RELIABILITY UNIT COMMITMENT IN ERCOT NODAL MARKET

by

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Presented to the Faculty of the Graduate School of

The University of Texas at Arlington in Partial Fulfillment

of the Requirements

for the Degree of

DOCTOR OF PHILOSOPHY

THE UNIVERSITY OF TEXAS AT ARLINGTON

May 2013

Acknowledgements

I would like to express my sincere appreciation and gratitude to my supervisor, Dr. Wei-Jen Lee, and my former supervisor, Dr. Raymond R. Shoults, for their guidance, encouragement, and continuous support throughout my Ph.D. program. My appreciation is extended to Dr. William E. Dillon, Dr. Rasool Kenarangui, Dr. Weidong Zhou, and Dr. David A. Wetz for their guidance as members of my graduate committee.

Grateful appreciation is also extended to all friends and members of Energy System Research Center at The University of Texas at Arlington for their valuable assistance during the course of my study.

I would also like to thanks all the members of ERCOT and ABB nodal market management system team for their support during the design and implementation of the nodal reliability unit commitment system.

Finally, I would like to express my deepest appreciation to all my family members for their love, encouragement, and continuous support.

February 13, 2013

Abstract

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The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) that ensures a reliable electric grid and efficient electricity markets in the ERCOT region. ERCOT has successfully transited from a zonal market to an advanced nodal market since Dec. 2010. In the new ERCOT nodal wholesale market, a reliability unit commitment (RUC) process has been designed and implemented to ensure transmission system reliability and security. The main objective of RUC is to ensure that enough resource capacity, in addition to ancillary service capacity, is committed in the right locations to reliably serve the forecasted load in the ERCOT system. The "make-whole" payment mechanism has been employed by ERCOT for RUC settlement to ensure all generating resources committed by RUC are adequately compensated for their operation costs.

The RUC is implemented in a security constrained unit commitment (SCUC) framework that minimizes the total operation costs based on generator three-part supply offers subject to various system and resource security constraints. The SCUC is comprised of two main functions: network constrained unit commitment (NCUC) and network security monitor (NSM). An efficient NCUC-NSM iteration clearing process has been proposed to solve the SCUC problem. Some enhanced features have been implemented in the SCUC engine to handle special resource scheduling such as

combined cycle resources, split generation resources and self-committed resources. The mixed integer programming (MIP) methodology has been adopted to solve the SCUC problem due to its robustness over other unit commitment algorithms.

The combined cycle unit (CCU) contributes a significant share of ERCOT total installed capacity. How to accurately and efficiently model the CCU is one of the key factors for a successful ERCOT nodal market. A robust CCU modeling is proposed for the SCUC in two different ways to facilitate market operations and ensure the system reliability. The configuration-based model is more adequate for bid/offer processing and dispatch scheduling and therefore it is adopted in the NCUC. On the other hand, the physical unit modeling is more adequate for the power flow and network security analysis and therefore it is adopted in the NSM.

Currently there are eight phase shifters in the ERCOT system. These phase shifters are primarily intended for relieving transmission overloads caused by variations in wind generation. To improve dispatch efficiency and accuracy, a phase shifter optimization model has been proposed to automatically determine the tap positions of the phase shifters in the RUC optimization.

During the design phase of the nodal RUC project, a prototype RUC program with the proposed combined cycle unit (CCU) modeling has been developed to verify the effectiveness of the CCU modeling. The prototype RUC program has been tested on a revised PJM 5-bus system and the results are very promising. Because of the positive testing results, the proposed CCU modeling has been adopted for the RUC project and eventually implemented for the production RUC by the vendor. The testing results from the production RUC have demonstrated that the proposed RUC system is very robust and can improve dispatch efficiency and system reliability as well as ensuring more effective congestion management.

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Chapter 1

Introduction

1.1 ERCOT Overview

The Electric Reliability Council of Texas (ERCOT) is the Independent System Operator (ISO) that operates the electric grid and manages the deregulated wholesale electricity market for the ERCOT region. ERCOT is one of the 10 independent system operators (ISOs) and regional transmission organizations (RTOs) of the ISO/RTO Council (IRC) in North America. The 10 ISOs and RTOs in North America serve two-thirds of electricity consumers in the United States as well as more than 50 percent Canada's population [1]. The map of the ISO/RTO operating regions is shown in Figure 1-1.

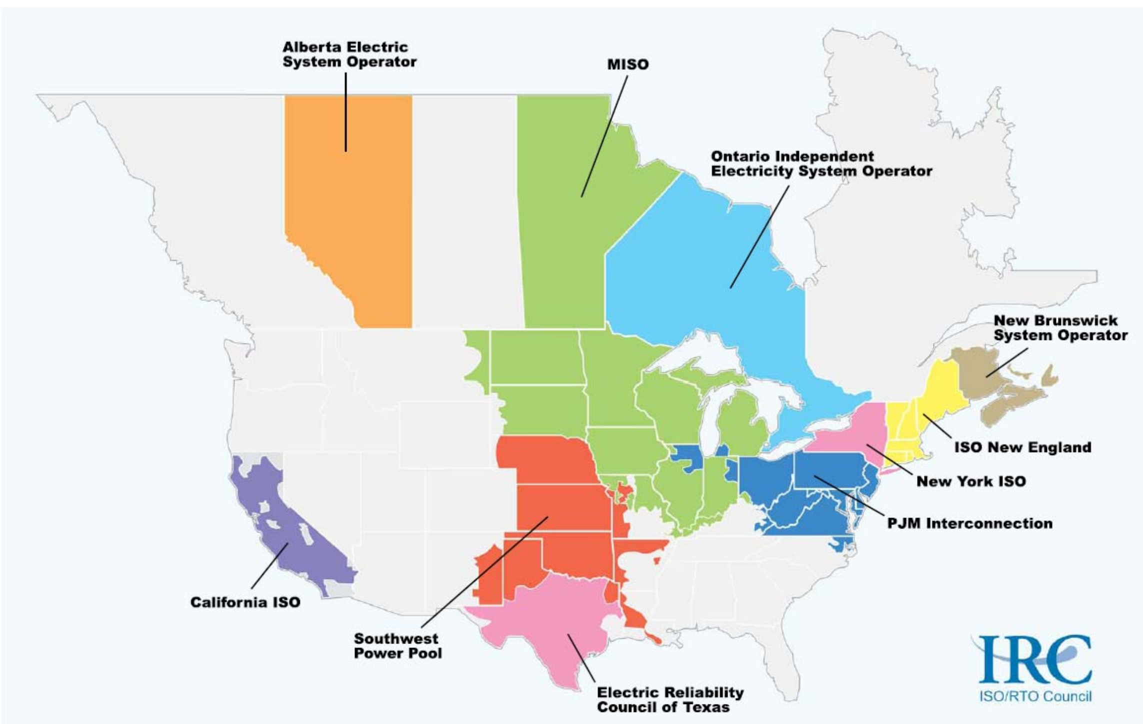

Figure 1-1 North America ISO/RTO Operating Regions

Source: http://www.isorto.org

The ERCOT region covers about 75 percent of land area in Texas. ERCOT manages the flow of electric power to 23 million Texas customers representing 85 percent of the state’s electric load. The ERCOT grid connects 40,500 miles of transmission lines and more than 550 generation units. ERCOT has 74,000 megawatts (MW) total generating capacity and a peak load of 68,305 MW recorded on August 3, 2011[1].The total energy used in 2011 is about 335 billion KWh and it is a 5% increase compared to 2010. There are more than 1,100 active market participants that generate, move, buy, sell or use wholesale electricity in ERCOT market. The total market size is around $34 billion based on the 335 billion KWh market volume and average $0.10/KWh rate [2].

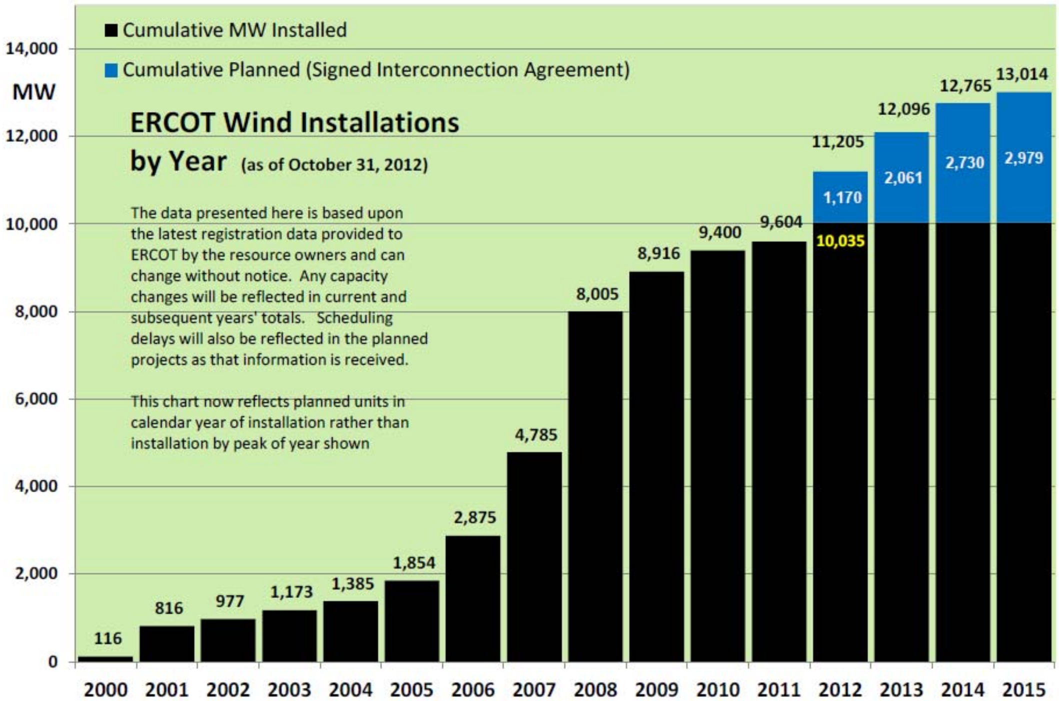

Figure 1-2 ERCOT Wind Generation Installation by Year

ERCOT's installed wind generation capacity is the highest among major ISOs in the United States. The ERCOT wind generation installation by year is shown in Figure 1-2. As of Oct. 31, 2012, ERCOT has 10,035 MW wind generation capacity installed with nearly 21,000 MW of additional wind generation under review. The wind generation record is 8,638 MW on Dec. 25, 2012 which accounts for 26 percent of total system load at the time. On the other hand, because the rapid increase of wind energy and the intermittence nature of thewind power, it imposes big challenges to system operation.

1.2 ERCOT Nodal Market

In 1999, Senate Bill 7 (SB7) restructured the Texas electricity market by unbundling the investor-owned utilities and creating retail customer choice in those areas. areas, and assigned ERCOT four primary responsibilities [2]:

- System reliability – planning and operations
- Open access to transmission
- Retail switching process for customer choice
- Wholesale market settlement for electricity production

In 2001, ERCOT began its single control area operation and opened both its wholesale and retail electricity market to competition based on a zonal market structure. In the zonal market, the ERCOT region is divided into congestion management zones (CMZs) which are defined by the commercially significant constraints (CSCs) [2] [4].

In 2003, the Public Utility Commission of Texas (PUCT) ordered ERCOT to develop a nodal wholesale market design. The redesigned ERCOT grid consists of more than 4,000 nodes and it will replace the existing CMZs. The implementation of the nodal market is expected to improve price signals, improve dispatch efficiencies and direct assignment of local congestion [3]-[5]. The changes between the ERCOT zonal and nodal market are summarized in Figure 1-3 below [3].

Zonal Market	Nodal Market
Transmission congestion rights (TCR)	Congestion revenue rights (CRR)
No day-ahead energy market Day-ahead market for ancillary services procured for capacity	Day-ahead energy and ancillary services co-optimized market (DAM)
Replacement reserve service (RPRS) and out-of-merit capacity (OOMC)	Day-ahead reliability unit commitment (DRUC)
Hour-ahead studies	Hourly reliability unit commitment (HRUC)
Portfolio-based offers by zone	Resource-specific offers
Balancing energy service (BES) every 15 minutes Zonal congestion management by portfolio for CSCs Resource-specific for local congestion	Security constrained economic dispatch (SCED) generally every five minutes (still 15-minute settlement) All congestion management will be resource-specific Enhanced load frequency control
Zonal average shift factors for resources	Actual shift factors for resources
Zonal market clearing prices for BES for generation and loads	Nodal locational marginal pricing (LMP) for generation. Zonal weighted LMP for loads

Figure 1-3 ERCOT Zonal Market vs. Nodal Market

On Dec. 1, 2010, ERCOT successfully launched the locational marginal pricing based Nodal Market. The redesigned comprehensive nodal market includes congestion revenue right (CRR) auction market, a day-ahead market (DAM), reliability unit commitment (RUC) and real-time security constrained economic dispatch (SCED).

A congestion revenue right (CRR) is a financial instrument that entitles the CRR owner to be charged or to receive compensation for congestion rents that arise in the day-ahead market (DAM) or in real-time. Owning a CRR doesn't provide the CRR owner a right to receive or obligation to deliver the physical energy. CRRs are defined by a MW amount, settlement point of injection (source) and settlement point of withdrawal (sink). There are two types of CRR ownership: point-to-point (PTP) Obligations and point-to-point (PTP) Options. The PTP Obligation may result in either a payment or a charger for the CRR ownership but the PTP Options can only result in a payment for the CRR

Ownership. CRRs are auctioned by ERCOT monthly and annually and the revenues collected from the auctions are returned to loads base on the load ratio share.

The day-ahead market (DAM) is a forward financial electricity market cleared in day-ahead. The DAM clearing process co-optimizes the energy offers and bids, ancillary services and certain types of congestion revenue rights (CRRs) by maximize system-wide economic benefits. The DAM clearing results include the unit commitments for resources with three-part supply offer, the awards for energy offers and bids, awards for ancillary services and awards for certain type of CRRs. The DAM scheduling also complies with network security constraint in addition to the usual resource constraints. The main purposes for the DAM are scheduling energy and ancillary services, providing price certainty and discovery for the next operating day.

The reliability unit commitment (RUC) is a daily or hourly process conducted to ensure sufficient generation capacity is committed to reliably serve the forecasted ERCOT demand [6]. RUC is also used to monitor and ensure the transmission system security by performing the network security analysis (NSA). The DAM clearing is based on the voluntary energy offers and bids instead of the load forecast. The resources committed in the DAM may not be sufficient to meet the actual energy and ancillary service capacity requirements in real-time. Hence the RUC process is needed to procure enough resource capacity to meet load forecast in addition to ancillary service capacity requirement. The RUC process works like a bridge filling the capacity gap between the financial DAM and real-time to ensure the reliable operation of the ERCOT market. There are three RUC processes used in the ERCOT nodal market:

- Day-ahead RUC (DRUC): DRUC runs once a day. It is used to determine if additional commitments needed to be made for the next operating day.

- Hourly RUC (HRUC): HRUC process is executed every hour. It is used to fine-tuning the commitment decision made by DRUC based on the latest system condition.
- Weekly RUC (WRUC): WRUC process is an offline planning tool. Its study period is configurable and could be up to one week.

During real-time operations, the security constrained economic dispatch (SCED) dispatches online generation resources based on their Energy Offer Curves to match the total system demand provided by the EMS while observing resource ramping and transmission constraints. The SCED process produces the base point and locational marginal prices (LMPs) for each generating resource. ERCOT uses these base points to deploy various ancillary services such as regulation up, regulation down, responsive reserve, and non-spinning reserve services to control system frequency and solve potential reliability issues [10].

The ERCOT nodal market structure is illustrated in Figure 1-4 [4]. The adjustment period is defined as the time between 1800 of day-ahead up to the 60 minutes prior to the operating hour. The MIS denotes the market information system which is an electronic communication interface used by ERCOT to provide information to the public and market participants.

The two-settlement system [10] has been adopted for the ERCOT nodal market. The two-settlement provides the ERCOT market participants with the option to participate in a forward market for energy. It consists of two markets: day-ahead forward market and real-time balancing market and it separates the settlements performed for each market. The Day-ahead market settlement is based on the scheduled hourly quantities and day-ahead hourly LMPs and the real-time market settlement is based on the actual 15-minutes quantity deviations from the day-ahead schedules priced at real-time LMPs.

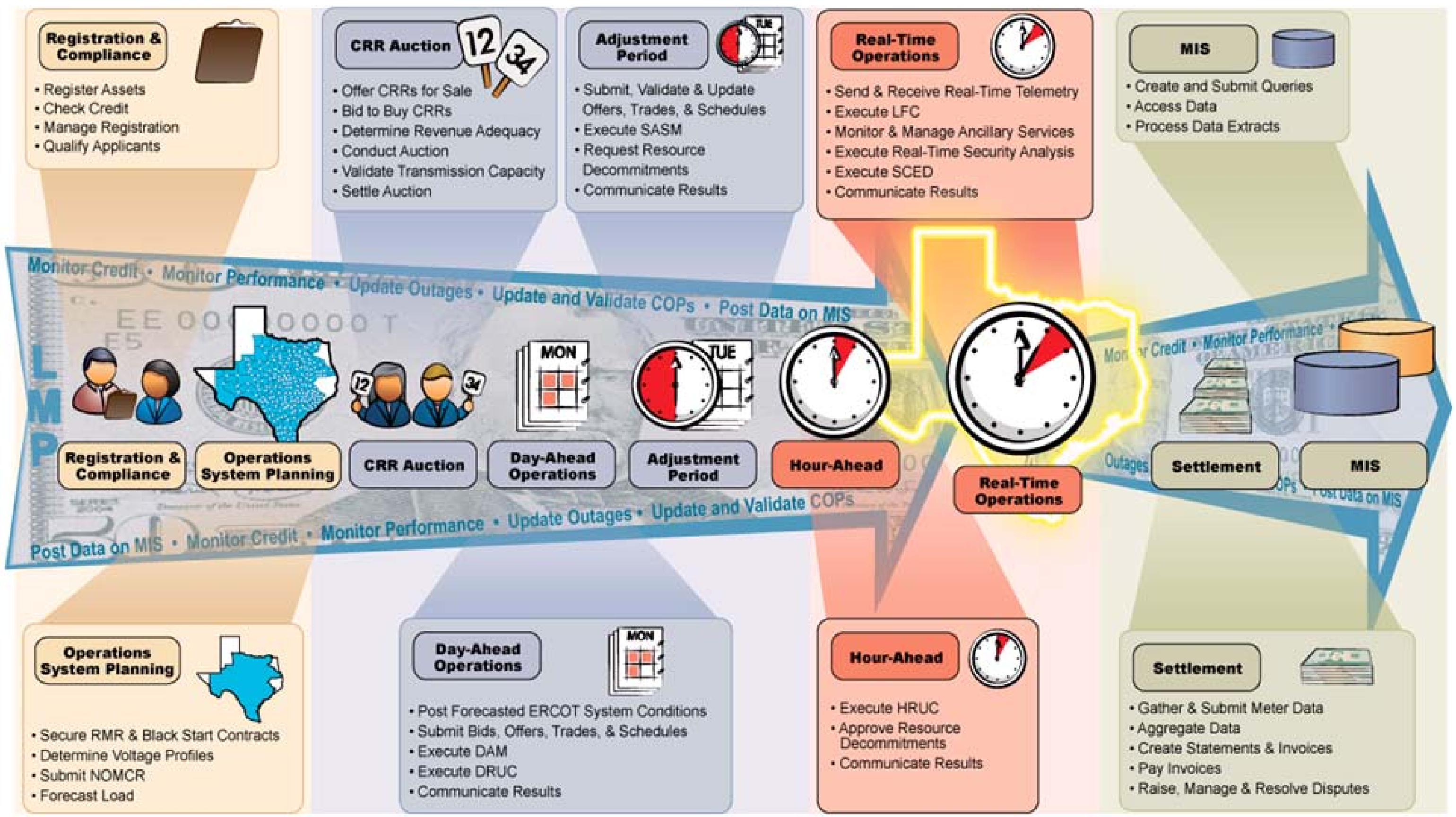

Figure 1-4 ERCOT Nodal Market Structure

1.3 Unit Commitment Review

1.3.1 Introduction

The unit commitment (UC) is the optimization process of determining the startup and shutdown schedules of generation units over a given study period [7]-[11]. The UC optimization is extensively used in short term daily system operations for study period from one to seven operating days and it is also used for operational planning and portfolio evaluation over longer time horizon.

The security constrained unit commitment (SCUC) is a major enhancement and extension of the conventional unit commitment [13]-[17]. In SCUC, the security is explicitly takes into account by ensuring transmission constraints both base case and post-contingency are within the limits. By incorporating security network constraints, the generation units are committed economically in a manner to ensure that the system is still secure for all credible contingencies.

SCUC has already replaced the conventional UC in many major electricity markets including the North America. In the deregulated electricity market, SCUC is utilized by ISO/RTO to clear the day-ahead market (DAM) and perform reliability unit commitment (RUC) [24]-[27]. The objective of SCUC is to minimize system operating costs while satisfying various system and resource constrains, such as power balance, system ancillary service requirements, transmission constraints, minimum and maximum generation limits, minimum up and down time limits, ramping up/down limits, tap position and limits of phase shifters [13].

With the increased penetration of renewable resources and the increase of demand response participation, how to model the uncertainty in the ISO SCUC becomes a big challenge. Recently, stochastic unit commitment [18] [19] [28] and robust unit commitment [29] have been proposed for uncertainty modeling and risk management.

The stochastic unit commitment minimizes the expected cost of the unit commitment problem. It is a conventional way to model the unit commitment problem with the real-time uncertainties. The advantage of the stochastic unit commitment is able to quantify the expectations such as evaluating probability of outcomes and the disadvantages are computationally challenging and difficulty to decide the exact and accurate distribution. However it requires the knowledge of probability distribution of the uncertain parameters. The robust unit commitment minimizes the cost of unit commitment problem for the worst case. It models the random demand using uncertainty sets instead of probability distributions. The advantages of the robust unit commitment are computationally tractable and free of distribution. However, it is unable to provide probability measure such as expectations and difficulty to choose the right uncertainty set [29]. Both of these two methods are still in the research phase and haven't been implemented in the ISO production system.

1.3.2 Unit Commitment Solution Methodology

The unit commitment problem is a complicated large-scale mixed-integer and nonlinear optimization problem which has been an active research topic for several decades. Recent literature review on the unit commitment solved either by the ISO or by the producers can be found in [47] [48]. As a consequence, various optimization algorithms such as exhaustive enumeration [49] [50], priority listing [51]-[53], dynamic programming [54]-[56], Lagrangian relaxation [57]-[65], mixed-integer programing [66]-[74], simulated annealing [75]-[77], and generic algorithms [78]-[81] have been developed to solve the optimal UC problem. Among these algorithms, the mixed integer programing (MIP) and Lagrangian relaxation (LR) are the most widely applied methods among industry.

Until recently, the LR was the primary solution method for the traditional unit commitment software executed by system operators in control center [24] [27]. However in the last decade, the advances in computer hardware and the commercial MIP solver make the MIP as the dominant practical solution to the large ISO size UC problems [24]-[27]. The comparisons between MIP and LR for the ISO unit commitment problem are discussed in [24], [82], and [83]. The main advantages of the MIP formulation over the LR formulation are that 1) it can provide a global optimality, 2) it provides a more accurate measure of optimality, 3) it improves the security constraints modeling and 4) it provides enhanced modeling capabilities and adaptability [24] [83]. In addition, the major benefit of using the MIP in the development is that it allows the developer to focus on the problem definition itself rather than the optimization algorithm development. It is much simpler to add new constraints into the MIP formulation without involving heuristic, which will reduce the software development cycle and facilitate its application to the large UC problem. Though the main disadvantage for the MIP formulation over LR is its scalability and run time [25], [68], and [69], the commercial MIP solvers are capable of solving the ISO size SCUC problem within acceptable time. The MIP formulation becomes the recent trend for the large and complex ISO SCUC problems including both day-ahead market clearing and reliability unit commitment.

Once the SCUC problem is formulated and represented in the MIP format, the solution can be sought by calling a standard MIP package such as CPLEX [84], GUROBI [85], LINDO [86], Xpress [87], and so on. Among of these MIP packages, the commercial CPLEX solver is well known for its high performance and it is robust and reliable. The CPLEX's mathematical programming technology enables analytical decision support for improving efficiency, reducing costs, and increasing profitability [84]. Hence the CPLEX/MIP has been widely utilized by the ISO to solve the SCUC problem.

1.4 Reliability Unit Commitment in ERCOT Zonal Market

The zonal market of ERCOT is based on the transfer capacity of the 345KV transmission network between CMZs. The CMZs are determined by clustering load and generator buses based on their shift factors on selected Commercially Significant Constraints (CSCs). In order to facilitate the zonal operations, transmission constraints are categorized into intra-zonal (local) and inter-zonal constraints.

In zonal market, the replacement reserve service (RPRS) performs similar functions as the RUC in the nodal market [20][30]. The RPRS market is run at the day-ahead and during the adjustment period if needed to procure additional capacity from specific generation or load resources to resolve system capacity insufficiency, inter-zonal and intra-zonal congestion. Required by ERCOT zonal protocols, the cost associated with the procurement of RPRS for capacity insufficiency and inter-zonal congestion are directly assigned to those market participants who have negatively impacted the system. The costs for intra-zonal congestion are uplifted to all loads in the ERCOT system. To distinguish between procured resources for relieving intra-zonal constraints versus inter-zonal and system capacity constraints, the clearing of the RPRS market employs a 3-step process:

- Step 1 procures capacity to resolve intra-zonal congestion using the resource category generic costs.
- Step 2 procures capacity to resolve inter-zonal congestion and system capacity constraints using market-based offers.
- Step 3 determines the RPRS market clearing prices for capacity.

The RPRS process has been officially online since early 2006 and it has greatly helped ERCOT operators to make the reliability commitment decisions. However the following challenges and deficiencies for the RPRS have also been identified by ERCOT:

- Due to the multi-step congestion relief process, there is no guarantee that the intra-zonal congestion will remain secure after the step2 procurement.
- The RPRS does not model the resource specific ancillary service (AS) schedules in the clearing. The ancillary schedules are submitted by Qualified Scheduling Entities (QSEs) on a portfolio basis and the RPRS only enforces a system capacity constraint for the system total online AS requirements. This approach cannot identify the AS deliverability problems and it may cause the RPRS under procurement problem.
- There are deficiencies in handling the scheduling of some special resources in RPRS. For instance, combined cycle resources are modeled the same as individual physical units. Therefore, the possibility of procuring a steam unit without the corresponding gas-turbine unit exists. If this situation occurs, ERCOT operators need to either manually deselect the resource or bring on the additional resources necessary to create feasible combined cycle configurations.

The above RPRS challenges and deficiencies have been considered during the nodal RUC design and most of them have been solved in the nodal RUC [6], [30]-[32].

1.5 Objectives of Dissertation

It has been widely accepted that the reliability unit commitment (RUC) process is required in the restructured electricity markets to maintain system reliability while minimizing the overall operational cost for committing additional units [20]-[23]. The RUC function has been implemented in many ISOs, such as PJM, NYISO, MISO, CASIO, and ISO-NE [23]-[27]. Unlike the day-ahead market (DAM) which provides a financial platform for market participants to trade energy, RUC is critical to power system security in such a way that it ensures sufficient online resource capacity is available at the right location to satisfy the demand in real-time. The RUC process utilizes the security constrained unit commitment (SCUC) framework with a full network model to enforce transmission flows and bus voltages within limit and to meet the (N-1) system reliability criteria. On the other hand, there are also some technical challenges and issues related to the RUC, such as combined cycle units modeling, wind modeling [20]-[22].

In ERCOT nodal market, the reliability unit commitment (RUC) process is needed to determine the commitment of additional offline available resources as necessary on top of those already self-committed for bilateral contracts and committed by other markets such as DAM, to meet the forecasted real-time demand plus the ancillary services (AS) capacity and meet the system's security requirements. The objectives of this dissertation is to develop a reliability unit commitment (RUC) system to improve the reliability and efficiency operation of ERCOT nodal market by addressing the issues and deficiencies observed in the zonal replacement reserve service (RPRS) market.

In this dissertation, the RUC is implemented in a security constrained unit commitment (SCUC) framework to minimize the total operation costs based on generator three-part supply offers subject to various system and resource security constraints. The NCUC-NSM iteration clearing process is applied to solve the SCUC problem. Some enhanced features are implemented in the SCUC to handle special resource scheduling such as combined cycle resources, split generation resources and self-committed resources. The mixed integer programming (MIP) methodology has been adopted to solve the SCUC problem.

The combined cycle unit is modeled in two different ways in SCUC. The configuration-based model is more adequate for bid/offer processing and dispatch scheduling and therefore it is adopted in the NCUC. On the other hand, the physical unit modeling is more adequate for the power flow and network security analysis and therefore it is adopted in the NSM.

The phase shifters installed in ERCOT are primarily for relieving transmission overloads caused by variations in wind generation. To improve dispatch efficiency and accuracy, a phase shifter optimization model has been proposed to automatically determine the tap positions of the phase shifters in the RUC optimization algorithm.

The proposed RUC system has been successfully implemented in the ERCOT production system. The results show that the proposed RUC system is very robust and can improve dispatch efficiency and ensure more effective congestion management.

