# OPTIMIZATION OF ELECTRICITY MARKETS IN THE PRICE BASED AND SECURITY CONSTRAINED UNIT COMMITMENT PROBLEMS FRAMEWORKS

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**ABSTRACT**

OPTIMIZATION OF ELECTRICITY MARKETS IN THE PRICE BASED AND SECURITY CONSTRAINED UNIT COMMITMENT PROBLEMS FRAMEWORKS

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Operation of the electricity markets is subject to a number of strict and specific constraints such as continuous load-generation balance, security of supply, and generation technology related limitations. Contributions have been made to two important problems of the Electricity Markets, in the context of this study.

In this study, Price Based Unit Commitment problem in the literature, which is a tool for the GENCO for operations planning, is extended considering the interdependencies between the Natural Gas (NG) and Electricity infrastructures and the uncertainty of Wind Power generation. The effect of the NG infrastructure physical limitations is considered via linearized NG transmission system equations, and the Wind energy sources and conventional generation resource uncertainties are simulated by Monte-Carlo simulations. The contribution of the forward energy Bilateral Contracts (BC), as a financial risk hedging tool is also included by modeling these in the proposed PBUC framework. In the case studies , it is observed that a GENCO could prevent its financial losses due to NG interruptions, by depositing only a portion of the midterm interrupted NG in the storage facilities.

The Security Constrained Unit Commitment (SCUC) Problem is widely accepted tool in the industry which models the market clearing process. This study integrates two novelties to the SCUC problem;

- A discrete demand response model to consider active participation of the consumers,

- A hybrid deterministic/stochastic contingency model to represent the *N-1* contingencies together with the uncertainties related with the wind power generation and system load.

It is observed that the curtailment of available wind power capacity would enable the TSO to take corrective actions against occurrence of the contingencies and realization of the uncertainties in the most possible economical manner.

*Keywords* — Deregulated Electricity Markets, Price Based Unit Commitment, Security Constrained Unit Commitment, Stochastic Programming, Renewable Energy Resources, Mixed Integer Programming, Linear Programming, Benders Decomposition, Energy Market Clearing, Financial Risk, Midterm Operation Planning

# ÖZ

## FİYAT TABANLI VE GÜVENLİK KISITLI ÜNİTE ATAMA PROBLEMLERİ ÇERÇEVESİNDE ELEKTRİK PİYASALARININ ENİYİLENMESİ

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Serbest Elektrik Piyasalarının işletilmesi sürekli üretim-tüketim dengesi, kaynak güvenliği ve üretim teknolojileri sınırlamalarıyla ilgili özel ve katı kısıtlara tabidir. Bu çalışmada Serbest Elektrik Piyasaları ile ilgili iki temel probleme katkı yapılmıştır.

Bu çalışmada Üretim A.Ş.'lerin işletme planlamasında kullandıkları Fiyat Tabanlı Ünite Atama problemi, Doğalgaz ve Elektrik altyapıları arasındaki karşılıklı bağımlılık ve Rüzgar Enerjisi üretimindeki belirsizlikleri gözönüne alacak şekilde genişletilmiştir. Doğalgaz altyapısının fiziksel kısıtları Doğrusallaştırılmış Doğalgaz İletim Sistemi denklemleriyle, Rüzgar Enerjisinde ve geleneksel üretim kaynaklarındaki belirsizlikler de Monte-Carlo benzetim yöntemi kullanılarak modellenmiştir. Ayrıca İleri Enerji İkili Anlaşmaları, önerilen çerçevede modellenmiş ve bunların finansal risk önlem aracı olarak katkıları da gözönüne alınmıştır. Uygulama çalışmalarında, bir Üretim A.Ş.'nin orta vadede kesintiye uğrayacak doğalgazın yalnızca bir kısmını depolama tesislerinde biriktirerek kesintilerden doğacak finansal kayıplarını engelleyebileceği gözlenmiştir.

Güvenlik Kısıtlı Ünite Atama problemi, piyasa eşleştirme sürecini modellemek için endüstride yaygın kabul görmüştür. Bu çalışma kapsamında ayrıca Güvenlik Kısıtlı Ünite Atama problemine iki yenilik eklenmiştir;

- Tüketicilerin aktif katılımını gözönüne almak için Ayrık Talep Tepkisi modeli,

- N-1 Durumsallıklarını ve Rüzgar Enerjisi Üretimi ve Sistem Talebi ile ilgili belirsizliklerle birarada gözönüne almak için bir hibrid Determisitik/Stokastik durumsallık modeli

Önerilen çerçevede, İletim Sistemi Operatörünün önceden belirlenen emre amade Rüzgar Enerjisi kapasitesini beklenen kapasitenin altında belirleyerek, durumsallıkların ve belirsizliklerin gerçekleşmesi halinde, elde kalan rezerv kapasite ile mümkün olan en ekonomik düzeltici tepkiyi verdiği gözlenmiştir.

*Anahtar kelimeler* ─ Serbest Elektrik Piyasaları, Fiyat Tabanlı Ünite Atama, Güvenlik Kısıtlı Ünite Atama, Stokastik Programlama, Yenilenebilir Enerji Kaynakları, Karışık Tamsayı Programlama, Doğrusal Programlama, Benders Ayrıştırma, Enerji Piyasaları Dengeleme, Finansal Risk, Orta Vadeli İşletme Planlaması

To My Wife, My Parents and my Brother

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# TABLE OF CONTENTS


ABSTRACT ..... iv
ÖZ ..... vi
ACKNOWLEDGEMENTS ..... ix
TABLE OF CONTENTS ..... x
NOMENCLATURE ..... xiii
CHAPTERS ..... 1
1 INTRODUCTION ..... 1
1.1 Deregulated Electricity Markets ..... 1
1.2 GENCO's Midterm Operation Planning Modeled as Price Based Unit Commitment Problem (PBUC) ..... 2
1.3 Hybrid Deterministic/Stochastic Energy and A/S Market Clearing Modeled as Security Constrained Unit Commitment (SCUC) ..... 5
2 LITERATURE SURVEY ..... 9
2.1 Related PBUC Literature ..... 10
2.2 Related SCUC Literature ..... 14
3 OVERVIEW OF ELECTRICITY AND NG INFRASTRUCTURES IN TURKEY ..... 17
3.1 Natural Gas Sector Overview ..... 17
3.1.1 History of NG in Turkey ..... 17
3.1.2 NG Consumption and Tariffs ..... 18
3.1.3 NG Infrastructure ..... 19
3.1.4 NG Restructuring in Turkey ..... 22
3.2 Electric Power Sector Overview ..... 23
3.2.1 Brief History ..... 23
3.2.2 Electricity Generation in Turkey ..... 23
3.2.3 Transmission and Distribution ..... 24
3.2.4 Electricity Demand ..... 25
3.3 Concerns Related To Interdependence ..... 26
3.3.1 Reliable Electric Energy for NG Infrastructure ..... 26
3.3.2 Security of NG Supplies ..... 27

3.3.3 Prices and Tariffs for NG and Electric Power Industries ................................ 27
3.3.4 Role of NG in the Expansion of Electricity Market ........................................ 28
3.3.5 Dependency of Electric Power on NG ............................................................ 28
3.3.6 NG Demand Projection and Contract Types ................................................... 28
3.3.7 Restructuring of NG Industry.......................................................................... 29
3.4 Summary ............................................................................................................ 30
4 PROPOSED METHOD ............................................................................................ 31
4.1 Stochastic PBUC Problem and Proposed Solution Methodology ........................... 32
4.1.1 Mathematical Model ........................................................................................ 32
4.1.2 Proposed Solution Methodology ..................................................................... 40
4.2 Hybrid Deterministic/Stochastic SCUC Problem and Proposed Solution Methodology ........................................................................................................... 50
4.2.1 Mathematical Model ........................................................................................ 50
4.2.2 Proposed Solution Methodology ..................................................................... 54
5 CASE STUDIES ........................................................................................................ 58
5.1 The Effect of NG Infrastructure on GENCO's Midterm Operational Scheduling... 58
5.1.1 Case 1: Base Case without any NG Constraints or Supply Interruptions: ....... 60
5.1.2 Case 2: Effect of NG Infrastructure Constraints: ............................................ 62
5.1.3 Case 3: Effect of NG Supply Interruptions: .................................................... 64
5.1.4 Case 4: Effect of NG Storage Facility:............................................................ 66
5.1.5 Summary , Verifications and Comparisons..................................................... 68
5.2 The Impact of the Wind Intermittency and Uncertainty and the Presence of Forward BCs on GENCO's Midterm Operational Scheduling ......................................................... 70
5.2.1 3 Hour Problem ............................................................................................... 70
5.2.2 One Year Example ........................................................................................... 73
5.3 The Impact of DR, Wind Power and System Demand Uncertainty on Synchronous Day Ahead Market Clearing.......................................................................................... 82
5.3.1 Six-Bus System ............................................................................................... 82
5.3.2 Modified IEEE 118-Bus System ..................................................................... 91
5.3.3 Northwest Region of Turkish Power System .................................................. 93
5.3.4 Verifications and Comparisons ....................................................................... 96
6 CONCLUSIONS......................................................................................................... 98
REFERENCES ............................................................................................................. 102
APPENDICES ............................................................................................................. 109
A. LINEAR REPRESENTATION OF FUEL AND EMISSION................................. 109

B. LINEAR REPRESENTATION OF HEAD DEPENDENT WATER-TO-POWER CONVERSION CURVE ........ 110
C. DC NETWORK EQUATIONS ........ 112
D. BENDERS DECOMPOSITION ........ 113
1. Benders Decomposition ........ 113
2. Application of Benders Decomposition to SCUC Problem ........ 115
3. A Simple Example ........ 117
VITA ........ 121

# NOMENCLATURE

**Indices:**

| | |
|---|---|
| *b* | Index of buses |
| *c* | Index of transmission lines |
| *d* | Index of load |
| *e* | Index of subareas |
| *f* | Index of pumped-storage units |
| *h* | Index of hydro units |
| *i* | Index of non-NG thermal units |
| *j* | Index of NG units |
| *k* | Index of DR provider bid segments |
| *l* | Index of hydro catchments |
| *m* | Index of pipelines |
| *n* | Index of NG contracts |
| *o* | Denotes a pumping state of pumped-storage unit |
| *p* | Index of power plants |
| *r* | Index of DRPs |
| *s* | Index of scenarios |
| *t* | Index of time periods (hour) |
| *u* | Index of NG storage facilities |
| *w* | Index of wind units |
| *z* | Index of BC periods |

**Dimensions:**

| | |
|---|---|
| *NB* | Number of buses |
| *NC* | Number of *N-1* contingencies |
| *NCM* | Number of hydro catchments |
| *NCO* | Number of non-NG thermal units |
| *ND* | Number of system loads |
| *NDR* | Number of DRPs |
| *NEG* | Number of emission groups of thermal units |
| *NFG* | Number of fuel groups of thermal units |
| *NG* | Total number of hydrothermal units |

| | |
|---|---|
| $NGC$ | Number of NG gas contracts |
| $NGS$ | Number of NG gas storage facilities |
| $NH_l$ | Number of hydro units of a hydro catchment $l$ |
| $NNG$ | Number of NG units |
| $NPH$ | Number of phase shifting transformers |
| $NPL$ | Number of NG plants |
| $NPP$ | Number of NG pipelines |
| $NPS$ | Number of pumped-storage hydro units |
| $NP_k$ | Number of pumping states of pumped-storage hydro unit $k$ |
| $NQ_r$ | Number of DRP bid segments |
| $NS$ | Number of scenarios |
| $NSA$ | Number of NG subareas |
| $NSE_i$ | Number of segments for the piecewise linearized emission curve for thermal unit $i$ |
| $NSF_i$ | Number of segments for the piecewise linearized input-output curve for thermal unit $i$ |
| $NSSE_i$ | Number of segments for the start-up emission curve of thermal unit $i$ |
| $NSSF_i$ | Number of segments for the start-up fuel curve of thermal unit $i$ |
| $NT$ | Number of time periods under study |
| $NW$ | Number of wind units |
| $NZ$ | Number of BC periods under study |

**Sets:**

| | |
|---|---|
| $CS_l$ | Set of hydro units belongs to catchment $l$ |
| $RC_h$ | Geographic reservoir connection matrix with $rc_{h'} = 1$ if hydro unit $h$ is a direct up stream of unit $h'$, otherwise $rc_{h'} = 0$ |
| $SBC$ | Set of units assigned to honor a BC |
| $SCT$ | Set of NG units utilizing a gas contract |
| $SFC$ | Set of firm NG contracts |
| $SGE$ | Denotes an emission group of thermal units |
| $SGF$ | Denotes a fuel group of thermal units |
| $SIC$ | Set of interruptible NG contracts |
| $SPL$ | Set of NG units in a plant |
| $SPP$ | Set of gas contracts belonging to a pipeline |
| $SSA$ | Set of NG units in a subarea |

| | |
|---|---|
| $SST$ | Set of NG units sharing a NG storage facility |
| $ST_z$ | Set of hours for the BC period $z$ |
| $STX$ | Set of transmission lines |

**Variables:**

| | |
|---|---|
| $C_{DRR,r}$ | Cost of scheduling DRR from DRP $r$ |
| $C_{EDRR,r}$ | Cost of utilizing scheduled DRR from DRP $r$ |
| $C_{ns}$ | Cost of NG usage from contract $n$ in scenario $s$ |
| $C_{pen,zs}$ | Penalty for deficient BC in period $z$ |
| $C_{us}$ | Cost of NG usage from storage facility $u$ in scenario $s$ |
| $DRR_{rt}$ | Scheduled DR from DRP $r$ at time $t$ |
| $DRR_{rts}$ | Deployed DR from DRP $r$ at time $t$ under scenario $s$ |
| $Em^{ET}$ | Type $ET$ emission of thermal unit |
| $E_{bc,z}$ | BC in period $z$ |
| $E_{def,zs}$ | Deficient BC in period $z$ in scenario $s$ |
| $E_{del,zs}$ | Delivered BC in period $z$ and scenario $s$ |
| $F$ | Fuel usage by unit |
| $F_{c,i}$ | Fuel cost function of unit $i$ |
| $F_{SR,i}$ | Bid-based scheduling cost function of unit $i$ spinning reserve |
| $F_{OR,i}$ | Bid-based scheduling cost function of unit $i$ operating reserve |
| $hw$ | Water head |
| $I$ | Commitment state |
| $I_g$ | Indicator for pumped-storage hydro unit generating mode |
| $I_{pn}$ | Indicator for pumped-storage hydro unit when pumping at state $n$ |
| $l_d$ | Involuntary load shedding at load $d$ |
| $nw$ | Natural inflow to the reservoir of hydro unit |
| $OR$ | Total Deployed Operating reserve |
| $OR_u$ | Scheduled operating up-reserve |
| $OR_d$ | Scheduled operating down-reserve |
| $P$ | Power generation |
| $P_{IMB}$ | Power generation in spinning interval |

$p_{m,its}$ Power generation of thermal unit $i$ at segment $m$at time $t$ in scenario $s$

$P_{\Psi,wts}$ Wind generation of unit $w$ at time $t$ and scenario $s$

$P_{bc}$ Power generation to satisfy BC

$P_g$ Power generation of pumped-storage unit

$P_{pn}$ Power usage of pumped-storage unit when pumping at state $n$

$PF_s$ GENCO's payoff in scenario $s$

$R_{bc,z}$ BC revenue in period $z$

$q^{out}$ NG withdrawn from storage facility $w$

$q^{in}$ NG injected to storage facility $w$

$RISK_s$ GENCO's downside risks in scenario $s$

$SD$ Shutdown cost

$SR$ Spinning reserve

$SR_u$ Scheduled spinning up-reserve

$SR_d$ Scheduled spinning down-reserve

$SU$ Startup cost

$s$ Spillage of hydro unit $s$

$TP$ Generation capacity offered to a real-time market

$ue_{m,its}$ Indicates whether thermal unit $i$ is started at segment $m$ of start-up emission curve (1/0) at time $i$ in scenario $s$

$u_{rts}^{k}$ Binary variable, takes value 1 if point $k$ of scheduled offer package DRP $r$ at time $t$ in scenario $s$ is utilized, 0 vice-versa

$U_{rt}^{k}$ Binary variable, takes value 1 if point $k$ of offer package DRP $r$ at time $t$ is scheduled, 0 vice-versa

$V_{wts}$ Volume of NG in storage facility $w$ at time $t$ in scenario $s$

$v_{jts}$ Reservoir volume of hydro unit $j$ at time $t$ in scenario $s$

$v_{m,its}$ Indicates whether thermal unit $i$ is started at segment $m$ of start-up cost curve (1/0) at time $t$ in scenario $s$

$w_{jts}$ Water discharge of hydro unit $j$ at time $t$ in scenario $s$

$w_{d,j(t-\tau)s}$ Water discharge to hydro unit $j$ from other hydro units with the delay time $\tau$ at time $t$ in scenario $s$

$w_g$ Water discharge of pumped-storage hydro unit when generating

$w_{pn}$ Water discharge of pumped-storage hydro unit when pumping

$yu$ Startup indicator

$yd$ Shutdown indicator

$\Delta_c$ Phase shift value for the transformer installed on line $c$

$\lambda$ Lagrange multiplier

$\theta_{b1}$ Voltage angle of bus $b1$

$\gamma_s$ Lagrange multiplier for risk constraint in scenario $s$

$\gamma_s$ Lagrange multiplier for risk constraint in scenario $s$

$\psi_{wts}$ Stochastic speed of wind unit $w$ at hour $t$ in scenario $s$

**Constants:**

$\alpha_h$ Constant term related to reservoir $h$

$\beta_n$ Restore rate of NG contract $n$

$A_w$ Area swept by the rotor of wind unit $w$

$cc_{rt}^{k}$ Scheduling cost of point $k$ of scheduled offer package DRP $r$ at time $t$

$c_{\mathrm{P},w}$ Power coefficient of wind unit $w$

$C_{0,n}$ Fixed cost for firm NG contract $n$

$DT$ Required down time

$ec_{rt}^{k}$ Deployment cost of point $k$ of scheduled offer package DRP $r$ at time $t$

$ET$ Denotes an emission type

$\overline{EDR}$ Expected downside risk tolerance

$Emb_{m,i}$ Slope of segment $m$ in linearized fuel emission curve of thermal unit $i$

$F_{\min,SGF}$ Minimum fuel limit for group $SGF$

$F_{\max,SGF}$ Maximum fuel limit for group $SGF$

$F_{\min,i}$ Fuel Consumption of thermal unit $i$ at minimum capacity

$Fb_{m,i}$ Slope of segment $m$ in linearized input-output curve of thermal unit $i$

$F_{\max,jt}$ Maximum NG usage allowed for unit $j$ at time $t$

$F_{\max,j}$ Maximum NG usage allowed for unit $j$ in one year

$MU$ Minimum up time

$MD$ Minimum down time

$MSR$ Maximum sustained ramp rate (MW/min) for thermal unit

$NP_f$ Number of pumping modes for pumped storage unit $f$

$p_s$ Probability for a scenario $s$

$P_{D,d}$ Power demand at load $d$

$P_{\min}$ Minimum generating capacity

$P_{\max}$ Maximum generating capacity

$p_{\max m,i}$ Maximum Power generation of thermal unit $i$ at segment $m$

$p_n$ Steady-state availability of NG contract $n$

$q_n$ Steady-state unavailability of NG contract $n$

$RU$ Ramp up limit

$RD$ Ramp down limit

$QSC_i$ Quick start capacity of thermal unit

$q_r^k$ $k$ th discrete DRR value of the bid of DRP $r$

$SE_{m,i}$ Start-up emission if started at segment $m$ for thermal unit $i$

$SF_{m,i}$ Start-up fuel consumption for thermal unit $i$ if started at segment $m$

$\rho f_{its}$ Fuel price of coal unit $i$ at time $t$ in scenario $s$

$TU_0$ Number of hours that the unit have been online at initially

$TD_0$ Number of hours that the unit have been offline initially

$T_0$ Target payoff of a GENCO

$UT$ Required up time

$UA_{nts}$ Availability of NG contract $n$ at time $t$ in scenario $s$

$V_{\max,u}$ Maximum NG volume limit in storage facility $u$

$V_{\min,u}$ Minimum NG volume limit in storage facility $u$

$V_{0,u}$ Volume of NG in storage facility $u$ at time 0

$V_{NT,u}$ Volume of NG in storage facility $u$ at time $NT$

$v_{0,h}$ Initial reservoir volume of hydro unit $h$

$v_{NT,h}$ Terminal reservoir volume of hydro unit $h$

$v_{\min,h}$ Minimum reservoir volume of hydro unit $h$

$v_{\max,h}$ Maximum reservoir volume of hydro unit $h$

$w_{\min,h}$ Minimum discharge of hydro unit $h$

$w_{\max,h}$ Maximum discharge of hydro unit $h$

$w_{\min g,k}$ Minimum discharge of pumped-storage hydro unit $k$ when in generation mode

$w_{\max g,k}$ Maximum discharge of pumped-storage hydro unit $k$ when in generation mode

$w_{pn,k}$ Water discharge of pumped-storage hydro unit $k$ when pumping at state $n$

$\rho_{bc}$ BC price

$\rho g_{ts}$ Market price for energy at time $t$ in scenario $s$

$\rho_n$ Price of one MMCF of interruptible NG contract $n$

$\rho or_{ts}$ Market price for operating reserve at time $t$ in scenario $s$

$\rho_{pen}$ Penalty price for a deficient BC

$\rho sr_{ts}$ Market price for spinning reserve at time $t$ in scenario $s$

$\rho_u$ Unit price of one MMCF of gas withdrawal from NG storage facility $u$

$v_{\mathrm{CI},w}$ Cut-in wind speed of wind unit $w$

$v_{\mathrm{CO},w}$ Cut-out wind speed of wind unit $w$

$v_{\mathrm{R},w}$ Rated wind speed of wind unit $w$

$VOLL_d$ Value of lost load at load $d$

$x_c$ Reactance of transmission line $c$

$\chi_n$ Interruption rate of NG contract $n$

$\eta$ Water-to-power conversion coefficient

$\partial_s$ Allowed system load imbalance for N-1 contingency scenario s

**Abbreviations:**

*A/S* Ancillary Services

*BC* Bilateral Contract

*DR* Demand Response

*DRR* Demand Response Reserve

*DRP* Demand Response Provider

*NG* Natural Gas

*GENCO* Generation Company

*TSO* Transmission System Operator

| | |
|---|---|
| *PBUC* | Price Based Unit Commitment |
| *SCUC* | Security Constrained Unit Commitment |
| *SR* | Spinning Reserve |
| *OR* | Operating Reserve |

# CHAPTER 1

# INTRODUCTION

## *1.1 Deregulated Electricity Markets*

The electricity industry had been comprised of vertically integrated utilities, in which all of the related operations are governed from a single center. However, the industry has been undergoing an enormous change towards a deregulated electricity market structure in which the generation, transmission, and distribution of electricity is maintained by private market participants.

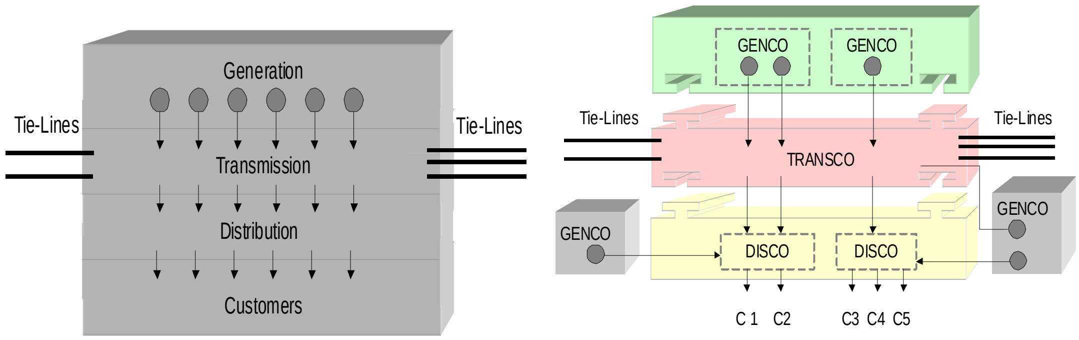


Fig 1.1 Vertically Integrated Industry vs Deregulated Electricity Market

There are two objectives to maintain an electricity market; ensuring a secure operation and facilitating an economic operation. Security is the most important aspect of the electric power systems which could be maintained by utilizing various services in a deregulated environment. Besides the electricity market should be economically operated to reduce the price of electricity consumption.

The Independent System Operator (ISO) or Transmission System Operator (TSO) is an entity, functioning to ensure the independent operational control of the grid. ISO commits and schedules some or all of the system resources as well as it curtail loads whenever necessary in order to maintain acceptable frequency, supply-demand balance and to ensure that there is no transmission line capacity violation.

A Generation Company (GENCO) operates and maintains its generating power plants. GENCOs are not affiliated with any other ISO or TSO, their prices are not regulated, and their objective is to maximize their own profit. In order to fulfill this objective they have the right to enter the energy or ancillary services (A/S) markets. They can sell energy to be consumed at any part of the transmission network, since the power would be delivered through the transmission and distribution systems. However, they can not discriminate between Distribution Companies and Retailers. They are responsible for their own financial planning and risk assessment.

A Distribution Company (DISCO) operates and maintains the part of the distribution network under its responsibility. A DISCO can purchase energy through bilateral contracts (BC) with the GENCOs or Retailers to meet its costumers' electricity consumption. DISCO is also responsible from the necessary investments to maintain and expand its network, as well as power quality, responding to network outages and A/S.

A Retail Company (RETAILCO) do not own or operate any part of the electric network, but they rather buy and re-sell electricity and other services to its costumers.

Deregulated electricity markets require independent authorities that have the jurisdiction over energy market transactions and licensing of market players. The Turkish Electricity Market Regulatory Authority had been established for as per Law no. 4628 and it was later renamed as Energy Market Regulatory Authority (EMRA) as per the provisions of Natural Gas Market Law no. 4646. With the enactment of the Petroleum Market Law no. 5015 and Liquefied Petroleum Gas (LPG) Market Law no. 5307, the Authority has been commissioned to regulate and supervise the petroleum and LPG markets. Members of the Energy Market Regulatory Board assumed duty on November 19, 2001

## *1.2 GENCO's Midterm Operation Planning Modeled as Price Based Unit Commitment Problem (PBUC)*

GENCOs use PBUC to optimally schedule their generation assets in order to maximize their profits. Minimizing costs is not always equivalent to maximizing profit, since the profit is the difference between revenue and the cost. The system generation-load balance and security is not considered in the PBUC problem since these are the responsibilities of the TSO. Besides, the market energy price signal is crucial for PBUC, since it defines the revenue. Each generating asset of the GENCO has its own technical constraints depending on the generation type (i.e., hydro, coal, NG, pumped storage, wind, PV). For instance, hydro units are subject to reservoir constraints, and water resource inflow defines the water volume stored in the reservoir. The hydro unit generation should be scheduled considering the minimum and maximum reservoir limitations. Extra constraints apply for those hydro units that are situated on the same river basin, having interconnected reservoirs. Different units have their own constraints specifying the technical and physical characteristics.

A simple example is presented in order to introduce the PBUC problem. Consider a three-hour example of a GENCO with one wind and one NG units. Assume that there are two scenarios with hourly wind forecasts of 100MW, 150MW, 170MW for the first scenario and 80MW, 130MW, 150MW for the second scenario, with a 50% probability in each case. The NG unit has a constant generation cost of $19/MWh with min/max power of 55MW and 200MW, respectively. The cost of A/S is not considered for simplicity. The real-time energy prices are $20/MWh and $15/MWh for scenarios 1 and 2, respectively. The objective is to maximize the expected profit of the GENCO and the optimal expected payoff is calculated to be $6,900, and the schedules of the units are given in Table 1.1. The wind unit utilizes all the available wind energy in both cases while the NG unit is not committed since it is only profitable for the first scenario. If scenario 1 is kept constant, the scheduling of the NG unit would not change until the market energy price for scenario 2 is increased over $18/MWh, for which the NG unit will offer energy at its maximum output (i.e. the optimal expected profit will be $7680, by scheduling the NG unit at 200 MW at each hour). This problem seems trivial, however when bigger systems with greater number of hours and units with specific constraints are considered, the problem gets much more complicated.

TABLE 1.1
OPTIMAL SCHEDULE WITH NO BCS AND NO COORDINATION

| Hours | | t=1 | t=2 | t=3 |
|---|---|---|---|---|
| Scenario 1 | Available Wind Power | 100 | 150 | 170 |
| | NG unit dispatch | 0 | 0 | 0 |
| Scenario 2 | Available Wind Power | 80 | 130 | 150 |
| | NG unit dispatch | 0 | 0 | 0 |
| Expected payoff | | $6,900 = 20*420*50% + 15*360*50% | | |

NG fired units introduce specific constraints, due to the fact that the fuel reaches the NG fired generating units via NG transmission pipelines. A GENCO having NG fired generating units has to consider the physical limitations of the NG transmission system in the scope of the PBUC. Consider a GENCO with NG units in its generating portfolio, which is giving generation bids to the electricity market. The forecasted market price might be high compared to the unit NG price, such that it might be profitable for the GENCO to operate its NG units at its maximum generation limits as given in the final part of the simple example. However, in reality there might be a number of other constraints related with the NG transmission system that would limit the power generation of the NG unit.

Several approaches are available for the modeling and solution of the PBUC problem. There are a large number of studies concerning the problem in a stochastic framework to handle the uncertainties such as available water inflow and renewable resources, energy and A/S market prices, fuel availability and prices. The studies regarding the PBUC problem is aimed addressing NG and Electricity networks interdependencies, emerging electric power sources such as wind energy, and financial risk hedging tools such as BC, in order to provide a complete assessment tool that would help the GENCOs decision making process in the complex electricity market environment.

One of the contributions of this study is the integration of the NG transmission constraints to the stochastic PBUC framework for assessing the effects of the NG transmission infrastructure on the midterm financial profile of the GENCO. The linearized constraints are imposed in order to reflect the mentioned upper limits of the NG transmission system. There is a tradeoff when we linearize the NG system such that the solution time for the NG network equations is highly improved, but it is impossible to calculate the pressure or flow at any point of the NG transmission system at a given time. Since, the focus is on the midterm financial evaluation of the GENCO, it is a fair assumption. Besides, the improved NG storage system model is developed for this study. The GENCO might store NG in the storage facilities, instead of generating electricity. The storage facilities are accordingly modeled to reflect both withdrawal from and deposit to the NG storage facilities. The proposed NG storage model is inevitable for a midterm study, while it would be sufficient only to model the withdrawal of NG from the storage for short-term (day-ahead) studies. The related results are as follows:

-Test results show that besides uncertainties in market prices and water inflow, GENCOs must further consider the NG infrastructure limitations in the optimal midterm scheduling. The proposed framework provides a complete midterm operation planning tool, while the ones existing in the literature are not sufficient to consider the interdependency issues.

- Case studies show that the NG storage facilities would improve the expected payoff of the GENCO against NG interruptions by providing NG at interrupted hours. The effect of utilizing the NG storage on the expected payoff is analyzed and it is observed that a considerable improvement in the expected payoff would be attainable even by a limited storage capacity in comparison with any NG interruptions.

Moreover, the effect of uncertainty in the wind power generation is also investigated for the GENCO's PBUC problem. The wind generation unit models and weekly BCs are integrated to the GENCO’s risk-constrained midterm hydrothermal scheduling. Case studies show that BCs could adversely affect the expected payoff and financial risk of the GENCO when only hydro units are considered. The expected payoff increases and the financial risk decreases with the addition of NG and wind units to the coordination. The algorithm is used to calculate the optimal weekly BC amount for both maximizing profit and minimizing financial risk throughout a mid-term period. The effect of the level of uncertainty and coordination of different number of units is further investigated using the proposed framework.

## *1.3 Hybrid Deterministic/Stochastic Energy and A/S Market Clearing Modeled as Security Constrained Unit Commitment (SCUC)*

TSOs use SCUC in order to obtain a commitment schedule at minimum production cost with considering the system reliability. The electric power system reliability has two components: adequacy and security. Adequacy refers to the fact that there should be enough generating resources to satisfy the peak system demand. Security refers to the notion that the power system has to withstand malfunctions of the system equipment such as generator or transmission line outages. In a deregulated power market, the TSO has to match generation and load ahead of time. Day-ahead market is one of the tools to balance generation and system load. The TSO receives the generation bids from the GENCOs and aggregates the bid curves to obtain the aggregated supply curve. Energy market price occurs at the intersection of the supply curve and the aggregated demand curve. If it is assumed that there is no transmission congestion in the transmission network, the intersection of the aggregated supply and load curves defines the single energy market price for the power system. Energy market clearing, the matching of the generation and the system load addresses the adequacy in the power system. The security should be provided by allocating reserves to cover for the possible system equipment outages.


Figure 1.2 Simple two bus example

The role of the SCUC could be described with an example. Consider the two-bus system given in Fig 1.2 as an example composed of three competing units to supply one load. G1 has a capacity of 60MWand submits a 20 $/MWh bid for energy and 3 $/MW for reserve. G2 has a capacity of 70MW and submits a 25 $/MWh bid for energy. G3 has a capacity of 80 MW and submits a 40 $/MWh bid for energy and 5 $/MW for reserve. Line capacity is taken as 50 MW. The optimal dispatch consists of 50MW from G1 and 10MW from G2. Assume the outage of G2 represents a credible contingency. The traditional approach to allocate reserve requirements without considering the network topology or any possible contingencies would schedule 70 MW (i.e., 10 MW reserve from G1 and 60 MW from G3), which is equal to the capacity of G2, the largest unit in the system. However, it is clear that G1 will not supply reserves once G2 is on outage, since the capacity of the line between G1 and the load is 50 MW and the pre-contingency line flow is already 50 MW. In comparison, the outage of G2 is simulated when scheduling reserves in our proposed algorithm, which results in supplying a 70 MW reserve from G3 and guarantees that the redispatch is feasible when G2 is on outage.

In the literature, the market clearing for energy and A/S is done in two different ways named as, sequential and simultaneous. In the sequential market, A/S and energy markets are both operated and cleared separately, which is easy to implement. However, this market structure has a number of flaws such as potential market power, and price reversal. Price reversal is the phenomenon that the lower quality services might be more expensive than the higher quality ones due to the sequential auction. The simultaneous market clearing considers all of the A/S offers together in the energy supply cost function. There are a number of studies to address simultaneous market clearing schemes in the literature consider only traditional generation reserves and model the system with a deterministic approach. However, a number of emerging concepts should be considered which affect the scheduling of energy and A/S such as renewable generation resources and demand side management. Demand Response

(DR) is a tariff or program to encourage the change in electricity consumption of the end-use consumers in order to mitigate the load at time frames when high market price occurs or when the grid security is jeopardized.

We propose a hybrid deterministic/stochastic model in which the equipment outage contingencies such as generating unit and transmission line outages are considered in a deterministic *N-1* contingency model, while the wind, load uncertainty is addressed through Monte-Carlo based scenarios in a standard two-stage stochastic programming model. An integer based bid structure is used to evaluate the contribution of DR bids to the reserve market. To better understand the importance of the proposed framework, consider a system, with high wind injection. A scheduling without consideration of wind and system load forecast errors might be suboptimal and even infeasible if the actual values happen to be different from the forecasted values. Besides, the consideration of deterministic *N-1* contingencies would increase system security and allows the algorithm to find an optimum scheduling suitable for corrective actions after the considered equipment outages. To address the computational complexity, the energy and A/S market clearing problem is decomposed to generate a master problem to solve the UC and reserve schedules, and subproblems for considering network security for pre-selected *N-1* contingencies and uncertainty scenarios. The proposed method would be used by a TSO or a vertical utility to clear the energy and A/S markets addressing the stochastic cost of security over the Monte-Carlo based wind, and load scenarios considered together with the deterministic *N-1* contingencies, which is not addressed in the literature.

Test cases show that wind power is curtailed in the base case to respond to the wind-load uncertainty scenarios by increasing the wind power unit generations with the remaining available wind energy when the uncertainty is realized. The curtailed wind power in the base case is utilized as spinning reserve in the presence of an *N-1* contingency or an uncertainty scenario. The sensitivity analysis is performed in order to understand the effect of the uncertainty level in the wind power and system load, to the overall cost. The effect of wind uncertainty depends on the penetration level. The system cost decreases as the wind penetration increases since the operating cost of wind power units is neglected. However, the expected cost increases considerably with the increasing wind forecast uncertainty for a high wind penetration. A scalability analysis is performed to understand the solution performance with the changing number of contingencies and scenarios.

The rest of the thesis is organized as follows: In Section 2 literature survey concerning the PBUC and SCUC frameworks is given. Section 3 introduces a survey study on the Turkish Electricity and the NG markets, and the interdependencies between the Turkish Electricity and NG infrastructures in order to give a snapshot of the two industries of the country. The proposed PBUC and SCUC frameworks and mathematical representations are given in Section 4. Section 5 includes the case study results focusing in three main analyses namely, The Effect of the NG Infrastructure on GENCO's Midterm Operational Scheduling, The Impact of the Wind Intermittency and Uncertainty and the presence of forward BCs on GENCO's Midterm Operational Scheduling, and The Impact of DR, Wind Power and System Demand Uncertainty on Synchronous Day Ahead Market Clearing. Section 6 concludes the thesis.

# CHAPTER 2

# LITERATURE SURVEY

Even the objectives of the PBUC and SCUC problems are different as described in previous chapter, both are UC problems and utilize similar modeling methods and solution algorithms. Large UC problems include exhaustive enumeration consisting unit commitment states being integer variables. Priority Listing, Dynamic Programming, Mixed Integer Programming with Benders Decomposition, Lagrange Relaxation, and Heuristic Methods are the solution methods applied to the UC problems.

Dynamic programming was the earliest optimization-based method to be applied to the UC problem. It is used extensively throughout the world. It has the advantage of being able to solve problems of a variety of sizes and to be easily modified to model characteristics of specific utilities. It is relatively easy to add constraints considering a single time interval but rather hard to add constraints concerning a single unit and more than one time intervals such as min on /off time constraints.

Application of Lagrangian Relaxation (LR) is much more recent than the dynamic programming. LR method is reasonable when greater number of units are considered. The non-convex UC problem structure is tackled with the augmented-LR approach but still the update of the LR multipliers is cumbersome and might lead to suboptimal solutions.

Mathematically, UC is a mixed-integer optimization problem with a large number of 0-1 variables, continuous and discrete control variables, and a series of prevailing equality and inequality constraints. The main difficulty of solving the MIP problems is the requirement of substantial computing power. The method gained popularity due to recent developments in the computer hardware and software technologies [83]. There are also hybrid methods to inherit the advantages of different methods.

MIP method is also utilized in this thesis to solve the proposed PBUC and SCUC problems. The literature survey regarding the PBUC and SCUC problems are given in the following sections 2.1 and 2.2 respectively.

## 2.1 Related PBUC Literature

GENCOs are responsible for the midterm operation planning which provides a basis for the optimal hourly bidding in a day-ahead market. The midterm operation planning will determine the optimal utilization of resources such as fuel, emission allowance, natural water resources and Renewable Energy Resources (RES) [1]-[3]. The modeling of NG contracts, forward BC in midterm operation planning studies provides a more robust scheduling of hydrothermal assets when considering uncertainties related to market prices.

Several approaches are available for the optimal midterm operation planning problem. A variable metric method was used in [4] to solve the dual maximization for achieving a good convergence property. A composite representation of thermal and hydro units was used in [5] for economic dispatch based on weekly and monthly requirements. A dual-decomposition of long-term planning problem was applied in [6],[7] for setting up easy-to-solve problems in subperiods. The framework in [8] is able to consider on and off-peak energy prices and user controlled multi-scenario water inflows. The interior point method is applied to solve the long-term scheduling problem, in which the hydro unit characteristics are linearly modeled. A two-stage DP method was proposed in [9] which is capable of handling nonconvex, nonlinear and stochastic characteristics of the problem. However, the DP technique might not be tractable in multi-reservoir systems due to the dimensionality problem. Reference [10] compared the stochastic dynamic programming and the deterministic optimization models with an inflow forecasting model for the long-term hydrothermal scheduling problem. The reference concludes that the two methods have similar performance and the deterministic model is superior in dry hydro periods.

