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Analysis of investment decision making in power systems under environmental regulations and uncertainties

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Analysis of investment decision making in power systems under environmental regulations and uncertainties

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DEDICATION

I would like to dedicate this dissertation to my beloved family who are always standing behind me under any circumstances. Thank you for your love, care and support throughout my life.

I would also like to thank my friends for their kind guidance, encouragement and consolation during my graduate study. I appreciated all the precious moments we spent together.

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ABSTRACT

The dissertation focuses on the study of environmental policies and their impacts on the power systems' planning. It consists of three parts, each of which addresses a single problem on environmental policies and generation expansion planning. In the first part of the dissertation, I compared the cap-and-trade policy and various carbon tax policies in a single period under the generation expansion framework. The problem was modeled as a bilevel problem where the lower level competing generation companies maximized their own profits under the regulations of the upper level. The policies were compared via their effectiveness and efficiency. Effectiveness referred to a policy's capability to control the amount of carbon emissions, and efficiency was measured with respect to five criteria: emissions price, renewable energy portfolio, total generation, total profit of generation companies and grid owner, and government revenue. In the second part, the model was extended to multi-period planning to gain better views into market dynamics. Cap-and-trade and four variations of carbon tax policies were integrated in a game-theory based generation expansion planning model to assess their impacts on new investments in renewable energy generation capacity. The most efficient tax policy and variations were obtained using inverse equilibrium models. The third part complemented the previous parts by conducting a realistic case study on the generation expansion planning under uncertainty. It studied the formulation and solution of investment decisions in new generation under the explicit representation of environmental policies and their associated uncertainty. A three-layer framework was proposed to study the investment decisions. The operations layer was used to represent the transmission physical flows under economic dispatch in the network; the assessment layer completed comprehensive assessment of candidate investment plans under uncertainty; the optimization layer was designed to compare the optimal investment decisions for the decision makers based on the optimization criteria. Our framework was tested on a realistic 240-bus WECC network, taking into account representative scenarios and investment plans.

CHAPTER 1. OVERVIEW

1.1 Background

If modern society is analogized as a human body, electricity can be compared with the blood that drives the operations of people's daily activities. It pumps from the large arteries such as refinery, to the the small capillaries such as cooking and farming. It is therefore of crucial importance to supply reliable and uninterrupted electricity. However, population growth and technological advancement have pushed power consumption to an unprecedented level, and the decision-making on future grid infrastructures must deal with problems and challenges inherent in generation expansion planning – a process for investors to seek strategies to build new generators in power systems.

First, market liberalization adds complexity to model market players interactions by introducing competitions among market players. Since the 1990s, power systems were changed from a vertically integrated structure, in which generation, transmission and distribution were all owned and regulated by a single system operator, to a decentralized structure, in which generation companies, transmission companies, distribution companies, load serving entities and individual consumers can make their own optimization decisions monitored by Independent System Operators [54]. The deregulated structure introduces competition among private entities in the energy markets. Game theory is widely applied to model the restructured power systems and characterize interactions among market players. When the models are not computationally tractable, simulations and/or heuristic methodologies are needed to obtain approximate outcomes.

Second, numerous environmental regulations have emerged and been imposed on the power systems. Electricity in current power systems is mainly generated from coal-fire generators. Coal, which requires millions years to form, will be depleted in the next century. Coal-fired generators also emit greenhouse gas, which is believed to be the main culprit for global warming. For the sake of future generations, current power systems have to be overhauled to create one that is both cleaner and more sustainable. However, generators which use renewable resources entail a large investment capital in large tracts of land for installation. For this reason renewable generators are unlikely to attract profit-seeking investors under the current economic model. Thus, environmental policies are proposed to restrict the pollutant emissions or require a minimum supply come from renewable resources, which will stimulate plentiful investments in renewable generators. Many associated programs have been implemented to incentivize renewable generator investments and promote participation in energy saving programs from the electricity end users. Thus, the implementation of environmental regulations plays an important role in generation expansion planning by introducing new constraints and mechanisms on the future grid.

Third, the decision-making process is difficult to formulate under the current uncertainty surrounding the energy market. Fuel prices, demand fluctuations and outages of operating elements were once the most popular discussed uncertainty sources in the operations and planning of the power systems. However, with penetration of renewable resources, renewable generation intermittency becomes a new significant source of uncertainty. If not carefully schemed, it might cause reliability issues and reduce generator efficiency. Renewable outputs are correlated spatially, and to electricity loads, which makes the modeling and simulation of the power systems tremendously complicated. Consideration of uncertainty makes depiction of the power system's decision-making more accurate.

To meet the growing demand and comply with environmental regulations, generation expansion is required to maintain the adequacy and reliability of power systems . Insightful knowledge of complex strategic behavior among market entities can support the oligopoly to exercise their powers toward better profitability in the liberalized energy market. A robust investment decision must take into account the challenges which arise future grids too, such as potential implementations of a myriad of regulations and their associated uncertainty.

1.2 Problem Introduction

In my dissertation, I studied the power systems' planning under environmental regulations by investigating the characteristics and impacts of the environmental policies in single-and multiple-period generation expansion planning. Based on a novel framework, I also conducted a comprehensive case study using a realistic test system to assess an independent generation company's investment plans under uncertainty from regulations, other market players, future loads and renewable resources. The following three sections are brief introductions to three papers in the dissertation.

1.2.1 Introduction to Comparison of Cap-and-Trade and Carbon Taxes

The carbon tax and cap-and-trade policies are two types of environmental policies that differ in approach, but have the potential to reduce greenhouse gas emissions and promote renewable energy. In both policies there is a cost associated with emissions created during energy generation. In the carbon tax policy, the emission price is predetermined, but the total actual emissions are determined by the market. In cap-and-trade policy, the total emissions are capped, but the emission price is determined by the market. The Regional Greenhouse Gas Initiative (RGGI), started in 2008, was the first carbon dioxide cap-and-trade program [51]. The carbon tax has not been formally and widely implemented in the U.S yet. However, it has been widely applied in some countries like New Zealand and Switzerland. The carbon tax is considered one of the possible future environmental regulations in the U.S. Currently there is very little in the literature that gives insight on the economic impacts of the carbon tax policy on the power systems. Moreover, it is unclear whether the carbon tax would be more beneficial in the power systems than existing regulations such as the cap-and-trade policy. It is very meaningful to compare the carbon tax policy with existing emission reduction policy to provide economic insights for future implementation.

In the first part of the dissertation, the model in [47] was extended to address the comparison between various carbon tax and cap-and-trade policies. Game theory models were used to integrate the environmental policies in a generation expansion planning framework. We compared the efficiency and effectiveness of these policies in the context of generation capacity expansion.

1.2.2 Introduction to Multi-Period Carbon Policies

In the the first segment, only a single period operation or planning was considered on a small network. The results were insufficient to illustrate the dynamics of the impacts from environmental policies on the power systems. Moreover, the example was too small to capture the complex interactions of real power systems. Therefore, in the second part, the model was further extended to consider multi-period planning to capture the market dynamics, and practically modeled two interdependent markets – energy and emissions markets. The periods were interconnected owing to the generator construction lead time. More details of the energy and emission markets were added. The formulation describes how the generation companies made decisions when they perceived the future dynamic carbon prices, and how the policies were determined when the regulator observed the long-term expansion strategies of generation companies. An IEEE 30-bus network was applied in this case study to reflect the complexity of the power system network.

1.2.3 Introduction to Assessment of Generation Expansion Planning

In previous works, we highlighted the comparison between various carbon tax and cap-and-trade policies. Generation expansion planning was not emphasized, and it only served as a way to comply with the environmental regulations. As a complement, the last paper studied the formulation and solution of investment decisions in new generations under explicit representation of environmental policies and associated uncertainty to gains insights into feasibility, effectiveness and robustness of investment strategies under a myriad of uncertainty sources. The proposed framework was applied to investigate the impacts of two categorizations of uncertainty – epistemic (systematic) and aleatoric (statistical) uncertainty on investment strategies. Uncertainty from renewable generation outputs and loads was modeled as aleatoric uncertainty, while uncertainty from governments, regulators and market players was modeled as epistemic uncertainty. The framework was tested in a realistic 240-bus system. The investment strategies were compared via various optimization criteria and assessed through assessment indicators comprehensively. Possible suggestions were presented to help the decision makers modify the existing plans.

1.3 Dissertation Structure

The dissertation consists of three papers. The first paper, published in *Handbook of CO2 in Power Systems*[45], appears in Chapter 2. The second paper, published in *Computers & Industrial Engineering*[44], is presented in Chapter 3. The third paper, in preparation for submission to *IEEE Transactions* *on Power Systems Special Section on "Power System Planning and Operation towards a Low-Carbon Economy"*, is included in Chapter 4. Concluding remarks in Chapter 5 summarizes the dissertation.

CHAPTER 2. COMPARING THE EFFECTIVENESS OF CAP-AND-TRADE AND CARBON TAXES POLICIES IN GENERATION EXPANSION PLANNING

Published in *Handbook of CO2 in Power Systems*

Yanyi He, Lizhi Wang and Jianhui Wang

ABSTRACT

Cap-and-trade and carbon taxes are two types of environmental policies that differ in their goals and approaches but both have the potential to reduce greenhouse gas emissions and promote renewable energy. We compare the effectiveness and efficiency of theses policies in the context of generation capacity expansion. Game theoretic models are used to integrate the environmental policies in a generation expansion planning framework. The most efficient tax policies and variations are obtained using the inverse equilibrium models. We compare cap-and-trade and carbon taxes with respect to five criteria: carbon price and tax, renewable energy portfolio, total energy generation, generation companies' and grid owner's total profit, and government revenue. Numerical experiments show the relative advantages, disadvantages, similarities, differences and limitations of the he policies.

2.1 Introduction

With increasing concerns on reducing greenhouse gas (GHG) emissions, which are a major contributor of global warming, renewable energy has been identified as a key solution to a sustainable future of energy supplies. Compared to the mature non-renewable generation technologies, one of the major disadvantages of renewable energy is the capital-intensive construction and manufacturing. In an effort to offset such disadvantages, environmental policies at the federal and regional levels have been playing an important role in promoting renewable energy for decades. According to the Energy Information Administration [5], renewable energy subsidies in the U.S. increased from \$1.4 billion to \$4.9 billion between 1999 and 2007. The results of the subsidies were mixed: electricity production from wind increased at a yearly rate of 32%, but the production of all other renewable energy sources (hydroelectric, biomass, geothermal, and solar) failed to increase continuously or significantly during that period.

There are mainly three types of environmental policies: market (such as cap-and-trade), incentive (such as carbon taxes and production tax credits), and mandate (such as renewable energy portfolio). Although they all have the overall effect of promoting renewable energy, they differ in specific policy goals and approaches, which also result in varying effectiveness. The cap-and-trade policy, for example, aims at reducing GHG emissions by setting an upper bound, or cap, of the total emissions from a power supplier. Initial amounts of emissions allowances are allocated to individual power suppliers, who can trade their allowances between them but the overall cap will not be exceeded. This policy does not directly penalize non-renewable energy or subsidize renewable energy, but focuses on controlling the total emissions as a system output. A market for trading emissions allowances is formed to set the carbon price, which determines only the revenue redistribution among power suppliers rather than revenues from or expenses to external sources. An alternative policy that also receives great attentions and discussions is carbon taxes, which are imposed on all emissions from electricity generation. This chapter contributes to the debates on the comparison of these policies from the following perspectives.

First, the comparison of effectiveness is under the context of generation expansion planning (GEP). This is motivated by the fact that once installed, the marginal cost of renewable generation is usually much lower than non-renewable one; but the major obstacle is that the prohibitive capital investment requirements limit new renewable capacity installment in the first place. The effectiveness of the policies should therefore be evaluated in terms of their capability to stimulate new investment in renewable energy. We also land our analysis of the generation expansion planning problem on the restructured electricity market, which has lead to major changes to the traditional generation expansion planning in the electricity industry [72]. The unbundling of generation and transmission make the generation expansion planning much more competitive for self-interested independent participants in electricity markets. In an old vertically-integrated electricity market, the investment in new generation resources was centrally planned in order to achieve a pre-specified system reliability level, and the cost was covered by ratepayers [23, 25, 77]. In a restructured electricity market, however, each generation company (GENCO) can pursue its own maximized profit by strategically investing in and operating its generating units. A non-arbitrage bilateral market equilibrium model presented in [47] is used for this analysis. This model not only captures the major factors of interest but also has the nice property of possessing a unique solution, thus provides a good basis for our extended analysis of generation expansion planning under environmental policies.

Second, we propose a novel inverse equilibrium model to determine the optimal carbon taxes. For a given overall emissions cap, the modeling of the cap-and-trade policy is relatively straightforward. However, there could exist multiple and different tax policies that can all achieve the same policy goal. For comparison with cap-and-trade, it is only fair and meaningful to use the *most effective* tax policy. The inverse equilibrium model we present enables us to determine such optimal tax policy that makes our comparison more meaningful. The carbon taxes policies we consider in our models are more general than just taxes; we consider taxes, subsidies (representing production tax credits), as well as variations of their combinations.

Third, the comparisons between cap-and-trade and carbon taxes are based on five criteria: carbon price and subsidy, renewable energy portfolio, total energy generation, GENCOs' and grid owner's total profit, and government revenue. Our intention is not to declare a winner or loser, but to provide a modeling tool and framework to analyze their advantages, disadvantages, similarities, differences, and limitations from objective and meaningful perspectives.

Environmental policies in electricity market has been a topic of numerous studies. Game theoretic models are used to analyze the equilibria with NO_x limits [31, 32]. A case study of the State of Maryland is conducted in [70] to investigate the economic and energy impacts from participation in a regional cap-and-trade system. Johnson [53] discusses the subsidies, carbon taxes and cap and trade. The author finds that new-source subsidies will accelerate the de-carbonization of the electricity generation. A comprehensive discussion of key technical challenges for the power industry in face of climate change is provided in [22]. Tabors et al. [73] analyze the impact of different policies including carbon taxes for the U.S. electric industry to reduce both acid rain production and global warming gases. A CO_2 cap-and-trade system is modeled in [82] to simulate the energy production of some regions in the U.S. However, this research does not consider the long-term generation expansion issues in sufficient details.

There also exist various models for analyzing market power exercise and GEP in an electricity market. Game theoretic models [33, 57, 59] are particularly suitable to capture the oligopolistic nature of GENCOs in an electricity market. Wang [79] presents a generation expansion planning model with uncertain demands and generator availabilities. Coalition and collusion of participants in electricity markets are studied using a cooperative game approach in [20, 41]. A non-cooperative incomplete information game approach is applied in [40] to model GENCOs' optimal bidding strategy within a set of discrete bids.

2.2 Models

In this section, we introduce the energy market models that we use to analyze and compare cap-and-trade and carbon taxes policies. Section 2.2.1 lists the nomenclature used in this chapter. Section 2.2.2 summarizes the non-arbitrage bilateral market equilibrium model presented in [47]. This model provides a basis for our analysis of generation capacity expansion under environmental policies. Section 2.2.3 extends the bilateral market equilibrium model to include GEP, in which individual GENCOs choose the quantity and type (renewable or non-renewable) of new generation installment to compete for maximum profits in a Nash-Cournot manner. The resulting Nash equilibrium is a linear complimentarity problem (LCP). Section 2.2.3 incorporates the carbon cap-and-trade policy into the GEP model. By regulating carbon emissions and prices, the regulator intends to encourage more investment in new renewable generation capacity. Section 2.2.4 presents new inverse equilibrium models for designing optimal carbon tax and subsidy policies for promoting new renewable generation and limiting carbon emissions. The optimal policy design models are linear programs with complementarity constraints.