1.6 Organization of the Dissertation

This dissertation consists of seven chapters and two appendixes. The contents of this dissertation are organized as follows.

Chapter 1 first presents the overview of ERCOT and its recently redesigned nodal market. Next it reviews the unit commitment problem and the associated solution methodologies. Then it discusses the issues with replacement reserve service (RPRS) in zonal market, last it discusses the objectives of the dissertation as well as the organization of this dissertation.

Chapter 2 first introduces the new RUC process under the new ERCOT nodal market design. Next it discusses the RUC input and pre-processing, then it discusses some special scheduling features of the RUC system. Last it presents the settlement of the nodal RUC process.

Chapter 3 discusses the proposed RUC solution engine implemented in the framework of security constrained unit commitment (SCUC). First, it presents the two main functional components of the SCUC: network constrained unit commitment (NCUC) and network security monitor (NSM). Next, it presents the proposed NCUC-NSM iterative clearing process for the RUC process.

Chapter 4 first reviews various ways of modeling of combined cycle resources in the literatures. Next it discusses the proposed combined cycle unit scheduling modeling for RUC.

Chapter 5 first introduces the wind integration in ERCOT and next it discusses the wind generation scheduling and the proposed phase shifter optimization in RUC.

Chapter 6 presents the test systems and case studies with the proposed RUC system. First, the author developed prototype RUC program is tested on a 5-bus test system with several test cases to illustrate the scheduling features especially the combined cycle resource scheduling. After that, the results of the production RUC software running on the ERCOT production system are discussed.

Chapter 7 summarizes the conclusion and contribution of this work. The dissertation concludes with the suggestions for future research.

Appendix A presents the notation used throughout the dissertation.

Appendix B presents the acronyms used throughout in the dissertation.

Chapter 2

Reliability Unit Commitment Process in Nodal Market

2.1 Reliability Unit Commitment Process

In the ERCOT nodal market, RUC is an important process to assess the need to commit generation capacity by evaluating the detailed network model instead of using simplified zones. The network model used in nodal market consists of more than 4000 nodes and all transmission lines greater than 60 KV. The main objective of RUC process is to recommend commitment of generation resources to ensure that enough capacity is committed in the right locations for reliable operation of the ERCOT market.

RUC commits additional generation capacity on top of the self-committed capacity projected by the current operating plans (COPs) submitted by the QSEs to meet the forecasted demand subject to transmission constraints and resource characteristics. As shown in Figure 2-1, there are three RUC processes used in the ERCOT nodal market [5] [6]:

- Day-Ahead RUC (DRUC): The DRUC process is executed daily at 1430 of the day-ahead after the close of the DAM. The DRUC study period covers the next operating day. The time step for each RUC interval is one hour. DRUC uses three-part supply offers that were considered but not awarded in the DAM.
- Hourly RUC (HRUC): The HRUC process is executed every hour. The HRUC study period is either (1) the balance of the current operating day, if the DRUC process has not been solved, or (2) the balance of the current operating day plus the next operating day, if the DRUC process has been solved. HRUC is used to fine-tune the resource commitments using the most updated load forecasts and outage information. HRUC is also used to approve or reject resource self-decommitment requests during the adjustment period.

- Weekly RUC (WRUC): The WRUC process is a look-ahead planning tool. Its study period is configurable and it could be up to one week. WRUC is used to help ERCOT manage generation resources that have startup times longer than the DRUC or HRUC study periods. The WRUC doesn't send commitment instruction to the QSE.

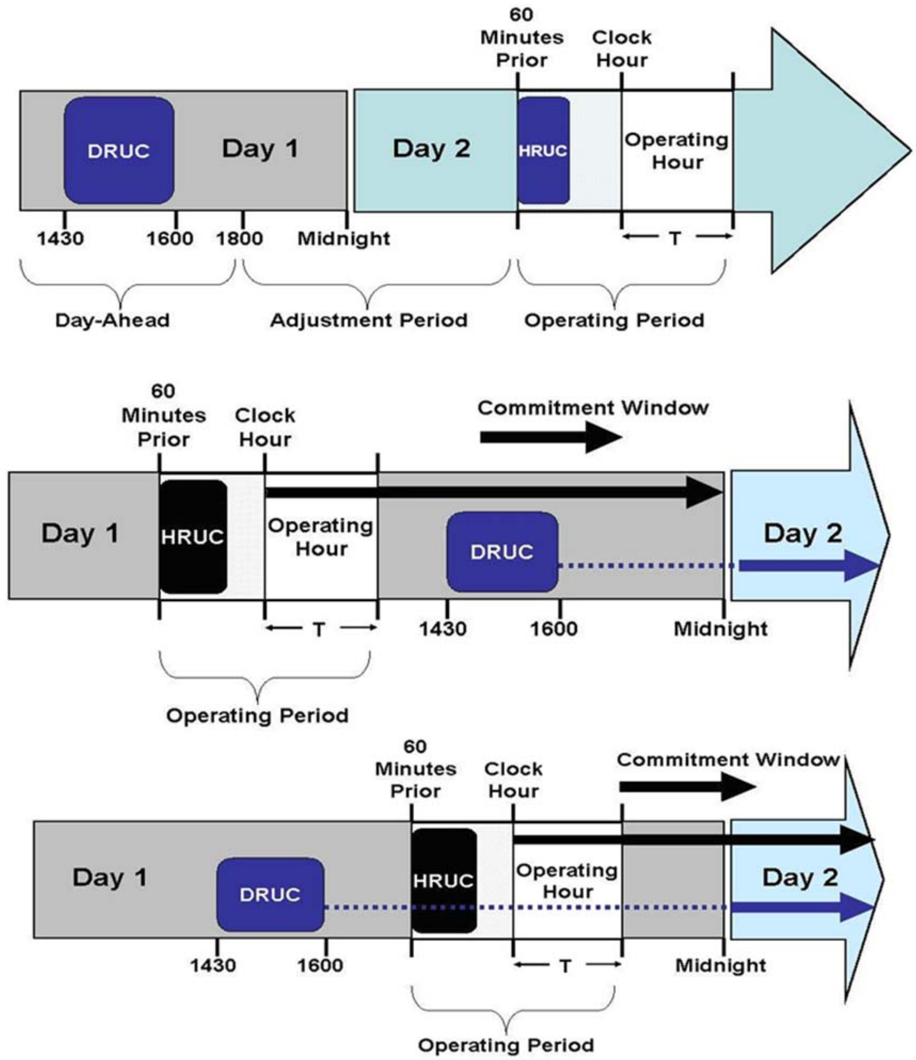

Figure 2-1 RUC Timeline Summary

It is also possible for the RUC processes to decommit self-committed generation resources; however, this will happen only if the decommitment is necessary to resolve transmission congestion that is otherwise irresolvable.

In addition to the dispatch instructions to notify each QSE of its resource commitment schedules, RUC also makes the following market information available:

- All binding and violated transmission constraints detected by RUC algorithm.
- All resources committed or decommitted by the RUC process.

2.2 RUC Input Data

The RUC input and initialization module retrieves various input data from interfaces of different external systems and prepares it for use by the market clearing module. The detail of the major input data is discussed as follows.

a) Current Operating Plan (COP)

The COP is an hourly plan submitted by a QSE reflecting anticipated operating conditions for each of the resources that it represents for each hour in the next seven operating days. The COP includes the following data:

- Resource name.
- The expected resource status: The operational state of a resource, e.g. ON-online, OFF-offline and available for commitment, OUT-offline and unavailable.
- High sustained limit (HSL): The maximum sustained energy production capability for a resource established by the QSE.
- Low sustained limit (LSL): The minimum sustained energy production capability for a resource established by the QSE. A resource's dispatch MW needs to be between LSL and HSL to respect the physical limit.
- Ancillary service resource responsibility capacity in MW for

- o Regulation up service (Reg-Up)
- o Regulation down service (Reg-Dn)
- o Responsive reserve service (RRS)
- o Non-Spinning reserve service (Non-Spin)

The high ancillary service limit (HASL) and low ancillary service limit (LASL) are dynamically calculated MW upper and low limit on a resource to reserve the part of the resource's capacity committed for Ancillary Service. The formula for the HASL and LASL calculation is shown below:

HASL = Max (LASL, HSL – Reg-Up – RRS - Non-Spin)

LASL = LSL + Reg-Dn

It should be noted that for combined cycle train (CCT) including multiple configurations, the QSE shall submit the COP for each operating configuration. For split generation resource (SGR), the QSE shall submit the COP for each logical SGR. One example of the COP for resource ALTA is shown in Table 2-1.

Table 2-1 An Example of COP

Resource Name	Operating Day	Hour Ending	Resource Status	LSL (MW)	HSL (MW)	Reg-Up (MW)	Reg-Dn (MW)	RRS (MW)	Non-Spin (MW)
ALTA	12/01/2012	1	OUT	11	110	0	0	0	0
ALTA	12/01/2012	2	OUT	11	110	0	0	0	0
ALTA	12/01/2012	3	OFF	11	110	0	0	0	0
ALTA	12/01/2012	4	OFF	11	110	0	0	0	0
…	…	…	…	…	…	…	…	…	…
ALTA	12/01/2012	15	ON	11	110	5	10	20	30
ALTA	12/01/2012	16	ON	11	110	10	5	10	20
ALTA	12/01/2012	17	ON	11	110	0	0	0	0
ALTA	12/01/2012	18	ON	11	110	0	0	10	0
…	…	…	…	…	…	…	…	…	…
ALTA	12/01/2012	24	OFF	11	110	0	0	0	0

b) Three-Part Supply Offer

The three-part supply offer is an hourly offer submitted by a QSE for a generation resource that it represents for each hour. The three-part supply offer contains three components: (1) startup offer for each cold, intermediate and hot condition, (2) a minimum-energy offer and (3) an energy offer curve. The energy offer curve is piece-wise linear non-decreasing curve and can be up to 10 price/quantity break points. Table 2-2 illustrates an example of the three-part supply offer.

Table 2-2 An Example of Three-Part Supply Offer

Resource Name	Operating Day	Hour Ending	Startup Offer ($)			MEO ($/MWh)	Energy Offer Curve (Q-MW, P-$/MWh)													
			Hot	Inter	Cold		Q1	P1	Q2	P2	Q3	P3	Q4	P4	Q5	P5	…	…	Q10	P10
ALTA	12/01/2012	1	1000	1200	1400	20	0	14	110	14										
ALTA	12/01/2012	2	1100	1300	1500	20	0	10	11	10	50	15	80	20	110	25				
ALTA	12/01/2012	3	1000	1000	1000	25	0	12	11	12	30	15	60	18	80	20	…	…	110	30
ALTA	12/01/2012	4	1100	1300	1500	25	0	14	11	14	20	15	30	20	50	30	…	…	110	40
…	…	…	…	…	…	…	…	…	…	…	…	…	…	…	…	…	…	…	…	…
ALTA	12/01/2012	24	1100	1300	1500	25	0	14	11	14	20	15	30	20	50	30	…	…	110	40

c) Mitigated Offer Cap Curve

The mitigated offer cap curve is used to cap the energy offer curves in real-time operations. The mitigated offer cap curve is calculated non-decreasing offer based on resource specific verifiable cost if available or based on the generic value. Similar to the three-part supply offer, the mitigated offer cap can be up to 10 price/quantity break points. One example is shown in Figure 2-2.

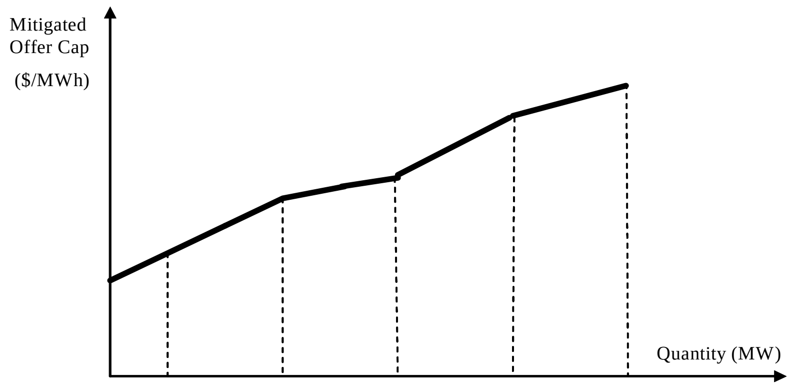

Figure 2-2 An Example of Mitigated Offer Cap Curve

d) Verifiable Cost

The RUC retrieves the resource specific verifiable cost from settlement system. The verifiable startup and minimum-generation cost are used to create offers for non-offer resources in RUC. The verifiable incremental energy cost is used to calculate the mitigated offer cap curve.

e) Resource Parameters

The RUC retrieves the following resource parameters submitted by the resource entity from registration system:

- Resource name.
- Resource type: steam turbine, hydro, gas turbine, combined cycle etc.
- Qualifying facility (QF) Status: A qualifying small power production facility or qualifying cogeneration facility under certain regulatory qualification criteria.
- Minimum online time: The minimum number of consecutive hours that the resource must be online before it can be shut down.

- Minimum offline time: The minimum number of consecutive hours the resource must be offline before it can be restarted.
- Normal ramp rate curve: It is a staircase curve submitted by the QSE and can be up to ten segments. Each segment indicates the rate of change in MW per minute of a resource within the corresponding output MW range.
- Emergency ramp rate curve: It is a staircase curve submitted by the QSE and can be up to ten segments. Each segment indicates the maximum rate of change in MW per minute of a resource within the corresponding output MW range to provide responsive reserve (RRS) deployed by ERCOT.
- Start time in hot, intermediate and cold temperature state: the stat time a.k.a. lead time specifies the number of hours from the ERCOT notice time (i.e. the time generators are notified of the commitment by ERCOT) to the time the generator can be started up in the corresponding temperature state. The start time is a function of the generator offline time.
- Maximum online time: The maximum number of consecutive hours a resource can be online before it needs to be shut down.
- Maximum daily starts: The maximum number of times a resource can be started up in an operating day under normal operating conditions.
- Hot-to-Intermediate Time: The number of hours that a resource after shutdown takes to cool down from hot temperature state to intermediate temperature state.
- Intermediate-to-Cold Time: The number of hours that a resource after shutdown takes to cool down from intermediate temperature state to cold temperature state.
- Maximum weekly starts: The maximum number of times a resource can be started up in seven consecutive days under normal operating conditions.

- Maximum weekly energy: The maximum energy in MWh a resource can produce in seven consecutive days.

Besides the resource parameters for regular resources, the combined cycle resources have additional resource parameters and they will be discussed in detail in Chapter 4.

f) Transmission Outage Data

The RUC retrieves the transmission outage information from outage scheduler (OS) and use the outage information to build the network topology.

g) Dynamic Rating from EMS

The RUC retrieves dynamic ratings data from the EMS for transmission equipment where available. The dynamic rating is used in network security monitor (NSM) function. The RUC uses default static ratings data from the EMS for the transmission equipment which don't have dynamic ratings data available. The dynamic ratings are weather-adjusted MVA limits for each hour of the study period for all transmission lines and transformers. There are three types of dynamic ratings:

- Normal rating: Normal rating is the rating at which a transmission element can operate without reducing its normal life expectancy. The normal ratings are enforced in NSM base case power flow study.
- Emergency rating: Emergency rating is the 2-hour rating of a transmission element. The emergency ratings are enforced in NSM during the post-contingency analysis.
- 15-minute rating: 15-minute ratings are short-term ratings of a transmission element. NSM will issue warnings if any of the 15-minute ratings are violated.

h) Generic Constraints from EMS

The generic constraints are the network/voltage constraints modeled as import/export energy constraints that are determined offline.

i) Load Forecast from EMS

The RUC retrieves the most current hourly load forecast from mid-term load forecast (MTLF) application from EMS for each weather zone. The MTLF predicts the hourly loads for the next 168 hours based on current weather forecast parameters within each weather zone. The accuracy of the load forecast is critical to the RUC since it is used by RUC to secure generation capacity

The MTLF has a self-training mode and is updated every hour for the next 168 hours. The following inputs are used by the MTLF [5]:

- Hourly forecasted weather parameters for the weather stations within the weather zones, which are updated at least once per hour; and
- Training information based on historic hourly integrated weather zone loads.

The ERCOT System-wide Load Forecast is calculated as the sum of load forecasts for all the weather zones. The network losses are already included in the load forecast that is considered in RUC processes.

j) Current and Historical Resource Commitment Status from EMS

The RUC retrieves both the current resource commitment status and historical resource commitment status of the current operating day from the EMS. The current commitment status indicates if the resource is online or offline at current time. The historical commitment status includes the following information:

- Number of startups in current operating day until the end of previous hour.
- Online hours at the end of previous hour since last status change.
- Offline hours at the end of previous hour since last status change.

It should be noted that the online hours and offline hours above are mutually exclusive. If the last status change is startup, i.e. from offline to online, the online hours is greater than 0 and the offline hours is 0. If the last status change is shutdown, i.e. from online to offline, the online hours is 0 and offline hours is greater than 0. Based on the historical commitment status, the RUC can determine the time when the resource changed status to online/offline.

k) Load Distribution Factors from EMS

The RUC retrieves the hourly load distribution factors (LDF) from EMS for each hour in the study period. Each load can be mapped to a specific electrical bus and a specific weather zone. Each load is classified as either conforming or non-conforming but not both. The LDF is used for bus load forecast.

l) Current Breaker and Switch Status from EMS

The HRUC retrieves the current breaker and switch status from SCADA/EMS and uses it plus changes indicated in Outage Scheduler to build network topology for the first study hour.

2.3 RUC Initialization and Pre-processing

2.3.1 Proxy Energy Offer Curve Creation

The RUC calculates proxy energy offer curves for all resources based on their mitigated offer caps to substitute their original energy offer curves. The calculated proxy energy offer curves will then be used by the RUC market clearing engine to determine the projected energy output level of each resource and to project potential congestion patterns for each hour of the RUC.

The RUC calculates the proxy energy offer curves by multiplying the mitigated offer cap by a configurable discount parameter and applying the cost for all generation resource output between high sustained limit (HSL) and low sustained limit (LSL).

The proxy energy offer curve is calculated in a way that discounts the incremental energy cost to ensure the self-committed online resources are used to the fullest extent before additional RUC commitment. This approach will minimize the out of market reliability commitment which may over mitigate the competitive market price. In turn, this approach will also minimize the RUC “make-whole” payment resulting from the startup and minimum-energy cost.

2.3.2 Modeling Resource Capacity Providing Ancillary Service

The RUC treats all resource capacity providing ancillary service (AS) as unavailable for the RUC study period, unless that treatment leads to infeasibility (i.e., that capacity is needed to resolve some local transmission problem that cannot be resolved by any other means). In such cases, the RUC will provide the information for each affected QSE of the amount of its resource capacity the projected hours that does not qualify to provide AS.

The following approach has been proposed to protect the ancillary service capacity. After the RUC creates the proxy energy offer curve for a resource, it modifies the proxy energy offer curve to protect the capacity providing ancillary services. First the RUC calculates Resources’ HASL and LASL based on the HSL, LSL, and ancillary service quantities from COP. Then the RUC modifies the portions of resource proxy energy offer curve outside HASL and LASL by assigning penalty factors for the corresponding ancillary services. The penalty factors are higher than any of the proxy energy offer curves but lower than transmission constraint penalty factor. The penalty factors for resource AS violation and transmission constraint violation are configurable parameters and can be adjusted by authorized users.

Figure 2-3 illustrates the proxy energy offer curve with ancillary services protection. As shown in the figure, the capacity providing regulation down service (Reg-Dn) will be assigned a negative penalty factor. The capacities providing regulation up service (Reg-Up), responsive reserve (RRS), and non-spinning reserve (Non-Spin) is assigned with the corresponding positive penalty factors with descending order. This is because that the quality and priority of Reg-Up is higher than RRS and the quality and priority of RRS is higher than Non-Spin. This descending order makes sure that if the ancillary service capacity violation happens, the Non-Spin will be violated before RRS and RRS will be violated before Reg-Up.

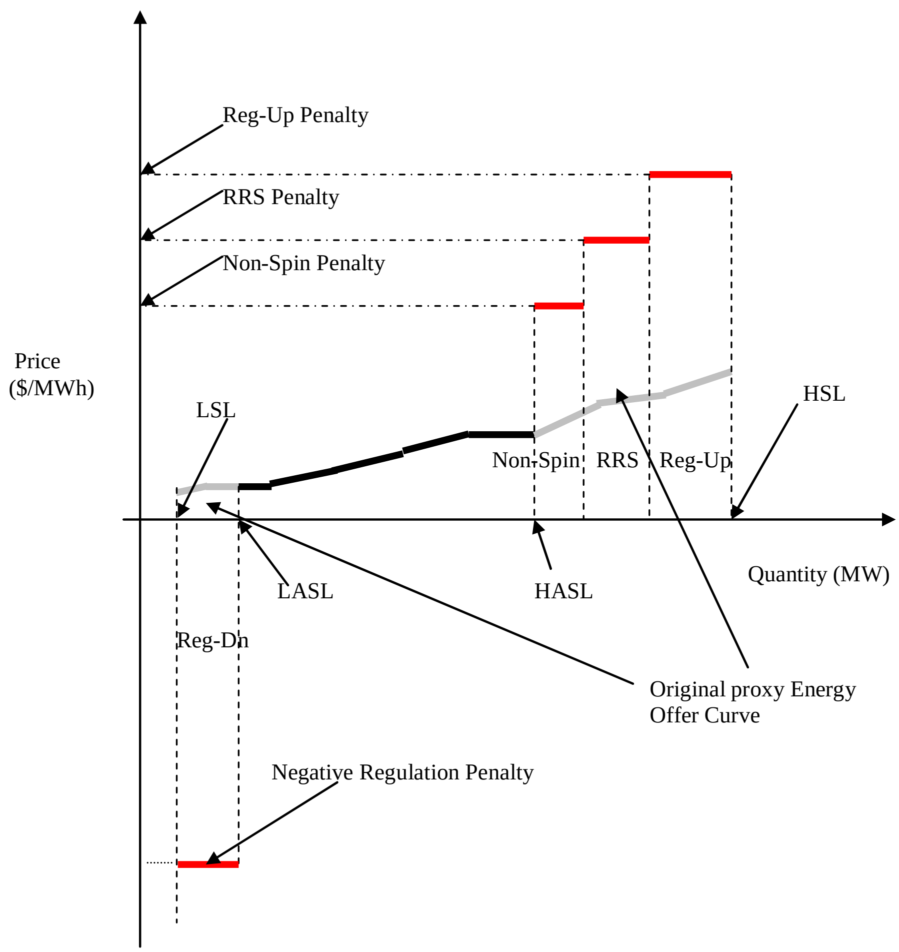

Figure 2-3 Proxy Energy Offer Curve with Ancillary Services Protection

2.3.3 Resource Initial Condition Determination

The current EMS online/offline status is used for the current hour (the hour when the RUC is executed). The historical commitment status passed from EMS is used for the status before the current hour. For future hours, the commitment status indicated in the COP is used. Due to the difference of the study period, the following rules are applied for different RUC processes:

- The DRUC and WRUC uses the historical commitment data, the online and offline status for the current operating hour and the COP status for remaining hours of the current operating day to project the initial commitment status at the beginning of the next operating day.
- The HRUC uses the historical commitment data and the online and offline status for the current operating hour to determine the resource's initial condition at the beginning of the next operating hour.

If the COP is not available for any resource for any particular hour from the current hour to the start of the RUC study then the resource status for those hours are considered as equal to that of the last known hour's COP for that resource.

It is expected that at most one configuration of the same combined cycle train (CCT) will have online COP status for any hour. However, in practice, it may occur that the same CCT has more than one configuration having online COP status for the same hour. In this case, for any hour before the RUC study period, the online configuration which has been online for the longest time is considered as online and all the other online configurations from the same CCT will be treated as offline.

If a resource is offline between the RUC execution and the beginning of the study period, the start time of the resource can affect its eligibility to be committed. The following logic has been proposed and implemented to enforce the start time constraint:

- First, the RUC determines the resource temperature state (hot/intermediate/cold) at the RUC execution based on the resource's historical offline time and hot-to-intermediate and intermediate-to-cold cooling time.

- Second, the RUC determines the start time corresponding to the temperature state
- Third, the RUC makes the resource unavailable for commitment from the current time to the start available time min (current time + configurable offset + start time, first hour resource scheduled online in the COP). Where the configurable offset is the delay time from the RUC execution time to the RUC notice of commitment to the resource, i.e. the RUC execution time.

Use DRUC as an example. Assume DRUC is executed at 1430 at current operating day with the study period as the next operating day. The configurable offset is set as 15 minutes. Resource ALTA has been offline for 14 hours based on its EMS historical commitment status and the COP status is also offline from HE15 of current operating day to HE24 of next operating day. The hot-to-intermediate time is 6 hour and the intermediate-to-cold time is 3 hour. The hot, intermediate and cold start time is 3, 6 and 12 hour respectively. Since the offline time (14 hours) is greater than hot-to-cold time (6+3=9 hours), the resource ALTA is in cold status at 1430. So the cold start time (12 hour) is used as the corresponding start time. Define OD is current operating day and OD+1 is next operating day. So the start available time is calculated as min(OD 1430 +1/4 hour+12 hours, OD+1 2400)=OD+1 0245. The RUC will set the resource ALTA as unavailable from HE1 to HE3 to observe the start time.

2.3.4 Bus Load Forecast

The RUC needs to determine a forecast of the load at each electrical bus for each hour in the study period before performing the network security analysis including both base case power flow and contingency analysis. The following steps are used in the bus load forecast:

- First, RUC identifies the non-conforming loads, allocates the MW schedules from the load distribution factor (LDF) for non-conforming loads to the mapping electrical buses directly and subtracts them from the weather zone load forecast.
- Second, RUC distributes the remaining weather zone load forecast to the conforming loads based on their LDF.
- Last, RUC identifies all the isolated loads and performs load rollover based on the load rollover definition if any.

2.3.5 DC Ties Modeling

Currently there are five DC Ties interconnected to ERCOT system. The location and capacity is shown in Figure 2-4. The Laredo DC Tie (DC_L) is a 100 MW variable frequency transformer located at the AEP Laredo VFT station and connects the ERCOT Region with CFE in Mexico, even though this interface is not a back-to-back HVDC converter, it is used as a DC Tie.

The following logic has been proposed and implemented for the DC Ties modeling in the RUC:

- Retrieve 15-minute DC Tie energy schedules from NERC eTag and aggregate to hour level for each DC Tie.
- Each DC Tie is modeled as an equivalent generator resource if the net energy schedule for the DC Tie shows a net import, otherwise it is modeled as an equivalent load resource.
- RUC treat the net DC Tie schedule as a fixed injection (import) or withdraw (export) in the network security analysis.
- RUC calculates the system total net DC Tie schedules by summing up the net DC Tie schedule across all the DC Ties for the same hour.
- RUC calculates the net system load to be served by ERCOT generation by

- o Subtracting the net system total DC Tie schedule from load forecast if the net schedule is import.
- o Adding the net system total DC Tie schedule to load forecast if the net schedule is export.

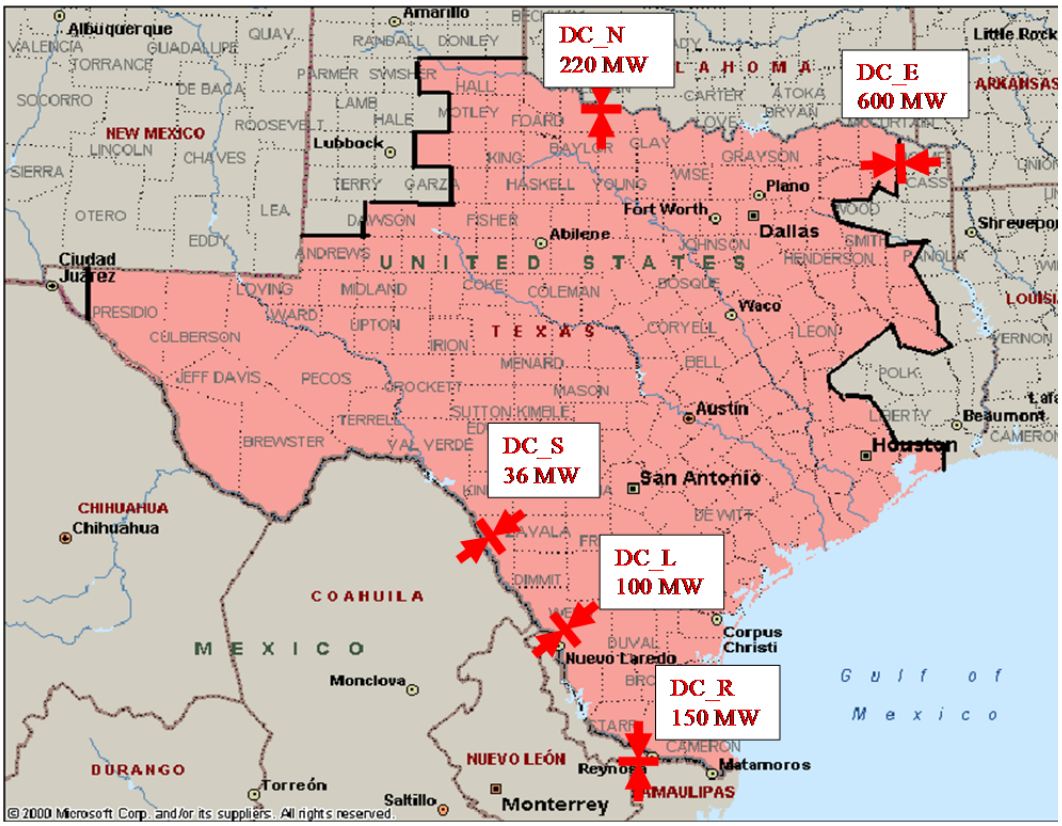

Figure 2-4 ERCOT DC Ties Location and Capacity

2.4 RUC Special Scheduling Features

2.4.1 Split Generation Resources

A split generation resource (SGR), a.k.a. a jointly owned unit (JOU), is a generation resource that has been split to function as two or more independent generation resources represented by different market participants. The individual SGR is treated as a logical resource in RUC and it can participate in the ERCOT nodal market the same as regular resources. Each individual SGR has a distinct full set of resource operation parameters and market submissions such as three-part supply offers and COP schedules. Due to the physical operational constraint, the individual SGRs in a generation facility must be committed or decommitted together by NCUC. For network security analysis, all the individual SGRs in a generation facility are treated as a single physical resource in NSM. The dispatch from individual SGRs is aggregated on a physical resource basis prior to being sent to NSM for evaluation. In turn, the NSM provides shift factors for the individual SGRs to NCUC. Note that the shift factors are identical since the individual SGRs belongs to a same physical resource.

