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; 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.
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](image-url)  
**Figure 3 (a) Generation scheduling**

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

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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 \([p_4, p_5]\) and 100MW elsewhere. Likewise, down reserves is expected to be 100MW for \([p_1, p_4]\) and 150MW for \(p_5\) and \(p_6\): 100MW that G1 can provide all the time and 50MW that G2 can provide for \(p_5\) and \(p_6\).

From the above, one need to notice that: 1) downward reserves were used in \(p_3\) and \(p_4\), which was unexpected from scheduling; 2) in \(p_4\), 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

\[ g \in G \]  Generating units, running from 1 to \( G \)

\[ \ell \in L_g \]  Startup intervals, running from 1 (hottest) to \( N_{tg} \)

\[ t \in T \]  Hourly periods in the time horizon, running from 1 to \( T \) hours

Unit’s Parameters

\[ C_{g}^{NL} \]  No-load cost of unit \( g \) [$/h]

\[ C_{g}^{LV} \]  Linear variable cost of unit \( g \) [$/MWh]

\[ C_{g}^{SU}_{\ell} \]  Cost of the interval \( \ell \) 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]

$P_g$ Minimum power output of unit $g$ [MW]

$P_g^\ast$ 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]

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

$P_{i}^{SU}$ 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]

$\bar{e}_{gt}$ 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]

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

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

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

$w_{gt}$ 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**

\[
\min \sum_{g \in G} \sum_{t \in T} \left[ C_{g}^{NL} \cdot u_{gt} + C_{g}^{LV} \cdot \delta_{gt} + C_{g,t}^{SU} \cdot v_{gt} + C_{g}^{SD} \cdot w_{gt} \right]
\]

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 \(\alpha_{t}\) and \(\beta_{t}\) 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 \( C_g^{SU} \) 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**

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

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

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

\begin{align*}
e_{gt} - e_{g(t-1)} & \leq RU_g * u_{g(t-1)} + SU_g * v_{gt} & \forall g, t \\
e_{g(t-1)} - e_{gt} & \leq RD_g * u_{gt} + SD_g * w_{gt} & \forall g, t
\end{align*}

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

\[u_{gt} * \bar{P}_g \leq p_{gt} \leq u_{gt} * \overline{P}_g\]

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)

\[C_{g,t}^{SU} \geq C_{g,k}^{SU'} \sum_{i=1}^{k} u_{g(t-i)}\]

\[\forall g, t, k \in [1, T_{N,t,g}^{SU}]\]
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:

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

**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].
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]:

---

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

**Figure 7** Operating states, including power trajectories for slow-start units  
Source: [33]
Ramp-Based Scheduling VS. Energy-Block Scheduling IN Day-Ahead Market (DAM) 2014

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

\[ p_{gT} \leq \left( \overline{P}_g - P_g \right) \times u_{gT} \quad \forall g \]  
(2)

\[ p_{gt} \geq 0 \quad \forall g, t \]  
(3)

Where \( \overline{P}_g \) and \( P_g \) 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.

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

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

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

\[ 0 \leq u_{gt} \leq 1 \quad \forall t \]  
(7)

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

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

\[ p_{gt} = \sum_{i=1}^{SU} p_{i}^{SU} \times v_{g(t-i+SUb+2)} + \sum_{i=2}^{SD} p_{i}^{SD} \times w_{g(t-i+2)} + \left\{ P_g \times (u_{gt} + v_{g(t+1)}) + p_{gt} \right\} \quad \forall t \]  
(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:

\[ e_{gt} = p_g * u_{gt} + \frac{p_{gt} + p_{g(t-1)}}{2} + \sum_{i=1}^{D} p_{i}^{SU} * w_{g(t-i+1)} + \sum_{i=1}^{D} p_{i}^{SD} * w_{g(t-i+1)} \quad \forall t \]

(10)

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

\[ \hat{p}_{gt} = p_g * (u_{gt} + v_{g(t+1)}) + p_{gt} \quad \forall t \]

(11)

And the total energy production is:

\[ \hat{e}_{gt} = \frac{p_g*(2u_{gt} + v_{g(t+1)} + w_{gt}) + p_{g(t-1)} + p_{gt}}{2} \quad \forall t \]

(12)