2.2.1 Nomenclature

Sets:

$\mathscr{F}$	set of GENCOs, $f \in \mathscr{F}$.	
$\mathscr{I}$	set of nodes, $i \in \mathscr{I}$.	
$\mathscr{H}$	set of power generating types, $h \in \mathscr{H}$.	
$\mathscr{G}$	set of generators, $(f,i,h) \in \mathscr{G}$.	
$\mathscr{K}$	set of transmission lines, $k \in \mathscr{K}$.	

Parameters:

X_{fih}	capacity of generator (f,i,h), which is of type h owned by GENCO f at node i.	(MW)
P_{i0}, Q_{i0}	parameters of linear demand function $p_i = P_{i0} - (P_{i0}/Q_{i0})q_i$, where p_i and q_i are the price and quantity of electricity, respectively.	(\$/MWh), (MWh)
E_{fih}	emissions rate of generator (f,i,h).	(ton/MWh)
H	power transfer distribution factors matrix.	dimensionless
T_k	transmission capacity of line k.	(MWh)
K_f	emissions allowance for GENCO f.	(ton)
C_{fih}	operating cost of generator (f,i,h).	(\$/MWh)
I_{fih}	investment cost of generator (f,i,h).	(\$/MWh)

GENCOs' decision variables:

x_{fih}	power generation of generator (f,i,h).	(MWh)
Δx_{fih}	expanded generation of generator (f,i,h).	(MWh)
s_{fj}	generation quantity sold by GENCO f to consumers at node j.	(MWh)
c_f	sales (positive) or purchase (negative) of emissions certificates.	(ton)

Grid owner's decision variables:

y_i	power injection at node i.	(MWh)

Dual variables:

ρ_{fih}	dual variables of Constraint (2.2).	(\$/MWh)
θ_f	dual variables of Constraint (2.3).	(\$/MWh)
λ_{k-}	dual variables of Constraint (3.7).	(\$/MWh)
λ_{k+}	dual variables of Constraint (3.8).	(\$/MWh)
δ_f	dual variables of Constraint (3.21).	(\$/ton)

Incentive policy maker's decision variables:

tax_{fih}	tax (positive) or subsidy (negative) of generator (f,i,h).	(\$/MWh)

Market clearing variables:

w_i	payment (charge) for generating (receiving) electricity at node i.	(\$/MWh)
p_s	emissions allowance price.	(\$/ton)

2.2.2 Energy Market Equilibrium Model

In this section, we summarize the non-arbitrage bilateral market equilibrium model presented in [47]. This model simulates the Nash-Cournot competition of power suppliers in a bilateral market and results in an LCP formulation, thus provides a modeling basis for our extended analysis of GEP under environmental policies.

A group of power producers $\mathscr{F}$ compete in a Nash-Cournot manner to maximize their own profits by determining the quantity of electricity generation and sales in a bilateral market. Each power producer $f \in \mathscr{F}$ owns a portfolio of generators $(fih) \in \mathscr{G}$, with marginal cost C_{fih} and generation capacity X_{fih}. The index (f,i,h) indicates the ownership $f \in \mathscr{F}$, location $i \in \mathscr{I}$, and type $h \in \mathscr{H}$ of the generator, respectively. The electricity network consists a group of nodes $\mathscr{I}$, connected by a group of transmission lines $\mathscr{K}$. The linear demand function at node i is assumed to be $p_i = P_{i0} - (P_{i0}/Q_{i0})\sum_f s_{fi}$. Here P_{i0} and Q_{i0} are parameters, p_i is the price at node i, and s_{fi} is the sales of producer f to node i. A producer gets paid (pays) w_i for generating (receiving) power at node i, thus $w_j - w_i$ represents the cost of transmitting power from node i to j. A grid owner is assumed to determine the power injection at each node y_i to maximize revenue $\sum_i w_i y_i$ subject to transmission constraints $|\sum_i H_{ik} y_i| \leq T_k, \forall k \in \mathscr{K}$, where H denotes the power transfer distribution factors matrix.

GENCO f's profit maximization problem is:

$$\max \quad \sum_j [P_{j0} - (P_{j0}/Q_{j0})(\sum_g s_{gj}) - w_j] s_{fj} - \sum_{i,h}(C_{fih} - w_i) x_{fih} \tag{2.1}$$

$$\text{s.t.} \quad x_{fih} \leq X_{fih} \quad (\rho_{fih}) \quad \forall i,h \tag{2.2}$$

$$\sum_j s_{fj} = \sum_{i,h} x_{fih} \quad (\theta_f) \tag{2.3}$$

$$s_{fj}, x_{fih} \geq 0 \quad \forall f,i,j,h. \tag{2.4}$$

The grid owner's revenue maximization problem is:

$$\max \quad \sum_i w_i y_i \tag{2.5}$$

$$\text{s.t.} \quad -\sum_i H_{ik} y_i \leq T_{k-} \quad (\lambda_{k-}) \quad \forall k \tag{2.6}$$

$$\sum_i H_{ik} y_i \leq T_{k+} \quad (\lambda_{k+}) \quad \forall k. \tag{2.7}$$

The market clearing condition is:

$$\sum_f s_{fi} - \sum_{f,h} x_{fih} = y_i \quad (w_i) \quad \forall i. \tag{2.8}$$

Assuming Nash competition among GENCOs and the grid owner, the market equilibrium solution can be obtained by solving the following first order conditions:

$$0 \leq s_{fj} \perp -P_{i0} + (P_{i0}/Q_{i0})(2s_{fj} + \sum_{g \neq f} s_{gj}) + w_j + \theta_f \geq 0 \quad \forall f,j \tag{2.9}$$

$$0 \leq x_{fih} \perp C_{fih} - w_i + \rho_{fih} - \theta_f \geq 0 \quad \forall f,i,h \tag{2.10}$$

$$0 \leq \rho_{fih} \perp X_{fih} - x_{fih} \geq 0 \quad \forall f,i,h \tag{2.11}$$

$$\sum_j s_{fj} = \sum_{i,h} x_{fih} \quad \forall f \tag{2.12}$$

$$w_i + \sum_k H_{ik}(\lambda_{k-} - \lambda_{k+}) = 0 \quad \forall i \tag{2.13}$$

$$0 \leq \lambda_{k-} \perp T_{k-} + \sum_i H_{ik} y_i \geq 0 \quad \forall k \tag{2.14}$$

$$0 \leq \lambda_{k+} \perp T_{k+} - \sum_i H_{ik} y_i \geq 0 \quad \forall k \tag{2.15}$$

$$\sum_f s_{fi} - \sum_{f,h} x_{fih} = y_i \quad \forall i. \tag{2.16}$$

An underlining assumption behind this formulation is that the GENCOs naively believe that their decisions will not affect transmission prices. It is shown in [47] that the market equilibrium solution to (2.9)-(2.16) uniquely exists.

2.2.3 Generation Expansion Planning Model

We extend the market equilibrium model to include GEP. Our analysis and comparison of environmental policies will be based on their effectiveness and efficiency in promoting new renewable installments and reducing GHG emissions.

We assume the investment cost for extending the capacity of generator (f,i,h) is I_{fih}, and the amount of new capacities Δx_{fih} are new decision variables of GENCOs'. The new profit maximization problem of GENCO f under GEP becomes:

$$\max \quad \textstyle\sum_j [P_{j0} - (P_{j0}/Q_{j0})(\sum_g s_{gj}) - w_j] s_{fj} - \sum_{i,h}(C_{fih} - w_i)x_{fih} - \sum_{i,h} I_{fih}\Delta x_{fih} \tag{2.17}$$

$$\text{s.t.} \quad x_{fih} \leq X_{fih} + \Delta x_{fih} \quad (\rho_{fih}) \quad \forall i,h \tag{2.18}$$

$$\textstyle\sum_j s_{fj} = \sum_{i,h} x_{fih} \quad (\theta_f) \tag{2.19}$$

$$s_{fj}, x_{fih}, \Delta x_{fih} \geq 0 \qquad \forall f,i,j,h. \tag{2.20}$$

The grid owner's problem remains the same. The market equilibrium conditions become:

$$0 \leq \rho_{fih} \perp X_{fih} + \Delta x_{fih} - x_{fih} \geq 0 \qquad \forall f,i,h \tag{2.21}$$

$$0 \leq \Delta x_{fih} \perp I_{fih} - \rho_{fih} \geq 0 \qquad \forall f,i,h \tag{2.22}$$

$$\text{Constraints (2.9)-(2.10) and (2.12)-(2.16).} \tag{2.23}$$

2.2.4 Cap-and-Trade Policy Model

The cap-and-trade policy sets a limit, or cap, on the amount of emissions each GENCO is allowed to produce. GENCOs can trade their emissions allowances among themselves so that individual GENCO's emissions may differ from their initial allowances but the total amount does not exceed the overall cap. Cap-and-trade has been a successful policy tool for limiting SO_x and NO_x emissions in the country. A variant of a cap-and-trade plan for GHG emissions is proposed in the American Clean Energy and Security Act of 2009, which was approved by the House of Representatives on June 26, 2009 and is still in consideration in the Senate.

In this section, we modify the GEP model from Section 2.2.3 to include the cap-and-trade policy. In particular, each GENCO will face a new emissions allowances constraint, which is a soft constraint and can be violated by purchasing additional allowances from other GENCOs. The market clearing conditions also include the balancing constraint between total sales and total purchases of the emissions allowances, which enforces the pre-determined emissions cap on the entire market. While the target of the cap-and-trade policy is to control emissions, it is expected to also encourage more investment in renewable generation. To evaluate its effectiveness in doing so, we classify GENCOs' generations into four types: existing non-renewable, existing renewable, new non-renewable, and new renewable generations, indicated by different values of h. The emissions rate of generator (f,i,h) is denoted as E_{fih}. The initial emissions allowances of GENCO f is assumed to be pre-determined and denoted as K_f. The market clearing price for emissions allowances is denoted as p_s.

Under the cap-and-trade policy, GENCO f's profit maximization problem is:

$$\max \quad \sum_j [P_{j0} - (P_{j0}/Q_{j0})(\sum_g s_{gj}) - w_j] s_{fj} - \sum_{i,h}(C_{fih} - w_i)x_{fih} - \sum_{i,h} I_{fih}\Delta x_{fih} + p_s c_f \tag{2.24}$$

$$\text{s.t.} \quad \sum_{ih} E_{fih}x_{fih} + c_f \leq K_f \qquad (\delta_f) \tag{2.25}$$

$$\text{Constraints (3.2)-(2.20).} \tag{2.26}$$

The grid owner's problem remains the same. The market equilibrium conditions become:

$$0 \leq \rho_{fih} \perp X_{fih} + \Delta x_{fih} - x_{fih} \geq 0 \qquad \forall f,i,h \tag{2.27}$$

$$0 \leq \delta_f \perp K_f - \sum_{i,h} E_{fih}x_{fih} - c_f \geq 0 \qquad \forall f \tag{2.28}$$

$$\delta_f = p_s \qquad \forall f \tag{2.29}$$

$$\sum_f c_f = 0 \tag{2.30}$$

$$0 \leq x_{fih} \perp (C_{fih} - w_i) + \rho_{fih} - \theta_f \geq 0 \qquad \forall f,i,h \tag{2.31}$$

$$0 \leq \Delta x_{fih} \perp I_{fih} - \rho_{fih} \geq 0 \qquad \forall f,i,h \tag{2.32}$$

$$\text{Constraints (2.9)-(2.10) and (2.12)-(2.16).} \tag{2.33}$$

A solution that satisfies Constraints (2.27)-(2.33) yields a Nash equilibrium solution under this model.

2.2.5 Optimal Incentive Policy Models

As alternatives to the cap-and-trade policy, taxes and subsidies also provide incentives for power producers to invest more in renewable energy and less in non-renewables. In this section, we construct an optimal incentive policy design model to facilitate the comparison of cap-and-trade and incentives in terms of cost effectiveness. The incentive policy design problem is inherently a bilevel problem. The lower level is the Nash game among the GENCOs and the grid owner. Each GENCO solves a profit maximization problem under exogenously determined tax and subsidy policies. The upper level's problem is to design the minimal incentive intervention in order to achieve a policy goal. In comparison with cap-and-trade, we choose the policy goal to be the limit on total emissions.

Let tax_{fih} denote the tax (positive) or subsidy (negative) of generator (f,i,h). Under such incentive policies, GENCO f's profit maximization problem is:

$$\max \quad \sum_j [P_{j0} - (P_{j0}/Q_{j0})(\sum_g s_{gj}) - w_j] s_{fj} - \sum_{i,h}(C_{fih} + tax_{fih} - w_i)x_{fih} - \sum_{i,h} I_{fih}\Delta x_{fih} \tag{2.34}$$

$$\text{s.t.} \quad \text{Constraints (3.2)-(2.20).} \tag{2.35}$$

The grid owner's problem remains the same. The market equilibrium conditions become:

$$0 \le \rho_{fih} \perp X_{fih} + \Delta x_{fih} - x_{fih} \ge 0 \qquad \forall f,i,h \tag{2.36}$$

$$0 \le x_{fih} \perp (C_{fih} + tax_{fih} - w_i) + \rho_{fih} - \theta_f \ge 0 \quad \forall f,i,h \tag{2.37}$$

$$0 \le \Delta x_{fih} \perp I_{fih} - \rho_{fih} \ge 0 \qquad \forall f,i,h \tag{2.38}$$

$$\text{Constraints (2.9) and (2.12)-(2.16).} \tag{2.39}$$

The upper level's optimal incentive policy design problem is formulated as the following bilevel optimization problem:

$$\min \quad \sum_i |tax_{fih}|/|\mathscr{I}| \tag{2.40}$$

$$\text{s.t.} \quad \sum_{fih} E_{fih} x_{fih} \le \sum_f K_f \tag{2.41}$$

$$\text{Constraints (2.36)-(2.39).} \tag{2.42}$$

The objective (2.40) is to minimize the average tax or subsidy intervention; Constraint (2.41) defines the goal of the policy, which could not be achieved without the incentives; Constraint (2.42) is the set of optimality conditions for the lower level's GEP problem under incentive policy intervention.

The incentive policy design model (2.40)-(2.42) could be modified to reflect different variations of the policies. In particular, we consider the following variations:

Uniform tax policy (UT): The taxes reflect the carbon taxes for non-renewable energy. Under this policy, no subsidy is provided to renewable energy production and the taxes for non-renewable energy production are the same across all nodes and all GENCOs. The following additional constraints will results in this policy:

$$tax_{fih} = tax_{fjh} \geq 0 \qquad \forall f,i,j,h. \tag{2.43}$$

Uniform subsidy policy (US): The subsidies reflect the production tax credits or investment tax credits for renewable energy. Under this policy, no tax is imposed on non-renewable energy production and the subsidies for renewable energy production are the same across all nodes and all GENCOs. The following additional constraints will result in this policy:

$$tax_{fih} = tax_{fjh} \leq 0 \qquad \forall f,i,j,h. \tag{2.44}$$

Uniform subsidy and tax policy (UST): This is a combination of UT and US. The following additional constraints will result in this policy:

$$tax_{fih} = tax_{fjh} \qquad \forall f,i,j,h. \tag{2.45}$$

Non-uniform tax policy (NT): This policy differs from UT in that the taxes for non-renewable energy production are allowed to differ from node to node. For those nodes where taxes are less effective (due to transmission congestion, for example), this policy has the flexibility to reduce the unnecessarily high taxes. The following additional constraints will results in this policy:

$$tax_{fih} \geq 0 \qquad \forall f,i,h. \tag{2.46}$$

Non-uniform subsidy policy (NS): Similar to NS, with non-uniform taxes and zero subsidy. The following additional constraints will results in this policy:

$$tax_{fih} \leq 0 \qquad \forall f,i,h. \tag{2.47}$$

Non-uniform subsidy and tax policy (NST): This is a combination of NS and NT. This policy is the most flexible variation in our analysis and is reflected in (2.40)-(2.42).

For notational convenience, in the remainder of the chapter, we will use the abbreviation CT to denote the cap-and-trade policy.