2.4.2 Self-Committed Resources

The reliability unit commitment performed in ERCOT is different from the traditional centralized unit commitment in the regulation environment. In the ERCOT market, most of the resources are already self-committed in COP before the RUC execution and the RUC is more like an incremental commitment problem. The self-committed resources are modeled as must-run resources in RUC and RUC can only decommit the self-committed resource to solve some transmission constraints otherwise irresolvable. The self-committed resources submissions are allowed to violate the resources input temporal constraints. RUC may not commit resources in other intervals just to meet the temporal constraints; however once the RUC-committed interval is connected to self-committed intervals, then all the temporal constraints need to be enforced.

2.4.3 RUC Startup Cost Eligibility

For the purpose of evaluating a resource's startup cost eligibility, all contiguous RUC-committed hours are considered as one RUC instruction. For each resource, only one startup cost is eligible per block of contiguous RUC-committed hours. Based on the nodal protocol [5], the startup cost for the contiguous RUC-commitment block may not be eligible to be included in the RUC make-whole payment if the designated start hour or last hour of the RUC instruction connects to a block of QSE-committed intervals that was QSE-committed before the RUC instruction was given. For example, consider the case where the QSE self-committed intervals are from HE1 to HE6 and all the other intervals are offline. If RUC commits interval from HE7 to HE12, which connects QSE-committed intervals, the startup at interval HE7 is not eligible for startup cost.

The startup cost modeling in optimization reflects the above settlement rules. The RUC NCUC optimization doesn't introduce additional resource startup cost in the objective function if RUC-committed hours connect to the QSE self-committed intervals.

2.4.4 SPS/RAP Modeling

A special protection system (SPS) or remedial action plan (RAP) is a set of automatic or pre-defined actions taken to relieve transmission security violations during the post-contingency condition. These SPSs and RAPs are sufficiently dependable to assume that they can be executed without loss of reliability to the ERCOT network. The SPSs and RAPs will be used for contingency analysis before considering a resource commitment and this logic will reduce the RUC over procurement.

NSM models all approved special protection systems (SPSs) and remedial action plans (RAPs) while performing the contingency analysis.

2.4.5 Mandatory Participation

The RUC commitment is physically binding and the resources committed by RUC are required to be online in real-time. The participation in RUC is mandatory for all available resources regardless of whether they are offered into RUC. Not submitting a startup offer and a minimum-energy offer does not prevent a resource from being committed in the RUC process. RUC will create three-part supply offers for all resources that did not submit a three-part supply offer but are specified in an offline available status in COP. For such non-offer resources, RUC process uses 150% of any approved resource specific verifiable startup cost and minimum-energy cost while determining the commitment schedule. If the verifiable costs have not been approved, RUC will use the applicable resource category generic startup offer cost and minimum-energy offer cost instead. However, during the settlement process, for such resources, only 100% of the approved verifiable or generic startup costs and minimum-energy cost are applied. This approach is intended to commit the resources with three-part supply offers before considering the non-offer resources. In turn, it will encourage resources to submit three-part supply offers into RUC if the resources want to be committed by RUC.

2.5 Settlement of RUC

The “make-whole” payment mechanism [5] [10] is employed by ERCOT for RUC settlement to make up the difference when the revenues that a RUC-committed resource receives are less than its operation costs. In general, the RUC settlement consists of the following three categories:

- RUC make-whole payment and charge.
- RUC clawback charge and payment.
- RUC decommitment payment and charge.

A. RUC Make-Whole Payment and Charge

For each RUC-committed resource, RUC settlement calculates the RUC guarantee which is the sum of the resource's eligible startup costs and minimum-energy costs during all RUC-committed hours. If the energy revenues that a RUC-committed resource receives during RUC-committed hours and QSE clawback intervals are less than the RUC guarantee, ERCOT will pay the resource RUC make-whole payment for that operating day to make up the difference.

ERCOT calculates RUC capacity-short charge to charge QSEs whose capacity are found short and caused the need for RUC commitment. If revenues from the RUC capacity-short charge are not enough to cover all RUC make-whole payments, ERCOT calculates the RUC make-whole uplift charge and the difference is uplifted to all QSEs based on a load ratio share basis.

B. RUC Clawback Charge and Payment

For each RUC-committed resource, if the RUC guarantee is less than the sum of the energy revenue, ERCOT charges the resource a RUC clawback charge for the operating day. The clawback rule encourages the QSE to self-commit resources to avoid high clawback charges and to participate in the day-ahead market. ERCOT uses a higher clawback percentage for resources that don't submit three-part supply offers in the day-ahead market than the ones that submitted three-part supply offers. ERCOT pays the revenues from all RUC clawback charges to all QSEs, on a load ratio share basis.

C. RUC Decommitment Payment and Charge

If the RUC decommit a QSE self-committed resource that is not scheduled to shut down within the operating day, then ERCOT pays the affected QSE an amount as a RUC decommitment payment. ERCOT charges each QSE a RUC decommitment charge, on a load ratio share basis.

Chapter 3

Reliability Unit Commitment Solution Engine

The security constrained unit commitment (SCUC) program is the core solution engine used by RUC to determine the optimum commitment schedules [6][13][30]. The SCUC engine is comprised of two major functional components:

- Network Constrained Unit Commitment (NCUC) and
- Network Security Monitor (NSM).

3.1 Network Constrained Unit Commitment (NCUC)

3.1.1 Introduction

The NCUC function is used to determine projected commitment schedules that minimize the total operation costs over the RUC study period while meeting forecast demand subject to transmission constraints and resource constraints. These resource constraints represent the physical and security limits on resources:

- High Sustained Limit (HSL) and Low Sustained Limit (LSL)
- Minimum online time
- Maximum online time
- Minimum offline time
- Maximum daily startup
- Startup time

The objective function of the NCUC is defined as the sum of startup cost, minimum-energy cost and incremental energy cost based on three-part supply offers while substituting a proxy energy offer curve for the energy offer curve. The NCUC also employs the penalty factors on violation of security constraints in the objective function to ensure a feasible solution.

The proxy energy cost curve is used in NCUC to determine the projected energy output level of each resource and to project potential congestion patterns for each hour of the RUC study period. However the dispatch pattern determined by NCUC is only used by NSM to perform network security analysis and it will not be sent to QSE for generator dispatch.

The NCUC treats all resource capacity providing ancillary services as unavailable by enforcing high penalty factors for resource specific ancillary service capacity. If the AS capacity from the specified resource is needed to resolve some local transmission congestion that cannot be resolved by any other means, the ancillary service capacity will be relaxed to resolve the infeasibility.

Normally the NCUC is executed several times iterating with NSM within the SCUC solution process. The first NCUC run is referred as the initial unit commitment (IUC). IUC has the same functionality as NCUC except that the network constraints are not considered. In the remaining NCUC executions, the network constraint data is prepared by the NSM. The network constraint data is then passed to the NCUC as additional constraints for enforcement in the optimization process.

3.1.2 Offline Time Dependent Startup Cost Modeling

The NCUC models the offline time dependent startup costs. In the generator three-part supply offers discussed in Chapter 2, QSE can specify different startup offers for hot, intermediate and cold temperature state. Correspondingly the startup cost is modeled as a staircase function of the calculated offline time up to 3 segments, i.e. hot, intermediate and cold state. An illustration of the staircase startup cost function is shown in Figure 3-1. The NCUC optimization determines which startup cost will be used based on the startup cost function.

Conceptually the startup cost is determined based on the following logic

$$SUC_{i,t} = \begin{cases} SUC_{i,t}^{hot} & \text{if } t_{i,t}^{off} \le T_i^{hot2inter} \\ SUC_{i,t}^{inter} & \text{if } T_i^{hot2nter} < t_{i,t}^{off} \le T_i^{hot2cold} \\ SUC_{i,t}^{cold} & \text{if } t_{i,t}^{off} > T_i^{hot2cold} \end{cases} \quad (1)$$

The above startup cost applies to the startup of both regular unit and combined cycle unit. If the combined cycle train has a up transition at interval t , the startup cost is the transition cost of CCT. The transition cost is calculated as the difference between to configuration and from configuration with a floor of 0 corresponding to the warm status of the after configuration at interval t.

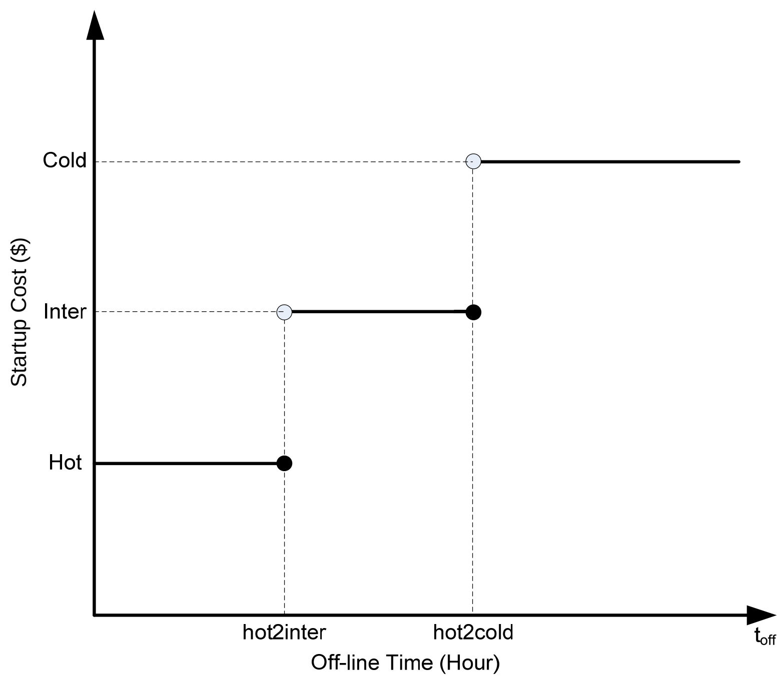

Figure 3-1 Staircase Startup Cost Function

The startup cost can be modeled as follows

$$ISU_{i,t,p} \ge SU_{i,t} - \sum_{k=1}^{T_{i,p}^{off}} U_{i,t-k} \quad \forall i, \forall t, \forall p \quad (2)$$

$$\sum_{p=1}^{NP_{i,t}} ISU_{i,t,p} \leq SU_{i,t} * NP_{i,t} \quad \forall i, \forall t \tag{3}$$

$$ISU_{i,t,p} \leq ISU_{i,t,p-1} \quad \forall i, \forall t, \forall p > 1 \tag{4}$$

$$SUC_{i,t} = ISU_{i,t,1} * SUC_{i,t}^{1} + \sum_{p=2}^{NP_{i,t}} \left[ISU_{i,t,p} * (SUC_{i,t}^{p} - SUC_{i,t}^{p-1}) \right] \tag{5}$$

The above startup cost applies to the startup of both regular unit and combined cycle unit. If the combined cycle train has a up transition at interval t , the startup cost is the transition cost of CCT. The transition cost is calculated as the difference between to configuration and from configuration with a floor of 0 corresponding to the warm status of the after configuration at interval t.

3.1.3 NCUC Solution Algorithm

As discussed in Chapter 2, the incremental energy offer curves in RUC are piece-wise linear. Hence the RUC optimization cost functions calculated from the integration of the incremental energy offer curves becomes quadratic. This makes the RUC optimization problem as a mixed integer quadratic programming (MIQP) problem. Compared to the linear MIP model, the MIQP model usually takes longer time to solve and the performance is not desirable for the large RUC problem. To solve this issue, the following two-step solution algorithm has been proposed for the NCUC:

- Unit commitment (UC) step.
- Economic dispatch (ED) step.

First, the UC step uses mixed integer programming (MIP) to solve the overall problem by treating the piece-wise linear incremental cost curves as staircase constant. Each segment of the incremental cost curve is modeled as a staircase curve as shown in Figure 3-2. The number of horizontal segments used for the approximation is determined in such a way that the areas between the original curve and the staircase segments (shown as shadowed area in Figure 3-2) is less than a user defined constant. The UC step determines the unit commitment schedules and binary variables including the unit commitment decision variables and the ones used for the startup cost modeling. The results of the binary variables from UC step are passed to ED step as fixed values.

Next, the ED step uses the quadratic programming (QP) to solve the same problem again with the original cost curve but with all the binary variables fixed at the solutions of the UC step. The ED step determines the unit dispatch schedules and market clearing prices.

The mathematic programming language AMPL [12] is adopted to model the MIP and QP problem and CPLEX [84] is utilized as the MIP and QP optimization solver.

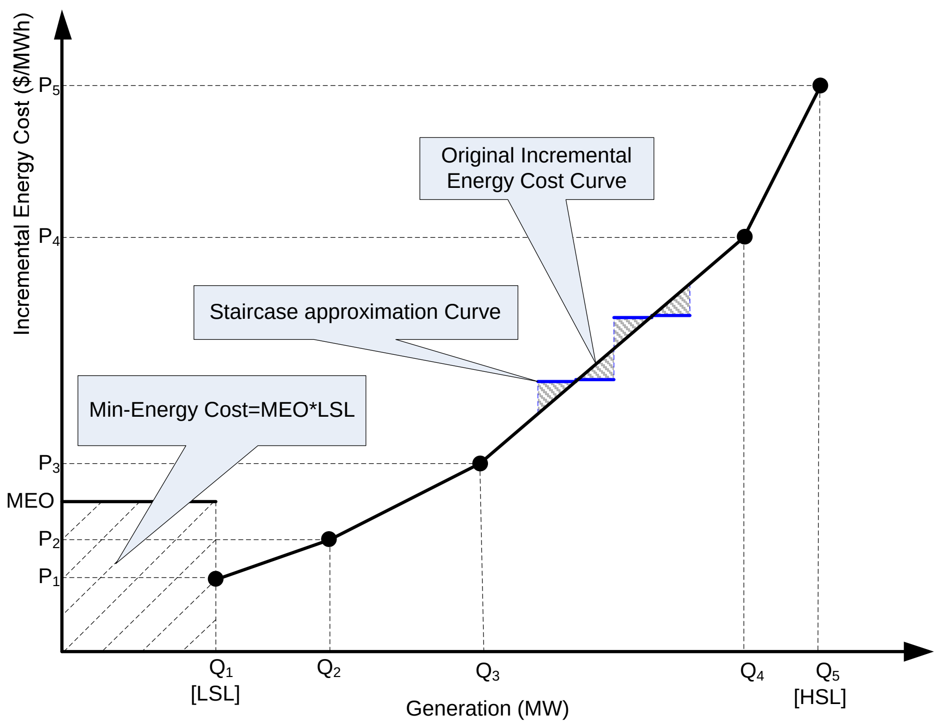

Figure 3-2 Incremental Cost Curve Approximation

3.1.4 NCUC Mathematic Formulation

The mathematic formulation of the NCUC is discussed as follows. The notation is illustrated in Appendix A.

A. Objective Function

The NCUC optimization objective function is defined as the sum of startup cost, minimum-energy cost and incremental energy cost.RUC also employs the penalty factors on violation of security constraints (slack variables) in the objective function to ensure a feasible solution.The NCUC objective function can be formulated as follows

$$\text{Minimize} \quad \left\{ \begin{array}{l} \sum_{i=1}^{NG} \sum_{t=1}^{T} \left[SUC_{i,t} + MEC_{i,t} + C_{i,t}\left(P_{i,t}\right) \right] + \sum_{s=1}^{NPS} \sum_{t=1}^{T} PSCOST_{s,t} \\ + Penalty_{pb} * \sum_{t=1}^{T} \left(Slack_{el,t} + Slack_{es,t} \right) + \sum_{c=1}^{NC} \sum_{t=1}^{T} \left[Penalty_{lc} * Slack_{lc,t} \right] \end{array} \right\} \quad (6)$$

The offline time dependent startup cost is discussed in Section 3.1.2. The resource minimum energy cost is formulated as below

$$MEC_{i,t} = U_{i,t} * MEO_{i,t} * P_{i,t}^{\min} \quad \forall i, \forall t \quad (7)$$

The incremental energy cost is discussed in Section 3.1.3. The incremental energy cost is linear term in UC step while it is quadratic term in ED step. The cost function of the phase shifter tap position is discussed in Section 5.4. The penalty factors are applied for the violation both the power balance constraint and transmission constraints.

B. NCUC Constraints

The NCUC optimization problem is subject to various resource constraints and security constraints shown as follows.

a) Power Balance Constraint

$$\sum_{i=1}^{N} P_{i,t} + Slack_{es,t} - Slack_{el,t} = D_t \quad \forall t \tag{8}$$

b) Resource Constraints

The resource minimum and maximum output constraints are formulated as below. In RUC, the $P_{i,t}^{\min}$ and $P_{i,t}^{\max}$ are the COP LSL and HSL respectively.

$$U_{i,t} * P_{i,t}^{\min} \le P_{i,t} \le U_{i,t} * P_{i,t}^{\max} \quad \forall i, \forall t \tag{9}$$

The resource startup and shutdown constraints are formulated as below.

$$U_{i,t} - U_{i,t-1} = SU_{i,t} \text{-} SD_{i,t} \quad \forall i, \forall t \tag{10}$$

$$SU_{i,t} + SD_{i,t} \le 1 \quad \forall i, \forall t \tag{11}$$

The constraint for the JOU can be written as follows:

$$U_{i,t} = U_{j,t} \quad \forall jou \in JOU, i, j \in JOUGEN_{jou} \tag{12}$$

It should be noted that the ramping up and down constraints currently are not modeled in the RUC because the current real-time SCED dispatches based on current system generation and doesn't look ahead [6][33].

c) Resource Temporal constraints

The minimum up time constraints are as follows:

$$\left(MNUP_i - 1\right) * SU_{i,t} \le \sum_{k=t+1}^{t+MNUP_i-1} U_{i,k} \quad \forall i, \forall t \tag{13}$$

The minimum down time constraints are as follows:

$$\begin{aligned} &\min\left(T-t, MNDN_i - 1\right) * SD_{i,t} + \sum_{k=t+1}^{\min\left(T-t, MNDN_i-1\right)} U_{i,k} \\ &\le \min\left(T-t, MNDN_i - 1\right) \ \forall i, \ t \le T-1 \end{aligned} \tag{14}$$

The minimum daily startup constraints are formulated as follows:

$$\sum_{t=1}^{T} SU_{i,t} \le MXSU_i \ \forall i \tag{15}$$

d) Network Constraints

The transmission constraints considering the phase shifter impact is shown below. The slack variables are applied here to model the transmission constraint violation. The network constraint mathematic limit is discussed in detail in Section 3.2.

$$\sum_{i=1}^{NG} SF_{ci,t} * P_{i,t} + \sum_{s=1}^{NPS} SF_{cs,t} * PST_{s,t} - Slack_{lc,t} \le F_{c,t}^{MathLimit} \ \forall c \tag{16}$$

C. Resource LMP

Once the NCUC optimization problem is solved, the resource LMP can be calculated as below.

$$LMP_{i,t} = \lambda_t - \sum_{c=1}^{NC} \left(SF_{ci,t} * SP_{c,t} \right) \tag{17}$$

3.2 Network Security Monitor (NSM)

The function network security monitor (NSM), a.k.a. network security analysis (NSA), evaluates the feasibility of the generation schedule for the intact (base case) network as well as for the post-contingency network states. AC power flow results are used to evaluate the feasibility of the base case. A linearized analysis is used to evaluate the impact of the postulated contingencies. The NSM is performed for each interval of the RUC study period to provide constraints for the NCUC function. For each violated constraint, a set of shift factors is calculated with respect to generation resources. The shift factors and the violated constraints are passed to the NCUC for enforcement.

The dynamic ratings for the transmission elements are used in the NSM. The normal rating is used for base case power flow study and the emergency rating is used for contingency analysis. In addition to the dynamic ratings, NSM also enforces a set of generic constraints. The generic constraints are limitations on one or more transmission elements which are used to protect the ERCOT transmission grid against transient instability, dynamic instability or voltage collapse. The generic constraints are modeled by NSM in both the base case and contingency analysis.

The NSM function supports load rollover schemes. A load rollover scheme transfers a load at a node (source node) to one or more receiving nodes when a network event causes the source node to be electrically de-energized. The receiving nodes may be in the same station or in different stations. The network events that may cause a load rollover include tripping of a breaker, outage of a transmission line or a transformer. If the receiving nodes are also de-energized, NSM will drop the rollover load from the network.

NSM models all approved special protection systems (SPSs) and remedial action plans (RAPs) while performing the contingency analysis. A SPS or RAP is a set of automatic or pre-defined actions taken to relieve transmission security violations during the post-contingency condition. These SPSs and RAPs are sufficiently dependable to assume that they can be executed without loss of reliability to the ERCOT network. The SPSs and RAPs will be used for contingency analysis before considering a resource commitment and this logic will reduce the RUC over procurement.

As illustrated in Figure 3-3, the NSM consists of the following main components:

a) Network Data Update

Retrieves the network model prepared by the preprocessor and imposes on it the latest NCUC generation schedule to establish the modified base case. The RUC Network topology used by NSM is built based on the normal network and outage schedules. All power flow computations uses a lossless model while satisfying the power flow constraints. Transmission constraints are based on dynamic ratings.

b) Base Case Power Flow Solution

Performs non-linear AC power flow solution on the modified base case prepared by network data update and computes the base case flows. A failure of the AC power flow to converge automatically triggers the execution of the non-linear DC power flow.

c) Contingency Topology Processor

Prepares the final contingency list, violations check list and generator allocation list for the DC contingency analysis.

d) Incremental Contingency Analysis

Performs Incremental (linear) contingency analysis by imposing contingencies based on the lists prepared by the contingency topology processor and determines the modified flows. If a SPS/RAP triggering condition is satisfied in a contingency, the contingency shall be ignored, i.e., it is assumed that SPS/RAP clears all constraint violations. NSM considers multilevel SPS/RAPS for breaker statuses, branch active power flows and network bus voltages.

e) Constraint Data Processing

Selects the critical network violated constraints and computes the shift factors (sensitivities) to be used by NCUC. The selection of critical network violated constraints is based on the "constraint monitoring margin" parameter specified by the user. The base case constraints and the worst contingency constraints with loading exceeding the constraint-monitoring margin are automatically selected.

The NSM calculates the constraint mathematic limit and passes it to NCUC for enforcement. The formulation of the network constraints mathematic limit can be deduced as follows:

$$
\begin{aligned}
& f_{c,t}^{NCUC} = f_{c,t}^{NSM^0} + \Delta f_{c,t}^{NCUC} \le F_{c,t}^{PhysicalLimit} \\
& \Rightarrow f_{c,t}^{NSM^0} + \sum_i SF_{ci,t} * \left(P_{i,t} - P_{i,t}^0\right) + \sum_s SF_{cs,t} * \left(PST_{s,t} - PST_{s,t}^0\right) \le F_{c,t}^{PhysicalLimit} \\
& \Rightarrow \sum_i SF_{ci,t} * P_{i,t} + \sum_s SF_{cs,t} * PST_{s,t} \le F_{c,t}^{PhysicalLimit} - f_{c,t}^{NSM^0} \\
& + \sum_i SF_{ci,t} * P_{i,t}^0 + \sum_s SF_{cs,t} * PST_{s,t}^0 \\
& \Rightarrow f_{c,t}^{NCUCMath} \le F_{c,t}^{MathLimit} \\
& where\ f_{c,t}^{NCUCMath} = \sum_i SF_{ci,t} * P_{i,t} + \sum_s SF_{cs,t} * PST_{s,t} \\
& F_{c,t}^{MathLimit} = F_{c,t}^{PhysicalLimit} - f_{c,t}^{NSM^0} + \sum_i SF_{ci,t} * P_{i,t}^0 + \sum_s SF_{cs,t} * PST_{s,t}^0
\end{aligned}
\tag{18}
$$

The NSM Flow at previous iteration can be formulated as

$$
\begin{aligned}
& f_{c,t}^{NSM^0} = \sum_i SF_{ci,t} * P_{i,t}^0 + \sum_s SF_{cs,t} * \left(PST_{s,t}^0 - PST_s^{neutral}\right) \\
& + \sum_n SF_{cn,t} * NCV_{n,t}^0 + F_{c,t}^{offset}
\end{aligned}
\tag{19}
$$

Substitute NSM Flow from above equation into NCUC Flow, the mathematic limit is calculated as below.

$$
\begin{aligned}
& F_{c,t}^{MathLimit} = F_{c,t}^{PhysicalLimit} + \sum_i SF_{ci,t} * P_{i,t}^0 + \sum_s SF_{cs,t} * PST_{s,t}^0 - \\
& \left[\sum_i SF_{ci,t} * P_{i,t}^0 + \sum_s SF_{cs,t} * \left(PST_{s,t}^0 - PST_s^{neutral}\right) + \sum_n SF_{cn,t} * NCV_{n,t}^0 + F_{c,t}^{offset} \right] \\
& = F_{c,t}^{PhysicalLimit} + \sum_s SF_{cs,t} * PST_s^{neutral} - \sum_n SF_{cn,t} * NCV_{n,t}^0 - F_{c,t}^{offset}
\end{aligned}
\tag{20}
$$

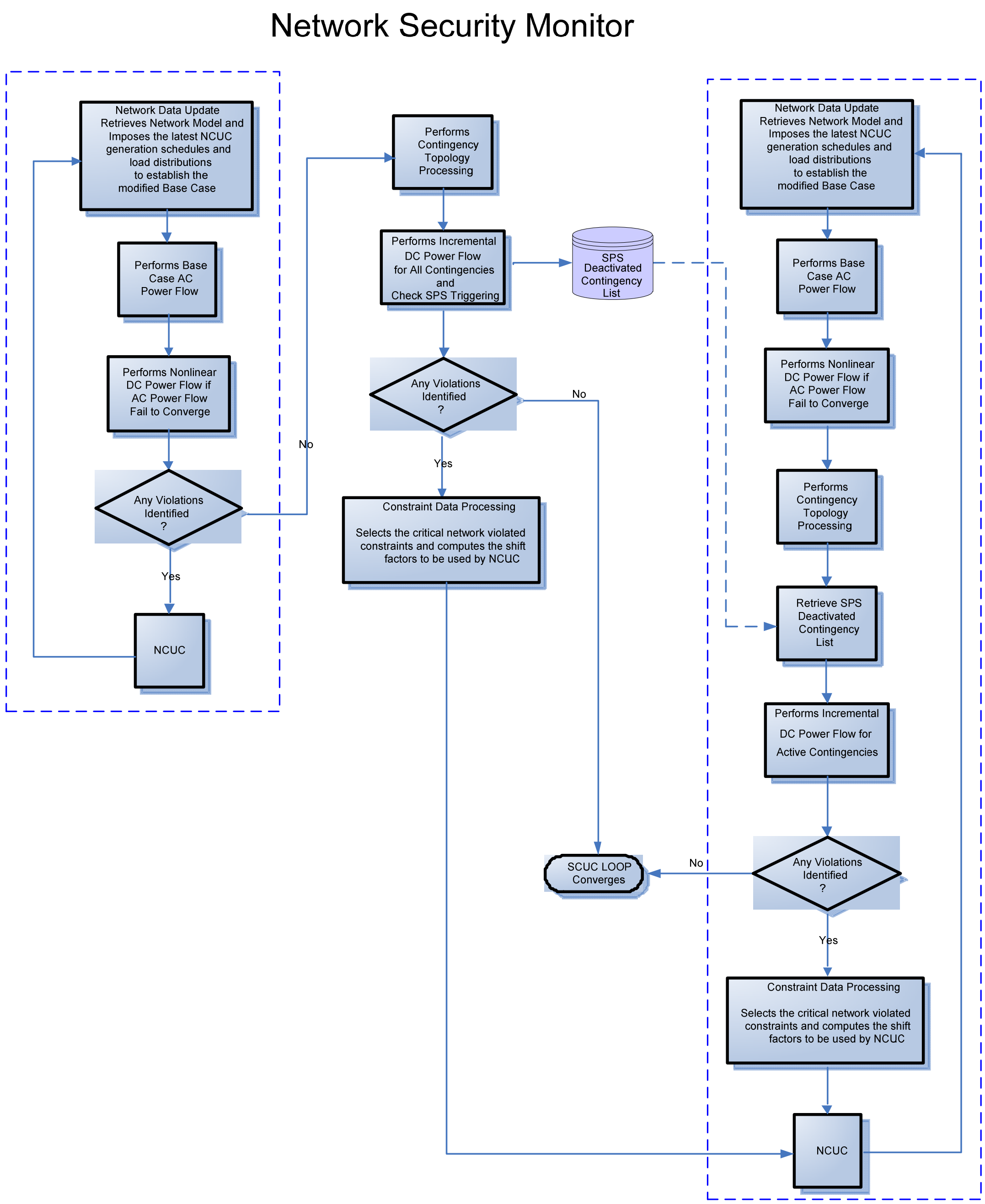

Figure 3-3 Flow Diagram of the NSM Process

3.3 RUC Clearing Process

The proposed RUC clearing process is shown in Figure 3-4. The NCUC and the NSM iterates several times to determine the final solution. The steps in the proposed solution process are as follows [6]:

1. Retrieve the initial base case data and superimpose on them the generation schedule determined by the latest NCUC (or IUC) execution.
2. Invoke NSM for the base case at each time interval in the study period to identify network constraints to be enforced in the NCUC solution.
3. Invoke NCUC to determine the revised generation schedule as impacted by enforcing the additional network constraints.
4. Steps 2 and 3 iterate until convergence is reached.
5. SPS/RAP Triggering Test: using the solved NCUC generation at Step 4, invoke NSM for all contingencies to test the SPS/RAP triggering conditions. Any contingencies that trigger SPS/RAP are ignored in the subsequent NCUC-NSM iterations.
6. Invoke NSM for the base case and all contingencies without SPS/RAP triggering as determined at Step 5 at each time interval in the study period to identify network constraints to be enforced in the NCUC solution.
7. Invoke NCUC to determine the revised generation schedule as impacted by enforcing the additional network constraints.
8. Step 6 and 7 iterate until convergence is reached.