For Equations \( \hat{p}_{gt} = \sum_{i=1}^{D} p_{i}^{SU} * v_{g_{t-i+1}} + \sum_{i=1}^{D} p_{i}^{SD} * w_{g_{t-i+1}} \) \( \forall t \) \quad (9) – \( \hat{e}_{gt} = \frac{p_g*(u_{gt} + v_{g(t+1)} + w_{gt}) + p_{g(t-1)} + p_{gt}}{2} \quad \forall t \)

(12), \( t \) is defined for all values, within and outside \([1, T]\). 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;

\[ C = C_g^{NL} * u_{gt} + C_g^{LV} * e_{gt} + C_g^{SU} * v_{gt} + C_g^{SD} * w_{gt} \]

(13)

\[ C_g^{SU} = C_g^{SU} + C_g^{NL} * SU_g \]

(14)

\[ C_g^{SD} = C_g^{SD} + C_g^{NL} * SD_g \]

(15)

\( C_{g,ISU} = C_{g,ISU} + C_{g,NL} * SU_g \)

(14) and

\( C_{g,ISD} = C_{g,ISD} + C_{g,NL} * SD_g \)

(15) redefine costs of startups and shutdowns, to take into account no-load costs during the startup and shutdown process. And \( SU_g = SD_g = 1 \) 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]

![Energy Use in 2013 and Generation Capacity in 2014 of ERCOT system](image)

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

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”.

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

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

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

---

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]:

[Reference to page 25 of an unknown source]
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:

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

\[
\text{InterVarCost} = \text{MinGenCost} \times \text{LSL} - \text{SlopVarCost} \times \text{LSL}
\]

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"](image)

A unit of LSL=130MW, MinGenCost=36.37$/MWh and SlopVarCost=25.46$/MWh, its “InterVarCost” can be approximated by \((36.37 - 25.46) \times 130 = 1418.3\) $/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 $\frac{MinProd}{MaxProd}$. 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 $3hr \times \left(\frac{100MW}{300MW}\right) = 1hr$, 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,

$$SDDuration = \frac{SUHDuration + SUCDuration}{2},$$

whereas for slow-start units,

$$SDDuration = SUHDuration.$$
“$T_{cold}$”

“$T_{cold}$” is a threshold, distinguishing hot from cold startup. If a unit were off for a period of time greater than “$T_{cold}$”, then the next startup of such unit would be considered as a “cold startup”, otherwise, it would be a “hot startup”.

“$T_{cold}$” 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 “SUH Costs” are activated during optimization, “$T_{cold}$” needs to be greater or equal to the addition of these two values. If “$T_{cold}$” is smaller than “MinDwTime”, then the unit will never have a hot startup. Therefore, for simplicity, “$T_{cold}$” are set to equal to the addition of “MinDwTime” and “SUHDuration”.

### 3.2.9 Start-Up and Shut-Down Capabilities

As mentioned in the previous section, start-up ramping rates are different from operating ramping rates. In this case study, they are referred to as start-up and shut-down 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 start-up and shut-down capabilities are simply:

\[
SURamp = SDRamp = \frac{MaxProd}{HotStartupDurations(0 \text{ to full load})};
\]

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

\[
SURamp = SDRamp = \frac{MinProd}{one \text{ period}}
\]

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. Various numerical values can be acquired for consequential analysis.

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.

---

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.

Notice the difference between total demand and net demand7.

---

7 Net Demand = Total Demand – Available Wind Power

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Base Case Building

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).
Ramp-Based Scheduling VS. Energy-Block Scheduling IN Day-Ahead Market (DAM) 2014

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

<table>
<thead>
<tr>
<th>Hour</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
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### Table 8 Power and Energy Demand Profiles of Day 25th December

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<th>14</th>
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</table>

Note: $D^P$, $D^P$ and $D^P$ indicate power [MW] at the end of the hour, which represent the same energy profile; $DE$ refers to total energy demand [MWh] for the hour.
Table 9 and Table 10 above are results obtained in scheduling stages. Notice here EngUC would give the exact same solution for DP1, DP2 and DP3 because 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.
## Ramp-Based Scheduling VS. Energy-Block Scheduling IN Day-Ahead Market (DAM) 2014

