786	47844	46574	46136	45906	44930
D^{P3}	32725	33282	33345	34534	36064	40303	45567	48063	46355	46355	45687	45149
D^{E}	33372	33004	33313	33939	35299	38183	42935	46815	47209	46355	46021	45418

Hour	13	14	15	16	17	18	19	20	21	22	23	24
D^{P1}	44087	43025	42492	42120	43475	45095	48829	49120	49397	48011	45948	43550
D^{P2}	43972	43141	42377	42235	43360	45210	48713	49235	49281	48126	45833	43665
D^{P3}	43754	43359	42158	42454	43141	45429	48495	49454	49063	48345	45614	43884
D^{E}	44451	43556	42759	42306	42798	44285	46962	48974	49258	48704	46979	44749

Table 7 Power and Energy Demand Profiles of Day 12th January

Hour	1	2	3	4	5	6	7	8	9	10	11	12
D^{P1}	37595	27951	27149	26440	26164	25982	26635	27398	28590	30174	31768	32730
D^{P2}	37542	28004	27096	26493	26111	26034	26582	27451	28537	30226	31716	32783
D^{P3}	37502	28044	27056	26533	26071	26075	26542	27491	28497	30267	31675	32823
D^{E}	34271	32773	27550	26794	26302	26073	26308	27017	27994	29382	30971	32249

Hour	13	14	15	16	17	18	19	20	21	22	23	24
D^{P1}	33274	33289	33475	33475	33794	33979	35997	38272	38936	39584	39741	38753
D^{P2}	33222	33342	33423	33528	33742	34032	35944	38324	38883	39637	39688	38806
D^{P3}	33181	33382	33382	33568	33701	34072	35904	38365	38843	39677	39648	38846
D^{E}	33002	33282	33382	33475	33635	33887	34988	37134	38604	39260	39663	39247

Table 8 Power and Energy Demand Profiles of Day 25th December

Note: D^{P1}, D^{P2} and D^{P3} indicate power [MW] at the end of the hour, which represent the same energy profile; D^{E} refers to total energy demand [MWh] for the hour

Approach	Demand	Fixed Cost [G$]	Dispatch Cost [G$]	Total Cost[8] [G$]	# SU[9]	Total Demand [GWh]
RmpUC	D^{P1}	7.682	28.598	36.279	106	1027.645
	D^{P2}	7.673	28.603	36.275	106	1027.645
	D^{P3}	7.690	28.604	36.293	113	1027.645
EngUC	D^{P1}& D^{P2} & D^{P3}	7.747	28.684	36.431	82	1027.645

Table 9 Scheduling Results for different demand profiles for Day 12th January

Approach	Demand	Fixed Cost [G$]	Dispatch Cost [G$]	Total Cost [G$]	# SU	Total Demand [GWh]
RmpUC	D^{P1}	3.975	16.613	20.588	26	777.243
	D^{P2}	3.968	16.618	20.586	27	777.243
	D^{P3}	3.973	16.612	20.585	26	777.243
EngUC	D^{P1}& D^{P2} & D^{P3}	3.882	16.749	20.631	20	777.243

Table 10 Scheduling Results for different demand profiles for Day 25th December

Table 9 and **Table 10** above are results obtained in scheduling stages. Notice here *EngUC* would give the exact same solution for D^{P1}, D^{P2} and D^{P3} because they they correspond to the same energy demand, while on the other hand, due to different power demand, different commitment decisions are acquired.

When comparing the two tables, note that find that fixed costs arising from *EngUC* are not necessarily higher than those of *RmpUC*. Yet, dispatch costs seem to be generally lower with the *RmpUC* approach. Consequently, # SU is also higher for ramp-based scheduling. That can be explained as *RmpUC* requires more startups of units to better prepare the system: while *EngUC* would only need to satisfy energy demand, *RmpUC* must satisfy both power and energy profiles. For total cost which is the summation of fixed cost and dispatch cost, *EngUC* seems to be always less cost-effective than *RmpUC* because more startups are required.

Table 11 - **Table 13** indicate ramp requirements (first row of each table) which is calculated by subtracting current period's demand from the next period's demand, for all power demand profiles for the day 12th January, as well as ramps that were available for both *RmpUC* and *EngUC* approaches (second and third rows). **Table 14** - **Table 16** show the same parameters, but for day 25th December.

[8] Total Cost = Fixed Cost + Dispatch Cost
[9] # SU: number of startup of units.

Hour	1	2	3	4	5	6	7	8	9	10	11	12
D^{P1}	-1008	43	696	700	2703	4460	6921	2613	-626	-1118	-89	-916
RmpUC	-6167	5411	5029	4327	3001	5376	6921	2613	-15362	-14681	-14312	-14331
EngUC	-5312	6904	6615	6234	6922	8802	6921	194	-14900	-14636	-14522	-13824

Hour	13	14	15	16	17	18	19	20	21	22	23	24
D^{P1}	-267	-959	-181	-80	1759	2284	3549	-3	-122	-1554	-2083	-2387
RmpUC	-14127	-13440	-12926	-12830	2875	3609	3549	-16815	-16784	-16668	-15753	-14776
EngUC	-13324	-13324	-13291	-12690	2954	3556	3468	-16660	-16660	-16547	-15844	-13707

Table 11 Ramp Requirements of D^{P1} for Day 12th January

Hour	1	2	3	4	5	6	7	8	9	10	11	12
D^{P2}	-1238	273	466	931	2473	4690	6691	2843	-857	-888	-320	-686
RmpUC	-6167	5749	5324	4371	2765	5424	6691	2843	-15426	-14694	-14332	-14312
EngUC	-5312	6539	6317	6111	6593	8801	6691	187	-14900	-14636	-14522	-13975

Hour	13	14	15	16	17	18	19	20	21	22	23	24
D^{P2}	-498	-728	-412	151	1529	2515	3319	228	-352	-1324	-2313	-2156
RmpUC	-14168	-13440	-12926	2165	2874	3090	3319	228	-16838	-16569	-15219	-14851
EngUC	-13324	-13324	-13116	2484	2954	3556	3319	8	-16660	-16489	-15599	-13903

Table 12 Ramp Requirements of D^{P2} for Day 12th January

Hour	1	2	3	4	5	6	7	8	9	10	11	12
D^{P3}	-1676	711	28	1368	2035	5128	6253	3281	-1294	-450	-757	-248
RmpUC	-6075	5942	5587	4756	3083	5271	6253	3281	-15368	-14829	-14376	-14385
EngUC	-5312	6606	6182	6230	7330	8426	6253	138	-14900	-14636	-14559	-14299

Hour	13	14	15	16	17	18	19	20	21	22	23	24
D^{P3}	-935	-291	-849	588	1091	2952	2881	665	-789	-886	-2751	-1719
RmpUC	-14405	-13440	-12940	2449	2079	2952	2881	678	-16996	-16494	-15007	-14984
EngUC	-13324	-13324	-13291	2484	2954	3504	2881	8	-16660	-16214	-15208	-14253

Table 13 Ramp Requirements of D^{P3} for Day 12th January

Hour	1	2	3	4	5	6	7	8	9	10	11	12
D^{P1}	6469	-9072	435	-505	-75	-469	-383	-837	-386	842	1039	999
RmpUC	6719	-9948	6370	-8278	-7099	-6600	-6192	-6108	-6108	3511	1371	1071
EngUC	5566	-9957	5728	-7617	-6541	-6432	-6432	-6432	-6432	4266	3760	1099

Hour	13	14	15	16	17	18	19	20	21	22	23	24
D^{P1}	187	-311	102	40	400	317	2466	2342	469	836	426	279
RmpUC	741	-6979	741	741	732	1295	2466	2342	1134	838	426	279
EngUC	874	-6869	874	874	1235	2106	4029	2342	995	964	426	0

Table 14 Ramp Requirements of D^{P1} for Day 25th December

Hour	1	2	3	4	5	6	7	8	9	10	11	12
D^{P2}	6363	-8967	329	-400	-181	-363	-488	-732	-491	948	934	1105
RmpUC	6703	-10023	6191	-8222	-7065	-6600	-6192	-6108	-6108	3519	1592	1235
EngUC	5566	-10034	5775	-7617	-6541	-6432	-6432	-6432	-6432	4505	3598	1105

Hour	13	14	15	16	17	18	19	20	21	22	23	24
D^{P2}	82	-206	-4	145	294	423	2361	2447	363	942	320	384
RmpUC	741	-6874	-6767	634	634	1319	2361	2447	922	942	667	384
EngUC	874	-6763	-6656	874	1235	2106	4468	2447	995	1070	572	0

Table 15 Ramp Requirements of D^{P2} for Day 25th December

Hour	1	2	3	4	5	6	7	8	9	10	11	12
D^{P3}	6283	-8886	249	-319	-261	-283	-569	-651	-572	1028	853	1185
RmpUC	6687	-9953	6034	-8355	-7023	-6600	-6192	-6108	-6108	2745	1820	1264
EngUC	5566	-9965	5488	-7617	-6541	-6432	-6432	-6432	-6432	4566	4082	1185

Hour	13	14	15	16	17	18	19	20	21	22	23	24
D^{P3}	1	-125	-84	226	214	503	2280	2528	283	1022	240	465
RmpUC	741	-6813	-6787	741	634	1324	2280	2528	1252	1022	393	465
EngUC	874	-6809	-6656	874	1251	2106	4389	2528	995	1150	726	0

Table 16 Ramp Requirements of D^{P3} for Day 25th December

Total ramp available of all committed units constitute the ramp schedules. Positive and negative values refer to upward and downward ramps correspondingly.

Not surprisingly, *RmpUC* has satisfied all various power demand profiles in both days, whereas *EngUC* results in non-energy supplied in multiple places. In **Table 11-Table 16**, cells highlighted in dark red indicate that the required ramp cannot be provided by committed units in that period. Cells highlighted in dark blue show that such scheduling just provide enough ramp availability to satisfy the ramp demands, that is to say, what is desired is exactly covered by committed units. Although it happens to *RmpUC* formulation as well: what is available is exactly the same as the demand of ramps, *RmpUC* is able to guarantee that enough ramp capabilities are always there when needed.

This is due to the reason that, although a unique energy profile can be derived from a given power profile, given an energy profile there are infinitely many possible power profiles [1, 33, 41, 60]. Meeting requirement of a power profile automatically satisfies the corresponding energy profile, yet this is not the case vice-versa. Thus, *EngUC* approach can result in a number of violations [1, 2].

All periods that marked in dark red, i.e., indicating ramp shortage, are supposed to have energy non-supplied. This is consistent with the information in the .gdx[10] file. Simulation stage is essentially a 5 minute economic dispatch; therefore 24 hours would give rise to 288 sub-periods in total.

[10] .gdx: A file with suffix .gdx, is a file that stores the values of one or more GAMS symbols such as sets, parameters variables and equations.

Period that ENS occurs	ENS [MW]
p95	110.681
p96	332.044
p97	400.976
p98	318.227
p99	236.227
p100	154.228
p101	72.228
p102	15.614
p237	6.679
p238	22.520
p239	40.843
p240	59.166
p241	53.329
p242	23.331
p243	4.166

Table 17 Energy non-supplied of D^{P2} of Day 12th January

Values shown on the first row of **Table 12** are ramps required from generating units moving from current period to the next. What units are able to supply are shown in the lower part of the table. Therefore, energy non-supplied would appear around the point when available ramp is smaller than what is needed. For one example, sub-period p96 (shown in **Table 17**) is the end of period 8, in which ramp shortage occurs. Consequently, energy demand cannot be met starting from the end of period 8 and extends to period 9. Similar observations can be found in period 20 as well.

One interesting observation worth mentioning is that, for day 12th January, five times out of six in all three power demand profiles, it appears to be: prior to the happening of ramp scarcity, one period before it would have just enough ramp scheduled to cover the demand. This observation suggests that the ramp-based UC model has made a decision itself while performing optimization, to use available ramp in the previous period instead of the following one. In this way, operational cost could be lower. I will still use period 8 of D^{P2} of Day 12th January as an example. As one can see in period 7, ramp scheduled is equal to the demand; which has left ramp available in period 8 is not even 7% of what is desired. One could expect, if the system stays in need of upward ramps in the subsequent periods, more energy non-supplied could appear.

Again, looking at period 9 of D^{P2} of Day 12th January, it requires a downward ramp which has released the system from running out of upward ramp capability.

For day 25th December, ramp shortages appear at the beginning of all three power demand profiles, as well as period 24. Two initial conditions with different unit sets and production levels are applied, both gave similar outcomes. Although, initial condition is carefully chosen to cover the requirement of energy demand in the first period, energy non-supplied could be the reason that, again *EngUC* overestimates units' ramping capability, i.e., fewer units may produce at a high level to fulfill energy demand profile, nevertheless, available ramp is limited from one period to another in this case. Ramp fulfillments of D^{P2} and D^{P3} show a similar pattern. What happened in period 8 of D^{P2} of Day 12th January as mentioned in the previous paragraph also appears in period 24 of D^{P1} on 25th December. **Table 18** below shows all energy non-supplied of D^{P2} on 25th.

Period that ENS occurs	ENS [MW]
p01	28.969
p02	141.538
p03	312.916
p04	488.475
p05	673.230
p06	870.003
p07	1089.030
p08	1337.583
p09	1596.786
p10	1856.545
p11	2120.264
p12	2394.647
p13	2189.913
p14	1509.216
p15	852.010
p16	265.113
p283	8.189
p284	32.391
p285	64.416
p286	96.440
p287	128.465
p288	160.490

Table 18 Energy non-supplied of D^{P2} of Day 25th December

Table 19 and **Table 20** following are results obtained in the simulation stage. Commitment decisions came out of the deterministic UC model are used to perform a 5 minute economic dispatch.