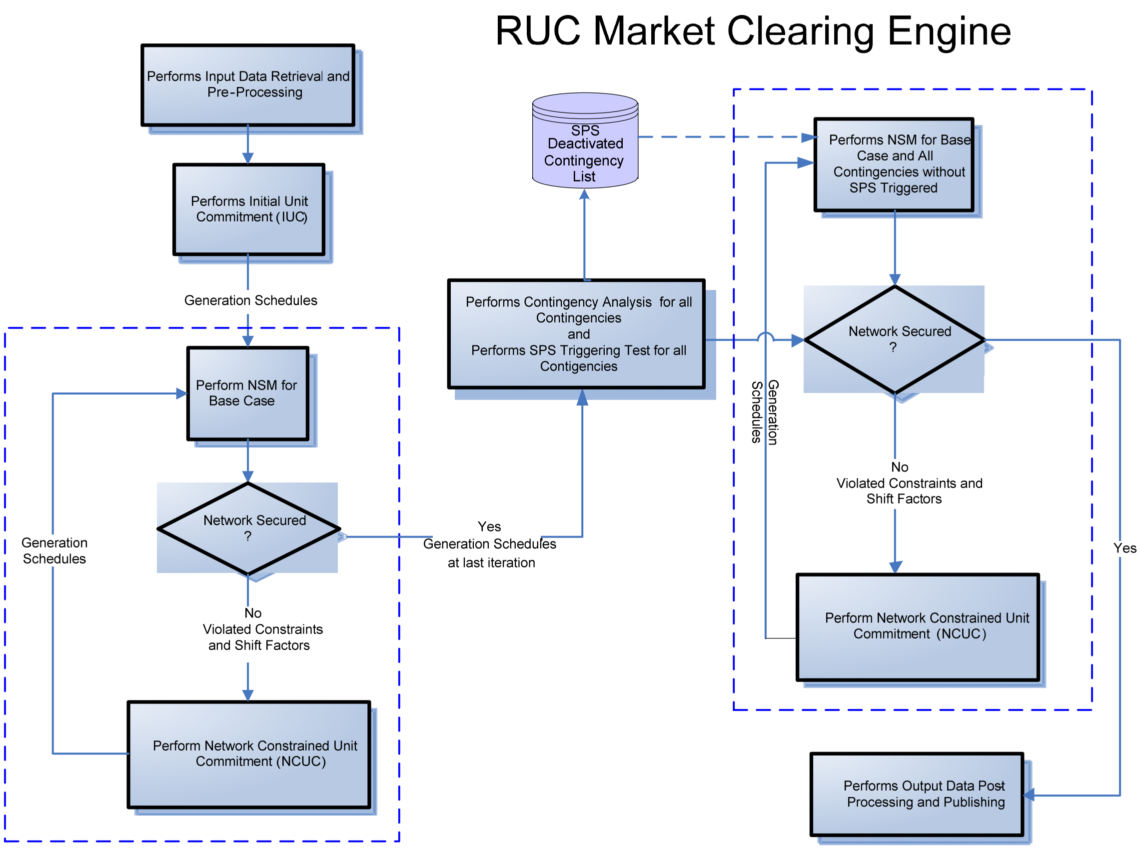

Figure 3-4 NCUC-NSM Solution Process

Chapter 4

Combined Cycle Unit Scheduling in RUC

4.1 Introduction

Due to an abundant supply and relative low prices of natural gas in the state of Texas, the combined cycle resource has been providing a significant portion of ERCOT's total installed capacity.

A combined cycle facility consists of one or more combustion turbines (CT), each with a heat recovery steam generator (HRSG). Steam produced by each HRSG is used to drive steam turbines (ST). Each steam turbine and each combustion turbine have an electrical generator that produces electricity power (CTG and STG) [34], [35]. Typical configurations contain one, two, or three combustion turbines each with a HRSG and single steam turbine. Because of fast response time, high thermal efficiency, relative short installation time, and low air emissions, combined cycle resources have been a popular choice for bulk power generation expansion. Figure 4-1 shows a typical configuration of a 2X1 power block (2 CT and 1 ST) combined cycle train (CCT) [41].

In practice, a CCT can operate at multiple configurations based on different combinations of CTs and STs. The configurations belong to the same CCT are mutually exclusive, i.e. only one configuration of the CCT can be scheduled and dispatched at each time point. The CCT can transit from one configuration to another configuration according to its operating limits. Due to its complicated operating characteristics, how to accurately and efficiently model the CCT becomes one of the key factors for a successful EROCT nodal market.

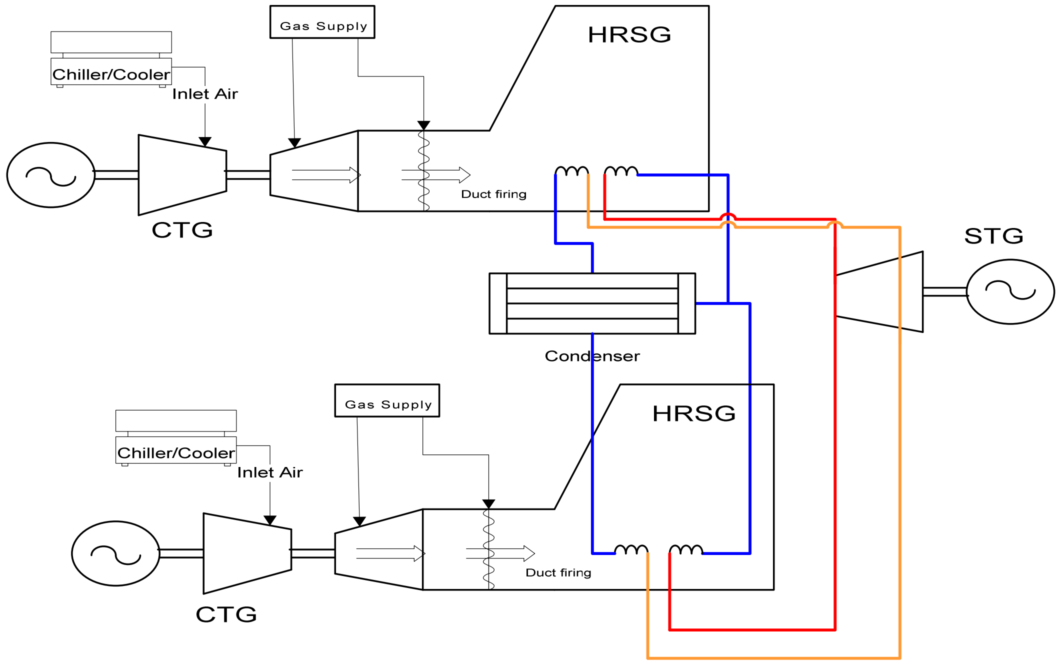

Figure 4-1 A typical 2X1 combined cycle train configuration

Literatures provide various alternatives to model CCTs in electricity markets. These alternatives try to balance the integrity of capturing the unique characteristics of the CCTs and performance of conquering the complicated scheduling problem up to an acceptable extent. This section reviews various ways of modeling of combined cycle resources [34]-[40]:

- Aggregate CCT modeling: This method simply represents a CCT by an aggregated one that is treated as a regular thermal unit. The unit commitment and dispatch decisions are made in each period with no regard to the state of each component. However, this could be problematic since component unit technical constraints cannot be correctly captured in this composite model.
- Pseudo unit modeling (PSU): The model represents a CCT with one or more pseudo units that comprise a single CT and its associated portion of the ST capacity. To avoid inconsistent commitment, it is required that all PSUs have the same

characteristics (startup cost, minimum generation cost, minimum loading point, incremental energy cost, minimum down time, and maximum capacity). As a consequence, the PSU model has difficulties to precisely represent these characteristics under different operating modes. The PSU approach has been implemented successfully by ISO NE, NYISO, MISO, PJM, and IESO.

- Configuration-based modeling: The approach models a combined cycle unit as multiple mutually exclusive configurations or combinations of CT and ST. CCTs can transition from one configuration to another one obeying predefined paths. The approach allows each configuration to submit offer into a market independently. Therefore, the flexibility would permit better representation of technical parameters and bid data from each CCT. Currently, this approach has been implemented in the CAISO MRTU market.
- Physical unit modeling: This alternative is to model physical components of a CCT. Each CT and ST is considered as an individual resource that may submit own startup cost, minimum up/down time, incremental energy cost etc. From scheduling perspective, this is not an ideal choice due to the complexity of handling dependency among components. However, this model is naturally fit for the EMS, OTS, Outage Scheduler, and other network security applications.

Generally speaking, the configuration-based model is more adequate for bid/offer processing and dispatch scheduling, on the other hand, the physical unit modeling is more adequate for the power flow and network security analysis.

4.2 Combined Cycle Unit Modeling in RUC

To satisfy both the network security requirements and the market optimization needs associated with combined cycle trains, the new MMS for ERCOT nodal market is required to support the modeling of CCT in two different ways:

- Configuration-based modeling approach takes into account each operational configuration of the combined-cycle train where each configuration is to be considered as a separate resource in the optimization process. Each configuration will be required to have its own distinct set of operating parameters, physical constraints, energy, and AS offer curves.
- Physical unit modeling is used in MMS while performing network security analysis. Each combustion turbine (CT) and steam turbine (ST) associated with a combined cycle facility is modeled as a separate unit. This approach is important to ensure an accurate assessment of base case power flow, contingency analysis, and special protection scheme (SPS) triggering conditions.

In 2007 the combined cycle resource conceptual design was accomplished to allow CCT to offer each configuration as separate generation resources into the day-ahead market. That allows a specified configuration of physical generation resources (CT or ST) with a distinct set of operating parameters and physical constraints in CCT registered with ERCOT. ERCOT's resource registration system also has been expanded to support for these additional parameters [41]. In April 2010, ERCOT submitted a nodal protocol revision request (NPRR) to revise nodal protocol requirements to encompass combined cycle resources. Two important definitions of combined cycle resources in the NPRR are shown as follows:

- Combined cycle train (CCT): The combinations of gas turbines and steam turbines in an electric generation plant that employs more than one thermodynamic cycle. In ERCOT Combined Cycle Trains are registered as a plant that can operate as a generation resource in one or more combined cycle generation resource configurations.

- Combined cycle generation resource (CCGR): A specified configuration of physical generation resources (gas and steam turbines), with a distinct set of operating parameters and physical constraints, in a combined cycle train registered with ERCOT.

As discussed in Chapter 3, the security constrained unit commitment (SCUC) solution engine is used in the RUC clearing process to find the optimum commitment schedules. The SCUC engine comprises two functional components: (a) network constrained unit commitment (NCUC) and (b) network security monitor (NSM) [6][13][30]. The following sections describe the detailed CCU modeling approaches used in NCUC and NSM.

4.2.1 CCU Modeling in NCUC

The NCUC function uses an advanced mixed integer programming (MIP) technique to determine optimized commitment and dispatch schedules for RUC. In NCUC, configuration-based CCT modeling is employed throughout. To reflect the physical operating characteristics of CCT, the CCT in the nodal MMS is modeled by a set of configurations (CCGR) along with the allowed transitions between the configurations and transitions with the offline state. Each configuration is considered as a logical resource. Similar to regular resources, each configuration has a distinct set of operating parameters, physical constraints including:

- Minimum online time.
- Maximum online time.
- Minimum offline time.
- Hot, intermediate, cold startup times.
- Maximum daily start up.
- Maximum weekly start up (used only by WRUC).

Besides the data submitted for the regular units, the following additional data for the CCT transition matrix is also needed:

- CCT registration data including configuration name and associated physical generators both primary and alternative to be used in case of primary generator is disconnected or outaged.
- Startup flag to indicate if the CCT can be startup to this configuration from offline.
- Shutdown flag to indicate if the CCT can be shut down from this configuration to offline.
- List of allowed transitions specifying the
  - From configuration
  - To configuration
  - Transition direction: up (additional generators are turned on) or down (some generators are turned off)

Note that the startup transition can be considered as a special up transition from the offline state. The shutdown transition can be considered as a special down transition from online state. Table 4-1 lists the configuration registration data for a simple CCT with 2 CTs and 1 ST.

Table 4-1 CCT Configuration Registration

Configuration Name	Configuration Type	Primary Unit	Alternative Unit
1	1CT+0ST	CT1	CT2
2	2CT+0ST	CT1,CT2	
3	1CT+1ST	CT1,ST	CT2
4	2CT+1ST	CT1,CT2,ST	

Only CT units can be mutually alternate, and only ST units can be mutually alternate, i.e. cannot replace CT with ST unit. If multiple alternative physical CCT resources are specified for a CCT configuration then following rules are applied sequentially in specified order to replace outaged or disconnected primary physical CCT resources [30]:

- Select alternative physical CCT resource with the highest voltage level of its connectivity node.
- Select alternative physical CCT resource with the highest capacity.
- Select alternative physical CCT resource that is first in the database table, i.e., randomly.

Figure 4-2 shows the equivalent configurations with primary and alternative units.

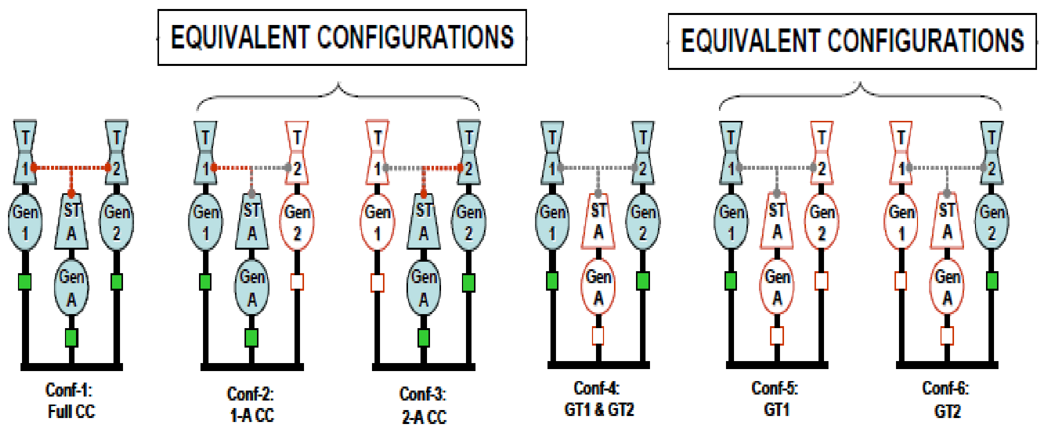

Figure 4-2 Equivalent configurations with primary and alternative units

The state transition diagram for the above CCT can be shown in Figure 4-3.

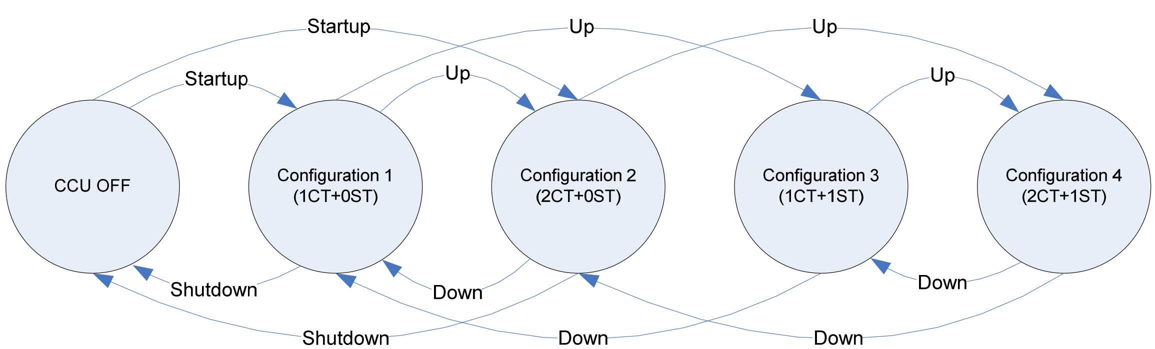

Figure 4-3 CCT State Transition Diagram

A transition matrix can be derived from the state transition diagram between configurations and offline (OFF) status. Table 4-2 lists the transition matrix derived from the state transition diagram in Figure 4-3 where "↑" and "↓" denote the up and down transitions respectively.

Table 4-2 CCT Transition Matrix

Transition Matrix		To Configuration				
		OFF	1	2	3	4
From Configuration	OFF		↑	↑		
	1	↓		↑	↑	
	2	↓	↓			
	3		↓			↑
	4				↓	

Above the main diagonal of the CCT transition matrix are upward transitions, i.e. the transitions in which at least one physical CCT resource is started. Below the main diagonal of CCT transition matrix are downward transitions, i.e. the transitions in which at least one physical CCT resource is turned off.

Most costs and constraints affect CCT configurations in the same way as other regular resources; however, the following additional logic applies to CCT:

- Minimum online time only applies to up transitions. The online time of the after transition is measured from the time when the configuration is started to the time when it is shut down (i.e., the configuration is no longer on). Since the minimum online time has already been satisfied in prior configuration, down transitions do not need to be enforced.
- The offline time is calculated using the following logic:
    - For configurations that can startup: The number of hours offline is measured from the time when the entire CCT is shut down to the CCT startup time.

- For configurations that transition in the up direction: The number of hours offline is measured from the time when the configuration is shut down (i.e., the configuration is no longer online) to the startup time.
- This calculated offline time is also used to determine the warmth state for startup cost and startup time calculations.

- The transition cost only applies to up transitions. It is calculated as the difference of the startup cost between the after and before configurations.
- Minimum offline time only applies to up transitions. The minimum offline time is not applicable for down transitions because all the physical units in the after configuration are online in the prior configuration.
- The number of startups is calculated by measuring the number of up transitions including startup for each configuration.
- The energy constraint applies to each configuration separately.
- The maximum on-line time applies to both the up and down transitions.
- If the CCT is initially offline, then all configurations need to satisfy their respective startup times.

Besides the constraints for the regular units in Section 3.1.4, the following extra constraints are enforced for the combined cycle resources:

$$\sum_{i \in CCGR_{cc}} U_{i,t} = U_{cc,t} \quad \forall cc, \forall t \tag{21}$$

$$\sum_{i \in CCGR_{cc}} U_{i,t} \leq 1 \ \forall cc, \forall t \tag{22}$$

$$\sum_{(j,i) \in CCFT_{cc}} U_{j,t} \geq U_{i,t+1} - (2 - U_{cc,t} - U_{cc,t+1}) \ \forall cc, \forall i \in CCGR_{cc}, \forall t \tag{23}$$

$$\sum_{(i,j) \in CCIT_{cc}} U_{j,t+1} \leq 1 - U_{i,t} \quad \forall cc, \forall i \in CCGR_{cc}, \forall t \tag{24}$$

$$\sum_{i \in CCGRSU_{cc}} U_{i,t} \geq U_{cc,t+1} - U_{cc,t} \quad \forall cc, \forall t \tag{25}$$

$$\sum_{i \in CCGRSD_{cc}} U_{i,t} \geq U_{cc,t} - U_{cc,t+1} \quad \forall cc, \forall t \tag{26}$$

4.2.2 CCU Modeling in NSM

The NSM function evaluates the feasibility of the generation schedule for the intact (base case) network as well as for the post-contingency network states. NSM function also models all approved special protection systems (SPSs) while performing the contingency analysis. The NSM is performed for each interval of the RUC study to provide constraints for the NCUC function. For each violated constraint, a set of shift factors is calculated with respect to all controllable resources including CCTs. The shift factors and the violated limits are passed to the NCUC for enforcement. The NCUC and the NSM iterates several times to determine the final solution [6].

In NSM, physical modeling of the individual generators within a CCU facility is important because the network models provided by network model management system (NMMS) are specified at the physical generation unit level. In addition, all the contingency definitions, outage schedules, and SPS triggering conditions are also defined at physical unit level. While NCUC is using configuration-based modeling and NSM is using physical unit-based modeling, a special interfacing mechanism needed to be established to allow these two functions to exchange information.

A. Energy Schedule Disaggregation

The resulting optimal energy schedules determined by NCUC need to be disaggregated to power outputs of physical CCT resources in order to be considered by NSM function. This translation is performed using capacity weights (HRL) as distribution factors. The optimal energy schedule for an online CC configuration ($EnergySch_{CCGR}$) is distributed to power outputs of physical CCT resources ($PowOut_{CCU,i}$) in the following way:

$$PowOut_{CCU,i} = \frac{HRL_{CCU,i}}{\sum_{i \in CCGR} HRL_{CCU,i}} \times EnergySch_{CCGR} \tag{27}$$

Table 4-3 Shows an example of CCT distribution factor. Assume CC1_3 is online and NCUC dispatches it at 80 MW. According to Equation 1, the energy schedule for Unit1 and Unit3 is calculated as 40MW respectively based on their HRL.

Table 4-3 CCT Distribution Factor

			CC1_1	CC1_2	CC1_3	CC1_4
CC1		**HRL**	**1X0**	**2X0**	**1X1**	**2X1**
Unit 1	CT	100	X	X	X	X
Unit 2	CT	100	A	X	A	X
Unit 3	ST	100			X	X
		300	**100**	**200**	**150**	**300**

B. Shift Factor Aggregation

After performing base case power flow and contingency analysis, NSM produces a set of shift factors for resolving violated constraint for the individual physical CCT resources. However, in order to allow NCUC to optimize energy offers for logical CCT configuration the aggregated shift factors are needed. Similar to the energy schedule disaggregation, the capacity (HRL) weighted average of shift factors for physical CCT resources in a CC configuration are used:

$$SF_{CCGR} = \frac{\sum_{i \in CCGR} \left(HRL_{CCU,i} \times SF_{CCU,i} \right)}{\sum_{i \in CCGR} \left(HRL_{CCU,i} \right)} \tag{28}$$

Aggregated shift factors are calculated for all possible CCU configurations (CCGR) and used accordingly within NCUC optimization process.

If there is a binding constraint and Unit1 has a shift factor 0.085 and Unit3 has a shift factor 0.077 respectively w.r.t. the binding constraint. According to equation 28 NSM calculates the aggregated shift factor for CC1_3 as (0.085*100)+(0.077*100)/(100+100)=0.081.

Chapter 5

Wind Generation Scheduling and Phase Shifter Optimization

5.1 ERCOT Wind Integration

The ERCOT region has garnered recognition as a national leader in integrating wind energy. Similar to many ISOs in the US, daily wind variation in ERCOT is negatively correlated with total system load [42]. The load tends to peak during the daytime when people are awake and using the most power for lighting, heating, and cooling, and when businesses and factories are in operation. Wind generation, however, tends to peak at night. Figure 5-1 shows ERCOT hourly average system total wind generation pattern versus system total load pattern in one month [32]. The average hourly wind generation may be close to minimum at the time of the daily system peak load. With very limited pumped storage capability, ERCOT needs to manage the increasing penetration of wind generation resources (WGRs) using advanced forecasting tools and enhanced operating procedures.

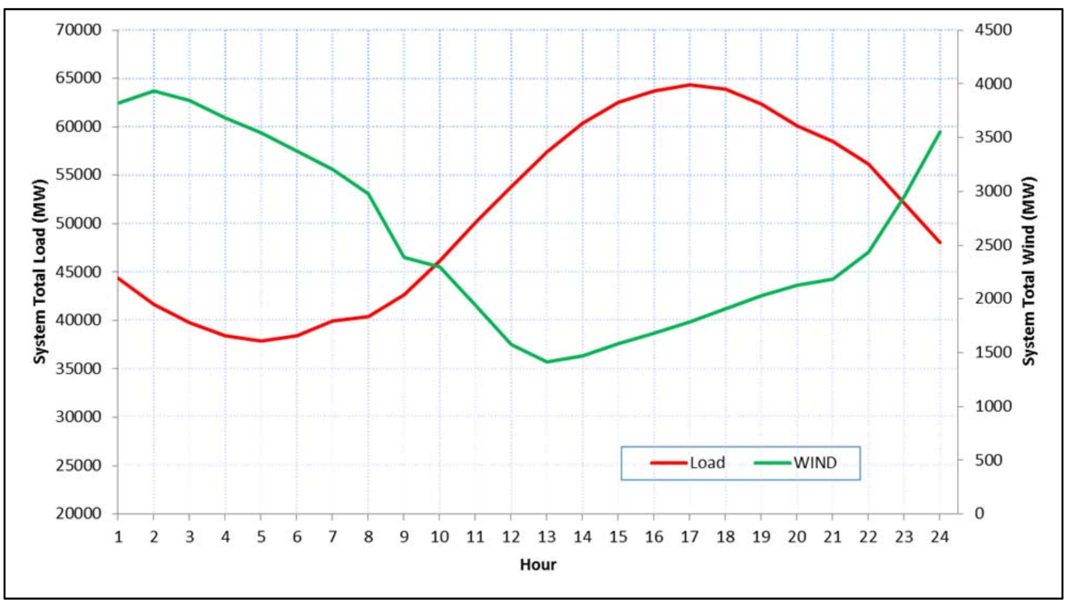

Figure 5-1 ERCOT Wind Generation vs. System Load

ERCOT has been experiencing several operational issues due to the growth of WGRs. For instance, mismatch between the WGR forecast and actual output and the high volatility of wind power generation create a challenge for maintaining system frequency. ERCOT operators are forced to use more expensive ancillary reserves more frequently in order to maintain frequency within the desired range. To address this issue, ERCOT is improving wind generation forecast tool for real-time operation while making changes to ancillary service requirement determination methodology to take into consideration the effects of wind generation [42]-[45].

In addition, wind farms in ERCOT are concentrated in the West Texas area; however, the major load centers are located in Dallas/Fort Worth and Houston areas. The amount of power transferred from WGRs to the load centers is limited by the existing transmission network capability. To fully utilize the available transfer capacity and take advantage of the latest wind generation forecasting, ERCOT has implemented an hourly limit calculation tool to monitor and enforce the latest transmission limits dynamically. ERCOT also has implemented a set of special protection schemes (SPSs) and mitigation plans to deal with local congestion issues that constrain the WGR generation [44]. In addition, tap settings of certain phase shifting transformers, such as phase shifter at Yellow Jacket, impact the maximum transmission capability from the ERCOT West Incorrect phase shifter tap settings could result in inefficient market solutions and higher market prices. To address this issue, a phase shifter optimization model has been proposed and implemented in RUC to automatically determine the optimal phase shifter tap settings.

As the installed generation capacity from WGRs grows rapidly, transmission system of ERCOT also needs to be expanded quickly to provide necessary transmission accesses for the new WGRs. How to allow customers to have access to the providers whose energy is generated by WGRs became one of the major challenges for the ERCOT system planning. In 2008, the Public Utility Commission of Texas (PUCT) ordered ERCOT to conduct several competitive renewable energy zones (CREZs) studies. Following the studies, the PUCT identified five CREZs in ERCOT based on the concentration of WGR potentials and financial commitments demonstrated by the developers. Later on, the PUCT further approved construction of 2,376 circuit miles of new 345-kV transmission to be completed by the end of 2013 to support higher wind penetration levels [46].