The effect of NG infrastructure and interdependencies were also considered in midterm NG planning studies. The impact of NG infrastructure contingencies on the power system operation was presented in [11] and the impact of renewable resources on reducing the dependence of electricity infrastructure on the NG infrastructure was discussed. The nonlinear NG network equations were considered in the SCUC problem using a decomposition approach [12]. A component-based model for the scheduling of combined-cycle gas units by mixed-integer programming was proposed in [13]. A two-phase nonlinear optimization model was proposed in [14] to model the integrated operation of NG network and power systems. In [15] and [16], a nonlinear optimization model was proposed by merging the traditional optimal power flow and NG network constraints. The short-term scheduling of integrated NG network and hydrothermal power system was solved in [17] by applying Lagrangian relaxation and dynamic programming. An integrated model was proposed in [18] for studying the interdependency of electricity infrastructure and NG system and the social sustainability of energy infrastructures. The integrated model considered NG network constraints as daily and hourly limits on pipelines, subareas, power plants, and generating units, and incorporated these constraints into the optimal solution of short-term SCUC. However, this integrated model is not capable of modeling the bidirectional utilization of NG storage facilities (withdrawal and storage), which is crucial for midterm operational planning. A network-based stock and flow type model was created in [19] to analyze the NG network response to disruptions. The NG flows between regions were represented and stocks were the regional NG storages. The model was used to assess the NG network against transmission disruption scenarios. However, the model did not include contractual NG deliveries to other users which would likely worsen electric power supply scenarios. For example, there might be a sufficient transmission capacity available on a NG pipeline which would feed a GENCO's power plants. The NG flow can ramp up quickly in the event of a pipeline disruption elsewhere or an unseasonably cold weather. However, that capacity could have already been contracted to other users, and NG usage of GENCO is subject to contract constraints which are considered in our framework. Logically, such emergencies would take precedent, but legally there might be no way out of contractual agreements. Consequently NG contracts are modeled in our study in order to assess the effects on the midterm operational planning. An analytical framework was proposed in [20] to study physical and economic aspects of interdependent infrastructures such as electric power, petroleum, NG, water, and communications systems. A modeling and analyses tool was developed to capture interdependencies, evaluate potential effects of disruptions in one infrastructure, and suggest strategies to mitigate shortcomings. These studies are looking from the TSO perspective and thus the objective is to minimize the social cost. A framework is necessary for the GENCOs to enable the profit maximization considering the NG infrastructure limitations as well as uncertainties. The contractual issues or interruptions described above and supply uncertainties could severely jeopardize the financial perspective of a GENCO if not considered properly. In addition, GENCO's financial risk should be considered in the same framework. The behavior of NG units could vary under different hydro conditions. For instance, NG units would tend to increase their generation output for lowering the total financial risk. This case could occur in scenarios with water supply shortages to prevent GENCOs from defaulting on their BCs. However, the NG output in practice could be constrained by physical limitations and contracts.

Consider a GENCO with hydro, thermal, and NG contracts for supplying its NG power plants. Since the residential NG demand is very high at certain seasons, NG suppliers in severe weather conditions could interrupt the supply to power plants. Such interruptions could have a significant impact on the GENCO's expected payoffs. In this study, the NG interruptions are also considered as uncertainties similar to those of hourly market prices and water inflows. A two-state continuous-time Markov chain model is used to represent available and unavailable states of NG interruptible contracts, considering interruptions for feeding residential costumers under severe winter conditions. The availability of NG storage could facilitate lower risks in such cases. The storage capacity should be determined in such cases based on forecasted market prices, and duration and frequency of NG interruptions. The modeling of storage is essential for a midterm study, since the storage facility could be used both for deposit and withdrawal purposes throughout the year, addressed through an improved NG storage model in this study. The storage model for the short-term study in [18] was simply represented by a gas inflow variable in the NG unit fuel balance equation. The short-term constraints considering capacity limits on pipelines, sub-areas, power plants, and units are adopted for the midterm stochastic model by increasing the time-span and introduction of scenario variables.

Wind energy is the fastest growing type of renewable energy due to its clean and indigenous nature. The 2008 global wind power market was 27GW exceeding the expectations in spite of global economic crises [21]. In addition to the uncertainty in forecasting water inflows and market prices of electricity and fuel (NG, coal, LPG), the midterm operation planning of a GENCO would consider the intermittency and the volatility of RES. The forecast errors in such cases could affect the GENCO's payoffs and risks which could also make GENCOs subject to penalties for defaulting on their scheduled power delivery.

The wind power uncertainty was considered in security-constrained unit commitment (SCUC) [22]. The impact of wind generation on regulation and load following requirements of the California Independent System Operator (ISO) was analyzed in [23]. Reference [24] studied the day-ahead unit commitment problem at the presence of high wind penetration. Reference [25] investigated the short-term effect of wind power forecast errors on UC and economic dispatch. It is observed that the stochastic model provides a more comprehensive solution as compared to a deterministic model. The GENCO's market optimization with wind generation assets and a pumped-storage facility was presented in [26]. The algorithm was modeled as a two-stage optimization by considering market prices and wind generation uncertainties. The studies considering wind power uncertainty together with other generating resources are generally focusing on short-term operation planning since precise wind power forecasts are rather available for short-term periods. However, a GENCO should be able to evaluate the mid-term potential of its wind power units to determine its mid-term operation plan. In addition to the modeling of NG infrastructure, this study also considers the wind forecast errors and analyzes the effect of wind generation volatility on the GENCO's midterm payoff.

There are several techniques for predicting the quantity of intermittent wind generation. These techniques are categorized into numeric weather prediction (NWP) methods, statistical methods, artificial neural networks (ANN) methods, and hybrid approaches. The NWP method provides wind speed forecasts given by a spatial distribution. A common approach to the short-term wind generation prediction is to refine the output of NWP models by the local weather information to obtain local wind conditions. Time series models are developed based on historical values. The advantage of ANN is to learn the relationship between inputs and outputs by a non-statistical approach. The objective of hybrid models is to benefit from the merits of each model and obtain a global optimal forecasting performance [27].

Forward BCs can potentially hedge real-time market price volatilities. A GENCO might use a midterm planning framework to optimize the utilization of resources including fuel, emission allowance, natural water resources and wind generation and to schedule its generating assets in conjunction with possible BCs for maximizing financial returns. A number of studies consider BCs in a GENCO's operation planning. In [28], the authors proposed a systematic negotiation scheme for BCs by utilizing a risk/payoff assessment of generators and loads. Different risk measures such as regret, Value at Risk (VaR) and dispersion from the mean and benefit measures as well as expected payoff and expected rate of return were used. Contract blocks, spot prices, demands were constant during the contract period. Reference [29] presented a methodology to aid the GENCO's decision-making during the negotiation process of BCs. The risk of deficit of Energy Availability (EA) and ensured energy (EE) of hydro units were utilized. The risk of deficit of EA and negative exposition in the spot market were used to assess the GENCO's position for negotiation. In [30], the authors proposed a stochastic energy procurement decision framework for large consumers. The supply portfolio was optimized considering uncertain pool prices, bilateral energy contracts, and self generation. Conditional VaR (CVaR) was used to formulate the risk, and the risk term was added to the objective function with a weight factor to address the tradeoff between cost and risk minimization. Reference [31] presented a GENCO's optimal bidding strategy that was modeled as a nonlinear mathematical program with equilibrium constraints. The competitive GENCO's profit maximization was considered as objective function and expected offers, uncertain system loads, and BCs were modeled with added constraints. In this study, forward BCs are modeled using integer variables to reflect the GENCO's income as well as payments due to the defaulting of the BC, in order to provide a complete analysis basis for midterm operational framework.

As a summary, this study proposes an optimization framework to study a GENCO's midterm operation planning problem with uncertain availability of wind, hydro, and thermal resources, under NG infrastructure limitations and unpredictable NG interruptions for NG fired generating units. Assessment of the NG infrastructure impact on stochastic midterm planning of a GENCO is impossible using the frameworks existing in the literature [4]-[20] unless these are explicitly modeled in the midterm hydrothermal problem. For this purpose, the linear stochastic network flow model is utilized for the NG model and an improved NG storage model is formulated which does not exist in [18]. The BC constraints are coordinated to hedge against the volatility of real time market prices. The mathematical model utilizes the risk-constrained stochastic PBUC framework [32], which is solved by a MIP solver. The performances of individual units for risk reduction are studied and compared with the risk reduction performance of all units considered together to evaluate possible alternatives in a GENCO's stochastic midterm scheduling.

## *2.2 Related SCUC Literature*

The objective of TSO's SCUC problem is to minimize the social cost of electricity utilization, which is different from the PBUC problem of GENCOs. This study also contributes to the existing SCUC literature by proposing a synchronous hybrid stochastic/deterministic market clearing framework. A/S are essential for the reliable operation of power systems since they provide additional available capacity in order to cover unplanned power system equipment outages as well as shifts from the forecasted system load and available renewable resource forecasts. As restructuring evolved, determining the cost of supplying A/S and finding out how these costs would change with respect to operating decisions has become a major issue [2]. The market clearing for energy and A/S is done in two different ways named as, sequential and simultaneous. In the sequential market, A/S and energy markets are both operated and cleared separately, which is easy to implement. However, this market structure has a number of flaws such as potential market power, and price reversal. Price reversal is the phenomenon that the lower quality services might be more expensive than the higher quality ones due to the sequential auction [33]-[35]. The simultaneous market clearing considers all of the A/S offers together in the energy supply cost function.

Reference [33] models the simultaneous market clearing as an Optimal Power Flow (OPF) problem, considering AC network constraints and pre-defined A/S requirements. The OPF problem is solved by relaxing the system constraints through Lagrange multipliers, from which the definitions for price of energy and A/S are defined. Reference [36] proposes a joint dispatch method to clear a multi-zonal electricity market. Hybrid sequential and joint market clearing is applied to solve the dispatch problem for ISO-NE [37]. However, consideration of unit start-up and shut-down costs, and determination of unit commitment states are not addressed in these studies, which are essential to reflect real costs. Simultaneous energy and A/S market clearing is modeled using an SCUC framework in [38]. The amount of A/S services is determined as an output of algorithm, through base case and contingency scenarios, without pre-defining the required reserve amounts. The modeling framework allows substitution of a higher quality service for a lower quality one to solve price reversal problem. These mentioned studies consider traditional generation resources with a deterministic approach. However, a number of emerging concepts should be considered which affect the scheduling of energy and A/S such as renewable generation resources and demand side management. These should be properly integrated to market clearing mechanisms in order to maximize the social benefit.

The effects of the wind uncertainty and penetration on network-constrained market-clearing problem is evaluated using a two-stage stochastic programming model in [39], in which the available wind power is the only uncertainty source. The wind, system load uncertainties are considered together in [40], in which a wind-load scenario tree is generated by discretization of distribution functions of forecast error. This approach might generate intractable scenario trees when the uncertainty of the available wind power for different sites could not be merged in a normal distribution, and when the equipment outage contingencies are considered on top of these uncertainties. There are other studies in the literature to evaluate the probability of occurrence of contingencies [41]-[44]. However, a framework is required to consider the contingencies and uncertainties together. This study considers the synchronous energy and A/S market clearing method with addressing the equipment outage contingencies using a deterministic *N-1* approach, and the wind power and system load forecast uncertainties in a stochastic framework.

DR is a tariff or program to encourage the change in electricity consumption of the end-use consumers in order to mitigate the load at time frames when high market price occurs or when the grid security is jeopardized [45]-[47]. DR can be motivated by either providing the end-user with time-varying rates or giving incentives to those costumers who are willing to participate a program to reduce their loads at times when the market-price for electric energy is too high or the system reliability is at stake. The former requires an advanced measurement and communication infrastructure in order to convey the real-time prices to end-use consumers, while the latter is more suitable for faster adaptation to current A/S markets. It is not only the advantage of those costumers receiving incentives by participating DR programs due to their load shifting activities, but also the other costumers are positively affected from the lowered market prices due to shifting demand. These programs also reduce the risk of exercising market power. The effects of the DR on electric energy markets are considered in a number of studies [48]-[52]. The DR concept should be addressed in order to model the response of the costumers to high energy prices in the market clearing process.

We propose a hybrid deterministic/stochastic model in which the equipment outage contingencies such as generating unit and transmission line outages are considered in a deterministic *N-1* contingency model, while the wind, load uncertainty is addressed through Monte-Carlo based scenarios in a standard two-stage stochastic programming model. To better understand the importance of the method, consider a system, with high wind injection. A scheduling without consideration of wind and system load forecast errors might be suboptimal and even infeasible if the actual values happen to be different from the forecasted values. Besides, the consideration of deterministic *N-1* contingencies would increase system security and allows the algorithm to find an optimal scheduling suitable for corrective actions after the considered equipment outages. A discrete bidding model for DRPs, using the MIP modeling techniques, is integrated in order to evaluate DR as a system reserve asset. To address the computational complexity, the energy and A/S market clearing problem is decomposed to generate a master problem to solve the UC and reserve schedules, and subproblems for considering network security for pre-selected *N-1* contingencies and uncertainty scenarios. The proposed method would be used by an ISO or a vertical utility to clear the energy and A/S markets as shown in the case studies, addressing the stochastic cost of security over the Monte-Carlo based wind, and load scenarios.

# CHAPTER 3

# OVERVIEW OF ELECTRICITY AND NG INFRASTRUCTURES IN TURKEY

The environmental and economic effects of energy production, delivery, and consumption have become more evident in recent decades leading to the consideration of energy, economics, and environment in a common platform. The use of natural gas and renewable energy was promoted in electric power industry due to their abundance and less adverse effects on environment. Although the rapid increase in fossil fuel prices has dampened the construction and the utilization of gas-fired electric power generating plants, NG is still considered as the most environmentally-friendly fuel source for generating bulk electric power in many countries.

Turkey has also exhibited a rising interest in utilizing NG which started in the mid-80s. The 22,108 million cubic meters (mcm) consumption in 2004 has increased to 35,100 in 2007 and is projected to increase to 67,000 mcm in 2020 which will exhibit a 203% increase. The electric energy production continues to be demonstrated as the primary source of utilization of NG [72]. Also domestic and industrial usage of NG is expected to increase with additions to transmission and distribution infrastructure.

This chapter takes a closer look at the current NG and electricity infrastructures and markets in Turkey and underlines the important aspects of interdependence between the two systems. In Sections 3.1 and 3.2; Turkish NG and electrical systems are reviewed and the correlations are highlighted. Interdependency issues are considered in Section 3.3. The concluding remarks, summarizing the chapter, are given in Section 3.4.

## *3.1 Natural Gas Sector Overview*

### 3.1.1 History of NG in Turkey

Turkey has been importing nearly all of its NG consumption from other countries due to its limited resources. The NG import was put into an agenda after a NG transportation agreement was signed with Russia (formerly the USSR) in 1986. Investments have been made to include other countries in such agreements with Turkey. The respective countries in the order of procurements are Russian Federation, Iran, Algeria, Nigeria, and Azerbaijan.

### 3.1.2 NG Consumption and Tariffs

Fig 3.1 depicts the NG usage with respect to potential users in Turkey. The growing increase confirms the vital role of NG as an energy source for Turkey. The electric energy generation sector utilizes more than 50% of this growing demand. The restructuring of Turkish electric energy system and the surge in the construction of combined cycle gas units by the private sector contributed to much of this demand growth. Such units exhibit improved efficiency, lower capital cost, reduced construction time, environmental compliance, and more expeditious permitting. The seasonality of demand is relatively high, especially in the residential sector which is an important gas consumer. Over 70% of the annual gas consumption in this sector is consumed between December and March [77]. Gas prices differ for industry and household consumers in various countries as reported by International Energy Agency (IEA) in Fig 3.2 and Fig 3.3.

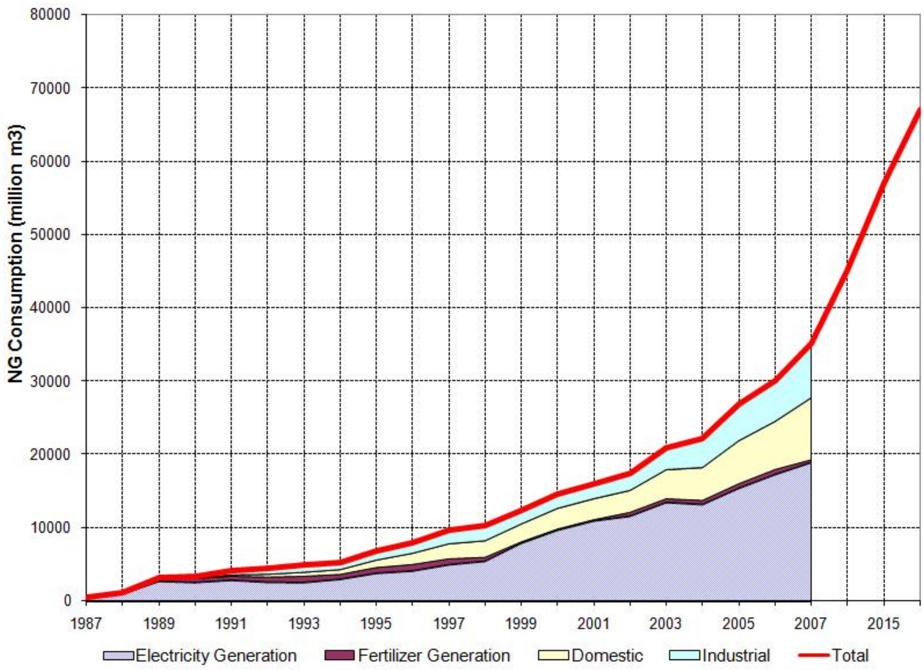


Fig 3.1. NG Usage in Turkey [72], [73]

In comparison with other IEA countries, Turkish gas prices for industrial consumers appear to be in the mid-range, whereas those for household consumers are in the lower range. This is the outcome of the uniform ceiling price when cross-subsidies were provided by industrial consumers to households. The prices for industrial consumers have increased since the late 1990s but not for household consumers which implies that cross-subsidies have increased [77].

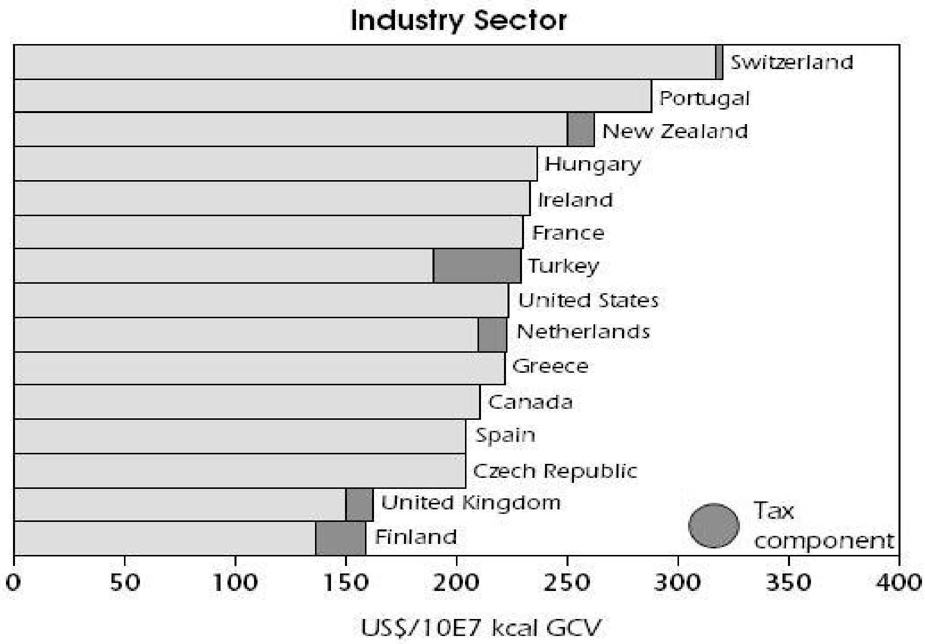


Fig 3.2. Industry sector gas prices in IEA countries

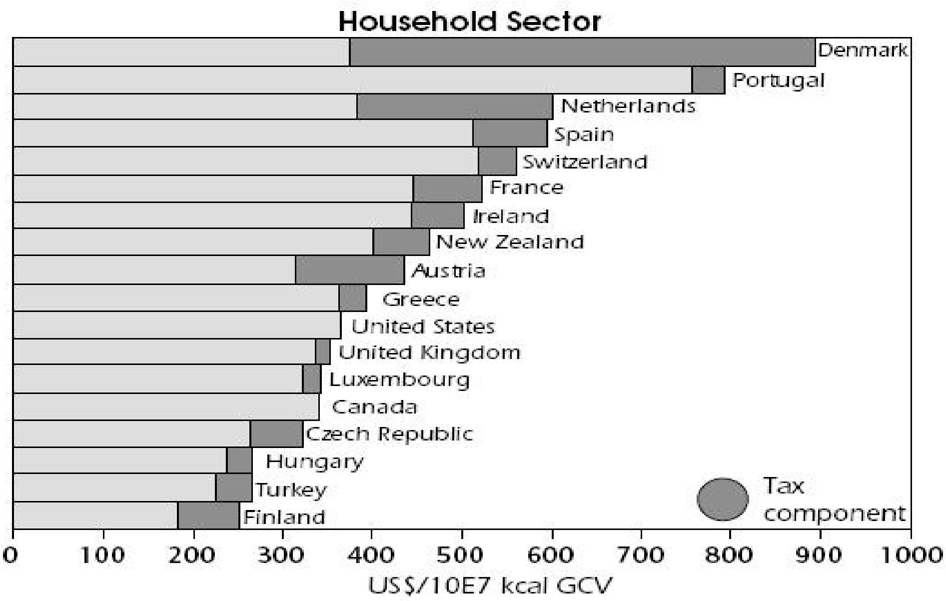


Fig 3.3. Household sector gas prices in IEA countries

### 3.1.3 NG Infrastructure

The transmission pipelines in Turkey are used for importing NG from Russian Federation (through Bulgaria) on the west, Iran, Azerbaijan and Turkmenistan on the east, as well as west side connections to Greece for transfer to European countries. Besides, efforts are made to extend NG pipelines within Turkey to satisfy the national demand. The total length of Turkish transmission and distribution pipelines reached 9,798 km, by the end of 2007. The capacity of transmission has increased in the northwest regions of the country as the industrial usage of NG intensifies. The NG transmission system of Turkey is as given in Fig 3.4, and major pipeline characteristics are given in Table 3.1 [77].

Approximately 75% of the world NG reserves are in the Russian Federation, Caspian Sea, and Middle Eastern countries in the region. Turkey's proximity to this extensive reserves and its role as a safe energy corridor to European consumption centers emphasize the importance of Turkey's NG transmission infrastructure for international trade purposes. The international NG projects of Turkey are given as:

- Turkey-Greece NG transmission pipeline is the first ring of the South European gas ring. The Italian market will accordingly have the opportunity to access the Caspian Sea gas.
- NABUCCO transit pipeline project which is expected to start its operation in 2013 with a capacity of 8.5 bcma.
- Azerbaijan-Turkey NG pipeline (Sahdeniz project)
- Liquefied NG (LNG) import terminal
- Trans-Adriatic pipeline project which will supply gas to Italy through the Albanian route and its extension to Ion-Adriatic project, which is planned to feed the West Balkan corridor, are scheduled to start operation by 2013 [71].

With respect to underground storage facilities for enhancing the NG supply security, the Silivri NG storage facility with 1.6 bcm capacity was established in 2007. Moreover, the engineering activity of a section of 1bcm of Tuz Lake NG underground storage facility is completed and the construction is in progress.

Electric power system represents a vital part for the NG infrastructure, which includes compressors, vanes, and pressure reducing and measurement stations, to carry on the described activities. Critical outages of electric power system components might create strong counter-effects on the domestic and international operations of NG infrastructures.

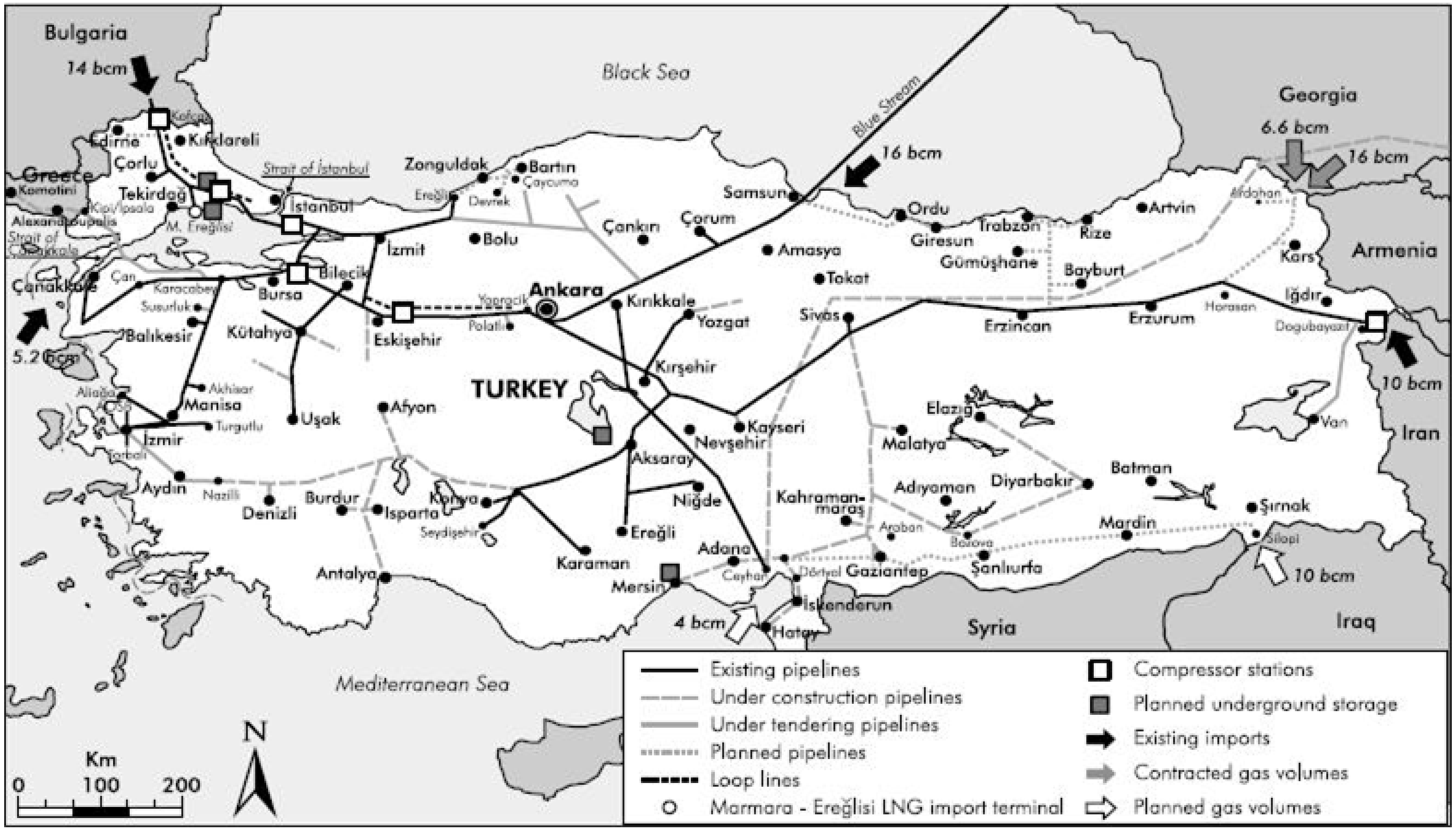


Fig 3.4. Turkish NG transmission system (source: BOTAS)

TABLE 3.1

NG PIPELINES IN TURKEY

| Pipelines | Length | Diameter | Date of operation |
|---|---|---|---|
| *Existing national pipelines* | | | |
| Main line Malkoçlar-Ankara | 842 km | 36 inches(")-24" | June 1987-Aug. 1988 |
| Pazarcık-Kdz. Eregli | 209 km | 24"-16" | January 1996 |
| Bursa-Çan | 208 km | 24"-8" | July 1996 |
| Çan-Çanakkale | 107 km | 12" | July 2000 |
| Eastern Anatolia main line | 1 491 km | 48"-40"-16" | December 2001 |
| Karacabey-Izmir | 241 km | 36" | April 2002 |
| Samsun-Ankara* | 501 km | 48" | January 2002 |
| *National pipelines under construction* | | | |
| Southern (Sivas-Mersin) | 565 km | 40" | |
| Sivas-Malatya | 168 km | 40" | |
| Malatya-Gaziantep | 182 km | 40" | |
| Gaziantep-Mersin | 215 km | 40" | |
| Konya-Izmir | 618 km | 40" | |
| Konya-Isparta | 217 km | 40" | |
| Isparta-Nazilli | 203 km | 40" | |
| Nazilli-Izmir | 198 km | 40" | |
| *Planned pipelines* | | | |
| Eastern Black Sea region | 308 km | 24"-12" | |
| Kdz. Eregli-Bartın | 141 km | 16"-12" | |
| Georgia border-Erzurum | 225 km | 48" | |
| Interconnector Turkey-Greece | 200 km | 36" | |

* The domestic part of the Blue Stream pipeline

### 3.1.4 NG Restructuring in Turkey

The NG industry in the world has been undergoing a significant restructuring with the introduction of competition, and expanded international trades [76]. Turkey has also taken steps to restructure its NG and electric industries since 2001 but the efforts on the establishment of a NG market has not been as successful as that in electrical energy market. The Petroleum Pipeline Corporation (BOTAS), which is a governmental organization, was a monopoly for import, transmission & distribution (urban areas excluded), trade and pricing until the enactment of 4646 NG Market Law (NGML) in 2001. However, progress in the first few years since the law was adopted has been quite slow. A supportive note is prepared by Energy Sector Management Assistance Program administered by the World Bank to assist policymakers by proposing a program of change which is aimed to enable Turkey to develop a modernized gas market structure by 2010 [79]. The restructuring of importing, wholesale trading, and transit functions of BOTAS is mainly addressed in the note. The incumbent BOTAS has started the process of transferring 4 bcm/year of its import contract signed in 1998 with GAZEXPORT, a subsidiary of Russian GAZPROM, to four private companies, which will end the BOTAS' monopoly on import activities [78].

## 3.2 *Electric Power Sector Overview*

### 3.2.1 Brief History

Turkish Electricity Authority (TEK), established in 1970, was a statutory monopoly until 1984. The participation of private sector starts in 1984 under different modes including Build-Operate-Transfer (BOT), Build-Own-Operate (BOO) and Transfer of Operating Rights (TOOR). In 1993, TEK was split into two state-owned companies including Turkish Electricity Generation-Transmission (TEAS) and Turkish Electricity Distribution Company (TEDAS). Finally TEAS was unbundled into three different companies responsible for different sub-sectors including EUAS (generation), TEIAS (transmission) and TETAS (wholesale) with Electricity Market Law issued in 2001. The unbundling of ownership will follow when the government proceeds with its privatization plan of other state-owned electricity sector companies, except for TEIAS. The electric energy procurement chain in Turkey is given in Fig 3.5. The new law also sets the stage for a new organization, the Energy Market Regulation Agency (EMRA), which will oversee the electric power and NG markets including setting tariffs, issuing licenses, and assuring competition.

### 3.2.2 Electricity Generation in Turkey

The total installed generation capacity of Turkey has reached 42.2 GW, and the total generating capacity has been 238.2 TWh by the end of year 2007. These values are expected to reach 78.2 GW and 378.2 TWh in 2016, including the proposed supplemental capacity investments [73].

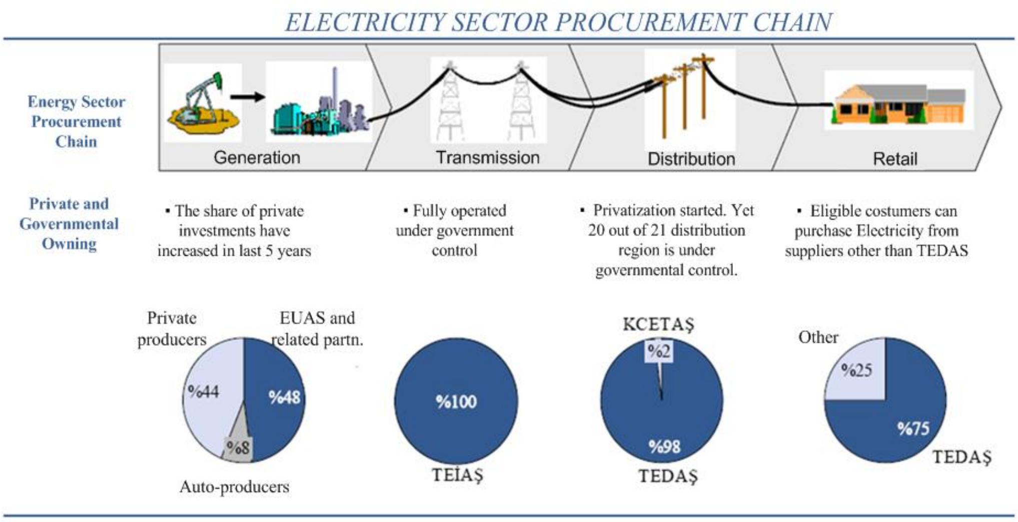


Fig 3.5. Electric Energy Procurement Supply Chain [75]

Electricity generation is divided into four main categories as: EUAS, private electric generation companies, auto-producers, and power plants subject to TOOR. Self generators are industrial companies which generate electricity for their own and their shareholder applications and they have the right to market the excess of generation. The share of private generation has grown in the last five years. The ratio of private investments in Turkey's total installed capacity is 44% by the end of 2008 as shown in Fig 3.5 [74]. EMRA has stated that a supply shortage will occur starting in 2012 when the total generation capacity is the sum of operating and licensed plants and those in construction phases. The capacity investment is addressed in the 2007 projection report [73].

### 3.2.3 Transmission and Distribution

Operation of transmission facilities in the country and planning of load dispatch and operation services is done by the government owned TEIAS. There are long distances between the main electricity generation and consuming areas. The main generation occurs in the eastern and southeastern parts of the Turkey relying on rich hydro generation capacities while the consumption concentrates in the northwestern part with large amounts of installed industrial load. The total length of transmission lines was 46,032.7 km in 2006 [80].

Turkey has interconnections with most of its neighboring countries, namely Bulgaria (400 kV), Azerbaijan (Nahceivan, 154 kV), Iran (154, 400kV), Georgia (220 kV), Armenia (220 kV), Syria (400 kV), Iraq (400 kV, operated at 154 kV) and Greece (400 kV). Turkey is not synchronously connected with neighboring systems but has actively pursued the synchronization of its network with the Union for the Co-ordination of Transmission of Electricity (UCTE) in Europe.

The privatization of TEDAS was initiated in 2004. The company is divided into 21 sub-regions and one of these regions is currently being operated privately with TOOR. Operating rights for distribution assets have been transferred to 20 newly established regional distribution companies as an arrangement for privatization. EMRA granted licenses and approved the tariffs of the companies. However, the privatization of distribution assets was postponed.

Distribution network losses are at 14.8% in Turkey which is more than twice that of OECD countries in 2007 [81]. Half of the losses are technical while the other half is theft. Rehabilitation of the existing network and investment in network operation tools, measurement, and telecommunication systems are necessary to improve reliability, reduce losses, and cope with network expansion needs.

### 3.2.4 Electricity Demand

The Net Total Electrical Energy Demand increased annually with an average of %8.07 since 2001, reaching a total of 143 GWh by the year 2006. The utilization of Electrical energy with respect to the sectors is given in Fig 3.6. Eligible costumers, having more than a specified amount of consumption, are free to purchase Electricity from companies other than TEDAS. Similar to the case in the NG, industry sector prices are high, when compared to the household sector. Electricity prices have been steady for both industrial and residential consumers since the mid-1990s. Although prices for industrial consumers were reduced by 5% in 2003, industrial electricity prices remain very close to the prices paid by households indicating cross-subsidies in favor of residential consumers.

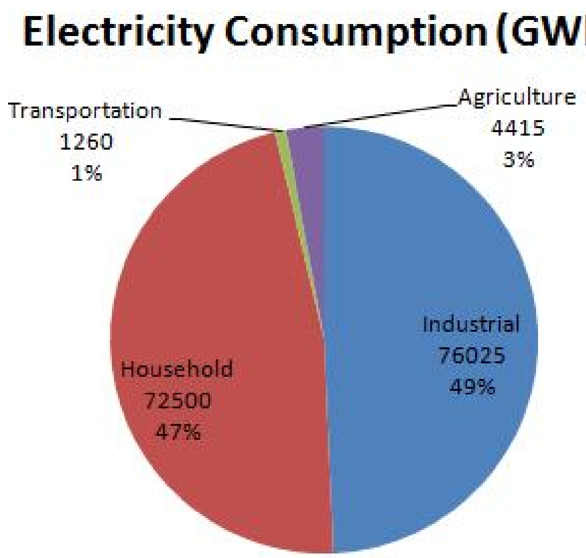


Fig 3.6. Electric Energy consumption in Turkey (Source: TEIAS)

The government expects prices to fall thorough the competition as the market evolves. The implementation of new tariff structure, which started in January 2005, includes the following principles:

- Costs not directly related to market operations must not be included.
- Cross-subsidies are not allowed. Instead, direct support will be given to the poor.
- Tariffs must be cost-reflective.
- Contribution of NG to Electricity Generation

NG is one of the most essential natural resources for electric power generation in Turkey. NG power plants have a total capacity of 14,204MW which is 33.7% of the country's 42,053MW installed electric generation capacity presently. This ratio is expected to be 30% in 2016. The expected growth of generation capacities with different resources is given as in Fig 3.7. In 2007, 48.5% of the total generated electric energy came from the NG power plants. This ratio is projected to be 41.2% in year 2016. This expectation rises to 45.43% in favor of NG powered plants if the minimum hydro resources are considered for 2016 [73].

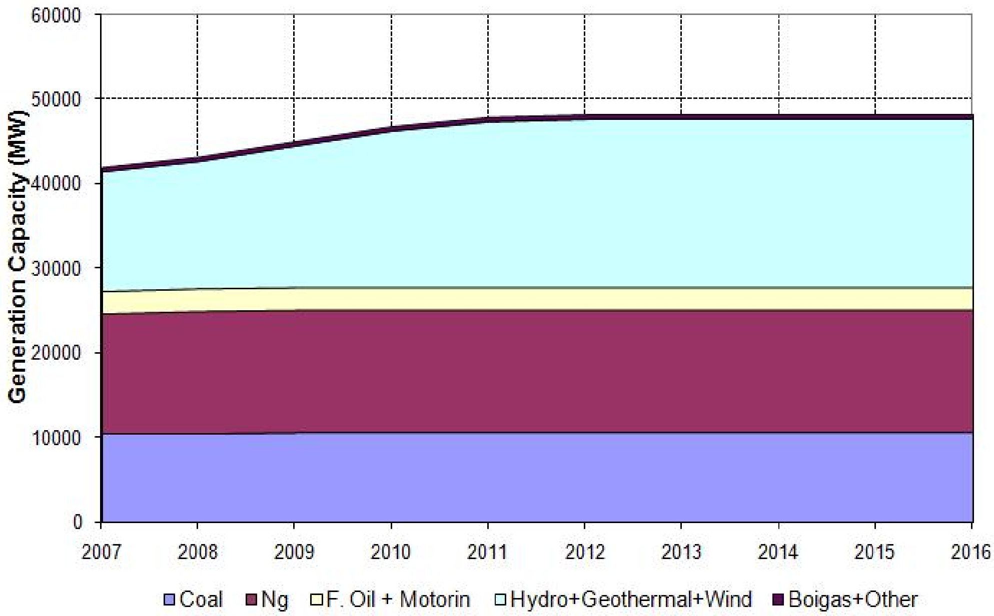


Fig 3.7. Power Generation Capacity in Turkey [75]

## *3.3 Concerns Related To Interdependence*

It is evident that electric power and NG infrastructures are strongly correlated. Electricity generation in Turkey is heavily dependent on NG and electricity supply operation will be affected by the availability, price, and security of NG supply. On the other side, the status of NG transmission system is defined by the availability of the electricity services. A reliable electricity generation, transmission and distribution system is crucial for the operation of NG infrastructure. The NG industry and market structure also affect the electricity generation since the electricity price would strongly depend on the NG price when 47.7% of plants are gas fired. These issues will be briefly described as follows.

### 3.3.1 Reliable Electric Energy for NG Infrastructure

The NG infrastructure in Turkey is of vital importance in satisfying the national demand and keeping the continuity of NG flow for international trade operations. However, NG transmission system relies on electrical system. Even though the gas valves are operated by pneumatic and manual equipment, the pressure reduction and metering stations (RMS), compressor stations, SCADA telemetering, and control and communication systems are operated by electric power. The effect of electric power outages on the NG infrastructure ought to be considered in particular at the northwestern region where intense industrial activities and a number of NG power plants are in place, and gateway pipelines to EU countries extend through Bulgaria and Greece. The NG pipeline interruption due to a severe electrical malfunction at that region will result in the country's inability to satisfy industrial demands and operate electric power plants with substantial financial losses due to interruptions in international NG trades.