As seen before in the scheduling stage, fixed cost and total cost are not necessarily lower with *EngUC* approach than with *RmpUC*. Despite slightly higher dispatch costs with *RmpUC*, operational costs are considerably lower with ramp-based scheduling. It implies that savings from unit production and penalty has well compensated costs resulted from more startups, as suggested in **Table 9** and **Table 10**.

In **Table 19** and **Table 20**, costs due to energy non-supplied is recorded, operational costs are different mostly because of these costs. It should be noted that this is a deterministic model, therefore no operating reserve is considered. That entails even more expenses for energy based scheduling due to demand-balance violations.

Furthermore, operational costs result from *RmpUC* and *EngUC* can be further apart. On 12^{th} January, they are quite similar, however, when compared for day 25^{th} December, operational costs derived from *EngUC* are almost twice as much as those from *RmpUC*. This is all as a result of high penalty cost of violations.

As described in earlier sections, Day 25^{th} December is a day with much more wind, resulting in lower total costs as a whole. Nonetheless, it seems that energy block scheduling is not good at dealing with system with lots of wind. Violation costs appear to be considerably higher than those on 12^{th} of January.

Notice thus far that only cases with certainties are inspected, and there has been no consideration of the range of uncertainties that could have happened in real life. Presumably, in a system like ERCOT, with such a high penetration of wind, energy based UC approach applied in the day-ahead market may require considerable reserves to function effectively. More detailed results are shown in **Appendix D**.

Approach	Demand	Fixed Cost [G$]	Dispatch Cost [G$]	Total Cost [11][G$]	Violations			Operational Cost[12] [G$]
					# Tot[13]	ENS[14] [GWh]	Cost[15] [G$]	
RmpUC	D^{P1}	7.669	28.594	36.263	0	0	0	28.594
	D^{P2}	7.661	28.600	36.261	0	0	0	28.600
	D^{P3}	7.677	28.605	36.282	0	0	0	28.605
EngUC	D^{P1}	7.734	28.548	36.282	8	0.0957	0.9569	29.505
	D^{P2}	7.736	28.544	36.280	13	0.1542	1.5419	30.086
	D^{P3}	7.747	28.534	36.280	18	0.3422	3.4217	31.955

Table 19 Simulation Results (5 min Economic Dispatch) for different demand profiles of Day 12th January

Approach	Demand	Fixed Cost [G$]	Dispatch Cost [G$]	Total Cost [G$]	Violations			Operational Cost [G$]
					# Tot	ENS [GWh]	Cost [G$]	
RmpUC	D^{P1}	3.975	16.608	20.583	0	0	0	16.608
	D^{P2}	3.968	16.614	20.582	0	0	0	16.614
	D^{P3}	3.973	16.609	20.582	0	0	0	16.609
EngUC	D^{P1}	3.882	16.608	20.490	21	1.518	15.181	31.788
	D^{P2}	3.882	16.608	20.490	21	1.518	15.181	31.789
	D^{P3}	3.882	16.609	20.491	21	1.518	15.181	31.789

Table 20 Simulation Results (5 min Economic Dispatch) for different demand profiles of Day 25th December

[11] Total Cost = Fixed Cost + Dispatch Cost
[12] Operational Cost = Dispatch Cost + Cost (of violations)
[13] # Tot stands for “number of total violations”
[14] ENS: Energy Non-Supplied
[15] Cost (of violations) = ENS [GWh] · 10,000 $/MWh

When comparing **Table 9** and **Table 10** versus **Table 19** and **Table 20**, dispatch costs resulting from the simulation stage are lower than those from scheduling stage. This is because more flexibility is provided with 5 minute dispatch, as in the simulation stage, than with 1 hour dispatch, as in the scheduling stage.

Overall, conventional unit commitment approach based on energy-block seems not to function appropriately in terms of meeting demand profiles. The complete case study has suggested that *EngUC* could give rise to a high dispatch cost (see **Table 20**) due to violations of demand-balance constraint. Three major causes are [33]:

1. Ramp Scarcity: the energy profile does not uniquely specify the power profile. Thereby, energy block scheduling is not able to guarantee that there are ramp capabilities to cope with all power profiles.
2. Infeasible Energy Delivery: due to ramp scarcity, the resulting energy profile from *EngUC* may not be feasible. Therefore, it may be that not enough energy could be delivered when needed.
3. Deterministic Unplanned Events: Significant amount of unallocated energy due to neglecting of startup and shutdown power trajectories of thermal units could exert impacts on the entire demand-supply balance. Consequently, inefficiency arises from deployment of generating resources [2].

5.1.4 Some Remarks about Wind

It is mentioned previously, the 25th of December is a day with maximum wind production through the whole 2012 year. And the ramp-based UC model used for case study includes wind curtailment ability. In order to have some observations of wind, the original hourly wind injection was scaled up 1.2 times.

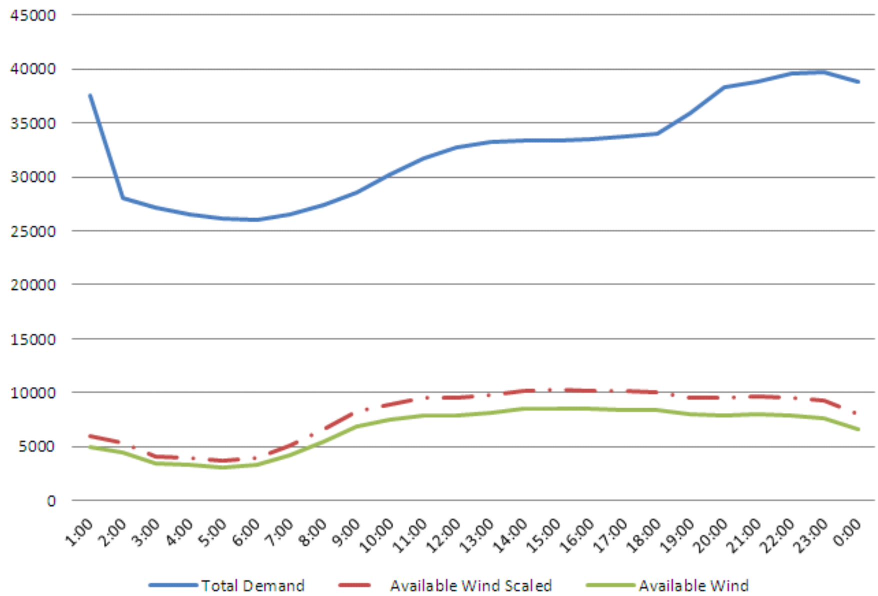
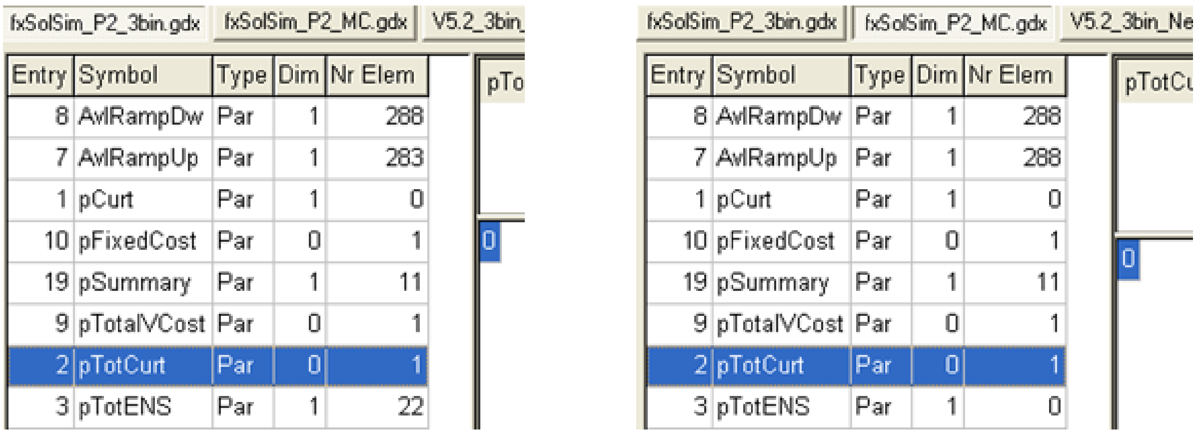


Figure 19 Total Demand and Wind Production on 25th December

Figure 19 shows the total demand versus wind productions. Two wind profiles are presented above; the one used in the study is the red dash-dot line. Taking D^{P2} of 25^{th} December as an example again, below is a screen capture of .gdx files showing total curtailment of wind.



fxSolSim_P2_3bin.gdx | fxSolSim_P2_MC.gdx | V5.2_3bin_

Entry	Symbol	Type	Dim	Nr Elem
8	AvlRampDw	Par	1	288
7	AvlRampUp	Par	1	283
1	pCurt	Par	1	0
10	pFixedCost	Par	0	1
19	pSummary	Par	1	11
9	pTotalVCost	Par	0	1
2	pTotCurt	Par	0	1
3	pTotENS	Par	1	22

pTo
0

fxSolSim_P2_3bin.gdx | fxSolSim_P2_MC.gdx | V5.2_3bin_Ne

Entry	Symbol	Type	Dim	Nr Elem
8	AvlRampDw	Par	1	288
7	AvlRampUp	Par	1	288
1	pCurt	Par	1	0
10	pFixedCost	Par	0	1
19	pSummary	Par	1	11
9	pTotalVCost	Par	0	1
2	pTotCurt	Par	0	1
3	pTotENS	Par	1	0

pTotCu
0

Figure 20 Wind Curtailment of *EngUC* (left) and *RmpUC* (right) approaches

Results demonstrate that there are no curtailments for each of the three power demand profiles. Although this day has the maximum wind injection through the year, it may still not achieve a point where curtailment is needed. After scaling up, 30% is the highest level that wind generations contribute; unscaled it was around 25%. Another reason may be neglect of network constraints.

It would seem that, continuing scaling up of wind production eventually could cause somewhat curtailment.

5.2 COMPUTATIONAL ASPECT

5.2.1 *ENGUC* VS. *RMPUC*

Approach	Constraints	Nonzero Elements	Continuous Variables	Binary Variables
RmpUC	66141	272350	21288	34783
EngUC	102566	589304	28248	21448

Table 21 Problem Size of *EngUC* & *RmpUC* on 12th January

Approach	Constraints	Nonzero Elements	Continuous Variables	Binary Variables
RmpUC	66141	272256	21288	34725
EngUC	102566	589864	28248	21455

Table 22 Problem Size of *EngUC* & *RmpUC* on 25th December

Table 21 and **Table 22** compare the problem size, essentially formulation of *EngUC* and *RmpUC* approaches. It seems that *EngUC* presents way larger number of constraints and nonzero elements and somewhat more continuous variables than *RmpUC*, despite the fact that *RmpUC* formulation includes units' startup and shutdown power trajectories. However, there exist few binary variables within *EngUC* formulation. This is because the ramp-based scheduling model used is built upon tight and compact formulations [16, 33, 38], while extra binary variables are for modeling variable startup costs [33, 61].

Although both approaches intrinsically only need commitment variables to be defined as binary as other variables take binary variables automatically, even if they are defined as continuous variables, [33, 38, 40] argue that it is convenient to define variables as binary to fully exploit the solver.

Approach	Demand	CPU Time [s]	Iterations	Nodes Explored
RmpUC	D^{P1}	9,781	21430	101
	D^{P2}	6,037	15367	EPS[16]
	D^{P3}	17,534	34717	493
EngUC	D^{P1}& D^{P2} & D^{P3}	1419,281	568154	10984

Table 23 Computational Burden of *EngUC* & *RmpUC* on 12th January

Approach	Demand	CPU Time [s]	Iterations	Nodes Explored
RmpUC	D^{P1}	6,848	14466	EPS
	D^{P2}	5,148	10106	EPS
	D^{P3}	5,491	11601	EPS
EngUC	D^{P1}& D^{P2} & D^{P3}	1898,969	1822832	22896

Table 24 Computational Burden of *EngUC* & *RmpUC* on 25th December

For an MIP formulation, problem size and tightness combined, define its computational burden [33, 38, 63, 64]. All experiments are performed on an Intel-i7 3.4-GHz personal computer with 16GB of RAM memory. [33, 58] **Table 23** and **Table 24** show an impression on the computation of the different models. As stated in [33], *RmpUC* is tighter formulation than *EngUC*. Therefore, it could find its solutions faster than *EngUC*.

5.2.2 TIGHT *ENGUC*

The mathematical formulation used in this study originated from [56], which is quite common in UC literatures [6, 17, 33, 40, 57]. In addition, some tests are also carried out with a tight and compact formulation proposed in [38]. This "Tight *EngUC*" is meant to solve energy block UC more efficiently. Hence, this small section is dedicated to do a small comparison on computational aspect, between the two formulations for energy block scheduling.

[16] The entry "EPS", which stands for epsilon, means very small but nonzero. [62]

Approach	Constraints	Nonzero Elements	Continuous Variables	Binary Variables
Tight EngUC	53907	226712	6984	34839
EngUC	102566	589304	28248	21448

Table 25 Problem Size of *Tight EngUC* & *EngUC* on 12th January

Approach	Constraints	Nonzero Elements	Continuous Variables	Binary Variables
Tight EngUC	53907	226622	6984	34784
EngUC	102566	589864	28248	21455

Table 26 Problem Size of *Tight EngUC* & *EngUC* on 25th December

Table 25 and **Table 26** indicate the problem size for both days. Apart from binary variables, *Tight EngUC* appears to possess more advantages: constraints, nonzero elements and continuous variables are many more with *EngUC* than with *Tight EngUC*.