### Table 11 Ramp Requirements of DP1 for Day 12th January

<table>
<thead>
<tr>
<th>Hour</th>
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<th>2</th>
<th>3</th>
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*Master in the Power Electric Industry (MEPI)*
### Table 13 Ramp Requirements of D³ for Day 12th January

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<tr>
<th>Hour</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
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<th>9</th>
<th>10</th>
<th>11</th>
<th>12</th>
</tr>
</thead>
<tbody>
<tr>
<td>D³1</td>
<td>-1676</td>
<td>711</td>
<td>28</td>
<td>1368</td>
<td>2035</td>
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<td>-757</td>
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<td>5587</td>
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### Table 14 Ramp Requirements of D³ for Day 25th December

<table>
<thead>
<tr>
<th>Hour</th>
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<th>2</th>
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<td>-386</td>
<td>842</td>
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<td>999</td>
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</tr>
</tbody>
</table>

---

*Master in the Power Electric Industry (MEPI)*
### Ramp Requirements of D^p2 for Day 25th December

<table>
<thead>
<tr>
<th>Hour</th>
<th>1</th>
<th>2</th>
<th>3</th>
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<tbody>
<tr>
<td>D^p2</td>
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<td>-8967</td>
<td>329</td>
<td>-400</td>
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<td>-363</td>
<td>-488</td>
<td>-732</td>
<td>-491</td>
<td>948</td>
<td>934</td>
<td>1105</td>
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<tr>
<td>RmpUC</td>
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</table>

### Ramp Requirements of D^p3 for Day 25th December

<table>
<thead>
<tr>
<th>Hour</th>
<th>15</th>
<th>16</th>
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<th>19</th>
<th>20</th>
<th>21</th>
<th>22</th>
<th>23</th>
<th>24</th>
</tr>
</thead>
<tbody>
<tr>
<td>D^p3</td>
<td>6283</td>
<td>-8886</td>
<td>249</td>
<td>-319</td>
<td>-261</td>
<td>-283</td>
<td>-569</td>
<td>-651</td>
<td>-572</td>
<td>1028</td>
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<td>RmpUC</td>
<td>6687</td>
<td>-9953</td>
<td>6034</td>
<td>-8355</td>
<td>-7023</td>
<td>-6600</td>
<td>-6192</td>
<td>-6108</td>
<td>-6108</td>
<td>2745</td>
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<td>EngUC</td>
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<td>-9965</td>
<td>5488</td>
<td>-7617</td>
<td>-6541</td>
<td>-6432</td>
<td>-6432</td>
<td>-6432</td>
<td>-6432</td>
<td>4566</td>
</tr>
</tbody>
</table>

Table 15 Ramp Requirements of D^p2 for Day 25th December

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 .gdx10 file. Simulation stage is essentially a 5 minute economic dispatch; therefore 24 hours would give rise to 288 sub-periods in total.

\[^{10}.gdx: A file with suffix .gdx, is a file that stores the values of one or more GAMS symbols such as sets, parameters variables and equations.\]
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 12^{th} January, it requires a downward ramp which has released the system from running out of upward ramp capability.

For day 25^{th} 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 12^{th} January as mentioned in the previous paragraph also appears in period 24 of D^{P1} on 25^{th} December. **Table 18** below shows all energy non-supplied of D^{P2} on 25^{th}.

<table>
<thead>
<tr>
<th>Period that ENS occurs</th>
<th>ENS [MW]</th>
</tr>
</thead>
<tbody>
<tr>
<td>p01</td>
<td>28.969</td>
</tr>
<tr>
<td>p02</td>
<td>141.538</td>
</tr>
<tr>
<td>p03</td>
<td>312.916</td>
</tr>
<tr>
<td>p04</td>
<td>488.475</td>
</tr>
<tr>
<td>p05</td>
<td>673.230</td>
</tr>
<tr>
<td>p06</td>
<td>870.003</td>
</tr>
<tr>
<td>p07</td>
<td>1089.030</td>
</tr>
<tr>
<td>p08</td>
<td>1337.583</td>
</tr>
<tr>
<td>p09</td>
<td>1596.786</td>
</tr>
<tr>
<td>p10</td>
<td>1856.545</td>
</tr>
<tr>
<td>p11</td>
<td>2120.264</td>
</tr>
<tr>
<td>p12</td>
<td>2394.647</td>
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<td>p13</td>
<td>2189.913</td>
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<td>p14</td>
<td>1509.216</td>
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<td>p15</td>
<td>852.010</td>
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<td>265.113</td>
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<td>p283</td>
<td>8.189</td>
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<td>32.391</td>
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<td>p285</td>
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<td>p286</td>
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<td>p287</td>
<td>128.465</td>
</tr>
<tr>
<td>p288</td>
<td>160.490</td>
</tr>
</tbody>
</table>