### 3.3.2 Security of NG Supplies

Since the domestic gas production is very low in Turkey, the country imports nearly all of its consumption. Diversification of gas import sources is the government policy for enhancing the security of supply. Turkey mitigated the supply disruption of 15 mcm/day in 2006 on its eastern procurements by purchasing additional NG from the Blue-Stream pipeline [83]. TPAO, which is a government owned petroleum and NG exploration and production company, is also developing international projects to support the NG supply security. The seasonality of demand has been dealt with by the import flexibility, supply interruptions, and interruptible loads.

Only a small portion of NG power plants is multi-fuel which might not tolerate unscheduled NG flow outages. Gas storage facilities would make significant contribution to security. The NG market players in Turkey are expected to fulfill economic and reliability constraints under the 2001 NG Market Law. The law obliges gas importers and wholesalers to provide storage for 10% of their imported gas. Since the mandatory storage adds an extra cost in a competitive operation, storage facilities are to be dealt when considering alternative approaches such as more flexible supply contracts, interruptible costumers, and arrangement of dual fuel capability, where economically feasible.

### 3.3.3 Prices and Tariffs for NG and Electric Power Industries

Constant price tariff is in effect for both industries which constitutes cross-subsidies notably from industrial consumers to residential consumers and between different geographical areas. Cost-based pricing is essential for a healthy energy market in Turkey. Distorted prices can prevent the timely and efficient private sector investments causing inefficient energy markets.

### 3.3.4 Role of NG in the Expansion of Electricity Market

Since Turkey is geographically close to several NG producing countries, and infrastructure costs are not excessive, the market economics for NG are favorable to other natural resources in Turkey. National policies should be further developed to ensure that NG can compete equally with coal as well as hydro and other renewable resources in the electricity market, provided that there are no market distortions for favoring specific resources. In this regard, discrimination against NG within the context of newly established priority for relying heavily on renewable resources must be avoided [79].

### 3.3.5 Dependency of Electric Power on NG

It is evident that NG has had a huge share of the Turkish total generated electricity in 2007. This dependence creates considerable risks and opportunities that have to be properly analyzed. Diverse technical and financial issues will have to be considered. For instance, NG prices and availability determine electricity prices which introduce upward volatility in electricity prices in the event of NG supply shortages. The NG prices will affect the commitment, dispatch, and generation cost of gas-fired generating units.

The northwest line carrying an annual 14 bcm gas from Russia plays an important role for that part of Turkey. An interruption or pressure loss in the pipeline system may lead to a loss of multiple gas-fired electric generators intensified in the northwest which could dramatically reduce the supplied electric power and jeopardize the power system security. Although pipeline contingencies could be compensated by underground gas storage facilities as the backup for the NG supply to generation units, the power dispatch and pertinent electricity market decisions could be affected by NG pipeline constraints and gas storage shortfalls [11]. The analyses considering the existing and new underground facilities in the Eastern Anatolia mainline and Blue-Stream pipeline in the northwest pipeline have to be studied in order to evaluate the effect of NG outages on electric energy production and delivery.

### 3.3.6 NG Demand Projection and Contract Types

The efficient operation of NG markets is crucial to electricity market operations. Even though the long term contracts contribute to the security of NG supply, their effect on the feasibility and possibility of cheaper supplies would have to be properly considered. Turkey, through BOTAS, has accepted major gas market risks and associated contingent liabilities, mainly through long-term gas import contracts with Take-or-Pay (ToP) provisions. Extending to 2012, the over-contracting of NG imports by BOTAS, in relation to reduced outlook for domestic gas requirements, has created a continuing financial obligation and inflexibility in import and wholesale competition. Consider the situation in Blue-stream pipeline. The construction of pipeline was completed in December 2002 with an initial schedule for delivering 2 bcm of NG in 2003. However, in March 2003, Turkey halted NG imports through Blue Stream which invoked a clause in the contract allowing either party to stop deliveries for six months. Turkish authorities cited weak domestic demand, and declared their intentions of renegotiating the price and volumes of NG imports. After a suit was filed in Stockholm's International Arbitration court, the two sides came to an agreement in November 2003 and the NG supply to Turkey resumed in December 2003. The Blue Stream’s formal inauguration took place in November 2005 at a metering station in Samsun, Turkey.

The scenario analyses based on demand projections show that ToP NG contracts covers or even overhangs all of the national demand for likely projections [9]. Considering the retarding effects of the 2007-2008 financial crises on developing economies, Turkey may have unused NG from ToP contracts until 2012 which could potentially encumber Turkey liabilities ranging from $1-5billion due to unused NG. Even if the demand would cover the contracted ToP NG, the situation could put the country’s NG market in an inflexible position and reduce the possibility of seeking cheaper supply of NG such as purchases from spot markets. Turkey should make concerted efforts for developing a portfolio approach and identify more flexible contracts through spot, medium and long-term markets [7].

### 3.3.7 Restructuring of NG Industry

Efforts for the establishment of a competitive NG market and the reduction of state role in the NG sector have been in place since the 2001 NGML. BOTAS is nominated to be the transmission system operator that will be responsible for defining transmission costs and setting up third party access tariffs. In the future, when imports from parties other than BOTAS expand and import volumes increase, congestion may develop in infrastructures as seen in many other IEA member countries. The generating companies fed from the national NG pipeline would be adversely affected from possible congestion scenarios that are likely to increase the costs. Arrangements for establishing dual fuel capacity and storage facilities are to be considered by generation companies to mitigate the effects of congestion. Furthermore, market-based mechanisms such as auctioning should be developed for a fair allocation of interconnection capacity.

## 3.4 Summary

Turkey is on the initial stages for the establishment of NG and electricity markets. The start of restructuring processes in such industries dates back to 2001. However, the performance of processes is different and generally in favor of electricity market. The NG consumption as an energy source is high in Turkey with the maximum share occupied by the electric power industry which makes the electricity sector highly dependent on a secure and reliable NG infrastructure. NG infrastructure has a special significance for Turkey as an international trade mechanism which is due to the country's critical geographical position. So the NG infrastructure would require a secure electricity service for its reliable operation. The overview for both NG and electricity sectors are given in this chapter and the interdependencies of NG and electricity infrastructures of Turkey are addressed. The reliable operation of such infrastructures is crucial and coupled scenarios studying major electrical generation, transmission and NG equipment failures must be analyzed to examine and enhance the interdependence for Turkey.

# CHAPTER 4

# PROPOSED METHOD

The Electricity Markets are comprised of different entities as TSO, GENCO, TRANSCO, DISCO, RETAILCO, etc., each of which have their own individual objectives and responsibilities as described in Chapter 1. This study contributes to two different problems of two different market entities, namely GENCO's PBUC problem with the objective of maximizing profits and TSO's SCUC problem with the objective of minimizing social cost of electrical energy while maintaining security constraints.

GENCOs are privately owned companies that have generating assets with the objective of maximizing their profits. GENCOs perform scheduling and maintenance activities in order to fulfill this objective considering different time intervals as short-term (one day to one month), mid-term (one month to one year), and long-term (one year to several years). Long-term planning studies output investment decisions in order to determine the type and construction time of the new generating assets in several years horizon. The mid-term operation planning provides a basis for the optimal hourly bidding in a day-ahead market. The midterm operation planning will determine the optimal utilization of resources such as fuel, emission allowance, and natural water resources. The NG fired generating units access the fuel via a physical infrastructure; NG transmission system. This study integrates the linear NG transmission system model and contract constraints to the mid-term operation planning which is modeled as PBUC problem. Moreover, the uncertainties regarding to the market energy and A/S prices, water inflow resources, fuel availability and RES are considered in the stochastic framework. The MIP representation of BCs are also modeled as a financial hedging tool against real-time energy market volatilities.

TSOs are profitless entities to coordinate, control and monitor the operation of the power system. Generally, TSOs operate a power exchange market to clear the demand and generation at minimum cost while maintaining security by allocating A/S ahead of time. This study proposes a hybrid deterministic/stochastic framework to consider the *N-1* contingencies and wind, load uncertainties in the stochastic SCUC context. Besides the MIP based DRP bid model is introduced to enable the scheduling of demand management.

The detailed mathematical descriptions and proposed solution methods of the considered PBUC and SCUC problems are given in the following two subsections of this chapter respectively.

## 4.1 Stochastic PBUC Problem and Proposed Solution Methodology

The mathematical representation of the PBUC problem will be given in the first part of this section 4.1. The objective function and problem constraints concerning non-NG thermal, NG, cascaded hydro, pumped-storage and wind power units, NG transmission system and BCs, and risk will be given in detail. In the second part, the proposed solution methodology considering decomposition of the problem among individual units will be described.

### 4.1.1 Mathematical Model

#### 4.1.1.1 Objective Function

The proposed objective function (1) is to maximize the expected payoffs over all scenarios. The payoff of a scenario is defined as the difference between revenues and expenses. The revenue (3) is due to sales of energy, spinning reserves, and operating reserves by non-NG thermal (Coal, Fuel Oil), NG, cascaded hydro, pumped-storage hydro, and wind units and the income from BCs. The cost (4) includes that of i) fuel, startup, and shutdown for non-NG thermal units; ii) NG contracts, storage, startup and shutdown; iii) startup and shutdown for cascaded hydro units; iv) startup and shutdown for pumped-storage hydro units; v) penalty for defaulting on the scheduled generation delivery.

$$\text{Max } \sum_{s=1}^{NS} p_s \cdot PF_s \tag{1}$$

which is equivalent to

$$\text{Max: } \sum_{s=1}^{NS} p_s \cdot \{REVENUE_s - COST_s\} \tag{2}$$

where

$$\begin{aligned} REVENUE_s = \quad & \sum_{i=1}^{NCO} \sum_{t=1}^{NT} \left[\rho g_{ts} \cdot TP_{its} + \rho sr_{ts} \cdot SR_{its} + \rho or_{ts} \cdot OR_{its}\right] \\ & + \sum_{j=1}^{NNG} \sum_{t=1}^{NT} \left[\rho g_{ts} \cdot TP_{jts} + \rho sr_{ts} \cdot SR_{jts} + \rho or_{ts} \cdot OR_{jts}\right] \\ & + \sum_{l=1}^{NCM} \sum_{h=1}^{NH_l} \sum_{t=1}^{NT} \left[\rho g_{ts} TP_{hts} + \rho sr_{ts} \cdot SR_{hts} + \rho or_{ts} \cdot OR_{hts}\right] \end{aligned}$$

$$+\sum_{f=1}^{NPS}\sum_{t=1}^{NT}\left[\rho g_{ts}\cdot TP_{fts}+\rho sr_{ts}\cdot SR_{fts}+\rho or_{ts}\cdot OR_{fts}\right]$$

$$+\sum_{w=1}^{NW}\sum_{t=1}^{NT}\left[\rho g_{ts}\cdot TP_{wts}+\rho sr_{ts}\cdot SR_{wts}+\rho or_{ts}\cdot OR_{wts}\right]$$

$$+\sum_{z=1}^{NZ}R_{bc,z} \tag{3}$$

and

$$COST_s=\sum_{i=1}^{NCO}\sum_{t=1}^{NT}\left[\rho f_{its}\cdot F_{its}+SU_i+SD_i\right]$$

$$+\sum_{n=1}^{NGC}C_{ns}+\sum_{u=1}^{NGS}C_{us}+\sum_{j=1}^{NNG}\sum_{t=1}^{NT}\left[SU_{jts}+SD_{jts}\right]$$

$$+\sum_{l=1}^{NCM}\sum_{h=1}^{NH_l}\sum_{t=1}^{NT}\left[SU_{hts}+SD_{hts}\right]+\sum_{f=1}^{NPS}\sum_{t=1}^{NT}\left[SU_{fts}+SD_{fts}\right]$$

$$+\sum_{z=1}^{NZ}C_{pen,zs} \tag{4}$$

#### 4.1.1.2 Non-NG (Coal, Fuel-Oil) Thermal Units Constraints

a) Fuel consumption and emission allowance constraints for groups of thermal units:

$$\begin{aligned}&F_{\min,SGF}\le\sum_{i\in SGF}\sum_{t=1}^{NT}F_{its}\le F_{\max,SGF}\qquad\forall SGF,s\\&\sum_{i\in SGE}\sum_{t=1}^{NT}Em_{its}^{ET}\le Em_{\max,SGE}^{ET}\quad\forall SGE,s,ET=\{SO_2,NO_x\}\end{aligned} \tag{5}$$

The fuel consumption and emission of a generating unit are expressed as quadratic function. By introducing extra integer variables, they can be piecewise linearized, and included into a MIP model. Details are provided in Appendix A.

b) Energy and ancillary services supplied by thermal units:

Constraint (7) shows limits for energy, spinning and operating reserves supplied by thermal units.

$$\begin{aligned}&P_{its}+SR_{its}+ORu_{its}\le P_{\max,i}\cdot I_{its}\\&P_{\min,i}\cdot I_{its}\le P_{its}\\&SR_{its}+OR_{its}\le 10\cdot MSR_i\cdot I_{its}\qquad\forall i,t,s\end{aligned} \tag{7}$$

c) The relationship between startup and shutdown indicators:

$$yu_{its}-yd_{its}=I_{its}-I_{i(t-1)s}$$

$$yu_{its}+yd_{its}\le 1,\ \forall i,s,t \tag{8}$$

d) Ramping up/down constraints:

$$P_{its}-P_{(i-1)ts}\le yu_{its}\cdot P_{\min,i}+RU_i\cdot(1-yu_{its})$$

$$P_{(i-1)ts} - P_{its} \le yd_{its} \cdot P_{\min,i} + RD_i \cdot (1 - yd_{its}) \quad \forall i, s, t \tag{9}$$

e) Minimum on/off time constraints:

The equations for minimum on time are given first.

$$UT_i = \max\{0, \min[NT, (MU_i - TU_{i0}) \cdot I_{i0}]\} \quad \forall i$$

$$\sum_{t=1}^{UT_i} (1 - I_{its}) = 0 \quad \forall i, s$$

$$\sum_{m=t}^{t+MU_i-1} I_{ims} \ge MU_i \cdot yu_{its} = 0 \quad \forall i, s, t = UT_i + 1, \ldots, NT - MU_i + 1$$

$$\sum_{m=t}^{NT} I_{ims} - yu_{its} \ge 0 \quad \forall i, s, t = NT - MU_i + 2, \ldots, NT \tag{10}$$

Minimum off time equations are as follows.

$$DT_i = \max\{0, \min[NT, (MD_i - TD_{i0}) \cdot (1 - I_{i0})]\} \quad \forall i$$

$$\sum_{t=1}^{DT_i} I_{its} = 0 \quad \forall i, s$$

$$\sum_{m=t}^{t+MD_i-1} (1 - I_{ims}) \ge MD_i \cdot yd_{its} \quad \forall i, s, t = DT_i + 1, \ldots, NT - MD_i + 1$$

$$\sum_{m=t}^{NT} (1 - I_{ims} - yd_{its}) \ge 0 \quad \forall i, s, t = NT - MD_i + 2, \ldots, NT \tag{11}$$

#### 4.1.1.3 NG Units Constraints

a) Fuel consumption and emission allowance constraints for groups of NG units

b) Energy and ancillary services supplied

c) Minimum on/off time and ramping up/down constraints

These constraints are identical to those of the non-NG thermal units constraints, given above. In addition, the NG units are also subject to NG infrastructure constraints that are given in the next section.

#### 4.1.1.4 NG Contracts and Infrastructure Constrains

NG contracts are modeled as firm (take-or-pay) or interruptible contracts with NG suppliers. Firm NG contracts have fixed costs. Interruptible NG contracts are utilized if it is either economical or required to satisfy certain constraints. The cost of a firm NG contract *n* is specified as

$$C_{ns} = C_{0,n}\,, \ \forall n \in SFC, \forall s \tag{12}$$

An interruptible NG contract will have its own quantity and price. The cost of an interruptible NG contract *n* depends on the gas usage

$$C_{ns} = \rho_n \sum_{t=1}^{NT} F_{nts}\,, \ \forall n \in SIC, \forall s \tag{13}$$

The NG usage from a specific NG contract at a specific scenario $s$ and time $t$ is limited by the availability of specific NG contracts defined by an integer availability variable $UA_{nts}$.

$$F_{nts} \le F_{\max,nt} .UA_{nts} \,, \ \forall n, \forall t, \forall s \tag{14}$$

The NG usage from a firm contract $n$ is equal to the contracted amount since it is prepaid.

$$\sum_{t=1}^{NT} F_{nts} = F_{\max,n} \,, \ \forall n \in SFC, \forall s \tag{15}$$

The NG usage from an interruptible contract $n$ cannot exceed the yearly contracted limit.

$$\sum_{t=1}^{NT} F_{nts} \le F_{\max,n} \,, \ \forall n \in SIC, \forall s \tag{16}$$

Note that daily, weekly, and monthly contract limits may be included similarly. NG network constraints define the relationship between the gas flow and pressure. The linear network flow model used in [18] for considering constraints on pipelines, sub-areas, power plants, and units is adopted for the midterm stochastic model. The hourly and yearly constraints are considered in this section. The daily, weekly, and monthly limits can be included similarly. The total NG usage from a contract $n$ of pipeline $m$ at time $t$ in scenario $s$ is equal to the sum of separate NG usages by individual NG units using that contract.

$$F_{nmts} = \sum_{j \in SCT(n)} F_{jnmts} \,, \ \forall n, \forall m, \forall t, \forall s \tag{17}$$

A gas pipeline can be fed by several NG contracts. The total NG usage of pipeline $m$ at time $t$ in scenario $s$ is equal to the sum of NG usage from all such contracts.

$$F_{mts} = \sum_{n \in SPP(m)} F_{nmts} \,, \ \forall m, \forall t, \forall s \tag{18}$$

Generating units that are located far from NG pumping stations can only burn a certain percentage of available NG. Accordingly, a subarea is defined for the NG consumption of such units. The total NG usage at subarea $e$ of pipeline $m$ at time $t$ in scenario $s$ is equal to the sum of NG usages by individual NG units in that subarea.

$$F_{mets} = \sum_{j \in SSA(e)} F_{jmets} \,, \ \forall m, \forall e, \forall t, \forall s \tag{19}$$

An NG unit $j$ can be supplied from multiple contracts, multiple pipelines, and multiple NG storage facilities.

$$F_{jts} = \sum_{m=1}^{NPP} \sum_{n \in SPP(m)} F_{jnmts} + \sum_{u=1}^{NGS} \left( q_{juts}^{out} - q_{juts}^{in} \right), \ \forall j, \forall t, \forall s \tag{20}$$

where $q_{juts}^{out}$ and $q_{juts}^{in}$ are zero if the NG unit $j$ is not connected to any storage facilities. The total NG injected into or withdrawn from the storage by individual units sharing the same storage is given as

$$q_{uts}^{in} = \sum_{j \in SST(u)} q_{juts}^{in} \ , \ \forall u, \forall t, \forall s \tag{21}$$

$$q_{uts}^{out} = \sum_{j \in SST(u)} q_{juts}^{out} \ , \ \forall u, \forall t, \forall s \tag{22}$$

NG volume balance equation for storage facility $u$ is

$$V_{u(t+1)s} = V_{uts} + q_{uts}^{in} - q_{uts}^{out} \ , \ \forall u, \forall t, \forall s \tag{23}$$

The term $V_{uts}$ is the volume of the NG storage $u$ at time $t$ and scenario $s$. This term could be obtained using the initial volume and the net injection and withdrawal amounts at each time step starting from the initial time 0 to time ($t$-1) as

$$V_{uts} = \sum_{j \in SCT(u)} \sum_{\tau=1}^{t-1} (q_{ju\tau s}^{in} - q_{ju\tau s}^{out}) + V_{w(0)s} \tag{24}$$

NG storage volume constraint of storage facility $u$ is

$$V_{\min,u} \le V_{uts} \le V_{\max,u} \ , \ \forall u, \forall t, \forall s \tag{25}$$

Initial and final volumes of NG storage facility $u$ are

$$V_{u(0)s} = V_{0,u} \ , \ \forall u, \forall s \tag{26}$$

$$V_{u(NT)s} = V_{NT,u} \ , \ \forall u, \forall s \tag{27}$$

The total cost of NG withdrawal from storage facility $u$ is

$$C_{us} = \rho_u . \sum_{t=1}^{NT} q_{uts}^{out} \ , \ \forall u, \forall s \tag{28}$$

The NG usage of a unit $j$ is subject to the following hourly and yearly limits

$$F_{jts} \le F_{\max,jt} \ , \ \forall j, \forall t, \forall s \tag{29}$$

$$\sum_{t=1}^{NT} F_{jts} \le F_{\max,j} \ , \ \forall j, \forall s \tag{30}$$

NG units that belong to a specific power plant are subject to the following hourly and yearly limits

$$\sum_{j \in SPL(p)} F_{jts} \le F_{\max,p} \ , \ \forall p, \forall t, \forall s \tag{31}$$

$$\sum_{j \in SPL(p)} \sum_{t=1}^{NT} F_{jts} \le F_{\max,p} \ , \ \forall p, \forall s \tag{32}$$

The NG usage from pipeline $m$ is subject to following hourly and yearly limits

$$F_{mts} \le F_{\max,mt} \ , \ \forall m, \forall t, \forall s \tag{33}$$

$$\sum_{t=1}^{NT} F_{mts} \le F_{\max,m} \ , \ \forall m, \forall s \tag{34}$$

The NG usage at subarea $e$ is subject to following hourly and yearly limits

$$F_{mets} \le F_{\max,met}\ ,\ \forall m, \forall e, \forall t, \forall s \tag{35}$$

$$\sum_{t=1}^{NT} F_{mets} \le F_{\max,me}\ ,\ \forall m, \forall e, \forall s \tag{36}$$

#### 4.1.1.5 Cascaded Hydro Units Constraints

a) Energy and ancillary services constraints supplied by hydro units:

The limits for energy, spinning reserve, and operating reserves supplied by hydro units are the same as given in (7).

b) Water to Power Conversion:

The conversion is expressed by a head-dependent function $P_{hts} = \eta_h \cdot w_{hts} \cdot H_{hts} \quad \forall h, t, s$ in which the water head level $H_{hts}$ is a function of reservoir volume, $H_{hts} = H_{0,h} + \alpha_h \cdot v_{hts}$. Here, $H_{0,h}$ and $\alpha_h$ are constant terms related to reservoir *h* which are determined by the physical size of reservoirs. Thus the head-dependent water-to-power conversion function is given as:

$$P_{hts} = \eta_h \cdot w_{hts} \cdot (H_{0,h} + \alpha_h \cdot v_{hts}) \qquad \forall h, t, s \tag{37}$$

By introducing extra integer variables, (37) can be piecewise linearized and included in a MIP model. Details are provided in Appendix B.

Generating reserve quantity of hydro units

$$\begin{aligned} P_{hts} + SR_{hts} + OR_{hts} \le \\ \eta_h \cdot w_{\max,h} \cdot (H_{0,h} + \alpha_h \cdot v_{hts}) \end{aligned} \tag{38}$$

c) Operating regions (water discharge limits):

$$w_{\min,h} \cdot I_{hts} \le w_{hts} \le w_{\max,h} \cdot I_{hts} \tag{39}$$

d) Reservoir volume limits:

$$v_{\min,\, h} \le v_{hts} \le v_{\max,\, h} \tag{40}$$

e) Initial and terminal reservoir volume:

$$v_{h0s} = v_{0,h} \qquad v_{hNTs} = v_{NT,h} \tag{41}$$

f) Water balance constraint for cascaded hydro units:

$$\begin{aligned} v_{h(t+1)s} = v_{hts} + RC_h \cdot w_{d,h(t-\tau)s} \\ - w_{hts} + nw_{hts} - s_{hts} \end{aligned} \qquad 42)$$

where $w_{d,h(t-\tau)s}$ represents the delayed water discharge to hydro unit *j* from other hydro units,

$$\begin{aligned} w_{d,h(t-\tau)s} = [w_{1(t-\tau_1)s}\ \Lambda\ w_{h-1(t-\tau_{h-1})s} \\ 0 \quad w_{h+1(t-\tau_{h+1})s}\ \Lambda\ w_{NH_l(t-\tau_{NH_l})s}] \quad h \in CS_l \end{aligned} \tag{43}$$

g) Minimum on/off time and ramping up/down constraints of hydro units: These constraints are similar as given in (9)-(11).

#### 4.1.1.6 Pumped-storage Hydro Units Constraints

a) Water-to-power conversion

b) Reservoir volume limits

c) Initial and terminal reservoir volume

d) Minimum on/off time and ramping up/down

The above constraints are the same as those of cascaded- hydro units. In addition, we consider the following constraints.

e) Operating regions (water discharge limits)

$$\begin{aligned} & w_{\min g,f} \cdot I_{g,fts} \le w_{g,fts} \le w_{\max g,f} \cdot I_{g,fts} \\ & w_{pn,fts} = w_{pn,f} \cdot I_{pn,fts} \\ & I_{g,fts} + \sum_{o=1}^{NP_f} I_{po,fts} \le 1 \end{aligned} \tag{45}$$

f) Generation constraints

$$\begin{aligned} & P_{fts} = P_{g,fts} - \sum_{o=1}^{NP_f} P_{po,f} \cdot I_{po,fts} \\ & P_{\min g,fts} \cdot I_{g,fts} \le P_{g,fts} \le P_{\max g,fts} \cdot I_{g,fts} \end{aligned} \tag{46}$$

g) Water balance constraint

$$v_{f(t+1)s} = v_{fts} - w_{g,fts} + \sum_{o=1}^{NP_f} w_{po,f} \cdot I_{pn,fts} \tag{47}$$

h) Energy and ancillary services offered to spot markets

$$SR_{p,fts} = \sum_{o=1}^{NP_f} SR_{po,f} \cdot I_{po,fts} \tag{48}$$

i) Generation reserve offered by a pumped-storage unit

$$\begin{aligned} & P_{g,fts} + SR_{g,fts} + ORu_{fts} \le \\ & \qquad \eta_k \cdot w_{\max g,f} \cdot (h_{0,f} + \alpha_f \cdot v_{fts}) \cdot I_{g,fts} \end{aligned} \tag{49}$$

#### 4.1.1.7 Wind Unit Constraints

**a)** The nonlinear wind speed to power conversion curve: After processing this nonlinear relationship, $P_{\psi,wts}$ is given as input to the PBUC algorithm.

$$P_{\psi,wts}(\psi_{wts}) = \begin{cases} 0 & \text{if } \psi_{wts} < v_{\mathrm{CI},w} \\ 0.5 c_{\mathrm{p},w} \cdot \rho_{\mathrm{air},w} \cdot A_w \cdot (\psi_{wts})^3 & \text{if } v_{\mathrm{CI},w} \le \psi_{wts} < v_{\mathrm{R},w} \\ P_{\mathrm{R},w} & \text{if } v_{\mathrm{R},w} \le \psi_{wts} < v_{CO,w} \\ 0 & \text{if } \psi_{wts} \ge v_{\mathrm{CO},w} \end{cases} \quad \forall w, \forall s \tag{50}$$

b) The wind generation is subject to

$$I_{wts} \cdot P_{\min,w} \le P_{wts} \le I_{wts} \cdot P_{\psi,wts}(\psi_{wts}) \;\; \forall k\,,\; \forall s \tag{51}$$

#### 4.1.1.8 Bilateral Contracts

A BC can be either physical or financial; the former indicates that the power transacted bilaterally is generated at and consumed by a pair of given network buses. A financial contract could be transacted by an external entity [32]. The proposed BC characteristics include:

1) $NZ$: 52 weeks for one year study;

2) $E_{bc,z}$: BC for period $z$;

3) $\rho_{bc}$: BC price ($/MWh) over the contract length;

4) $\rho_{pen}$: BC penalty price ($/MWh) over the contract length.

The BC energy $E_{bc,z}$ is subject to

$$E_{bc,\min} \le E_{bc,z} \le E_{bc,\max} \;\; ,\forall z \tag{52}$$

A flexible $E_{bc,z}$ in (27) can be adjusted by a GENCO for profit by following seasonal load variations. A flat case shown in the case studies is represented by $E_{bc,min} = E_{bc,z} = E_{bc,max}$. The revenue $R_{bc,z}$ is paid to the GENCO prior to period $z$ as

$$R_{bc,z} = \rho_{bc} . E_{bc,z} \;\; , \forall z \tag{53}$$

GENCO can offer its excess energy to the real-time market. This concept is included in the first three terms of (3). If the GENCO fails to deliver its BC, it would make a penalty payment as represented by the last term of (4). The deficient energy is

$$E_{def,zs} = \max\{0, (E_{bc,z} - E_{del,zs})\}, \;\; \forall z\,,\; \forall s \tag{54}$$

$E_{del,zs}$ is the delivered BC energy that will be further discussed in the next subsection. The deficient BC term in the MIP formulation is introduced by using an external binary variable $W$, where

$$0 \le E_{def,zs} - [E_{bc,z} - E_{del,zs}] \le M \cdot [1 - W_{zs}]$$

$$0 \le E_{def,zs} \le M \cdot W_{zs} \;\; , \forall z\,, \forall s \tag{55}$$

Here $M$ is a large positive number and $W_{zs}$ is the binary index to indicate whether there is a contract deficiency at scenario $s$ and contract period $z$. That is $W_{zs}$ is equal to 1 when $E_{bc,z} < E_{del,\, zs}$, otherwise it is 0. The deficiency penalty $C_{pen,\, zs}$ is the product of deficient energy and the penalty price as

$$C_{pen,zs} = \rho_{pen} . E_{def,zs} \;\; , \forall z \;\; , \;\; \forall s \tag{56}$$

At the optimal solution, one of the constraints in (57) would be binding since $E_{def,zs}$ has a cost impact and (54) would be satisfied. Since the deficiency penalty is only considered in the objective function, (57) would replace (55).

$$[E_{bc,z} - E_{del,zs}] \le E_{def,zs}, \quad 0 \le E_{def,zs}, \ \forall z, \ \forall s \tag{57}$$

#### 4.1.1.9 Coordination of Units for BC

A number of generating units among a GENCO's generation assets are chosen to satisfy the BC energy. A portion of the hourly generation are allocated for BC, which sums up to represent the delivered BC as

$$\begin{aligned} &\sum_{i\in SBC}\sum_{t\in ST_z} P_{bc,its} + \sum_{j\in SBC}\sum_{t\in ST_z} P_{bc,jts} + \sum_{h\in SBC}\sum_{t\in ST_z} P_{bc,hts} \\ &\quad + \sum_{k\in SBC}\sum_{t\in ST_z} P_{bc,kts} + \sum_{w\in SBC}\sum_{t\in ST_z} P_{bc,wts} = E_{del,zs} \end{aligned}, \forall z, \forall s \tag{58}$$

If wind units are only considered in the coordination, the first four terms on the left hand side of (58) will be zero. The sum of BC power and power offered to the real-time market is the total power generation of a unit at time $t$ under contract period $z$ and scenario $s$. This condition is given for a NG unit in (59), but it also applies to cascaded hydro and wind units.

$$P_{bc,jts} + TP_{jts} = P_{jts}, \ \forall z, \forall s, \ \forall t \in ST_z \tag{59}$$

#### 4.1.1.10 Risk Constraints

The stochastic formulation described above is a risk-neutral model that is only concerned with the optimization of expected payoff. However, a GENCO may also be concerned with its risk. A GENCO would set a target payoff $T_0$, and the risk associated with its decision is measured by the failure to meet the target. That is, if the payoff for a scenario is larger than the target, the associated downside risk is zero; otherwise, it is the difference between the payoff and its target as

$$RISK_s = \max\{0, T_0 - PF_s\}, \ \forall s \tag{60}$$

The expected downside risk should be lower than a target risk,

$$\sum_{s=1}^{NS} p_s . RISK_s \le \overline{EDR} \tag{61}$$

The risk constraints are further discussed in [53].

### 4.1.2 Proposed Solution Methodology

#### 4.1.2.1 Decomposition procedure

The original problem is decomposed into subproblems for non-NG thermal, NG, hydro, pumped-storage, wind units, and coordination units which are grouped together to satisfy a

BC. The unit status indicators are defined for each scenario separately. Bundle constraints were utilized to force the undistinguishable scenarios to have the same rendered decision variables, namely unit status indicators [32]. In this study, the unit status indicators are the same for every scenario. This formulation removes the necessity of using bundle constraints at the expense of a longer solution time since the decomposition is not among scenarios. The removal of bundle constraints reduces the number of Lagrangian multipliers and simplifies the updating of multipliers.

#### 4.1.2.2 Decoupling expected downside risk constraint

The expected downside risk constraint (61) is the only coupling constraint among different types of generating units. The constraint can be decoupled by relaxing it into the objective function by using the Lagrangian multiplier $\gamma_s$. With the constant terms dropped, we have

$$Min \sum_{s=1}^{NS} p_s \cdot \left(-PF_s + \gamma_s.RISK_s\right) \tag{62}$$

Considering the definition of downside risk (60), we have

$$Min \sum_{s=1}^{NS} p_s \cdot \left(-PF_s + \gamma_s.\max\{0, T_0 - PF_s\}\right) \tag{63}$$

If the payoff of a scenario *s* is higher than the targeted payoff,

$$-PF_s + \gamma_s.\max\{0, T_0 - PF_s\} = -PF_s \tag{64}$$

Otherwise,

$$-PF_s + \gamma_s.\max\{0, T_0 - PF_s\} = -(1+\gamma_s)PF_s + \gamma_s.T_0 \tag{65}$$

(64) can be viewed as a special case of (65) where $\gamma_s = 0$. After relaxing the risk constraint, we proceed by decomposing different unit types down to single unit problems.

#### 4.1.2.3 Decoupling constraints among non-NG thermal units

The non-NG thermal unit subproblem is given in (66). Fuel allocation and emission allowance are considered by using Lagrange relaxation [53]. The non-NG thermal unit subproblem is further decomposed into single non-NG thermal unit *i* subproblem in (67).

$$Min\left\{\sum_{i=1}^{NCO}\sum_{t=1}^{NT}\sum_{s=1}^{NS}\left\{\begin{array}{l} p_s \cdot (1+\gamma_s) \cdot \left[\begin{array}{l} -(\rho g_{ks} \cdot TP_{its} + \rho sr_{ts} \cdot SR_{its} \\ +\rho or_{ts} \cdot OR_{its}) + SU_{its} + SD_{its} \end{array}\right] \\ + p_s \cdot \left[\rho f_{its}.F_{its}\right] \end{array}\right\}\right.$$

$$+ \sum_{gf=1}^{NFG} p_s \cdot \left\{\begin{array}{l} \lambda_{\max gf,s} \cdot (\sum_{i \in SGF} \sum_{t=1}^{NT} F_{its} - F_{\max gf}) - \\ \lambda_{\min gf,s} \cdot (\sum_{i \in SGF} \sum_{t=1}^{NT} F_{its} - F_{\min gf}) \end{array}\right\}$$

$$+\sum_{ge=1}^{NEG}\sum_{ET}p_s\cdot\left\{\lambda_{\max ge,s}^{ET}\cdot(\sum_{i\in SGE}\sum_{t=1}^{NT}Em_{its}^{ET}-Em_{\max ge}^{ET})\right\}\Bigg\} \tag{66}$$

$$Min\left\{\sum_{t=1}^{NT}\sum_{s=1}^{NS}\left\{\begin{array}{l}p_s\cdot(1+\gamma_s)\cdot\begin{bmatrix}-(\rho g_{ks}\cdot TP_{its}+\rho sr_{ts}\cdot SR_{its}\\+\rho\, or_{ts}\cdot OR_{its})+SU_{its}+SD_{its}\end{bmatrix}\\+p_s\cdot(\rho f_{its}+\lambda_{\max\ gf,s}-\lambda_{\min\ gf,s})\cdot F_{its}\end{array}\right\}\right\},\ \forall i$$

$$\left.\sum_{ET}\lambda_{\max ge,s}^{ET}\cdot\sum_{t=1}^{NT}p_s\cdot Em_{its}^{ET}\right\} \tag{67}$$

### 4.1.2.4 Hydro subproblems for each catchment

In order to avoid the decomposition of coupling constraints among hydro units in one catchment, the hydro subproblems for each catchment given in (68) are solved.

$$Min\left\{\sum_{h=1}^{NH_l}\sum_{t=1}^{NT}\sum_{s=1}^{NS}p_s.(1+\gamma_s).\left\{\begin{array}{l}-\begin{bmatrix}\rho g_{ts}\cdot TP_{hts}+\rho sr_{ts}\cdot SR_{hts}\\+\rho or_{ts}\cdot OR_{hts}\end{bmatrix}\\+SU_{hts}+SD_{hts}\end{array}\right\}\right\},\ \forall l \tag{68}$$

### 4.1.2.5 Subproblems for each Pumped-storage unit

The pumped- storage hydro unit subproblem is given as

$$Min\left\{\sum_{t=1}^{NT}\sum_{s=1}^{NS}p_s.(1+\gamma_s).\left\{\begin{array}{l}-\begin{bmatrix}\rho g_{ts}\cdot TP_{fkts}+\rho sr_{ts}\cdot SR_{fts}\\+\rho or_{ts}\cdot OR_{fts}\end{bmatrix}\\+SU_{fts}+SD_{fts}\end{array}\right\}\right\},\ \forall f \tag{69}$$

### 4.1.2.6 Subproblems for each wind unit

The wind unit subproblem is given as

$$Min\left\{\sum_{t=1}^{NT}\sum_{s=1}^{NS}p_s.(1+\gamma_s).\left\{-\begin{bmatrix}\rho g_{ts}\cdot TP_{wts}+\rho sr_{ts}\cdot SR_{wts}\\+\rho or_{ts}\cdot OR_{wts}\end{bmatrix}\right\}\right\},\ \forall w \tag{70}$$

### 4.1.2.7 Subproblems for each NG unit

The NG infrastructure constraints are coupling constraints that are relaxed by applying the Lagrangian relaxation method. The subproblems for NG units are given in (71), which is further decomposed into subproblems for each NG unit in (72). In (71), the first term is the expected revenue of selling energy and ancillary services minus the startup and shutdown costs for NG units. The second and third terms are the cost of NG usage from contracts and NG withdraw from storage facilities respectively. The fourth to seventh terms represent plant (32), pipeline (34), subarea (36), and max contract for NG usage constraints (15) and (16) respectively. The last three terms relax upper and lower volume limits (25) and final volume (27) for gas storage facilities, respectively. The group fuel and emission allowance constraints are omitted for NG units for the sake of simplicity. However, these constraints may be relaxed as in done (66) and (67).