5.2 Short-Term Wind Generation Forecasting

Each hour ERCOT produces and updates a few types wind generation forecasts for a rolling 48-hour in both system level and individual WGR level. The detail forecast types are described as follows:

a) Total ERCOT wind power forecast (TEWPF): It represents a probability distribution of the hourly production potential from all wind-power in ERCOT for each of the next 48 hours.

b) Short-Term wind power forecast (STWPF): it represents an hourly 50% probability of exceedance forecast of the generation in MWh per hour from each WGR. ERCOT uses the probabilistic TEWPF and select the forecast that the actual total ERCOT WGR production is expected to exceed 50% of the time (50% probability of exceedance forecast). To produce the STWPF, ERCOT allocates the TEWPF 50% probability of exceedance forecast to each WGR such that the sum of the individual STWPF forecasts equal the TEWPF forecast.

c) Wind-powered generation resource production potential (WGRPP): The generation in MWh per hour from a WGR that could be generated from all available units of that resource allocated from the 80% probability of exceedance of the TEWPF. WGRPP is specific to each wind generator and is based on information provided by each WGR, meteorological information, and data collected directly by ERCOT.

The WGRPP is lower than the STWPF for the same WGR since WGRPP is produced as 80% probability of exceedance of the forecast while STWPF is produced as 50% probability of exceedance.

5.3 Wind Generation Scheduling in RUC

The WGRs are required to keep the COP up to date to reflect latest wind forecast and changes in capacity or resource status. For the first 48 hours of the COP, a QSE representing a WGR must enter an HSL value that is less than or equal to the most recent STWPF provided by ERCOT for that WGR to show its production potential. The balance of the 168 hours beyond 48-hours in the COP must also be provided by the QSE for the WGR using its best estimate for the production potential. Originally Nodal Protocols require WGR to enter HSL based on its WGRPP. Since WGRPP is more conservative (i.e. lower) compared to STWPF, it may cause over commitment in RUC and hence WGRPP was changed to STWPF as the basis for the HSLs in COP in a later protocol revision.

Different from DAM, RUC is a reliability process and all the physical resources including WGRs are required to participate in RUC by submitting a valid COP. Hence both resource status and resource limits including HSL, LSL and ancillary service schedules in the COP are used in RUC scheduling. The full capacity of HSL is considered in RUC as maximum dispatch limit. Since WGRs are required to update their COP HSL constantly based on the most current STWPF, RUC is able to take into account the most recent WGR output potential in its scheduling from the WGR COP.

To verify the WGR COP HSL update accuracy, Figure 5-2 is drawn to show the system total STWPF, WGRPP and WGR COP total HSL for operating day 12/06/2012 at the snapshot of DRUC execution time (12/05/2012 14:30). The real-time wind generation is also included in the figure for comparison. Figure 5-2 shows that the DRUC WGR COP HSL is above WGRPP and close to STWPF as expected which indicates that QSE followed the requirement to update the WGR COP according to the STWPF. All the 4 lines are following the same RT wind trend even they have differences due to forecasting error in day ahead.

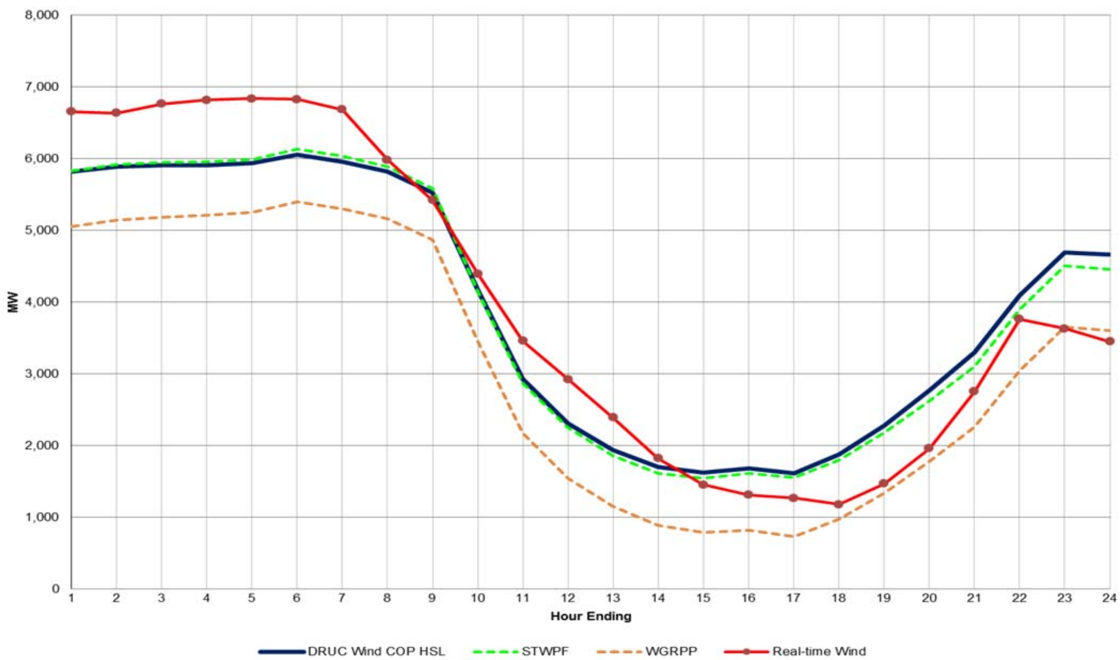

Figure 5-2 Wind Scheduling in DRUC

In RUC make-whole settlement, all QSEs that were capacity-short in each RUC will be charged for that shortage as RUC capacity-short charge. To determine whether a QSE is capacity-short, the WGRPP for the WGR used in the corresponding RUC is considered the available capacity of the WGR when determining responsibility for the corresponding RUC charges, regardless of the real-time output of the WGR. Even the high value STWFP is used as HSL for RUC input to reduce RUC over commitment, the low value WGRPP is used in RUC settlement to account for the WGR capacity.

5.4 Phase Shifter Optimization in RUC

5.4.1 Introduction

Currently, there are eight phase shifters installed and operated in the ERCOT system. These phase shifters are primarily intended for relieving transmission overloads caused by variations in wind generation. These phase shifters can be utilized to transfer large amounts of power produced by WGRs from West Texas to ERCOT load centers more effectively.

In real-time operation, ERCOT determines the transmission overloading conditions and communicates the desired phase shifter tap settings to the phase shifter Operators as required. The Phase Shifter Operators are responsible for adjusting the Phase Shifters tap setting in real-time and telemeter the current tap setting to EMS SCADA system. Based on the telemetered Phase Shifter tap settings, EMS state estimator (SE) solves the base case power flow and the real-time contingency analysis (RTCA) performs contingency analysis.

The detail phase shifter information is shown in Table 5-1. The step increment indicates the phase angle change in degree per step change. All the eight phase shifters have the same low, high and neutral step. The maximum degree change for each phase shifter is ±1.875*16=±30 degree.

Table 5-1 Phase Shifter Parameters

No	Phase Shifter Name	Station Name	Low Step	High Step	Neutral Step	Step Increment (degree)
1	BGLK_SOURCE_TAPS	BGLK	1	33	17	1.875
2	FIREROCK_138_PS_H_4448	FIREROCK	1	33	17	1.875
3	HAMILTON_PS2_1335	HAMILTON	1	33	17	1.875
4	N_SHARPE_138_PS_1336	N_SHARPE	1	33	17	1.875
5	NLARSW_PST1_1337	NLARSW	1	33	17	1.875
6	PUTN_138_PS_1338	PUTN	1	33	17	1.875
7	THOMASTN_SR_THO1	THOMASTN	1	33	17	1.875
8	YELWJCKT_PS_1_H_4448	YELWJCKT	1	33	17	1.875

Figure 5-3 shows the ERCOT DAM LMP contour map for one operating hour. The eight phase shifter locations are shown in the map as black dots with a number on the side. It can be observed that the west zone has lower LMP compared to north zone due to the binding constraint from west to north. It also shows that there are a small red zone and a small blue zone in the west zone because there is binding local constraint between them with the flow direction from the blue zone to the red zone.

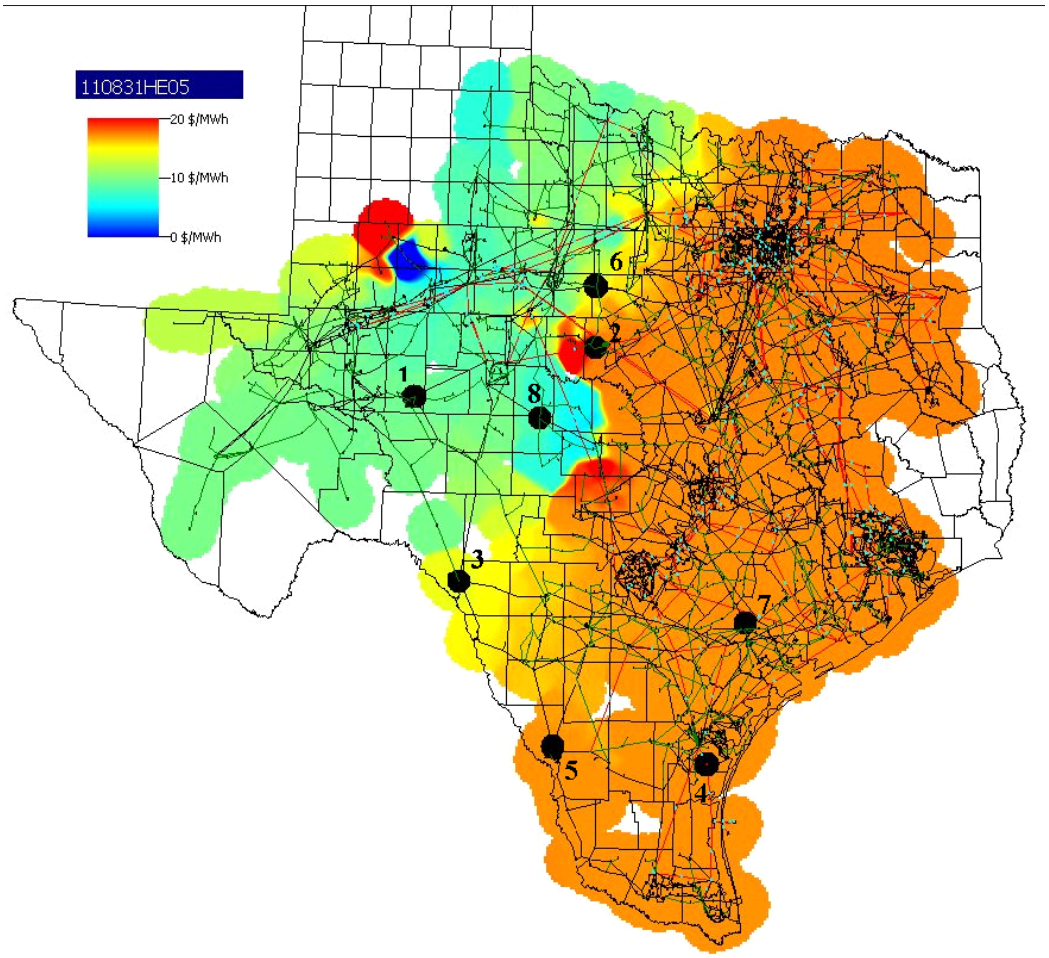

Figure 5-3 ERCOT Phase Shifter Locations

In the beginning of nodal market, RUC did not have the capability to optimize the phase shifter tap in their optimization engine. In order to model the impact of the phase shifters, ERCOT system operations was requested to calculate an hourly tap position for each phase shifter based on the WGR forecast and system load condition 2 days ahead of operating day. Then the calculated tap positions were passed to RUC as fixed values for network security analysis. This approach was better than the neutral settings for all the hours but it also caused some market issues. This is because the calculation was performed 2 days ahead with a lot of assumption and estimation and it could be much different from real-time tap setting which can be freely adjusted according to real-time operation condition. In some cases, the inaccurate calculated tap setting caused some unrealistic congestion in RUC.

In order to solve the above issue and better model the phase shifters in RUC scheduling, the enhancement of phase shifter tap optimization has been implemented in RUC since July 2011. With this new enhancement, RUC Operator has the option to enable or disable the optimization for each individual phase shifter in market operator interface (MOI). When the phase shifter optimization is enabled, the hourly absolute phase shifter tap positions are modeled as control variables in the optimization engine of network security constrained unit commitment (NCUC). The shift factor of phase shifters with respect to the transmission constraint is defined as MW/tap, i.e. the MW flow change on the constraint with respect to each tap position change. In the NCUC, the cost function for moving the tap is modeled as a positive V-shaped curve around the initial tap position (not necessary the neutral tap position) with a very small slope ($/tap), e.g. 0.0001. One example of the V-shaped cost curve is shown in Figure 5-4. In some cases, the initial tap is set the same as neutral tap. The phase shifter tap positions are determined automatically as part of RUC optimization solutions. If the phase shifter has impact to the binding transmission constraint, it will be the most economic resource to be scheduled away from its initial position to solve the congestion because the pre-defined cost for the tap movement is set very small comparing with offer prices from regular resources. Otherwise the phase shifter will be set at the initial tap position.

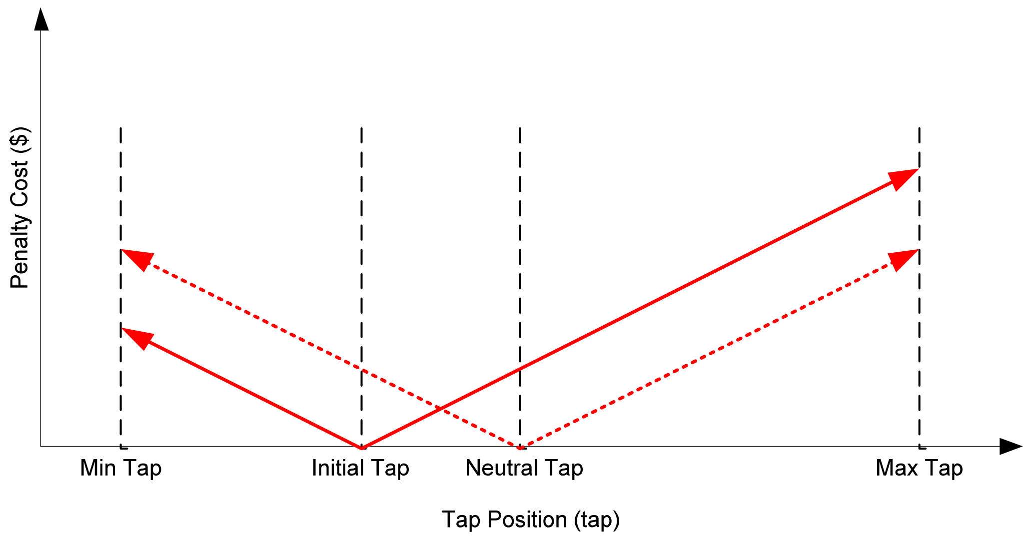

Figure 5-4 V-shaped Phase Shifter Movement Penalty Cost Function

5.4.2 Phase Shift Modeling in RUC

A. Power Injection Model of Phase Shifter

The one-line diagram of a transmission line with phase shifter is shown in Figure 5-5.

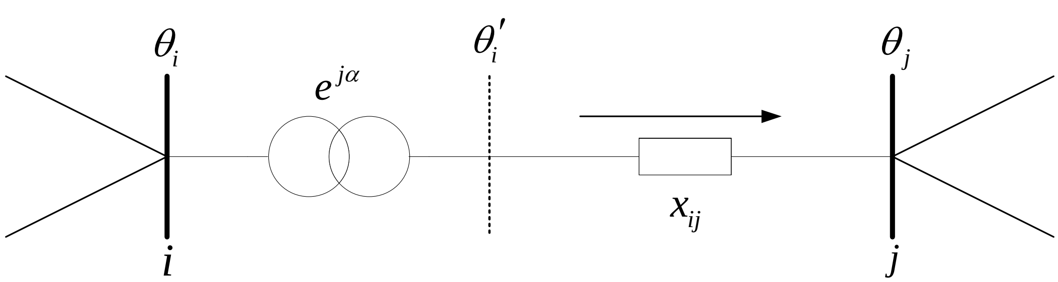

Figure 5-5 Transmission Line with Phase Shifter

Where i and j is the from bus and to bus respectively

θ_i and θ_j is phase angle at bus i and j respectively.

α is the phase angle shift from the phase shifter.

x_{ij} is the reactance of the transmission line in per unit.

The linear DC power flow on phase shifter from bus i to j bus is

$$f_{ij} = \frac{\theta_i + \alpha - \theta_j}{x_{ij}} = \frac{\theta_i - \theta_j}{x_{ij}} + \frac{\alpha}{x_{ij}} \tag{29}$$

According to the Equation above, the transmission line with phase shifter can be equivalently treated as a normal line with reactance x_{ij} and an withdrawn $\frac{\alpha}{x_{ij}}$ at bus i and an injection $\frac{\alpha}{x_{ij}}$ at bus j.This equivalent treatment is referred as power injection model (PIM) [89][90]. The equivalent power injection model of phase shifter can be shown in Figure 5-6.

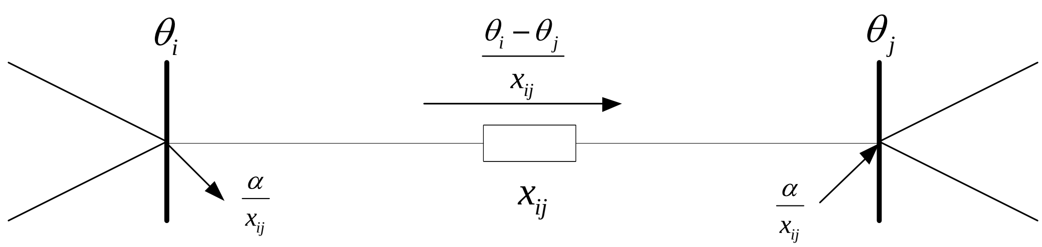

Figure 5-6 Phase Shifter Power Injection Model

B. Shift Factor of Phase Shifter

The shift factor of this phase shifter to a branch mn is defined as the change in flow in branch $mn(\Delta f_{mn})$ due to a change in unit angle ($\Delta\alpha$) (1 radian) of the phase shifter angle. There is a fundamental difference in the manner by which phase shifter sensitivities to a constraint is determined from the conventional shift factor determination from a bus to a constraint.

Conceptually, when determining the shift factor from a bus to a constraint, one can inject 1 MW at a bus and withdraw the same 1 MW at the slack (reference) bus and determine how much of that 1 MW injection flows though the constraint (e.g. branch $mn\left(\Delta f_{mn}\right)$). This approach directly gives the shift factor of this bus to the constraint.

For the shift factor from a phase shifter to a constraint, one need to change the angle by 1 radian and observe how much the flow changes through the constraint (e.g. branch $mn\left(\Delta f_{mn}\right)$). This approach directly gives the shift factor of the phase shifter to this constraint. This is achieved by injecting $-1/x_{ps}$ at bus i and $+1/x_{ps}$ at bus j and then determining the change in flow on the constraint (e.g. branch $mn\left(\Delta f_{mn}\right)$). The equation below describes this.

Phase Shifter Shift factor SF_{PS-rad} (MW/radian) to constraint on branch mn is:

$$SF_{ps-rad} = \frac{1}{x_{mn}} \times \begin{bmatrix} \cdots & 1 & \cdots & -1 & \cdots \end{bmatrix} \times \left[B^{'}\right]^{-1} \times \begin{bmatrix} \vdots \\ \frac{-1}{x_{ps}} \\ \vdots \\ \frac{+1}{x_{ps}} \\ \vdots \end{bmatrix} \tag{30}$$

Where x_{mn} is the per unit reactance of branch mn and

$\begin{bmatrix} \cdots & 1 & \cdots & -1 & \cdots \end{bmatrix}$ is the row vector with 0 in all locations except index m (value=1) and n (value=-1) and

$\begin{bmatrix} \cdots & \frac{-1}{x_{ps}} & \cdots & \frac{+1}{x_{ps}} & \cdots \end{bmatrix}^T$ is the column vector with 0 in all locations except index i (value= $\frac{-1}{x_{ps}}$) and j (value= $\frac{+1}{x_{ps}}$).

In the NCUC optimization the control variable is the phase shifter tap position, therefore the shift factor derived above in terms of MW/radian needs to be transformed to MW/tap.

$$SF_{ps-tap} = SF_{ps-rad} \times TapStepInRadians \qquad (31)$$

Where SF_{ps-tap} is the shift factor of phase shifter in MW/tap.

C. Cost Function of Phase Shifter

As illustrated in Figure 5-4, the cost function for moving the phase shifter tap in the NCUC optimization is modeled as a positive V-shaped curve around the initial tap position. The formulation is shown as follows:

$$PSCOST_{ps,t} = C_{ps} * \left(PST_{s,t} - PST_{0s,t} \right) \quad \forall s, \forall t \qquad (32)$$

Chapter 6

RUC Study and Results Analysis

During the design phase of the nodal RUC project, a prototype RUC program was developed with the proposed combined cycle unit (CCU) modeling to verify the effectiveness of the CCU modeling. The prototype RUC program utilizes AMPL [12] as modeling language and CPLEX [84] as optimization solver. The prototype RUC program has been tested on a revised PJM 5-bus system [88] and the results are very promising. Some of the test results are shown in Section 6.1 to illustrate the effectiveness of the proposed algorithm. Because of the positive testing results, the proposed CCU modeling has been adopted for the RUC project and eventually implemented for the production RUC by the vendor and used in ERCOT.

For clarity and simplicity, first numerical cases running from the prototype RUC program on the revised PJM 5-bus system are used to illustrate the primary features of the RUC. Next the simulation results running from the production RUC software delivered by the vendor on the real ERCOT system are presented to demonstrate the robustness and effectiveness of the RUC clearing process.

6.1 RUC Study on PJM 5-bus Test System

The one-line diagram of the revised PJM 5-bus system [88] is shown in Figure 6-1. The revised PJM 5-bus system has 5 generation resources and 3 loads. To illustrate the proposed combined cycle resource scheduling logic, the BRIGHTON resource is set up as a combined cycle train (CCT) with 2 mutually exclusive configurations: BRIGHTON_CC1_1 and BRIGHTON_CC1_2. The detail parameters of CCT BRIGHTON_CC1 are listed in Table 6-1-Table 6-3.

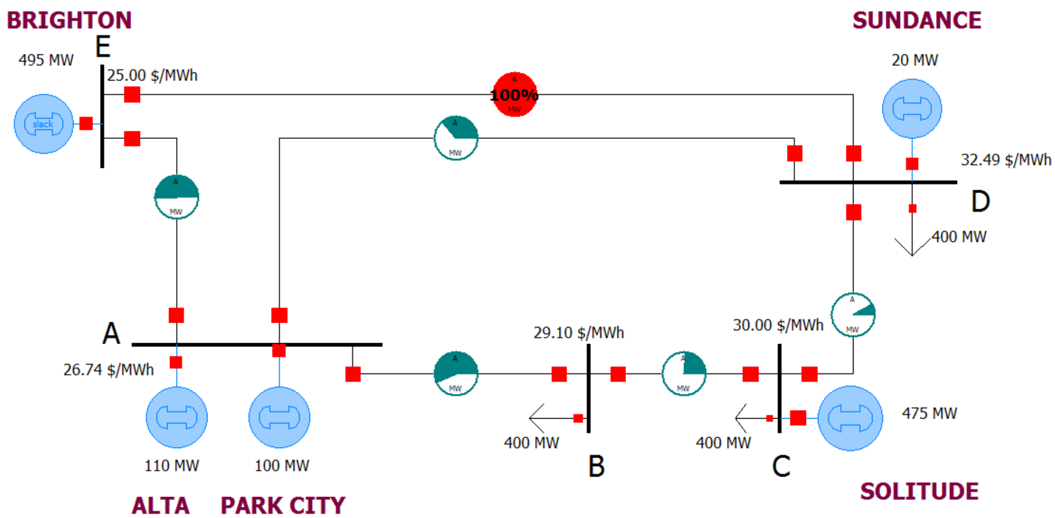

Figure 6-1 Revised PJM 5-bus Test System

Table 6-1 BRIGHTON_CC1 Configuration Registration

Configuration Name	Configuration Type	Primary Unit	Alternative Unit
BRIGHTON_CC1_1	1CT+1ST	CT1,ST1	CT2
BRIGHTON_CC1_2	2CT+1ST	CT1,CT2,ST1	

Table 6-2 BRIGHTON_CC1 Transition Data

CCT Name	From Configuration	To Configuration	Transition Direction
BRIGHTON_CC1	BRIGHTON_CC1_1	BRIGHTON_CC1_2	Upward
BRIGHTON_CC1	BRIGHTON_CC1_2	BRIGHTON_CC1_1	Downward

Table 6-3 BRIGHTON_CC1 Startup and Shutdown Flag

CCT Name	Configuration Name	Startup Flag	Shutdown Flag
BRIGHTON_CC1	BRIGHTON_CC1_1	Y	Y
BRIGHTON_CC1	BRIGHTON_CC1_2	N	N

Table 6-4 Bus Load Distribution Factor of the 5-bus System

Bus	A	B	C	D	E
Bus LDF	0	1/3	1/3	1/3	0

Table 6-5 Line Data of the 5-bus System

Line No	From Bus	To Bus	R (%)	X (%)	Limit (MW)
1	A	B	0	2.81	500
2	A	D	0	3.04	500
3	A	E	0	0.64	500
4	B	C	0	1.08	500
5	C	D	0	2.97	500
6	D	E	0	2.97	240

The bus load distribution factor and line data of the 5-bus system are presented in Table 6-4 and Table 6-5 respectively.

For simplicity, the DRUC scheduling logic is used for all the cases. The study period is 24 hours of the next operating day and the study interval is 1 hour. The hour ending (HE) convention is used in the study. To clearly illustrate the UC results, the transmission constraint is only enforced in case 3 and all the other cases are tested in unconstrained mode.

The resource parameters and resource three-part supply offers are listed in Table 6-6 and Table 6-7 respectively. The three-part offer submitted by QSE is hourly specific and can be different from hour to hour. Also the energy offer curve from the three-part offer can be piece-wise linear and up to 10 break points. For clarity and simplicity, each resource only has a constant three-part supply offer with only one staircase segment energy offer curve

Table 6-6 Resource Parameters

Resource ID	Resource Name	Bus	Pmin (MW)	Pmax (MW)	MNUP (Hour)	MNDN (Hour)	Hot2int (Hour)	Hot2cold (Hour)	MXUP
G1	ALTA	A	11	110	4	5	3	5	3
G2	PARK CITY	A	10	100	4	5	3	5	3
G3	SOLITUDE	C	52	520	4	5	3	5	3
G4	SUNDANCE	D	20	200	4	5	3	5	3
G5	BRIGHTON_CC1_1	E	100	300	4	5	8	20	3
G6	BRIGHTON_CC1_2	E	300	600	6	7	8	20	3

Table 6-7 Resource Three-Part Supply Offer

Resource ID	Startup Cost ($)			Min-Energy ($/MWh)	Energy Offer Curve (Q-MW, P-$/MWh)					
	Hot	Inter	Cold		Q1	P1	Q2	P2	Q3	P3
G1	1000	1200	1400	20	0	14	110	14		
G2	1100	1300	1500	20	0	15	100	15		
G3	3000	3500	4000	40	0	30	520	30		
G4	2000	2500	3000	50	0	40	200	40		
G5	5000	6000	8000	30	0	20	300	20		
G6	10000	12000	16000	30	0	25	600	25		

6.1.1 Case 1 of the 5-bus System

This test case simulates the resource commitment for the 5-bus system with a low peak load 900MW in the unconstrained mode. In this case, all the resources are offline available in the study period (24 hours of the operating day) without self-commitment.

The resource initial condition for this test case is listed in Table 6-8. In this case, all the resources are set up as being offline for long time at the beginning of the study period. The initial condition in this case makes sure all the resources are in cold status at the beginning of the study period and will have a cold startup if it is committed in the study period. The positive value indicates the online time and the negative value indicates the offline time, e.g. -100 indicates the resource has been offline for 100 hours at the beginning of the study period (0000).

Table 6-8 Resource Initial Condition

Resource ID	G1	G2	G3	G4	G5	G6
Initial On Time (Hour)	-100	-100	-100	-100	-100	-100

The hourly system load and the UC solution is presented in Table 6-9. The table consists of 4 sections. The first section of the table shows the hourly system load and the system lambda. The second section shows the resource commitment status for each resource each hour: the value 0 with red color indicates that the resource is offline in this hour and not committed, the value 1 with green color indicates that the resource is committed online by UC and the value 1 with yellow color indicates that the resource is self-committed online in COP by QSE. The third section shows resource hourly dispatch and the fourth section shows resource hourly production cost which equals to the sum of resource startup cost, min-gen cost and incremental energy cost. The total row under section 2-4 is the sum for values of all the units for the specified hour, i.e. total number of online resources, total dispatch MW and total production cost for the specified hour respectively.

It shows that the system load is met by the generation for all the hours. Figure 6-2 shows the hourly system load and system lambda for the 24 hour study period. It can be observed that the system lambda is high during peak hours and is low at off-peak.