*Table 18 Energy non-supplied of D^{P2} of Day 25^{th} 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 12th January, they are quite similar, however, when compared for day 25th 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 25th 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 12th 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.
<table>
<thead>
<tr>
<th></th>
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<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td># Tot$^{13}$</td>
<td>ENS$^{14}$ [GWh]</td>
</tr>
<tr>
<td>RmpUC</td>
<td>D$^{p1}$</td>
<td>7.669</td>
<td>28.594</td>
<td>36.263</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
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<td>D$^{p2}$</td>
<td>7.661</td>
<td>28.600</td>
<td>36.261</td>
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<td>0</td>
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<tr>
<td></td>
<td>D$^{p3}$</td>
<td>7.677</td>
<td>28.605</td>
<td>36.282</td>
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<td>0</td>
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<tr>
<td>EngUC</td>
<td>D$^{p1}$</td>
<td>7.734</td>
<td>28.548</td>
<td>36.282</td>
<td>8</td>
<td>0.0957</td>
</tr>
<tr>
<td></td>
<td>D$^{p2}$</td>
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<td>7.747</td>
<td>28.534</td>
<td>36.280</td>
<td>18</td>
<td>0.3422</td>
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</table>

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

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<th></th>
<th></th>
<th></th>
<th></th>
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</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td># Tot $^{13}$</td>
<td>ENS [GWh]</td>
</tr>
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<td>D$^{p1}$</td>
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<td>16.608</td>
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<td>0</td>
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<td></td>
<td>D$^{p2}$</td>
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<td>20.582</td>
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<td>0</td>
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<tr>
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<td>D$^{p3}$</td>
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<td>16.609</td>
<td>20.582</td>
<td>0</td>
<td>0</td>
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<tr>
<td>EngUC</td>
<td>D$^{p1}$</td>
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<td>16.608</td>
<td>20.490</td>
<td>21</td>
<td>1.518</td>
</tr>
<tr>
<td></td>
<td>D$^{p3}$</td>
<td>3.882</td>
<td>16.609</td>
<td>20.491</td>
<td>21</td>
<td>1.518</td>
</tr>
</tbody>
</table>

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 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^2 of 25th December as an example again, below is a screen capture of .gdx files showing total curtailment of wind.

![Figure 19 Total Demand and Wind Production on 25th December](image)

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

Table 21 Problem Size of ENGUC & RMPUC on 12th January

<table>
<thead>
<tr>
<th>Approach</th>
<th>Constraints</th>
<th>Nonzero Elements</th>
<th>Continuous Variables</th>
<th>Binary Variables</th>
</tr>
</thead>
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<td>34783</td>
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<td>589304</td>
<td>28248</td>
<td>21448</td>
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</table>

Table 22 Problem Size of ENGUC & RMPUC on 25th December

<table>
<thead>
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<th>Approach</th>
<th>Constraints</th>
<th>Nonzero Elements</th>
<th>Continuous Variables</th>
<th>Binary Variables</th>
</tr>
</thead>
<tbody>
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<td>34725</td>
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<td>102566</td>
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<td>28248</td>
<td>21455</td>
</tr>
</tbody>
</table>

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.
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]
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.

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.
References


electricity. Regulation of Energy Utilities Training Course. Florence, Italy: Florence School of Regulation


2014].


Ramp-Based Scheduling VS. Energy-Block Scheduling IN Day-Ahead Market (DAM) 2014


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**

(“SUH Durations”, “SUC Durations” and “SDD Durations”)

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.

![Diagram of models and their functionalities](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.

![Schematic Illustration of Single Node System](image)

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

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 25\textsuperscript{th} December, as well as wind injection for consecutive 24 periods.