$$
Min\left\{\sum_{j=1}^{NNG}\sum_{t=1}^{NT}\sum_{s=1}^{NS} p_s.(1+\gamma_s)\cdot\left\{\begin{array}{l}-\begin{bmatrix}\rho g_{ts}\cdot TP_{jts}+\rho sr_{ts}\cdot SR_{jts}+\\ \rho or_{ts}\cdot OR_{jts}\end{bmatrix}\\ +SU_{jts}+SD_{jts}\end{array}\right\}\right.
$$

$$
+\sum_{m=1}^{NPP}\sum_{t=1}^{NT}\sum_{n\in SPP(m)}\sum_{j\in SCT(n)}\sum_{s=1}^{NS} p_s.\rho_n.F_{jnmts}
$$

$$
+\sum_{w=1}^{NGS}\sum_{t=1}^{NT}\sum_{j\in SST(w)}\sum_{s=1}^{NS} p_s.\rho_w.q_{jwts}^{out}
$$

$$
+\sum_{p=1}^{NPL}\sum_{s=1}^{NS} p_s\cdot\left\{\lambda_{\max,ps}\cdot\left(\sum_{j\in SPL(p)}\sum_{t=1}^{NT}F_{jts}-F_{\max,p}\right)\right\}
$$

$$
+\sum_{m=1}^{NPP}\sum_{s=1}^{NS} p_s\cdot\left\{\lambda_{\max,ms}\cdot\left(\sum_{n\in SPP(m)}\sum_{j\in SCT(n)}\sum_{t=1}^{NT}F_{jnmts}-F_{\max,m}\right)\right\}
$$

$$
+\sum_{e=1}^{NSA}\sum_{s=1}^{NS} p_s\cdot\left\{\lambda_{\max,es}\cdot\left(\sum_{j\in SSA(e)}\sum_{t=1}^{NT}F_{jts}-F_{\max,e}\right)\right\}
$$

$$
+\sum_{m=1}^{NPP}\sum_{n\in SPP(m)}\sum_{s=1}^{NS} p_s\cdot\left\{\lambda_{\max,ns}\cdot\left(\sum_{j\in SCT(n)}\sum_{t=1}^{NT}F_{jnmts}-F_{\max,n}\right)\right\}
$$

$$
+\sum_{u=1}^{NGS}\sum_{s=1}^{NS} p_s\cdot\left\{\lambda_{\max,us}\cdot\left(\sum_{t=1}^{NT}V_{uts}-V_{\max,u}\right)\right\}
$$

$$
-\sum_{u=1}^{NGS}\sum_{s=1}^{NS} p_s\cdot\left\{\lambda_{\min,us}\cdot\left(\sum_{t=1}^{NT}V_{uts}-V_{\min,u}\right)\right\}
$$

$$
\left.+\sum_{u=1}^{NGS}\sum_{s=1}^{NS} p_s\cdot\lambda_{NT,us}\cdot\left(V_{uNTs}-V_{NT,u}\right)\right\} \tag{71}
$$

$$
Min\left\{\sum_{t=1}^{NT}\sum_{s=1}^{NS}\left\{\begin{array}{l}\left[p_s\cdot(1+\gamma_s)\cdot\begin{bmatrix}-(\rho g_{ts}\cdot TP_{jts}+\rho sr_{ts}\cdot SR_{jts}+\\ \rho or_{ts}\cdot OR_{jts})+SU_{jts}+SD_{jts}\end{bmatrix}\right]\\ +\left[p_s\cdot\left(\lambda_{\max,ps}+\lambda_{\max,es}\right)\cdot F_{jts}\right]\end{array}\right\}\right\}
$$

$$
+\sum_{m=1}^{NPP}\sum_{t=1}^{NT}\sum_{n\in SPP(m)}\sum_{s=1}^{NS} p_s.\rho_n.F_{jnmts}+\sum_{u=1}^{NGS}\sum_{t=1}^{NT}\sum_{s=1}^{NS} p_s.\rho_u.q_{juts}^{out}
$$

$$
+\sum_{m=1}^{NPP}\sum_{s=1}^{NS} p_s\cdot\left\{\lambda_{\max,ms}\cdot\left(\sum_{n\in SPP(m)}\sum_{t=1}^{NT}F_{jnmts}\right)\right\}
$$

$$+\sum_{m=1}^{NPP}\sum_{n\in SPP(m)}\sum_{s=1}^{NS}p_s\cdot\left\{\lambda_{\max,ns}\cdot\left(\sum_{t=1}^{NT}F_{jnmts}\right)\right\}$$

$$+\sum_{u=1}^{NGS}\sum_{s=1}^{NS}p_s\cdot\left\{\left(\lambda_{\max,us}-\lambda_{\min,us}\right)\cdot\left(\sum_{t=1}^{NT}\sum_{\tau=1}^{t-1}(q_{ju\tau s}^{in}-q_{ju\tau s}^{out})\right)\right\}$$

$$+\sum_{u=1}^{NGS}\sum_{s=1}^{NS}p_s\cdot\left\{\lambda_{NT,us}\cdot\left(\sum_{\tau=1}^{NT-1}(q_{ju\tau s}^{in}-q_{ju\tau s}^{out})\right)\right\}\Bigg\}\Bigg\} \tag{72}$$

#### 4.1.2.8 Subproblems for Each BC Coordination

In order to avoid decomposition of constraints (55) and (57) which are related to BC, the separate unit problems are solved as a single problem, for those units which participate in coordination to satisfy the BC energy. For instance if one wind unit and a hydro-catchment are coordinated to satisfy the BC, the related problem is as given in (73).

$$Min\left\{\begin{array}{c}\sum_{h=1}^{NH_l}\sum_{t=1}^{NT}\sum_{s=1}^{NS}p_s.(1+\gamma_s).\left\{\begin{array}{l}-\begin{bmatrix}\rho g_{ts}\cdot TP_{hts}+\rho sr_{ts}\cdot SR_{hts}\\ +\rho or_{ts}\cdot OR_{hts}\end{bmatrix}\\ +SU_{hts}+SD_{hts}\end{array}\right\}\\ +\sum_{t=1}^{NT}\sum_{s=1}^{NS}p_s.(1+\gamma_s).\left\{-\begin{bmatrix}\rho g_{ks}\cdot TP_{wts}+\rho sr_{ts}\cdot SR_{wts}\\ +\rho or_{ts}\cdot OR_{wts}\end{bmatrix}\right\}\\ -\sum_{z=1}^{NZ}R_{bc,z}+\sum_{z=1}^{NZ}C_{pen,z}\end{array}\right\} \tag{73}$$

#### 4.1.2.9 Consideration of the Uncertainities

Four types of uncertainties are considered for representing

- Market prices for energy and ancillary services,
- Natural water inflows,
- NG interruptible contracts' outages,
- Wind power

When simulating natural inflows, it is assumed that the water inflow to a reservoir in period $t$ is independent of inflow to other reservoirs. However, it is dependent on its $(t-1)$ inflow. That is, the water inflow to a reservoir follows a discrete Markov chain which is independent of inflows to other reservoirs. Two stochastic and distributed models, i.e., log- normal and Pearson type-3, are used to describe river inflows [54], [55]. In this study, the log-normal distribution model is used to simulate the average natural water inflow in seasonal, monthly, or weekly periods. In order to simulate the hourly water inflow profile, we consider $Z_{h,k,t}=Z_{h,k}+\zeta_{h,k,t}$ where $\zeta_{h,k,t}$ is a normal distributed random number with zero mean and 10% deviation $N(0,0.1)$ and

$$Z_{h,k} = \rho_{h,k-1} \cdot Z_{h,k-1} + (1-\rho_{h,k-1}^{2})^{1/2} \cdot \varepsilon_{h,k} \tag{74}$$

where $Z_{h,k}$ is the unit Normal random variable $N(0,1)$. $\rho_{h,k-1}$ is the time serial correlation coefficient for inflows in periods $k-1$ and $k$. $\varepsilon_{h,k}$ are independent identically random variables following the distribution of $N(0,1)$. Also, $Z_{h,k} = (w_{h,k} - \mu_{h,k}) / \sigma_{h,k}$ where $w_{h,k} = \ln(y_{h,k})$. $y_{h,k}$ is the natural water inflow to reservoir $h$ in period $k$, and $\mu_{h,k}$ and $\sigma_{h,k}$ are mean and standard deviation of $w_{h,k}$, respectively. Also,

$$\rho_{h,k-1} = \frac{\sum_{t=1}^{T}(w_{h,k,t} - \overline{w}_{h,k}) \cdot (w_{h,k-1,t} - \overline{w}_{h,k-1})}{\sqrt{\sum_{t=1}^{T}(w_{h,k,t} - \overline{w}_{h,k})^2 \cdot \sum_{t=1}^{T}(w_{h,k-1,t} - \overline{w}_{h,k-1})^2}} \tag{75}$$

where $\overline{w}_{h,k}$ is the average river inflow for reservoir $h$ in period $k$ (each period covers $T$ time span)

The time series method introduced in [56],[57] is used to simulate uncertainties of energy and ancillary services prices. The Ornstein-Uhlenbeck mean reversing process is employed to simulate price uncertainties of energy and ancillary services [53], [58].

A two-state continuous-time Markov chain model is used to represent available and unavailable states of NG interruptible contract gas, considering interruptions due to additional demand from residential costumers under severe winter conditions [32], [61], [69]. The interruptible NG contract gas availability is simulated for a specified time period with the assumption that contract gas availability is at available state at the beginning of period. Assume the steady state availability of the interruptible gas contract $n$ of pipeline $m$ is $p_n$ and its unavailability is $q_n = 1 - p_n$. The interruption rate of an interruptible NG contract is calculated as given below:

$$\frac{(\text{mean interrupted time})}{(\text{mean available time}) + (\text{mean interrupted time})}$$

It is obvious that the ratio is closely correlated with the weather conditions. This ratio could be calculated using historical data, namely the interruption periods due to weather conditions. Using $\chi_n$ and $\beta_n$, we represent the restore and interruption rates for the contract $n$.

The associated conditional probabilities for interruptible gas contract are as given as follows:

$$p(UA_t = 1 | UA_{t0} = 1) = p_n + q_n . e^{-(\chi_n + \beta_n).(t-t_0)}$$

$$p(UA_t = 0 | UA_{t0} = 1) = q_n - q_n . e^{-(\chi_n + \beta_n).(t-t_0)}$$

$$p(UA_t = 1 | UA_{t0} = 0) = p_n - p_n . e^{-(\chi_n + \beta_n).(t-t_0)}$$

$$p(UA_t = 0 | UA_{t0} = 0) = q_n + p_n . e^{-(\chi_n + \beta_n).(t-t_0)} \quad (76)$$

We use $\{UA_{nts}, t=1,\dots, NT\}$ in the Monte-Carlo simulation to simulate interruptible gas contract availabilities in which $UA_{nts} = 1$ indicates that the contract $n$ is available at time $t$ at scenario $s$, while $UA_{nts} = 0$ indicates otherwise. For the simulation of $UA_{nts}$ , it should be started from a known initial condition and using the given probabilities above, simulation of the NG availability for contract $\pi$ for the study interval should be done. Fig 4.1 depicts the NG availability simulation.

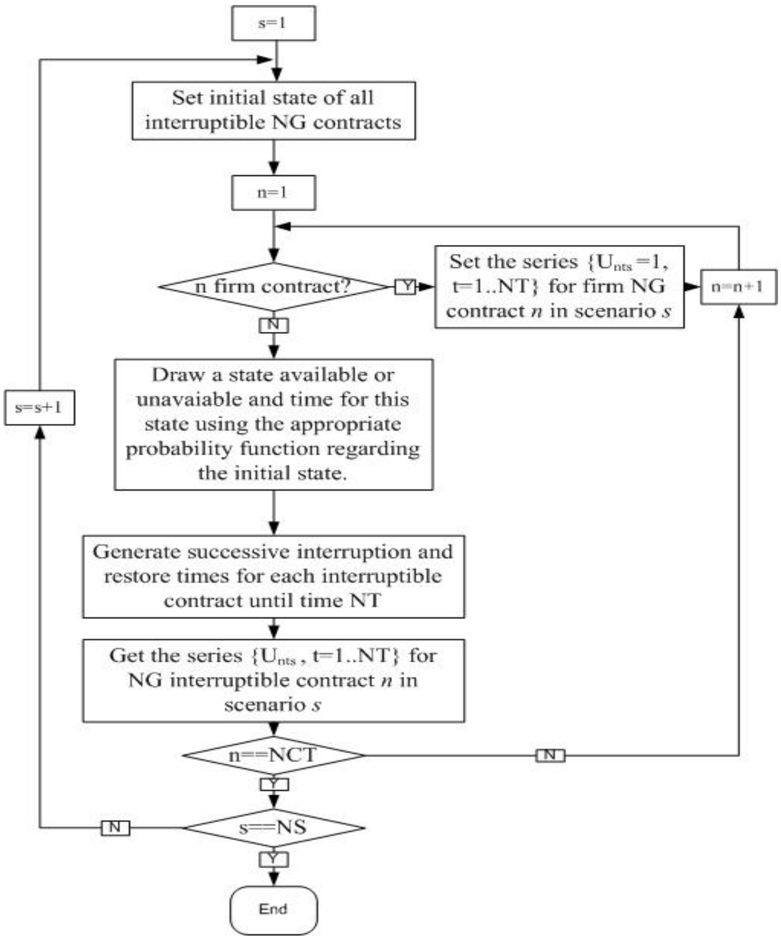


Fig 4.1. Flowchart of NG interruption simulation

In order to simulate the wind uncertainty, the method proposed in [59] is utilized. Auto-regressive moving average (ARMA) series is used for the modeling of forecast errors. The wind speed forecasts and ARMA parameters are assumed to be available for the wind units. The forecast errors are simulated using the ARMA series with known parameters and added to the forecasted wind speed to obtain the wind speed for a specific scenario. The ARMA(1,1) series is used to model wind speed forecast errors as described below.

$$X_0 = 0, \qquad Z_0 = 0$$
$$X_k = \phi \cdot X_{k-1} + Z_k + \theta \cdot Z_{k-1}$$
$$W_k = W_{f,k} + X_k \tag{77}$$

where $X_k$ is the wind speed forecast error in k-hour forecast, $Z_k$ is the random Gaussian variable with zero mean and standard deviation $\sigma_k$, $N(0, \sigma_k)$. For $k \geq 2$ the variance of the $X_k$ in ARMA(1,1) model is given as in (78).

$$V_k = \sigma_z (\phi^{2(k-1)} + (1+\theta^2 + 2\phi\theta)\sum_{i=1}^{k-1}\phi^{i-1}) \tag{78}$$

The standard deviation of the forecast error is given as $\sigma(X_k) = \sqrt{V_k}$. The Monte Carlo simulation method is used to generate wind scenarios. The wind forecast and three Monte Carlo weekly wind power simulations are depicted in Fig 4.2.

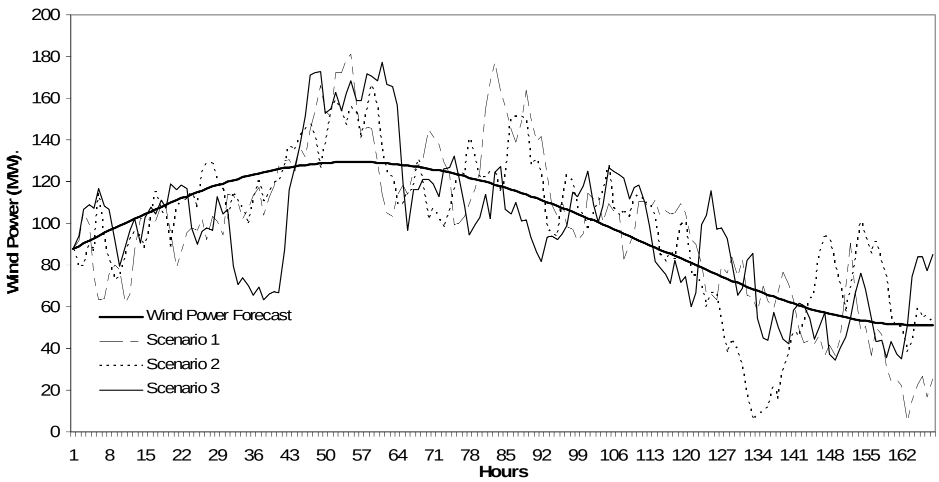


Fig 4.2 Wind power forecasts and Monte Carlo simulations

A low-discrepancy Monte Carlo method, represented by Latin Hypercube, is used to generate a set of scenarios. The Latin Hypercube sampling method will generate evenly distribution random numbers in an arbitrary number of dimensions with a single sample in each axis-aligned hyperplane. Thus a relatively smaller number of samples are used to reach the same convergence [56]. The scenarios consider market price, natural water inflow uncertainties, NG interruptible contract gas interruptions, and wind power uncertainties.. Accordingly, a GENCO will include certain circumstances in the decision model by assigning probabilities to scenarios. Using stochastic programming, a probability $p_s$ is assigned to each scenario that reflects the possibility of its occurrence.

Computational requirements for the scenario-based stochastic programming depend on the number of scenarios. The scenario reduction can reduce the computational time by eliminating scenarios with very low probabilities and bundling scenarios that are very close in terms of statistical metrics. This technique will achieve a goodness-of-fit tradeoff between computation speed and results accuracy [60]. Probabilities for all initial scenarios generated by the Monte Carlo method are the same. However, after scenario reduction, new probabilities will be reassigned by the reduction process. Details can be seen in [61].

#### *4.1.2.10* Proposed Solution Steps

The algorithm flowchart is shown in Fig 4.3. The subproblems for non-NG thermal units, NG units, cascaded hydro units, pumped-storage units, wind units and coordinated units for BC are solved in parallel when the coupling risk constraint is relaxed. Each subproblem related to an individual unit is solved to maximize the expected payoff of all scenarios in the entire study horizon. For the NG unit subproblem in particular, coupling constraints are checked for constraints on NG contracts, pipelines, plants, subareas, and gas storage. The Lagrangian multipliers are updated using the subgradient method and iterations continue until the difference between the objective functions in two consecutive iterations is smaller than a predefined threshold and an optimal or suboptimal solution is reached. After the solution of individual unit subproblems, the risk is calculated. If the risk aversion limit is met, the optimal solution is calculated. Otherwise, the Lagrangian multipliers $\gamma_s$ is updated for the risk inequality constraint (60) and returned to recalculate individual unit subproblems. The risk Lagrangian multipliers are initially set to zero for all scenarios and updated using the subgradient method afterwards [53],[61],[62], [67].

The target risk and profit are essential factors, which could impact the convergence of the algorithm. A GENCO might calculate the factors based on the following steps:

1) The problem is solved by assuming an initial target profit and without considering risk constraints. The proposed algorithm would calculate the appropriate expected risk. Otherwise, go to step 2 if the risk is not within the GENCO's tolerance.

2) The proposed algorithm is implemented with risk constraints to calculate the optimum profit. If the target profit is too high and the target risk is not attainable, the GENCO would decrease its target profit and repeat this step.

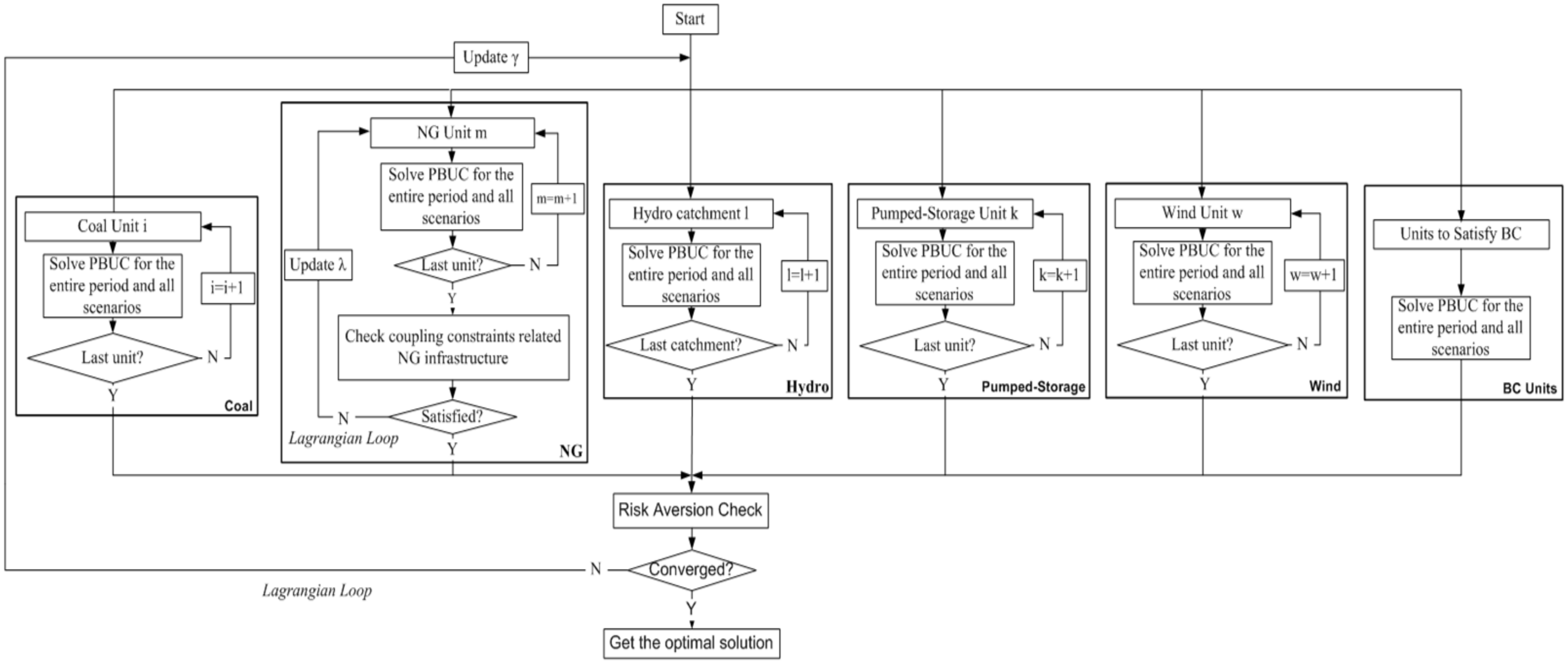


Fig 4.3. Flowchart of the midterm stochastic hydrothermal scheduling

## 4.2 Hybrid Deterministic/Stochastic SCUC Problem and Proposed Solution Methodology

The mathematical representation of the SCUC problem will be given in the first part of this section. The objective function will be described and problem constraints concerning base case and *N-1* contingency, wind power generation and system load uncertainty will be described. In the second part solution methodology based on Benders Decomposition will be explained in detail.

### 4.2.1 Mathematical Model

#### 4.2.1.1 Objective Function

There are three major summation terms in the objective function. The first major term is composed of base case generation fuel cost, the allocation of ancillary service capacities, and startup and shutdown costs. The second major term is the capacity allocation cost of demand response. The last major term is the expected cost composed of the generation fuel cost due to deployment of spinning and operating reserves, energy cost of deployment of DRP reserves, and cost of involuntary load shedding for wind, load uncertainty scenarios. Linear representation of the fuel cost is given in Appendix A. The scenarios are organized in a manner that *s=1* to *NC* represent the *N-1* contingencies and *s=NC+1* to *NS* represent the wind and load uncertainties.

$$\min \sum_{t=1}^{NT} \left\{ \sum_{i=1}^{NG} \begin{bmatrix} F_{c,i}(P_{it0}) \\ + F_{SR,i}(SR_{u,it}) + F_{SR,i}(SR_{d,it}) \\ + F_{OR,i}(OR_{u,it}) + F_{OR,i}(OR_{d,it}) \\ + SU_{it} + SD_{it} \end{bmatrix} \right.$$
$$+ \sum_{r=1}^{NDR} C_{DRR,rt}$$
$$\left. + \sum_{s=\mathrm{N}C+1}^{NS} p_s \left\{ \begin{aligned} & \sum_{i=1}^{NG} (F_{c,i}(P_{its}) - F_{c,i}(P_{it0})) \\ & + \sum_{r=1}^{NDR} C_{EDRR,rts} + \sum_{d=1}^{ND} VOLL_d \cdot l_{dts} \end{aligned} \right\} \right\} \tag{79}$$

It is appropriate to breakdown the problem variables into two parts in the two-stage stochastic programming context namely: first stage and second stage variables [65].

- The first stage variables: Commitment states ($I_{,it}$), base case power generations ($P_{it0}$ ,$P_{wt0}$),and scheduled spinning and operating reserves from units ($SR_{u,it}$, $SR_{d,it}$, $OR_{u,it}$, $OR_{d,it}$) and DRPs ($DRR_{rt}$) for each hour $t$,

- The second stage variables: Scenario power generations ($P_{SPIN,its}$, $P_{its}$, $P_{wts}$), deployed spinning and operating reserves from units ($SR_{its}$, $OR_{its}$) and deployed DRPs ($DRR_{rts}$), and involuntary load shedding ($l_{dts}$) for each scenario $s$ and hour $t$

As seen from major terms one and two of (79), the first stage variables have to be determined prior to the realization of the uncertainties. This is the reason why these variables' costs are considered with a probability of one. The cost terms related with the second stage variables of a wind, load uncertainty scenario $s$ is multiplied with the probability of the scenario $p_s$, to obtain the expected social cost function, as seen in the third major term of (79), since they are realized once the uncertainty is revealed. It should be noted that only the wind, load uncertainties are considered (i.e. $s= NC+1$ to $NS$) for the calculation of expected social cost in the third major term since the $N$-$1$ contingencies are considered in a deterministic manner. The objective function is subject to base case and $N$-$1$ contingency and wind, load uncertainty scenario constraints as given in (85)-(95). The non-spinning operating reserves are not considered in this study since these will increase the computational complexity due to the consideration of extra unit commitment variables and related coupling constraints.

#### 4.2.1.2 DR Model

DRPs are market entities that combine individual consumers who are willing to offer DR and bid considering the aggregated demand capacity. The bid should be in a discrete form since the DRP has an accumulated demand response of the end-users which is not continuously controllable. The DR bid is assumed to have two parts: 1) the capacity cost of reserve, and 2) the energy cost of reserve if the scheduled DR is deployed by the ISO. The model is formulated using MIP formulation to fit the SCUC model. (80)-(81) represent the scheduled DRR amount from DRP $r$ at time interval $t$ and the related capacity cost respectively. It should be noted that the $q^0_r$ should be greater than the minimum required amount determined by the ISO. (82) and (83) give the actual utilized DRR from DRP $r$ under scenario $s$ at time interval $t$.

$$DRR_{rt} = q_r^0 U_{rt}^0 + \sum_{k=1}^{NQ_r} \lambda_r^k U_{rt}^k \qquad \forall r,\ \forall t \tag{80}$$

$$C_{DRR,rt} = cc_{rt}^0 q_r^0 U_{rt}^0 + \sum_{k=1}^{NQ_r} cc_{rt}^k \lambda_r^k U_{rt}^k \quad \forall r,\ \forall t \tag{81}$$

$$DRR_{rts} = q_r^0 u_{rts}^0 + \sum_{k=1}^{NQ_r} \lambda_r^k u_{rts}^k \quad \forall r,\ \forall t,\ \forall s \tag{82}$$

$$C_{EDRR,rts} = ec_{rt}^0 q_r^0 u_{rts}^0 + \sum_{k=1}^{NQ_r} ec_{rt}^k \lambda_r^k u_{rts}^k \qquad \forall r,\ \forall t,\ \forall s \tag{83}$$

$$\lambda_r^k = q_r^k - q_r^{k-1} \ \forall r \tag{84}$$

The integer variable $U^k_{rt}$ is equal to one if the discrete DR offer point $k$ of the DRP $r$ is scheduled at time $t$, and $u^k_{rts}$ is equal to one if that point is actually deployed under scenario $s$ at time $t$. Fig 4.4 depicts an example for the proposed DR bid structure. Consider the DRP $r$ gives a bid composed of five discrete DR amounts in MW and related unit prices in \$/MW. Consider that the "x" marks denote that the discrete DR offer point $k$ is scheduled (i.e. $U^0_{rt}$, $U^1_{rt}$, $U^2_{rt}$, $U^3_{rt}$=1, and $U^4_{rt}$=0), and the "+" marks denote that the discrete DR offer point $k$ is deployed under scenario $s$ (i.e. $u^0_{rt}$, $u^1_{r}=1_t$ and $u^2_{rt}$, $u^3_{rt}$, $u^4_{rt}$=0). Extra integer variables, to ensure the DR offers with lower price are scheduled and deployed first, are not needed, since the offer-price curve is monotonically increasing. The reason for that is the demand for electricity decreases as its price increases [2].

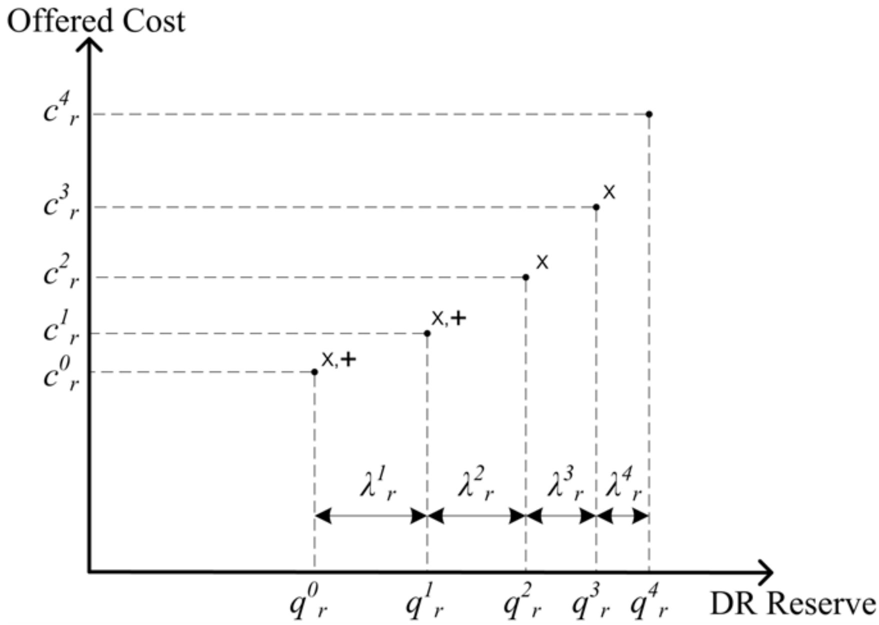


Fig 4.4.. Discrete DR bid curve and scheduling, and deployment decisions. The "x" marks denote that the discrete point k is scheduled, and the "+" marks denote that it is deployed under scenario s

### 4.2.1.3 Base Case Constraints

Power balance equation for base case is given in (85). Load shedding is not allowed for the base case, since the consumers would fully utilize the available generation capacity. The wind power constraints (50) and (51) given in Section 4.1.1.7 are also considered for wind units.

$$\sum_{i=1}^{NG} P_{it0} + P_{wt0} = \sum_{d=1}^{ND} P_{D,dt0} \qquad \forall t \tag{85}$$

Unit generation and reserve constraints

$$P_{it0} + SR_{u,it} + OR_{u,it} \le P_{\max,i} \cdot I_{it}$$

$$P_{it0} - SR_{d,it} - OR_{d,it} \geq P_{\min,i} \cdot I_{it}$$

$$0 \leq SR_{u,it} \leq SR_{\max,i}$$

$$0 \leq SR_{d,it} \leq SR_{\max,i}$$

$$0 \leq OR_{u,it} \leq OR_{\max,i}$$

$$0 \leq OR_{d,it} \leq OR_{\max,i} \quad \forall i, \forall t$$

$$0 \leq DRR_{rt} \leq DRR_{\max,r} \quad \forall r, \forall t$$

$$0 \leq P_{wt0} \leq P_{\psi,wt0} \qquad \forall w, \forall t \tag{86}$$

Ramping up and down limits and Minimum on/off time limits are as given below. The start-up and shut-down indicators *yu* and *yd* are as defined in (8).

$$P_{it0} - P_{(i-1)t0} \leq yu_{its} \cdot P_{\min,i} + RU_i \cdot (1 - yu_{its})$$

$$P_{(i-1)t0} - P_{it0} \leq yd_{its} \cdot P_{\min,i} + RD_i \cdot (1 - yd_{its}) \quad \forall i,t \tag{87}$$

Minimum on/off time limits are as given in (10) and (11)

Fuel and emission limits related to the thermal units can be added as in [66]. The generalized network constraints refer to the network security constraints under base case and contingencies and uncertainty scenarios. The open form of the generalized network constraints given by (88) is explained in Appendix C.

$$C_{net}(P_{it0}, P_{wt0}) \leq 0 \quad , \forall t \tag{88}$$

#### 4.2.1.4 *N-1* Contingency and Wind, Load Scenario Constraints

(89) and (90) ensure that the system load under a scenario *s* is in balance with the hydrothermal unit generations, deployed generation reserves, DRRs, and involuntary load shedding.

$$\sum_{i=1}^{NG} P_{its} + \sum_{r=1}^{NDR} DRR_{rts} + \sum_{d=1}^{ND} l_{dts} + \sum_{w=1}^{NW} P_{wts} = \sum_{d=1}^{ND} P_{D,dts} \qquad \forall t, \ \forall s \tag{89}$$

$$P_{its} = P_{it0} + SR_{its} + OR_{its} \qquad \forall i, \ \forall t, \ \forall s \tag{90}$$

The deployed reserves in a scenario *s* are limited by the scheduled capacities. The wind power generation in scenario *s* at time is limited by the available wind power.

$$-SR_{d,it} \leq SR_{its} \leq SR_{u,it} \qquad \forall i, \ \forall t, \ \forall s$$

$$-OR_{d,it} \leq OR_{its} \leq OR_{u,it} \qquad \forall i, \ \forall t, \ \forall s$$

$$-DRR_{d,rt} \leq DRR_{rts} \leq DRR_{u,rt} \quad \forall r, \ \forall t, \forall s$$

$$0 \leq P_{wts} \leq P_{\psi,wts} \qquad \forall w, \forall t, \forall s$$

$$0 \leq l_{dts} \leq l_{dt,\max} \qquad \forall d, \forall t, \forall s$$

$$l_{dts} = 0 \quad \forall d \text{ , } \forall t \text{ , } s = \{1,..., NC\} \tag{91}$$

Note that the involuntary load shedding variables are set to zero for the first *NC N-1* contingency scenarios, since they are treated deterministically. Ramping limits for hydrothermal unit power generations under scenario *s* is given as follows

$$P_{its} - P_{(i-1)ts} \leq yu_{its} \cdot P_{\min,i} + RU_i \cdot (1 - yu_{its})$$

$$P_{(i-1)ts} - P_{its} \leq yd_{its} \cdot P_{\min,i} + RD_i \cdot (1 - yd_{its}) \quad \forall i, s, t \tag{92}$$

The above mentioned constraints are enforced for the N-1 contingency and wind, load uncertainty scenarios (i.e. *s=1,...,NS*). However, there are extra constraints that have to be considered for the *N-1* contingency scenarios (i.e. *s=1,...,NC*). The system load balance is defined as the total demand minus the allowable system imbalance $\partial$ once an equipment outage contingency occurs as given in (93). The amount of system imbalance is defined by the type of the contingency, and this is the maximum value that the system frequency stays inside acceptable range once the contingency occurs [66]. The spinning reserve of generating units would be available after the contingency occurs. The spinning generating reserve is considered for supplying the load immediately after the occurrence of contingencies in (93) and (94). Notice that DR is not considered for these equations, since the effect of sudden load reduction might not necessarily be in favor of the frequency stability.

$$\sum_{i=1}^{NG} P_{IMB,its} + \sum_{w=1}^{NW} P_{wts} \geq \sum_{d=1}^{ND} P_{D,dt0} - \partial_s \quad \forall s \in \{1,..., NC\} \text{ , } \forall t \tag{93}$$

$$P_{IMB,its} = P_{it0} + SR_{its} \quad \forall i \text{ , } \forall s \in \{1,..., NC\} \text{ , } \forall t \tag{94}$$

The network constraints are enforced under scenario *s* as follows

$$\mathbf{G} \ (P_{its}, P_{wts}, SR_{its}, OR_{its}, DRR_{rts}, l_{dts}) \leq 0 \qquad \forall t \text{ , } \forall s \tag{95}$$

### 4.2.2 Proposed Solution Methodology

#### 4.2.2.1 Decomposition of the Original Problem

The original problem is an MIP problem given by the objective function (79), subject to constraints (85)-(95). It would only be practical to solve the given problem directly with a MIP solver for limited system sizes. However, for large systems and greater number of contingencies and wind, load uncertainties, the problem might be intractable due to the increased size of constraints. Benders decomposition is applied to the original problem to obtain a master UC and reserve scheduling problem and network subproblems related with each scenario considering *N-1* contingencies and uncertainty scenarios concerning wind power generation and system load. Mathematical Description of Benders Decomposition is given in Appendix D. Master problem excludes the network constraints (88), (95), while considering Benders cuts sent from the network check subproblems. These subproblems check network security under base case and equipment outage contingencies and uncertainty scenarios, using the assigned variables from the master problem solution. The details of the master UC problem and the network subproblems are given as follows.

#### 4.2.2.2 Master UC and Reserve Scheduling Problem

The master UC problem is obtained by taking out the network check constraints from the original problem. Besides, it includes the network cuts coming from the base case and scenario network check subproblems, as seen in the last two equations of (96). The master problem includes all of the first and second-stage variables described in Section 4.2.2.1. The description of the master problem is given as follows.

min (79)

s.t.

Constraints (85)-(87), (89)-(94)

$$C_{net}(P_{it0}, P_{wt0}) \leq 0 \qquad \forall t$$

$$C_{net}(P_{its}, P_{wts}, DRR_{rts}, l_{dts}) \leq 0 \qquad \forall t, \forall s \tag{96}$$

#### 4.2.2.3 Network Check Subproblems

The dc network check subproblems ensure that the transmission line flow limits are not violated under the base case and considered *N-1* contingency and wind, load uncertainty scenarios, for each hour. Those network subproblems get the values of the variables assigned from the master problem and detect flow violations, and finally send cuts to the master UC problem related with the violation hours. The explicit problem representation is given as follows:

$$Minimize \quad v(\hat{\mathbf{y}}) = \mathbf{1}^{\mathbf{T}}\mathbf{s}_{\mathbf{1}} + \mathbf{1}^{\mathbf{T}}\mathbf{s}_{\mathbf{2}} \tag{97o}$$

$$\mathbf{B}'\boldsymbol{\theta} + \mathbf{B}_{\Delta}\Delta = \mathbf{A}\hat{\mathbf{P}}_{\mathbf{G}} + \mathbf{W}\hat{\mathbf{P}}_{\mathbf{W}} + \mathbf{R}\hat{\mathbf{P}}_{\mathbf{DRR}} - \mathbf{D}(\mathbf{P}_{\mathbf{D}} - \hat{\mathbf{P}}_{\mathbf{LS}}) \qquad \rightarrow \quad \mathbf{u}^{\mathbf{r}} \tag{97a}$$

$$PL_c = \frac{\theta_{b1} - \theta_{b2} - \Delta_c}{x_c}, \ \forall c \in STX \tag{97b}$$

$$PL_c - s_{1,c} \leq PL_{c,\max}, \ \forall c \in STX \tag{97c}$$

$$PL_{c,\min} \leq PL_c + s_{2,c}, \ \forall c \in STX \tag{97d}$$

$$\Delta_{c,\min} \leq \Delta_c \leq \Delta_{c,\max}, \ \forall c \in STX \tag{97e}$$

$$s_{1,c}, s_{2,c} \geq 0, \ \forall c \in STX \tag{97f}$$

The bold characters mean that the variable is a matrix or a vector. In the upper equations **B'** (NBxNB) is the DC power flow matrix composed of the inverses of the line reactances, $\mathbf{B}_{\Delta}$

(NBxNPH) is the phase shifter transformers incidence matrix, $\boldsymbol{A}$ (NBxNG) is the non-wind generators incidence matrix, $\boldsymbol{W}$ (NBxNW) is the wind generators incidence matrix, $\boldsymbol{R}$ (NBxNDR) is the DRP incidence matrix, $\boldsymbol{D}$ (NBxND) is the load incidence matrix. $\boldsymbol{\theta}$(NB), $\Delta$(NPH), $\hat{\mathbf{P}}_{\mathbf{G}}$ (NG), $\hat{\mathbf{P}}_{\mathbf{W}}$ (NW), $\hat{\mathbf{P}}_{\mathbf{DRR}}$ (NDR), $\mathbf{P}_{\mathbf{D}}$ (ND), $\hat{\mathbf{P}}_{\mathbf{LSS}}$ (ND) are the bus voltage angle, phase shifting transformer setting, non-wind generation, wind generation, DRP, demand and load shedding vectors respectively.

This problem is solved for base case and scenario *s,* consisting of *N-1* contingency and wind, load uncertainty scenarios, at each hour *t.* Consequently there are (NS+1)xNT network subproblems. Notice that the values of the $\mathbf{P}_{\mathbf{D}}$, $\mathbf{B'}$, and $\mathbf{B}_{\Delta}$ are updated at each scenario *s* and regarding the different realizations of uncertainties and topology changes due to contingency cases and vectors with cap sign are computed at master problem. $PL_c$ is the MW flow on line *c,* connecting bus *b1*, to bus *b2*. $\Delta_c$ is the phase shift value for the phase shifter transformer located between buses *b1* and *b2*. If the value of the objective function is greater than 0, i.e. $v(\hat{\mathbf{y}}) > 0$, this indicates that there is a violation for scenario $s$ at time *t*, and the following Benders cut is formed, which was given in (96).

$$v(\hat{\mathbf{y}}) - (\mathbf{y} - \hat{\mathbf{y}})^{\mathbf{T}} \mathbf{F}^{\mathbf{T}} \mathbf{u}^{\mathbf{r}} \le 0 \tag{98}$$

where

$$\mathbf{y} = \begin{bmatrix} \hat{\mathbf{P}}_{\mathbf{G}}{}^{T} & \hat{\mathbf{P}}_{\mathbf{W}}{}^{T} & \hat{\mathbf{P}}_{\mathbf{DRR}}{}^{T} & \hat{\mathbf{P}}_{\mathbf{LS}}{}^{T} \end{bmatrix}^{T} \tag{99}$$

$$\mathbf{F} = -\begin{bmatrix} \mathbf{A}^{T} & \mathbf{W}^{T} & \mathbf{R}^{T} & \mathbf{D}^{T} \end{bmatrix}^{T} \tag{100}$$

The value of $\boldsymbol{\pi}^{\mathbf{r}} = -\mathbf{F}^{\mathbf{T}} \mathbf{u}^{\mathbf{r}}$ represents the incremental change in the total violation. Notice that the elements of the vector $\hat{\mathbf{P}}_{\mathbf{G}}$ are composed of scheduled power generation and deployed unit reserves as given explicitly in (90). Consequently, the generated cuts would enable the master problem to optimally adjust the reserve limits as well as the other master problem variables to mitigate the violation.