2.3 Numerical Analysis

A simple 5-bus test example is used to demonstrate our models. We will further discuss the advantages and disadvantages between those policies with respect to five criteria.

2.3.1 Data

The 5-bus electricity network is shown in Figure 2.1. Nodes B, C, and D are demand nodes, and nodes A, C, D, and E are supply nodes. There are two GENCOs in the market. GENCO 1 owns generators in nodes A and C, and GENCO 2 owns generators in nodes D and E. The demand and supply data are given in Table 2.1, and transmission data in Table 2.2. The emissions rates for non-renewable and renewable generators are assumed to be 50 and 0 ton/MWh, respectively. We also assume that the two GENCOs receive equal initial emissions allowances in the CT policy.

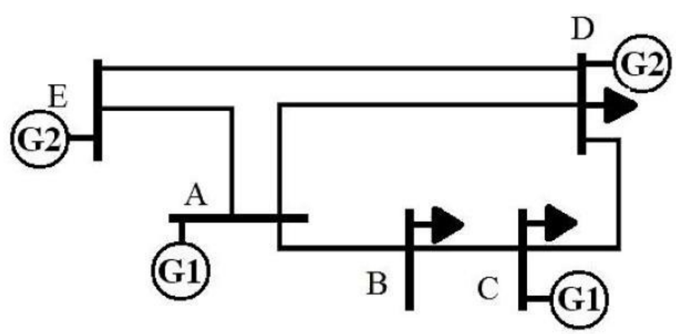

Figure 2.1 5-bus test example

Table 2.1 Demand and supply data

node	P_{i0}	Q_{i0}	C_{fi1}	C_{fi2}	C_{fi3}	C_{fi4}	I_{fi3}	I_{fi4}	X_{fi1}	X_{fi2}
A	-	-	1	8	6.5	1	2	15	60	300
B	200	600	-	-	-	-	-	-	-	-
C	100	600	1	8	6.5	1	2	15	50	300
D	200	600	1	5	4.5	1	4	15	70	350
E	-	-	1	5	4.5	1	4	15	55	500

Table 2.2 Transmission data

line	A-B	B-C	C-D	D-E	E-A	A-D
T_k	377	77	233	240	360	159

2.3.2 Results

In this section, we compare cap-and-trade with incentive polices with respect to five criteria: carbon price and subsidy, renewable energy portfolio, total energy generation, GENCOs' and grid owner's total profit, and government revenue, detailed in Sections 2.3.2.1-2.3.2.5.

2.3.2.1 Carbon Price and Subsidy

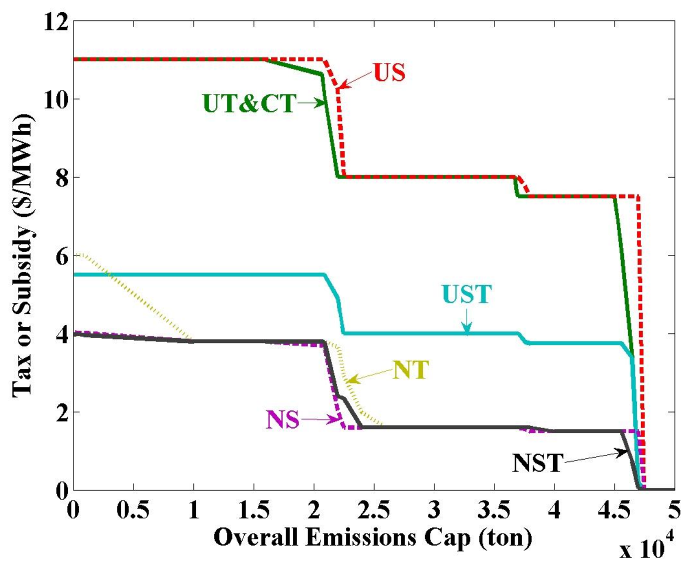

Figure 2.2 Policy comparison on carbon price and subsidy

In the cap-and-trade policy, the emissions allowances price p_s (in \$/ton) is a natural criterion for evaluating the cost efficiency of the policy. For a given overall emissions cap, the lower the price is, the higher the cost efficiency is. We also identify similar criteria from incentive policies for comparison. For incentive policies, the average tax or subsidy $\frac{\sum_i |tax_{fih}|}{|\mathscr{I}|}$ (in \$/MWh) is a comparable criterion with a different unit. To facilitate the comparison, we convert the emissions allowance price p_s to (\$/MWh) using the emissions rate parameter E_{fih}. Figure 2.2 shows the tax or subsidy equivalent criteria of different policies as functions the overall emissions cap. We point out the following findings:

1. The UT and CT policies are equally cost effective on this criterion. This is not surprising since in the CT, the carbon price p_s is universal for all GENCOs, which is equivalent to a uniform carbon tax. These two policies, however, do show different performances on other criteria.

2. US is intuitively similar to UT (and thus CT) in the sense that they both uniformly reduce the cost differences between renewable and non-renewable generations. However, US turns out to be slightly less cost effective than UT in certain segments of the curves. This is because of the fact that electricity demands are decreasing functions of prices. Providing subsidies to GENCOs will reduce the cost and price of electricity, which in turn leads to higher generation and emissions. UT and CT have the opposite effect. Therefore, UT and CT could require less taxes to reduce the same amount of emissions than US requires subsidies.

3. Nonuniform policies (NS, NT, and NST) are more effective than uniform ones (US, UT, and UST) because the former policies have the flexibility to reduce the taxes and subsidies in places where the cost effectiveness is limited by transmission or generation capacity constraints.

4. When the overall emissions cap is around 46,000 tons, the NS shows lower cost efficiency than NT for the same reason of demand functions. When the cap is around 25,000 tons, however, the NT appears to be more cost effectiveness than NS. This is largely due to transmission constraints. Tax policies reduce generation, especially from non-renewable sources; whereas subsidy policies increase generation, especially from renewable sources. Under transmission constraints, the cost efficiency of subsidy policies is more likely to be discounted due to lack of transmission capacities to deliver the increased generation.

5. Mixed tax and subsidy policies (UST and NST) are more cost effective than tax only (UT and NT) and subsidy only (US and NS) ones. They reduce the level of incentives approximately by half.

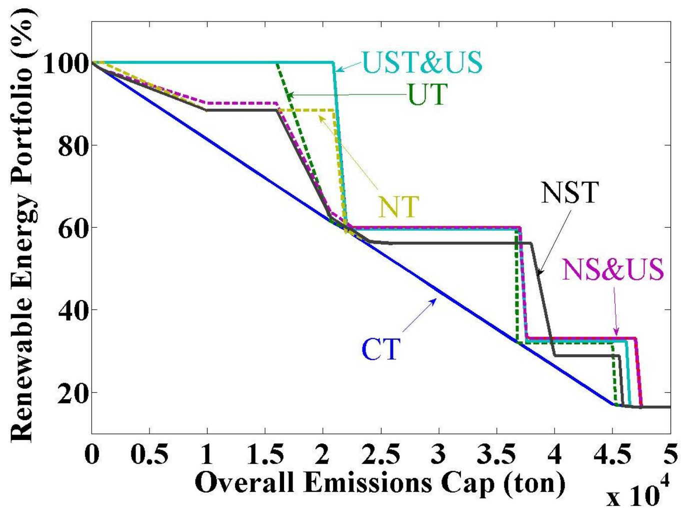

Figure 2.3 Policy comparison on renewable energy portfolio

2.3.2.2 Renewable Energy Portfolio

Although none of the policies being modeled in Section 2.2 has a specific target on renewable energy portfolio, they are all expected to stimulate more investment and generation of renewable energy and thus increase the renewable energy portfolio. In this section, the criterion for policy comparison is the percentage of renewable energy generation as a function of overall emissions cap. This criterion indicates the policies' effectiveness in stimulating new investments in renewable energy. Figure 2.3 shows the policy comparison on renewable energy portfolio. We point out the following findings:

1. As the overall emissions cap reduces from 47,000 tons to 0, CT gradually increases the renewable energy portfolio from about 20% to 100% in a straight line. All other incentive policies could only increase the renewable energy portfolio in step functions, showing lack of flexibility in continuous control. This is due to the nature of incentive policies. Under the pure incentive policy models, GENCOs invest in the less costly generation exclusively, regardless how close the costs of renewable and non-renewable generation are. When the incentives are large enough to offset the cost difference, GENCOs tend to switch to the other generation all together, resulting in the step function type of behaviors.

2. Among the incentive policies, NST is the most flexible policy thus its curve looks closest to CT.

It also outperforms NS and NT, representing the advantage of combining taxes and subsidies over using them alone.

3. UST overlaps with US for the most part. UST also out performs UT around the 20,000-ton cap.

2.3.2.3 Total Electricity Generation

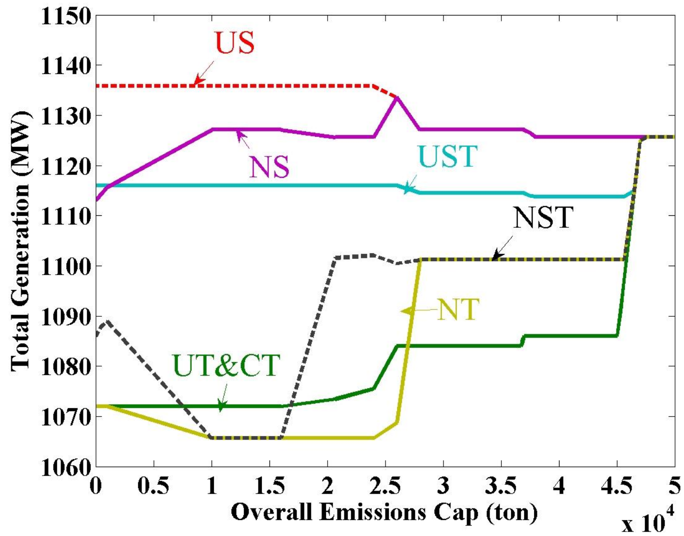

Figure 2.4 Policy comparison on total electricity generation

Total electricity generation is another criterion for comparison, indicating the policies' impact on electricity prices. The lower the generation, the higher the price. Figure 2.3 shows the policy comparison on total electricity generation as a function of overall emissions cap. We point out the following findings:

1. US increases electricity generation as the overall emissions cap reduces. This is because a lower cap will lead to more subsidies, lower cost, thus more generation.

2. Opposite to US, the UT and CT policies lead to reduced electricity generation.

3. UST results in a sharp decrease in generation around the 46,000-ton cap, which coincides with the sudden increase in renewable energy portfolio. Below that cap level, the generation curve is relatively flat, indicating the overall balance between taxes and subsidies.

4. NS overlaps with US for the most part. When the cap is smaller than around 22,000 tons, NS has lower generation because it provides less subsidies than US.

5. NST has lower generation than UST because, as demonstrated in Figure 2.6, NST is tax-dominant whereas UST is subsidy-dominant. When the cap is smaller than around 10,000 tons, NST becomes more subsidy-dominant, which causes its performance to change direction.

6. NST shows similar performance with NT due to its tax-dominant nature. The subsidy components in NST could also result in higher generation.

7. NT results in higher generation than UT in certain segments due to its non-uniform nature of policy. When the overall emissions cap becomes tighter, it results in lower generation than UT. This can be attributed to transmission congestions caused by non-renewable energy generation where NT does not impose taxes.

2.3.2.4 GENCOs' and Grid Owner's Total Profit

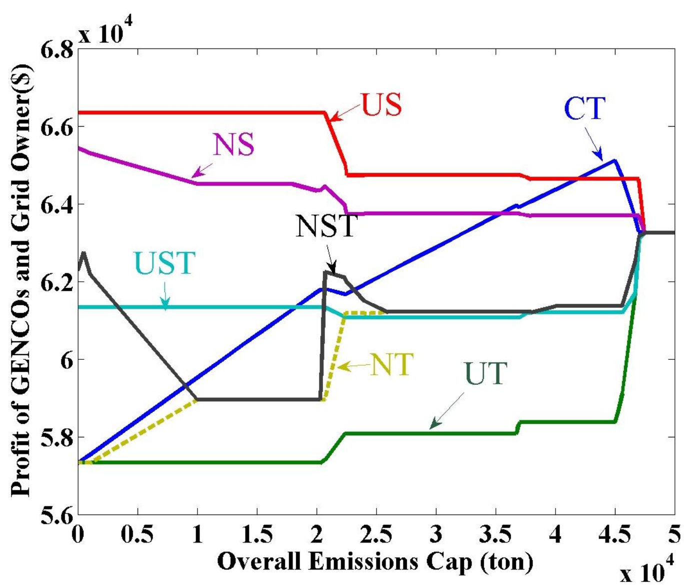

Figure 2.5 Policy comparison on GENCOs' and grid owner's total profit

We also compare the policies' impact on GENCOs' and grid owner's total profit as a function of overall emissions cap in Figure 2.5. The total profit is calculated as the summation of objective values of all GENCOs and the grid owner. This criterion also indicate the potential perceptions and reactions from GENCOs and grid owners towards the policies. We point out the following findings:

1. Under CT, the total profit is expected to decrease as the overall emissions cap gets tighter. Counter-intuitively, the opposite trend is observed when the cap is not very tight. This can be explained with the fact that the original Nash equilibrium without CT may not be Pareto optimal; when CT introduces additional emissions constraints, the new equilibrium solution dominates the original one in terms of total profit. Of course, this phenomenon soon gets offset by the increasingly tight cap, which eventually leads to a gradually decreasing total profit.

2. UT and CT result in different total profits. This is because under UT, the government extracts taxes from the GENCOs, whereas CT only redistributes profits within the GENCOs.

3. US provides the most generous subsidies to GENCOs, thus leads to highest total profits. NS is similar but less so due to its flexibility in reducing subsidies where not effective or necessary.

4. UT and NT have the opposite effect as US and NS.

5. UST and NST show similar performance as total electricity generation for similar reasons explained in Section 2.3.2.3.

6. The NST has a peak around the 21,000-ton cap. This is largely caused by transmission capacity limits, which could affect the effectiveness of incentives, possibly causing the total profit to either increase or decrease.

2.3.2.5 Government Revenue

Government revenue, either positive from taxes or negative from subsidies, as a function of overall emissions cap is calculated as another criterion for comparison with CT, which is revenue neutral for government. Results are shown in Figure 2.6 and findings are highlighted as follows:

1. US requires a significant amount of subsidy expenses to be effective. NS is similar but less so.

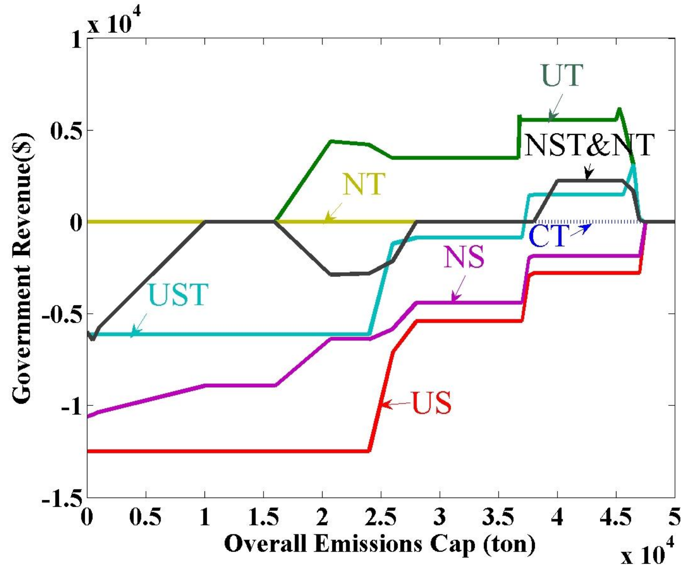

Figure 2.6 Government's income

2. UT results in positive revenues, which nevertheless decreases and eventually vanishes as the cap becomes tighter. This is because GENCOs are switching to renewable energy to avoid high tax penalties.