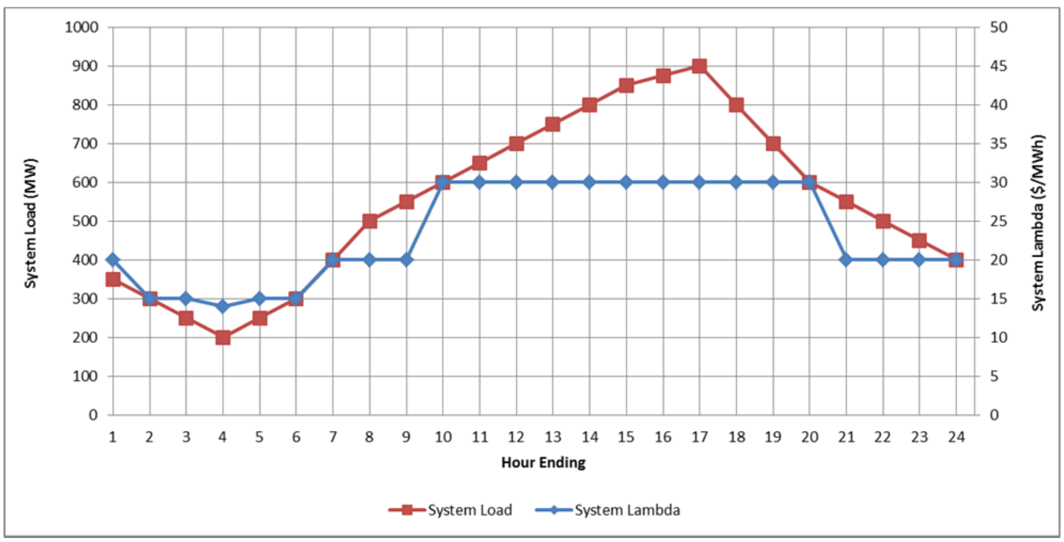

Figure 6-2 Case 1 System Load and System Lambda

Table 6-9 Case 1 Hourly System Load and UC Solution

System Load (MW) and System Lambda ($/MWh) for Each Hour																								
HE	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Load	350	300	250	200	250	300	400	500	550	600	650	700	750	800	850	875	900	800	700	600	550	500	450	400
SL	20	15	15	14	15	15	20	20	20	30	30	30	30	30	30	30	30	30	30	30	20	20	20	20
Resource Commitment Status for Each Hour																								
Unit	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
G1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G3	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0
G4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
G5	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	3	3	3
Resource Dispatch (MW) for Each Hour																								
Unit	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
G1	110	110	110	90	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
G2	100	90	40	10	40	90	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
G3	0	0	0	0	0	0	0	0	52	90	140	190	240	290	340	365	390	290	190	90	52	0	0	0
G4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
G5	140	100	100	100	100	100	190	290	288	300	300	300	300	300	300	300	300	300	300	300	288	290	240	190
G6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	350	300	250	200	250	300	400	500	550	600	650	700	750	800	850	875	900	800	700	600	550	500	450	400
Resource Production Cost ($) for Each Hour																								
Unit	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
G1	3006	1606	1606	1326	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606
G2	3050	1400	650	200	650	1400	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550
G3	0	0	0	0	0	0	0	0	6080	3220	4720	6220	7720	9220	10720	11470	12220	9220	6220	3220	2080	0	0	0
G4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
G5	11800	3000	3000	3000	3000	3000	4800	6800	6760	7000	7000	7000	7000	7000	7000	7000	7000	7000	7000	7000	6760	6800	5800	4800
G6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	17856	6006	5256	4526	5256	6006	7956	9956	15996	13376	14876	16376	17876	19376	20876	21626	22376	19376	16376	13376	11996	9956	8956	7956

Figure 6-3 shows the combined cycle train (CCT) BRIGHTON_CC1 commitment status for the 24 hour study period. One can see the configuration BRIGHTON_CC1_1 (1CT+1ST) has been committed for all the hours with startup at HE1 and shutdown after HE24. The configuration BRIGHTON_CC1_1 can be startup and shutdown according to the CCT parameters. The CCT commitment status in this case satisfies all the CCT resource constraints including temporal constraints, startup and shutdown constraints.

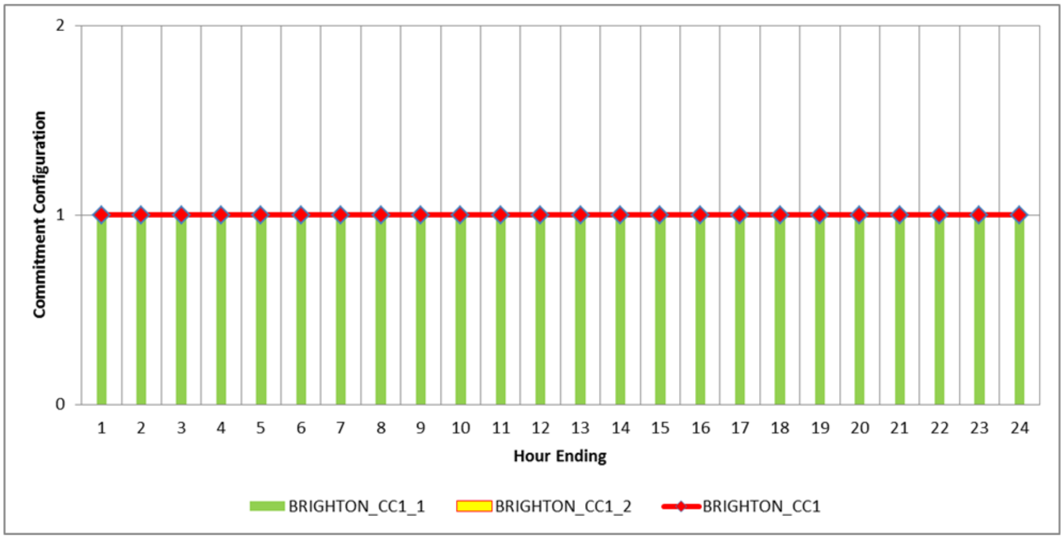

Figure 6-3 Case 1 Commitment Status of BRIGHTON_CC1

Figure 6-4 shows the dispatch of the CCT BRIGHTON_CC1. It shows that the CCT is dispatched within P_{min} and P_{max} for all the hours. It also can be seen that the CCT is dispatched down in the off-peak and dispatched high in the peak hours.

Figure 6-5 shows the production cost of the CCT BRIGHTON_CC1. The production cost includes the startup cost, min-gen cost and incremental energy cost. The min-gen cost and incremental energy cost are applied for all the 24 hour since the CCT has been committed for all the hours. At HE1, BRIGHTON_CC1_1 is started up from cold status so the cold startup cost ($8000) is applied. The min-gen cost equals to

MEO*P_{min}=30*100=$3000. The incremental cost is 20*(140MW-100MW)=$800. So the production cost=startup cost ($8000)+min-gen cost ($3000)+incremental energy cost ($800)=$11800. This is consistent with the production cost at HE1 for the CCT.

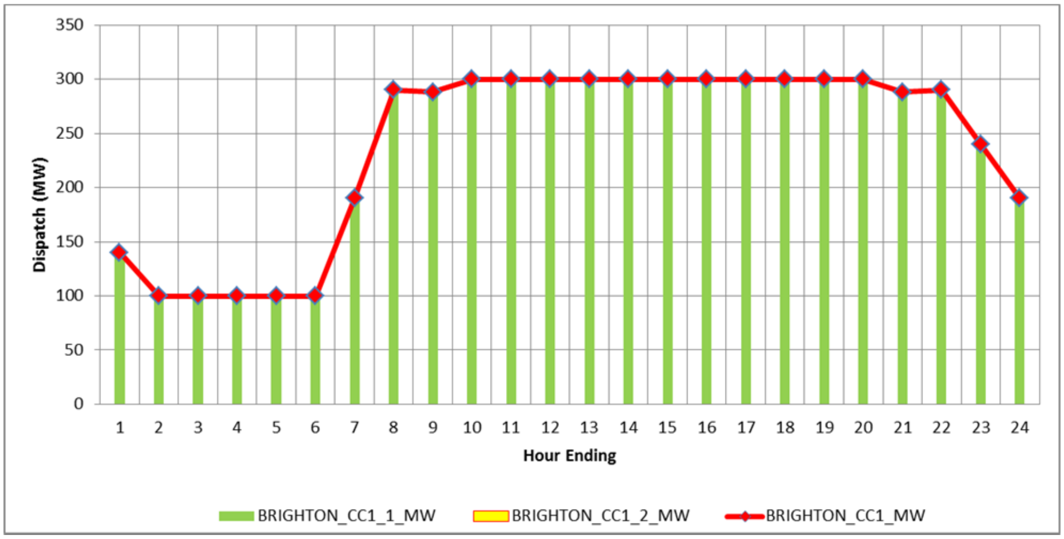

Figure 6-4 Case 1 Dispatch of BRIGHTON_CC1

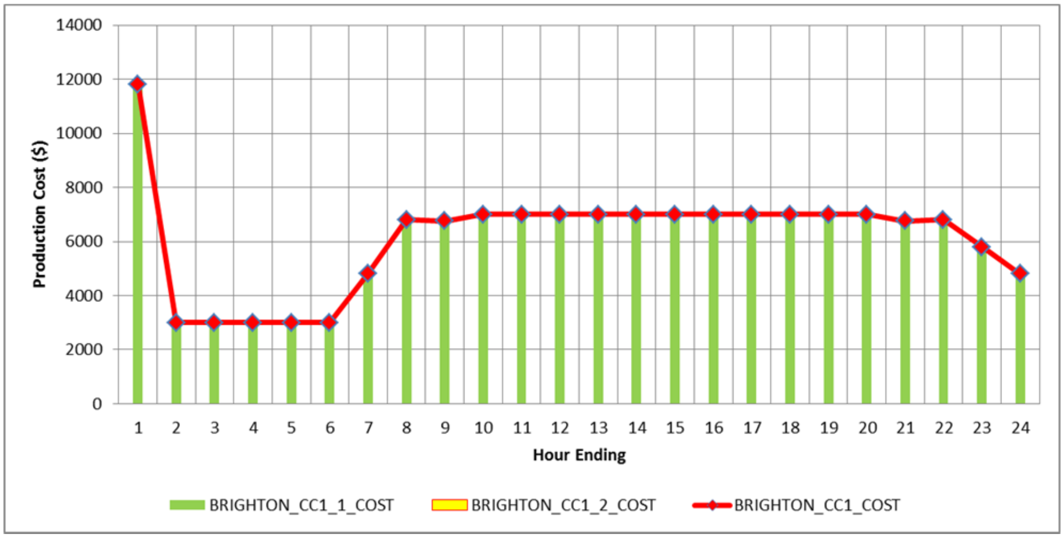

Figure 6-5 Case 1 Production Cost of BRIGHTON_CC1

6.1.2 Case 2 of the 5-bus System

Case 2 has the same input as case 1 except the system load has been increased with peak load as 1400MW. The hourly system load and the UC solution is presented in Table 6-10.

Figure 6-6 shows the hourly system load and system lambda for the 24 hour study period. It can be observed that the system lambda is $30/MWh for all the hours except at HE17 and HE4. HE4 has the lowest load in the study period and the system lambda is 20$/MWh. HE17 has the peak load 1400MW and the system lambda is $40/MWh.

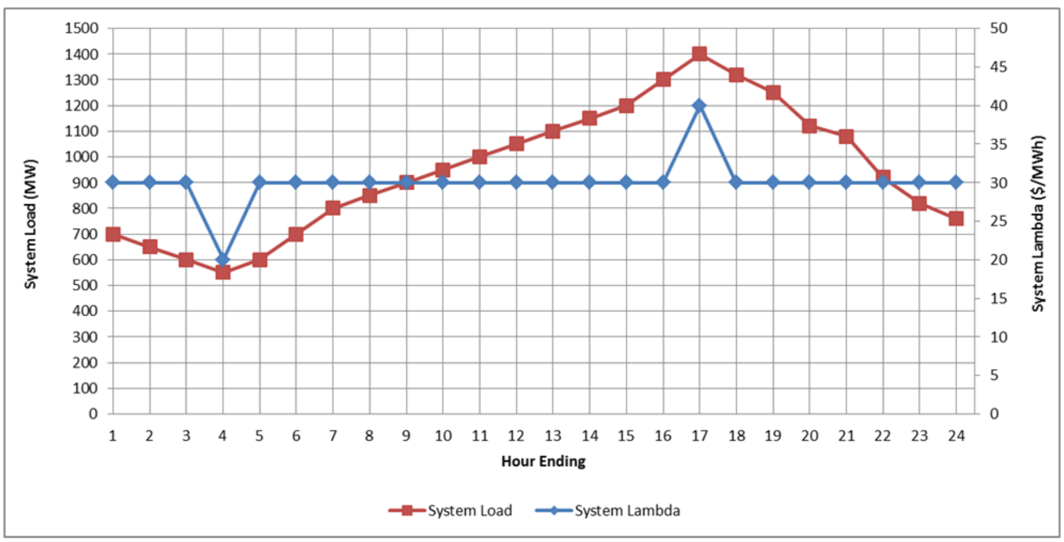

Figure 6-6 Case 2 System Load and System Lambda

Table 6-10 Case 2 Hourly System Load and UC Solution

System Load (MW) and System Lambda ($/MWh) for Each Hour																								
HE	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Load	700	650	600	550	600	700	800	850	900	950	1000	1050	1100	1150	1200	1300	1400	1320	1250	1120	1080	920	820	760
SL	30	30	30	20	30	30	30	30	30	30	30	30	30	30	30	30	40	30	30	30	30	30	30	30
Resource Commitment Status for Each Hour																								
Unit	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
G1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G3	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
G5	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	1	1	1
G6	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	0	0	0
Total	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	5	4	4	4	4	4	4	4
Resource Dispatch (MW) for Each Hour																								
Unit	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
G1	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
G2	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
G3	190	140	90	52	90	190	290	340	390	440	490	240	290	340	390	490	520	510	440	310	270	410	310	250
G4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	70	0	0	0	0	0	0	0
G5	300	300	300	288	300	300	300	300	300	300	300	0	0	0	0	0	0	0	0	0	0	300	300	300
G6	0	0	0	0	0	0	0	0	0	0	0	600	600	600	600	600	600	600	600	600	600	0	0	0
Total	700	650	600	550	600	700	800	850	900	950	1000	1050	1100	1150	1200	1300	1400	1320	1250	1120	1080	920	820	760
Resource Production Cost ($) for Each Hour																								
Unit	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
G1	3006	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606
G2	3050	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550
G3	10220	4720	3220	2080	3220	6220	9220	10720	12220	13720	15220	7720	9220	10720	12220	15220	16120	15820	13720	9820	8620	12820	9820	8020
G4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6000	0	0	0	0	0	0	0
G5	15000	7000	7000	6760	7000	7000	7000	7000	7000	7000	7000	0	0	0	0	0	0	0	0	0	0	7000	7000	7000
G6	0	0	0	0	0	0	0	0	0	0	0	24500	16500	16500	16500	16500	16500	16500	16500	16500	16500	0	0	0
Total	31276	14876	13376	11996	13376	16376	19376	20876	22376	23876	25376	35376	28876	30376	31876	34876	41776	35476	33376	29476	28276	22976	19976	18176

Figure 6-7 shows the combined cycle train (CCT) BRIGHTON_CC1 commitment status for the 24 hour study period. One can see the configuration BRIGHTON_CC1_1 (1CT+1ST) has been committed for HE1-HE11. BRIGHTON_CC1_1 has been online for 11 hours that satisfies its minimum online time (6 hours). At HE12 the configuration BRIGHTON_CC1_1 is transited up to configuration BRIGHTON_CC1_2. Configuration BRIGHTON_CC1_2 stays online until HE21 and it transits down to configuration BRIGHTON_CC1_1 at HE22. Then BRIGHTON_CC1_1 stays online until HE24. Configuration BRIGHTON_CC1_2 has met both the minimum online time (6 hours) and minimum offline time (6 hours) during the online period. Because DRUC only covers one operating day, DRUC assumes that all units including CCT are offline after the end of the study period. Since BRIGHTON_CC1_2 can't be shutdown according to the CCT shutdown constraints in Table 6-3, BRIGHTON_CC1_2 is transited down to BRIGHTON_CC1_1 at HE22 which can be shut down after HE24 to meet the shutdown constraint. As described in the CCU modeling, the minimum online time is only enforced for the up transition and is not enforced for the down transition. Because of this logic, BRIGHTON_CC1_1 stays online for only 3 hours from HE22 to HE24 after the down transition which is less than its 6 hour minimum online time. The CCT commitment status in this case satisfies all the CCT resource constraints including temporal constraints, startup and shutdown constraints.

Figure 6-8 shows the dispatch of the CCT BRIGHTON_CC1. It shows that the CCT is dispatched within P_{min} and P_{max} for the corresponding configuration for all the hours. During HE1-HE11 and HE22-HE24, BRIGHTON_CC1_1 is dispatched and the dispatch MW is less or equal to its P_{max} 300MW. During HE12-HE21, the CCT is in a higher configuration BRIGHTON_CC1_2 and it is fully dispatched to its P_{max} 600MW.

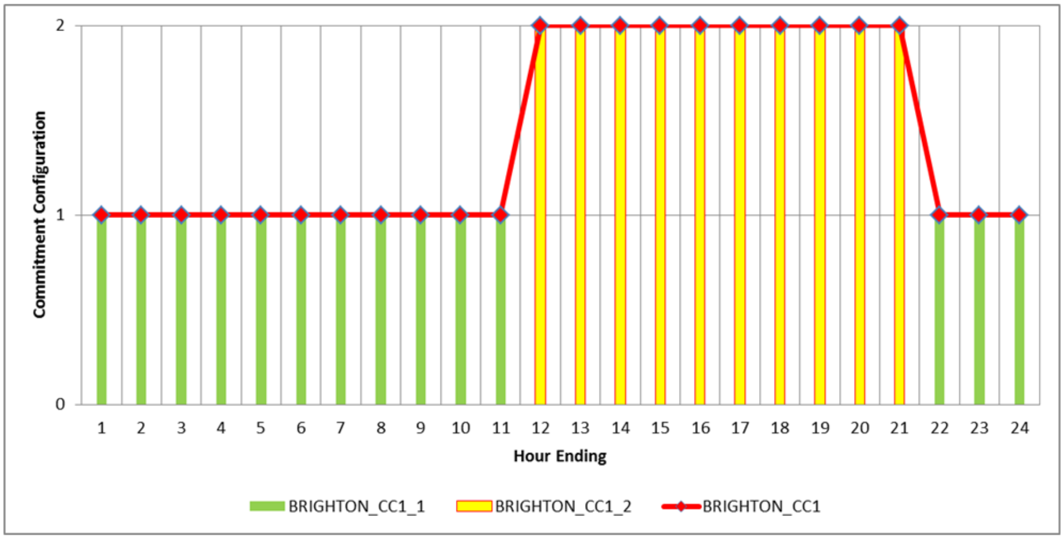

Figure 6-7 Case 2 Commitment Status of BRIGHTON_CC1

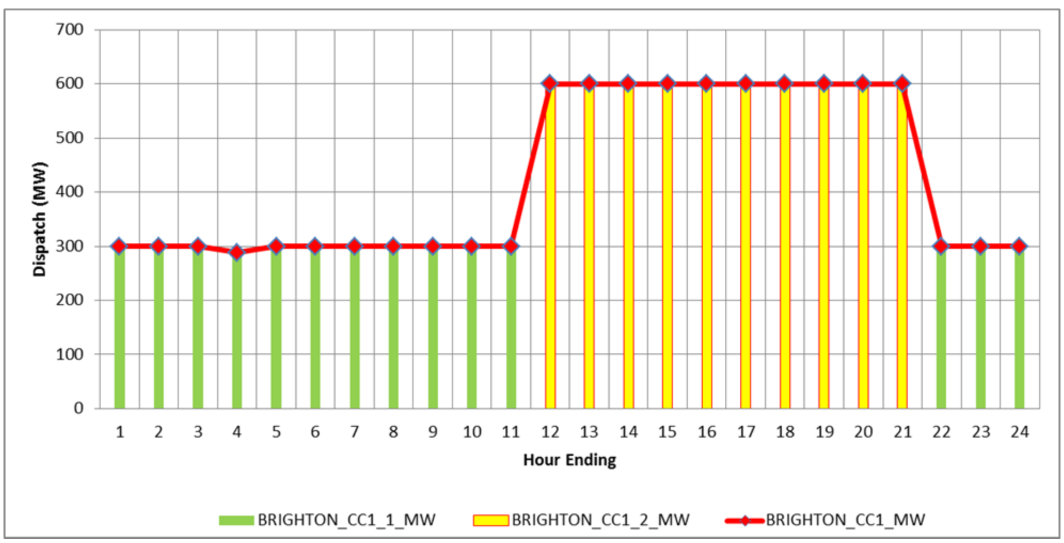

Figure 6-8 Case 2 Dispatch of BRIGHTON_CC1

Figure 6-9 shows the production cost of the CCT BRIGHTON_CC1. At HE1, BRIGHTON_CC1_1 is started up from cold status so the cold startup cost ($8000) is applied. The min-gen cost equals to MEO*P_{min}=30*100=$3000. The incremental cost is 20*(300MW-100MW)=$4000. So the production cost=startup cost ($8000)+min-gen cost ($3000)+incremental energy cost ($4000)=$15000. This is consistent with the production cost at HE1 for the CCT. At HE12, BRIGHTON_CC1_1 is transited up to BRIGHTON_CC1_2 and the up transition cost is applied in this hour. Since BRIGHTON_CC1_2 has been offline for long time and in cold status, the cold transition cost is applied. As described in the CCU modeling, the transition cost is calculated as the difference of the startup cost between the after and before configurations for the warm status of the after configuration. In this case, the cold transition cost= BRIGHTON_CC1_2 cold startup cost - BRIGHTON_CC1_1 cold startup cost=16000-8000=$8000. The min-gen cost equals to MEO*P_{min}=30*300=$9000. The incremental cost is 25*(600MW-300MW)=$7500. So the production cost=transition cost ($8000)+min-gen cost ($9000)+incremental energy cost ($7500)=$24500. This is consistent with the production cost at HE12 for the CCT. At HE22, BRIGHTON_CC1_2 is transited down to BRIGHTON_CC1_1 and the transition cost is not applied for the down transition in this hour. So the production cost=transition cost ($0)+min-gen cost ($3000)+incremental energy cost ($4000)=$7000. This is consistent with the production cost at HE22 for the CCT.

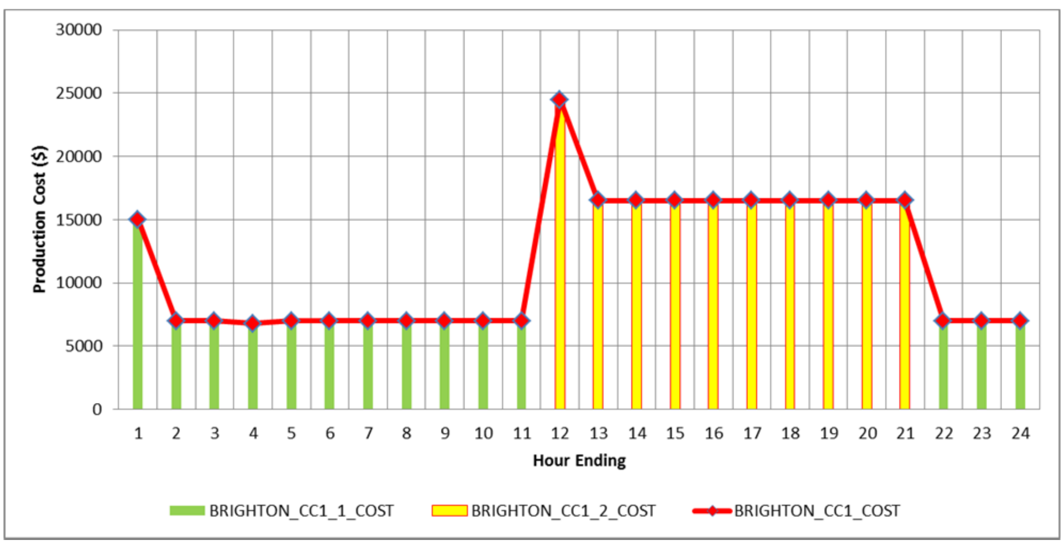

Figure 6-9 Case 2 Production Cost of BRIGHTON_CC1

6.1.3 Case 3 of the 5-bus System

This case simulates resource commitment and scheduling with transmission constraint enforced in the optimization. The same input data from case 2 is adopted for this case. In addition, the base case flow on line ED is enforced in the UC for this case. For simplicity, only the base case constraint is modeled in the study. The same logic used for the base case constraint can be applied to the contingency constraint.

The base case bus shift factor w.r.t to line ED can be calculated based on the line data listed in Table 6-5. Assume bus A is the slack bus, the bus shift factors w.r.t. line ED is listed in Table 6-11.

Table 6-11 Bus Shift Factor w.r.t. Line ED of the 5-bus System

Bus	A	B	C	D	E
Shift Factor	0	-0.1509	-0.209	-0.3685	0.112

The hourly system load and the UC solution for this case is presented in Table 6-12. It can be observed that the committed pattern has changed for G4, G5 and G6. G4 has negative shift factor -0.3685 w.r.t. the line ED and G5 and G6 has positive shift factor 0.112 w.r.t. the line. G4 is more expensive than G5 and G6 and it is only committed for HE17 in unconstrained case 2. In case 3 to solve the congestion, G4 is committed for HE12-HE21 and G6 is only committed for HE14-HE19.

Figure 6-10 shows the hourly system load and system lambda for the 24 hour study period. It can be observed that the system lambda is lower during the peak hours HE14-HE19.

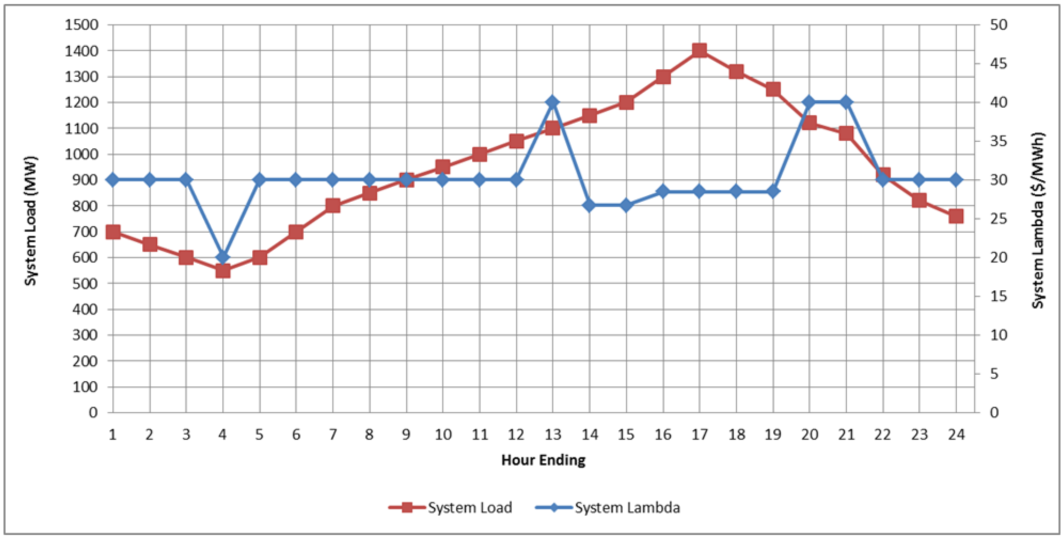

Figure 6-10 Case 3 System Load and System Lambda

Figure 6-11 shows the comparison of line ED flow between case 2 and case 3. One can see that the line flow in case 2 exceeds the line limit 240MW during HE12-HE21 since the transmission constraint is not enforced in case 2. One also see that the line flow in case 3 is less than or equal to the line limit 240MW during HE12-HE21 which illustrates that the transmission constraint is enforced in case 3 as expected. Figure 6-12 shows the hourly system production cost comparison between unconstrained case 2 and constrained case 3. It can be observed in some hours the hourly production cost in constrained case 3 is less than the production cost in unconstrained case 2. But the total production cost across the 24 hours from constrained case 3 is greater than the one from case 2 since the additional transmission constraint is introduced in case 3.