Approach	CPU Time [s]	Iterations	Nodes Explored
TightEngUC	10.562	22497	35
EngUC	1419.281	568154	10984

Table 27 Computational Burden of *Tight EngUC* & *EngUC* on 12th January

Approach	CPU Time [s]	Iterations	Nodes Explored
TightEngUC	5.85	12153	EPS
EngUC	1898.969	1822832	22896

Table 28 Computational Burden of *Tight EngUC* & *EngUC* on 25th December

Computational burdens are illustrated above respectively in **Table 27** and **Table 28**. Apparently, *Tight EngUC* has improved on *EngUC* overwhelmingly. Depending on particular sets of data, the tight and compact formulation of UC is at least more than 100 times faster than normal energy block formulation. It leads to the conclusion that computational efficiency could be better achieved through more tight and compact formulation of models.

6.0 Conclusion and Future Work

The essential objective of this master thesis is to compare the two different unit commitment formulations; one is ramp-based scheduling and another is conventional energy block scheduling. In order to do so, ERCOT is chosen for this case study. What has been said about ERCOT is that: it is an independent system, which is small enough to study, but big enough to matter, which this is what makes it appealing to researchers.

6.1 Conclusions

This thesis presented comparisons between a new UC scheduling approach, which is based on power trajectories, and conventional energy-block based UC scheduling. Drawbacks of implicit assumptions in the traditional UC formulations are also demonstrated. Since this entire case study is built on the basis of a realistic system, all results obtained are of practical sense.

Ramp-based scheduling has better prepared the system for the 5 minute dispatches. This case study has assumed all information is given, and has ignored uncertainties. Taking into account startup and shutdown power trajectories helps avoid ramp scarcity and infeasible energy delivery, unlike energy-block scheduling, which could have jeopardized entire system overestimating ramp capabilities.

Moreover, wind energy penetration has been increasing worldwide. UC scheduling based on power appears to manage the situation better as compared with the conventional approach.

To sum up, unit commitment algorithm for market clearing should be based on power instead of energy. Actual power trajectories need to be taken into consideration, as well as startup and shutdown power trajectories must be incorporated.

6.2 Future work and Extensions

Due to time limitation, this case study could not continue with more experiments. But one can carry on future work about some aspects brought up below.

Although tests performed thus far do not have networks involved, trials were still conducted for curiosity. With prior worries about the computation power of existing machine, the program ended up with a “running out of memory” warning. It is related to inverse a matrix of gigantic size. There are some present algorithms, regarding decoupling matrices and matrix inversion techniques [68-71]. This could be one way of continuing, another is to look into the original network data, trying to find a way to simplify it without losing information.

Secondly, as described in previous sections, there is some work left with wind. There are no observations of wind curtailment in my study. One can continue investigating how the models react with variations of wind injections. Moreover, among all kinds of intermittent energy, wind is a quite common one. The case study could be extended to include more energy sources of this kind.

Finally, the case study assumed that everything is known. Later on, one could continue the study by taking uncertainties into consideration, performing experiments under different frameworks, such as robust framework and stochastic framework. This could give more aside information about commitment strategies.

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Appendix A

For cases or units that are not mentioned explicitly in this section, they either have direct information given from a credible source or sensible estimations can be created by benchmarking. Mode facts on data are presented following:

Ramp limits ("RampUp" and "RampDw"):

For wind farms, there is a limit of Base Point deviation which for wind generation is 20 % deviation from the base point (as opposed to generator base point deviation limit of 10%) and the base point is issued based on persistence for the next 5 minutes [19]. That is to say, wind farms cannot violate base point deviation limit, the ramp over 5 minutes cannot be higher than 20% of the previous base point. Since in ERCOT's "60-Day SCED Disclosure", base points for each wind farm are given, the ramp limits can be therefore calculated.

For hydro power plants, [21] states that ramp rate is "10 minutes to full load" for both conventional hydro and pumped storages. Hence, all hydro units are of ramp limits of six times their capacities.

A ramp rate of 0.66%/min, which is equivalent to 39.6%/hr is applied to all combined cycle units [22].

Durations ("SUHDurations", "SUCDurations" and "SDDurations")

Since hot and cold startup durations are scaled down, fractional numbers appear. As mentioned in previous chapters, rounding is needed. For durations end up less than one, they are all discretized to one. For numeric values greater than one, appropriate rounding is applied. Finally, it becomes an integer.

Appendix B

This appendix provides a general description of short term planning, including unit commitment. One can refer to [18], which is the basis of this section, for more details.

In a regulated electric industry, the primary purpose of central operator is to satisfy load while minimizing costs. Therefore, choosing wisely among all options is critical. Operating models are commonly used to pre schedule, simulate, etc.

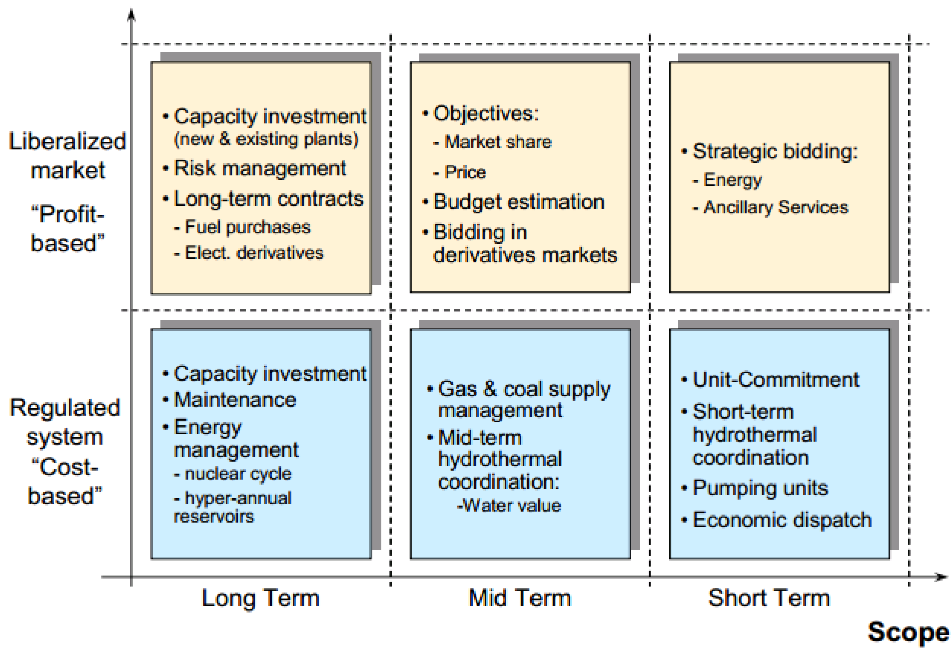

Figure 21 Functions covered by different types of models Source: [33]

Models are arranged in terms of the time scope of the decision variables involved forming a hierarchy, such that solutions can be fed into others if obtained from higher ranking model. The **Figure 21** above is a summary of functionalities of models depending on time horizons.

Since this thesis focuses on short term planning, to be more specific, unit commitment (UC) in a regulated business, more concentration is put on this weekly schedule problem, also known as unit commitment. Economic dispatch is also one kind of short-term planning, where decisions on generators' output level are made after unit commitment has decided the generators' status to be on/off.

Formulations could either include hydro units or not. However, they are modeled in another way, different from thermal units since they have storage capabilities. This is what makes the concept "water value". The objective of UC is to obtain an hourly schedule for all generators weekly ahead or one day ahead. In the cases where hydroelectric plants are present, decisions need to be made on how to allocate limited water resources to achieve maximum efficiency. Moreover, short-term models sometimes need to receive input from medium- or long- term models to achieve optimally management.

Intensive researches have been done on the unit commitment problem, various techniques are proposed and used to solve this problem. Please refer to Section 2.2 of [18] for more information.

Model Assumptions

1) The transmission grid is not included in the model (single node approach), moreover, different operating modes (must-run, must-run at full load) are used to oblige certain units to produce when required to accommodate grid constraints.

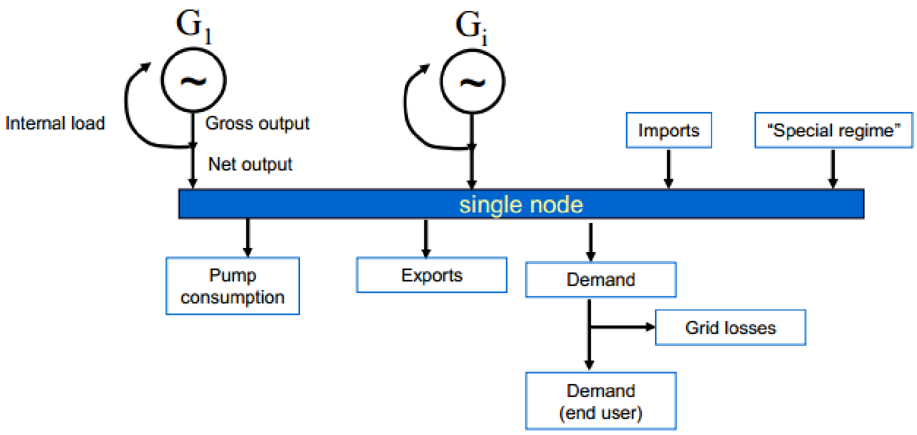

Figure 22 Schematic Illustration of Single Node System

2) The chronological evolution of the system hour-by-hour must be modelled: A time-wise representation of hourly periods is used.

3) A thermal unit is allowed to start up or shut down at any time of day: The solver may be "helped" by limiting the standard startup and shutdown times to eliminate binary variables.

4) An equivalent aggregate model is used for each catchment basin.

Note assumption 4) is for models including hydro units. In addition to model assumptions, unit constraints also need to be paid much attention.

Thermal Units Constraints

Gross and net power

They are usually related through a coefficient k, also named as auxiliary load factor [18]:

$$Net\ Power = Gross\ Power \times k$$

Maximum and Minimum Output Limits

Thermal units can produce neither above their maximum capacity nor below their minimum stable load.

Ramping Constraints

They are also called gradient constraints, limiting rates of changes of power output in two consecutive periods.

Logical Consistency Constraints relating Startups and Shutdowns

They are formulated in a way such that startup and shutdown decisions could not be made simultaneously.

Minimum Up and Down Time

This is an operational constraint, requiring units to remain on or off for a certain number of hours after start-up or shutdown before being shut off or started up again, respectively. They are meant to prevent boiler wear and damage caused by changes in temperature.

Cost Considerations

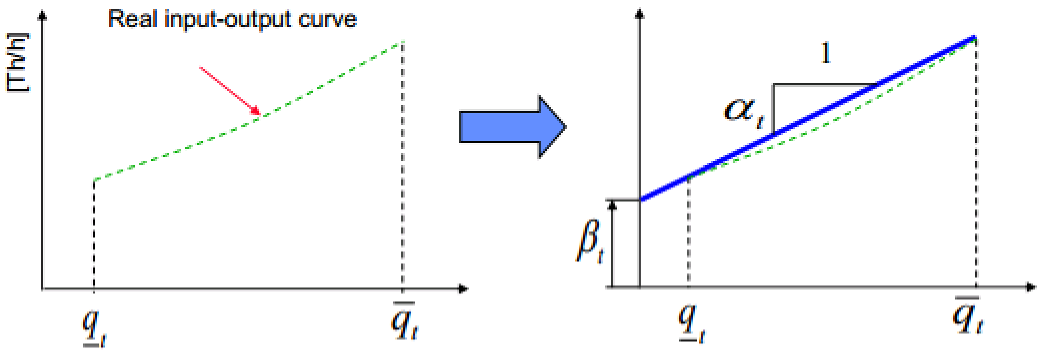

Figure 23 relating fuel expenditure with unit gross output

Simplifications are applied, assuming linear relationship between fuel expenditure and unit output. Operation and maintenance (O&M) costs are generally seen as proportional to the gross output. More information on costs approximation can be found in [18] and many other places.

Hydro Units Constraints

Intrinsically, hydro plants operate in a different way. "Run-of-the-river plants", which have no reservoirs attached, power outputs from them depend on the water flow conditions. While "Regulating stations" which could store water enable energy management over time. Please refer to section 2.6.1 of [18] for more operating principles.

Energy balance

In short, what has been used considering efficiency, plus what has left in the reservoir shall always be equal to energy stored originally in the reservoir.

Output limits

Net output is limited by the maximum capacity, taking into account auxiliary load factor. Likewise, pumping storage is limited by its nominal capacity.

Limits to equivalent reservoirs and long-term guidelines

Storage in reservoirs is subject to some strict limits. For example, given a weekly model, volume stored remains the same throughout the week.

Complexity Constraints

Demand balance constraint

Net electricity output must equal to the demand in each period.

Thermal power spinning reserve constraint

It helps react to unforeseen events in a centralized context, and enables companies to participate in ancillary service markets in a liberalized industry.

Lastly but not least, the objective function can be formulated as minimizing all costs, including fuel, O&M and energy non-supplied.

Appendix C

Figure 24 below is the power and energy demand respectively for day 25th December, as well as wind injection for consecutive 24 periods.