3. UST and NST are generally balanced between tax revenues and subsidy expenses, with occasional dominance of one incentive over the other.

2.4 Conclusions

In this chapter, we compare the effectiveness of the cap-and-trade and carbon taxes policies under a generation expansion planning context in an electricity market. The contributions of this study include integrated modeling framework for environmental policies under generation capacity expansion, novel inverse equilibrium approaches for optimal tax and subsidy policies, and multiple perspectives of policy comparison.

We make the following summarizing remarks on our findings from Section 2.3:

1. The similarities and differences between cap-and-trade and carbon taxes policies are demon-

strated in Figures 2.2-2.6. They show similar performances in terms of market-wide uniform carbon taxes and total electricity generation; cap-and-trade outperforms carbon taxes in continuous and flexible control of renewable energy portfolio and total profit of GENCOs and the grid owner; carbon taxes create a revenue stream to the government, whereas cap-and-trade does not.

2. The uniform subsidy and uniform tax policies have similar effectiveness in terms of minimal required tax and subsidy in \$/MWh and stimulating new renewable generation installation. However, they both have their own limitations. Subsidies require expenditure of tax payers money, whereas taxes are politically unpopular. A combination of both appears to be a better policy than either one alone. Subsidies have also shown the tendency of resulting in misleadingly low energy prices, which in turn lead to higher consumptions and thus more emissions.

3. Nonuniform tax only or subsidy only policies show superior performance than uniform ones. When taxes and subsidies are combined, uniform policy appears to be a more smooth function of overall emissions cap.

There are caveats in our analysis. First, we consider a small 5-bus example with artificial data for numerical analysis, which could fail to capture some characteristics of real energy markets. Second, the optimal incentive policy models are linear programs with complementarity constraints, the global optimal solutions of which are computationally challenging to obtain. It is our expectation that our analysis would shed light on new perspectives and approaches to qualitative and quantitative comparisons of environmental policies.

One of future research directions is to also include renewable portfolio standard into analysis, which would require an extension of load serving entities into our models to be the point of such regulation.

CHAPTER 3. CAP-AND-TRADE VS. CARBON TAXES: A QUANTITATIVE COMPARISON FROM A GENERATION EXPANSION PLANNING PERSPECTIVE

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ABSTRACT

We compare the effectiveness and efficiency of cap-and-trade and carbon tax policies in a generation expansion planning framework. The effectiveness refers to a policys capability to control the amount of carbon emissions, and the efficiency is measured with respect to seven criteria: average emissions price, actual emissions, renewable energy portfolio, total generation, total profit of Gencos and grid owner, economic welfare, and emissions adjusted economic welfare. Cap-and-trade and four variations of carbon tax policies are integrated in a game-theoretic based generation expansion planning model to assess their impacts on new investment in renewable energy generation capacity. A case study is conducted on a 30-bus test system, and numerical results provide insights on the advantages and disadvantages of these policies.

3.1 Introduction

The push toward a cleaner and more sustainable environment is resulting in new pressures on the electric power industry. The numerous fossil fired power plants that operate today make the industry one of the largest man-made carbon dioxide emitters. There are many climate change initiatives in various stages of development and implementation that will strongly influence the future course of the industry. Cap-and-trade (C&T) and carbon tax are among the most widely implemented and debated environmental regulations. Also known as emissions trading, C&T is a market-based policy for controlling pollutant emissions. Generating companies (Gencos) are required to hold an equivalent amount of allowances to offset their pollutant emissions. Initial allowances can be grandfathered or auctioned through a regulatory agency, and can be traded later on among Gencos. The total amount of emissions allowances is limited by a pre-determined cap, which will be gradually tightened over time. The European Union emissions trading scheme is the largest multi-national greenhouse gas emissions trading scheme in the world. In the U.S., a successful SO_2 C&T program was established under the framework of the Acid Rain Program of the 1990 Clean Air Act. The Regional Greenhouse Gas Initiative [10] and the Western Climate Initiative (including four Canadian provinces) [13] have also started CO_2 trading programs. Carbon tax is an incentive-based policy that levies taxes on burning fossil fuels or emitting carbon dioxide [49]. The motivation is to reflect the negative externalities caused by non-renewable electricity generation but not directly accounted for in energy prices. A number of European countries have implemented carbon taxes, including Denmark, Finland, the Netherlands, Norway, Sweden, Switzerland, and the UK. Some states in the U.S. are also considering imposing carbon taxes.

Many scholars have weighed in the discussion or debate between C&T and carbon tax [34, 36, 39, 50, 56, 66, 67], some being in favor of one policy over the other. Avi-Yonah and Uhlmann [19] argue that a carbon tax is a better response to global warming than C&T due to its simplicity and capability to provide an immediate carbon price signal. Metcalf [63] discusses the issues that should be taken into account in designing a carbon tax to reduce U.S. greenhouse gas emissions, including revenue distribution, administration, impact on households, application to C&T, and efficiency in the face of uncertainty. The author also responses to criticisms of a carbon tax. Keohane [56] argues that C&T has a number of important advantages over a carbon tax, such as political feasibility, cost effectiveness, broad participation, equity in the international context, and controlling the cumulative quantity of emissions. Johnson [53] proposes a decarbonization strategy for the electricity sector by "imposing carbon fees and applying the revenue exclusively to subsidize new, low-carbon generation sources." Ruth et al. [70] investigate the economic and energy impacts from participation in the regional greenhouse gas initiative through a case study of the State of Maryland. In [45], we presented an earlier and much simplified model for comparing C&T and carbon tax policies. In that model, all initial allowances are assumed to be grandfathered, thus no auction process is captured. Moreover, it is a single-period model, which cannot be used to study Gencos' banking behavior and market dynamics over time as the emissions cap decreases.

Our study chimes in the discussion with some new perspectives. First, we compare C&T and carbon tax policies from the perspective of generation expansion planning (GEP). In 2007, the U.S. renewable energy capacity accounted for 10.9% of its total electric power industry net summer capacity, and the actual generation was 8.5% [15]. To achieve the "20% renewable energy by 2020" renewable portfolio standard (RPS) proposed in the American Clean Energy and Security Act of 2009, as well as other RPS goals already established in more than thirty states in the U.S., significant renewable energy expansion is essential in the next decade. We construct a GEP model to provide a quantitative framework for the implementation and comparison of C&T and carbon tax policies. Second, our analysis of carbon taxes is generalized to include tax credits and subsidies, such as the production and investment tax credits being offered to renewable energy Gencos. Over the past years, the availability of these tax credits (or lack of them) has had apparent effect on new renewable capacity installment in the U.S. [16]. Third, we propose a bilevel optimization approach to determine four variations of tax policies that are comparable with C&T with respect to their effectiveness in controlling carbon emissions. Last but not least, we define eight efficiency criteria to facilitate the comparison: weighted average carbon price/tax, emissions price over time, actual emissions, renewable energy portfolio, total generation, total profit of Gencos and grid owner, economic welfare, and emissions adjusted economic welfare.

Effectiveness and efficiency are two important measures of an environmental policy. A policy's effectiveness refers to its capability to achieve a certain goal (such as tons of emissions reduced or percentage of renewable energy generation increased), whereas its efficiency measures what it takes to achieve that goal (such as the amount of taxes collected or tax credits paid). C&T focuses on policy effectiveness by explicitly limiting the overall emissions cap, but the price of carbon is left for the market to determine. On the other hand, a carbon tax focuses on policy efficiency by levying a predetermined tax rate, but the actual reduction of carbon emissions is subject to market manipulation. To facilitate a meaningful and fair comparison, we design a carbon tax that has an equivalent effectiveness in terms of emissions cap. This carbon tax policy will be compared with C&T against the aforementioned eight efficiency criteria.

GEP has been a topic of intensive study in the electricity industry, especially after the transition from a vertically integrated operational monopoly to a deregulated structure that embraces competition and interaction among multiple market participants [29, 48]. Several game theoretic models have been proposed for GEP in market competition settings [24, 30, 37, 47, 81]. Our model is a modified version of the non-arbitrage bilateral market equilibrium model presented in [47]. This model not only captures the major factors of GEP and market competition but also is computationally tractable, thus it provides a good basis for our extended analysis of GEP under C&T and carbon tax policies.

The rest of the paper is organized as follows. In Section 3.2, we first introduce a baseline GEP model and then make two extensions that incorporate C&T and carbon tax policies. A case study on a simple 30-bus network is reported in Section 3.3, which analyzes the numerical results against the eight comparison criteria in detail. Section 3.4 concludes the paper.

3.2 Models

3.2.1 Nomenclature

Sets:

$\mathscr{F}$	set of Gencos, $f, g \in \mathscr{F}$.	
$\mathscr{I}$	set of nodes, $i, j \in \mathscr{I}$.	
$\mathscr{H}$	set of power generation types of technologies, $h \in \mathscr{H}$, 1 is renewable, 2 is nonrenewable.	
$\mathscr{B}$	set of load blocks, $b \in \mathscr{B}$.	
$\mathscr{L}$	set of transmission lines, $l \in \mathscr{L}$.	

Parameters:

X_{fih}	capacity of existing generator (f,i,h), which is of technology h owned by Genco f at node i.	(MW)
P^0_{itb}, Q^0_{itb}	parameters of the inverse demand function $p = P^0_{itb} - \frac{P^0_{itb}}{Q^0_{itb}} q$, where p and q are electricity price and quantity, respectively.	(\$/MWh, MWh)
E_{fih}	carbon emissions rate of generator (f,i,h).	(ton/MWh)

H	power transfer distribution factors matrix.	dimensionless
W_l	transmission capacity of line l.	(MW)
C_{fiht}	operating cost of generator (f,i,h) at period t.	($/MW)
I_{fih}	investment cost of generator (f,i,h).	($/MW)
K_t	carbon emissions allowance cap at period t.	(ton)
L_b	duration of load block b.	(hour)
β	discount rate.	dimensionless
T	number of planning periods.	dimensionless
ΔX_{fiht}	maximal expansion capacity for technology h for Genco f at node i in period t.	(MW)

Gencos' decision variables:

x_{fihtb}	power generation of generator (f,i,h) at load block b of period t.	(MW)
Δx_{fiht}	expanded generation of generator (f,i,h) at period t.	(MW)
s_{fjtb}	generation quantity sold by Genco f to consumers at node j at load block b of period t.	(MW)
a_{ft}	bidding emissions allowance certificates of Genco f at period t.	(ton)
k_{ft}	banked emissions allowance certificates of Genco f at period t.	(ton)

Grid owner's decision variables:

y_{itb}	power injection at node i at load block b of period t.	(MW)

Dual variables:

θ_{ftb}	dual variables of Constraint (3.2).	($/MWh)
ρ_{fihtb}	dual variables of Constraint (3.3).	($/MWh)
γ_{fiht}	dual variables of Constraint (3.4).	($/MW)
λ^+_{ltb}	dual variables of Constraint (3.7).	($/MWh)
λ^-_{ltb}	dual variables of Constraint (3.8).	($/MWh)
δ_{ft}	dual variables of Constraint (3.22).	($/ton)

Policy maker's decision variables:

tax_{iht}	tax (positive) or subsidy (negative) of generator (i,h) at period t.	(\$/MWh)

Market clearing variables:

w_{itb}	payment (charge) for generating (receiving) electricity at node i at load block b of period t.	(\$/MWh)
$p_t^{CO_2}$	emissions allowance price in auction policy at period t.	(\$/ton)

3.2.2 Baseline Generation Expansion Planning Model

We consider an electricity transmission network, which consists of a set of nodes $\mathscr{I}$ connected by a set of transmission lines $\mathscr{L}$. A group of Gencos $\mathscr{F}$ compete in a Nash-Cournot manner to maximize their own profits by generating and selling electricity in a bilateral market. Each Genco $f \in \mathscr{F}$ owns a portfolio of generation units with varying marginal costs C_{fih}, capacities X_{fih}, and carbon emissions rate E_{fih}. The index (f,i,h) indicates the ownership $f \in \mathscr{F}$, location $i \in \mathscr{I}$, and type of technology $h \in \mathscr{H}$ of the generation unit. If profitable, Gencos will expand the generation capacities, at the cost of I_{fih} for generator (f,i,h). At each node $i \in \mathscr{I}$, the demand of electricity is characterized by an inverse linear demand function $p_{itb} = P^0_{itb} - \frac{P^0_{itb}}{Q^0_{itb}} \sum_f s_{fitb}$, where P^0_{itb} and Q^0_{itb} are parameters, p_{itb} is the price at node i at load block b in period t, and s_{fitb} is the electricity sales from Genco f to node i at load block b in period t. This definition of inverse demand function captures the differences of demand elasticity in varying locations i, time periods t, and seasonal load variations b. A Genco gets paid (pays) w_i for generating (receiving) power at node i, thus $w_j - w_i$ is the cost of transmitting power from node i to j. A grid owner is assumed to coordinate the power flows to maximize his revenue subject to transmission line capacity constraints. It is assumed that all players have complete information of each other and that there is no arbitragers in the market.

Consider the baseline scenario in which neither C&T nor carbon taxes is imposed on the energy market, and all Gencos solve a multi-period GEP problem to maximize the present value of their own profits over the next T periods. Genco f's GEP problem is formulated as follows:

$$\max_{s,x,\Delta x} \quad \sum_{j,t,b} \beta^{t-1} L_b [P^0_{jtb} - (P^0_{jtb}/Q^0_{jtb})(\textstyle\sum_g s_{gjtb}) - w_{jtb}] s_{fjtb}$$

$$-\sum_{i,h,t,b}\beta^{t-1}L_b(C_{fiht}-w_{itb})x_{fihtb}-\sum_{i,h,t}\beta^{t-1}I_{fih}\Delta x_{fiht} \tag{3.1}$$

$$\text{s.t.} \quad \sum_j s_{fjtb}=\sum_{i,h}x_{fihtb} \quad (\theta_{ftb}) \quad \forall t,b \tag{3.2}$$

$$x_{fihtb}\leq X_{fih}+\sum_{\tau=1}^{t-1}\Delta x_{fih\tau} \quad (\rho_{fihtb}) \quad \forall i,h,t,b \tag{3.3}$$

$$\Delta x_{fiht}\leq \Delta X_{fiht} \quad (\gamma_{fiht}) \qquad \forall i,h,t \tag{3.4}$$

$$s_{fjtb},x_{fihtb},\Delta x_{fiht}\geq 0 \qquad \forall f,i,j,h,b. \tag{3.5}$$

The first term in the objective function (3.1) is the revenue from electricity sales less transmission cost. The second term is the generation cost adjusted by transmission revenue, and the third one is the investment cost. All revenues and costs are converted to the present value with a discount factor β. Constraint (3.2) is the balance of production and sales; (3.3) is the generation capacity constraint, which allows Gencos to expand their generation capacities in any period; Constraint (3.4) shows the expansion limits for Genco f; and (3.5) requires that all sales and generation be non-negative. We make the simplifying assumption that the investment lead time is one period for all generation technologies, as reflected in constraint (3.3). The Greek letters in parentheses are the dual variables of the associated constraints.

The grid owner is assumed to be a price taker with respect to the transmission cost w_i. His revenue maximization problem for all period t and load block b is the following linear program:

$$\max_y \qquad \sum_i w_{itb}y_{itb} \tag{3.6}$$

$$\text{s.t.} \quad \sum_i H_{il}y_{itb}\leq W_l \quad (\lambda^+_{ltb}) \quad \forall l \tag{3.7}$$

$$-\sum_i H_{il}y_{itb}\leq W_l \quad (\lambda^-_{ltb}) \quad \forall l. \tag{3.8}$$

The decision variable y_{itb} is the net injection to node i, which equals power generation less consumption. Since the sign of y_{itb} is unconstrained, the term $w_{itb}y_{itb}$ computes the grid owner's revenue (positive) or loss (negative). The objective function (3.6) maximizes this transmission revenue. In constraints (3.7) and (3.8), H denotes the power transfer distribution factors matrix [71], which is derived from the Kirchhoff's laws and the network topology. The term $\sum_i H_{il}y_{itb}$ computes the amount of power flow through line l, which is constrained in (3.7)-(3.8) to be within the transmission capacity W_l in either direction.