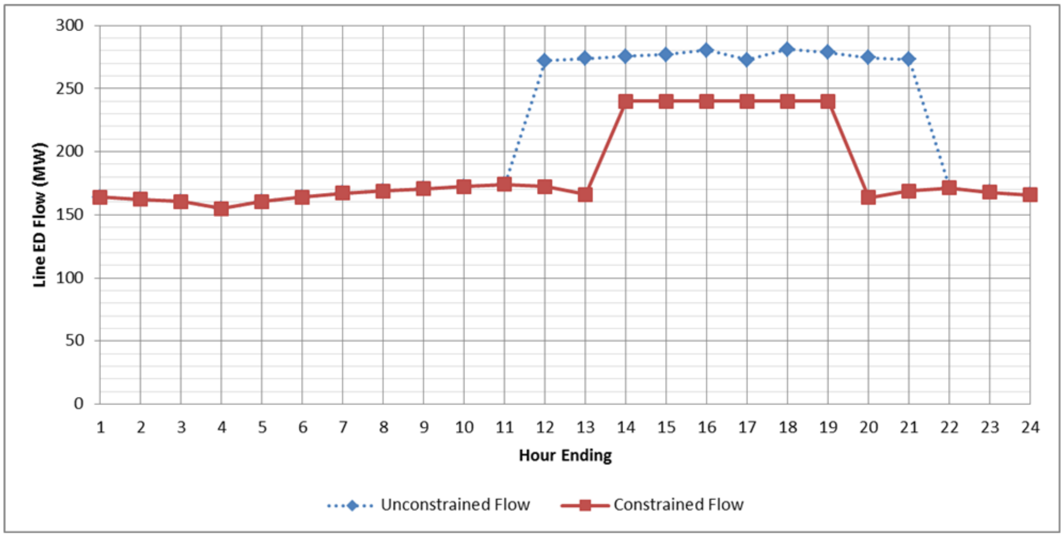

Figure 6-11 Case 3 Line ED Flow VS Case 2 Line Flow

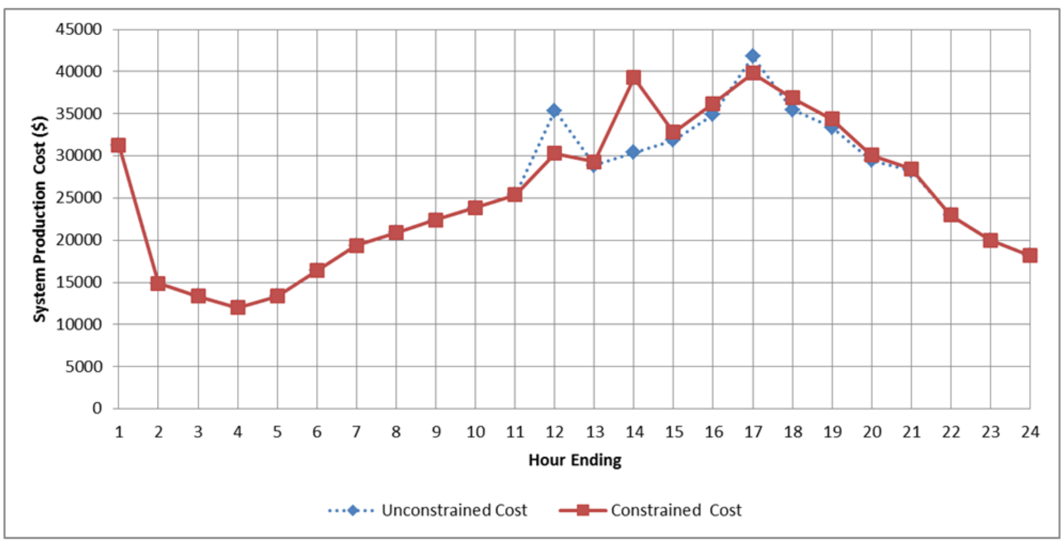

Figure 6-12 Case 3 Unconstrained Cost VS Case 2 Constrained Cost

Table 6-12 Case 3 Hourly System Load and UC Solution

System Load (MW) and System Lambda ($/MWh) for Each Hour																								
HE	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Load	700	650	600	550	600	700	800	850	900	950	1000	1050	1100	1150	1200	1300	1400	1320	1250	1120	1080	920	820	760
SL	30	30	30	20	30	30	30	30	30	30	30	30	40	26.74	26.74	28.50	28.50	28.50	28.50	40	40	30	30	30
Resource Commitment Status for Each Hour																								
Unit	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
G1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G3	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G4	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	0	0	0
G5	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	1	1	1	1	1
G6	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	0	0	0	0	0
Total	4	4	4	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	4	4	4
Resource Dispatch (MW) for Each Hour																								
Unit	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
G1	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
G2	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
G3	190	140	90	52	90	190	290	340	390	440	490	520	520	420.2	475.5	520	520	520	520	520	520	410	310	250
G4	0	0	0	0	0	0	0	0	0	0	0	20	70	20	20	64.1	137.9	78.87	27.18	90	50	0	0	0
G5	300	300	300	288	300	300	300	300	300	300	300	300	300	0	0	0	0	0	0	300	300	300	300	300
G6	0	0	0	0	0	0	0	0	0	0	0	0	0	499.8	494.5	505.9	532.1	511.1	492.8	0	0	0	0	0
Total	700	650	600	550	600	700	800	850	900	950	1000	1050	1100	1150	1200	1300	1400	1320	1250	1120	1080	920	820	760
Resource Production Cost ($) for Each Hour																								
Unit	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
G1	3006	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606
G2	3050	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550
G3	10220	4720	3220	2080	3220	6220	9220	10720	12220	13720	15220	16120	16120	13127	14784	16120	16120	16120	16120	16120	16120	12820	9820	8020
G4	0	0	0	0	0	0	0	0	0	0	0	4000	3000	1000	1000	2764	5718	3355	1287	3800	2200	0	0	0
G5	15000	7000	7000	6760	7000	7000	7000	7000	7000	7000	7000	7000	7000	0	0	0	0	0	0	7000	7000	7000	7000	7000
G6	0	0	0	0	0	0	0	0	0	0	0	0	0	21995	13863	14148	14802	14278	13820	0	0	0	0	0
Total	31276	14876	13376	11996	13376	16376	19376	20876	22376	23876	25376	30276	29276	39277	32803	36187	39795	36909	34384	30076	28476	22976	19976	18176

Figure 6-13 shows the combined cycle train (CCT) BRIGHTON_CC1 commitment status for the 24 hour study period. One can see the commitment status of the CCT has changed from case 2. During HE1-HE13, the configuration BRIGHTON_CC1_1 has been committed. It has been online for 13 hours before it transits up to BRIGHTON_CC1_2 at HE14. It satisfies its 6 hour minimum online time. During HE14-HE19 BRIGHTON_CC1_2 has been committed. It has been online for 6 hours and satisfies its 6 hours minimum online time before it transits down to BRIGHTON_CC1_1 at HE20. During HE20-HE24, BRIGHTON_CC1_1 is committed. The CCT commitment status in this case satisfies all the CCT resource constraints including temporal constraints, startup and shutdown constraints.

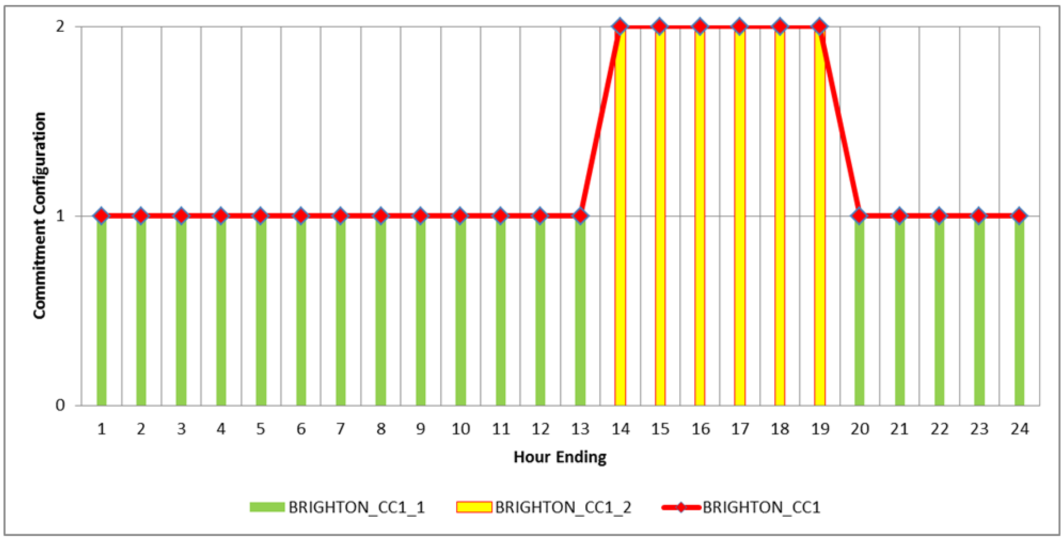

Figure 6-13 Case 3 Commitment Status of BRIGHTON_CC1

Figure 6-14 shows the dispatch of the CCT BRIGHTON_CC1. It shows that the CCT is dispatched within P_{min} and P_{max} for the corresponding configuration for all the hours. During HE14-HE19, the CCT is in a higher configuration BRIGHTON_CC1_2 and it is partially dispatched around 500MW to prevent the overloading on line ED since it has positive shift factor (0.112) w.r.t the active constraint ED. This is different from unconstrained case 2 in which the CCT is fully dispatched to its P_{max} 600MW.

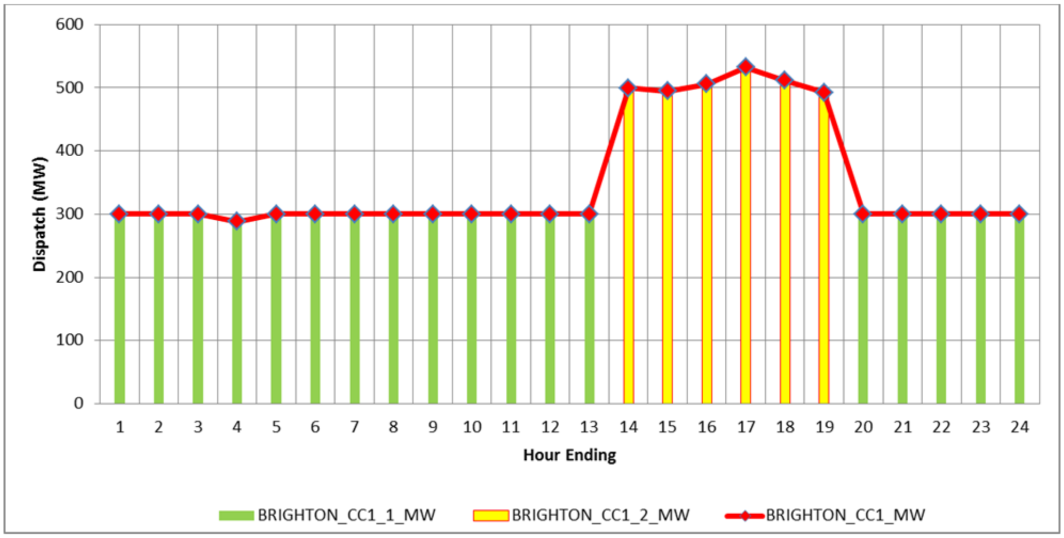

Figure 6-14 Case 3 Dispatch of BRIGHTON_CC1

Figure 6-15 shows the production cost of the CCT BRIGHTON_CC1. At HE1, BRIGHTON_CC1_1 is started up from cold status and dispatched at 300MW. The production cost for HE1 is $15000 which is the same as the one in case 2. At HE14, BRIGHTON_CC1_1 is transited up to BRIGHTON_CC1_2 and the up transition cost is applied in this hour. Since BRIGHTON_CC1_2 has been offline for long time and in cold status, the cold transition cost is applied. The same as case 2, the cold transition cost= BRIGHTON_CC1_2 cold startup cost- BRIGHTON_CC1_1 cold startup cost=16000-8000=$8000. The min-gen cost equals to MEO*P_{min}=30*300=$9000. The incremental cost is 25*(499.8MW-300MW)=$4995. So the production cost=transition cost ($8000)+min-gen cost ($9000)+incremental energy cost ($4995)=$21995. This is consistent with the production cost at HE14 for the CCT. At HE20, BRIGHTON_CC1_2 is transited down to BRIGHTON_CC1_1 and the transition cost is not applied for the down transition in this hour. So the production cost=transition cost ($0)+min-gen cost ($3000)+incremental energy cost ($4000)=$7000. This is consistent with the production cost at HE20 for the CCT shown in Figure 6-15.

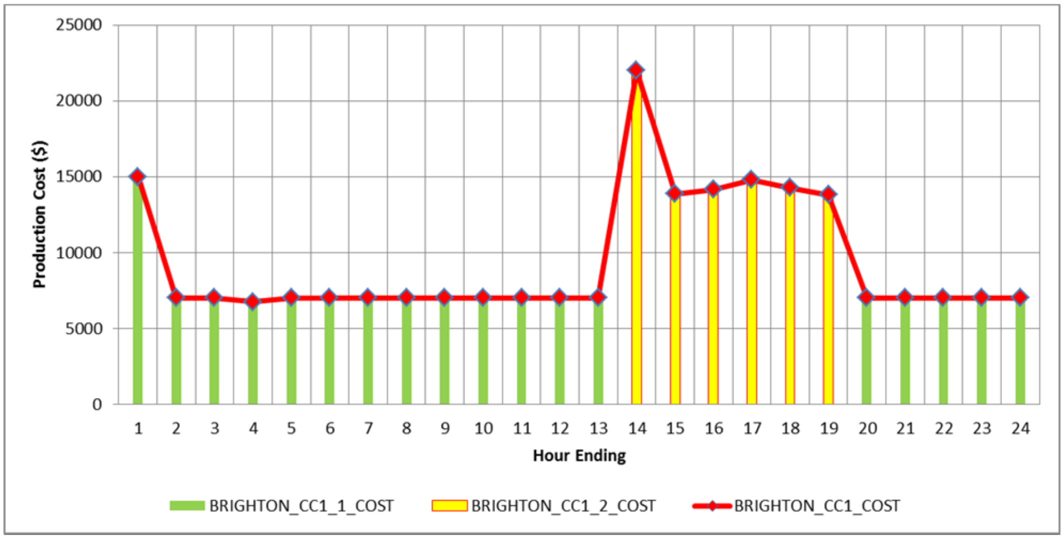

Figure 6-15 Case 3 Production Cost of BRIGHTON_CC1

Figure 6-16 shows the LMP of CCT BRIGHTON_CC1 and system lambda for each hour. One can see during HE14-HE19, the CCT LMP is equal to its incremental energy cost and is less than the system lambda. This is because line ED is congested during EH14-HE19 with non 0 shadow price and BRIGHTON_CC1 has a positive shift factor w.r.t. line ED. Since LMP=system lambda-sum(shift factor*shadow price), the calculated LMP is less than system lambda due to the positive shift factor. This is consistent with the LMP in Figure 6-16. One also can see the BRIGHTON_CC1_2 is a marginal unit satisfying the optimal condition during HE14-HE19: the LMP equals to its incremental energy cost and the dispatch is greater than P_{min} (300MW) and less than P_{max} (600MW).

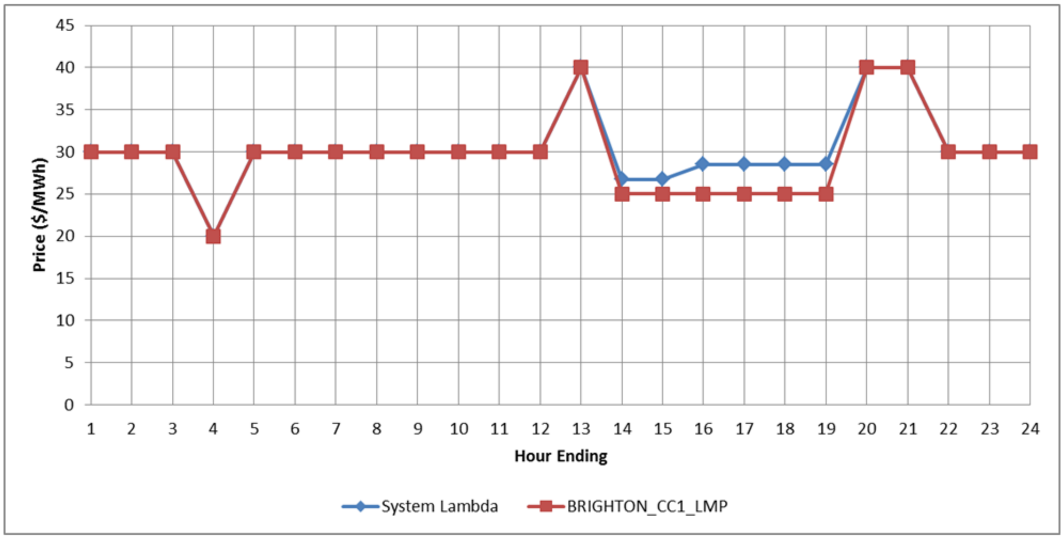

Figure 6-16 Case 3 LMP of BRIGHTON_CC1

6.1.4 Case 4 of the 5-bus System

This case is used to verify the resource initial condition modeling, self-commit modeling and startup cost eligibility modeling. This case uses the same system load as case 1 and the transmission constraint is not enforced for simplicity. The resource initial condition has been revised from case 1 and is listed in Table 6-13. At the beginning of the study period, G1 has been offline for 2 hours, G4 has been online for 24 hours and G3 has been online for 2 hours. Assume G4, G5 and G6 still have been offline for long time (100 hours) the same as case 1. Also assume G5 has been self-committed online from HE10 to HE20 by indicating its online status in the COP.

Table 6-13 Case 4 Resource Initial Condition

Resource ID	G1	G2	G3	G4	G5	G6
Initial On Time (Hour)	-2	24	2	-100	-100	-100

The hourly system load and the UC solution is presented in Table 6-14.G1 has initial condition as offline for 2 hours and it must satisfy its minimum offline time (5 hours) to be committed by RUC. One can see G1 is offline during HE1-HE3 to meet its min offline time even it is more economical than other resources. G2 has initial condition as online 24 hours so the startup cost should not be applied if RUC commits it at HE1. One can see that G2 has been committed for HE1-HE24 due to its low price. The production cost for G2 at HE1 equals to min-gen cost (10*20) + incremental energy cost (15*(100-10))=200+1350=$1550. This is consistent with the G2 production cost shown in Table 6-14. G3 has initial condition as online for 2 hours. Based on the self-commitment logic, if the resource self-commitment can violate the temporal constraint and RUC shall not commit unit just to meet unit self-commitment temporal constraint unless it is economic to do so. In this case, G3 has high cost so it is not committed during HE1-HE8 even the startup cost can be 0 if the unit is committed at HE1. This verifies that the self-commitment logic is working as expected.

Figure 6-17 shows the hourly system load and system lambda for the 24 hour study period.

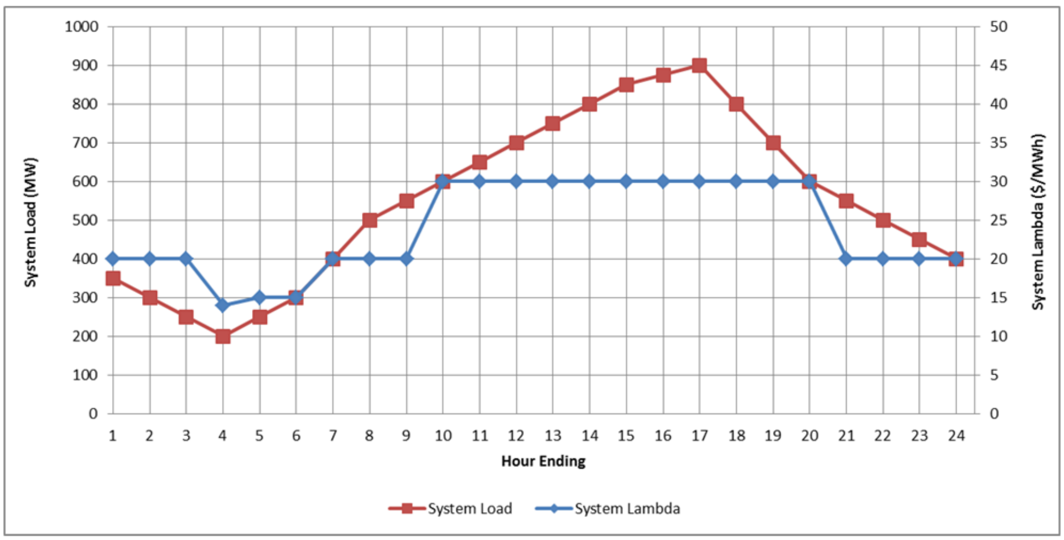

Figure 6-17 Case 4 System Load and System Lambda

Table 6-14 Case 4 Hourly System Load and UC Solution

System Load (MW) and System Lambda ($/MWh) for Each Hour																								
HE	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Load	350	300	250	200	250	300	400	500	550	600	650	700	750	800	850	875	900	800	700	600	550	500	450	400
SL	20	20	20	14	15	15	20	20	20	30	30	30	30	30	30	30	30	30	30	30	20	20	20	20
Resource Commitment Status for Each Hour																								
Unit	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
G1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G3	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0
G4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
G5	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	2	2	2	3	3	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	3	3	3
Resource Dispatch (MW) for Each Hour																								
Unit	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
G1	0	0	0	90	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
G2	100	100	100	10	40	90	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
G3	0	0	0	0	0	0	0	0	52	90	140	190	240	290	340	365	390	290	190	90	52	0	0	0
G4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
G5	250	200	150	100	100	100	190	290	288	300	300	300	300	300	300	300	300	300	300	300	288	290	240	190
G6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	350	300	250	200	250	300	400	500	550	600	650	700	750	800	850	875	900	800	700	600	550	500	450	400
Resource Production Cost ($) for Each Hour																								
Unit	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
G1	0	0	0	2326	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606	1606
G2	1550	1550	1550	200	650	1400	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550
G3	0	0	0	0	0	0	0	0	6080	3220	4720	6220	7720	9220	10720	11470	12220	9220	6220	3220	2080	0	0	0
G4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
G5	6000	5000	4000	3000	3000	3000	4800	6800	6760	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	6760	6800	5800	4800
G6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	7550	6550	5550	5526	5256	6006	7956	9956	15996	10376	11876	13376	14876	16376	17876	18626	19376	16376	13376	10376	11996	9956	8956	7956

Figure 6-18 shows the combined cycle train (CCT) BRIGHTON_CC1 commitment status for the 24 hour study period. One can see the configuration BRIGHTON_CC1_1 has been committed for HE1-HE9 and HE21-HE24 and it connects the self-commitment during HE10-HE20. The CCT commitment status in this case satisfies all the CCT resource constraints including temporal constraints, startup and shutdown constraints.

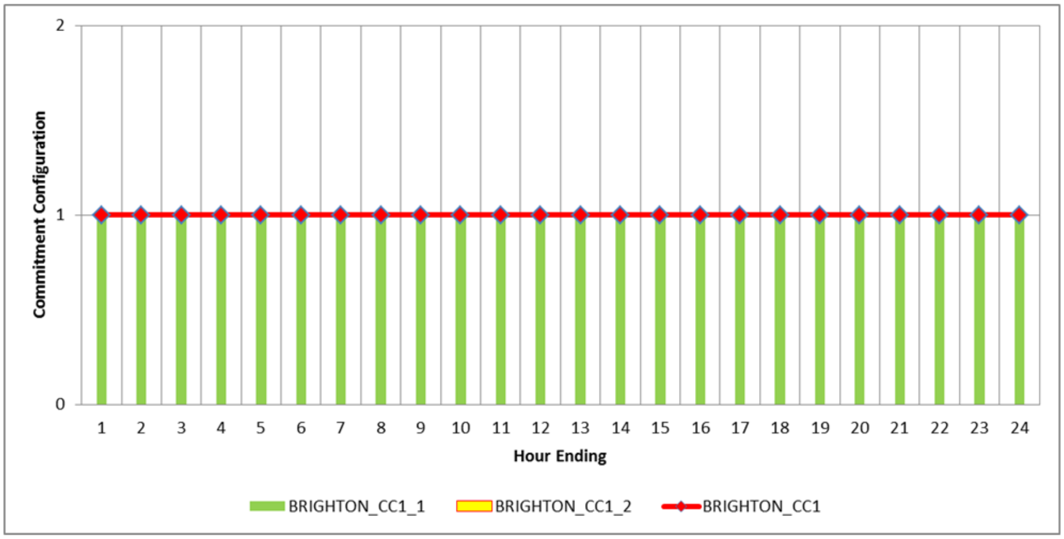

Figure 6-18 Case 4 Commitment Status of BRIGHTON_CC1

Figure 6-19 shows the dispatch of the CCT BRIGHTON_CC1. It shows that the CCT is dispatched within P_{min} and P_{max} for all the hours. It also can be seen that the CCT is dispatched down in the low load hours and dispatched high in the peak hours.

Figure 6-20 shows the production cost of the CCT BRIGHTON_CC1. The min-gen cost is applied for all the RUC committed hours (HE1-HE9 and HE 21-HE24) and the incremental energy cost is applied for all the online 24 hours. Since the RUC commitment block (HE1-HE9) is connected to the self-commitment block (HE10-HE20), the startup cost is not applied for the startup hour (HE1) according to the startup cost eligibility rule. So at HE1, the production cost=startup cost ($0)+min-gen cost ($3000)+incremental energy cost ($3000)=$6000. This is consistent with the CCT production cost at HE1 shown in Figure 6-20. During HE2-HE6, BRIGHTON_CC1_1 is dispatched at P_{min} (100MW) so the production cost =min-gen cost=$3000. During HE10-HE20, BRIGHTON_CC1_1 is self-committed so the production cost=incremental energy cost=(300-100)*20=$4000. During HE21-HE24, the CCT is RUC committed and the production cost=min-gen cost+ incremental energy cost.

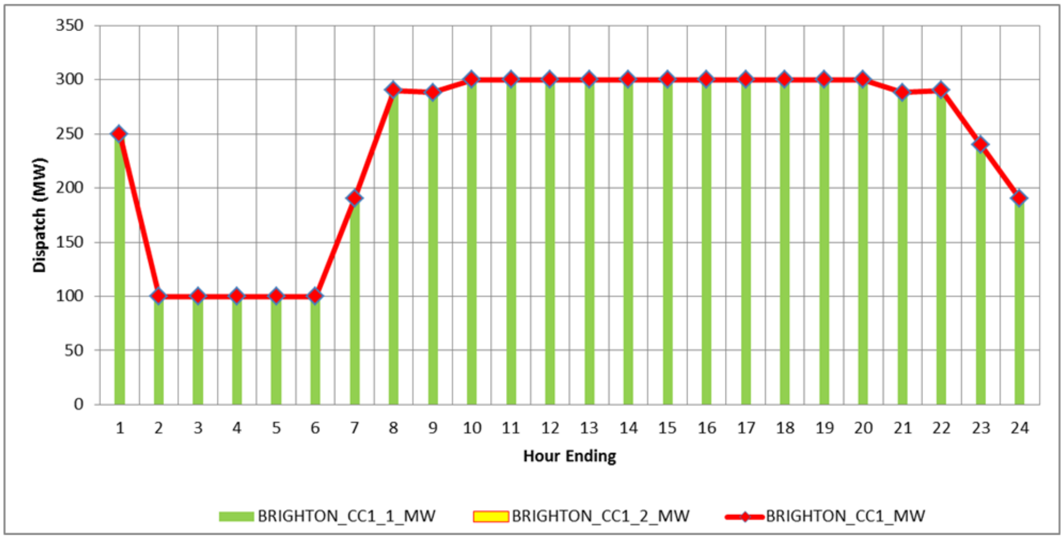

Figure 6-19 Case 4 Dispatch of BRIGHTON_CC1

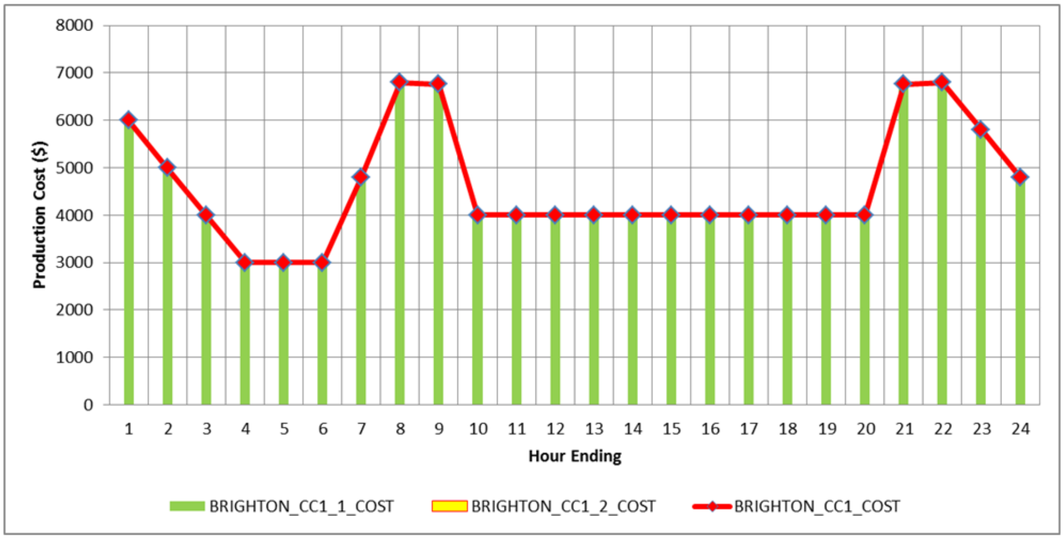

Figure 6-20 Case 4 Production Cost of BRIGHTON_CC1

6.2 RUC Study on ERCOT System

The proposed RUC system has been successfully implemented in ERCOT production system. This section discusses the RUC study in the real ERCOT production system with more than 550 physical generation units. MMS schedules the logic resources instead of physical units. Using operating day 12/17/2012 as an example, there are more than 630 logical generating resources submitted COPs including 262 combined cycle generation configurations belonging to 63 combined cycle trains (CCTs).

6.2.1 DRUC and HRUC Execution Performance

Table 6-15 illustrates the monthly summary for the DRUC and HRUC execution from May 2012 to Nov. 2012. It shows that the maximum run time is 41 minutes for DRUC and 34 minutes for HRUC. The average runtime for both DRUC and HRUC is less than 10 minutes normally except 11.4 minutes for Jun. 2012 DRUC. Since DRUC is the first RUC run for the next operating day, it usually takes longer time than the HRUC run.

The execution summary for the seven months demonstrates that the performance for both DRUC and HRUC is well within the runtime requirement.