### 4.2.2.4 Proposed Solution Steps

The solution algorithm is given as in Fig 4.5. The master UC problem is solved at the first place and the optimal values for the first and second-stage variables are obtained. Using the obtained values, the network problems for base case and each scenario is solved for each time *t*.

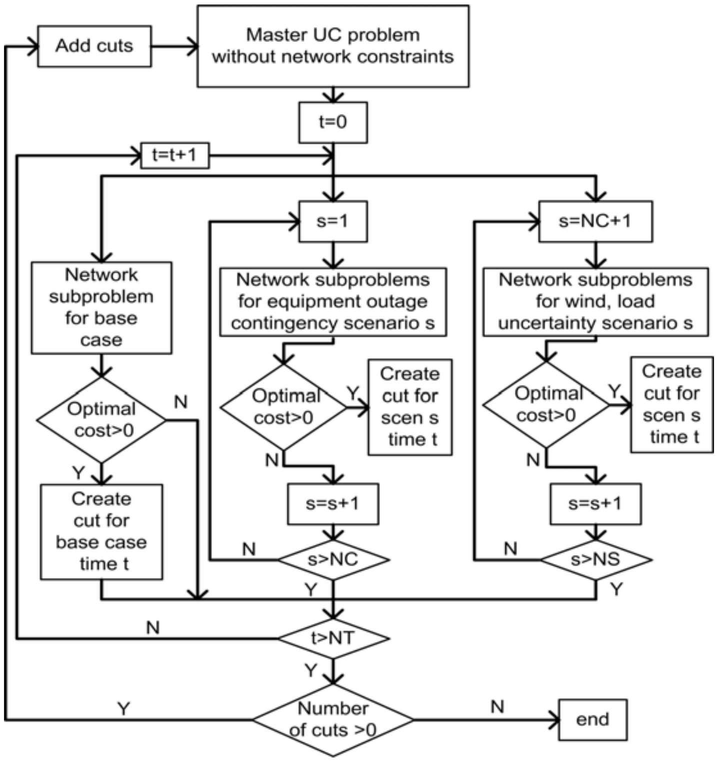


Fig 4.5. SCUC solution algorithm flowchart

If the optimal value for a network subproblem at time *t* is higher than zero, which is an indicator of a network violation for the related case at time *t*, then a network cut is generated associated with that network problem. If there are no network violations after the network subproblems for base case and each scenario *s* considering contingency and uncertainty scenarios for each hour *t*, the algorithm is stopped. Otherwise, the master problem is solved again with the generated cuts are added.

# CHAPTER 5

# CASE STUDIES

In this section, the observations out of the case studies considering the proposed PBUC and SCUC frameworks are described in detail. The comparative analyses are also included in order to convey the proposed algorithms structural and performance differences than the other ones existing in the literature.

The case studies could be divided into three main analyses, namely; The Effect of the NG Infrastructure on GENCO's Midterm Operational Scheduling, The Impact of the Wind Intermittency and Uncertainty and the presence of forward BCs on GENCO's Midterm Operational Scheduling, and The Impact of DR, Wind Power and System Demand Uncertainty on Synchronous Day Ahead Market Clearing. The first two analyses have been performed using the proposed PBUC framework given in Section 4.1. The third analysis utilizes the hybrid deterministic/stochastic SCUC framework described in detail in Section 4.2. These three analyses are discussed in Sections 5.1, 5.2 and 5.3 respectively.

## *5.1 The Effect of NG Infrastructure on GENCO's Midterm Operational Scheduling*

A GENCO with 3 coal units, 12 NG units, 11 hydro units, and 3 pumped-storage units is considered to analyze the effect of NG constraints on the midterm hydrothermal scheduling problem. The wind power generation is not considered in this analysis in order to capture the effect of NG infrastructure and related uncertainties. The scheduling horizon is one year with hourly intervals. The detailed generating unit data, market prices for energy and ancillary services are given in http://motor.ece.iit.edu/data/NGInfraPBUC. We assume uniform market clearing prices (MCPs) for all units. Locational marginal prices (LMPs) can be incorporated similarly.

The eight NG units are fed from the NG transmission network as seen in Fig 5.1. There are eight units related to Pipeline 1. Consequently, these units would be subject to limits on pipelines, contracts, and plants. Pipeline 2 is divided into two zones, and if Zone 1 is considered to be geographically far from gas well, the four units located in this zone would be able to access only a proportion of pipeline capacity due to subarea constraints. The yearly NG usage limit for Zone 1 is 37,200 MMCF (subarea limit).The units in Zone 3 of Pipeline 2 share a storage facility to which NG could be deposited. The stored NG could be withdrawn when necessary, i.e. the pipeline outage due to seasonal interruptions. In this study, NG storage facilities are not considered except in Case 4, where an NG storage facility with a capacity of 1,000 MMCF is located in Zone 3 for supplying NG units within Zone 3. The cost of utilizing the storage is $2,170 per MMCF. NG contracts are shown in Table 5.1. Pipeline 1 has one firm and one interruptible contract while Pipeline 2 has one interruptible contract. The yearly pipeline constraints are 155,000 and 90,000 MMCF for Pipelines 1 and 2, respectively.

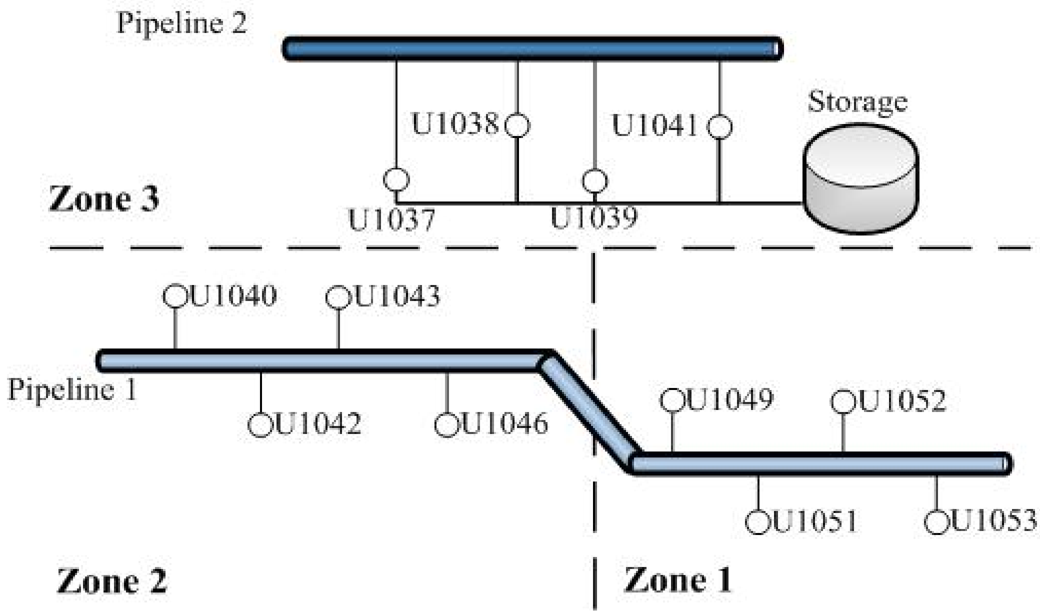

Fig 5.1. NG units and infrastructure

TABLE 5.1

NG CONTRACTS

| Pipeline # | Contract # | Type | Amount (MMCF) | Cost or Price |
|---|---|---|---|---|
| 1 | 1 | Firm | 36,000 | $70,200,000 |
| 1 | 2 | Interruptible | 117,500 | $2,170 / MMCF |
| 2 | 3 | Interruptible | 88,400 | $2,100 / MMCF |

The following four cases are considered:

Case 1: Base case without any NG constraints or supply interruptions

Case 2: Effect of NG infrastructure constraints

Case 3: Effect of NG supply interruptions

Case 4: Effect of NG storage facilities

These cases are discussed as follows.

### 5.1.1 Case 1: Base Case without any NG Constraints or Supply Interruptions:

This base case includes all the units but does not consider NG constraints or supply interruptions. This case is to be used as reference to show the effect of NG infrastructure and its interruptions in the following cases. Besides, the results of this case could be taken as the outcomes of frameworks proposed in [32] and [84], since these also do not consider the NG infrastructure constraints.

TABLE 5.2

PROBABILITY OF EACH SCENARIO AFTER SCENARIO REDUCTION

| **Scenario** | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|
| **Probability** | 0.07 | 0.11 | 0.02 | 0.07 | 0.08 | 0.08 |
| **Scenario** | 7 | 8 | 9 | 10 | 11 | 12 |
| **Probability** | 0.1 | 0.05 | 0.09 | 0.09 | 0.13 | 0.11 |

TABLE 5.3 CASE 1 PAYOFF

| **Scenario** | **Risk Neutral Payoff ($)** | **Risk Constrained Payoff ($)** | **Change (%)** |
|---|---|---|---|
| 1 | 496,829,660 | 492,811,146 | -0.81 |
| 2 | 455,159,262 | 457,308,285 | 0.47 |
| 3 | 470,330,464 | 469,255,240 | -0.23 |
| 4 | 478,319,870 | 481,583,723 | 0.68 |
| 5 | 486,346,522 | 485,826,120 | -0.11 |
| 6 | 507,895,434 | 501,879,197 | -1.18 |
| 7 | 468,243,935 | 471,056,266 | 0.60 |
| 8 | 460,055,586 | 461,652,104 | 0.35 |
| 9 | 488,026,721 | 485,933,588 | -0.43 |
| 10 | 493,015,056 | 487,823,577 | -1.05 |
| 11 | 531,379,691 | 523,638,213 | -1.46 |
| 12 | 467,052,288 | 469,049,789 | 0.43 |
| **Expected Payoff ($)** | 485,849,996 | 484,407,904 | -0.30 |
| **Target ($)** | 485,849,996 | | - |
| **Downside Risk ($)** | 9,331,555 | 8,309,323 | -10.95 |

The uncertainties in market price and natural water inflow are considered in the scenarios. The scenarios are reduced to 12 since the value of the objective function does not change much based on this number of scenarios [60], [68]. The probability of each reduced scenario is given in Table 5.2.

A risk neutral model is considered first which aims to maximize the expected scenario payoffs. Scenarios 2 and 8 have lower payoffs as a function of market prices and natural water inflows. If the GENCO sets its target payoff at $485,849,996, which is the expected payoff for the risk neutral case, the corresponding probability for the set of scenarios below the target payoff is 0.46 (i.e., 0.11 + 0.02 + 0.07 + 0.1 + 0.05 + 0.11). The expected downside risk is $9,331,555. The expected downside risk would be decreased with the inclusion of risk constraints.

TABLE 5.4 CASE 1 USAGE OF NG CONTRACTS

| **Scenario** | **Contract 1 NG (MMCF)** | | **Contract 2 NG (MMCF)** | | **Contract 3 NG (MMCF)** | |
|---|---|---|---|---|---|---|
| | **Risk Neutral Case** | **Risk Cons. Case** | **Risk Neutral Case** | **Risk Cons. Case** | **Risk Neutral Case** | **Risk Cons. Case** |
| 1 | 36,000 | 36,000 | 88,517 | 86,424 | 41,591 | 41,286 |
| 2 | 36,000 | 36,000 | 76,479 | 75,708 | 39,106 | 39,060 |
| 3 | 36,000 | 36,000 | 81,876 | 80,441 | 39,987 | 39,814 |
| 4 | 36,000 | 36,000 | 84,181 | 83,409 | 40,544 | 40,483 |
| 5 | 36,000 | 36,000 | 83,865 | 82,446 | 40,498 | 40,341 |
| 6 | 36,000 | 36,000 | 91,697 | 88,965 | 41,921 | 41,670 |
| 7 | 36,000 | 36,000 | 82,393 | 81,655 | 40,374 | 40,266 |
| 8 | 36,000 | 36,000 | 77,743 | 76,966 | 38,811 | 38,702 |
| 9 | 36,000 | 36,000 | 85,611 | 83,758 | 40,872 | 40,648 |
| 10 | 36,000 | 36,000 | 85,266 | 83,140 | 40,957 | 40,611 |
| 11 | 36,000 | 36,000 | 91,562 | 88,319 | 42,185 | 41,726 |
| 12 | 36,000 | 36,000 | 80,332 | 79,756 | 39,912 | 39,868 |
| **Exp. Value** | 36,000 | 36,000 | 84,429 | 82,827 | 40,661 | 40,462 |

Table 5.3 shows scenario payoffs for risk neutral and risk-constrained models (minimum risk). The downside risk is $8,309,323 with the inclusion of risk constraints, which shows a 10.95% less risk than that of the risk neutral case. However, the expected payoff decreases by 0.3% in the risk-constrained case. This is the cost of risk aversion. Table 5.4 shows the NG usage of different contracts for risk neutral and risk-constrained cases. The firm NG contract is fully utilized in both cases and the interruptible NG is consumed when market prices are high. The interruptible NG contract usage decreases in all scenarios with the introduction of risk constraints. This is because NG units are shut down in specific hours to reduce the downside risk.

### 5.1.2 Case 2: Effect of NG Infrastructure Constraints:

All units and NG infrastructure constraints are used to show the effect of NG constraints on the midterm hydrothermal scheduling. These constraints, formulated in Section 4.1.1.4, are on pipelines, subareas, plants, and units.

TABLE 5.5 CASE 2 PAYOFF

| Scenario | Risk Neutral Payoff ($) | Risk Constrained Payoff ($) | Change (%) |
|---|---|---|---|
| 1 | 492,174,884 | 487,461,689 | -0.96 |
| 2 | 452,984,686 | 455,218,835 | 0.49 |
| 3 | 467,379,771 | 466,489,686 | -0.19 |
| 4 | 474,772,772 | 478,266,777 | 0.74 |
| 5 | 483,012,610 | 481,939,429 | -0.22 |
| 6 | 502,690,545 | 494,945,756 | -1.54 |
| 7 | 465,237,823 | 468,108,097 | 0.62 |
| 8 | 457,819,092 | 459,446,279 | 0.36 |
| 9 | 484,277,365 | 482,318,666 | -0.40 |
| 10 | 489,136,100 | 482,952,060 | -1.26 |
| 11 | 525,411,762 | 515,473,413 | -1.89 |
| 12 | 464,728,792 | 466,871,393 | 0.46 |
| **Expected Payoff ($)** | 482,164,144 | 480,180,559 | -0.41 |
| **Target ($)** | 482,164,144 | | - |
| **Downside Risk ($)** | 8,850,597 | 7,791,967 | -11.96 |

TABLE 5.6

ZONE GAS USAGES OF UNITS IN CASE 1 AND CASE 2 (RISK NEUTRAL CASE)

| Scenario | Zone 1 NG (MMCF) | | Zone 2 NG (MMCF) | | Zone 3 NG (MMCF) | |
|---|---|---|---|---|---|---|
| | **Case 1** | **Case 2** | **Case 1** | **Case 2** | **Case 1** | **Case 2** |
| 1 | 60,283 | 37,045 | 64,234 | 64,234 | 41,591 | 41,591 |
| 2 | 53,100 | 37,162 | 59,379 | 59,379 | 39,106 | 39,106 |
| 3 | 55,156 | 37,073 | 62,720 | 62,720 | 39,987 | 39,987 |
| 4 | 56,927 | 37,037 | 63,253 | 63,253 | 40,544 | 40,544 |
| 5 | 56,237 | 37,181 | 63,628 | 63,628 | 40,498 | 40,498 |
| 6 | 60,820 | 37,075 | 66,877 | 66,877 | 41,921 | 41,921 |
| 7 | 55,605 | 37,092 | 62,788 | 62,788 | 40,374 | 40,374 |
| 8 | 52,262 | 36,957 | 61,482 | 61,482 | 38,811 | 38,811 |
| 9 | 57,384 | 37,103 | 64,227 | 64,227 | 40,872 | 40,872 |
| 10 | 57,848 | 37,169 | 63,418 | 63,418 | 40,957 | 40,957 |
| 11 | 61,340 | 37,188 | 66,222 | 66,222 | 42,185 | 42,185 |
| 12 | 53,967 | 37,136 | 62,365 | 62,365 | 39,912 | 39,912 |
| **Exp. Value** | 56,968 | 37,116 | 63,460 | 63,460 | 40,661 | 40,661 |

TABLE 5.7

CASE 2 EXPECTED USAGES FROM NG CONTRACTS

| Contract 1 NG (MMCF) | | Contract 2 NG (MMCF) | | Contract 3 NG (MMCF) | |
|---|---|---|---|---|---|
| Risk Neutral | Risk Cons. | Risk Neutral | Risk Cons. | Risk Neutral | Risk Cons. |
| 36,000 | 36,000 | 64,577 | 62,157 | 40,661 | 40,465 |

Table 5.5 shows scenario payoffs with risk neutral and risk-constrained model when considering NG infrastructure constraints. The downside risk is decreased by 11.96% against a drop in the expected payoff of 0.41%. When we adopt commitment decisions given in Case 1, the expected payoff changes to \$481,881,658. The difference in the expected payoff is \$282,486 (i.e., \$482,164,144 - \$481,881,658) which represents the cost of ignoring NG infrastructure constraints in decision-making.

Therefore, the target payoff in this case should not be the same as that in the previous case when the NG infrastructure constraints were not considered. The GENCO would experience a lower payoff than its expectation if it does not update the target payoff. The value of the downside risk is \$8,850,597 for a target payoff \$481,881,658. If the GENCO sets its target payoff at \$485,849,996 as in Case 1, the probability for the set of scenarios below the target payoff would be 0.63 (i.e., 0.11 + 0.02 + 0.07 + 0.08 + 0.1 + 0.05 + 0.09 + 0.11) with an expected downside risk of \$10,914,617. This indicates that ignoring NG constraints could affect the GENCO's midterm schedule and increases the financial risk. Table 5.6 shows the total NG usage of generating units located in Zone 1 for Cases 1 and 2. We observe that the subarea constraint would limit the NG usage of units in Zone 1 to slightly lower than the upper limit (37,200 MMCF) even though the higher gas utilization in Zone 1 would lead to a higher payoff. The generating units in Zones 2 and 3 are unaffected since their NG usage remains within limits. The decrease in scenario payoffs is due to NG subarea limits. The expected NG usages from contracts for risk neutral and risk-constrained cases are given in Table 5.7. When compared with the risk neutral case in Case 1, we see that the NG usage from the interruptible contract of Pipeline 1 has decreased by 19,582 (i.e., 84,429 - 64,577) MMCF, which is due to binding subarea constraints in Zone 1. The units in Zone 1 would utilize the firm NG and the interruptible NG usage is limited by the subarea constraint. The interruptible contract in Pipeline 2 has not changed when compared to that in Case 1 since the midterm scheduling of units fed from Pipeline 2 does not violate the NG constraints.

Furthermore, the sensitivity of risk with respect to the target payoff is studied for Case 2. It is cumbersome to represent the sensitivity of the risk with respect to expected payoff analytically due to the complexity of the problem. Instead, the change of risk is evaluated for Case 2 by evaluating the minimum achievable risk values at different target profit values. The results are depicted in Fig 5.2. The expected payoff for the risk neutral case was \$482,164,144 with a downside risk of \$8,850,597. The analysis for case 2 is repeated for the GENCO for target payoffs starting from \$460,000,000 to \$485,000,000 with increasing steps of \$5,000,000. The points are connected with linear curves to obtain 5 linear segments. The slopes of the curve segments given in Fig 5.2 is calculated as 0.16, 0.33, 0.40, 0.45 and 0.53 from segment 1 to segment 5 respectively. This shows that the rate of change in the lowest achievable risk increases as the GENCO increases its target profit. Consider that the GENCO has two different target profits namely \$460,000,000 and \$480,000,000 with lowest achievable risks 0 and \$6,730,647 respectively. The \$1,000,000 of increase in target profit will result \$163,250 and \$529,779 of increase in lowest achievable risk respectively. Consequently, the extra risk exposition increases when the GENCO updates its target profits in the increasing direction. This nonlinearity in the risk-expected profit is a result of nonlinearities in the unit and NG system models. A similar analysis is trivial when the GENCO updates its target profits in the decreasing direction. Notice that even though the downside risk was decreased by 11.96% with the considerations of risk constraints in Case 2, the GENCO would have to update the target payoff to \$460,000,000 in order to reduce the risk to zero.

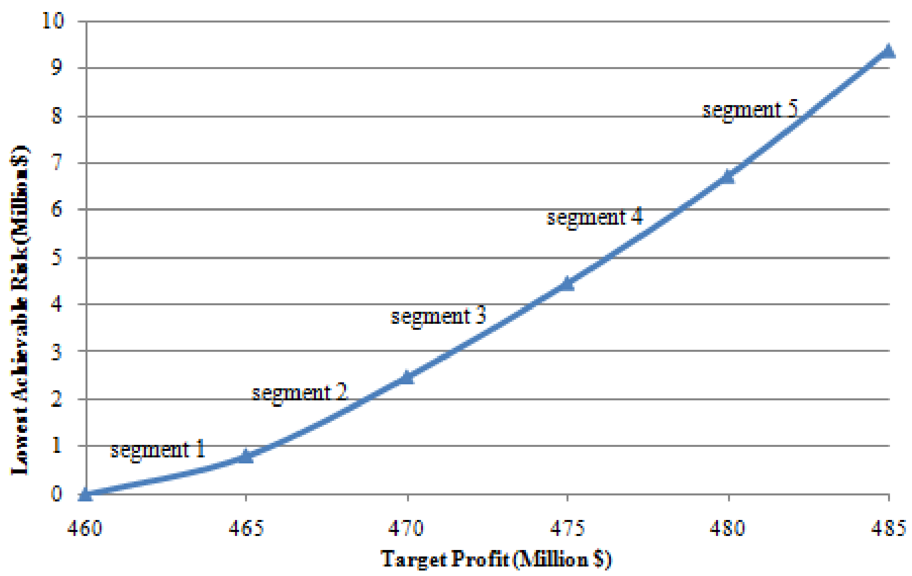


Fig 5.2. Downside risk versus target payoff for Case 2

### 5.1.3 Case 3: Effect of NG Supply Interruptions:

In this case, we study the effect of NG interruptions on the GENCO's payoff in a midterm scheduling. In severe weather conditions, the increasing NG demand for heating in residential areas is supplied by interruptible NG contracts. The interruption rate, which is defined as the ratio of the mean interruption time to the sum of mean interruption and mean available times [69], is taken as 0.1 for this case study and interruptions are simulated for the winter period. Table 5.8 depicts the scenario payoffs when considering NG interruptions and constraints for both risk neutral and risk-constrained conditions. If the GENCO determines a target payoff \$465,492,606 for the risk neutral case, the downside risk probability is 0.46 (i.e., 0.11 + 0.02 + 0.07 + 0.1 + 0.05 + 0.11). The downside risk is \$8,469,522 and the expected payoff is decreased by \$16,671,538 (i.e., \$482,164,144 - \$465,492,606). This is the potential loss in the midterm stochastic hydrothermal scheduling due to NG interruptions. When compared with Case 1, the consideration of NG interruptions with NG infrastructure constraints further decreases the GENCO's expected payoff by \$20,357,390 (i.e., \$3,685,852-\$16,671,538). The amount of decrease could change with the rate of the NG interruptions. If the GENCO sets its target payoff to \$485,849,996 as in Case 1, the probability for the set of scenarios below the target payoff would be 0.87 (i.e., 0.07 + 0.11 + 0.02 + 0.07 + 0.08 + 0.08 + 0.1 + 0.05 + 0.09 + 0.09 + 0.11) with an expected downside risk of \$23,126,635. This indicates that ignoring the NG network constraints could affect the GENCO's midterm schedule and further increases financial risks. With the consideration of risk constraints, the downside risk decreases by 12.19% against a drop in the expected payoff of 0.37%. Table 5.9 gives the NG usage of gas contracts for each scenario for both risk neutral and risk considered cases.

TABLE 5.8 CASE 3 PAYOFF

| Scenario | Risk Neutral Payoff (\$) | Risk Constrained Payoff (\$) | Change (%) |
|---|---|---|---|
| 1 | 474,871,828 | 470,491,695 | -0.92 |
| 2 | 437,655,315 | 439,855,079 | 0.50 |
| 3 | 451,281,020 | 450,284,507 | -0.22 |
| 4 | 458,324,947 | 461,706,329 | 0.74 |
| 5 | 466,314,926 | 465,310,161 | -0.22 |
| 6 | 484,836,849 | 477,901,647 | -1.43 |
| 7 | 449,183,674 | 451,958,605 | 0.62 |
| 8 | 442,057,657 | 443,691,623 | 0.37 |
| 9 | 467,325,199 | 465,484,983 | -0.39 |
| 10 | 472,370,528 | 466,607,116 | -1.22 |
| 11 | 507,151,877 | 498,283,516 | -1.75 |
| 12 | 448,957,954 | 451,049,157 | 0.47 |
| **Expected Payoff (\$)** | 465,492,606 | 463,761,550 | -0.37 |
| **Target (\$)** | 465,492,606 | | - |
| **Downside Risk (\$)** | 8,469,522 | 7,436,840 | -12.19 |

TABLE 5.9

CASE 3 EXPECTED USAGES FROM NG CONTRACTS

| **Contract 1 NG (MMCF)** | | **Contract 2 NG (MMCF)** | | **Contract 3 NG (MMCF)** | |
|---|---|---|---|---|---|
| **Risk Neutral** | **Risk Cons.** | **Risk Neutral** | **Risk Cons.** | **Risk Neutral** | **Risk Cons.** |
| 36,000 | 36,000 | 64,577 | 62,550 | 30,086 | 29,975 |

The NG contract utilization further decreases when compared with Case 2 due to NG interruptions. The NG usage does not decrease in Pipeline 1 with respect to Case 2 even if there are any NG interruptions. This is due to the fact that NG usage in Case 2 was already limited by subarea constraints and the unused gas at interrupted hours are shifted to other hours in Case 3. The decrease in gas usage from Contract 2 due to the interruptions is 10,575 MMCF (i.e., 40,661- 30,086).

### 5.1.4 Case 4: Effect of NG Storage Facility:

This case includes all the units, NG infrastructure constraints, NG interruption cases, and NG storage facilities. NG can be stored for use at constrained hours. In this case, the NG storage in Zone 3 is considered.

TABLE 5.10 CASE 4 PAYOFF

| **Scenario** | **Risk Neutral Payoff ($)** | **Risk Constrained Payoff ($)** | **Change (%)** |
|---|---|---|---|
| 1 | 489,727,434 | 486,554,727 | -0.65 |
| 2 | 451,626,645 | 453,729,519 | 0.47 |
| 3 | 465,703,256 | 465,115,114 | -0.13 |
| 4 | 472,760,956 | 475,928,829 | 0.67 |
| 5 | 480,924,774 | 481,293,666 | 0.08 |
| 6 | 499,767,150 | 493,687,013 | -1.22 |
| 7 | 463,433,285 | 466,117,361 | 0.58 |
| 8 | 456,442,454 | 457,561,335 | 0.25 |
| 9 | 482,096,447 | 481,359,263 | -0.15 |
| 10 | 486,971,597 | 481,762,048 | -1.07 |
| 11 | 522,165,865 | 515,108,551 | -1.35 |
| 12 | 463,117,388 | 464,735,786 | 0.35 |
| **Expected Payoff ($)** | 480,028,588 | 478,840,621 | -0.25 |
| **Target ($)** | 480,028,588 | | - |
| **Downside Risk ($)** | 8,618,523 | 7,674,844 | -10.95 |

The storage is assumed to be full prior to the study period and NG injection to the storage by units is assumed to be zero at all periods (i.e., $q^{in}_{wts}$=0, $\forall t$, $\forall s$). Table 5.10 depicts the scenario payoffs for both risk neutral and risk-constrained cases. Table 5.11 gives the expected usage of NG contracts under risk neutral and risk-constrained cases.

Fig 5.3 depicts the expected payoff against the NG storage size. When there is no storage, the expected payoff is $465,492,606 as given in Case 3. The expected payoff is improved by 3.03% to $480,028,588 for the first 1,000 MMCF storage. However, the improvement is only 0.09% with a payoff of $480,456,556 for adding the second 1,000 MMCF of storage, and 0.08% with a payoff of $480,841,268 for the third 1,000 MMCF of storage. This is because the GENCO would choose to burn NG from the storage at the most profitable hours. The payoff improvement for the first 1,000 MMCF storage is higher than the next 2,000 MMCF since the GENCO uses the first 1,000 MMCF of additional NG at most profitable hours. The expected payoff could be improved significantly with the addition of 1,000 MMCF of NG storage when compared with the no-storage Case 3. The downside risk for this case has decreased by 10.95% against a drop in the expected payoff of 0.25% with the addition of risk constraints.

TABLE 5.11

CASE 4 EXPECTED USAGES FROM NG CONTRACTS

| Contract 1 NG (MMCF) | | Contract 2 NG (MMCF) | | Contract 3 NG (MMCF) | |
|---|---|---|---|---|---|
| Risk Neutral Case | Risk Cons. Case | Risk Neutral Case | Risk Cons. Case | Risk Neutral Case | Risk Cons. Case |
| 36,000 | 36,000 | 64,577 | 63,577 | 30,977 | 30,763 |

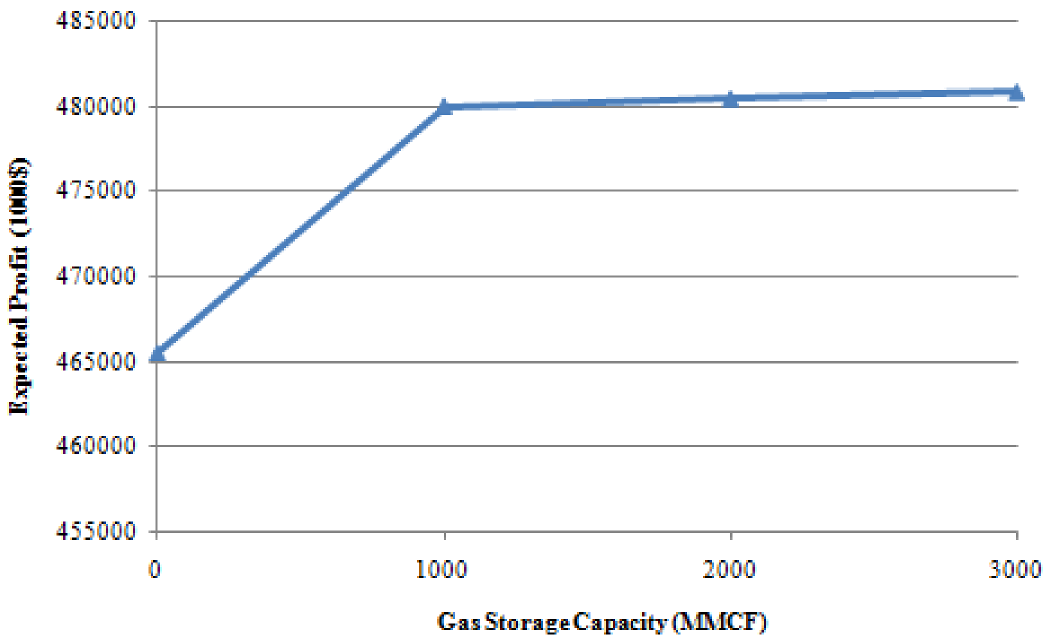


Fig 5.3. NG Storage Capacity versus Expected payoff, risk neutral case

### 5.1.5 Summary , Verifications and Comparisons

The four cases are summarized in Table 5.12. The GENCO's expected payoff decreases when considering NG constraints and interruptions. Furthermore, the expected financial downside risk and downside risk probability increase if the GENCO does not update its midterm target payoff and uses the target payoff determined in the base case for Cases 2 and 3. Thus, the GENCO could run a risk free case when considering NG constraints and interruptions and then determine a suitable target payoff and reduce the risk, which would lead to a more realistic risk-constrained midterm scheduling results.

TABLE 5.12

COMPARISON OF RESULTS OF CASES 1-4 WITH RISK NEUTRAL SOLUTIONS

| | Case 1 | Case 2 | Case 3 | Case 4 |
|---|---|---|---|---|
| **Expected Payoff ($)** | 485,849,996 | 482,164,144 | 465,492,606 | 480,028,588 |
| **Downside Risk ($)** | 9,331,555 | 10,914,617 | 23,126,635 | 12,028,208 |
| **Down. Risk Probability** | 0.46 | 0.63 | 0.87 | 0.63 |
| **Target ($)** | 485,849,996 | | | |

TABLE 5.13

COMPARISON OF RISK NEUTRAL CASES RESULTS

| Cases | Expected Payoff ($) | Downside Risk ($) | Target ($) |
|---|---|---|---|
| **5: Coal Units Only** | 22,423,534 | 1,101,054 | 22,423,534 |
| **6: NG Units Only** | 140,688,206 | 4,396,534 | 140,688,206 |
| **7: Hydro Units Only** | 232,620,703 | 2,178,677 | 232,620,703 |
| **8: PS Units Only** | 69,760,163 | 995,095 | 69,760,163 |
| **Sum of Cases 5-8** | 465,492,606 | 8,671,360 | 465,492,606 |
| **9: All Units Together** | 465,492,606 | 8,469,522 | 465,492,606 |
| **Change (%)** | 0.00 | 2.33 | 0.00 |

TABLE 5.14

COMPARISON OF RISK REDUCTION OF CASES

| Cases | Expected Payoff ($) | Downside Risk ($) | Target ($) |
|---|---|---|---|
| **5: Coal Units Only** | 22,338,606 | 1,052,037 | 22,423,534 |
| **6: NG Units Only** | 140,117,126 | 4,231,735 | 140,688,206 |
| **7: Hydro Units Only** | 232,370,729 | 2,054,221 | 232,620,703 |
| **8: PS Units Only** | 69,464,139 | 551,639 | 69,760,163 |
| **Sum of Cases 5-8** | 464,290,600 | 7,889,632 | 465,492,606 |
| **9: All Units Together** | 463,761,550 | 7,436,840 | 465,492,606 |
| **Change (%)** | 0.11 | 5.74 | 0.00 |

A reduction of 10,575 MMCF of NG was observed for Contract 3 in Case 3 as compared to Case 2 due to an NG interruption. The interruption resulted in an expected payoff reduction of \$16,671,538. However, the expected payoff increased to \$14,535,982 when a 1,000 MMCF NG storage was considered in Zone 3. In other words, 87.2% of the reduction in expected payoff, which was due to the NG interruption, was recovered with the addition of storage. The NG storage was 9% of the interrupted NG. In this case, the GENCO utilized the stored NG at most profitable hours.

Table 5.13 and Table 5.14 list the results of optimizing the individual types of units separately or together for risk neutral and risk-constrained cases, respectively. The results of risk neutral case show that the scheduling of all units together with a target payoff that is equal to the sum of individual payoffs would result in a lower expected downside risk than the sum of those for individual risks. This could be explained by the fact that the variance of the sum of two normal distributed random variables is always less than or equal to the sum of their variances. Hence, a GENCO should determine a target by including all its units rather than considering them individually. For the risk-constrained case, the sum of lowest achievable risk for Case 3, which represents a combined solution of all generating units, is lower than the sum of separate downside risks of individual groups of units. The 5.75% improvement is because the consideration of all the units with a single total target payoff would provide more alternatives for risk reduction.

Concerning the optimality of the results, Case 2 solutions could be considered. The algorithm calculates the optimal expected payoff as \$482,164,144. This solution should be the highest achievable expected payoff for the considered uncertainty scenarios in order to be the global optimal solution. In other words, if a group of variables are forced to a different value than the algorithm calculated, a lower expected payoff would be expected. Consequently, when Case 1 UC solutions are forced to Case 2 analyses, the expected payoff should be lower than the optimal expected payoff value. In fact, the mentioned forced calculation results with a lower expected payoff \$481,881,658 as expected. This observation verifies the optimality of the results.

Case 1 could be taken as the outcomes of the frameworks such as [32] and [83] which are not considering the NG infrastructure limitations. It is seen from the results of the Case 2 that, ignoring the NG limitations while determining the UC of generating assets lead to a profit loss of \$282,486. Moreover, the potential benefit of limited NG storage in the storage facilities that has been depicted in Cases 3 and 4, could be evaluated with the proposed framework having detailed NG storage model besides the network constraints.

## 5.2 *The Impact of the Wind Intermittency and Uncertainty and the Presence of Forward BCs on GENCO's Midterm Operational Scheduling*

This analysis focuses on the wind power intermittency and volatility, and consideration of the BCs as risk hedging tools for the GENCO. The coordination concept described under section 4.1.1.9 is utilized to increase the risk reduction performance of the GENCO assets. The NG infrastructure model considered in section 4.1.1 is also employed throughout this analysis. We first present a simple three-hour example to introduce the benefit of the coordination for one wind and one NG units. A more realistic example considering a GENCO with 8 NG, 4 cascaded hydro units, and 3 wind units will also be discussed.

### 5.2.1 3 Hour Problem

This example illustrates the impact of BCs on the coordination of wind and NG units, and the GENCO's payoff. Consider a three-hour example of a GENCO with one wind and one NG units. Assume that there are two scenarios with hourly wind forecasts of 100MW, 150MW, 170MW for the first scenario and 80MW, 130MW, 150MW for the second scenario, with a 50% probability in each case. The NG unit has a constant generation cost of \$19/MWh with min/max power of 55MW and 200MW, respectively. The cost of ancillary services is not considered for simplicity. The real-time energy prices are \$20/MWh and \$15/MWh for scenarios 1 and 2, respectively. Only real-time market is considered without BCs in Case 1 to serve as a base case. The effect of BC coordination is analyzed in Cases 2-4.

*Case 1*: This case serves as the base case in which no BC is considered and energy is offered only to the real-time market. The wind unit utilizes all the available wind energy in both cases while the NG unit is not committed since it is only profitable for the first scenario. The expected payoff is \$6,900 in Table 5.15. When the target payoff is the same as the expected payoff, the downside risk is \$750. The same target payoff is also used for the following cases.

*Case 2:* A BC of 400MWh with an energy price of \$18/MWh and penalty price of \$30/MWh is introduced in this case. The wind-NG coordination is not considered, wind unit is assigned to BC, and NG energy is offered to the real-time market. The BC price is lower than the energy price of scenario 1 and higher than that of scenario 2. The GENCO satisfies its BC with wind and uses BC to hedge its expected payoff. The schedule for units is given in Table

5.16. The available energy is 420MWh in scenario 1 and 360MWh in scenario 2. The 20MWh excess energy is offered to the real-time market in scenario 1, while a penalty for the 40MWh deficiency is paid in scenario 2. The expected payoff drops by $100 to $6,800 due to the penalty payment, while the risk decreases to $450 when BCs are utilized. The downside risk is decreased since the GENCO is not exposed to the real-time market in scenario 2.

TABLE 5.15

OPTIMAL SCHEDULE WITH NO BCS AND NO COORDINATION

| Hours | | t=1 | t=2 | t=3 |
|---|---|---|---|---|
| Scenario 1 | Available Wind Power | 100 | 150 | 170 |
| | NG unit dispatch | 0 | 0 | 0 |
| Scenario 2 | Available Wind Power | 80 | 130 | 150 |
| | NG unit dispatch | 0 | 0 | 0 |
| BC | | 0 | | |
| Expected payoff | | $6,900 = 20*420*50% + 15*360*50% | | |

TABLE 5.16

OPTIMAL SCHEDULE OF 400 MWH BC WITH NO COORDINATION

| Hours | | t=1 | t=2 | t=3 |
|---|---|---|---|---|
| Scenario 1 | Available Wind Power | 100 | 150 | 170 |
| | NG unit dispatch | 0 | 0 | 0 |
| Scenario 2 | Available Wind Power | 80 | 130 | 150 |
| | NG unit dispatch | 0 | 0 | 0 |
| BC | | 400 | | |
| Expected payoff | | $6,800 = (400*18+20*20)*50% + (400*18-30*40)*50% | | |

TABLE 5.17

OPTIMAL SCHEDULE OF 400 MWH BC WITH WIND-NG COORDINATION

| Hours | | t=1 | t=2 | t=3 |
|---|---|---|---|---|
| Scenario 1 | Available Wind Power | 100 | 150 | 170 |
| | NG unit dispatch | 200 | 0 | 0 |
| Scenario 2 | Available Wind Power | 80 | 130 | 150 |
| | NG unit dispatch | 55 | 0 | 0 |
| BC | | 400 | | |
| Expected payoff | | $7,090 = (400*18+220*20+200*(-19))*50% (400*18+15*15-55*19))*50% | | |

*Case 3:* The NG unit is added to the coordination. The wind and NG unit schedules are given in Table 5.17. The expected payoff increases to $7,090 in this Case and the financial risk is decreased to $240. The wind unit is scheduled in both scenarios as in previous Cases. The NG unit is scheduled up to its capacity in scenario 1 and the NG generation is offered to the real-time market since the market price is higher than its generation cost. In scenario 2, the unit is committed at hour 1 with a minimum capacity of 55MW to supply the deficient BC of 40MWh, and the excess energy of 15MWh is offered to the real-time market. Here the NG unit provides a means of satisfying the BC energy at the presence of wind generation volatility.