Under a Nash equilibrium, the grid owner's and all the Gencos' linear programming problems should achieve optimality at the same time. Additionally, in order for the market to clear, the grid owner's power injection decision y_{itb} and all the Gencos' power generation x_{fihtb} and sales s_{fitb} decisions must be balanced:

$$\sum_f s_{fitb} - \sum_{f,h} x_{fihtb} = y_{itb} \quad (w_{itb}) \quad \forall i,t,b. \tag{3.9}$$

The shadow price of this constraint determines the transmission cost w_{itb}. Therefore, we obtain necessary and sufficient conditions for a market equilibrium:

$$0 \leq s_{fjtb} \perp \beta^{t-1} L_b(-P^0_{itb} + \frac{P^0_{itb}}{Q^0_{itb}}(s_{fjtb} + \sum_g s_{gjtb}) + w_{jtb}) + \theta_{ftb} \geq 0 \; \forall f,j,t,b \tag{3.10}$$

$$0 \leq x_{fihtb} \perp \beta^{t-1} L_b(C_{fiht} - w_{itb}) + \rho_{fihtb} - \theta_{ftb} \geq 0 \qquad \forall f,i,h,t,b \tag{3.11}$$

$$0 \leq \Delta x_{fiht} \perp \beta^{t-1} I_{fih} + \gamma_{fiht} - \sum_b \sum_{\tau=t+1}^{T} \rho_{fih\tau b} \geq 0 \qquad \forall f,i,h,t \tag{3.12}$$

$$\gamma_{fiht} \perp \Delta X_{fiht} - \Delta x_{fiht} \geq 0 \qquad \forall f,i,h,t \tag{3.13}$$

$$\sum_j s_{fjtb} = \sum_{i,h} x_{fihtb} \qquad \forall f,t,b \tag{3.14}$$

$$0 \leq \rho_{fihtb} \perp X_{fih} - x_{fihtb} + \sum_{\tau=1}^{t-1} \Delta x_{fih\tau} \geq 0 \qquad \forall f,i,h,t,b \tag{3.15}$$

$$w_{itb} + \sum_l H_{il}(\lambda^-_{ltb} - \lambda^+_{ltb}) = 0 \qquad \forall i,t,b \tag{3.16}$$

$$0 \leq \lambda^-_{ltb} \perp T_{l-} + \sum_i H_{il} y_{itb} \geq 0 \qquad \forall l,t,b \tag{3.17}$$

$$0 \leq \lambda^+_{ltb} \perp T_{l+} - \sum_i H_{il} y_{itb} \geq 0 \qquad \forall l,t,b \tag{3.18}$$

$$\text{Market clearing condition (3.9).} \tag{3.19}$$

Here, (3.10)-(3.15) and (3.16)-(3.18) are the optimality conditions of (3.1)-(3.5) and (3.6)-(3.8), respectively.

Due to the assumption that the grid owner and all Gencos are profit-maximization oriented and the fact that renewable energy is economically disadvantaged compared to conventional fossil-fuel based generation technologies, very little investment in new renewable generation capacities can be expected as a result of the market equilibrium. This is the very motivation of environmental policies such as C&T and carbon taxes that aim to stimulate more investment in new renewable energy and achieve a more sustainable energy portfolio.

3.2.3 GEP under Cap-and-Trade

Under the C&T regulation, an overall emissions cap is imposed on the energy system. Gencos must compete for the limited amount of allowances and make their power generation decisions accordingly. The amount of emissions that Gencos are allowed to produce must not exceed the equivalent amount of the allowances that they hold. Allowances can be banked or traded among Gencos, but the total amount of allowances, and thus emissions, will not exceed the overall cap. A variation of C&T is that Gencos receive their initial allowances through grandfathering rather than the allowance market; this case is discussed in [45]. In this paper, we assume that all allowances must be purchased.

We assume that Gencos take the allowance price $p_t^{\mathrm{CO_2}}$ as exogenously determined, and then determine the amount of allowances a_{ft} that they want to purchase from the allowances market. Genco f's GEP problem is formulated as follows::

$$\begin{aligned}
\max_{s,x,\Delta x,a,k} \quad & \textstyle\sum_{j,t,b} \beta^{t-1} L_b [P^0_{jtb} - (P^0_{jtb}/Q^0_{jtb})(\sum_g s_{gjtb}) - w_{jtb}] s_{fjtb} \\
& - \textstyle\sum_{i,h,t,b} \beta^{t-1} L_b (C_{fiht} - w_{itb}) x_{fihtb} - \sum_{i,h,t} \beta^{t-1} I_{fih} \Delta x_{fiht} \\
& - \textstyle\sum_t \beta^{t-1} p_t^{\mathrm{CO_2}} a_{ft} \qquad (3.20)\\
\text{s.t.} \quad & \text{Constraints (3.2)-(3.5)} \qquad (3.21)\\
& \textstyle\sum_{ihb} L_b E_{fih} x_{fihtb} = a_{ft} + k_{f(t-1)} - k_{ft} \quad (\delta_{ft}) \qquad \forall t. \qquad (3.22)
\end{aligned}$$

Compared to the baseline model (3.1)-(3.5), the additional term in the objective function (3.20) is the cost of allowances. The variable a_{ft} is the quantity of purchase (positive) or sales (negative) of emissions allowances. Constraint (3.22) requires the balance between allowances and emissions. The left-hand-side is the emissions from electricity generation; the variable k_{ft} is the banked amount of allowances, thus the right-hand-side computes the available allowances for period t.

The grid owner's problem (3.6)-(3.8) stays the same. The market clearing conditions include (3.9) and:

$$\textstyle\sum_f a_{ft} \le K_t \quad (p_t^{\mathrm{CO_2}}) \quad \forall t. \qquad (3.23)$$

This condition requires that the total allowances acquired by the Gencos do not exceed the overall cap of the energy system, and that the allowance price should reflect the shadow price. It should be noted that although the overall emissions allowances are capped by K_t for all periods, the actual emissions of a particular period could possibly exceed the cap due to extra allowances banked from previous periods.

The market equilibrium conditions become:

$$\text{Constraints (3.10), (3.12)-(3.18)} \tag{3.24}$$

$$0 \leq x_{fihtb} \perp \beta^{t-1} L_b (C_{fiht} - w_{itb}) + \rho_{fihtb} - \theta_{ftb} + L_b \delta_{ft} E_{fih} \geq 0 \quad \forall f,i,h,t,b \tag{3.25}$$

$$0 \leq k_{ft} \perp \delta_{ft} - \delta_{f(t+1)} \geq 0 \qquad \forall f,t \tag{3.26}$$

$$0 \leq a_{ft} \perp \beta^{t-1} p_t^{\mathrm{CO_2}} - \delta_{ft} \geq 0 \qquad \forall f,t \tag{3.27}$$

$$\sum_{ihb} E_{fih} x_{fihtb} + k_{ft} = a_{ft} + k_{ft-1} \qquad \forall f,t \tag{3.28}$$

$$\text{Market clearing conditions (3.9)} \tag{3.29}$$

$$0 \leq p_t^{\mathrm{CO_2}} \perp K_t - \sum_f a_{ft} \geq 0 \qquad \forall t \tag{3.30}$$

3.2.4 GEP under Carbon Taxes

Under the carbon tax policy, electricity generation is taxed on a \$/MWh basis. We also allow negative taxes, which represent subsidies. Under such policy, Genco f's GEP problem becomes:

$$\begin{aligned} \max_{s,x,\Delta x} \quad & \sum_{j,t,b} \beta^{t-1} L_b [P^0_{jtb} - (P^0_{jtb}/Q^0_{jtb})(\textstyle\sum_g s_{gjtb}) - w_{jtb}] s_{fjtb} \\ & - \textstyle\sum_{i,h,t,b} \beta^{t-1} L_b (C_{fiht} - w_{itb} + tax_{iht}) x_{fihtb} - \sum_{i,h,t} \beta^{t-1} I_{fih} \Delta x_{fiht} \qquad (3.31) \\ \text{s.t.} \quad & \text{Constraints (3.2)-(3.5).} \qquad (3.32) \end{aligned}$$

The grid owner's problem (3.16)-(3.18) and the market clearing condition both stay the same, thus the necessary and sufficient conditions for a Nash equilibrium are:

$$0 \leq x_{fihtb} \perp \beta^{t-1} L_b (C_{fiht} - w_{itb} + tax_{iht}) + \rho_{fihtb} - \theta_{ftb} \geq 0 \quad \forall f,i,h,t,b \tag{3.33}$$

$$\text{Constraint (3.10), (3.12)-(3.19).} \tag{3.34}$$

3.2.5 Carbon Tax Policy Model

The variable tax_{iht} is treated as an exogenous parameter in model (3.31)-(3.32), but it is actually a decision to be made by policy makers. We present a bilevel optimization model to determine the carbon tax policy in such a way that it will result in an equivalent yet implicit cap on carbon emissions of the market equilibrium. As such, the effectiveness of the the carbon tax policy is set side by side with C&T, and they are then compared with respect to the eight efficiency criteria. The carbon tax policy model is formulated as follows:

$$\min_{tax,s,x,\Delta x,a,k} \quad \frac{1}{|\mathscr{I} \times \mathscr{H}|T} \sum_{i,h,t} |tax_{iht}| \tag{3.35}$$

$$\text{s.t.} \quad \text{Constraints (3.33)-(3.34)} \tag{3.36}$$

$$\sum_{\tau=1}^{t} \sum_{f,i,h,b} L_b E_{fih} x_{fih\tau b} \leq \sum_{\tau=1}^{t} K_\tau, \forall t. \tag{3.37}$$

At the lower level, the Nash equilibrium conditions (3.33)-(3.34) are imposed to anticipate the impact of carbon taxes on the market equilibrium, in which the taxes are treated as parameters. Constraint (3.37) requires that the taxes should be sufficient to achieve the same effectiveness as C&T in terms of caps on total emissions. Notice that cumulative emissions caps are used in (3.37), which is consistent with C&T. In C&T, actual emissions are not necessarily bounded by individual years' caps due to banked allowances from previous years, but cumulative emissions are bounded by cumulative caps because borrowing allowances from future years is not allowed. The objective function (3.35) is to minimize the average amount of taxes or subsidies. The resulting model is a linear program with linear complementarity constraints. Several existing algorithms and software are available for solving such problem [17, 18, 38, 43, 7, 6, 78].

Additional constraints can be used to formulate variations of the carbon tax policy model (3.35)-(3.37). We consider the following four variations:

- **Uniform tax (UT)**: This is a tax only policy, thus no subsidies or tax credits are provided. The amount of taxes for a same generation type is also uniform across all nodes and consistent throughout the entire time horizon. This policy can be formulated by adding the following constraints to (3.35)-(3.37):

$$tax_{iht} = tax_{i'ht'} \geq 0, \forall i, i', t, t', h.$$

- **Nodal uniform tax (UTn)**: This policy differs with UT in that taxes can vary by time period but must stay uniform across nodes:

$$tax_{iht} = tax_{i'ht} \geq 0, \forall i, i', t, h.$$

- **Nonuniform tax (NT)**: This policy differs with UT in that the amount of taxes can differ by node and by time period:

$$tax_{iht} \geq 0, \forall i, h, t.$$

- **Nonuniform tax and subsidy (NTS)**: Both taxes and subsidies can be applied at the same time, and the amount of taxes and subsidies can differ by node and by time period. This policy is fully captured by the model (3.35)-(3.37), thus no additional constraints are needed.

3.3 Numerical Analysis

We conduct a case study on an IEEE 30-bus transmission network to demonstrate our approach. Network data are from [80] with modification. As shown in Figure 3.1, nodes 1, 2, 5, 8, 11 and 13 are supply nodes, and 2, 3-5, 7, 8, 10, 12, 14-21, 23, 24, 26, 29 and 30 are demand nodes. Each supply node has one renewable generator and one non-renewable generator. There are three Gencos in the market. Genco 1 owns generators at nodes 2 and 5, Genco 2 owns generators at nodes 1 and 13, and Genco 3 owns generators at nodes 8 and 11. The demand and supply data are given in Table 3.1, and the transmission data are given in Table 3.2. We assume the discount factor β is 1 since we only study three periods. For computational tractability, we consider only one load block and three planning periods in this case study. Computational results are obtained using General Algebraic Modeling System (GAMS) [6] and Interior Point Optimizer (IPOPT) [7]. We used a desktop computer with a 3.00GHz Intel Pentium CPU. It takes 5 to 10 minutes to obtain one solution.

Computational results for C&T and the four variations of carbon tax policies are obtained. We first specify $551,000$ tons as the overall emissions cap for the three periods, which is a little bit higher

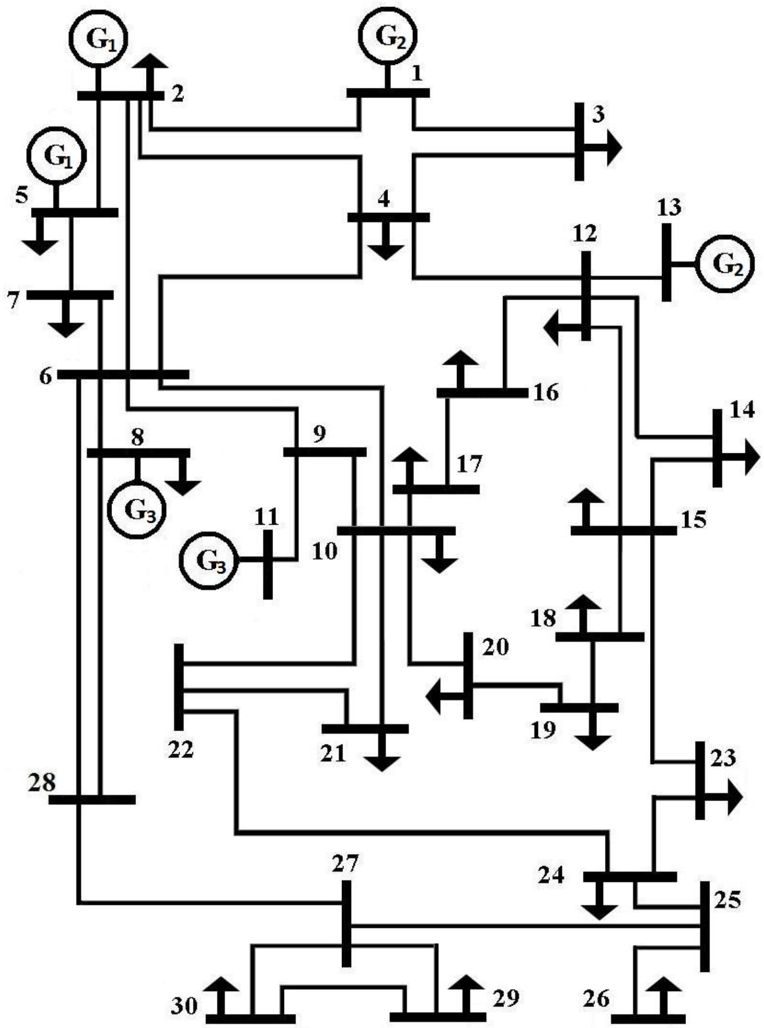

Figure 3.1 30-bus network example

than the total emissions under the baseline GEP case. The investment capacity ΔX_{fiht} are all set to be 500 MW. We compute Nash equilibrium solutions for C&T from (3.24)-(3.30), and for the carbon tax policies from (3.35)-(3.37) with additional constraints for the variations. We then iteratively decrease the overall emissions cap until zero. Eight efficiency criteria are computed from these results and plotted as functions of the overall emissions cap for three periods. Results and interpretations are provided in the following subsections.