	A	B	C	D	E	F	G	H	I	J	K
31											
32		* demand			P00	30998.78				P00	5745.144
33											
34			[MW]	[MW]				[MW]	[MW]		
35			Power	Energy				Power	Energy		
36											
37		h01	37542.32	34270.55				5925.46	5835.30		
38		h02	28004.16	32773.24				5354.21	5639.83		
39		h03	27095.86	27550.01				4116.83	4735.52		
40		h04	26493.02	26794.44				3913.68	4015.25		
41		h05	26110.80	26301.91				3712.32	3813.00		
42		h06	26034.45	26072.63				3999.25	3855.79		
43		h07	26582.30	26308.38				5035.21	4517.23		
44		h08	27451.14	27016.72				6635.63	5835.42		
45		h09	28537.08	27994.11				8212.62	7424.12		
46		h10	30226.38	29381.73				8954.21	8583.41		
47		h11	31715.68	30971.03				9509.77	9231.99		
48		h12	32782.74	32249.21				9471.94	9490.85		
49		h13	33221.71	33002.23				9828.95	9650.44		
50		h14	33341.97	33281.84				10154.89	9991.92		
51		h15	33422.51	33382.24				10239.12	10197.01		
52		h16	33528.05	33475.28				10199.39	10219.25		
53		h17	33741.54	33634.80				10118.53	10158.96		
54		h18	34031.96	33886.75				9986.24	10052.39		
55		h19	35944.30	34988.13				9538.08	9762.16		
56		h20	38324.34	37134.32				9471.06	9504.57		
57		h21	38883.13	38603.74				9666.62	9568.84		
58		h22	39636.99	39260.06				9478.84	9572.73		
59		h23	39688.05	39662.52				9209.54	9344.19		
60		h24	38805.89	39246.97				7943.09	8576.32		

Figure 24 Power & Energy Demand of D^{P2} on Day 25th December (left); Wind Injection (right)

As described in an earlier chapter, original wind production is seen as power profile. While wind energy profiles are obtained with the same approach as used for net demand profiles: taking the average value of two consecutive power demands. Based on D^{P2} shown in **Figure 24**, two other power profiles are created presented in **Figure 25** and **Figure 25.**

* demand			P00	31039.05
	[MW] Power	[MW] Energy		
h01	37502.05	34270.55		
h02	28044.43	32773.24		
h03	27055.59	27550.01		
h04	26533.29	26794.44		
h05	26070.53	26301.91		
h06	26074.72	26072.63		
h07	26542.03	26308.38		
h08	27491.41	27016.72		
h09	28496.81	27994.11		
h10	30266.65	29381.73		
h11	31675.41	30971.03		
h12	32823.01	32249.21		
h13	33181.44	33002.23		
h14	33382.24	33281.84		
h15	33382.24	33382.24		
h16	33568.32	33475.28		
h17	33701.27	33634.80		
h18	34072.23	33886.75		
h19	35904.03	34988.13		
h20	38364.61	37134.32		
h21	38842.86	38603.74		
h22	39677.26	39260.06		
h23	39647.78	39662.52		
h24	38846.16	39246.97		

Figure 25 Power and Energy Demand of D^{P1} on Day 25th December

* demand			P00	30946.01
	[MW] Power	[MW] Energy		
h01	37595.09	34270.55		
h02	27951.39	32773.24		
h03	27148.63	27550.01		
h04	26440.25	26794.44		
h05	26163.57	26301.91		
h06	25981.68	26072.63		
h07	26635.07	26308.38		
h08	27398.37	27016.72		
h09	28589.85	27994.11		
h10	30173.61	29381.73		
h11	31768.45	30971.03		
h12	32729.97	32249.21		
h13	33274.48	33002.23		
h14	33289.20	33281.84		
h15	33475.28	33382.24		
h16	33475.28	33475.28		
h17	33794.31	33634.80		
h18	33979.19	33886.75		
h19	35997.07	34988.13		
h20	38271.57	37134.32		
h21	38935.90	38603.74		
h22	39584.22	39260.06		
h23	39740.82	39662.52		
h24	38753.12	39246.97		

Figure 26 Power and Energy Demand of D^{P3} on Day 25th December

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
1		* thermal generation																				
2			Bus	MaxProd	MinProd	IniProd	IniState	RampUp	RampDw	nterVarCos	lopeVarCo	linUpTime	linDwTime	SDCost	SDDuratior	SUHCost	UHDuratio	SUCCost	UCDuratio	Tcold	SURamp	SDRamp
3			Ord	[MW]	[MW]	[MW]	[h]	[MW/h]	[MW/h]	[€/h]	[€/MWh]					$		$		h	[MW]	[MW]
4		AMOCOOIL_CC1_1	1	500	150	0	-8	198	198	1418.16	32.7356	6	8	0	1	17500	1	39500	1	9	166.667	166.667
5		AMOCOOIL_CC2_9	1	516.3	221.8	0	-8	204.455	204.455	2419.61	32.7356	6	8	0	1	18070.5	1	40787.7	1	9	221.8	221.8
6		ATKINS_ATKINSG7	1	20	5	0	-1	16	16	1409.27	54.5594	1	1	0	1	727.4	1	727.4	1	2	40	40
7		AZ_AZ_G1	1	46	17.48	0	-1	36.8	36.8	138.04	40.21	1	1	0	1	2363.7	1	2363.7	1	2	92	92
8		AZ_AZ_G2	1	46	17.48	0	-1	36.8	36.8	138.04	40.21	1	1	0	1	2363.7	1	2363.7	1	2	92	92
9		AZ_AZ_G3	1	46	17.48	0	-1	36.8	36.8	138.04	40.21	1	1	0	1	2363.7	1	2363.7	1	2	92	92
10		AZ_AZ_G4	1	46	17.48	0	-1	36.8	36.8	138.04	40.21	1	1	0	1	2363.7	1	2363.7	1	2	92	92
11		B_DAVIS_B_DAVIG1	1	335	131.32	324.615	8	107.8	107.8	7338.71	41.8289	8	8	0	1	3000	1	3000	3	9	131.32	131.32
12		B_DAVIS_CC1_2	1	687	144	0	-8	251.46	251.46	9787.22	32.7356	6	8	0	1	7474.31	1	8967.05	1	9	229	229
13		BASTEN_CC1_2	1	573	140	0	-8	251.46	251.46	7771.76	32.7356	6	8	0	1	19959.1	1	19959.1	1	9	191	191
14		BBSES_UNIT1	1	635	304.8	615.315	24	93.5	93.5	21182.3	18	24	12	0	1	44450	1	75565	6	13	111.216	111.216
15		BBSES_UNIT2	1	635	304.8	0	-12	96.6	96.6	21894.3	18	24	12	0	1	44450	1	75565	6	13	51.36	51.36
16		BFM_HYD_ST1	1	20	7.6	0	-8	37.8	37.8	77.406	41.8289	8	8	0	1	3661.5	1	6956.85	3	9	7.6	7.6
17		BOSQUESW_CC1_2	1	265	107	0	-8	207.9	207.9	2803.87	32.7356	6	8	0	1	4156.32	1	5559.08	1	9	107	107
18		BOSQUESW_CC2_4	1	578	105	0	-8	87.12	87.12	1591.32	32.7356	6	8	0	1	6810	1	6810	1	9	192.667	192.667
19		BRAUNIG_CC1_2	1	525	131.25	0	-4	95.04	95.04	1855.85	32.7356	6	4	0	1	36174.5	1	62430.2	1	5	175	175
20		BRAUNIG_VHB1	1	220	55	0	-8	134.4	134.4	2585.26	41.8289	8	8	0	1	7847.82	1	15764.2	2	9	55	55
21		BRAUNIG_VHB2	1	240	55	0	-8	15	15	625.87	41.8289	8	8	0	1	9073.57	1	15212.5	2	9	55	55
22		BRAUNIG_VHB3	1	420	65	0	-8	15	15	203.7	41.8289	8	8	0	1	16891.5	1	32093.9	1	9	65	65
23		BRAUNIG_VHB6CT5	1	50	18	0	-1	40	40	908.395	40.21	1	1	0	1	904.539	1	904.539	1	2	100	100
24		BRAUNIG_VHB6CT6	1	50	18	0	-1	40	40	904.834	40.21	1	1	0	1	926.016	1	926.016	1	2	100	100
25		BRAUNIG_VHB6CT7	1	50	18	0	-1	59.4	59.4	648.299	40.21	1	1	0	1	968.176	1	968.176	1	2	100	100
26		BRAUNIG_VHB6CT8	1	50	18	0	-1	42.7	42.7	386.509	40.21	1	1	0	1	954.527	1	954.527	1	2	100	100
27		BTE_CC1_4	1	383	10	0	-4	7.92	7.92	109.09	32.7356	6	4	0	1	3346.65	1	3346.65	1	5	127.667	127.667
28		BVE_CC1_2	1	636	144	0	-8	132.66	132.66	1718.98	32.7356	6	8	0	1	7505.95	1	17088.5	1	9	212	212
29		BYU_CC1_3	1	142	81	0	-4	272.052	272.052	11364.7	36.3729	4	4	0	1	4970	1	11218	2	5	81	81
30		CAL_CC1_2	1	203	128	196.707	4	224.136	224.136	1472.71	32.7356	4	4	0	1	5698.08	1	6810	2	5	128	128
31		CALAVERS_JKS1	1	566	100	0	-12	120	120	22250.3	18	24	12	0	1	39620	1	67354	6	13	446.4	446.4
32		CALAVERS_JKS2	1	800	270	775.2	24	69	69	9270.95	18	24	12	0	1	56000	1	95200	6	13	153.563	153.563
33		CALAVERS_JTD1	1	460	100	0	-12	69	69	9270.95	18	24	12	0	1	32200	1	54740	5	13	311.946	311.946
34		CALAVERS_JTD2	1	460	100	0	-12	67.5	67.5	5191.73	18	24	12	0	1	32200	1	54740	6	13	400.8	400.8
35		CALAVERS_OWS1	1	450	65	0	-8	137.6	137.6	712.95	41.8289	8	8	0	1	17883	1	33977.7	1	9	69.2308	69.2308
36		CALAVERS_OWS2	1	430	65	0	-8	36.48	36.48	3485.28	41.8289	8	8	0	1	17063.3	1	33907.7	1	9	66.1538	66.1538
37		CARBN_BSP_1	1	17.5	2.5	0	-1	14	14	336.875	54.5594	1	1	0	1	727.4	1	727.4	1	2	35	35
38		CBEC_CC1_2	1	270	135	0	-4	106.92	106.92	0	36.3729	6	4	0	1	9108.67	1	14448.6	2	5	135	135
39		CBEC_CC2_2	1	273	136.5	0	-4	108.108	108.108	0	36.3729	6	4	0	1	8245.86	1	17317	2	5	136.5	136.5
40		CBY_CBY_G1	1	800	224	775.2	8	239.7	239.7	2201.07	38.1916	8	8	0	1	27959	1	53310	2	9	224	224
41		CBY_CBY_G2	1	800	228	0	-8	241	241	1228.82	38.1916	8	8	0	1	27959	1	53310	2	9	228	228
42		CBY4_CC1_4	1	592.2	163	0	-8	316.8	316.8	2852.07	32.7356	6	8	0	1	29783.3	1	49001.5	1	9	197.4	197.4
43		CCEC_CC1_4	1	440	25	0	-4	174.24	174.24	272.724	32.7356	6	4	0	1	5725.79	1	5725.79	1	5	146.667	146.667

Figure 27 Generator Characteristics for partial units

Figure 27 shows the data layout for Generator Characteristics used in this case study, representing the realistic ERCOT system.

Thus far, data presented above are all used for scheduling stage, as for simulation stage, demands, both wind input and net demand, for every 5 minutes interval are needed (therefore 288 sub periods in total). It can be easily produced according to the original hourly profiles: either assuming linear lines between two points or by interpolation, a smoother line could be obtained. The only distinction caused by using these two sub period profiles is, smoother demand would require less ramp in simulation stages.

In the case study, I have used all linear profiles (**Figure 28**), which results in more challenging situations to test commitment decisions from the two scheduling approaches. If one is interested, simulations with smooth sub period demand profiles could be performed.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1		DATOS EN POTENCIA												5745,14	
2															
3			* demandSub				31039,05			* WindSub					
4					Power									sc00	
5				p01	31577,6					p01	.		36	5760,17	
6				p02	32116,2					p02	.		36	5775,2	
7				p03	32654,8					p03	.		36	5790,22	
8				p04	33193,4					p04	.		36	5805,25	
9				p05	33732					p05	.		36	5820,27	
10				p06	34270,6					p06	.		36	5835,3	
11				p07	34809,1					p07	.		36	5850,33	
12				p08	35347,7					p08	.		36	5865,35	
13				p09	35886,3					p09	.		36	5880,38	
14				p10	36424,9					p10	.		36	5895,4	
15				p11	36963,5					p11	.		36	5910,43	
16				p12	37502,1					p12	.		36	5925,46	
17				p13	36713,9					p13	.		36	5877,85	
18				p14	35925,8					p14	.		36	5830,25	
19				p15	35137,6					p15	.		36	5782,64	
20				p16	34349,5					p16	.		36	5735,04	
21				p17	33561,4					p17	.		36	5687,44	
22				p18	32773,2					p18	.		36	5639,83	
23				p19	31985,1					p19	.		36	5592,23	
24				p20	31197					p20	.		36	5544,62	
25				p21	30408,8					p21	.		36	5497,02	
26				p22	29620,7					p22	.		36	5449,42	
27				p23	28832,6					p23	.		36	5401,81	
28				p24	28044,4					p24	.		36	5354,21	
29				p25	27962					p25	.		36	5251,09	
30				p26	27879,6					p26	.		36	5147,98	
31				p27	27797,2					p27	.		36	5044,86	
32				p28	27714,8					p28	.		36	4941,75	
33				p29	27632,4					p29	.		36	4838,63	
34				p30	27550					p30	.		36	4735,52	
35				p31	27467,6					p31	.		36	4632,4	
36				p32	27385,2					p32	.		36	4529,29	
37				p33	27302,8					p33	.		36	4426,17	
38				p34	27220,4					p34	.		36	4323,06	
39				p35	27138					p35	.		36	4219,94	
40				p36	27055,6					p36	.		36	4116,83	
41				p37	27012,1					p37	.		36	4099,9	
42				p38	26968,5					p38	.		36	4082,97	
43				p39	26925					p39	.		36	4066,04	