Table 6-15 DRUC and HRUC Execution Monthly Summary

Month	DRUC Execution			HRUC Execution		
	Execution count	Runtime Avg (min)	Runtime Max (min)	Execution count	Runtime Avg (min)	Runtime Max (min)
May-12	31	7.2	18	744	6.2	17
Jun-12	29	11.4	41	719	7.2	19
Jul-12	31	7.4	35	744	6.2	20
Aug-12	31	6.8	26	744	6.5	24
Sep-12	30	6.3	16	720	6.7	22
Oct-12	31	9.0	31	744	7.8	31
Nov-12	30	7.8	29	721	6.9	34

To compare the nodal DRUC execution performance with the zonal RPRS, the execution monthly summary of RPRS is shown in Table 6-16.

Table 6-16 Zonal RPRS Execution Monthly Summary

Month	Execution Count	Runtime Avg (min)	Runtime Max (min)
May-10	31	38.4	56.82
Jun-10	30	37.5	64.9
Jul-10	31	34.2	52.12
Aug-10	31	41.8	61.55
Sep-10	30	35.5	49.95
Oct-10	31	33.4	44.4
Nov-10	30	34.7	45.97

It can be observed that the DRUC average execution time is much less than the average execution time for RPRS for each of the 7 months which demonstrates that the RUC clearing process has higher performance than the RPRS process. The primary reason is because that the RUC clearing and modeling logic is more advanced compared to RPRS. The hardware upgrade and CPLEX solver improvement may also contribute to the higher performance to some extent.

6.2.2 ERCOT RUC Study

Figure 6-21 shows the DRUC hourly scheduling summary for operating day 10/30/2012. The Self Scheduled HASL/HSL/LSL/LASL indicates the system total QSE self-scheduled HSL/HASL/LSL/LASL calculated based on the COP of online resources. The RUC Load Forecast is the net load requirement calculated as the sum of MTLF and DC Tie Load. The Real-time Load is the real-time actual load from EMS telemetry. It can be observed that the RUC Load Forecast is overall close to the Real-time Load with some small errors. The RUC Recommended HSL is the output of the RUC optimization which is calculated as the sum of HSL of both self-committed units and RUC committed units. The RUC Recommended HSL will equal to the Self Scheduled HSL if there is no RUC commitment for the specific hour.

As we can see in Figure 6-21, the Self Scheduled HASL is less than the RUC Load Forecast at HE17, HE18 and HE20 which indicates that additional capacity need to be committed to meet the load forecast by reserving the ancillary services limits. As expected in this case, the RUC Recommended HSL is higher than the Self Scheduled HSL indicating additional offline capacity has been committed.

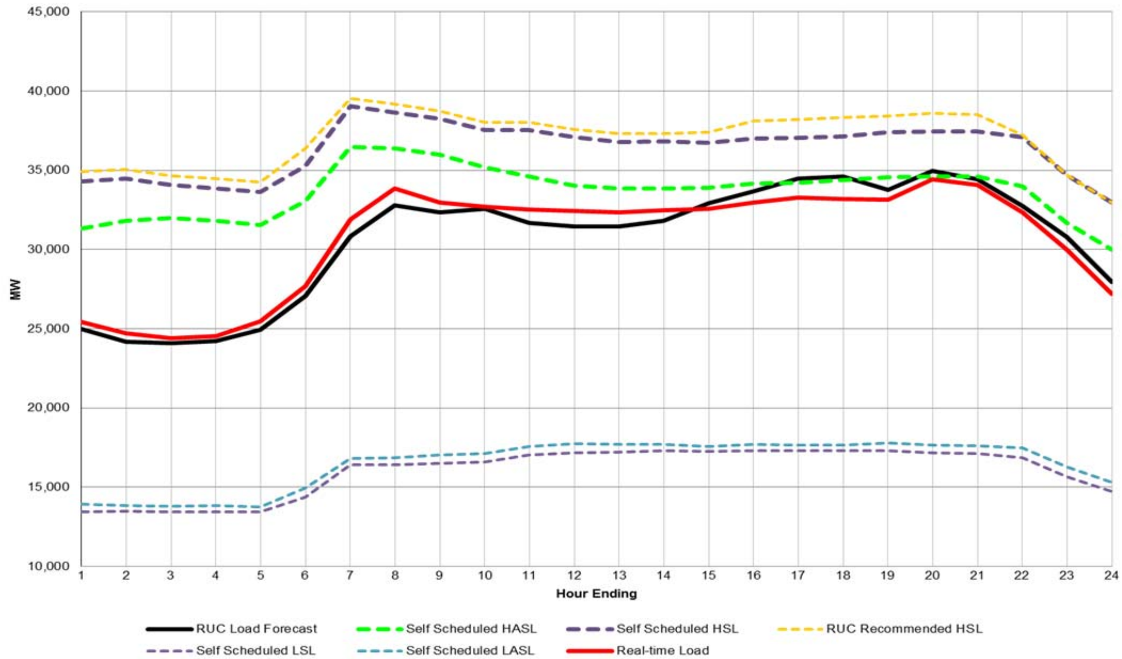

Figure 6-21 DRUC Schedule Summary for 10/30/2012

Figure 6-22 shows the DRUC hourly schedule summary by resource type for operating day 10/30/2012. The resource schedules (a.k.a. RUC clearing) are used to project the congestion pattern in the RUC optimization. It can be observed that resource type NUC (nuclear), CLLIG (coal) and CCGT90 (combined cycle greater than 90 MW) are base load units and take up most of the total generation. It should be noted that the RUC clearing results can be quite different from the real-time SCED clearing in some cases. One possible reason is that RUC uses the proxy energy offer curve instead of actual energy offer curve for RUC clearing. The proxy energy offer curve is calculated by multiplying the mitigated offer cap curves with a very small discount factor. This approach will make sure to dispatch low cost self-committed units first before commit offline units. However it may result in different generation pattern in RUC compared to real-time SCED.

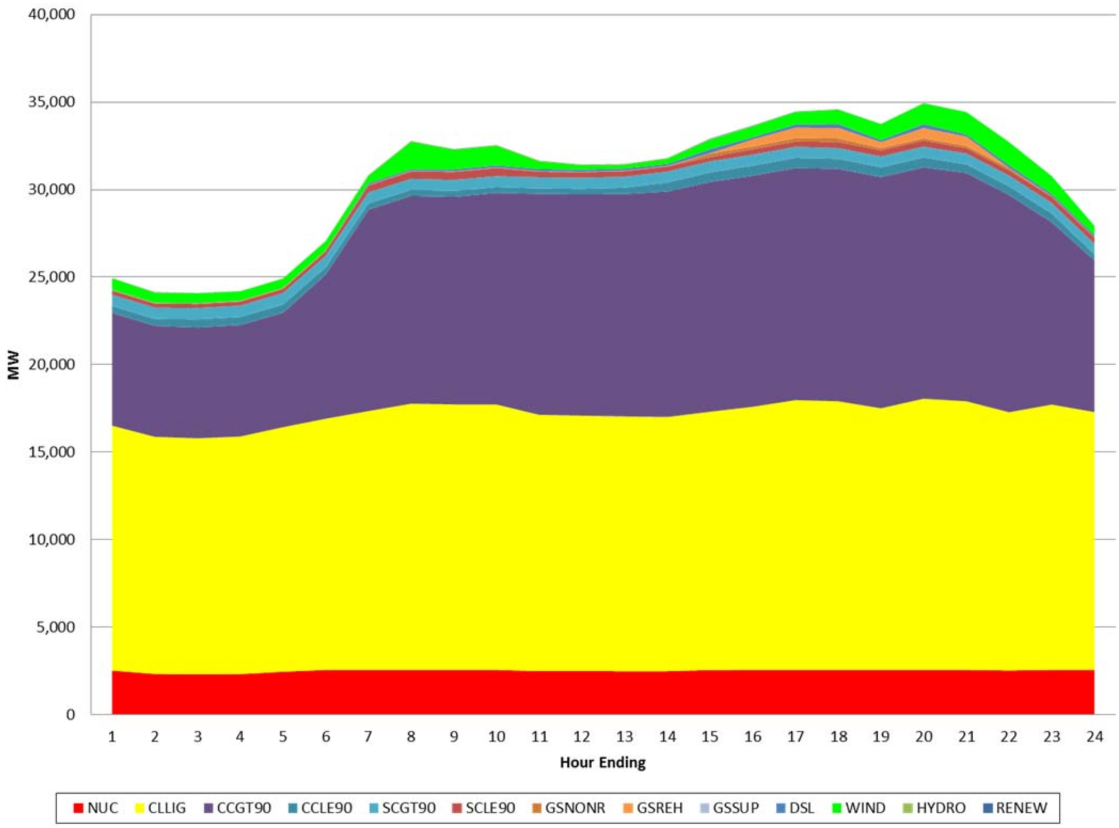

Figure 6-22 DRUC Schedule Summary by Resource Type for 10/30/2012

Figure 6-23 demonstrates the DRUC average monthly schedule for Oct. 2012. It can be observed that the RUC Load Forecast is very close to the Real-time Load. The RUC Recommended HSL is also very close to the Self Scheduled HSL indicating minimal RUC commitment for this month. This is reasonable because that the Self Scheduled HASL is well above the RUC Load Forecast which means that there is more available capacity margin for RUC dispatch.

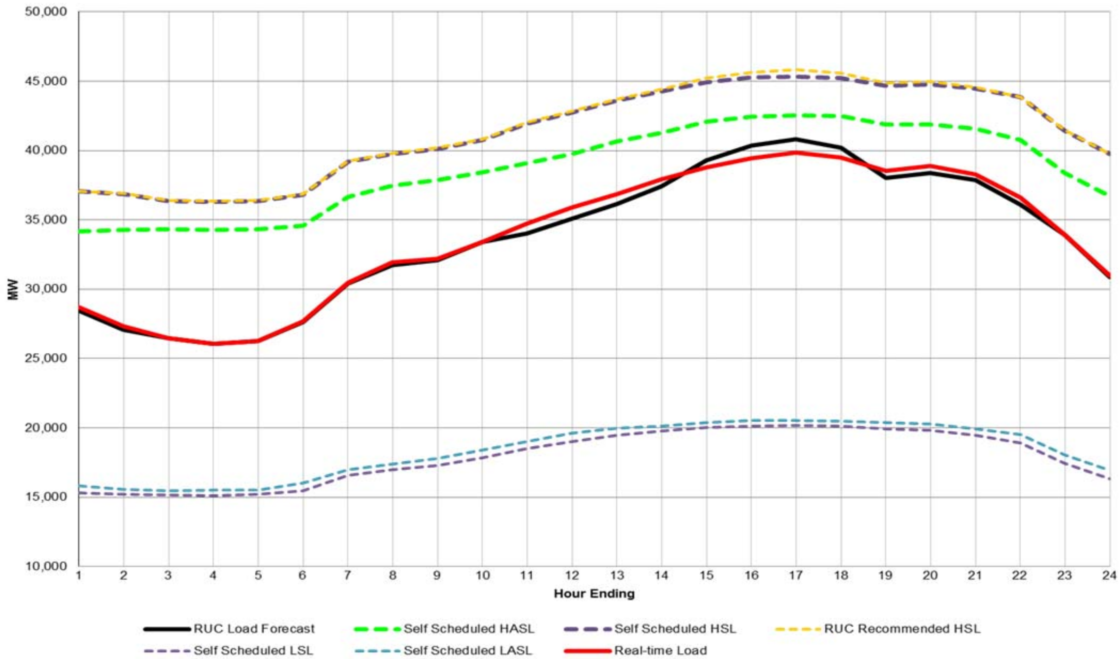

Figure 6-23 DRUC Monthly Schedule Summary for Oct. 2012

Figure 6-24 and Figure 6-25 illustrate the DRUC schedule summary for operating day 08/01/2012 and 12/06/2012 respectively. Operating day 08/01/2012 has the highest load in 2012 at HE17 and HE18, more than 65000MW in both hours. But the Self Scheduled HASL already exceeds the RUC Load Forecast and there is no RUC commitment in this case. For operating day 12/06/2012, there is one unit committed by the DRUC for HE13-HE20 because of less available capacity margin.

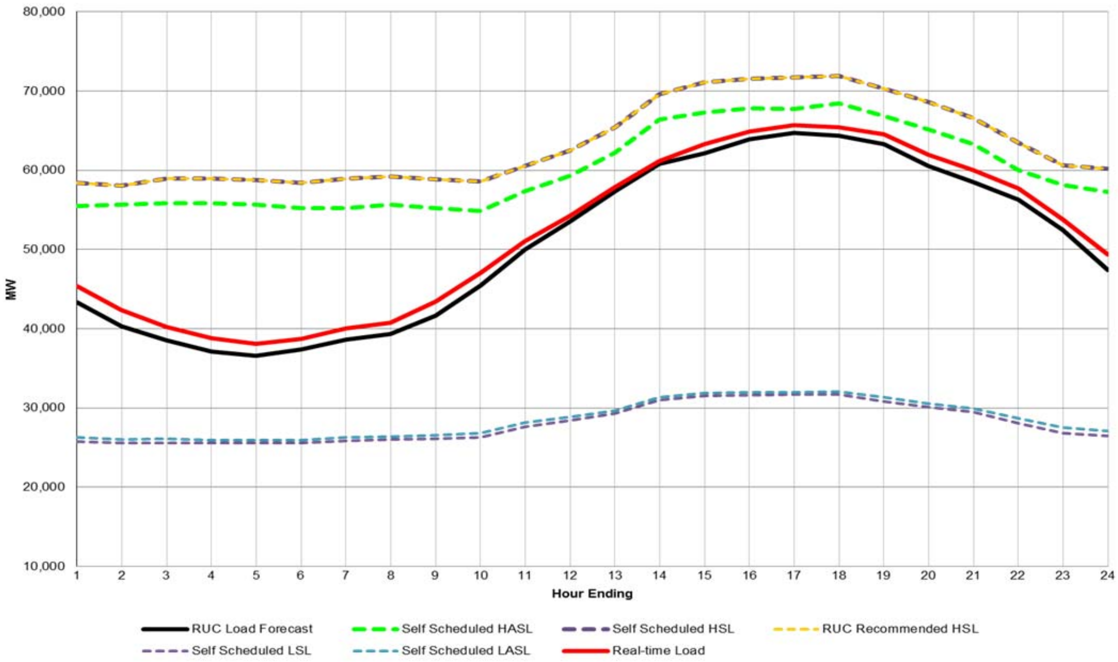

Figure 6-24 DRUC Schedule Summary for 08/01/2012

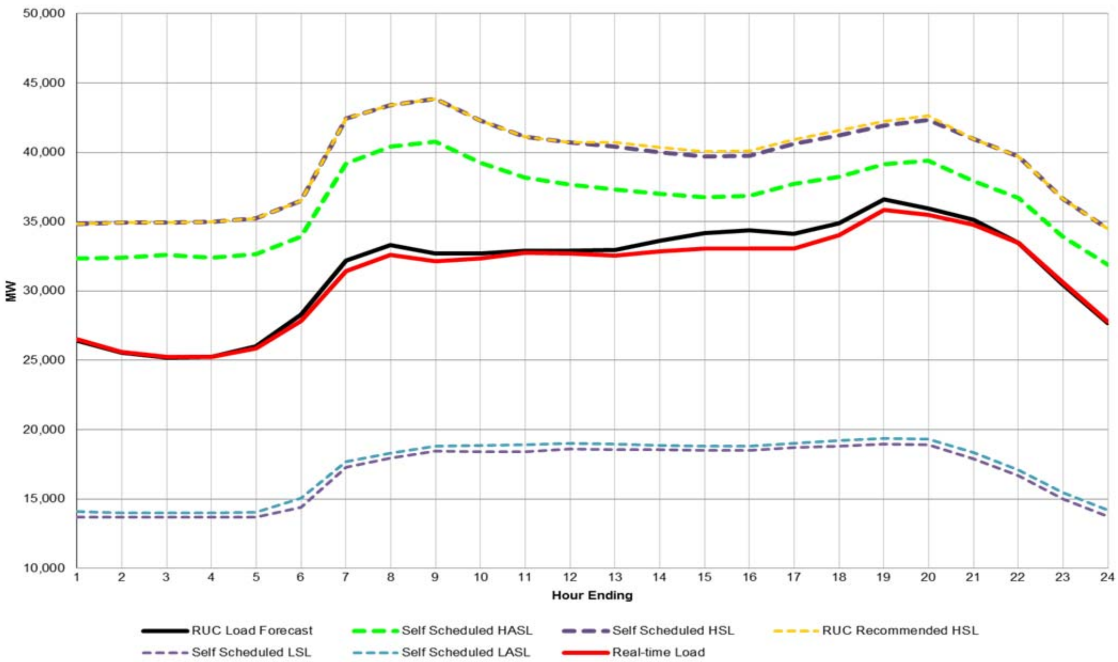

Figure 6-25 DRUC Schedule Summary for 12/06/2012

6.2.3 Phase Shifter Optimization

Figure 6-26 shows the DRUC optimized phase shifter tap position for the eight phase shifters for each hour of operating day 11/11/2012. One can see the phase shifters tap positions stay at their neutral position 17 (also initial position) at most of the time except for HE1-HE10 for YELWJCKT_PS_1_H_4448 and HAMILTON_PS2_1335. The tap positions of these two phase shifters were moved up for HE1-10 to solve the congestion since they have negative shift factors w.r.t the binding constraints at that time.

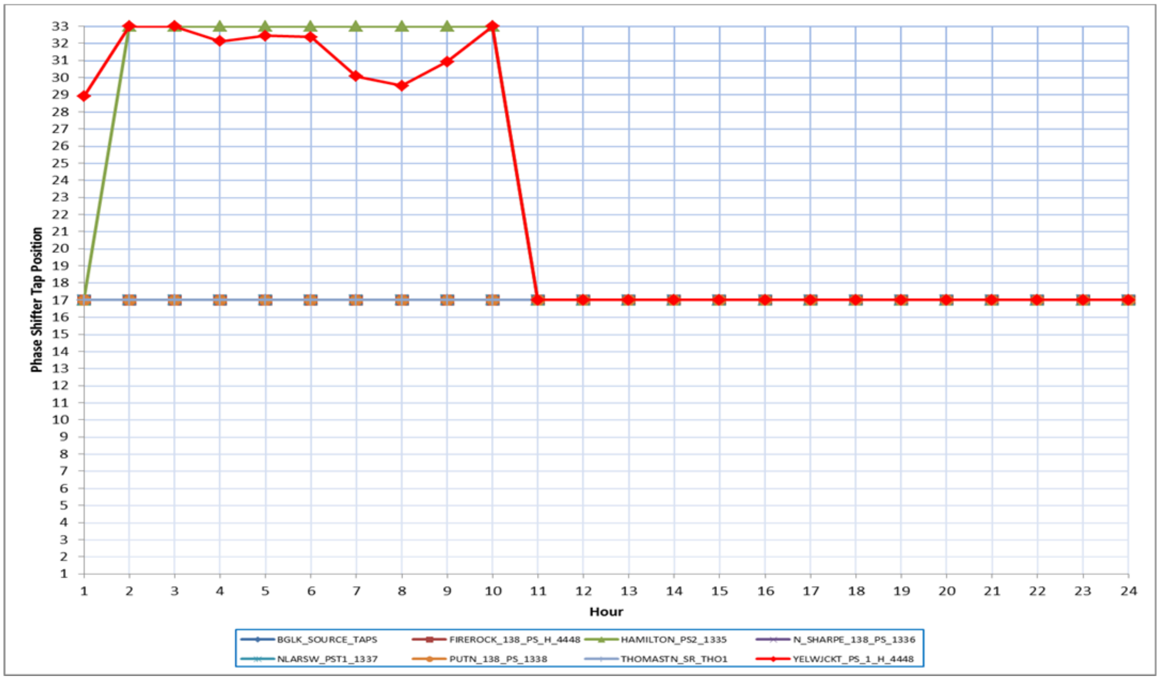

Figure 6-26 DRUC Phase Shifter Tap Positions for 11/11/2012

Figure 6-27 shows the average DRUC hourly phase shifter tap position for the eight phase shifters in Oct. 2012. It can be observed that the average tap positions stay around the neutral point (17) most of the time since they have no impact on the binding constraints. In addition, the tap positions for some phase shifters are changing from hour to hour to solve the congestion. The results demonstrate the effectiveness of phase shifter optimization, i.e. the phase shifters should stay at their initial/neutral tap positions unless they are needed to solve transmission congestion.

Figure 6-27 DRUC Average Phase Shifter Tap Positions

Chapter 7

Conclusion and Recommendation for Future Studies

7.1 Conclusion

The case study and test results have demonstrated the benefit and effectiveness of the proposed RUC modeling especially for the combined cycle unit (CCU) modeling. During the design phase of the RUC project, a prototype RUC program was developed with the proposed CCU modeling to verify the effectiveness of the CCU modeling. The prototype RUC program has been tested on a revised PJM 5-bus system and the results are very promising. Because of the positive testing results, the proposed CCU modeling has been adopted for the RUC project and eventually has been implemented for the production RUC. The testing results from the production RUC have demonstrated the proposed RUC system is very robust and can improve dispatch efficiency and system reliability as well as ensuring more effective congestion management.

The proposed RUC modeling has solved many challenges and deficiencies identified in zonal RPRS market and greatly improved dispatch efficiency and system reliability. The contribution of this research can be summarized as follows:

- The proposed single step and NCUC-NSM iterative clearing process improves the accuracy and efficiency of unit dispatch and congestion management.
- The proposed two steps (UC and ED) NCUC solution algorithm decomposes the complex MIQP problem into MIP and QP step and solves them sequentially. This approach can enhance the solution performance without sacrificing accuracy.
- The proposed configuration based combined cycle unit (CCU) modeling represents the CCT more accurately and efficiently. The configuration-based model is more adequate for bid/offer processing and dispatch scheduling and therefore it is adopted

in the NCUC. On the other hand, the physical unit modeling is more adequate for the power flow and network security analysis and therefore it is adopted in the NSM.

- The proposed phase shifter optimization utilizing the power injection model (PIM) can solve congestion more efficiently in an automatic manner which can improve market efficiency and improve system reliability.
- The proposed offline time dependent startup cost modeling can represent the startup cost more accurately and improve market efficiency.
- The proposed ancillary service (AS) capacity modeling can protect the resource specific AS capacity from dispatching unless the reservation leads to unresolved transmission constraints. This approach reduces the AS undeliverable problem and improves the system security.

7.2 Recommendation for Future Studies

More study can be performed to verify the benefit and effectiveness of the proposed RUC modeling.

The rapid increase of wind energy in ERCOT and the characteristic that wind power is far less predictable than system load, it imposes big challenges to system operation. Future study should be done to better handle wind generation in RUC.

The incremental energy cost is discounted in RUC optimization to minimize the RUC commitment. This may cause dispatch inconsistency and different congestion pattern between RUC and real-time SCED. Further study can be performed to determine a good balance between RUC commitment and dispatch.

The proposed SCUC framework can be extended to include the ramp rate modeling to consider the ramp constraint between each interval of the study period. The

SCUC framework can also be adapted for the real-time commitment (RTC) which is used to commit quick start units close to real-time.

The RUC discussed in this dissertation is a deterministic UC problem. To better manage the uncertainties in UC, future research can be extended to stochastic unit commitment and robust unit commitment.

Appendix A

Notation

Indices:

i	Index for generating units.
s	Index for phase shifters.
t	Index for hours.
c	Index for transmission constraints.
cc	Index for combined cycle trains.
jou	Index of jointly owned unit
p	Index of startup cost segment

Variables:

$U_{i,t}$	On-line status indicator of unit i at interval t.
$U_{cc,t}$	On-line status indicator of combined cycle train cc at interval t.
$SU_{i,t}$	Startup indicator of unit i at interval t.
$SD_{i,t}$	Shutdown indicator of unit i at interval t.
$ISU_{i,t,p}$	Status indicator of startup cost segment p of unit i at interval t.
$P_{i,t}$	Dispatch MW of unit i at interval t.
$Slack_{el,t}$	Slack variable of energy long at interval t.
$Slack_{es,t}$	Slack variable of energy short at interval t.
$Slack_{lc,t}$	Slack variable of line constraint at interval t.
$PSCOST_{s,t}$	Cost function of phase shifter s at interval t.
$PST_{s,t}$	Tap position of phase shifter s at interval t.
$SUC_{i,t}$	Startup cost of unit i at interval t.
$MEC_{i,t}$	Minimum-energy cost of unit i at interval t.

$C_{i,t}$ — Incremental energy cost of unit i at interval t.

Parameters:

C_{ps} — Cost of moving phase shifter by 1 tap position.

NG — Number of units.

NPS — Number of phase shifters.

T — Number of intervals in the study period.

$PST_{0s,t}$ — Initial tap position of phase shifter s at interval t.

$Penalty_{pb}$ — Penalty cost of power balance violation.

$Penalty_{lc}$ — Penalty cost of line constraint violation.

D_t — Net system load at interval t.

$SF_{ci,t}$ — Shift factor of unit i w.r.t. constraint c at interval t.

$SF_{cs,t}$ — Shift factor of phase shifter s w.r.t. constraint c at interval t.

$F_{c,t}^{MathLimit}$ — Mathematic limit of transmission constraint c at interval t.

$P_{i,t}^{\min}$ — Minimum generating capacity of unit i at interval t.

$P_{i,t}^{\max}$ — Maximum generating capacity of unit i at interval t.

JOU — Set of physical jointly owned units

$JOUGEN_{jou}$ — Set of logical unit of physical jointly owned unit jou.

$MNUP_i$ — Minimum up time of unit i.

$MNDN_i$ — Minimum down time of unit i.

$MXSU_i$ — Maximum startup times of unit i.

$F_{c,t}^{PhysicalLimit}$ — Physical limit of constraint c.

$f_{c,t}^{NCUC}$	Actual flow of constraint c .in NCUC.
$f_{c,t}^{NSM^0}$	Actual flow of constraint c .from previous NSM iteration.
$f_{c,t}^{NCUCMath}$	Mathematic flow of constraint c in NCUC.
$F_{c,t}^{MathLimit}$	Mathematic limit of constraint c in NCUC.
$PST_s^{neutral}$	Neutral position of phase shifter s .
$NCV_{n,t}^0$	Non-controllable variable, i.e. load in RUC.
$F_{c,t}^{offset}$	DC linearization offset (error) of constraint c .
$T_{i,p}^{off}$	Offline time corresponding to the startup cost segment p of unit i .
$NP_{i,t}$	Number of startup cost segment of unit at interval t .
$SUC_{i,t}^p$	Startup cost at segment p of unit i at interval t .
$MEO_{i,t}$	Minimum energy offer ($/MWh) of unit i at interval t .
$CCGR_{cc}$	Set of configurations of combined cycle train cc .
$CCFT_{cc}$	Set of feasible transition of CCT cc (FROM_CONFIG, TO_CONFIG).
$CCIT_{cc}$	Set of infeasible transition of CCT cc (FROM_CONFIG, TO_CONFIG).
$CCGRSU_{cc}$	Set of configurations which can be started up of CCT cc .
$CCGRSD_{cc}$	Set of configurations which can be shutdown of CCT cc .

Appendix B

Acronyms

AS	ancillary service
CCGR	combined cycle generation resource
CCT	combined cycle train
CCU	combined cycle unit
CMZ	congestion management zone
COP	current operating plan
CREZ	competitive renewable energy zone
CRR	congestion revenue right
CSC	commercially significant constraint
CT	combustion turbine
DAM	day-ahead market
DRUC	day-ahead reliability unit commitment
DC Tie	direct current tie
ERCOT	Electric Reliability Council of Texas, Inc.
EMS	Energy Management System
HASL	high ancillary service limit
HE	hour ending
HEL	high emergency limit
HRSG	heat recovery steam generator
HRUC	hourly reliability unit commitment
HSL	high sustained limit

IRC	ISO/RTO Council
ISO	independent system operator
IUC	initial unit commitment
JOU	jointly owned unit
KV	Kilovolt
LASL	low ancillary service limit
LDF	load distribution factors
LEL	low emergency limit
LMP	locational marginal price
LR	Lagrangian relaxation
LSL	low sustained limit
MIP	mixed integer programing
MIQP	mixed integer quadratic programming
MMS	market management system
MOI	market operator interface
MTLF	mid-term load forecast
MW	megawatt
MWh	megawatt hour
NCUC	network constrained unit commitment
NMMS	network model management system
Non-Spin	non-spinning reserve service

NSA	network security analysis
NSM	network security monitor
PIM	power injection model
PSU	pseudo unit modeling
PUCT	Public Utility Commission of Texas
QF	qualifying facility
QP	quadratic programming
QSE	qualified scheduling entity
RAP	remedial action plan
RARF	resource asset registration form
Reg-Down	regulation down service
Reg-Up	regulation up service
RMR	reliability must-run
RPP	renewable production potential
RPRS	replacement reserve service
RRS	responsive reserve service
RTCA	real-time contingency analysis
RTC	real-time commitment
RTO	regional transmission organizations
RUC	reliability unit commitment
SCADA	supervisory control and data acquisition
SCED	security constrained economic dispatch

SCUC	security constrained unit commitment
SE	state estimator
SGR	split generation resource
SPS	special protection scheme
ST	steam turbine
STWPF	short-term wind power forecast
TEWPF	total ERCOT wind power forecast
UC	unit commitment
WGR	wind-powered generation resource
WGRPP	wind-powered generation resource production potential
WRUC	weekly reliability unit commitment

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