*Case 4:* The BC energy is treated as a variable between 200-600 MWh in Case 4. The algorithm calculates the optimal BC as 525MWh. The expected payoff is $7132.5 while the risk is increased slightly to $295. It is possible to decrease the risk by constraining the risk constraints as shown in the 1 year problem. The schedule of units is given in Table 5.18. The NG unit is turned on at all hours in Case 4 to satisfy BCs in coordination with the wind unit and offer the excess energy to the real-time market. The market price in Scenario 1 is profitable for the NG unit, while it is the opposite in scenario 2. However, the additional BC energy enables the NG unit to be turned at hours 2 and 3 which would increase the expected payoff to be higher than that in Case 3. The BC limit adjustments increase the expected payoff of GENCO.

TABLE 5.18

OPTIMAL SCHEDULE OF BC WITH WIND-NG COORDINATION

| Hours | | t =1 | t = 2 | t =3 |
|---|---|---|---|---|
| Scenario 1 | Available Wind Power | 100 | 150 | 170 |
| | NG unit dispatch | 200 | 200 | 200 |
| Scenario 2 | Available Wind Power | 80 | 130 | 150 |
| | NG unit dispatch | 55 | 55 | 55 |
| BC Energy (MW) | | 400 | | |
| Expected payoff | | $7,132.5 = (525*18+495*20-200*3*19)*50% + (525*18-55*3*19))*50% | | |

*Discussions:* The summary of expected payoffs and risks is given in Table 5.19. This problem shows the benefits of BC and its coordination with a diversified set of generating assets. The available wind energy is utilized in all 4 Cases. The NG unit is not scheduled in Cases 1 and 2 since real-time market prices are not profitable. It is coordinated in Case 3 by supplying the wind unit in Scenario 2 and preventing penalty payments. It is also committed in all three hours since BC is increased in Case 4. The expected payoff is the highest by adding BC in Case 4. The financial risk is increased in Case 4 since the GENCO makes a lower payoff in Scenario 2 to boost the payoff in Scenario 1 and increase the expected payoff. The risk would be reduced in Case 4 with the addition of risk constraints. The BC optimization and its wind-NG coordination increase the expected payoff and decrease the expected risk of GENCO by preventing it to be fully exposed to volatile real-time market prices.

TABLE 5.19

3 HOURS PROBLEM PAYOFF AND RISK SUMMARY

| Cases | Expected Payoff ($) | Expected Risk ($) |
|---|---|---|
| **1: No BC and No Coordination** | 6900 | 750 |
| **2: Fixed BC and No Coordination** | 6800 | 450 |
| **3: Fixed BC with Coordination** | 7,090 | 260 |
| **4: Variable BC with Coordination** | 7,132.5 | 292.5 |

### 5.2.2 One Year Example

A GENCO with 8 NG, 4 cascaded hydro and 3 wind units is chosen to demonstrate the proposed results. It is assumed that there are no transmission constraints and all units are subject to uniform real-time market prices. The detailed generating unit data, and market prices for energy and ancillary services are given in http://motor.ece.iit.edu/data/WindBCPBUC. The uncertainty of real-time market prices, natural water inflows, and wind generation are considered. A value of 4MW, that is the 2% of the nominal power output of wind turbine, is used in scenarios as the standard deviation of the wind forecast error for each wind turbine. The Monte Carlo method is used to initially obtain 100 scenarios which are reduced to 12 final scenarios since the objective function does not change much based on this number [60], [68]. The probabilities of reduced scenarios are given in Table 5.20. All GENCO units are considered for the one-year stochastic operation planning problem. The NG infrastructure is shown in Fig 5.4. The NG units fed by Pipeline 1 are located in two zones. Zone 1 is a subarea since it is far from the NG supply. The yearly NG supply from Zone 1 is limited to 37,200 MMCF (subarea limit). NG contracts are shown in Table 5.21. The yearly pipeline constraint is 155,000 MMCF for Pipeline 1. The Cases are listed in Table 5.22. In Cases 2 and 3, the weekly BC energy is fixed at 50,750MWh. In Case 4, BC energy is considered as a variable between 28,000 and 58,500MWh for calculating the optimal weekly BC. The energy price is 46 $/MWh and the penalty price for deficient energy is 200 $/MWh.

TABLE 5.20

PROBABILITY OF EACH SCENARIO AFTER SCENARIO REDUCTION

| **Scenario** | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|
| **Probability** | 0.07 | 0.11 | 0.02 | 0.07 | 0.08 | 0.08 |
| **Scenario** | 7 | 8 | 9 | 10 | 11 | 12 |
| **Probability** | 0.1 | 0.05 | 0.09 | 0.09 | 0.13 | 0.11 |

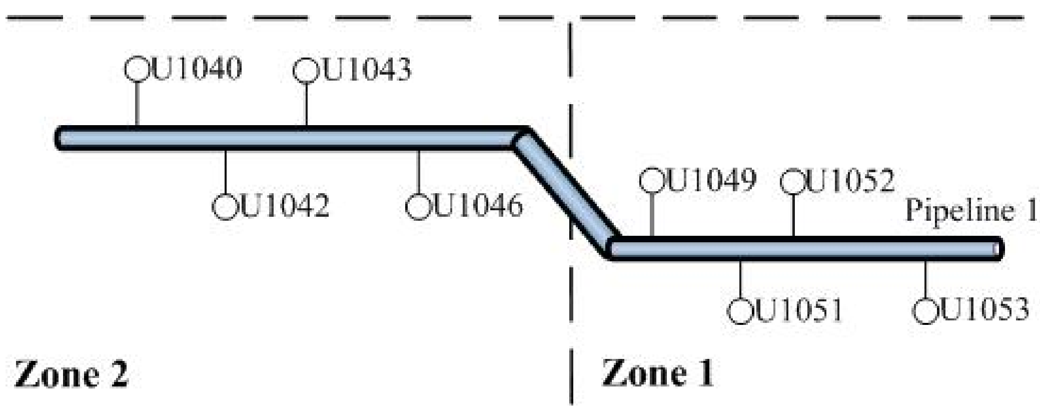


Fig 5.4. NG infrastructure

TABLE 5.21

NG CONTRACTS

| Pipeline # | Contract # | Type | Amount (MMCF) | Cost or Price |
|---|---|---|---|---|
| 1 | 1 | Firm | 36,000 | $70,200,000 |
| 1 | 2 | Interruptible | 117,500 | $2,170 / MMCF |

TABLE 5.22

1 YEAR PROBLEM CASES

| Case | Coordination | BC Energy |
|---|---|---|
| 1 | - | None |
| 2 | 4 Hydro | Fixed Energy |
| 3 | 4 Hydro + 1 NG | Fixed Energy |
| 4 | 4 Hydro + 1 NG + 3Wind | Fixed Energy |
| 5 | 4 Hydro + 1 NG + 3Wind | Variable Energy |

#### *5.2.2.1 Case 1: No BC*

The GENCO units are scheduled using the real-time market prices. The unit commitment and dispatch are defined by real-time market prices, natural water inflows and available wind generation. Table 5.23 and Table 5.24 show scenario payoffs and NG usages. When the risk neutral model is considered, the expected payoff is $312,025,369 and the downside risk is

$5,335,124 with a probability of 0.46. The individual payoff of NG, hydro, and wind units are calculated as $102,843,689, $98,896,229 and $110,285,448, respectively. The downside risk is decreased by 3.97% to $5,123,521 with the introduction of risk constraints. The expected payoff drops by 0.09% to decrease the expected downside risk. Table 5.24 shows the BC and subarea NG usages. The NG usage in Zone I is limited by the subarea constraint.

TABLE 5.23

CASE 1 PAYOFFS IN THE 1 YEAR PROBLEM

| Scenario | Risk Neutral Payoff ($) | Risk Constrained Payoff ($) | Change (%) |
|---|---|---|---|
| 1 | 319,185,336 | 318,717,369 | -0.15 |
| 2 | 292,937,108 | 293,414,276 | 0.16 |
| 3 | 304,127,650 | 304,223,128 | 0.03 |
| 4 | 309,480,887 | 309,974,915 | 0.16 |
| 5 | 312,394,559 | 312,014,515 | -0.12 |
| 6 | 326,141,298 | 324,881,948 | -0.39 |
| 7 | 302,910,136 | 303,368,423 | 0.15 |
| 8 | 297,004,406 | 297,232,244 | 0.08 |
| 9 | 315,075,266 | 314,005,654 | -0.34 |
| 10 | 315,952,780 | 315,280,269 | -0.21 |
| 11 | 335,465,052 | 334,291,840 | -0.35 |
| 12 | 300,781,954 | 301,270,430 | 0.16 |
| **Expected Payoff ($)** | 312,025,369 | 311,752,084 | -0.09 |
| **Target ($)** | 312,000,000 | | |
| **Downside Risk ($)** | 5,335,124 | 5,123,521 | -3.97 |

TABLE 5.24

CASE 1 NG USAGE IN THE 1 YEAR PROBLEM

| Scenario | Contract NG Usage (MMCF) | | Zone NG Usage (MMCF) | |
|---|---|---|---|---|
| | Contract 1 | Contract 2 | Zone 1 | Zone 2 |
| 1 | 36,000 | 63,541 | 36,800 | 62,742 |
| 2 | 36,000 | 59,773 | 37,095 | 58,678 |
| 3 | 36,000 | 62,781 | 37,058 | 61,723 |
| 4 | 36,000 | 63,825 | 37,158 | 62,667 |
| 5 | 36,000 | 63,560 | 37,135 | 62,425 |
| 6 | 36,000 | 65,892 | 37,045 | 64,847 |
| 7 | 36,000 | 63,348 | 37,130 | 62,219 |
| 8 | 36,000 | 61,983 | 37,150 | 60,833 |
| 9 | 36,000 | 63,090 | 36,711 | 62,378 |
| 10 | 36,000 | 62,754 | 36,851 | 61,903 |
| 11 | 36,000 | 65,051 | 37,146 | 63,905 |
| 12 | 36,000 | 63,025 | 37,128 | 61,897 |
| **Expected** | 36,000 | 63,252 | 37,037 | 62,215 |

#### *5.2.2.2 Case 2: 4 Hydro + 1 NG Coordination and Fixed BC Energy*

Cascaded hydro units of the GENCO are subject to a fixed BC energy. The hydro units are responsible for satisfying the weekly BC in 1 year. The GENCO makes penalty payments for defaulting at certain weeks when the water inflow is insufficient. This fact leads to a negative payoff of $69,913,914 for cascaded hydro units. The BC was intended to hedge the GENCO's risks due to uncertainties; however, cascaded hydro units with water inflow uncertainties will not satisfy BC constraints when water resources are insufficient. The scenario scheduling and payoffs for NG and wind units remain unaffected since their energy is offered to the real-time market as in Case 1. Table 5.25 shows the scenario payoffs for Case 2. The expected payoff drops to $168,810,146 which is a %54 decline in comparison with Case 1. The downside risk increases to $168,784,777 which is due to penalty payments. The hydro units are supposed to deliver 2,639 GWh of BC energy in 52 weeks. However, due to water shortages the GENCO is subject to penalty payments in each scenario. Table 5.26 shows the delivered BC energy by hydro units in each scenario. When hydro units are assigned to supply BC, the expected payoff drops dramatically as compared to Case 1 and scenario payoffs are below the target.

TABLE 5.25

CASE 2 PAYOFFS IN THE 1 YEAR PROBLEM

| Scenario | Risk Neutral Payoff ($) | Scenario | Risk Neutral Payoff ($) |
|---|---|---|---|
| 1 | 146,856,062 | 7 | 135,217,217 |
| 2 | 123,625,881 | 8 | 123,717,177 |
| 3 | 133,483,744 | 9 | 141,754,259 |
| 4 | 142,725,647 | 10 | 149,182,014 |
| 5 | 144,880,294 | 11 | 164,106,324 |
| 6 | 153,090,415 | 12 | 141,933,252 |
| **Expected Payoff ($)** | 143,215,223 | | |
| **Target ($)** | 312,000,00 | | |
| **Downside Risk ($)** | 168,784,777 | | |

TABLE 5.26

CASE 2 DELIVERED BC ENERGY IN THE 1 YEAR PROBLEM

| Scenario | Delivered Energy (MWh) | Scenario | Delivered Energy (MWh) |
|---|---|---|---|
| 1 | 1,598.18 | 7 | 1,609.96 |
| 2 | 1,587.29 | 8 | 1,569.03 |
| 3 | 1,597.49 | 9 | 1,586.05 |
| 4 | 1,627.74 | 10 | 1,626.14 |
| 5 | 1,621.95 | 11 | 1,620.78 |
| 6 | 1,600.22 | 12 | 1,667.81 |

#### 5.2.2.3 *Case 3: 4 Hydro + 1 NG Coordination and Fixed BC Energy*

The cascaded hydro and NG units are coordinated in Case 3 with a constant weekly BC. Table 5.27 shows that the expected payoff is higher than those of previous Cases. The expected payoffs for NG and hydro units are calculated as \$106,080,484 and \$98,984,802, while the wind schedule remains unchanged. The hydro unit payoff makes a net increase of \$168,898,716 when the cascaded hydro units are supported by NG units to satisfy BCs and prevent penalty payments. The added NG provides a tool to satisfy BCs by relaxing the dependency on uncertain water inflows. The NG payoff increases by \$3,236,795 when NG units supply BCs. The payoff of individual NG units could decrease based on prices in the real-time market and those of BC energy as observed in the 3-hour example. The coordination of NG and hydro units would decrease the risk by 49.4% to \$2,702,192 as compared to that in Case 1 when a risk neutral algorithm is considered. This also leads to the fact that constant price and energy of BC reduce the GENCO's financial risk when the NG unit with deterministic fuel conditions is added to the coordination. The NG unit provides a guaranteed source to satisfy BCs in the case of water shortages. The risk could be further decreased by considering risk constraints in the formulation.

#### 5.2.2.4 *Case 4: 4 Hydro + 1 NG + 3 Wind Coordination and Fixed BC Energy*

Wind units are further added to the coordination of 4 cascaded hydro and 1 NG unit. In Table 5.28, the expected payoff increases to \$333,540,888 by increasing every scenario's payoff above the target and mitigating the downside risk. The payoffs for NG, hydro, and wind units are \$110,038,248, \$102,830,699, and \$120,671,941, respectively. The wind units would increase payoffs by supplying BCs and offering energy to the real-time market. Hence, the coordination would enhance the GENCO's midterm scheduling and lead to higher payoffs and smaller risks. Case 4 considers the sensitivity of risk with respect to the standard deviation of the wind forecast uncertainty. The coordination of wind, NG and cascaded hydro units is included. The target profit is updated to \$333,000,000 for this analysis since the coordination has increased the expected profit in Case 4. The results are depicted in Fig 5.5 which shows that the wind forecast precision has a crucial impact on a GENCO's financial risk expectations. As mentioned earlier, the results given in Table 5.28 were obtained using a 2% standard deviation of the nominal wind power. In Fig 5.5, the financial risk is \$ 2,954,180 when the wind forecast uncertainty is excluded. In this case, the uncertainty related to water inflow and market price is considered. The risk increases as a nonlinear response to the increasing uncertainty. The lowest achievable downside risk is \$11,584,835 for a 5% standard deviation.

TABLE 5.27

CASE 3 PAYOFFS IN THE 1 YEAR PROBLEM

| Scenario | Risk Neutral Payoff ($) | Risk Constrained Payoff ($) | Change (%) |
|---|---|---|---|
| 1 | 319,726,149 | 319,206,030 | -0.16 |
| 2 | 300,490,430 | 300,908,507 | 0.14 |
| 3 | 308,258,680 | 308,311,908 | 0.02 |
| 4 | 312,900,050 | 312,468,195 | -0.14 |
| 5 | 316,618,813 | 316,080,077 | -0.17 |
| 6 | 324,321,630 | 323,166,015 | -0.36 |
| 7 | 307,157,264 | 307,557,796 | 0.13 |
| 8 | 303,215,792 | 303,497,439 | 0.09 |
| 9 | 316,982,758 | 316,307,652 | -0.21 |
| 10 | 319,840,549 | 319,342,067 | -0.16 |
| 11 | 334,613,540 | 333,554,113 | -0.32 |
| 12 | 308,019,740 | 308,670,174 | 0.21 |
| **Expected Payoff ($)** | 315,350,735 | 315,077,937 | -0.09 |
| **Target ($)** | 312,000,000 | | - |
| **Downside Risk ($)** | 2,702,192 | 2,529,455 | -6.39 |

TABLE 5.28

CASE 4 PAYOFFS IN THE 1 YEAR PROBLEM

| Scenario | Risk Neutral Payoff ($) | Scenario | Risk Neutral Payoff ($) |
|---|---|---|---|
| 1 | 339,126,029 | 7 | 325,228,883 |
| 2 | 319,557,902 | 8 | 322,651,801 |
| 3 | 326,446,447 | 9 | 335,166,626 |
| 4 | 330,395,946 | 10 | 337,634,670 |
| 5 | 334,095,784 | 11 | 354,675,867 |
| 6 | 342,944,310 | 12 | 322,867,144 |
| **Expected Payoff ($)** | 333,540,888 | | |
| **Target ($)** | 312,000,00 | | |
| **Downside Risk ($)** | 0 | | |

The effect of number of NG units in coordination is also depicted in Fig 5.5. If the number of NG units in coordination increased to 5, it is observed that the downside risk decreases due to the deterministic nature of NG units. The rate of change in the lowest achievable risk for the coordination of 4 Hydro, 1 Wind, and 5 NG decreases with respect to the 4 Hydro, 1 Wind, and 1 NG case, since the increased number of NG units in the coordination creates more possibilities to mitigate the financial risks due to the uncertainty of the wind units. The lowest achievable downside risk reduces to $5,619,520.

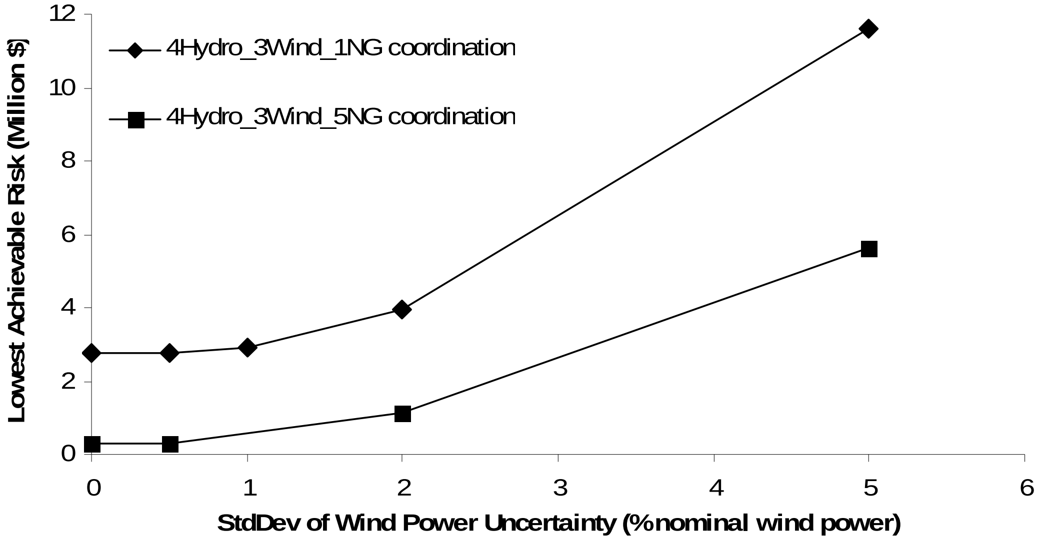


Fig 5.5. Financial risks versus wind forecast errors for different coordination levels

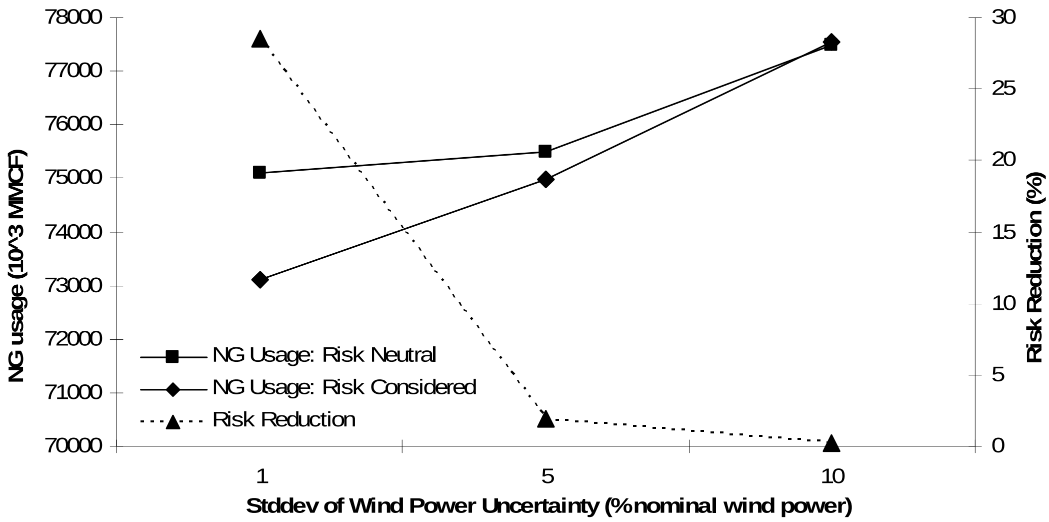


Fig 5.6 Total NG Utilization versus wind forecast errors

Moreover, the response of NG scheduling to increasing wind uncertainty is analyzed for the coordination of 4 Hydro, 1 Wind, and 5 NG. The utilized NG amount under risk neutral and risk considered cases are plotted versus the standard deviation of wind uncertainty in Fig 5.6. Two different comparisons could be made from Fig 5.6, the change of NG utilization for increasing wind uncertainty levels under risk neutral runs, and the change of NG utilization for a fixed uncertainty level between the risk free and risk considered runs. The first risk neutral comparison shows that NG utilization increases as the wind uncertainty increases. It becomes more profitable to schedule the NG units for more hours in order to satisfy the BC and maximize the profit. The second comparison shows that the algorithm decreases the NG utilization for the fixed 1% standard deviation of wind uncertainty, between the risk neutral and risk considered runs in order to minimize the financial risk. The expected energy production of NG units is 3.978GWh for the risk neutral case, while this value drops to 3.899 GWh to reduce risks But for higher uncertainty levels (5%, 10%) the NG utilization difference is not as significant as in 1% case since the algorithm can not decrease the risk level by NG schedule adjustments due to considerable increase in the wind uncertainty levels. Consequently, GENCO can no more aim the same target profit of $333,000,000 for high wind uncertainties and it should update its target profit. The expected energy of NG units is 3.44 GWh at 10% wind uncertainty for both risk neutral and considered cases. The NG utilization is higher for 10% case compared to the 1% case even the total energy generation is lower. This is due to the fact that NG units are committed at more hours but lower power outputs at 10% case resulting with lower total expected energy.

#### *5.2.2.5 Case 5: 4 Hydro + 1 NG + 3 Wind Coordination and Variable BC Energy*

In addition to the coordination in Case 4, the weekly BC energy here may take any value between 28,000 and 58,500MWh. The expected payoff in Table 5.29 increases to $334,308,722. Fig 5.7 shows the optimal weekly BC energy. The algorithm determines a higher (lower) BC energy for weeks when real-time energy price forecast are relatively lower (higher). The GENCO could make the highest payoff in uncertain real-time energy and ancillary service prices, and uncertain water inflows and wind resources. The proposed algorithm can determine BC and penalty prices and optimal allocations of weekly energy.

TABLE 5.29

CASE 5 PAYOFFS IN THE 1 YEAR PROBLEM

| Scenario | Risk Neutral Payoff ($) | Scenario | Risk Neutral Payoff ($) |
|---|---|---|---|
| 1 | 339,969,879 | 7 | 325,806,490 |
| 2 | 319,957,248 | 8 | 323,206,938 |
| 3 | 327,163,019 | 9 | 335,965,466 |
| 4 | 331,113,337 | 10 | 338,531,322 |
| 5 | 334,923,002 | 11 | 355,537,537 |
| 6 | 344,172,751 | 12 | 323,646,294 |
| **Expected Payoff ($)** | 334,308,722 | | |
| **Target ($)** | 312,000,00 | | |
| **Downside Risk ($)** | 0 | | |

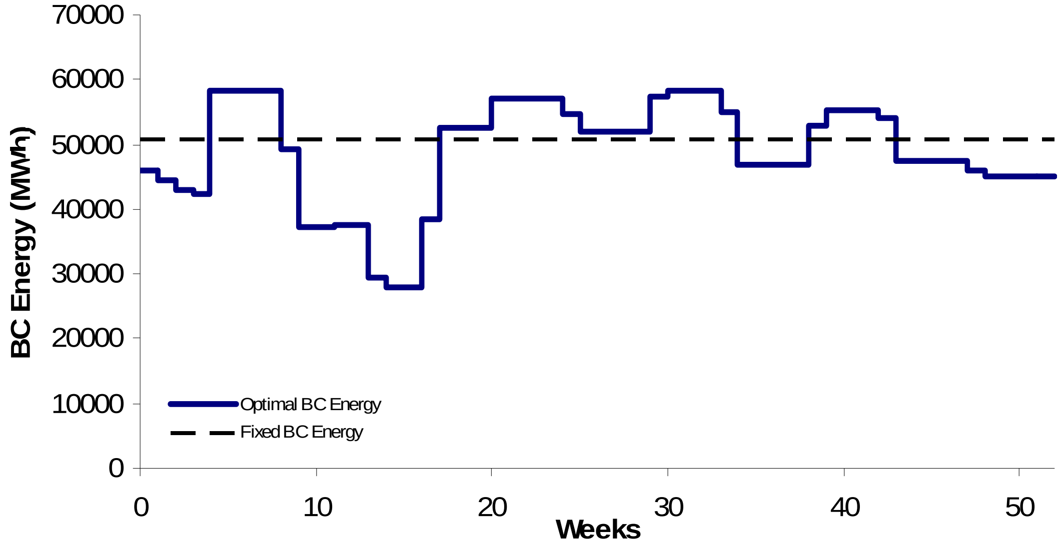


Fig 5.7. Optimal deliverable BC energy vs. fixed BC energy

TABLE 5.30

COMPARISON OF CASES 1-5 RESULTS WITH LOWEST RISK

| Cases | Expected Payoff ($) | Downside Risk ($) | Target ($) |
|---|---|---|---|
| **1: No Coordination and No BC** | 311,752,084 | 5,123,521 | 312,000,000 |
| **2: 4 Hydro units** | 143,215,223 | 168,784,777 | |
| **3: 4 Hydro + 8NG units** | 315,077,937 | 2,529,455 | |
| **4: 4 Hydro + 8NG + 3W units** | 333,540,888 | 0 | |
| **5: 4 Hydro + 8NG + 3W units with Variable BC energy** | 334,308,722 | 0 | |

### *5.2.2.6 Discussions*

The results are summarized in Table 5.30. In Case 1, the generation is offered to the real-time market with a target payoff of $312,000,000. When hydro units are committed to satisfy the BC in Case 2, the expected payoff decreases since water inflow resources are insufficient, and the GENCO is subject to penalty payments if NG and wind unit schedules are the same as those in Case 1. One NG unit is coordinated with cascaded hydro units in Case 3 and the expected payoff is higher than that in Case 1 with a lower financial risk. This is because NG and cascaded hydro units are coordinated to supply the BC energy. The coordination will avoid penalty payments and offer energy to the real-time market when it is profitable. The wind units are also coordinated in Case 4 which increases the flexibility to satisfy the BC energy and leads to a higher expected payoff and zero downside risk. In Case 5, the weekly BC energy is varied to calculate the optimal deliverable energy in one year.

## 5.3 *The Impact of DR, Wind Power and System Demand Uncertainty on Synchronous Day Ahead Market Clearing*

The proposed SCUC model and decomposition method given in section 4.2 is applied to a six-bus system to capture the essential characteristics, and to modified IEEE-118 bus system to assess performance of the method for a practical system. Finally the method is applied to clear the northwest region of Turkish electric power market, where industrial facilities are intensified.

### 5.3.1 Six-Bus System

The six-bus system data for generating units, transmission lines and system load is identical to the system given in [39], except a wind unit with maximum power output of 20MW is added at bus 6. One-line diagram of the system is given in Fig 5.8. Each DRP gives the same bid information composed of three discrete points with DRR values ($q^k_r$) of 1.8MW, 3.6MW and 5.4MW, and scheduling prices ($cc^k_{rt}$) of 10, 13 and 16 $/MW for the respective discrete bid points at each time interval. The deployment cost ($ec^k_{rt}$) is equal to 10 $/MW at each point of each offer at each time interval. The *VOLL* is assumed to be $450 at each load bus.

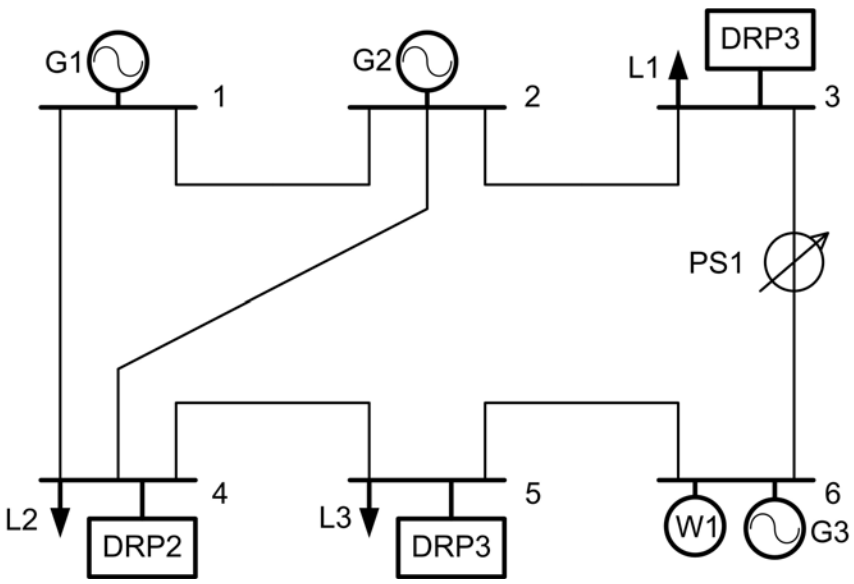


Fig 5.8. One-line diagram for six-bus system

1,500 scenarios are created to simulate wind-load uncertainties, and scenario reduction techniques are used to reduce the number of scenarios to 10 [60], [68]. The standard deviation of the error term in the wind forecast error ARMA model is assumed to be gradually increasing from 0 to %6.5 of the forecasted wind power from $t$=0 to 24. The standard deviation of system load forecast error is taken to be %3 of the forecasted load at each time interval. The probability of the scenarios is given in 4.31. The scenarios for available wind power is depicted in Fig 5.9.

TABLE 5.31
PROBABILITY OF EACH SCENARIO AFTER SCENARIO REDUCTION

| **Scenario** | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **Probability** | 0.26 | 0.12 | 0.08 | 0.07 | 0.14 |
| **Scenario** | 6 | 7 | 8 | 9 | 10 |
| **Probability** | 0.09 | 0.02 | 0.07 | 0.07 | 0.08 |

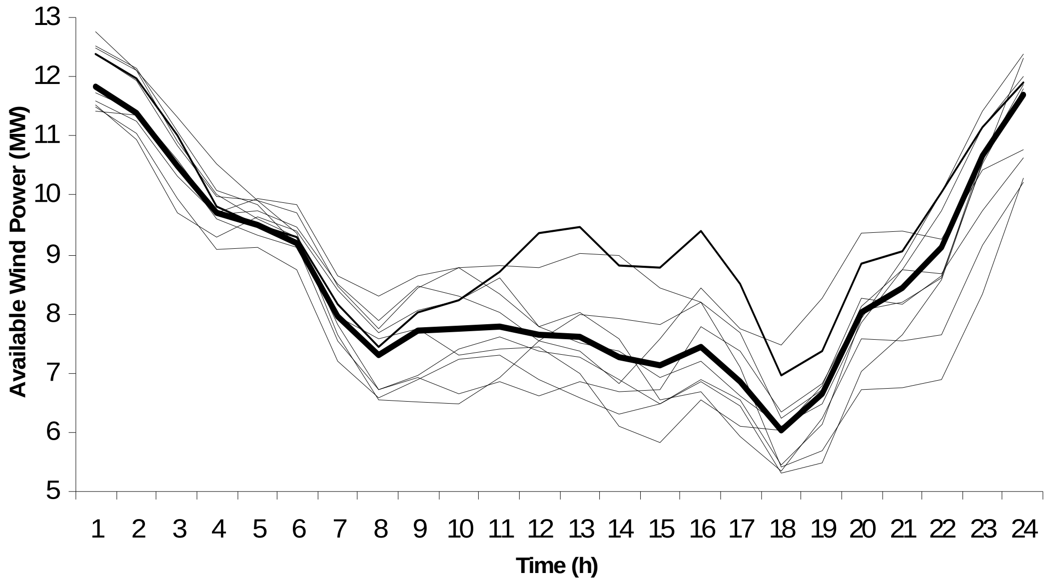


Fig 5.9. Forecasted available wind power and scenarios. Bold line is the forecasted available wind power

Three case studies are considered to capture the properties of the hybrid market clearing algorithm and MIP modeling of the DRP reserves.

Case 1: Deterministic case.

Case 2: Stochastic solution with wind power and system load uncertainty scenarios.

Case 3: Hybrid Deterministic/Stochastic solution with *N-1* contingencies and wind, and load uncertainty scenarios

TABLE 5.32
CASE 1 GENERATION DISPATCH (MW)

| Hour | G1 | G2 | G3 | W1 |
|---|---|---|---|---|
| 1 | 161.88 | 10 | 0 | 11.82 |
| 2 | 162.05 | 0 | 0 | 11.4 |
| 3 | 156.33 | 0 | 0 | 10.51 |
| 4 | 153.13 | 0 | 0 | 9.7 |
| 5 | 153.67 | 0 | 0 | 9.49 |
| 6 | 159.51 | 0 | 0 | 9.18 |
| 7 | 173.91 | 0 | 0 | 7.95 |
| 8 | 191.92 | 0 | 0 | 7.3 |
| 9 | 206.97 | 0 | 0 | 7.7 |
| 10 | 218.79 | 0 | 0 | 7.75 |
| 11 | 230 | 0 | 0.4 | 7.79 |
| 12 | 230 | 0 | 8.16 | 7.66 |
| 13 | 230 | 10 | 4.42 | 7.61 |
| 14 | 230 | 10 | 6.19 | 7.28 |
| 15 | 230 | 11.71 | 10 | 7.12 |
| 16 | 230 | 18.47 | 10 | 7.43 |
| 17 | 230 | 19.27 | 10 | 6.85 |
| 18 | 230 | 10.64 | 10 | 6.04 |
| 19 | 230 | 10 | 9.25 | 6.64 |
| 20 | 230 | 0 | 9.08 | 8.02 |
| 21 | 230 | 0 | 8.61 | 8.44 |
| 22 | 227.57 | 0 | 0 | 9.11 |
| 23 | 199.39 | 0 | 0 | 10.68 |
| 24 | 194 | 0 | 0 | 11.68 |

TABLE 5.33
CASE 2 BASE CASE GENERATION DISPATCH (MW)

| Hour | G1 | G2 | G3 | W1 |
|---|---|---|---|---|
| 1 | 161.88 | 10 | 0 | 11.82 |
| 2 | 170.6 | 0 | 0 | 2.85 |
| 3 | 161.72 | 0 | 0 | 5.12 |
| 4 | 158.9 | 0 | 0 | 3.93 |
| 5 | 161.54 | 0 | 0 | 1.63 |
| 6 | 161.48 | 0 | 0 | 7.21 |
| 7 | 173.91 | 0 | 0 | 7.95 |
| 8 | 192.57 | 0 | 0 | 6.64 |
| 9 | 214.67 | 0 | 0 | 0 |
| 10 | 223.45 | 0 | 0 | 3.1 |
| 11 | 230 | 0 | 1.9 | 6.28 |
| 12 | 230 | 0 | 9.83 | 5.99 |
| 13 | 230 | 10 | 9.85 | 2.18 |
| 14 | 230 | 10 | 6.19 | 7.28 |
| 15 | 230 | 18.82 | 6.54 | 3.47 |
| 16 | 230 | 25.9 | 10 | 0 |
| 17 | 230 | 26.12 | 10 | 0 |
| 18 | 230 | 13.01 | 7.63 | 6.04 |
| 19 | 230 | 10 | 10 | 5.89 |
| 20 | 230 | 0 | 10 | 7.1 |
| 21 | 230 | 0 | 10 | 7.05 |
| 22 | 230 | 0 | 0 | 6.68 |
| 23 | 210.07 | 0 | 0 | 0 |
| 24 | 198.34 | 0 | 0 | 7.35 |

#### 5.3.1.1 *Case 1: Deterministic case*

This case would provide a reference to compare cases 2-4 with the deterministic solution, in which no contingency and uncertainty exists. The *N-1*contingencies and wind, load uncertainty scenarios are not considered in the deterministic case, instead the forecasted values of available wind power and system load are assumed. The total cost is calculated to be $99,061. Table 5.32 depicts the scheduling of three thermal units and the wind units for the study horizon. Available wind power is fully utilized, since the wind units are assumed to be price-takers, and have zero bidding. G1 is scheduled for all of the hours since it is the cheapest unit. G2 is kept on in the first hour due to min-on constraints. G2 is scheduled to generate between hours 11-21, while G3 is on between 13-19, since these are the next expensive units in ascending order. Obviously, no reserves are scheduled in the deterministic case.

#### 5.3.1.2 *Case 2: Stochastic solution with wind power and system load uncertainty scenarios.*

This case includes wind, load uncertainties through Monte-Carlo scenarios, without considering *N-1* contingencies. The algorithm optimally clears the energy and A/S market by ensuring the problem constraints are satisfied. The system cost increases to $103,646. Table 5.33 gives the unit generations for the base case for Case 2. When Table 5.33 is compared to Table 5.32, it is observed that the available wind power is curtailed for all of the scenarios, which is due to the minimization of cost. It is observed that the algorithm curtails the wind power for the base case in order to have an adjustment range for the uncertainty scenarios and the amount of scheduled unit reserves is reduced as a consequence. The algorithm prefers to schedule wind units below the available wind power capacity at certain hours so that it could use the excess of wind as spinning up reserves in the case of a *N-1* contingency or an uncertainty scenario. The system cost increases to $104,733 when the wind generation is forced to be equal to the available wind power under base case and all of the uncertainty scenarios due to the allocated expensive reserves. Fig 5.10 depicts the wind power generations under base case and uncertainty scenarios.