Figure 28 partial 5-minute sub period demand data for Day 25th Decembe

	A	B	C	D	E	F	G	H	I	J	K
1											
2		* Network Information									
3								R	X	Pmax	
4		*	From bus i		To Buss j		Circuit ID	[p.u.]	[p.u.]	[MW]	
5	Line01		38320	.	38360	.	1	0,02333	0,01886	18	
6	Line02		38320	.	38310	.	1	0,00559	0,12788	70	
7	Line03		38310	.	38330	.	1	0,03847	0,12455	143	
8	Line04		38310	.	38340	.	1	0,00336	0,0109	143	
9	Line05		5947	.	5948	.	1	0,00483	0,02344	103	
10	Line06		2806	.	2810	.	1	0	0,363	62,5	
11	Line07		2806	.	2808	.	1	0	0,363	62,5	
12	Line08		2806	.	2809	.	1	0	0,363	62,5	
13	Line09		2808	.	2858	.	1	0,00003	0,0004	478	
14	Line10		2808	.	2860	.	1	0,00003	0,0004	478	
15	Line11		2809	.	2857	.	1	0,00003	0,0004	478	
16	Line12		2809	.	2859	.	1	0,00003	0,0004	478	
17	Line13		2807	.	2810	.	1	0	0,363	62,5	
18	Line14		2807	.	2808	.	1	0	0,363	62,5	
19	Line15		2807	.	2809	.	1	0	0,363	62,5	
20	Line16		8427	.	8435	.	1	0,01539	0,05085	73	
21	Line17		8427	.	8430	.	1	0,00128	0,04525	224	
22	Line18		8427	.	8432	.	1	0,01119	0,06563	103	
23	Line19		3524	.	3525	.	1	0,08076	0,10987	72	
24	Line20		350	.	363	.	1	0,0055	0,0203	45	
25	Line21		350	.	356	.	1	0,0043	0,0162	45	
26	Line22		6292	.	6293	.	1	0,00087	0,00498	209	
27	Line23		6269	.	6273	.	1	0,00013	0,00031	60	
28	Line24		6265	.	6266	.	1	0,04107	0,0394	30	
29	Line25		6265	.	6274	.	1	0,01338	0,0319	60	
30	Line26		6268	.	6273	.	1	0,02238	0,031	38	
31	Line27		6266	.	6267	.	1	0,00848	0,02759	75	
32	Line28		6273	.	6274	.	1	0,01003	0,02393	60	
33	Line29		6276	.	6275	.	1	0,00456	0,1137	62,5	
34	Line30		6276	.	6281	.	1	0,01457	0,04792	75	
35	Line31		6276	.	6278	.	1	0,00341	0,01774	105	
36	Line32		6277	.	6275	.	1	0,00491	0,1	84	
37	Line33		6277	.	6282	.	1	0,00386	0,02092	105	
38	Line34		6275	.	6290	.	1	0,00314	0,01756	209	
39	Line35		6275	.	6291	.	1	0,0017	0,00964	209	
40	Line36		6226	.	6292	.	1	0,00375	0,02124	209	
41	Line37		6226	.	6275	.	1	0,00114	0,0061	293	
42	Line38		6253	.	6270	.	1	0,01533	0,03926	60	
43	Line39		6253	.	6255	.	1	0,0024	0,094	91,7	
44	Line40		6253	.	6266	.	1	0,0098	0,03189	75	
45	Line41		6255	.	6772	.	1	0,00071	0,00605	271	
46	Line42		6255	.	6256	.	1	0,0033	0,01811	209	
47	Line43		6301	.	6302	.	1	0,05592	0,05389	30	
48	Line44		6267	.	6268	.	1	0,00702	0,02284	75	
49	Line45		6224	.	6228	.	1	0,00523	0,1272	62,5	

Figure 29 partial ERCOT Network Data

Figure 29 is a snapshot of the network information. For each line, bus ID, line impedance and transmission capacity are included. Circuit ID is used to distinguish multiple lines between two buses. There are totally 6820 lines incorporated in the complete data set.

Appendix D

From both UC models, not only commitment decisions are obtained, but production levels of each unit. Since there are almost 300 generators, it is unrealistic to show everything tabular, instead, schematic presentations are utilized. Figures below are directly created from GAMS:

Figure 30 – Figure 36 are results in scheduling stage for day 12th January,

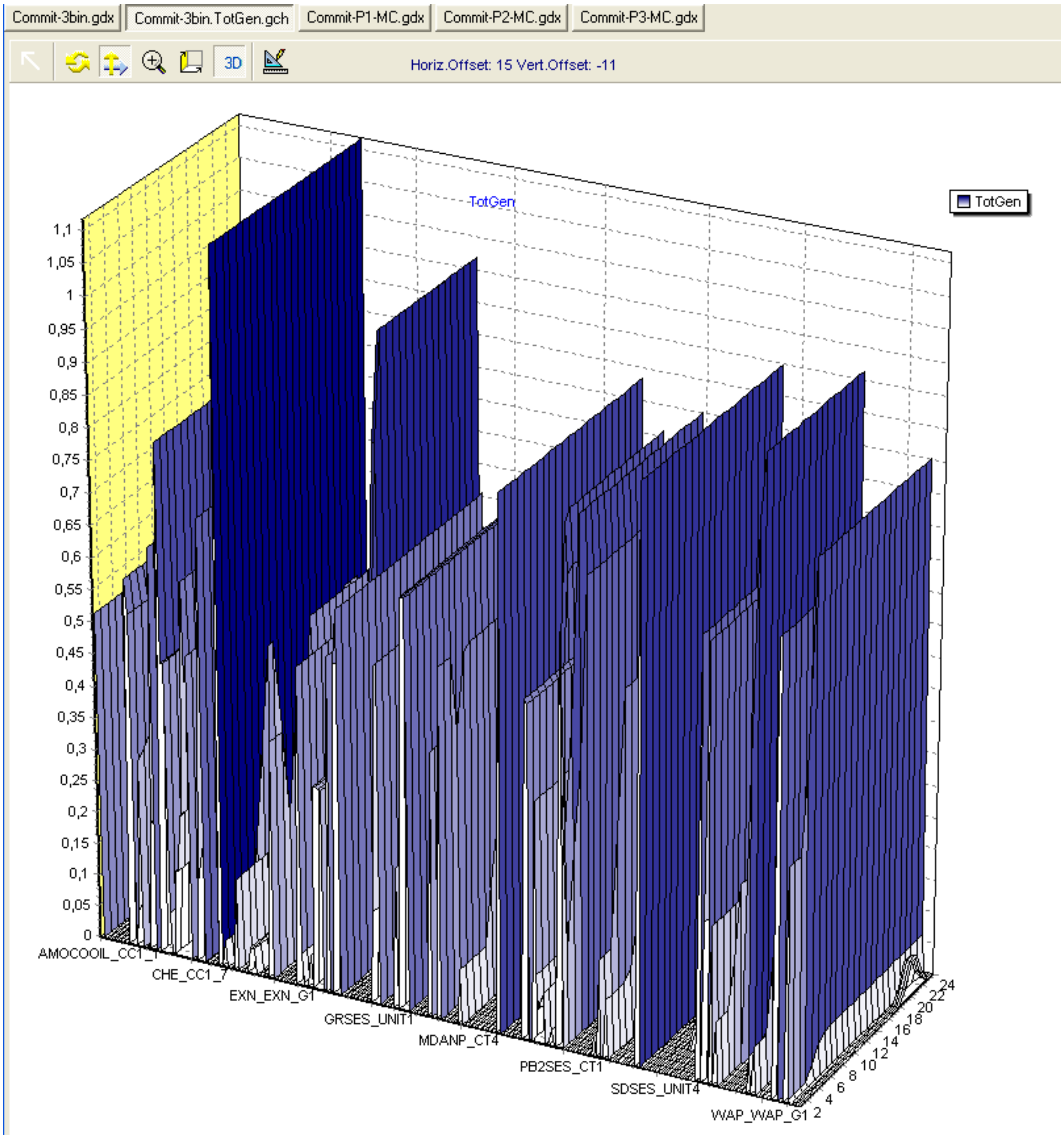

Figure 30 Production level for each unit with *EngUC*

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
1	**Unit\Hour**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**
2	DDPEC_CC1_4	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116
3	SCES_UNIT1	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898
4	MNSES_UNIT3	0.835	0.835	0.835	0.835	0.835	0.835	0.835	0.835	0.835	0.835	0.835	0.835	0.835	0.835	0.835	0.835	0.835	0.835	0.835	0.835	0.835
5	CALAVERS_JKS2	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
6	PANDA_S_CC1_1	0.645344	0.328544	0.4832	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
7	WCPP_CC1_4	0.366	0.366	0.366	0.484408	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802
8	WAP_WAP_G6	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715
9	WAP_WAP_G5	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
10	TGCCS_CC1_3	0	0	0	0	0	0.455	0.816152	0.912	0.912	0.912	0.912	0.912	0.912	0.912	0.912	0.912	0.912	0.912	0.912	0.912	0.912
11	FRNYPP_CC2_6	0	0	0	0	0	0	0.421	0.804605	0.9687	0.9687	0.9687	0.9687	0.9687	0.9687	0.9687	0.9687	0.9687	0.9687	0.9687	0.9687	0.9687
12	CVC_CC1_2	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696
13	FRNYPP_CC1_6	0	0	0	0	0	0	0.421	0.802665	0.9638	0.9638	0.9638	0.9638	0.9638	0.9638	0.9638	0.9638	0.9638	0.9638	0.9638	0.9638	0.9638
14	STP_STP_G1_J01	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689
15	STP_STP_G2_J01	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816
16	KMCHI_CC1_2	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455
17	KMCHI_CC2_2	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455
18	JCKCNTY2_CC1_3	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644
19	PANDA_T1_CC1_1	0.4228	0.1456	0.294154	0.4228	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
20	BVE_CC1_2	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636
21	CBY_CBY_G2	0.228	0.228	0.228	0.228	0.318	0.559	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.559	0.318	0.318	0.559	0.8	0.8	0.8	0.8
22	FTR_CC1_9	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604
23	CBY_CBY_G1	0.224	0.224	0.224	0.224	0.232353	0.472053	0.711753	0.8	0.8	0.8	0.8	0.8	0.8	0.623458	0.445356	0.337456	0.577156	0.753786	0.8	0.8	0.8
24	CBY4_CC1_4	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922
25	BOSQUESW_CC2_4	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578
26	NEDIN_CC1_2	0	0	0	0	0	0	0.441	0.74196	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76
27	LOSTPI_CC1_2	0.55	0.55	0.55	0.425929	0.541606	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
28	GUADG_CC2_2	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535
29	OECCS_CC1_4	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532
30	GUADG_CC1_2	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53
31	FREC_CC2_2	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528
32	BRAUNIG_CC1_2	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525
33	OECCS_CC2_4	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525
34	FRONTERA_CC1_3	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517
35	AMOCOOIL_CC2_9	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163
36	B_DAVIS_CC1_2	0	0	0	0	0	0.144	0.39546	0.64692	0.687	0.687	0.687	0.687	0.687	0.687	0.687	0.687	0.687	0.687	0.687	0.687	0.687
37	AMOCOOIL_CC1_1	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
38	FERGCC_CC1_4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
39	NUECES_B_CC1_2	0	0	0	0	0	0.134	0.39932	0.66464	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67
40	JACKCNTY_CC1_3	0	0	0	0	0	0.304	0.556252	0.637	0.637	0.637	0.637	0.637	0.637	0.637	0.637	0.637	0.637	0.637	0.637	0.637	0.637
41	PSG_CC1_2	0.154	0.154	0.154	0.327368	0.542	0.542	0.542	0.542	0.542	0.542	0.542	0.542	0.542	0.542	0.542	0.542	0.542	0.542	0.542	0.542	0.542
42	CHE_CC1_7	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479
43	CALAVERS_JTD1	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46
44	CALAVERS_JTD2	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46
45	CCEC_CC1_4	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44
46	LGE_CC1_4	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415
47	BASTEN_CC1_2	0	0	0	0	0	0	0.14	0.39146	0.573	0.573	0.573	0.573	0.573	0.573	0.573	0.573	0.573	0.573	0.573	0.573	0.573

Figure 31 partial Tabulated Unit Production level [GW] in descending order with *EngUC*