<table>
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<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
<th>G</th>
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Figure 24 Power & Energy Demand of D\textsuperscript{D2} on Day 25\textsuperscript{th} 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\textsuperscript{D2} shown in Figure 24, two other power profiles are created presented in Figure 25 and Figure 25.
### Figure 25: Power and Energy Demand of D^P1 on Day 25th December

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### Figure 26: Power and Energy Demand of D^P3 on Day 25th December

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* Master in the Power Electric Industry (MEPI)*
| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U | V |
| 2 | | A | 500 | 100 | 0 | -8 | 198 | 198 | 1120 | 12 | 32735 | 6 | 8 | 0 | 1 | 17500 | 1 | 3500 | 1 | 9 | 16667 | 16667 |
| 3 | | B | 500 | 500 | 0 | -8 | 204455 | 204455 | 21955 | 3 | 32735 | 6 | 8 | 0 | 1 | 16707 | 1 | 4073 | 1 | 9 | 2218 | 2218 |
| 4 | | C | 1000 | 1000 | 0 | -8 | 14859 | 14857 | 54399 | 4 | 32735 | 6 | 8 | 0 | 1 | 727 | 1 | 727 | 1 | 9 | 40 | 40 |
| 5 | | D | 1500 | 1500 | 0 | -8 | 138 | 138 | 1385 | 1 | 32735 | 6 | 8 | 0 | 1 | 235 | 1 | 2583 | 1 | 9 | 52 | 52 |
| 6 | | E | 2000 | 2000 | 0 | -8 | 138 | 138 | 1385 | 1 | 32735 | 6 | 8 | 0 | 1 | 235 | 1 | 2583 | 1 | 9 | 52 | 52 |
| 7 | | F | 2500 | 2500 | 0 | -8 | 138 | 138 | 1385 | 1 | 32735 | 6 | 8 | 0 | 1 | 235 | 1 | 2583 | 1 | 9 | 52 | 52 |
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| 9 | | H | 3500 | 3500 | 0 | -8 | 138 | 138 | 1385 | 1 | 32735 | 6 | 8 | 0 | 1 | 235 | 1 | 2583 | 1 | 9 | 52 | 52 |
| 10 | | I | 4000 | 4000 | 0 | -8 | 138 | 138 | 1385 | 1 | 32735 | 6 | 8 | 0 | 1 | 235 | 1 | 2583 | 1 | 9 | 52 | 52 |
| 11 | | J | 4500 | 4500 | 0 | -8 | 138 | 138 | 1385 | 1 | 32735 | 6 | 8 | 0 | 1 | 235 | 1 | 2583 | 1 | 9 | 52 | 52 |
| 12 | | K | 5000 | 5000 | 0 | -8 | 138 | 138 | 1385 | 1 | 32735 | 6 | 8 | 0 | 1 | 235 | 1 | 2583 | 1 | 9 | 52 | 52 |
| 13 | | L | 5500 | 5500 | 0 | -8 | 138 | 138 | 1385 | 1 | 32735 | 6 | 8 | 0 | 1 | 235 | 1 | 2583 | 1 | 9 | 52 | 52 |
| 14 | | M | 6000 | 6000 | 0 | -8 | 138 | 138 | 1385 | 1 | 32735 | 6 | 8 | 0 | 1 | 235 | 1 | 2583 | 1 | 9 | 52 | 52 |
| 15 | | N | 6500 | 6500 | 0 | -8 | 138 | 138 | 1385 | 1 | 32735 | 6 | 8 | 0 | 1 | 235 | 1 | 2583 | 1 | 9 | 52 | 52 |
| 16 | | O | 7000 | 7000 | 0 | -8 | 138 | 138 | 1385 | 1 | 32735 | 6 | 8 | 0 | 1 | 235 | 1 | 2583 | 1 | 9 | 52 | 52 |
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| 19 | | R | 8500 | 8500 | 0 | -8 | 138 | 138 | 1385 | 1 | 32735 | 6 | 8 | 0 | 1 | 235 | 1 | 2583 | 1 | 9 | 52 | 52 |
| 20 | | S | 9000 | 9000 | 0 | -8 | 138 | 138 | 1385 | 1 | 32735 | 6 | 8 | 0 | 1 | 235 | 1 | 2583 | 1 | 9 | 52 | 52 |
| 21 | | T | 9500 | 9500 | 0 | -8 | 138 | 138 | 1385 | 1 | 32735 | 6 | 8 | 0 | 1 | 235 | 1 | 2583 | 1 | 9 | 52 | 52 |
| 22 | | U | 10000 | 10000 | 0 | -8 | 138 | 138 | 1385 | 1 | 32735 | 6 | 8 | 0 | 1 | 235 | 1 | 2583 | 1 | 9 | 52 | 52 |