Table 3.1 Demand and supply data

node	P_{i0t}	Q_{i0t}	C_{fi1t}	C_{fi2t}	I_{fi1t}	I_{fi2t}	X_{fi1}	X_{fi2}
1	-	-	2	0	8	20	100	20
2	300	600	2	0	8	20	200	30
3	300	450	-	-	-	-	-	-
4	300	480	-	-	-	-	-	-
5	300	510	2	0	8	20	400	50
6	-	-	-	-	-	-	-	-
7	300	570	-	-	-	-	-	-
8	300	540	2	0	8	20	300	30
9	-	-	-	-	-	-	-	-
10	300	480	-	-	-	-	-	-
11	-	-	2	0	8	20	400	40
12	300	420	-	-	-	-	-	-
13	-	-	2	0	8	20	300	40
14	300	360	-	-	-	-	-	-
15	300	330	-	-	-	-	-	-
16	300	300	-	-	-	-	-	-
17	300	330	-	-	-	-	-	-
18	300	360	-	-	-	-	-	-
19	300	390	-	-	-	-	-	-
20	300	420	-	-	-	-	-	-
21	300	450	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-
23	300	510	-	-	-	-	-	-
24	300	540	-	-	-	-	-	-
25	-	-	-	-	-	-	-	-
26	300	540	-	-	-	-	-	-
27	-	-	-	-	-	-	-	-
28	-	-	-	-	-	-	-	-
29	300	450	-	-	-	-	-	-
30	300	420	-	-	-	-	-	-

Table 3.2 Transmission data

line	capacity	line	capacity	line	capacity
1-2	13,000	4-12	6,500	21-22	3,200
1-3	13,000	12-13	6,500	15-23	1,600
2-4	6,500	12-14	3,200	22-24	1,600
3-4	13,000	12-15	3,200	23-24	1,600
2-5	13,000	12-16	3,200	24-25	1,600
2-6	6,500	14-15	1,600	25-26	1,600
4-6	9,000	16-17	1,600	25-27	1,600
5-7	7,000	15-18	1,600	28-27	6,500
6-7	13,000	18-19	1,600	27-29	1,600
6-8	3,200	19-20	3,200	27-30	1,600
6-9	6,500	10-20	3,200	29-30	1,600
6-10	3,200	10-17	3,200	8-28	3,200
9-11	6,500	10-21	3,200	6-28	3,200
9-10	6,500	10-22	3,200	-	-

3.3.1 Carbon Price

The carbon price $p_t^{CO_2}$ (\$/ton) and carbon tax (or subsidy) $|tax_{iht}|$ (\$/MWh) are natural efficiency indicators for comparison. However, individual period's carbon price or taxes may not be able to reflect overall policies' impacts. We calculate the weighted average emissions price as the indicators rather than prices themselves. The weighted average emissions price (\$/ton) is defined as $\frac{\sum_{fiht} tax_{fih} x_{fiht}}{\sum_{fiht} E_{fih} x_{fiht}}$ for tax policies, and $\frac{\sum_t p_t^{CO_2} \cdot a_{ft}}{\sum_{fiht} E_{fih} x_{fiht}}$ for C&T. The weighted average emissions price give us an evaluation of actual payment on per carbon emissions through the whole planning horizon. This indicator is plotted as functions of $K_1 + K_2 + K_3$ in Figure 3.2, which correspond to time periods $t = 1$, $t = 2$ and $t = 3$ respectively. We make the following observations from this figure:

- NTS can have negative price, which means the tax policy is dominant when the cap is loose. The average emissions price is the lowest due to the balance between tax and subsidy policies in NTS.
- NT has the second lowest weight average carbon price. Since in NT, tax can vary across nodes. In some nodes the tax could be zero although they produce non-renewable energy, and the tax can be high in some area although the area is already clean, thus the total payment for per emissions is low in NT.

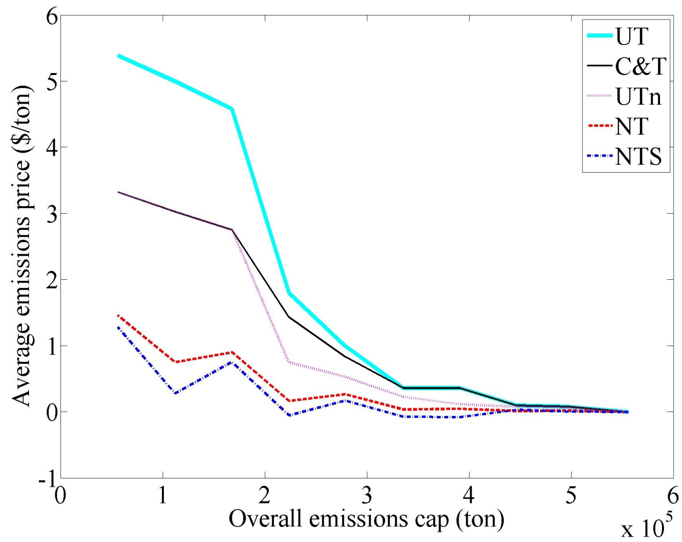

Figure 3.2 Weighted average carbon price

- UT has the highest weighted average carbon price. When the emissions cap is low, and the tax will be very high in the first period to reduce the carbon emissions (because in the first period, there is no expanded renewable energy.) Since in UT, the carbon price is the same across all periods, the carbon price keep high, then the weighted price will be higher than others.

- When the cap is greater than 350,000 tons, C&T and UT are almost overlapped, but greater than UTn. Because in C&T, constraints (3.26) and (3.27) requires $\delta_{ft} - \delta_{f(t+1)} \geq 0$, $0 \leq -\delta_{ft} + p_t^{CO_2} \perp a_{ft}$. As long as the auction amount a_{ft} is not zero, $\delta_{ft} = p_t^{CO_2} \geq 0$, and if there is banked allowance, $p_t^{CO_2} = p_{t+1}^{CO_2}$. But in UTn, there are no similar constraints, the carbon tax in the first period could be different than second periods, UTn is smaller than C&T for the weighted average price when the cap is large. UT have uniform tax all the time, it automatically satisfies $tax_t = tax_{t+1}$, similar to $p_t^{CO_2} = p_{t+1}^{CO_2}$. This is the reason UT and C&T are similar when the cap is large.

- when the total cap is less than $180,000$ tons, C&T is closed to UTn. Because in both C&T and UTn, the regulator can be traded as a special Genco who makes profit by selling emissions. The difference between C&T and UTn is the banked allowance from UTn is paid at future period's price, while the banked allowance in C&T is paid at current period's price. When the cap is tight, no allowance is banked, C&T and UTn are equivalent.

3.3.2 Emissions Price Over Time

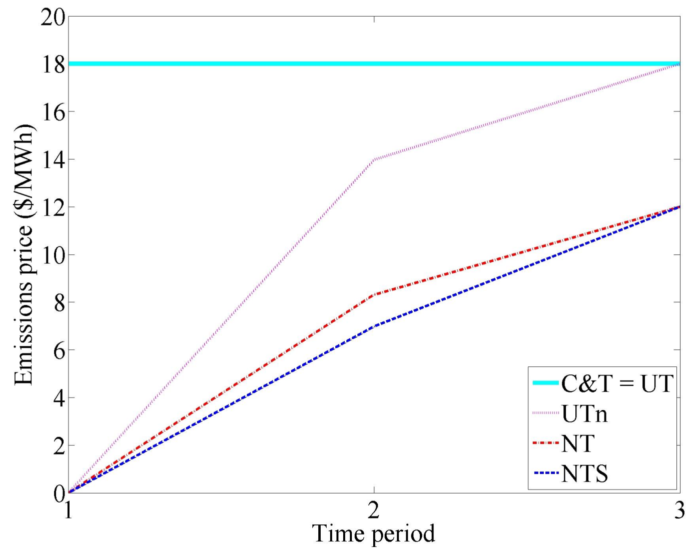

Figure 3.3 Emissions price over time

The emissions prices are plotted as functions of periods in Figure 3.3. The total emissions reduction is 40% compared to baseline GEP model. We find that UT and C&T are all constant in three periods. The reason is explained in 3.3.1. For NT, NTS and UTn, the first period's prices are all zero due to surplus of first period's emissions allowance. As the emissions gets tighter, the emissions price goes up. Averagely, NT and NTS's prices are less than others, since environmental policies are inactive in some places. NTS is less than NT, because the subsidy is designed to promote renewable energy, while the tax is to reduce non-renewable energy.

3.3.3 Actual Emissions

The actual emissions $\sum_{fihtb} L_b E_{fih} x_{fihtb}$ are plotted as functions of $K_1 + K_2 + K_3$ in Figure 3.4. We find that UTn, NT, NTS and C&T are all on the 45 degree line, which means that the actual emissions under these policies will be as much as the emissions cap. However, the actual emissions under UT are lower than the cap. The reason is that the time-consistent requirement makes UT unable to meet the

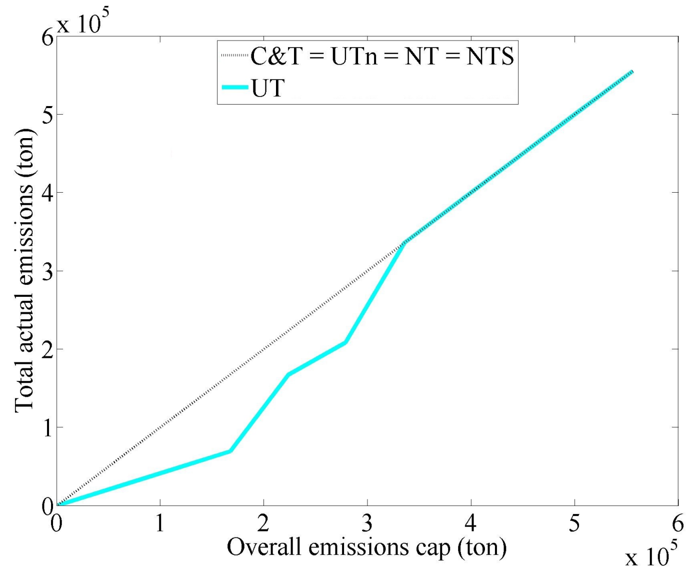

Figure 3.4 Total actual emissions

emissions cap exactly. If the taxes were to be lowered in the first period, then the first period's emissions would go above the cap.

3.3.4 Renewable Energy Portfolio

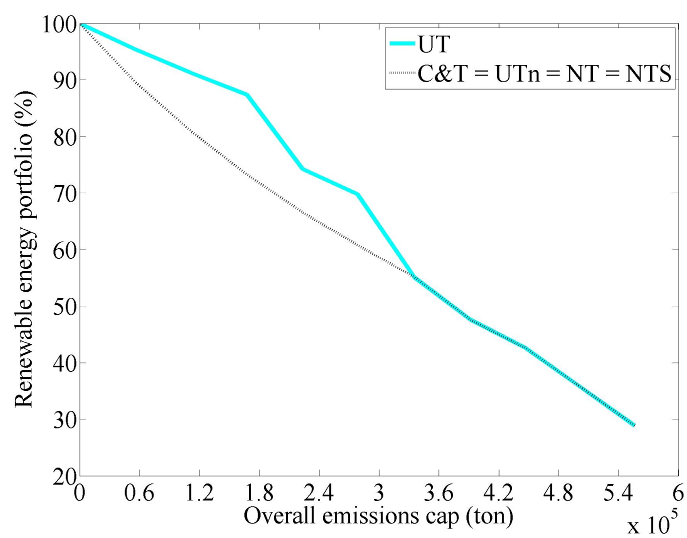

Figure 3.5 Renewable energy portfolio

Renewable energy portfolio is defined as the ratio of renewable generation to total generation $\frac{\sum_{fitb} x_{fi1tb}}{\sum_{fihtb} x_{fihtb}}$. Neither C&T nor carbon tax policies explicitly targets on increasing renewable energy portfolio, but the RPS policies established in more than thirty states in the U.S. do so in a mandatory manner. Therefore, it is meaningful to examine the resulting renewable energy portfolio as a result of C&T or carbon tax policies. This result also indicates the increased capacity of renewable generation. Figure 3.5 shows the renewable energy portfolios as functions of $K_1+K_2+K_3$. This figure shows a close connection with Figure 3.4, because the amount of actual emissions reflects to a great extent the installed renewable generation capacity and thus renewable energy portfolio, with a negative correlation.

3.3.5 Total Generation

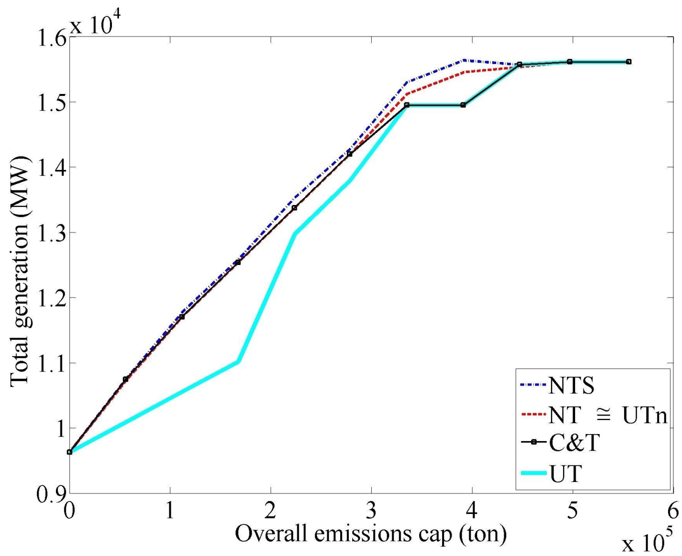

Figure 3.6 Total generation

Figure 3.6 shows the total generation in three periods as functions of $K_1+K_2+K_3$. Total generation is an estimate of electricity price, since the price is linear function of demand. Increasing generation usually results in decreasing electricity price. In Figure 3.6, the total generation of all policies are closed to others, and goes down as the emissions cap tightens, which means the electricity price gets higher. The higher electricity price is to compensate the carbon tax payment or renewable energy investment. The NTS stands out a little, because the subsidy policies in NTS promote more renewable energy than other policies. All the curves converge to 15,500 MW, which is also total generation in the baseline case.

3.3.6 Gencos' and Grid Owner's Total Profit

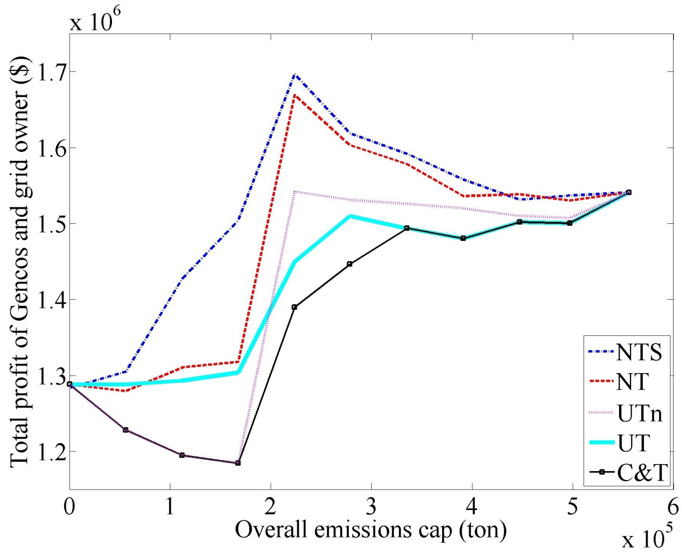

Figure 3.7 Gencos' and grid owner's total profit

Gencos' and grid owner's total profit is defined as:

$$\sum_{fjtb} \beta^{t-1} L_b [P^0_{jtb} - P^0_{jtb}/Q^0_{jtb}(\sum_g s_{gjtb})] s_{fjtb}$$
$$- \sum_{fihtb} \beta^{t-1} L_b (C_{fiht} + tax_{iht}) x_{fihtb} - \sum_{fiht} \beta^{t-1} I_{fih} \Delta x_{fiht} \tag{3.38}$$

This value indicates the impact of environmental policies on market players and the potential perceptions and reactions from Gencos and grid owner. Results are shown in Figure 3.7, from which we have the following findings:

- In NTS, Genco can earn some subsidy while produce renewable energy, thus NTS has the highest profit.
- NT is less than NTS only. In NT, the tax is nonuniform. In some places, the tax is low and tax payment is low, thus the profit is not reduced a lot.