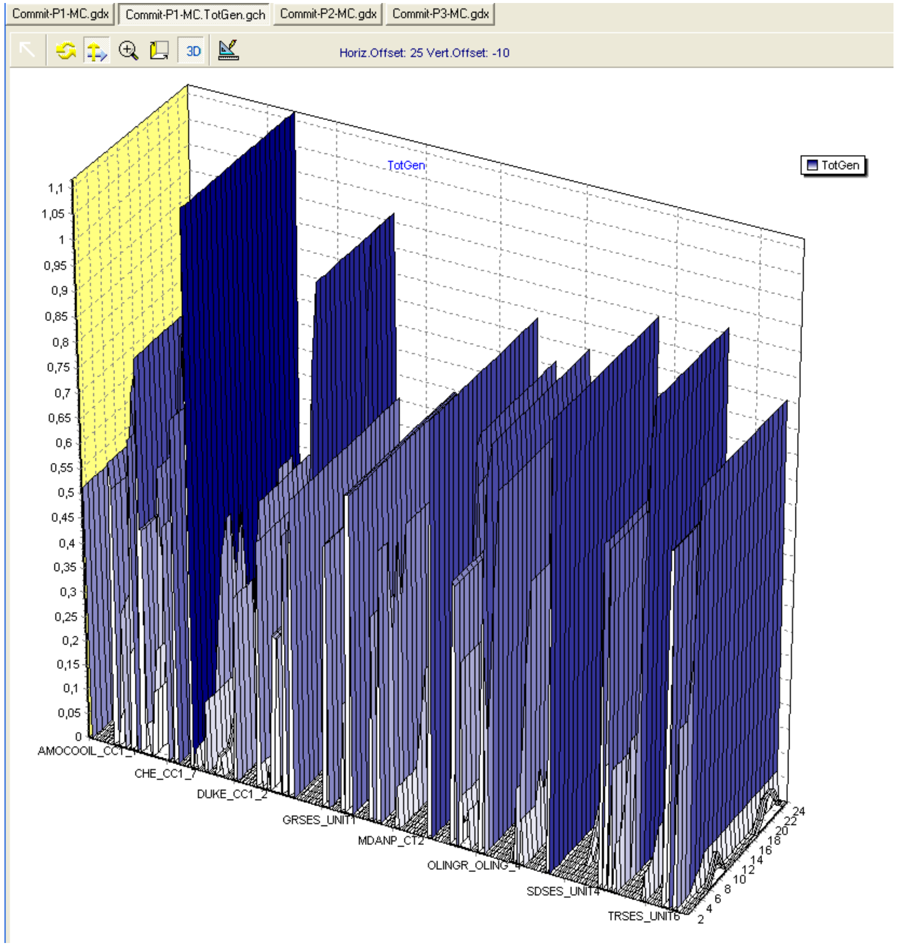

Figure 32 Production level for each unit of D^{P1} with *RmpUC*

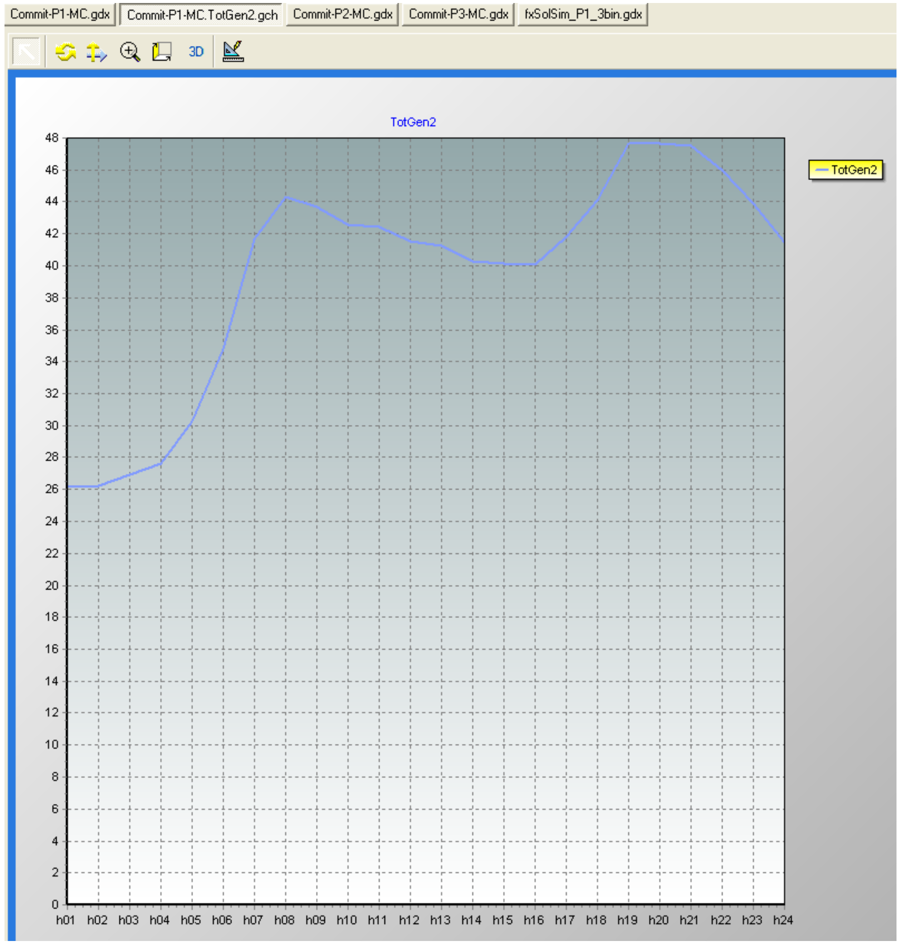

Figure 33 Total generation in each hour of D^{P1} with *RmpUC*

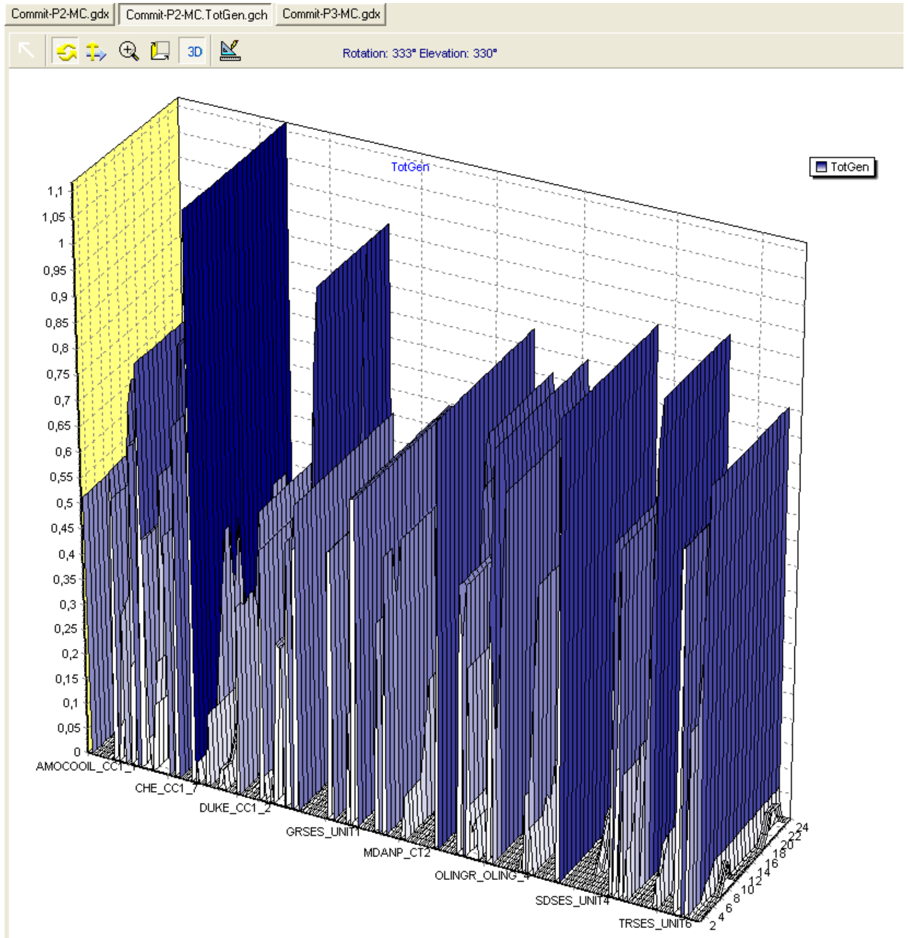

Figure 34 Production level for each unit of D^{P2} with *RmpUC*

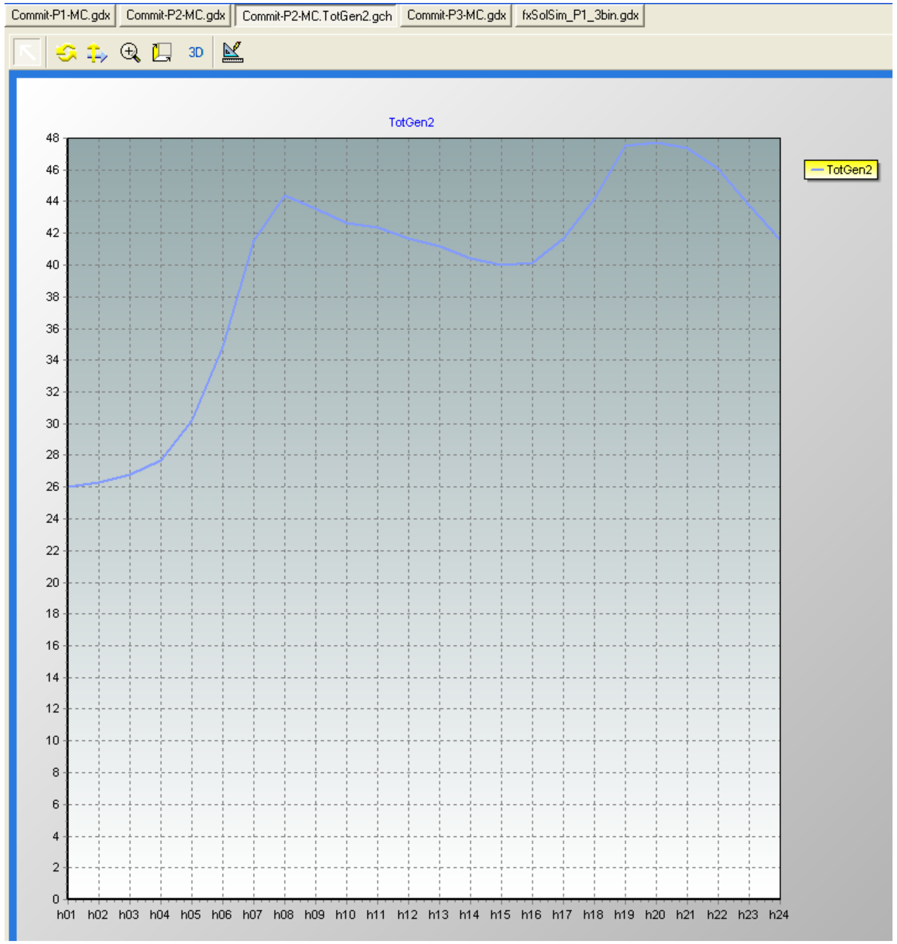

Figure 35 Total generation in each hour of D^{P2} with *RmpUC*

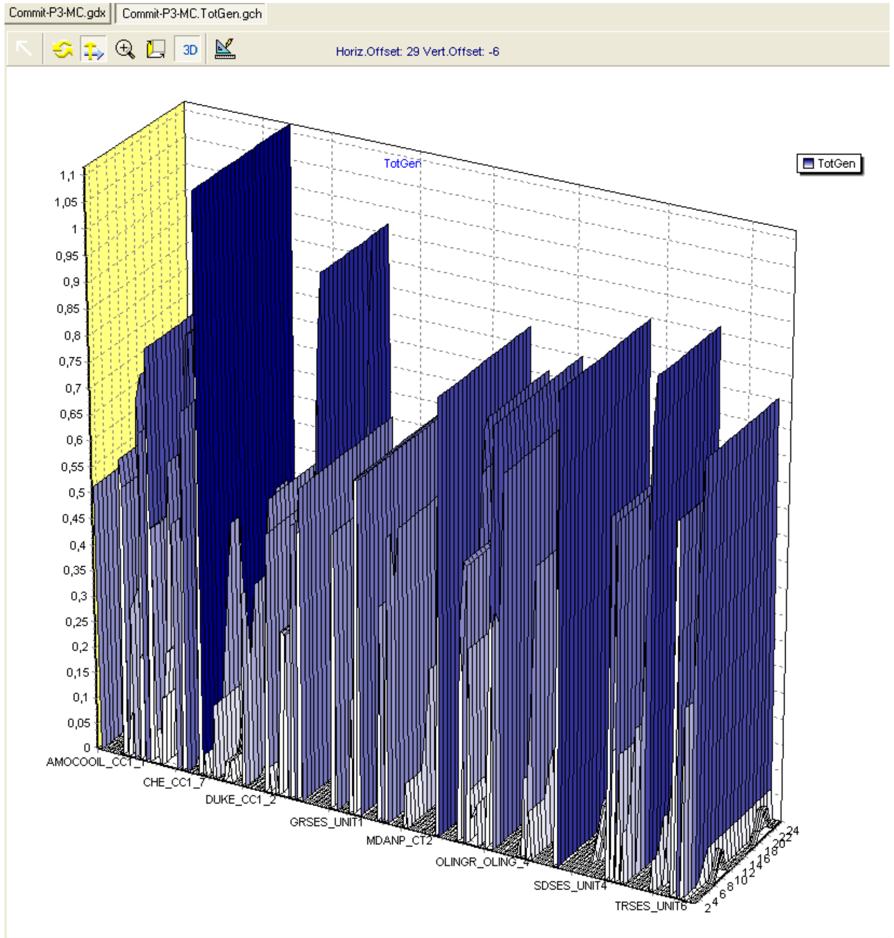

Figure 36 Production level for each unit of D^{P3} with *RmpUC*

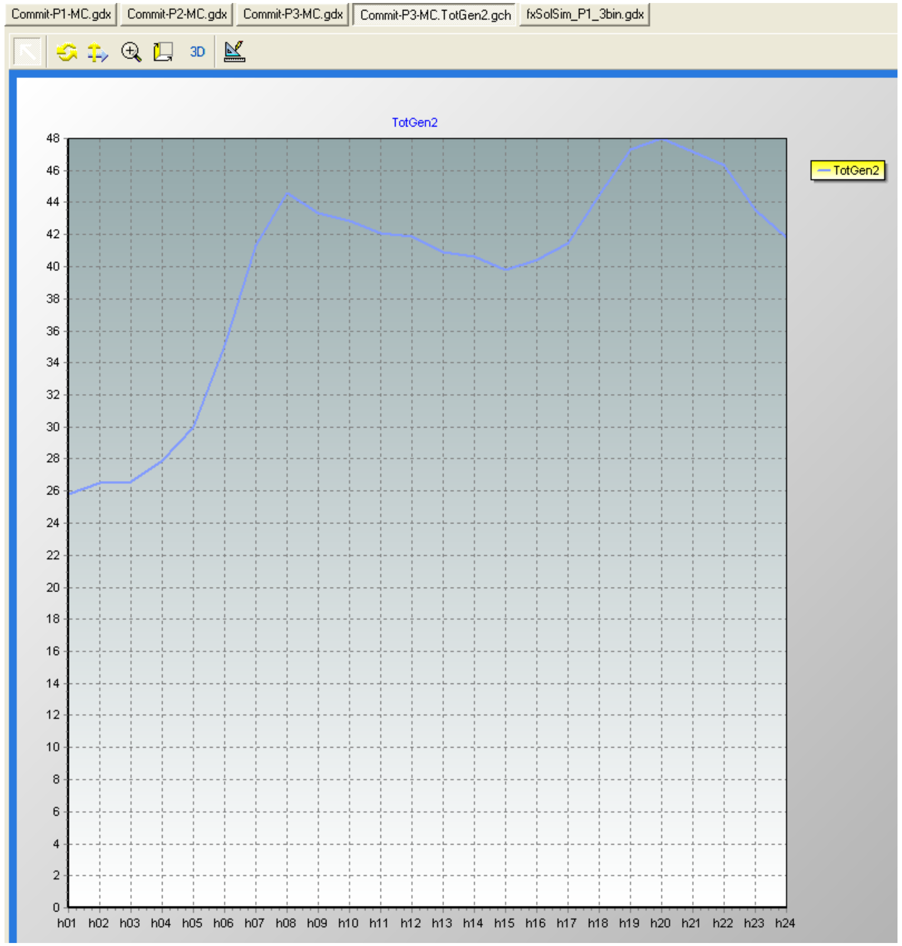

Figure 37 Total generation in each hour of D^{P3} with *RmpUC*

Figure 38 – Figure 44 are scheduling results for day 25th December. Energy block based commitment decision is shown first, followed by ramp-based commitment decisions for the three different power demand profiles.