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.
Ramp-Based Scheduling VS. Energy-Block Scheduling IN Day-Ahead Market (DAM)

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](image)
## Ramp-Based Scheduling VS. Energy-Block Scheduling IN Day-Ahead Market (DAM) 2014

### Partial Tabulated Unit Production level [GW] in descending order with EngUC

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Note: EngUC = Engineering Unit Cost.
Figure 32 Production level for each unit of $D^1$ with $RmpUC$

Figure 33 Total generation in each hour of $D^1$ with $RmpUC$
Ramp-Based Scheduling VS. Energy-Block Scheduling IN Day-Ahead Market (DAM) 2014

Figure 34 Production level for each unit of $D^3$ with $RmpUC$

Figure 35 Total generation in each hour of $D^3$ with $RmpUC$
Ramp-Based Scheduling VS. Energy-Block Scheduling IN Day-Ahead Market (DAM) 2014

Figure 36 Production level for each unit of D³ with RmpUC

Figure 37 Total generation in each hour of D³ 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.
### Ramp-Based Scheduling VS. Energy-Block Scheduling IN Day-Ahead Market (DAM)

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

| Date       | 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       | Total Production |
|------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|
| DAM 2014   | 01/01   | 01/02   | 01/03   | 01/04   | 01/05   | 01/06   | 01/07   | 01/08   | 01/09   | 01/10   | 01/11   | 01/12   | 01/13   | 01/14   | 01/15   | 01/16   | 01/17   | 01/18   | 01/19   | 01/20   | 01/21   | 01/22   | 01/23   | 01/24   | 01/25   | 01/26   | 01/27   | 01/28   | 01/29   | 01/30   | 01/31   | 02/01   |
| DAM 2014   | 02/01   | 02/02   | 02/03   | 02/04   | 02/05   | 02/06   | 02/07   | 02/08   | 02/09   | 02/10   | 02/11   | 02/12   | 02/13   | 02/14   | 02/15   | 02/16   | 02/17   | 02/18   | 02/19   | 02/20   | 02/21   | 02/22   | 02/23   | 02/24   | 02/25   | 02/26   | 02/27   | 02/28   | 02/29   | 02/30   | 02/31   | 03/01   |
| DAM 2014   | 03/01   | 03/02   | 03/03   | 03/04   | 03/05   | 03/06   | 03/07   | 03/08   | 03/09   | 03/10   | 03/11   | 03/12   | 03/13   | 03/14   | 03/15   | 03/16   | 03/17   | 03/18   | 03/19   | 03/20   | 03/21   | 03/22   | 03/23   | 03/24   | 03/25   | 03/26   | 03/27   | 03/28   | 03/29   | 03/30   | 03/31   | 04/01   | 04/02   |
| DAM 2014   | 04/01   | 04/02   | 04/03   | 04/04   | 04/05   | 04/06   | 04/07   | 04/08   | 04/09   | 04/10   | 04/11   | 04/12   | 04/13   | 04/14   | 04/15   | 04/16   | 04/17   | 04/18   | 04/19   | 04/20   | 04/21   | 04/22   | 04/23   | 04/24   | 04/25   | 04/26   | 04/27   | 04/28   | 04/29   | 04/30   | 05/01   | 05/02   | 05/03   |

*Note: The table continues with similar entries.*
Figure 40 Production level for each unit of D¹ with RmpUC

Figure 41 Total generation in each hour of D² with RmpUC
Ramp-Based Scheduling VS. Energy-Block Scheduling IN Day-Ahead Market (DAM) 2014

Figure 42 Production level for each unit of D² with RmpUC

Figure 43 Total generation in each hour of D² with RmpUC

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Figure 44 Production level for each unit of D³ with RmpUC

Figure 45 Total generation in each hour of D³ with RmpUC