- Counter-intuitively, C&T, NTS and NT firstly increase when the emissions cap decreases. This is because the Nash equilibrium in the case study is not Pareto optimal. The environmental policies do not necessarily compromise economic benefits of Gencos and grid owner.
- UTn and C&T are less profitable than UT when the cap is low. Compared to C&T and UTn, UT results in a higher investment cost in renewable generation, but Gencos also spend less on emissions tax payment. the overall effect leads to more profit in UT.

3.3.7 Economic Welfare

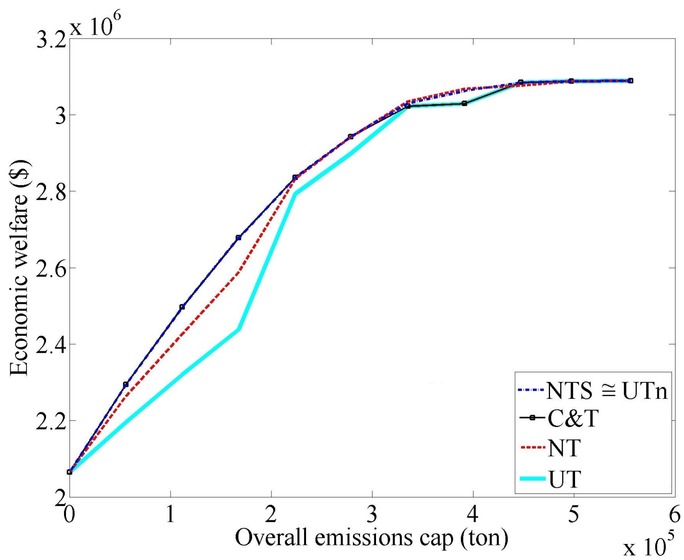

Figure 3.8 Economic welfare

The economic welfare as the present value of consumer surplus, Gencos' profits, grid owner's profit, and regulator's tax income is formulated as :

$$\sum_{fjtb} \beta^{t-1} L_b [P^0_{jtb} s_{fjtb} - P^0_{jtb}/(2Q^0_{jtb})(\sum_g s_{fjtb})^2] \\ - \sum_{fihtb} \beta^{t-1} L_b C_{fiht} x_{fihtb} - \sum_{fiht} \beta^{t-1} I_{fih} \Delta x_{fiht} \quad (3.39)$$

This criterion indicates the integrated economic impact of the environmental policies on general stake holders of power systems. Results are shown in Figure 3.8, from which we can see that all policies are very similar on this criterion, and the economic welfare follows the intuitive decreasing trend as the emissions tightens. This results could provide a quantitative estimate of the economic cost of imposing an environmental policies. UT has the least economic welfare since it is the harshest policy. Combination of tax and subsidy policies will neutralize the final policies' impacts on economic welfare, which results in the most economic welfare for NTS.

3.3.8 Emissions Adjusted Economic Welfare

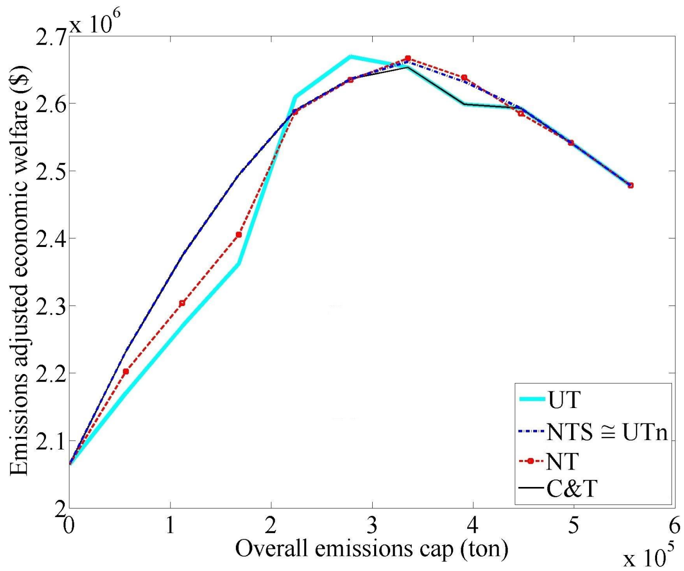

Figure 3.9 Emissions adjusted economic welfare

Complementary to economic welfare, the criterion of emissions adjusted economic welfare is defined to subtract the cost of emissions from the economic welfare. The monetary cost of emissions is hard to estimate, but it is more important to take into account the cost of emissions than knowing the exact value. An arbitrary value of $1.0/ton is used in this case study. Results are shown in Figure 3.9. We observe that NTS, UTn, NT and C&T still have similar relationship as in Figure 3.8 (because they have the same actual emissions), but they all have an optimal adjusted welfare. UT results in higher optimal adjusted welfare than other policies, because it has the lowest amount of actual emissions, which makes all the difference when cost of emissions is valued.

3.4 Conclusion

In this paper, we compare the effectiveness and efficiency of C&T and Carbon taxes by quantifying their impacts on Genco's generation expansion planning decisions in a competitive electricity market. Our modeling approach has the following strengths:

- All C&T and carbon tax policies are modeled in a GEP framework, which is particularly suitable for assessing the effectiveness of the policies in stimulating new investment in renewable energy.
- The GEP model has a multi-period planning time horizon, thus is able to analyze Gencos' banking behavior and market dynamics as emissions cap is tightened over time.
- A bilevel optimization model is used to design a carbon tax policy that will lead to the same emissions cap as in C&T. This approach enables one to put the effectiveness of all policies side by side and focus on the comparison of eight efficiency criteria.

From the numerical results of a 30-bus network case study, we could not claim a clear winner or loser. All policies show their relative advantages and disadvantages with respect to different criteria. Nevertheless, we gain some insights on the policies, as discussed in Section 3.3 and briefly summarized below:

- C&T is similar to UTn and UT at different emissions cap ranges. The reason lies in the implicit constraints that C&T only banks allowance if future carbon price is the same as current carbon price. Therefore, C&T is similar to UT when there is banking allowance in all periods, and similar to UTn when there is no banking allowance.
- Non-uniform incentive policies have the flexibility to impose different taxes or subsidies at different locations. As such, they have the potential to reduce unnecessary cost and lead to higher total profit for Gencos and the grid owner. Moreover, a combination of taxes and subsidies could be more efficient than using taxes alone.
- Contrary to NT, UT is meant to stay constant over the entire planning period. such requirement makes it the highest tax policy, which leads to the least amount of actual emissions and the highest

renewable energy portfolio. With appropriate cost of emissions, UT can leads to the highest emissions adjusted economic welfare. UT also reduces the policy uncertainties for Gencos' GEP.

Our research results and analysis have several notable caveat and limitations. We model Gencos' strategic auction and trading behavior in C&T in an implicit manner and do not separately capture the allowance market and energy market. We assume all market players have perfect information of each other, and no uncertainties on the demand or supply side are considered. Restrictions on arbitrage of emissions allowances are also ignored in the models. Limited by the computational complexity of the models, our case study is conducted on 30-bus system, and solved to an acceptable level, but the results can be generalized to larger and more complex energy systems. Future research should be directed to address these limitations.

CHAPTER 4. INVESTMENT STRATEGY ASSESSMENT UNDER UNCERTAINTY

In preparation for submission to a journal paper

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ABSTRACT

Investment in new generation capacity is essential in order for the power system to provide reliable and economical electricity to meet the growing demand. However, capacity investment is a long-term process with numerous challenges. The emerging environmental policies play an important role in the planning by imposing new constraints and mechanisms on the grid. Uncertainty from various sources, such as intermittency of renewable resources, and investment decisions made by other market participants, also makes the risk and return hard to measure.

We develop a new modeling framework to facilitate investment decision making with explicit consideration of environmental regulations and uncertainty. This methodology is able to project the profitability and risk of different investing plans over the next couple of decades. The modeling framework has a three-layer structure. The top layer, called the optimization layer, is the interface with the decision maker and the framework, which compares a set of candidate investment plans against a set of decision market optimization philosophies and preferred risk-and-return tradeoff criteria. The middle layer, called the assessment layer, backs up the optimization layer with a comprehensive assessment of each plan using both probabilistic and scenario analysis, providing suggestions on potential improvement. The bottom layer, called the operations layer, is the computational engine of the framework to compute deterministic DC optimal power flows (OPF) for the whole planning horizon.

We demonstrate the advantages of our modeling framework by using a representative case study of the 240-bus WECC test system. Results with proper visualization reveal insightful consequences of an investment plan, which in turn helps decision makers to identify directions of potential improvement

and come up with better investment plans.

4.1 Introduction

The push toward a cleaner and more sustainable environment is bringing new pressures on the electric power industry. The numerous fossil fired power plants that operate today create the largest source of stationary carbon dioxide (CO_2) emitters. There are many climate change initiatives, in various stages of development, whose implementation will strongly influence the future course of the industry and consequently the entire nature of electricity planning and future operations. The various initiatives aim to reduce the environmental footprint of the electricity sector and will entail fundamental changes in the way power systems operate, the role electricity customers play and the scope and nature of future resource investments. In The restructured competitive environment, in distinct contrast to that of the vertically integrated utility industry, the generation and transmission planning decisions are undertaken by different entities on an increasingly decentralized basis. Such decisions are subject to the constraints imposed by the existing climate change initiatives, a patchwork of mandates, incentives and voluntary programs – each with its distinct targets and goals. These developments impact the planning environment significantly since they introduce various additional sources of uncertainty that further complicate the investment decision-making process.

The basic objective is to study the formulation and solution of investment decisions in new generation resources that are compliant with the requirements of environmental policies and explicitly consider their attendant uncertainty. Environmental policies take various forms and influence resource investment decisions in different ways. For example, the creation of renewable portfolio standards (RPS), which requires a specified fraction of the load and/or energy be supplied by renewable resources by a defined date, has resulted in the growing push to implement renewable energy projects at deeper penetrations. Other legislative acts, such as a carbon tax, the provision of production/investment tax credits and the implementation of time-of-use pricing, create incentives for compliance with policy goals but need not mandate such actions. The legislatively improved introduction of a carbon cap-and-trade mechanism and the use of renewable energy certificates via legislation sets up new markets to implement a flexible structure for meeting the goals of reduced greenhouse gas emissions. Such structures provide individual power producers the flexibility to trade emissions allowances among themselves and provide incentives to some to install improved abatement technology. The policies, be they mandates or voluntary or market-based, have a large influence on planning decisions. They may create unparalleled opportunities for the investment in renewable resources or may force the resource owners to create cleaner generation sources than ever before. Moreover, they create new opportunities and challenges in the planning and operations of the power systems and in the effective investment decision-making process.

A salient feature is the need to explicitly consider the broad range of uncertainty associated with the repercussions and ramifications of such environmental policies. Such consideration is very important in the framing of investment decisions and results in the addition of complications to what is already a very complex decision-making process.

We devote the remainder of this section to setting the context within which our work is developed, provide a brief survey of the state of the art and delineate the key requirements for the methodology.

4.1.1 Need for Additional Investments in the Era of New Environmental Legislation

Electricity demand is expected to grow continually and steadily for decades to come. In the EIA Annual Energy Outlook 2013, forecasts indicate that electricity consumption will increase by 28% from 2011 to 2040 at approximately a 1% per annum rate [15]. To accommodate such growth in electricity demand, new capacity of electricity generation must be built at a pace that meets or exceeds the growth of demand and retirement of old generators to maintain power system reliability. The additions of capacity must be done in such a way that the reliability of the power systems is appropriately maintained.

The North American Electric Reliability Corporation (NERC) considers reliability to consist of the system adequacy – the condition that sufficient resources are installed to provide customers with a continuous supply of electricity to meet their demands and security – the ability of the bulk power systems to withstand sudden, unexpected disturbances. A prerequisite for adequacy and security is that the system has available capacity at all times which exceeds the demand. The assurance of reliability becomes considerably complicated in the era where many new requirements must be met as a result of new legislation and regulatory initiatives and decisions. We next review the nature of these requirements.

Numerous environmental regulations have been imposed on the electric power industry, which was responsible for 33% of greenhouse gas emissions in the U.S. in 2011 [11]. Such regulations have imposed additional considerations, which need to be taken into account by investment decisions makers. The following section discusses the requirements of four representative regulations and policies that impact investment decisions.

Production tax credit: PTC is incentive provided by the federal government in the form of tax credits for one MWh of renewable energy delivered to the grid. Such credits decreases the tax obligations of the renewable generator owners, which serves as a subsidy to renewable generator investment costs [8]. It was initiated in 1992 in the U.S, which sometimes are not provided due to prevailing political presences.

Cap-and-trade This regulation constrains the aggregate emissions of polluting electricity generation resources. The limit or cap is either administratively allotted or sold via an auction to generator owners in the form of permits or allowances to emit or discharge specified amount of pollutants. The number of allowances represents the required cap on a pollutant. Any violation of emissions beyond the allowances is subject to penalty. Excess allowances may be banked, used to offset pollution emissions of other facilities, or traded in markets of emission allowances. The expenses of emission allowances introduce additional costs of the energy by polluting resources. The cap-and-trade policy imposes limits on the production quantity as well as price competitiveness of generation from polluting resources, and the introduced emission markets lead to additional complexity of strategic decision-makings. Regional Greenhouse Gas Initiative (RGGI) [51] is the largest voluntary CO_2 cap-and-trade program in the U.S., with nine states involved. California started its own CO_2 cap-and-trade program in December 2012 [1].

Carbon tax A tax is imposed on the CO_2 content of fuels used for producing energy and other productions so as to explicitly represent the costs of the emissions by a polluting generation unit. Compared to the cap-and-trade policy, the carbon tax is determined by legislative agencies, bypassing the need to set up new market structure. Many economists believe such a tax to be an efficient means for CO_2 reduction. The carbon tax policy has been implemented in some countries like Switzerland and Australia, but has not been adopted by large carbon-based electricity generation nations such as America or China.

Renewable Portfolio Standards The standards specify minimal renewable generation targets to be provided by renewable resources by prescribed dates [12]. Such standards impose these obligations on electricity supply entities, such as investor-owned utilities and electricity service providers. Qualified renewable energy production may earn certificates for every unit of electricity injected into the grid that indicates compliance with the obligations. The compliance with RPS relies on the competition in the energy markets and the efficiency of transmission networks. Therefore, more price competitions will be stimulated between different types of renewable energy. This policy encourages the development of cost-competitive renewable technologies and the investment of pathways to transmit increased renewable generations. Renewable and alternative energy portfolio standards have been mandatorily or voluntarily established in 38 states in the U.S and the District of Columbia by 2013.

The thrust of numerous environmental legislation efforts is to either directly restrain the pollutant emissions or to promote investments into new renewable technology projects so as to satisfy RPS requirements. As electricity demand grows continually, renewable generation to meet load must be increased commensurately. There are various other regulating mechanisms, such as feed-in-tariffs for the purchase of excess renewable energy injections by residential or small commercial customers to further promote these objectives. The ultimate goal goes beyond the reduction of emissions and the deeper penetration of generation resources into the grid to make the future power grid a sustainable system to meet future customers' energy requirements.