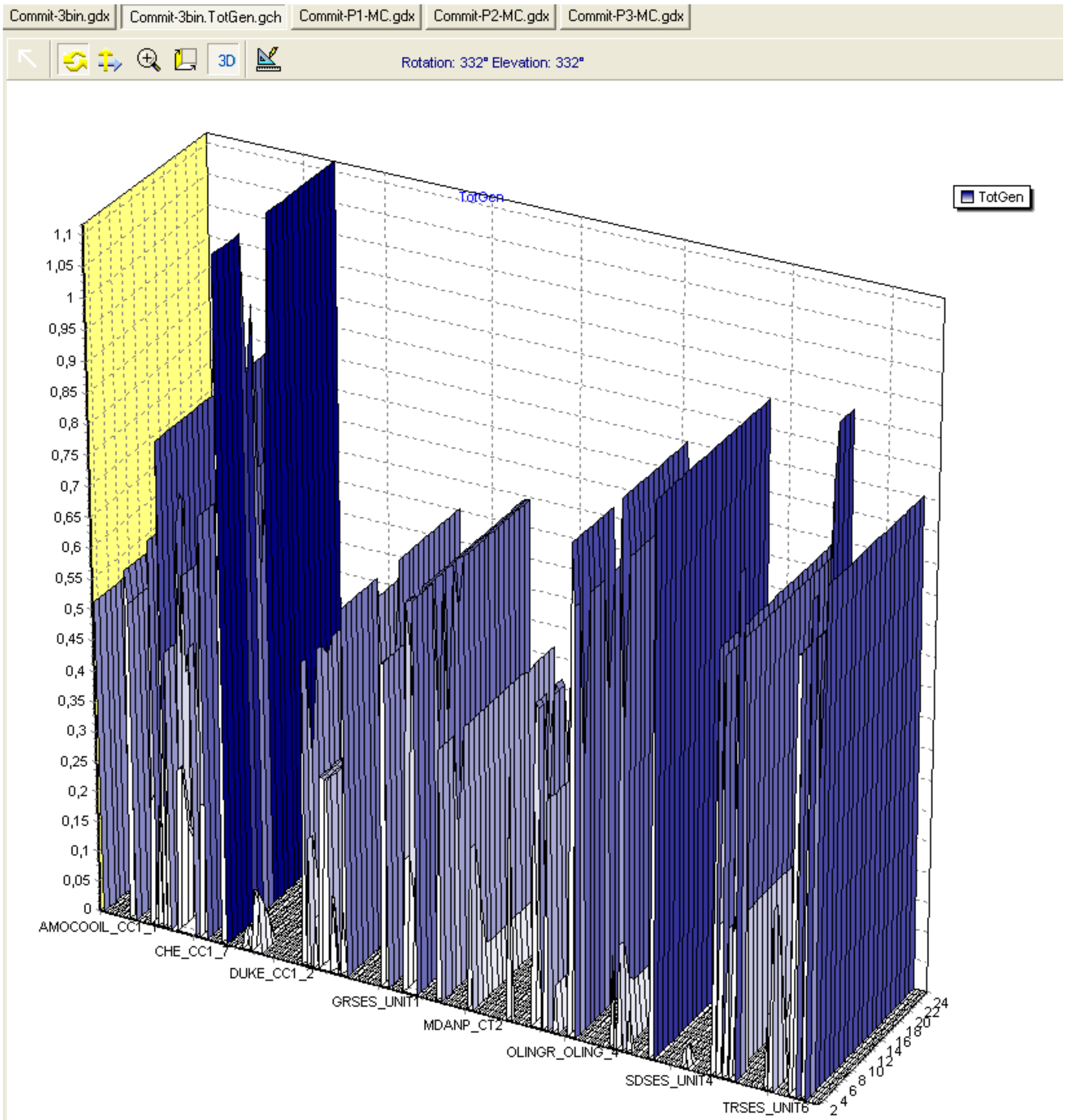

Figure 38 Production level for each unit with *EngUC*

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
1	**Unit\Hour**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**Total Productio**
2	DDPEC_CC1_4	1.116	1.116	1.116	1.116	1.116	1.116	0.873015	0.992518	0.550582	0.674064	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116	25.4101786
3	SCES_UNIT1	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	0.898	21.552
4	CALAVERS_JKS2	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	19.2
5	WCPP_CC1_4	0.802	0.802	0.484408	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	18.930408
6	PANDA_S_CC1_1	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.4832	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	18.8832
7	WAP_WAP_G6	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	17.16
8	WAP_WAP_G5	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	17.04
9	STP_STP_G1_J01	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	16.536
10	CVC_CC1_2	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.420384	0.696	0.66148	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	0.696	16.393864
11	STP_STP_G2_J01	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	0.6816	16.3584
12	PANDA_T1_CC1_1	0.7	0.7	0.4228	0.7	0.7	0.7	0.7	0.499354	0.7	0.7	0.4228	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	16.0449544
13	BVE_CC1_2	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	0.636	15.264
14	KMCHI_CC1_2	0.6455	0.6455	0.389882	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	15.236382
15	JCKCNTY2_CC1_3	0.644	0.644	0.388976	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	0.644	15.200976
16	KMCHI_CC2_2	0.6455	0.6455	0.6455	0.6455	0.6455	0.389882	0.6455	0.389882	0.6455	0.570722	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	0.6455	14.905986
17	CBY4_CC1_4	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	0.5922	14.2128
18	BOSQUESW_CC2_4	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	0.578	13.872
19	FTR_CC1_9	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.389184	0.15	0.389184	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	0.604	13.612368
20	BRAUNIG_CC1_2	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	12.6
21	OECCS_CC1_4	0.532	0.532	0.532	0.462118	0.532	0.532	0.321328	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	0.532	12.487446
22	AMOCOOIL_CC2_9	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	0.5163	12.3912
23	GUADG_CC1_2	0.53	0.53	0.53	0.53	0.53	0.32012	0.53	0.32012	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	12.30024
24	AMOCOOIL_CC1_1	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	12
25	OECCS_CC2_4	0.525	0.525	0.3171	0.525	0.525	0.525	0.3171	0.525	0.3171	0.3171	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525	11.7684
26	FERGCC_CC1_4	0.5	0.5	0.331124	0.5	0.5	0.480287	0.5	0.5	0.5	0.5	0.302	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	11.6134106
27	CALAVERS_JTD2	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	11.04
28	GUADG_CC2_2	0.535	0.535	0.535	0.535	0.535	0.535	0.32314	0.11128	0.095	0.095	0.256926	0.468786	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	0.535	10.980132
29	CHE_CC1_7	0.479	0.479	0.289316	0.479	0.479	0.479	0.479	0.289316	0.289316	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	0.479	10.926948
30	CCEC_CC1_4	0.44	0.44	0.26576	0.44	0.44	0.44	0.44	0.44	0.26576	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	10.21152
31	LGE_CC1_4	0.415	0.415	0.415	0.415	0.25066	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.408166	0.415	0.415	0.415	0.415	0.415	9.788826
32	CBY_CBY_G1	0.67035	0.716362	0.476662	0.236962	0.224	0.224	0.224	0.224	0.224	0.224	0.224	0.224	0.224	0.224	0.224	0.224	0.224	0.224	0.4637	0.7034	0.8	0.8	0.8	0.8	9.603436
33	CBY_CBY_G2	0.469	0.71	0.469	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.349792	0.590792	0.795189	0.8	0.8	0.8	9.203773
34	OKLA_OKLA_G1_J01	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	0.3774	9.0576
35	FPPYD1_FPP_G1_J01	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	7.728
36	FPPYD1_FPP_G1_J02	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	0.322	7.728
37	FPPYD1_FPP_G2_J01	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	7.632
38	FPPYD1_FPP_G2_J02	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	0.318	7.632
39	BTE_CC1_4	0.208	0.21592	0.22384	0.23176	0.23968	0.2476	0.25552	0.26344	0.27136	0.27928	0.2872	0.29512	0.30304	0.31096	0.31888	0.3268	0.33472	0.34264	0.35056	0.35848	0.3664	0.37432	0.38224	0.383	7.17076
40	TGCCS_CC1_3	0.816152	0.816152	0.455	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.455	0.816152	0.912	0.912	0.912	0.912	7.006456
41	STP_STP_G1_J04	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	0.2506	6.0144
42	STP_STP_G2_J04	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	0.2478	5.9472
43	CBEC_CC1_2	0.27	0.27	0.16308	0.135	0.135	0.135	0.135	0.135	0.135	0.135	0.135	0.135	0.24192	0.27	0.248904	0.27	0.27	0.27	0.16308	0.27	0.27	0.27	0.27	0.27	5.001984
44	INGLCOSW_CC1_4	0.2226	0.2226	0.13445	0.2226	0.2226	0.2226	0.17719	0.08904	0.13445	0.2226	0.2226	0.2226	0.2226	0.2226	0.2226	0.2226	0.2226	0.2226	0.2226	0.2226	0.2226	0.2226	0.2226	0.2226	4.9871304
45	JACKCNTY_CC1_3	0.637	0.556252	0.304	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.304	0.556252	0.637	0.637	0.637	0.637	4.905504
46	CBEC_CC2_2	0.273	0.273	0.164892	0.1365	0.1365	0.1365	0.1365	0.1365	0.1365	0.1365	0.1365	0.1365	0.244608	0.1365	0.1365	0.13918	0.198269	0.273	0.164892	0.273	0.273	0.273	0.273	0.273	4.597341
47	TXCTY_CC1_1	0.298	0.298	0.193008	0.075	0	0	0	0	0	0	0	0.075	0.193008	0.298	0.298	0.298	0.298	0.298	0.298	0.298	0.298	0.298	0.298	0.298	4.410016

Figure 39 partial Tabulated Unit Production level [GW] in descending order with *EngUC*