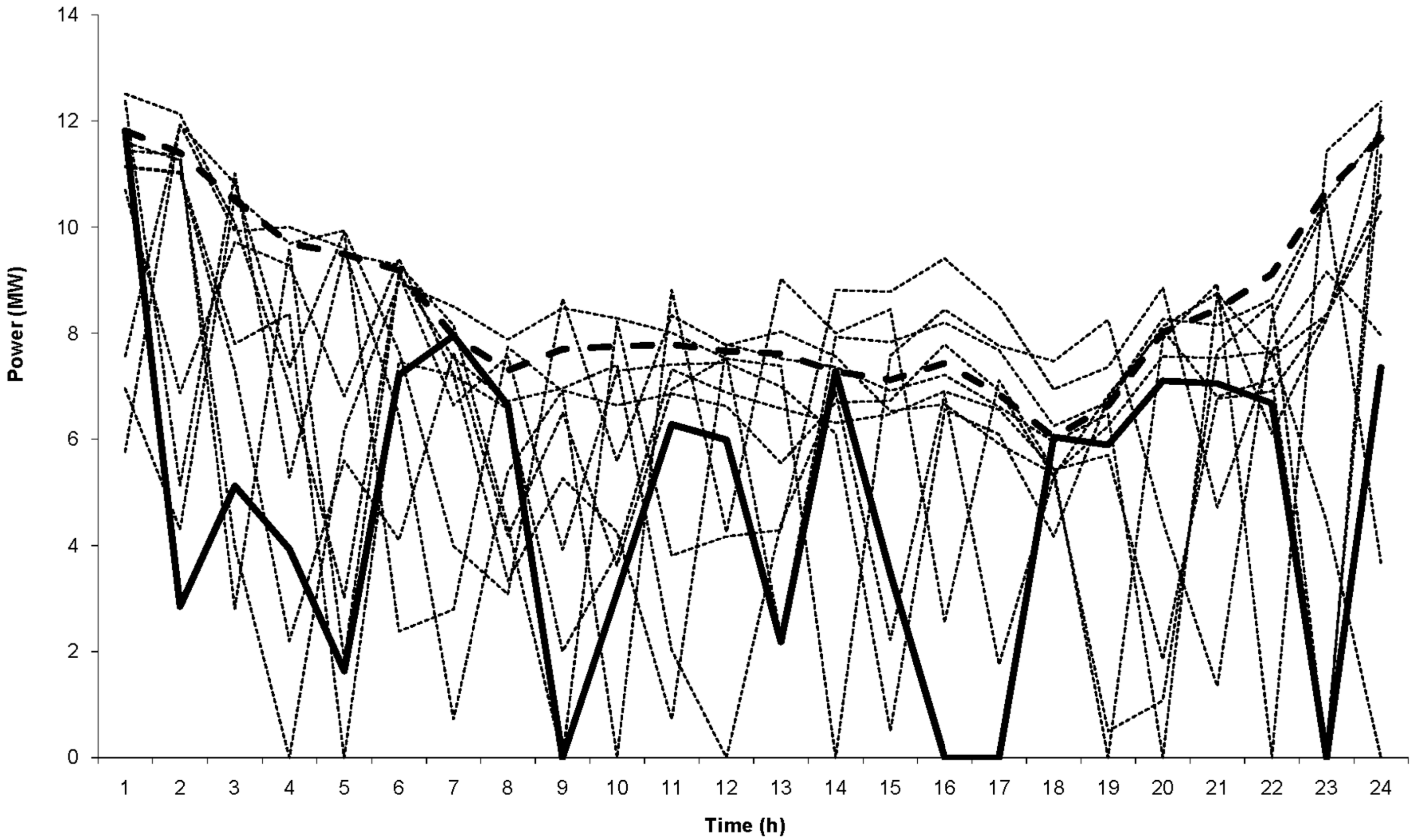


Fig 5.10. Wind power generation in Case II. Thick solid line represents base case scheduling, thick dotted line represents the available capacity, thin dotted lines depict generation schedules under uncertainty scenarios

TABLE 5.34

CASE 2 RESERVE DISPATCH (MW)

| Hour | $OR_u$ | | | $OR_d$ | | | DR | | |
|---|---|---|---|---|---|---|---|---|---|
| | G1 | G2 | G3 | G1 | G2 | G3 | DRP1 | DRP2 | DRP3 |
| 1 | 5.07 | 0 | 0 | 0.07 | 0 | 0 | 0 | 0 | 0 |
| | | | | | | | | | |
| 2 | 0 | 0 | 0 | 8.48 | 0 | 0 | 0 | 0 | 0 |
| 3 | 0 | 0 | 0 | 5.54 | 0 | 0 | 0 | 0 | 0 |
| 4 | 0 | 0 | 0 | 3.45 | 0 | 0 | 0 | 0 | 0 |
| 5 | 0 | 0 | 0 | 3.33 | 0 | 0 | 0 | 0 | 0 |
| 6 | 2.53 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | 10.82 | 0 | 0 | 0.18 | 0 | 0 | 0 | 0 | 0 |
| 8 | 3.46 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | 0.27 | 0 | 0 | 7.17 | 0 | 0 | 0 | 0 | 0 |
| 10 | 0 | 0 | 0 | 3.01 | 0 | 0 | 0 | 0 | 0 |
| 11 | 0 | 0 | 6.67 | 0 | 0 | 0.53 | 0 | 0 | 0 |
| 12 | 0 | 0 | 0 | 0 | 0 | 4.25 | 1.8 | 1.8 | 1.8 |
| 13 | 0 | 0 | 0 | 0 | 0 | 5.29 | 0 | 0 | 1.8 |
| 14 | 0 | 5.17 | 3.81 | 0 | 0 | 2.18 | 0 | 0 | 0 |
| 15 | 0 | 0 | 3.46 | 0 | 8.82 | 0 | 0 | 0 | 0 |
| 16 | 0 | 0.18 | 0 | 0 | 15.9 | 0 | 0 | 0 | 0 |
| 17 | 0 | 5.46 | 0 | 0 | 9.46 | 0 | 0 | 0 | 0 |
| 18 | 0 | 6.04 | 2.37 | 0 | 3.01 | 0 | 0 | 0 | 0 |
| 19 | 0 | 0 | 0 | 0 | 0 | 4.47 | 5.4 | 3.6 | 3.6 |
| 20 | 0 | 0 | 0 | 0 | 0 | 1.18 | 0 | 1.8 | 0 |
| 21 | 0 | 0 | 0 | 0 | 0 | 3.76 | 5.4 | 5.4 | 5.4 |
| 22 | 0 | 0 | 0 | 1.16 | 0 | 0 | 1.8 | 3.6 | 1.8 |
| 23 | 3.16 | 0 | 0 | 7.95 | 0 | 0 | 0 | 0 | 0 |
| 24 | 0 | 0 | 0 | 3.85 | 0 | 0 | 0 | 0 | 0 |

The reserve dispatch is given in Table 5.34. The algorithm does not schedule any spinning reserve, while allocating operating reserves, DRs in Case 2. These are the maximum deployable reserves available for the uncertainty scenarios, and determined on the basis of the scenario data. Involuntary load shedding is utilized in scenarios 1,2,4,5, and 7, with amounts of 790, 50, 370, 120 and 5,210 kWh respectively. Notice that maximum amount of shedding occurs in the 7th scenario which has the least probability. Here the probability of the occurrence of the wind, load uncertainties is considered and load shedding is utilized whenever its contribution to the stochastic cost is less than allocating additional generating reserve with probability of one. The system cost increases to $103,747 when involuntary load shedding is not allowed.

Case 1 results could be interpreted as calculated with a deterministic framework which is proposed in [38]. When the UC decisions out of this case is applied to Case 2, a feasible solution could not be calculated due to the fact that consideration of wind, load uncertainties requires reserve allocation, and no spinning, operating generating unit reserves and DRs were allocated in Case 1 due to perfect wind power and system load forecast assumption.

### *5.3.1.3 Case 3: Hybrid Deterministic/Stochastic Solution*

Two *N-1* contingencies of G3 outage and a transmission line (between buses 3-6) are considered together with the 10 wind, load uncertainty scenarios. The system cost increases to $104,995 in Case 3,with the consideration of *N-1* contingencies. The reserve dispatch for Case 3 is given in Table 5.35. The DR schedule is omitted in the table since it is identical to Case 2. Being different than Case 2, the spinning reserves are scheduled to be immediately deployed when the G3 is on outage, to keep the frequency oscillations inside the safe limits. As an addition base case wind generation is curtailed in Case 3 to participate the *N-1* contingency and uncertainty scenarios, similar to Case 2.

TABLE 5.35

CASE 3 RESERVE DISPATCH (MW)

| Hour | $SR_u$ | $OR_u$ | | | $OR_d$ | | |
|---|---|---|---|---|---|---|---|
| | G2 | G1 | G2 | G3 | G1 | G2 | G3 |
| 1 | 0 | 5.07 | 0 | 0 | 0.07 | 0 | 0 |
| 2 | 0 | 0 | 0 | 0 | 8.48 | 0 | 0 |
| 3 | 0 | 0 | 0 | 0 | 5.54 | 0 | 0 |
| 4 | 0 | 0 | 0 | 0 | 3.45 | 0 | 0 |
| 5 | 0 | 0 | 0 | 0 | 3.33 | 0 | 0 |
| 6 | 0 | 2.53 | 0 | 0 | 0 | 0 | 0 |
| 7 | 0 | 10.8 | 0 | 0 | 0.18 | 0 | 0 |
| 8 | 0 | 3.46 | 0 | 0 | 0 | 0 | 0 |
| 9 | 0 | 0.27 | 0 | 0 | 7.17 | 0 | 0 |
| 10 | 0 | 0 | 0 | 0 | 3.01 | 0 | 0 |
| 11 | 0 | 0 | 0 | 6.67 | 0 | 0 | 0.53 |
| 12 | 0 | 0 | 0 | 0 | 0 | 0 | 4.25 |
| 13 | 0 | 0 | 0 | 0 | 0 | 0 | 5.29 |
| 14 | 0 | 0 | 5.17 | 3.81 | 0 | 0 | 2.18 |
| 15 | 1.28 | 0 | 0 | 3.46 | 0 | 8.82 | 0 |
| 16 | 2.57 | 0 | 0.18 | 0 | 0 | 15.9 | 0 |
| 17 | 3.15 | 0 | 5.46 | 0 | 0 | 9.46 | 0 |
| 18 | 3.96 | 0 | 6.04 | 2.37 | 0 | 3.01 | 0 |
| 19 | 2.43 | 0 | 0 | 0 | 0 | 0 | 4.47 |
| 20 | 0 | 0 | 0 | 0 | 0 | 0 | 1.18 |
| 21 | 0 | 0 | 0 | 0 | 0 | 0 | 3.76 |
| 22 | 0 | 0 | 0 | 0 | 1.16 | 0 | 0 |
| 23 | 0 | 3.16 | 0 | 0 | 7.95 | 0 | 0 |
| 24 | 0 | 0 | 0 | 0 | 3.85 | 0 | 0 |

Case 3 considers the *N-1* contingencies together with the uncertainty scenarios, and the system cost increases to $104,995 from $103646, in order to satisfy the security in the occurrence of the contingencies. References such as [40]-[42] considering the wind and load uncertainties would be matched with Case 2 results, while the contingencies are still omitted. Consequently a scheduling omitting contingencies would result with involuntary load shedding or even blackouts due to the scheduling insensitive to contingencies. This is verified by forcing the Case 2 UC solutions to the Case 3 analysis and no feasible solution is found due to the fact that Case 2 scheduling results with line flow violations due to the credible contingency of outage of transmission line between buses 3-6 in Case 3. It should be noted that involuntary load shedding is not allowed for *N-1*contingencies since these are treated deterministically.

#### *5.3.1.4 Sensitivity Analysis:*

A sensitivity analysis is performed to evaluate the effects of the level of wind power and system load forecast uncertainties. Fig 5.11 depicts the uncertainty levels versus calculated expected costs. In order to compare the effect of wind and load uncertainties, the standard deviations of wind uncertainty is divided by maximum power output of wind unit and standard deviation of load uncertainty is divided by maximum system load. First the system load uncertainty is fixed to Case 3 value (3%) and wind power uncertainty is varied starting from Case 3 value (6.5%) to 32% which is represented with the curve with "x" markers. Then, the wind power uncertainty is fixed to Case 3 value (6.5%) and system load uncertainty is varied starting from Case 3 value (3%) to 12% which is represented with "Δ" markers. For the former, we observe that wind power uncertainty does not change the expected system cost significantly, which will be discussed later. However, the expected system cost sharply increases due to allocation and deployment of additional reserves to respond to the volatile system load.

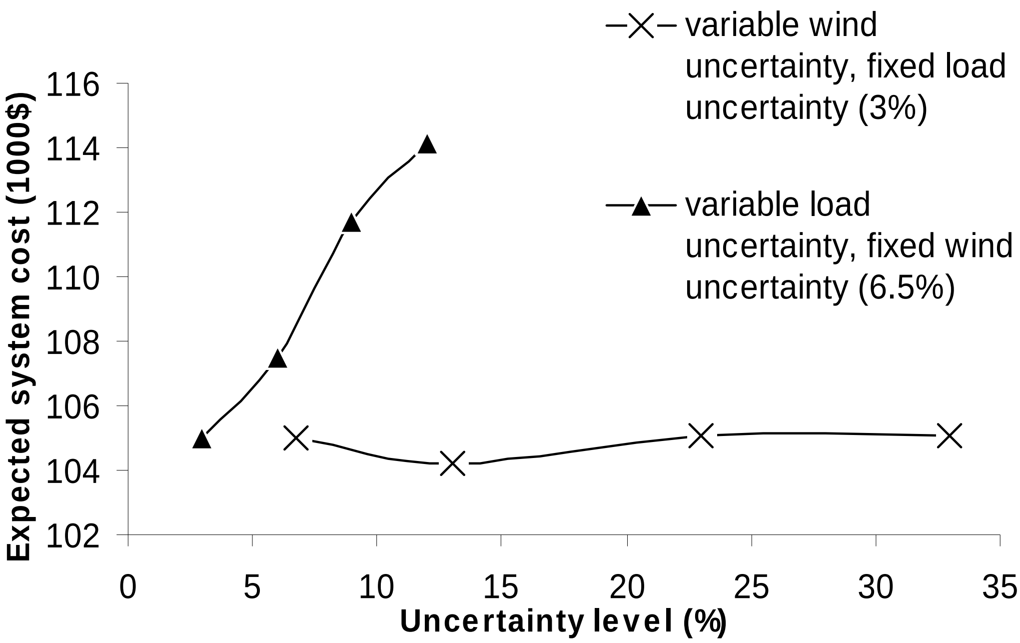


Fig 5.11. Expected system cost versus wind power and system load uncertainty.

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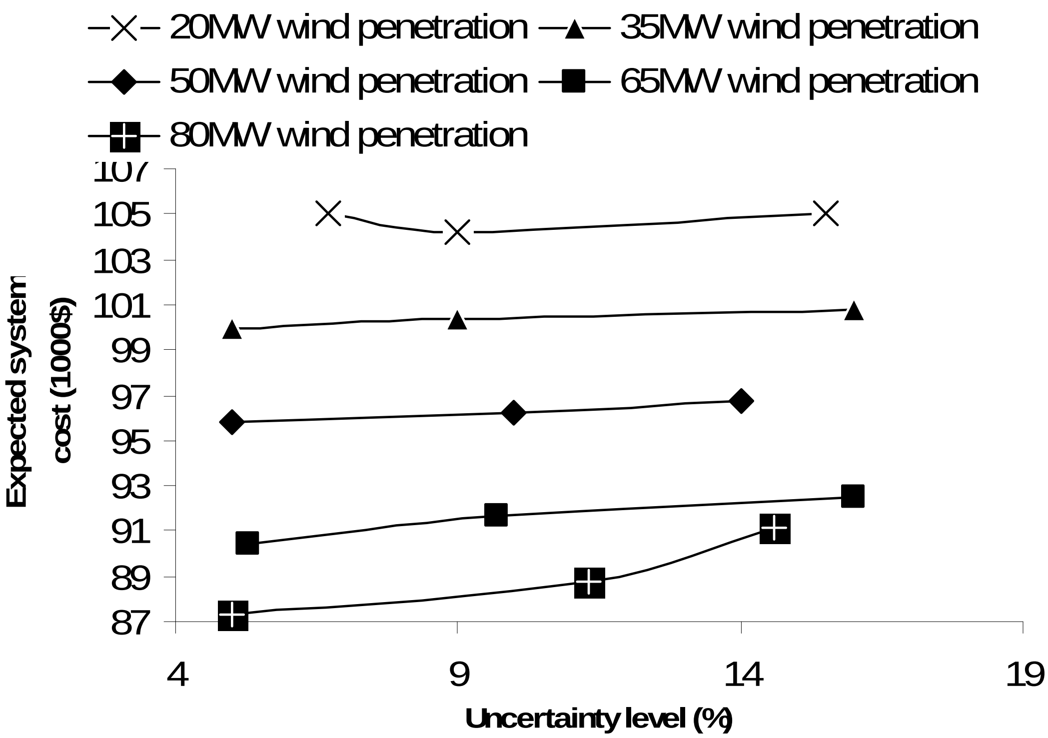


Fig 5.12. Expected system cost versus wind power uncertainty with penetration level as parameter. The load uncertainty is 3% .

Fig 5.12 depicts the expected cost for different values of uncertainty levels at each different wind penetration level when the system load uncertainty standard deviation is kept at 3%. It could be seen that for lower levels of wind penetration, the sensitivity of the expected system cost with respect to wind power forecast uncertainty is insignificant. But as we increase the penetration level, the expected cost makes sharper increases as the forecast uncertainty increases. This is due to the fact that significant amount of reserves has to be allocated and deployed in order to cover for the larger wind power uncertainties

### 5.3.2 Modified IEEE 118-Bus System

Modified IEEE 118-Bus system is used to evaluate the efficiency of the method. Three wind units are added to 54 existing units. There are 186 branches, and 91 loads in the system. There assumed to be 50 DRPs at certain load buses, giving bids to the reserve market. The VOLL is assumed to be 400 $/MWh for each load bus. Seven *N-1* contingencies are considered, outage of generators at buses 77, 82, 105, 113 and outage of lines 17-113, 114-115 and 17-113. The wind power and system load uncertainties are represented by 1500 Monte Carlo scenarios. The number of scenarios are reduced to 12 by using forward-backwards scenario reduction techniques [60], [68]. The detailed system data could be reached from motor.ece.iit.edu/data/Energy_AS_Clearing.

The total expected system cost is calculated to be $1,232,786 when the DRRs are not considered. Only the generation reserve bids are considered in this calculation. A total of 1260 MWh upwards operating reserve capacity is allocated from units 7, 34, 35, 37, 40, 45, 47, 48, 51, and 53, while 2312 MWh downwards operating reserve capacity is allocated from units 7, 34, 35, 37, 39, 40, 43, 45, 47, 48, 51, and 53. 15.01 MWh involuntary load shedding occurs at buses 45 and 46, under wind, load uncertainty scenario 8. When the discrete DRP bids are considered the expected total cost reduces to $1,229,402. The allocation of upwards operating reserves reduce to only 67MWh from units 35, 40, 43, 45, 47, and 48 and the downwards operating reserves reduce to 1187MWh taken from units 7, 26, 35, 39, 40, 43, 45, 47, and 48. 2652 MWh DRR capacity is allocated from different DRPs and these are deployed for both contingency and wind, load uncertainty scenarios whenever they are cheaper than generating unit upwards operating reserve bids. Besides, no involuntary load shedding is observed in the calculated schedule. Wind scheduling is also changed between the DRR enabled and disabled cases. When the DRR is disabled, the algorithm curtails much wind than the DRR enabled case in order to provide an adjustment range for the *N-1* contingencies and uncertainty scenarios. 2388MWh of wind energy is curtailed in the DRR disabled case while only 972MWh of wind is curtailed in the DRR enabled case.

There are 519,504 variables, 181,800 inequality constraints, and 131,856 equality constraints for the master problem. There are 731 variables, 372 inequality and 304 equality constraints in each dc network subproblem. The solution time is 1 hour, 42 minutes.

#### 5.3.2.1 Scalability Analysis

It is necessary to make a scalability analysis to evaluate the performance of the method when the number of *N-1* contingencies and the uncertainty scenarios are increased. For this purpose, two different tests were performed. First three *N-1* contingencies are considered together with 12, 18, and 24 uncertainty scenarios respectively. The change of the solution time with respect to the number of uncertainty scenarios is observed from the results of this test. Secondly, the number of *N-1*scenarios is changed as 3, 7, and 11 while the number of uncertainty scenarios is kept at 12. This gives information about the dependence of performance to the number of *N-1* contingencies. The number of variables, equality, and inequality constraints for both of the scalability tests are given in Table 5.36. Fig 5.13 depicts the solution times for both tests.

TABLE 5.36

SCALABILITY ANALYSIS PROBLEM DIMENSIONS

| *N-1* Contingencies | Uncertainty Scenarios | Variables | Equality Constraints | Inequality Constraints |
|---|---|---|---|---|
| 3 | 12 | 422,640 | 111,552 | 146,088 |
| | 18 | 583,488 | 157,776 | 199,944 |
| | 24 | 744,336 | 204,000 | 253,800 |
| 3 | 12 | 422,640 | 111,552 | 146,088 |
| 7 | | 519,504 | 131,856 | 181,800 |
| 11 | | 616,368 | 152,160 | 217,512 |

It is observed that the slope of the solution time curves, decreases as the number of contingencies and uncertainties increase. This is due to the fact that some contingencies or uncertainty scenarios require more reserve allocation and once these are resolved extra added contingencies or scenarios might not require extra reserve allocation. Besides performance is more sensitive to number of *N-1* contingencies since one contingency introduces more equality and inequality constraints to the problem than one uncertainty scenario does.

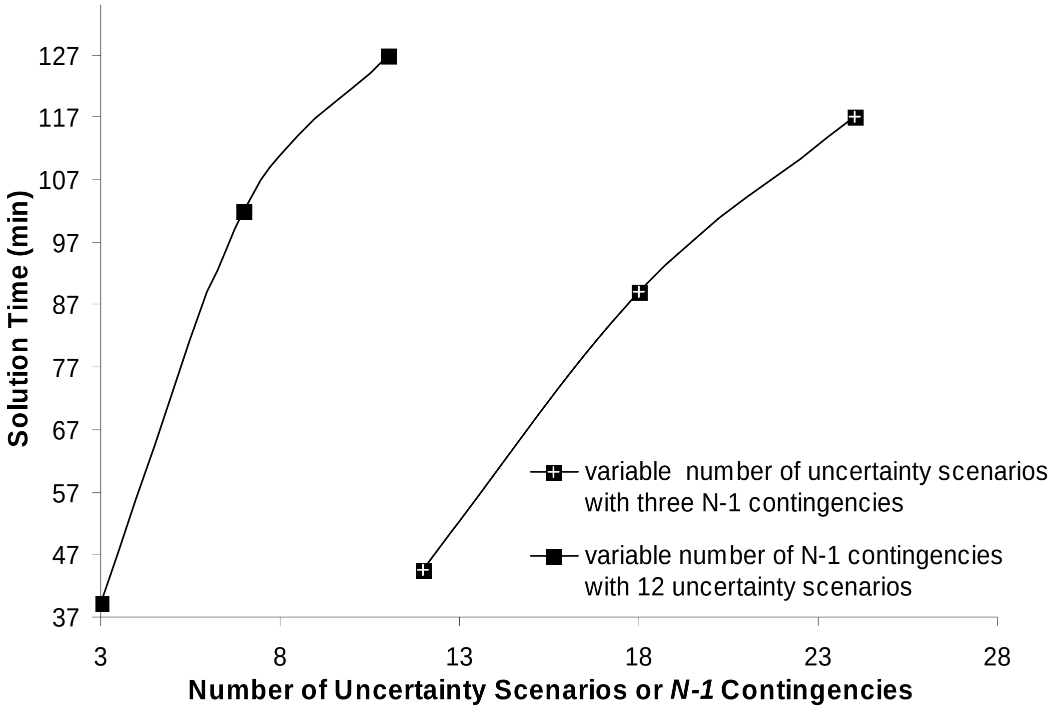


Fig 5.13. Solution times versus *N-1*contingency or uncertainty scenario number.

### 5.3.3 Northwest Region of Turkish Power System

Turkey has taken major steps towards building the country's Electricity Market since the enactment of "Turkish Electricity Market Law" in 2001. The total installed generation capacity of Turkey has reached 42.2 GW, and the total generating capacity has been 238.2 TWh by the end of year 2007. Electricity generation is divided into four main categories as: EUAS (Electrical Generation Company) that belongs to government, private electric generation companies, self generators, and power plants subject to Transfer of Operation Rights (TOOR). Self generators are industrial companies which generate electricity for their own and their shareholder applications and they have the right to market the excess of generation. The share of private generation has grown in the last five years. The ratio of private investments in Turkey's total installed capacity is 44% by the end of 2008. The Energy and A/S markets are cleared by the governmental system operator company named "Turkish Electricity Transmission Company" (TEIAS) [70].

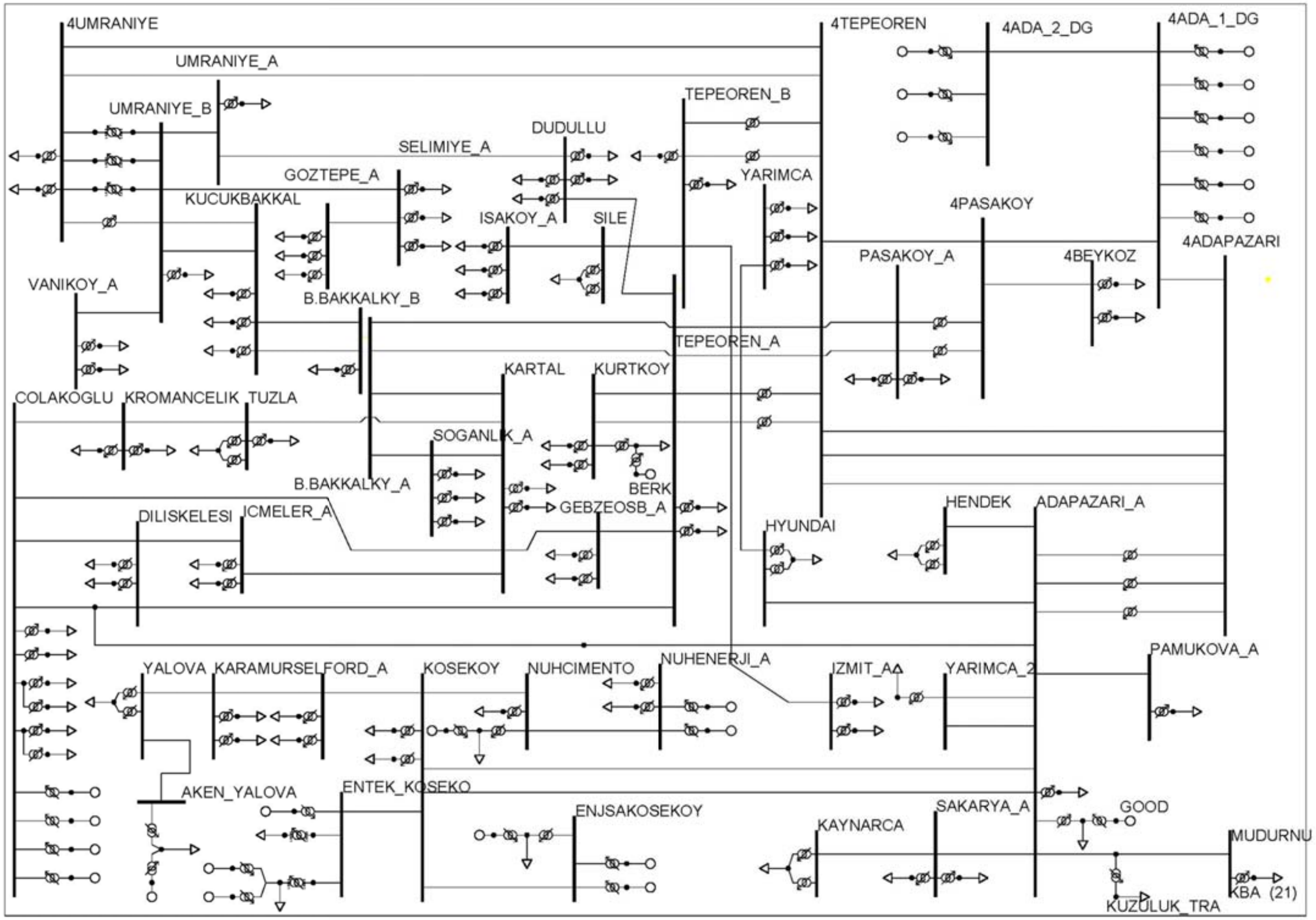


Fig 5.14 Northwest Region of Turkish Electric Power Network

In this section, Energy and A/S markets clearing study is performed for the northwest region of Turkish Power System. This subsystem includes intense industrial activities, and proposed framework would investigate the effects of DR and wind, load uncertainty to the energy and A/S market clearing for the regional market.

The subsystem is composed of 173 buses, 28 thermal generating units, 66 branches, and 131 transformers. Fig 5.14 depicts the one line diagram of the network. Two *N-1* contingencies are considered as the outages of one of the generators at bus NUHENERJI_A, and transmission line COLAKOGLU-KROMANCELIK. 1500 scenarios are created to simulate wind, load uncertainties and these are reduced to 12 scenarios using scenario reduction techniques. the standard deviations for wind and load uncertainties are taken to be 6.5%, and 4% respectively. Considerable industrial loads appear at buses DILISKELESI, COLAKOGLU, ICMELER, DUDULLU and GEBZEOSB. These loads are mostly composed of ship yards, steel and cement manufacturing facilities and an industrial zone. Six individual DRPs are located at residential load and industrial zone buses. Three wind farms with 100 MW peak capacities are located at three buses SILE, KARAMURSEL and YALOVA. Detailed data is included in the web reference given in previous section 5.3.2. Six potential DRP buses are selected as DILISKELESI, COLAKOGLU, DUDULLU, KOSEKOY, KUCUKBAKKAL, and GEBZEOSB, since these are both residential and industrial loads, that are likely to include consumers willing to participate a DR program. For instance cement factories might opt to curtail their consumption in such hours required by the ISO, and shift their production. The DRP bids are composed of three discrete DRR values of 7,14 and 21 MW with prices of 7, 9, and 11 \$/MW respectively. The deployment cost is taken to be 2.5 \$/MW.

TABLE 5.37

ALLOCATED DRRS FROM DRPS

| **Hour** | | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **DRP** | **1** | 7 | 7 | 0 | 0 | 0 | 0 | 0 | 14 | 7 | 7 | 7 | 7 |
| | **2** | 0 | 7 | 7 | 0 | 7 | 0 | 7 | 14 | 7 | 0 | 7 | 7 |
| | **3** | 7 | 0 | 7 | 0 | 0 | 0 | 7 | 14 | 14 | 7 | 7 | 7 |
| | **4** | 7 | 0 | 0 | 0 | 7 | 0 | 7 | 7 | 0 | 0 | 0 | 0 |
| | **5** | 0 | 0 | 7 | 0 | 0 | 0 | 7 | 7 | 7 | 0 | 0 | 7 |
| | **6** | 7 | 7 | 0 | 0 | 7 | 7 | 7 | 14 | 7 | 0 | 7 | 7 |
| **Hour** | | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** |
| **DRP** | **1** | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 14 | 21 | 7 | 7 | 7 |
| | **2** | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 14 | 14 | 0 | 7 | 0 |
| | **3** | 14 | 14 | 7 | 7 | 14 | 14 | 0 | 14 | 14 | 14 | 14 | 7 |
| | **4** | 7 | 7 | 7 | 0 | 7 | 7 | 0 | 0 | 0 | 7 | 7 | 0 |
| | **5** | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 14 | 0 | 7 | 0 |
| | **6** | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 14 | 7 | 7 | 7 | 0 |

The problem is solved first with considering only reserves from the generating units. The system expected day-ahead scheduling cost is calculated as \$546,581. The contingencies, and wind, load uncertainties are addressed with allocating operating reserves from generating units and curtailment of base case wind power. No expensive spinning reserves are allocated since the excess wind power capacity due to the curtailment of available base case wind power is used to cover for the contingency and uncertainty scenarios. The total amount of base case curtailment is calculated to be 1114 MWh. The expected system cost reduces to \$537,315 with the consideration of DRPs. The DRs replace the operating reserves from the generating units. Besides limited amount of spinning reserves from generating units are allocated. The curtailment of wind power reduces to 534MWh resulting with a lower expected system cost. The amounts of allocated DRRs are shown in Table 5.37. The DRP numbers refer to the DRPs on the buses that are mentioned in the previous paragraph respectively.

### 5.3.4 Verifications and Comparisons

In order to verify the accuracy and optimality of the results, the input data from [38] is used. At first stage, the 6-bus system given in [38] is used as the input data to the proposed algorithm. The system scheduling cost and unit power generations and reserve schedules are calculated for the Case 1 and Case 2 given in the reference [38]. The system costs are calculated as \$105,621 and \$106,436 for Case 1 and 2 respectively, which are identical to results given in [38]. The generation schedule for Case 1 is given in Table 5.38.

At second stage, the IEEE 118-Bus input data with the consideration of generating reserves from [38] is used to verify the proposed algorithm solution with the existing literature. The proposed algorithm calculates the system cost \$1,356,989.1. Reference [38] calculates the Case 1 system cost \$1,357,344.6. The difference between the optimal system costs is 0.02% ( (\$1,357,344.6-1,356,989.1) / 1,356,989.1 ), which is negligible. It might be assumed that these two results are practically identical. The small difference between the results are originated from the following reasons:

- First the reference [38] uses a two stage Benders algorithm, while we used a single stage Benders decomposition
- Second the optimality gap for the MIP solver might have been set to a different value in reference [38]. The optimality gap is a solver parameter that adjusts the convergence.

As a third verification of optimality, the wind power schedule determined by the algorithm, which was given in Fig. 5.10, is modified by forcing the wind schedule to pre-specified values. It is expected that the expected system cost would increase when the wind schedule is changed incrementally from the optimal schedule calculated by the proposed algorithm. The scheduled wind outputs were 0 MW and 6.04 MW for hours 17 and 18 respectively at the optimal point. These schedules are forced to 3.00 MW and 3.04 MW for hour 17 and 18 respectively. The expected system cost increases to $103,650, from the optimal cost for Case 2 which was calculated to be $103,646. The cost increase is so small due to the fact that there is only an incremental change from the optimal point. This observation provides another verification for the optimality of the result.

TABLE 5.32
GENERATION DISPATCH FOR INPUT DATA OF CASE 1 FROM REFERENCE [38] (MW)

| Hour | G1 | G2 | G3 |
|---|---|---|---|
| 1 | 173.69 | 10 | 0 |
| 2 | 173.45 | 0 | 0 |
| 3 | 166.84 | 0 | 0 |
| 4 | 162.83 | 0 | 0 |
| 5 | 163.16 | 0 | 0 |
| 6 | 168.69 | 0 | 0 |
| 7 | 181.86 | 0 | 0 |
| 8 | 199.21 | 0 | 0 |
| 9 | 214.67 | 0 | 0 |
| 10 | 226.54 | 0 | 0 |
| 11 | 230 | 0 | 8.18 |
| 12 | 230 | 10 | 5.82 |
| 13 | 230 | 12.03 | 10 |
| 14 | 230 | 13.47 | 10 |
| 15 | 230 | 18.83 | 10 |
| 16 | 230 | 25.9 | 10 |
| 17 | 230 | 26.12 | 10 |
| 18 | 230 | 16.68 | 10 |
| 19 | 230 | 15.89 | 10 |
| 20 | 230 | 10 | 7.1 |
| 21 | 230 | 10 | 7.05 |
| 22 | 230 | 0 | 6.68 |
| 23 | 210.07 | 0 | 0 |
| 24 | 205.69 | 0 | 0 |

# CHAPTER 6

# CONCLUSIONS

This study contributes to two main problems of the deregulated electricity markets namely the PBUC problem of the GENCOs and the SCUC problem of the TSOs. The NG infrastructure is linearly modeled in order to consider the physical limitations of the NG transmission system. The wind power generation models and BCs as financial hedging tools are also integrated to achieve a complete PBUC framework. Regarding the SCUC problem, a discrete DRP bidding model is proposed to evaluate the demand management in the market clearing process. Moreover, a hybrid deterministic/stochastic model is constructed in order to enable the evaluation of the deterministic *N-1*contingencies together with the wind, load uncertainties.

The NG infrastructure constraints are incorporated into the GENCO's risk-constrained hydrothermal scheduling. Test results show that besides uncertainties in market prices and water inflow, GENCOs must further consider the NG infrastructure limitations in the optimal midterm scheduling. The NG storage facilities would improve the expected payoff of the GENCO against NG interruptions by providing NG at interrupted hours. The effect of utilizing the NG storage on the expected payoff is analyzed and it is observed that a considerable improvement in the expected payoff would be attainable even by a limited storage capacity in comparison with any NG interruptions. In addition, the solution for the optimization of the individual types of units separately is compared with that of all units together. It is observed that the solution of all units together would provide a better chance for any risk reductions.

The wind generation unit models and weekly BCs are introduced to a GENCO's risk-constrained midterm hydrothermal scheduling. A small system demonstration is included to introduce the concept of coordination. Case studies show that BCs could adversely affect the expected payoff and financial risk of the GENCO when only hydro units are considered. The expected payoff increases and the financial risk decreases with the addition of NG and wind units to the coordination. The observations are given as follows:

- Forward BCs are used to hedge GENCOs' financial risks against uncertain market prices.

- The coordination in midterm operation planning could introduce flexibility to satisfy BCs when more deterministic NG units are available.

- An uncertain GENCO could utilize the proposed algorithm to calculate its highest expected payoff in coordination with BCs. It should be noted that the wind forecast uncertainty has a great impact on the midterm operational analysis. A GENCO should utilize accurate forecasting tools to obtain a sound financial perspective since the financial risk increases nonlinearly with the increments in wind power forecast uncertainty.

- The amount of consumed NG for NG fired units increases as the wind uncertainty increases for the risk neutral case, when the risk minimization constraints are not considered. When the wind uncertainty is fixed and relatively low, the algorithm decreases the NG utilization in order to decrease the financial risk as the risk constraints are included. However this decrease in the NG utilization is not observed for higher wind uncertainties since it does not mitigate the risk due to high uncertainty. GENCO should determine its target profit carefully under such high wind uncertainties.

- GENCOs with different types of generating units can use this algorithm for the midterm planning of optimal BCs and real-time energy market offers.

The verification of optimality of results could not be done through an existing study in the literature due to the fact that proposed PBUC algorithm study horizon is one year and there is no data available in the literature to consider in the proposed framework. Besides very small problems (such as given in section 5.2.1.3) are constructed and solved both in simple MATLAB m-file and the proposed framework implemented in C++ environment. The results are calculated to be the same verifying the algorithm in a small scale problem. Besides, the optimality of the algorithm is verified by forcing the UC states in the Case 2 (section 5.1.2) to the Case 1 (section 5.1.1) calculations. The expected profit decreases compared to the unforced solution for the PBUC maximization problem. This observation verifies the optimality of the proposed PBUC solutions.

The conclusions given above are concerned with the GENCO's PBUC problem. The conclusions regarding the TSO's SCUC problem are as follows:

Synchronous clearing of energy and A/S markets is superior to sequential methods, since it eliminates price reversal and potential market power [1]-[4]. Wind power is a popular renewable energy resource, and stochastic market clearing methods are proposed to address the volatile nature of wind power [13]-[14]. While these studies consider wind power and system load forecast uncertainties, they do not address the contingencies such as generating unit and transmission line outages. The contingencies should be considered together with the uncertainties during the market clearing process since the system must be secure in the presence of a contingency.

We propose a synchronous market clearing scheme both considering equipment outage contingencies in a deterministic *N-1*contingency model, while the wind power and system load uncertainties are represented in two-stage stochastic programming model with Monte Carlo scenarios. To reduce the computational complexity, the problem is decomposed into a master UC and reserve scheduling problem, and network subproblems. Other than wind power and system load uncertainty, DRRs are modeled to fit the MIP problem formulation framework. The DRPs are aggregators that combine separate DRRs in a single bidding curve for the day ahead A/S market. The DRRs are not continuously adjustable reserves, but these are aggregated volunteer costumers that could reduce their consumption to zero when requested. For that reason, we propose a discrete DRR bid structure rather than a continuous one, since it reflects the true behavior of DRRs. The proposed model is solved using CPLEX 11.0 MIP solver.

The proposed method is used to analyze the effect of *N-1* contingencies, wind-load scenarios and DRP bids in a six-bus system. When the contingency and uncertainty scenarios are both considered, it is observed that wind power is curtailed in the base case to respond to the wind-load uncertainty scenarios by increasing the wind power unit generations with the remaining available wind energy when the uncertainty is realized. The curtailed wind power in the base case is utilized as spinning up reserves in the presence of an *N-1* contingency or an uncertainty scenario. The sensitivity analysis show that the expected system cost is more sensitive to load uncertainty level. The effect of wind uncertainty depends on the penetration level. The system cost decreases as the wind penetration increases since the operating cost of wind power units is assumed to be zero. However, the expected cost increases considerably with the increasing wind forecast uncertainty for a high wind penetration. A modified IEEE 118-bus system is analyzed to evaluate the performance of the solution method for a practical system. A scalability analysis is performed and it is observed that the rate of change in the algorithm solution time sharply decreases as the contingencies or uncertainty scenarios increase due to the fact that once some contingencies or uncertainty scenarios are resolved with a specific reserve allocation, this might resolve some other contingencies without further computation. Furthermore, it is observed that solution performance is more sensitive to the number of *N-1*contingencies, since contingencies add more variables and constraints to the problem when compared with uncertainty scenarios. Finally it has been shown that integration of the DR concept to the northwest region Turkish Electricity market reduces the wind power curtailment and day-ahead scheduling cost.