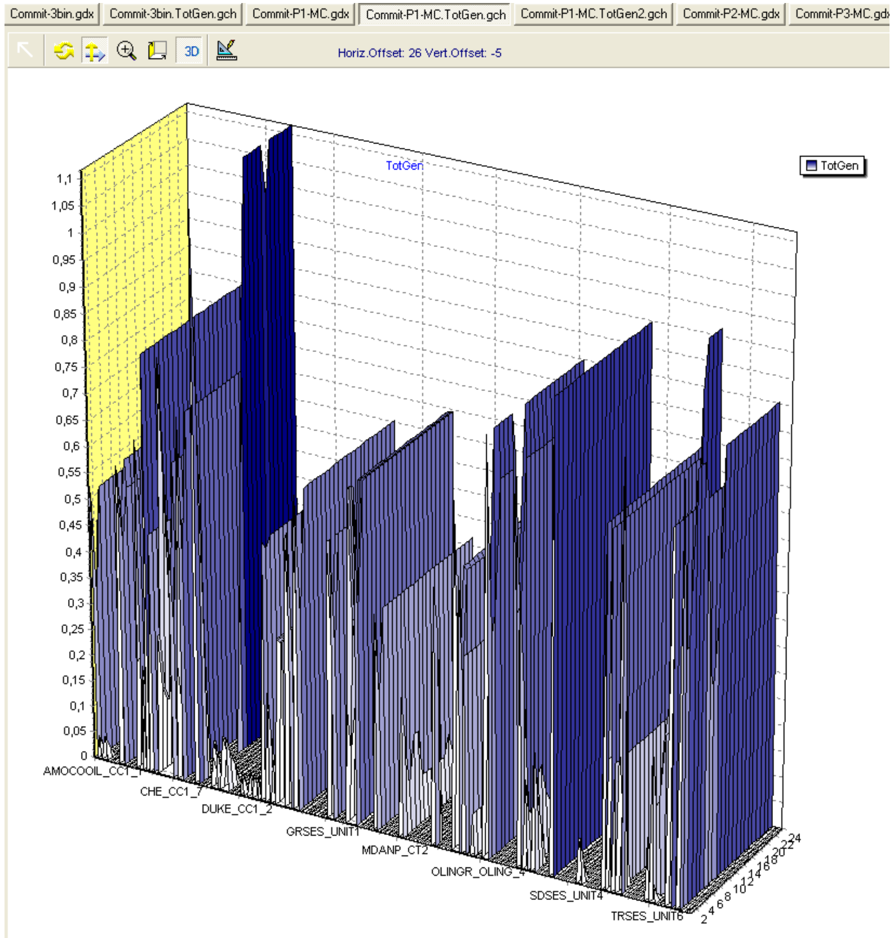

Figure 40 Production level for each unit of D^{P1} with *RmpUC*

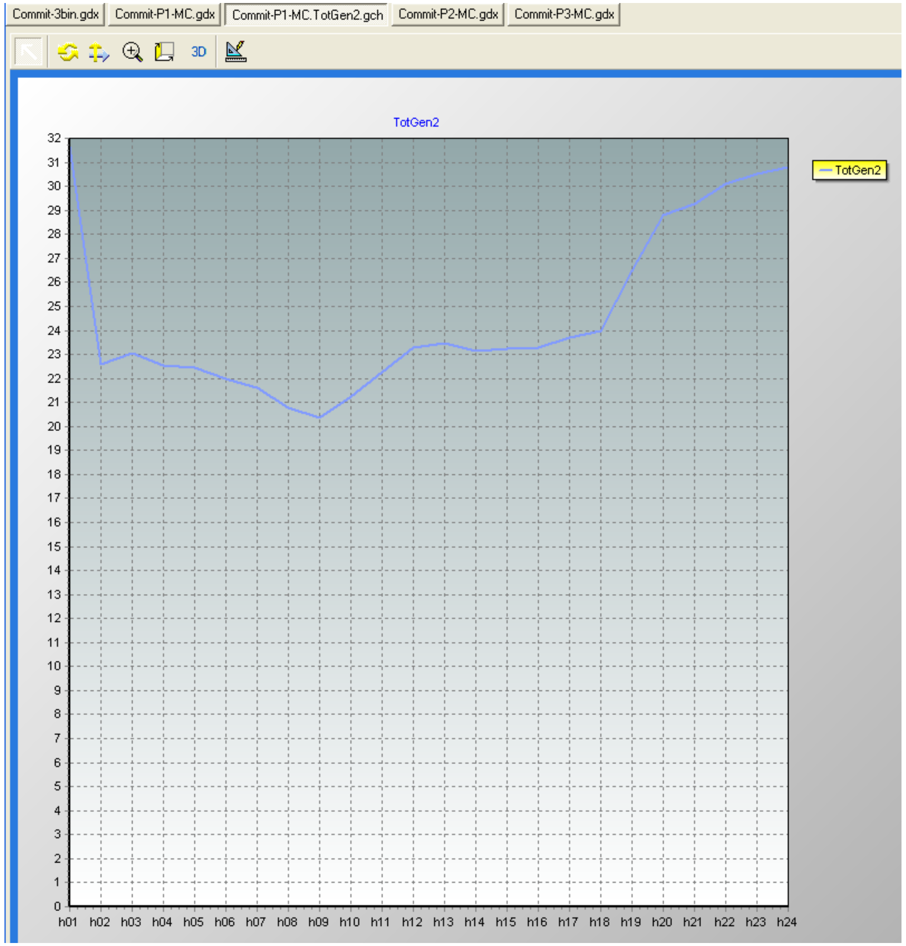

Figure 41 Total generation in each hour of D^{P1} with *RmpUC*

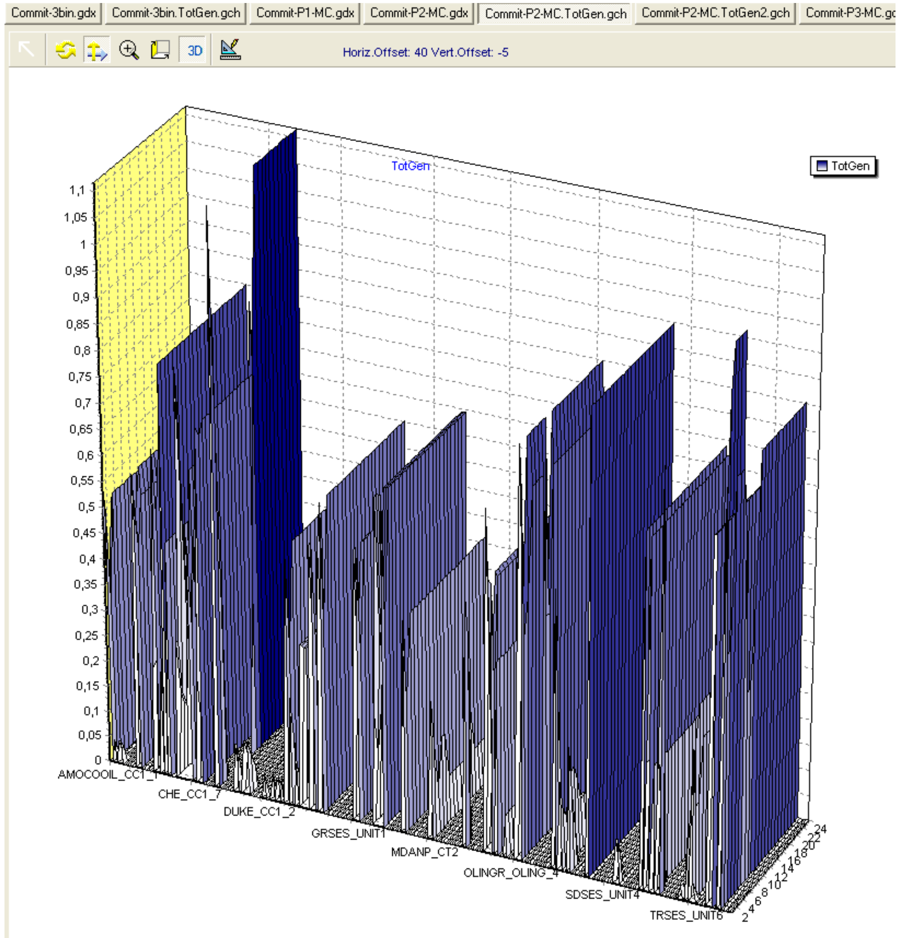

Figure 42 Production level for each unit of D^{P2} with *RmpUC*

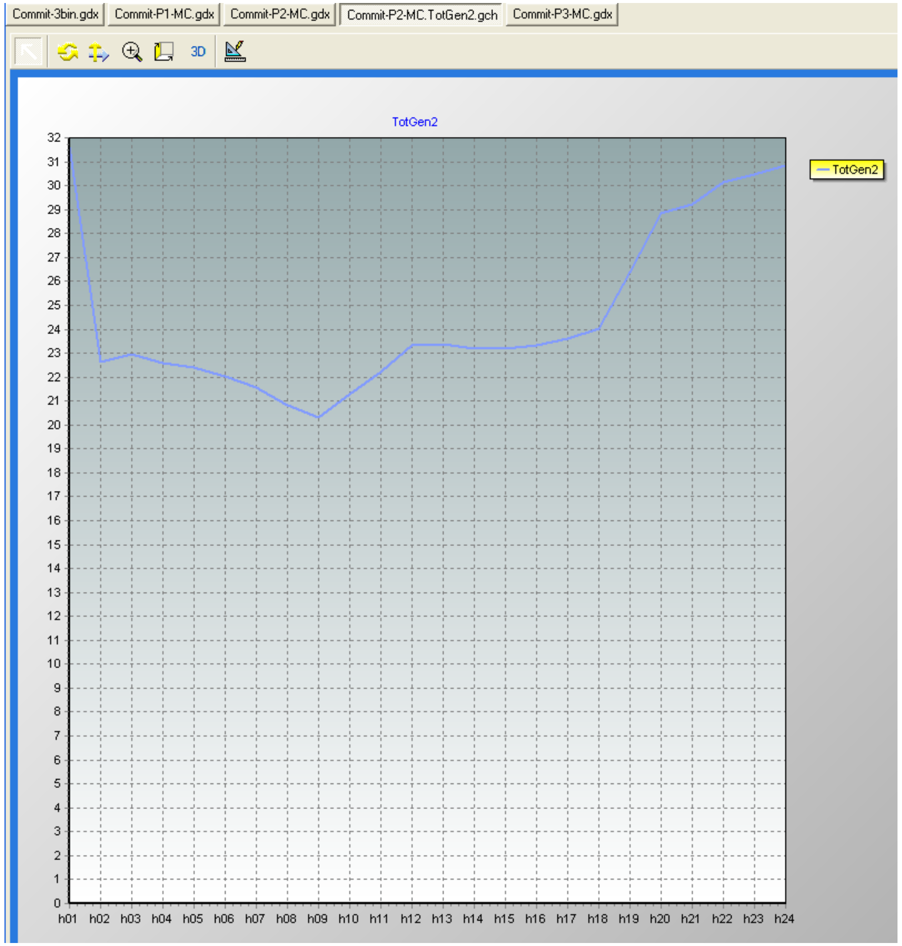

Figure 43 Total generation in each hour of D^{P2} with *RmpUC*

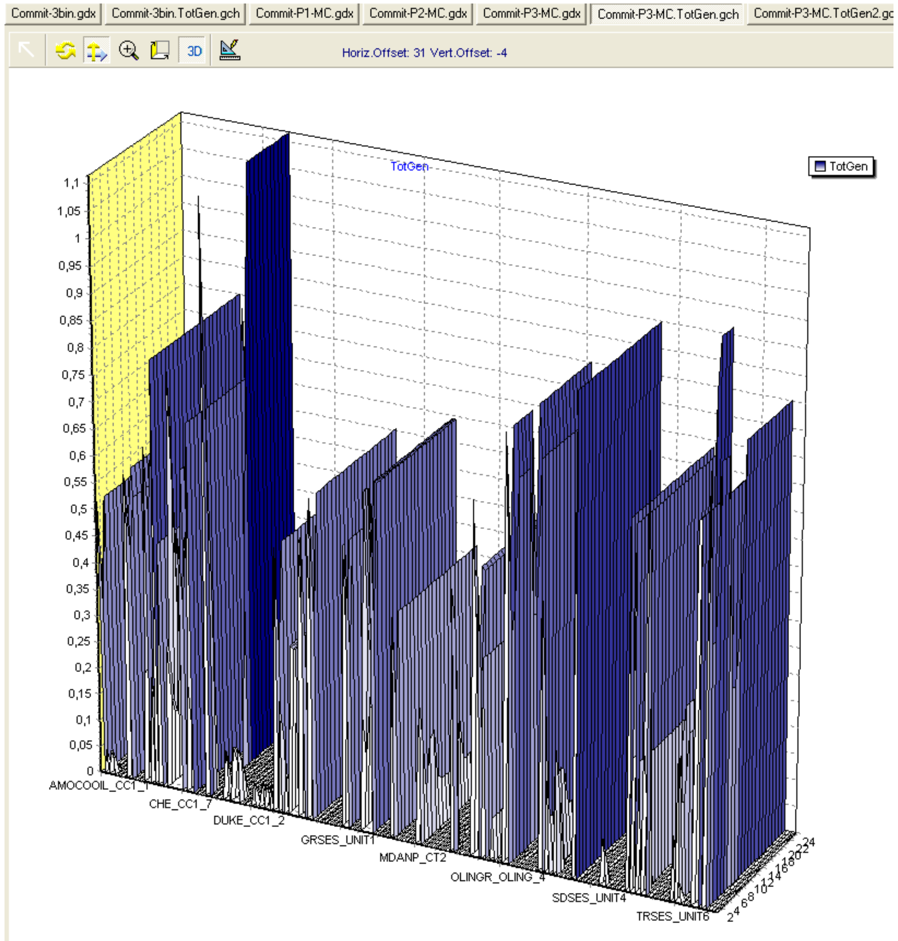

Figure 44 Production level for each unit of D^{P3} with *RmpUC*

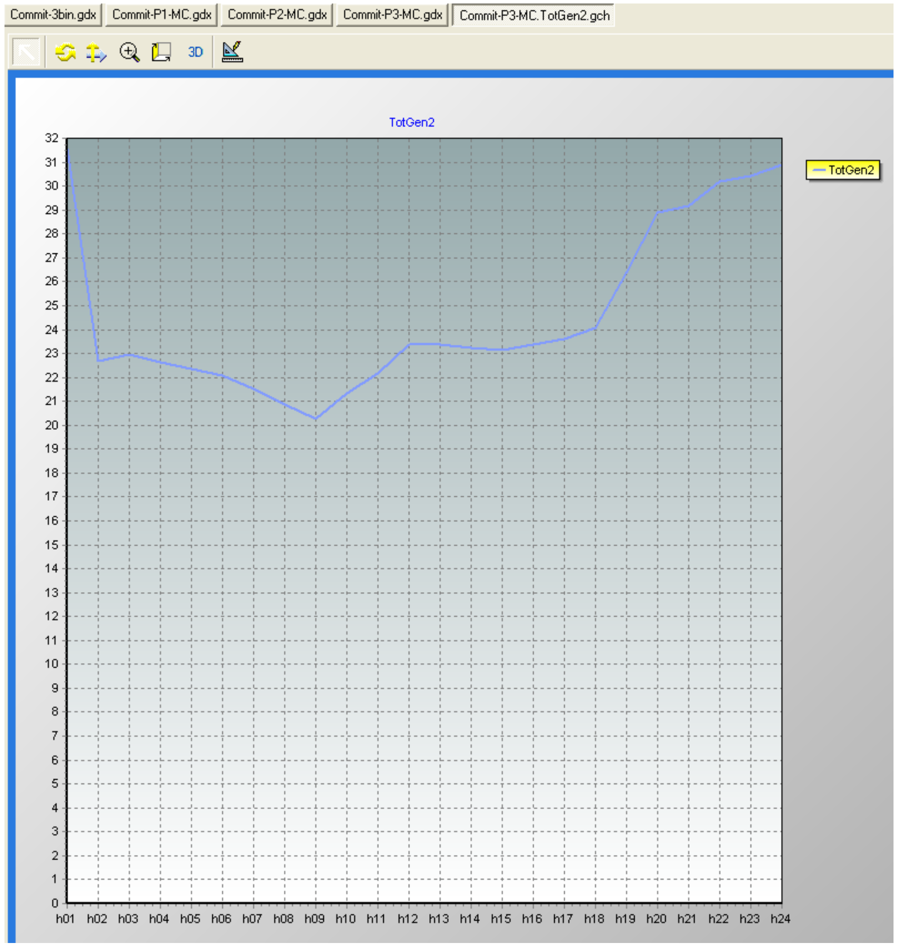

Figure 45 Total generation in each hour of D^{P3} with *RmpUC*