The proposed SCUC solutions are verified by using the input data from the existing literature [38] and same schedules and optimal system costs are calculated. Besides the schedule calculated in Case 2 (section 5.3.1.2) is slightly perturbed by forcing the base case schedules at hours 17 and 18 to slightly different values than the optimal point to verify the optimality of the proposed SCUC solution. It is observed that the expected system cost slightly increases than the calculated optimal system cost verifying the optimality of the proposed solution.

The proposed PBUC and SCUC frameworks provide substantial tools to evaluate the effect of the uncertainties to the GENCOs operational planning and TSOs day-ahead scheduling problems. These frameworks would be extended to address the potential future studies:

- Wind uncertainty is studied in the proposed framework. However the effects of other renewable types such as PV, Solar thermal might be integrated to the existing PBUC and SCUC frameworks.

- The effect of the transmission line MW losses are neglected by using a DC formulation. Losses might be considered byadding a quadratic loss term to the generation and load balance equation. An AC approach might also be developed in order to consider the bus voltage magnitudes.

- The interdependency of electric power systems and NG transmission systems is integrated to the PBUC framework. Similarly the interdependendices of power systems between communications systems (SCADA and automation systems, LFC) might be studied in a similar framework to consider the limits and contingencies of communicaton systems. Transportation systems are also begining to depend on electric power systems with the introduction of electric vehicles comncept. This should be also considered in the planning studies.

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# APPENDIX A

# LINEAR REPRESENTATION OF FUEL AND EMISSION

Generally, fuel consumption and emission of thermal units are expressed as quadratic function. Generating unit $i$ 's fuel consumption and emission in scenario $s$ is linearized as:

$$F_{its} = F_{\min,i} \cdot I_{its} + \sum_{m=1}^{NSF_i} p_{m,its} \cdot Fb_{m,i} + \sum_{m=1}^{NSSF_i} v_{m,its} \cdot SF_{m,i} \tag{A1}$$

$$Em_{its}^{ET} = Em_{\min,i} \cdot I_{its} + \sum_{m=1}^{NSE_i} p_{m,its} \cdot Emb_{m,i} + \sum_{m=1}^{NSSE_i} ue_{m,its} \cdot SE_{m,i} \tag{A2}$$

$$P_{its} = P_{\min,i} \cdot I_{its} + \sum_{m=1}^{NSF_i} p_{m,its} \quad , \ \forall i,t,s \tag{A3}$$

$$0 \le p_{m,its} \le p_{\max\, m,i}$$

The linear representation of fuel cost in (79) is given as $F_{c,i}(P_{its}) = \rho_{fuel} . F_{its}$ , where $\rho_{fuel}$ is the unit fuel price.

# APPENDIX B

# LINEAR REPRESENTATION OF HEAD DEPENDENT WATER-TO-POWER CONVERSION CURVE

The two variable head dependent water-to-power conversion curve was given in (37). Using this function, the water head and discharge parameters are considered to calculate power output of cascaded hydro and pumped-storage units. A heuristic method is used to convert the conversion curve into a piecewise linear function [63], [64] which can be incorporated into the MIP problem. For the sake of discussion, we rewrite (37) as (B1) by ignoring subscripts.

$$P = \eta \cdot w \cdot [hw_0 + \alpha \cdot v] \tag{B1}$$

We divide $w$ and $v$ into subintervals $[w_i, w_{i+1}]$ and $[v_j, v_{j+1}]$, where $i = 1\Lambda\ m-1, j = 1\Lambda\ n-1,$ . Thus the original function is divided into a $(m-1)\cdot(n-1)$ grid in which each point corresponding to the original function is $P_{i,j} = \eta \cdot w_i \cdot [hw_0 + \alpha \cdot v_j]$ as shown in Fig B1. Thus (B1) is approximated by (B2).Each grid element is divided into two triangles, i.e., upper left and lower right, and $\varsigma_{i,j}$ and $\zeta_{i,j}$ are indexes to represent the location in the two triangles.

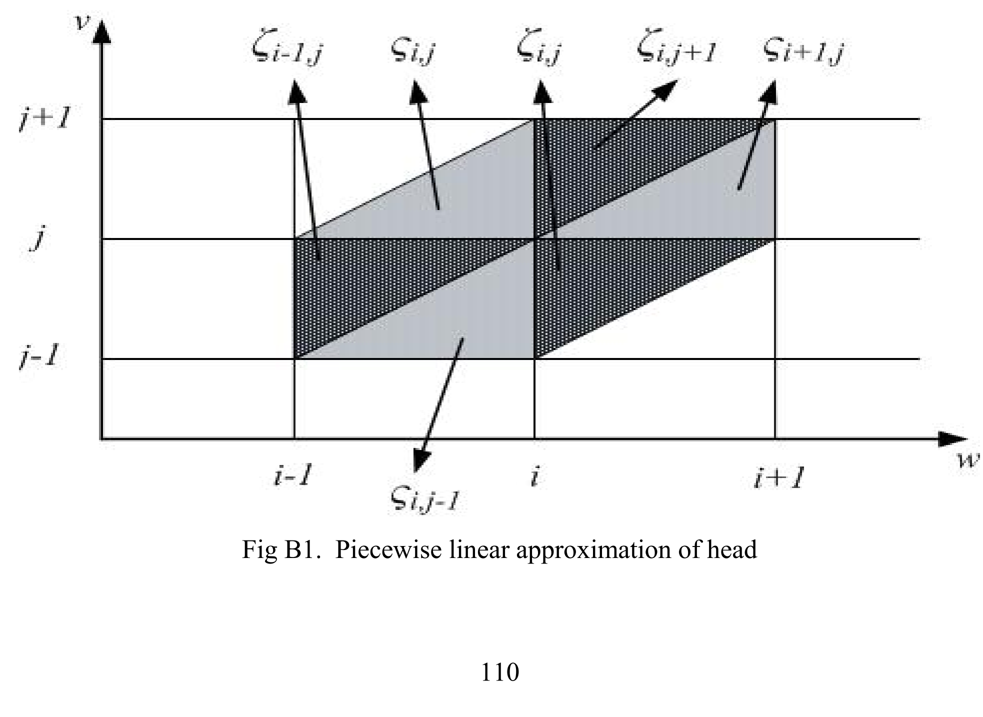


Fig B1. Piecewise linear approximation of head

$$
\begin{aligned}
& w=\sum_{i=1}^{m}\sum_{j=1}^{n} w_i \cdot \phi_{i,j} \qquad v=\sum_{i=1}^{m}\sum_{j=1}^{n} v_j \cdot \phi_{i,j} \\
& \sum_{i=1}^{m}\sum_{j=1}^{n} (\varsigma_{i,j}+\zeta_{i,j})=1 \qquad \sum_{i=1}^{m}\sum_{j=1}^{n} \phi_{i,j}=1 \\
& \phi_{i,j} \le \varsigma_{i,j-1}+\varsigma_{i,j}+\varsigma_{i,j+1}+\zeta_{i-1,j}+\zeta_{i,j}+\zeta_{i+1,j} \\
& P=\sum_{i=1}^{m}\sum_{j=1}^{n} P_{i,j} \cdot \phi_{i,j} \qquad \phi_{i,j} \ge 0 \quad , \quad \varsigma_{i,j}, \zeta_{i,j} \in \{0,1\}
\end{aligned}
\tag{B2}
$$

# APPENDIX C

# DC NETWORK EQUATIONS

The DC power flow equations and flow constraints can be represented as following . The bold characters mean that the variable is a matrix or a vector.

$$\boldsymbol{B'\theta} + \boldsymbol{B_{\Delta}\Delta} = \boldsymbol{P_G} - \boldsymbol{P_D} \tag{C.1}$$

$$PL_c = \frac{\theta_{b1} - \theta_{b2} - \Delta_c}{x_c}, \ \forall c \in STX \tag{C.2}$$

$$PL_{c,\min} \le PL_c \le PL_{c,\max}, \ \forall c \in STX \tag{C.3}$$

$$\Delta_{c,\min} \le \Delta_c \le \Delta_{c,\max}, \ \forall c \in STX \tag{C.4}$$

In the upper equations $\boldsymbol{B'}$ is the DC power flow matrix composed of the inverse line reactances, $\boldsymbol{B_{\Delta}}$ is the phase shifter transformers incidence matrix, $\boldsymbol{\theta}$, $\Delta$, $\boldsymbol{P_G}$ and $\boldsymbol{P_D}$ are the bus voltage angle, phase shifting transformer setting, bus generation injection and bus demand vectors respectively. $PL_c$ is the MW flow on line *c,* connecting bus *b1*, to bus *b2*. $\Delta_c$ is the phase shift value for the phase shifter transformer located between buses *b1* and *b2*.

# APPENDIX D

# BENDERS DECOMPOSITION

## 1. Benders Decomposition

A mixed-integer program has the following form. The bold characters mean that the variable is a matrix or a vector.

$$\begin{aligned} &\mathit{Minimize}\ z = \mathbf{c}^{\mathbf{T}}\mathbf{x} + \mathbf{d}^{\mathbf{T}}\mathbf{y} \\ &s.t. \qquad \mathbf{Ay} \geq \mathbf{b} \\ &\qquad \mathbf{Ex} + \mathbf{Fy} \geq \mathbf{h} \\ &\qquad \mathbf{x} \geq \mathbf{0}, \mathbf{y} \in \mathbf{S} \end{aligned} \qquad \text{P1} \tag{D.1}$$

where,

$\boldsymbol{A}$: $m \times n$ matrix,

$\mathbf{E}$: $q \times p$ matrix,

$\mathbf{F}$: $q \times n$ matrix,

$\boldsymbol{x}$, $\boldsymbol{c}$ : $p$ vectors,

$\boldsymbol{y}, \boldsymbol{d}$ : $n$ vector, y could be real numbers or integers

$\boldsymbol{b}$ : $m$ vector,

$\boldsymbol{h}$ : $q$ vector,

$\boldsymbol{S}$ : an arbitrary subset of an n-dimensional space

Since $\boldsymbol{x}$ is continuous and $\boldsymbol{y}$ includes integers, (P1) is a mixed-integer problem. If $\boldsymbol{y}$ values are fixed, (P1) is linear in $\boldsymbol{x}$. Hence, (D.1) is written as:

$$\underset{\mathbf{y} \in \mathbf{R}}{\text{Minimize}} \left\{ \mathbf{d}^{\mathbf{T}}\mathbf{y} \middle| \mathbf{Ay} \geq \mathbf{b} + \mathit{Min}\left\{ \mathbf{c}^{\mathbf{T}}\mathbf{x} \mid \mathbf{Ex} \geq \mathbf{h} - \mathbf{Fy}, \mathbf{x} \geq \mathbf{0} \right\} \right\} \tag{D.2}$$

where,

$$\mathbf{R} = \left\{ \mathbf{y} \middle| \text{ there exists } \mathbf{x} \geq \mathbf{0} \text{ such that } \mathbf{Ex} \geq \mathbf{h} \text{ - } \mathbf{Fy}, \mathbf{Ay} \geq \mathbf{b}, \mathbf{y} \in \mathbf{S} \right\} \tag{D.3}$$

So, the original problem can be decoupled into a master problem and a subproblem.

**Initial master problem (MP1)**

We begin with solving the following MP1 (D.4).

$$
\begin{aligned}
& \textit{Minimize } z_{lower} \\
& s.t. \quad z_{lower} \geq \mathbf{d}^{\mathbf{T}}\mathbf{y} \\
& \qquad \mathbf{Ay} \geq \mathbf{b} \\
& \qquad \mathbf{y} \in \mathbf{S}
\end{aligned}
\qquad \text{MP1} \qquad \text{(D.4)}
$$

Here, we use $z$, instead of $\mathbf{d}^{\mathbf{T}}\mathbf{y}$, as the objective function. Meanwhile, the inner part of minimization (D.2) is a subproblem rewritten as follows:

**Primal subproblem (SP1)**

$$
\begin{aligned}
& \textit{Minimize } \mathbf{c}^{\mathbf{T}}\mathbf{x} \\
& \text{s.t.} \quad \mathbf{Ex} \geq \mathbf{h} - \mathbf{F\hat{y}} \qquad \rightarrow \quad \mathbf{u^p} \\
& \qquad \mathbf{x} \geq \mathbf{0}
\end{aligned}
\qquad \text{SP1} \qquad \text{(D.5)}
$$

**Step 1. Solve MP1**

- Obtain an initial lower bound solution given as $\hat{z}_{lower}$ and $\mathbf{\hat{y}}$. If MP1 is infeasible so will be the original problem P1. If MP1 is unbounded, set $\hat{z}_{lower} = \infty$ in (D.4) for $\mathbf{\hat{y}}$ (an arbitrary element of S), and go to step 2.

**Step 2. Solve SP1**

- If SP1 is feasible $\hat{z}_{upper} = \min\{\hat{z}_{upper}, \mathbf{d}^{\mathbf{T}}\mathbf{\hat{y}} + \mathbf{c}^{\mathbf{T}}\mathbf{\hat{y}}\}$ is the upper-bound solution of the original problem P1 for $\hat{\boldsymbol{x}}$ .If $\left|\hat{z}_{upper} - \hat{z}_{lower}\right| \leq \varepsilon$ for P1, then stop the process. Otherwise, generate a new cut $z_{lower} \geq \mathbf{d}^{\mathbf{T}}\mathbf{y} + \mathbf{(h - Fy)}^{\mathbf{T}}\mathbf{\hat{u}^p}$ (feasibility cut) for MP2 (D.7) and go to Step 3. The new cut could also be in the form of $z_{lower} \geq \mathbf{d}^{\mathbf{T}}\mathbf{y} + w(\mathbf{\hat{y}}) - (\mathbf{y} - \mathbf{\hat{y}})^{\mathbf{T}}\mathbf{F}^{\mathbf{T}}\mathbf{\hat{u}^p}$, where $w(\mathbf{\hat{y}})$ is the optimal solution of SP1.

- If SP1 is infeasible, solve SP2, which is to minimize violation (infeasibility) of SP1, and introduce a new cut $\mathbf{(h - F\hat{y})}^{\mathbf{T}}\mathbf{\hat{u}^r} \leq 0$ or (infeasibility cut) for MP2 (D.7,), and go to Step 3. The new cut could also be in the form of $v(\mathbf{\hat{y}}) - (\mathbf{y} - \mathbf{\hat{y}})^{\mathbf{T}}\mathbf{F}^{\mathbf{T}}\mathbf{\hat{u}^r} \leq 0$, where $v(\mathbf{\hat{y}})$ is the optimal solution of SP2. SP2 is given as follows

$$
\begin{aligned}
& \textit{Minimize } \mathbf{1}^{\mathbf{T}}\mathbf{s} \\
& \text{s.t.} \quad \mathbf{Ex} + \mathbf{Is} \geq \mathbf{h} - \mathbf{F\hat{y}} \qquad \rightarrow \quad \mathbf{u^r} \\
& \qquad \mathbf{x} \geq \mathbf{0}, \mathbf{s} \geq \mathbf{0}
\end{aligned}
\qquad \text{(D.6)}
$$

where **1** is the unit vector.

**Step 3. Solve MP2**

- MP2 is formulated either as (D.7) or (D.8), where we add the feasibility cut (second constraint) or the infeasibility cut (third constraint) as discussed in Step 2.

$$\begin{aligned} &\textit{Minimize } z_{lower} \\ &s.t. \quad z_{lower} \geq \mathbf{d^T y} \\ &\qquad \mathbf{Ay \geq b} \\ &\qquad z_{lower} \geq \mathbf{d^T y + (h - Fy)^T u_i^p}, i = 1,\ldots,n_p \\ &\qquad \mathbf{(h - F\hat{y})^T u_i^r} \leq 0, i = 1,\ldots,n_r \\ &\qquad \mathbf{y \in S} \end{aligned} \qquad \text{MP2} \qquad \text{(D.7)}$$

$$\begin{aligned} &\textit{Minimize } z_{lower} \\ &s.t. \quad z_{lower} \geq \mathbf{d^T y} \\ &\qquad \mathbf{Ay \geq b} \\ &\qquad z_{lower} \geq \mathbf{d^T y} + w(\mathbf{\hat{y}})_i - \mathbf{(y - \hat{y})^T F^T u_i^p}, i = 1,\ldots,n_p \\ &\qquad v(\mathbf{\hat{y}})_i - \mathbf{(y - \hat{y})^T F^T u_i^r} \leq 0, i = 1,\ldots,n_r \\ &\qquad \mathbf{y \in S} \end{aligned} \qquad \text{MP2} \qquad \text{(D.8)}$$

- If MP2 is feasible, obtain a new lower bound solution $\hat{z}_{lower}$ with respect to $\mathbf{\hat{y}}$ for the original problem P1. Go to Step 2.
- If MP2 is unbounded, specify $\hat{z}_{lower} = \infty$ with $\mathbf{\hat{y}}$ as an arbitrary element of S. Go to Step 2.
- If MP2 is infeasible, so is the original problem P1. Stop the process.

It should be noted that the Benders cut $z_{lower} \geq \mathbf{d^T y} + w(\mathbf{\hat{y}}) - \mathbf{(y - \hat{y})^T F^T u^p}$ indicates that we could decrease the objective value of the original problem by updating $\mathbf{y}$ from $\mathbf{\hat{y}}$ to a new value. The value of represents the incremental change $\boldsymbol{\pi}^\mathbf{p} = -\mathbf{F^T u^p}$ represents the incremental change in the optimal objective. Similarly, the Benders cut $v(\mathbf{\hat{y}}) - \mathbf{(y - \hat{y})^T F^T u^r} \leq 0$ indicates that we could update $\mathbf{\hat{y}}$ to a new value to eliminate constraint violations in SP1 based on $\mathbf{\hat{y}}$ given in the master problem. The value of $\boldsymbol{\pi}^\mathbf{r} = -\mathbf{F^T u^r}$ represents the incremental change in the total violation.

## *2. Application of Benders Decomposition to SCUC Problem*

The SCUC problem can be abstracted into a similar form to (D.1), as shown in (D.9)

$$\begin{aligned} &\textit{Minimize } z = \mathbf{d^T y} \\ &s.t. \qquad \mathbf{Ay \geq b} \\ &\qquad \mathbf{Ex + Fy \geq h} \end{aligned} \qquad \text{(D.9)}$$

where $\boldsymbol{y}$ represents all the variables such as Commitment states ($I_{,it}$), base case and scenario power generations ($P_{it0}$ ,$P_{wt0,}$ $P_{SPIN,its}$, $P_{its}$, $P_{wts}$), scheduled and deployed spinning and operating reserves from units ($SR_{u,it}$, $SR_{d,it}$, $OR_{u,it}$, $OR_{d,it}$, $SR_{its}$, $OR_{its}$) and DRPs ($DRR_{rt}$, $DRR_{rts}$), and involuntary load shedding ($l_{dts}$) for each scenario $s$ and hour $t$; $\boldsymbol{x}$ represents all the variables in power flow, such as branch flows, voltage angles and phase shifting angles.

The solution procedure for the Benders Decomposition of SCUC problem will be slightly simpler than the solution given above, due to the fact that $\mathbf{c}^{\mathbf{T}}\mathbf{x}$ term is not present in the objective function (i.e., there is no cost component related to the branch flows, voltage angles, and phase shifting angles). The solution procedure is given as follows

Step 1.) Solve MP1 which is actually the UC problem

$$\begin{aligned} &\mathit{Minimize}\ z = \mathbf{d}^{\mathbf{T}}\mathbf{y} \\ &s.t. \quad \mathbf{Ay} \geq \mathbf{b} \end{aligned} \qquad \text{MP1} \tag{D.10}$$

In MP1 $\boldsymbol{y}$ can be divided into two groups; $\boldsymbol{y1}$ and $\boldsymbol{y2}$. $\boldsymbol{y1}$ represents the generation dispatch base case and scenario power generations ($P_{it0}$ ,$P_{wt0,}$ $P_{SPIN,its}$, $P_{its}$, $P_{wts}$), deployed spinning and operating reserves from units ($SR_{its}$, $OR_{its}$) and DRPs ($DRR_{rts}$), and involuntary load shedding ($l_{dts}$) for each scenario $s$ and hour $t$; and $\boldsymbol{y2}$ represents all other variables in unit commitment. What's useful in checking network constraint is $\boldsymbol{y1}$.

Step 2.) Solve SP2 given in (D.6), and let $v(\hat{\mathbf{y}}) = \mathbf{1}^{\mathbf{T}}\mathbf{s}$. In order to eliminate violations, the Benders cut (infeasibility cut) which is the third constraint given in D.8 is introduced and added to the master problem.

$$v(\hat{\mathbf{y}}) - (\mathbf{y} - \hat{\mathbf{y}})^{\mathbf{T}}\mathbf{F}^{\mathbf{T}}\mathbf{u}^{\mathbf{r}} \leq 0 \tag{D.11}$$

Note that (D.6) can be solved for base case and *N-1* and wind, load uncertainties for each hour, i.e., one SP2 for base case and each scenario, at each hour. If $v(\hat{\mathbf{y}}) = \mathbf{0}$ for all hours, which means there is no violation in any of the hours for all of the scenarios and UC solutions satisfy all network constraints, the original problem is solved. Otherwise add the Benders cut to UC problem to form MP2. Since the term represents incremental change in the total violation, the explicit form of the infeasibility cuts for the SCUC problem is given as follows

Step 3.) Solve MP2

$$\begin{aligned} &\mathit{Minimize}\ z = \mathbf{d}^{\mathbf{T}}\mathbf{y} \\ &s.t. \quad \mathbf{Ay} \geq \mathbf{b} \\ &\qquad v(\hat{\mathbf{y}})_i - (\mathbf{y} - \hat{\mathbf{y}})^{\mathbf{T}}\mathbf{F}^{\mathbf{T}}\mathbf{u}_{\mathbf{i}}^{\mathbf{r}} \leq 0 \end{aligned} \qquad \text{MP2} \tag{D.12}$$

The final solution based on Benders Decomposition may require an iterative process between the master problem and subproblems. The flowchart of the Benders Decomposition solution of the SCUC problem is given in Fig 4.5.

## 3. *A Simple Example*

Parameters for the 3-bus network in Fig D.1 are listed in Table D.1. Load data are listed in Table D.2. MVA base is 100. Assume that bus 3 is the reference bus. Unit data are listed in Table D.3. Determine the least cost commitment and dispatch for G1 and G2 that can supply the load and ensure the reliability of the network.

Case 1. Assuming the phase shifter is not used

Case 2. Assuming the phase shifter is used

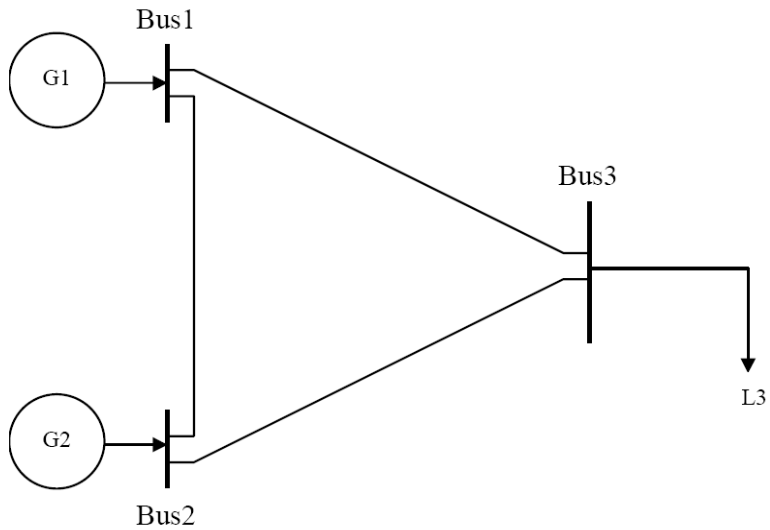


Fig D.1 One-line Diagram of the 3-bus Network

TABLE D.1
BRANCH PARAMETERS

| From Bus | To Bus | X (p.u) | Flow Limit (MW) | Maximum Phase Shifting Angle (degree) |
|---|---|---|---|---|
| 1 | 2 | 0.1 | 1000 | - |
| 1 | 3 | 0.2 | 400 | - |
| 2 | 3 | 0.5 | 1000 | 30 |

TABLE D.2
LOAD DATA

| Load | Bus | MW |
|---|---|---|
| L3 | 3 | 600 |

TABLE D.3
UNIT DATA

| Unit | Bus | Maximum Capacity (MW) | Minimum Capacity (MW) | Incremental Cost ($/MWh) |
|---|---|---|---|---|
| G1 | 1 | 1000 | 100 | 10 |
| G2 | 2 | 500 | 10 | 20 |

Case 1:

Step 1.) Solve MP1

$$\begin{aligned}
&\textit{Minimize} \quad 10\mathrm{PG}_1 + 20PG_2 \\
&s.t. \\
&\qquad \mathrm{PG}_1 + PG_2 = 600 \\
&\qquad 100I_1 \le PG_1 \le 1000I_1 \\
&\qquad 10I_2 \le PG_2 \le 500I_2
\end{aligned}$$

Solving the above optimization problem, we get the following solution

$$\begin{aligned}
&I_1 = 1, \quad I_2 = 0 \\
&\mathrm{PG}_1 = 600, \ \ \mathrm{PG}_1 = 600 \\
&\textit{Total} \quad \textit{Cost} = 6000
\end{aligned}$$

Step 2.) Form and solve SP2 for network security check. First the problem SP2 is constructed regarding equation (D.6) as follows

$$\textit{Minimize} \quad v(\hat{\mathbf{y}}) = \mathbf{1}^{\mathrm{T}}\mathbf{s_1} + \mathbf{1}^{\mathrm{T}}\mathbf{s_2} \tag{D.13o}$$

$$\mathbf{B}'\boldsymbol{\theta} + \mathbf{B}_{\Delta}\Delta = \mathbf{P_G} - \mathbf{P_D} \qquad \rightarrow \ \mathbf{u^r} \tag{D.13a}$$

$$PL_c = \frac{\theta_{b1} - \theta_{b2} - \Delta_c}{x_c}, \ \forall c \in STX \tag{D.13b}$$

$$PL_c - s_{1,c} \le PL_{c,\max}, \ \forall c \in STX \tag{D.13c}$$

$$PL_{c,\min} \le PL_c + s_{2,c}, \ \forall c \in STX \tag{D.13d}$$

$$\Delta_{c,\min} \le \Delta_c \le \Delta_{c,\max}, \ \forall c \in STX \tag{D.13e}$$

$$s_{1,c}, s_{2,c} \ge 0, \ \forall c \in STX \tag{D.13 f}$$

In SP2 **1** is a vector of ones, and $\mathbf{u^r}$ is the dual multiplier vector of constraints D.13a since $\hat{\mathbf{y}}$ coming from the master problem exists in those constraints. In the case that $v(\hat{\mathbf{y}}) \ge 0$, network violations exists with the $\hat{\mathbf{y}}$ ($\boldsymbol{P_G}$ vector is computed in MP1). In order to eliminate violations, the Benders infeasibility cut is introduced and added to the master problem.

$$v(\hat{\mathbf{y}}) - (\mathbf{y} - \hat{\mathbf{y}})^{\mathbf{T}}\mathbf{F}^{\mathbf{T}}\mathbf{u^r} \le 0 \tag{D.12}$$

Returning back to problem, SP2 is given as follows

$$Minimize \quad s_1 + s_2 + s_3 + s_4 + s_5 + s_6$$

$$\begin{bmatrix} 15 & -10 & -5 \\ -10 & 12 & -2 \\ -5 & -2 & 7 \end{bmatrix} \begin{bmatrix} \theta_1 \\ \theta_2 \\ \theta 3 \end{bmatrix} + \begin{bmatrix} 0 \\ -2 \\ 2 \end{bmatrix} \Delta_{2-3} = \begin{bmatrix} 600 \\ 0 \\ 0 \end{bmatrix} - \begin{bmatrix} 0 \\ 0 \\ 600 \end{bmatrix}$$

$$\theta_3 = 0$$

$$PL_{1-2} = 10(\theta_1 - \theta_2)$$

$$PL_{1-3} = 5(\theta_1 - \theta_3)$$

$$PL_{2-3} = 2(\theta_2 - \theta_3 - \gamma_{2-3})$$

$$PL_{1-2} - s_1 \le 1000, \qquad -1000 \le PL_{1-2} + s_2$$
$$PL_{1-3} - s_3 \le 400, \qquad -400 \le PL_{1-3} + s_4$$
$$PL_{2-3} - s_5 \le 1000, \qquad -1000 \le PL_{2-3} + s_6$$
$$\Delta_{2-3} = 0$$

Solving the above equations, we get the following solution.

$$s_1 = 0, \quad s_2 = 0, \quad s_3 = 50, \quad s_4 = 0, \quad s_5 = 0, \quad s_6 = 0$$
$$u_1^r = 0.1506, \quad u_2^r = 0.0256, \quad u_3^r = -0.5994$$
$$Total \quad Violation = 50$$

Since $F = -\begin{bmatrix} 1 & 0 \\ 0 & 1 \\ 0 & 0 \end{bmatrix}, \; and \quad u^r = -\begin{bmatrix} 0.1506 \\ 0.0256 \\ -0.5994 \end{bmatrix}$, we have

$$-F^T u^r = \begin{bmatrix} 1 & 0 \\ 0 & 1 \\ 0 & 0 \end{bmatrix}^T * \begin{bmatrix} 0.1506 \\ 0.0256 \\ -0.5994 \end{bmatrix} = \begin{bmatrix} 0.1506 \\ 0.0256 \end{bmatrix}$$

The Benders cut would be

$$50 + 0.1506(PG_1 - 600) + 0.0256(PG_2 - 600) \le 40.36$$

Step 3.) Form the MP2 by adding the generated cut to the MP1 and solve

$$Minimize \quad 10\mathrm{PG}_1 + 20PG_2$$
$$s.t.$$
$$\mathrm{PG}_1 + PG_2 = 600$$
$$100I_1 \le PG_1 \le 1000I_1$$
$$10I_2 \le PG_2 \le 500I_2$$
$$50 + 0.1506(PG_1 - 600) + 0.0256(PG_2 - 600) \le 40.36$$

Solving the above optimization problem, we get the following solution.

$$I_1 = 1, \quad I_2 = 1$$
$$PG_1 = 200, \quad PG_2 = 400$$
$$Total \quad Cost = 10000$$

Case 2:

Step 1) formulation and solutions for MP1 in Case 2 are the same as those in Case 1

Step 2) Solve SP2

$$Minimize \quad s_1 + s_2 + s_3 + s_4 + s_5 + s_6$$

$$\begin{bmatrix} 15 & -10 & -5 \\ -10 & 12 & -2 \\ -5 & -2 & 7 \end{bmatrix} \begin{bmatrix} \theta_1 \\ \theta_2 \\ \theta 3 \end{bmatrix} + \begin{bmatrix} 0 \\ -2 \\ 2 \end{bmatrix} \Delta_{2-3} = \begin{bmatrix} 600 \\ 0 \\ 0 \end{bmatrix} - \begin{bmatrix} 0 \\ 0 \\ 600 \end{bmatrix}$$

$$\theta_3 = 0$$

$$PL_{1-2} = 10(\theta_1 - \theta_2)$$

$$PL_{1-3} = 5(\theta_1 - \theta_3)$$

$$PL_{2-3} = 2(\theta_2 - \theta_3 - \gamma_{2-3})$$

$$PL_{1-2} - s_1 \le 1000, \qquad -1000 \le PL_{1-2} + s_2$$

$$PL_{1-3} - s_3 \le 400, \qquad -400 \le PL_{1-3} + s_4$$

$$PL_{2-3} - s_5 \le 1000, \qquad -1000 \le PL_{2-3} + s_6$$

$$-0.5623 * 100 \le \Delta_{2-3} \le 0.5623 * 100$$

Solving the above equations, we get the following solution.

$$s_1 = 0, \quad s_2 = 0, \quad s_3 = 0, \quad s_4 = 0, \quad s_5 = 0, \quad s_6 = 0$$

$$Total \quad Mismatch = 0$$

Since there is no mismatch the problem converges.

# VITA

EDUCATION

Illinois Institute of Technology (IIT), Chicago, IL, USA

**Visiting Research Scholar** 2008-2010

Middle East Technical University (METU), Ankara, Turkey

**Candidate for Ph.D. in Electrical Engineering** 2010

Emphasis: Control Theory and Applications & Power Systems

Thesis Title: “Interdependence of Natural Gas and Electrical Energy Infrastructures”

Passed Qualifying Exam Dec 2005

**M.S. in Electrical and Electronics Engineering** 2003

Thesis Title: “Application of Evolutionary Strategy Algorithm to Synchronous Generator Parameter Estimation”

Istanbul Technical University (ITU), Istanbul, Turkey

**Bachelor’s degree in Electrical Engineering**

Undergraduate Thesis: PLC based DC motor control.

SKILLS

- Power System Analysis Tools: Power Systems steady-state and dynamic analysis, Power Systems Command and Control, EMTP/ ATP, PSCAD, PSS/E, Matlab SimPowerSystems, Matlab Matpower toolbox
- Programming: C, C++, UML, FORTRAN, VB, Java, MATLAB M-File, MEX, SIMULINK programming, Microsoft Visual C++ 6.0, embedded Visual C++ 4.0, VS 2005-2008, Borland Developer Studio 6.0, Rhapsody real time UML, Sun Studio, Hi-tech (PICC, PICC-18), IAR, Keil compilers for microchip PIC microcontrollers, MICROCHIP ICE-2000 emulator and ICD-2 debugger modules, Proteus PIC simulation software, CFC, Easy adaptation to any C,C++ compiler, Easy adaptation to any high-low level programming language
- Hardware Design & Firmware: Schematic and PCB design, Embedded systems, SPI, I2C, Industrial Ethernet, DNP 3.0, MODBUS, TCP/IP, PROFIBUS, RS-485/232, M2M, Analog-Digital circuit design, SCADA, OOD, UML, RTOS, GSM/GPRS, GPS, PLD, FGPA, Intel(80186-8) & Microchip assembler languages, ORCAD 9.0, PSPICE, PCAD, CAMTASTIC, Xilinx ISE, DIGSI

PROFESSIONAL EXPERIENCE

Illinois Institute of Tech, Chicago, USA

**Senior Research Associate** 2008-2010

- Development of stochastic Price Based Unit Commitment (**PBUC)** tool for large scale GENCOs
- Development of stochastic Security Constrained Unit Commitment **(SCUC)** tool for ISOs and TSOs operating large scale power systems
- Development of **stochastic simulation** for natural renewable resources (wind power, water inflow resources)
- Development of **energy market price forecasting** tool
- Development of synchronous energy and Ancillary Services **market clearing** tool

in **C++, Matlab**, and **GAMS** environments

TUBITAK – Uzay, DGGS group, Ankara, Turkey

**Senior, Chief Research Engineer** 2001-2008

- Firmware and Hardware development team leader for HESKON small hydroelectric power plant (HEPP) SCADA system project:
    - o Determined the hardware platform, **RTOS** and development tools for the local unit controllers (LCUs), evaluated benchmark software generated with **Rhapsody in C++ UML** tool on a number of industrial computers (**SBC, PCI, PC/104 based computers**) with various RTOS (**Windows CE, RTLinux, QNX, BlueCat Linux**). Configured generator compact relay (SIPROTEC 7UM62) through **DIGSI** using **CFC** logic functions.
    - o Developed real-time software, firmware modules for the HEPP LCUs; communication modules (**TCP, UDP, MODBUS/TCP, DNP3.0/TCP,** and propriety protocols), main control modules and I/O interface modules, using **Rhapsody in C++ real time UML tool** for Windows CE 5.0 RTOS. The LCUs were responsible of time critical tasks related with the hydro unit.
    - o Configured managed and unmanaged **Industrial Ethernet** switches (Advantech EKI-7000, Ruggedcom RS900G, RS8000, RS500), industrial controllers (Advantech UNO-2170, Arcom-Zeus and Arcom-Gemini SBC).
    - o Dispatched job tasks among 5 engineers in the project subgroup. The project has been completed in August-2008 and commissioned to client Turkish Electromechanics Industry (www.temsan.gov.tr)
- Bogazici DISCO Master Planning and Feeder Automation Project
    - o Designed PIC18F8722 based digital 3-phase energy analyzer with non-volatile memory for recording of the electrical parameters and **MODBUS RS-232/485** communication. Implemented MCU-Energy Measurement Chip comm. via **SPI** and MCU-Real Time Clock (RTC) comm. via **I2C** standards. Device has been used for data logging and monitoring at more than 300 major distribution transformers in Istanbul. The results have been used for Istanbul metropolitan distribution system master planning studies.
    - o Implemented a database and monitoring application communicating energy analyzers through MODBUS and propriety protocols
    - o Designed PIC18F8722 base Automated Test Equipment (**ATE**), hardware design and implemented and tested firmware. Device is used in functional test of distribution automation RTUs and its sub modules. The device increased the functional test capabilities from 10 RTU/day to 40 RTU/day.
    - o Implemented automation project for the Industrial Ironing Machine for SARAR Co. Eskisehir, using **Siemens S7-200 PLC**.
    - o Designed and implemented wireless SCADA system hardware, software design and implementation for the solar car to race at the TUBITAK Formula G **solar cars** race. Designed CPU card, peripheral cards and implemented firmware. Implemented CPU-**GPS** and CPU-TELIT GM-864 **GPRS** module communication firmware implementation. The project car came 2$^{nd}$ out of the race.
    - o Designed and executed system tests for the distribution automation **SCADA** system. Designed and prototyped various analog and digital circuits and systems; i.e. RTU analog current monitor card, RTU digital I/O functional test card and test bed.
    - o Developed server side MMI software for distribution system **SCADA** software, which was a multi-process, mult-tasking software running on **Solaris OS**. Development took place in **Sun Workshop, Sun Studio IDEs**. Utilized **Rogue Wave Tools++** library.

TUBITAK – Uzay, DGGS group, Ankara, Turkey

**Research Engineer** 2000 - 2001

- Power system analyst:
    - o Collected mathematical model data from the field, for the Turkish power system. Data has been used at dynamical and steady-state analysis of Turkish national power- system.

- Load flow, N-1 contingency load flow, steady state and dynamic stability studies, short circuit analysis on various power systems including Turkish system.

TEACHING EXPERIENCE

Technical Vocational School of Higher Education, METU, Ankara, TURKEY

**Lecturer- Industrial Automation and SCADA** 2002 - 2003

Developed syllabus and overall course structure

RECENT PhD RELATED STUDIES ON POWER SYSTEMS

- Security Constrained Unit Commitment (SCUC) and Price Based Unit commitment (PBUC) for large power systems, Mixed Integer Programming (MIP), Renewable Energy resources modeling, Power Market Operations, Optimal power flow algorithms based on linear programming and interior point algorithms, Optimum Reactive Power generation dispatch.

PUBLICATIONS AND PAPERS

[1] Cem Sahin, Ismet Erkmen, "Application of Evolutionary Strategy Algorithm to Economic Dispatch Problem," Presented at the 2002 Turkish Automatic Control Congress (TOK), Ankara, Turkey
[2] Cem Sahin, Ismet Erkmen, "Application of Evolutionary Strategy Algorithm to Synchronous Generator Parameter Estimation," Presented at the 2003 North American Power Symposium (NAPS), Idaho, Moscow
[3] Cem Sahin, Mohammed Shahidehpour, Ismet Erkmen "Interdependence of NG and Electricity Infrastructures in Turkey," Presented at the 2009 IEEE PES General Meeting, Calgary, Canada
[4] Cem Sahin, Zuyi Li, Mohammed Shahidehpour, Ismet Erkmen "Impact of Natural Gas System on GENCO's Risk-Constrained Hydrothermal Scheduling," accepted for publication at IEEE Transactions on Power Systems
[5] Cem Sahin, Mohammed Shahidehpour, Ismet Erkmen "Midterm Risk of Power Generation Companies with
Wind, Hydro, and Natural Gas Generating Unit," submitted to ElsevierEnergy
[6] Cem Sahin, Mohammed Shahidehpour, "A Hybrid Deterministic/Stochastic Energy and Ancillary Services Synchronous Market Clearing," submitted to IEEE Transactions on Power Systems

LANGUAGES

Bilingual; English & Turkish