The compliance with environmental policies imposes requirements in the planning of future systems. Under environmental policies, generation companies must either retire much of the coal-fired generation resources or make large investments in pollution abatement technology. However, investment in renewable generation projects, with their large amounts of capital and land requirements, may be attractive alternatives. The deeper penetration by renewable resources poses daunting challenges to managing the intermittency and variability nature of the outputs and the integration issues with the provision of ancillary services. In addition, the expansion of the transmission grid to assure the deliverability to the grid of the added renewable generation is a critically important challenge that must be explicitly considered in the planning framework. Clearly, the requirements imposed by environmental legislations introduce many new complications into planning. Moreover, the enactment of future environmental legislation and the introduction of new regulatory initiatives are difficult to predict accurately and are subject to a wide range of uncertainty sources. Such uncertainty must be considered in the planning and investment decision-making. The following section discusses additional sources of uncertainty and their categorizations.

4.1.2 Sources of Uncertainty

Planning, by its nature, deals with the uncertain future. The uncertainty arises from the statuses of operating elements, as well as unpredictable human factors of the energy regulators, producers and consumers. We classify all the sources of uncertainty into the categories of aleatoric and epistemic uncertainty [62], and use different approaches to deal with them.

Aleatoric uncertainty is intrinsically random and cannot be eliminated or reduced through more accurate measurements. However, the uncertainty is statistically quantifiable. Therefore, aleatoric uncertainty is also known as statistical uncertainty. For instance, wind speed uncertainty is aleatoric, because each measurement of wind speed at a given location at a given time point is physically obtainable. Moreover, the average wind speed may be statistically estimated from all the collected measurements. Other examples of aleatoric uncertainty that are relevant to the investment decision-making process include electricity demand, both short-and-long term, power outputs from renewable energy sources, forced outages of generation units and transmission lines, weather conditions and the economic situation.

Epistemic uncertainty arises from factors we may know but, in practice, we do not. Specific reasons for such uncertainty may be because we cannot measure with sufficient accuracy, or the information is kept confidential. Therefore, epistemic uncertainty is also known as systematic uncertainty. For instance, the generation investment decisions of other firms constitute confidential information and so the probabilities associated with such decisions are unknown. Thus, their investment decisions constitute an epistemic uncertainty. Other examples of epistemic uncertainty that are relevant to the investment decision-making process include government policies, technology breakthroughs, economic conditions and investment decisions made by other entities.

This classification of uncertainty sources is useful as it helps us to determine the approach to deploy for probabilistic risk assessment and to collect the appropriate data. For epistemic sources of uncertainty, we identify meaningful scenarios under which we assess both the likely and the high-impact realizations of uncertainty. For aleatoric sources of uncertainty, we approximate their cumulative distribution functions (c.d.f.s) from past data and use probabilistic methods to estimate the expected values of the metrics of interest. Investment decisions are not only affected by the uncertainty, but also the resources and technology development.

4.1.3 Resource Characteristics and Investment Decisions

This section provides a brief review of supply-and demand-side resource considerations in investment decisions. The investment decisions in the case study are made in the context of the existing power systems. As such, in undertaking every investment decision, the salient characteristics of supply and demand resources and the interactions of each resource with the existing resource mix must be explicitly considered.

Table 4.1 provides a listing of the key economic advantages and disadvantages of some common generation technologies. The analysis of resource alternatives requires careful weighting of the investment-fixed-and operation-variable-costs of a resource. Compared to renewable resources, the operation costs of fossil-fuel-fired generation are high and increase under both a carbon tax or cap-and-trade policy. Carbon sequestration technology can reduce the carbon emissions, but entails additional investment costs for the retrofit. Investors can choose to either retire or retrofit an existing fossil-fuel-fired generator. In the light of environmental policies, gas-fired generators and renewable generators are key expansion alternatives in the next decade. Gas-fired generation has lower emission rate than fossil-fuel-fired units such as coal-fired and distilled oil units and the current glut in low price gas supplies makes gas-fired resources a viable investment alternative. Renewable resources entail considerable upfront investments and typically, have large area requirements for their installations. Their highly uncertain variability and intermittency nature is a key disadvantage. The available rebates and PTCs lighten the costs and their extremely low or zero fuel costs are advantages. The cost of wind and other technologies has been steeply brought down over the last few years. For example, PV costs have declined steeply in the past two years [9]. Actually, the levelized costs of the same renewable technology may vary at different locations due to state and local policies, land costs and other factors. Storage

Table 4.1 Brief economic comparisons of technology

Technology	Advantages	Disadvantages
OTEC	renewable resources; long life times; zero fuel cost	extremely high investment costs; low capacity factor
IBGCC	low CO_2 emissions; high efficiency;long life times	no significant drawbacks
nuclear	zero emissions; high efficiency	long lead times; nuclear waste issue
NGCC	high efficiency; constant output	moderate emissions
oil	high efficiency; constant output	very high operations cost, intensive emissions
solar PV	renewable resources	large land requirements
geothermal	renewable resources; very long life times	high investment cost
solar thermal	renewable resources; possible 24-h supply source	heavy water usage requirements
MSW	renewable resources; waste-to-energy; reduces needs for landfills	high operational costs
hydro	renewable resources; low operations costs	scheduling complexity
onshore wind	renewable resources; zero operations cost	require large land
offshore wind	renewable resources	high investment cost; longer lead time
IGCC	high efficiency output	high emission rate; high operations cost
wave Power	renewable resources; predictable output	high investment cost

technology has the ability to smooth the fluctuations of intermittent energy [35, 58, 65]. Storage acts symbiotically with renewable intermittent generation and can be an effective coupling to manage the intermittency issues.

In addition to supply-side alternatives, demand has considerable promise. The Federal Energy Regulatory Commission defines demand response (DR) as “changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized [64].” The effective deployment of DR resources is a topic of wide current interests.

Selective common technologies are considered as our investment candidates by weighting the cons, pros and trade-offs of the technologies in the markets, reliability, and compliance with environmental policy requirements in the case study.

4.1.4 Review of the Literature

There is a rich body of literature on investment decision-making in power systems, including generation expansion and transmission expansion. In past publications, each has a specific focus and address certain challenges of the investment problem. The literature of highest relevance in the mathematical programming also listed approaches to solutions of investment problems. We compare the literature from the perspectives of the comprehensiveness of the formulation, consideration of uncertainty, solution approach and computational tractability, and discuss their contributions and deficiencies along with the perspectives.

- Linares et al. in [60] studied oligopolists generation expansion planning Nash equilibrium in the markets, explicitly considering energy, emission trading and green energy certificates markets. It is the first model to incorporate three markets and solve their equilibria simultaneously. Energy prices increase with the introduction of certificates market, and can be compensated by emissions markets. However, in the real world, it is unlikely to obtain perfect information of the planning environment to achieve Nash equilibrium. The model is also static, and lacks uncertainty consideration.

- Bakirtzis et al. in [21] considered three types of time lengths in the model – short-term operations, mid-term scheduling decisions and long-term cost-minimization planning in a vertical market structure. The environmental considerations were presented as costs of allowances and penalties. A real Greek power system was tested to illustrate effects of demand, fuel prices and CO_2 prices uncertainty on the planning decisions. The model had a good granularity on describing the power system, however, it did not address the competition among investors.

- Jin et al. in [52] integrated transmission expansion, generation expansion and pool-based market operations in the framework by constructing a three-level mixed integer problem to represent the panning and operations relationships among the entities. The transmission expansion planning was done by the system regulator at the upper level, subject to the Nash equilibrium of generation capacity expansion at intermediate level and equilibrium of the pool market at the lower level. The authors proposed a hybrid algorithm to solve the case study with a large testing system. Regarding the formulation and associated computational issue, it is difficult to consider uncertainty under the authors' framework.

- Roh et al. in [69] studied the competitions and interactions among generation and transmission companies under uncertainty. The companies are regulated by the ISO to maximize their expected profits under uncertainty. The authors solved the problem by using a proposed iterative process. The iterative process is applicable to models with multiple decision makers. The profit maximization model of Trancos is debatable. ISO prefers to maximize the social welfare, while this model has a high probability to lose the social welfare.

- Tekiner et al. in [74] computed the Pareto front of expected values of system cost and air emissions for a multi-period long-term generation expansion planning under uncertainty of demand and distribution line outages. The Pareto front was equivalent to the sensitivity analysis of carbon prices. With growing concerns on the environment (increasing carbon prices), investment cost was not a big hindrance to renewable investment. The case study was limited to a few periods with load blacks and does not delineate the oligopoly nature in the energy market.

- He et al. [44] compared the applications of the carbon tax and cap-and-trade policies in a generation expansion background. They found the impacts of the carbon tax and cap-and-trade policies to be equivalent to some extent, by comparing the effectiveness like social welfare, carbon taxes, allowance prices, and profits. The formulation in [44] was not extendable to large-scaled cases, and failed to show more insights of generation planning with various technology options.

- Zhou et al. in [83] studied a centralized generation investor's expansion strategies under RPS and subsidies policies, subject to fuel transportation. The goal of the authors was to achieve the effective and efficient subsidy or tax policy to meet the prescribed RPS, the sensitivity analysis of policy prices with respect to fuel prices, renewable technology investment costs, and transmission capacity. It provided insights of designing incentive policies in promoting renewable technologies.[83] emphasized on policy design and lost precision of modeling generation companies.

Table 4.2 Literature reviews

Literature	granularity & time	transmission	policy	market	uncertainty	computation
[60]	load blocks, multi-periods	no	certificate, trading	oligopoly	no	LCP
[21]	hourly, mid-time maintenance, multi-periods	no	REC	centralized	no	MILP
[52]	one representative load	yes	no	oligopoly and follower	no	MPEC,Integer
[69]	load blocks, multi-periods	yes	no	between Gencos and Trancos	yes	MILP and equilibrium, heuristic
[74]	load blocks, multi-periods	yes	emission cost	centralized	yes	simulation
[44]	multi-periods	yes	C&T, carbon tax	oligopoly	no	LPCC
[83]	single period	yes	RPS, subsidies	centralized	no	nonlinear, bi-level, heuristic
M-28	hourly, multi-periods	yes	tax, RPS	oligopoly	yes	LP

Table 4.2 summarizes the literature with respect to different perspectives. Literature emphasized different characteristics in their studies and let go of others. None of the literature is good in all perspectives. For example, most of the previous works bring down the granularity for the long-term planning. Epistemic and aleatoric uncertainties are not addressed at the same time. Some of the models are too complex to extend, such as mathematical programming with equilibrium constraints.

In our work, which is called "M-28", we try to make some improvements with tradeoffs among the characteristics. We would consider hourly load patterns in the operations, transmission network, environmental policies like renewable portfolio standards and carbon tax, strategic behavior, and different sources of uncertainty.

4.1.5 Contributions

M-28 is structured to directly address the deficiencies identified in the previous section. In M-28, we propose a new framework for investment planning in power systems that have relatively high resolutions of details in power system operations (such as hourly load patterns, temporal and spatial correlation of renewable energy and demand). We take the profit maximization from the perspective of an independent generation investor who explicitly incorporates environmental policy requirements. To avoid the assumption of complete information, the entities' strategic behaviors in the competitive energy market are modeled as a source of uncertainty. Categorizations of uncertainty enable both probabilistic analysis and scenario analysis of the investment decisions. M-28 provides the decision maker with a range of optimization criteria to accommodate different return and risk measures, and risk tolerance attitudes or preferences. The investment candidates are assessed carefully by computing all the metrics of interest to provide quantification of the impacts of environmental regulation requirements and other sources of uncertainty. The results are potentially helpful for decision makers to make potential improvements toward better investment plans. The framework is able to deploy a computational engine capable of application to realistically sized large-scale grids.

The remaining sections are organized as follows. We provide a detailed description of the modeling framework in Section 4.2, including functions and coordination mechanism on the proposed layers. Section 4.3 reports the results of our representative case study using the 240-bus WECC model. The case study illustrates the ability of our framework to assess effectively various investment candidates under different sensitivity cases. We provide concluding remarks in Section 4.4 that summarizes over key findings and conclusions. We also discuss directions for future work in Section 4.4. Section 4.5 includes the framework formulations, and assumptions and parameters used in the case study.

4.2 Modeling Framework

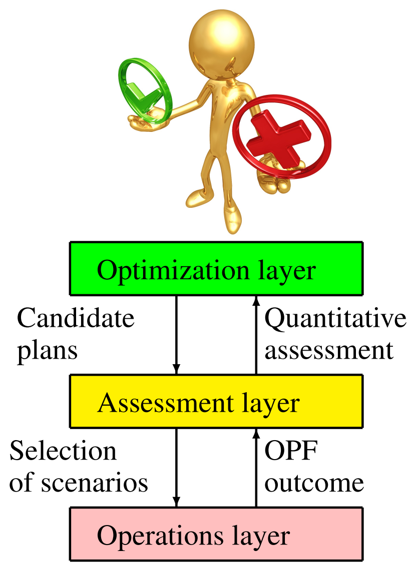

Figure 4.1 Framework

The framework is designed to answer two fundamental questions: for a given investment plan, how does one assess its effectiveness and second, for a given set of investment plans, how to compare their relative effectiveness. We take the perspective of a specific generation company, which we refer to as the investing generation company, or iGENCO. The objective of the framework is to maximize the present value of the total profit of iGENCO over a given planning period (such as 20 years). The profit consists of revenue from sales of energy and tax credits less investment cost and operations cost. All the revenue and cost terms are converted to the first year of planning to account for the time value of money. To address these two questions, our new framework is designed to consist of three layers, as shown in Figure 4.1:

- The top layer, which is the interface between the model and the investment decision maker, is the optimization layer. This layer takes a set of candidate investment plans from the decision maker and compares their relative profitability with respect to a pre-determined set of criteria. This layer addresses the second fundamental question.

- The middle layer is the assessment layer, which is given an investment plan, epistemic scenarios and probability distributions of aleatoric uncertainty, and provides a quantitative assessment with explicit consideration of uncertainty. This layer addresses the first fundamental question.
- The bottom layer is the operations layer, which solves an OPF problem and returns market outcomes for a given set of network configuration under a scenario realization. This layer is a computational engine of the modeling framework.

This framework has the following salient features:

Modeling granularity Several details of power systems are incorporated, such as load pattern, temporal and spatial correlation of renewable energy, and hourly optimal power flow.

Policy We model the effect of policy by adjusting cost parameters. For example, the production tax credits will reduce the variable cost of renewable energy generation, whereas a carbon tax will increase it.

Transmission Transmission network and expansion is included in the modeling to address the topology impacts on the energy delivery and generation planning. The transmission network is invested and regulated by the system operator.

Market The market is liberalized energy market with oligopoly generating companies. The strategic behavior of rival generating companies in the market is not directly modeled; rather it is treated as a source of epistemic uncertainty.

Uncertainty We adopt the categorization of aleatoric and epistemic sources of uncertainty and use different approaches to deal with the two types. For aleatoric uncertainty, probability density functions of random variables are assumed to be known, and we apply probabilistic analysis to quantify the impacts of such uncertainty. For epistemic uncertainty, sets of relevant scenarios are assumed to be predetermined and we use scenario analysis to determine their impacts.

Computation We use linear approximated DC power flows to formulate the energy market.

Details of the three-layer modeling framework are presented in subsequent subsections.

4.2.1 Optimization Layer

The optimization layer, which is the interface with the decision maker, compares multiple candidate investment plans against a given set of optimization criteria. The inputs to this layer include a list of candidate investment plans and a set of optimization criteria. These inputs are provided by the investment decision maker. The outputs of this layer are a set of quantitative measures of all the candidate investment plans against the criteria. The output information will help the decision maker to compare the risk and return of multiple investment alternatives against various measures.

The following are several commonly used optimization criteria:

Expected profit is probability weighted average profit over all the scenarios. This is a common criterion for risk neutral decision makers. A major challenge is probability assignment to epistemic scenarios. Since no historical data are available to estimate such probabilities, subjective judgment will be used.

Standard deviation of profit measures the risk of the uncertain profit. The combination of expected value and standard deviation is commonly used to determine the tradeoff between return and risk of an investment. Projects with higher returns (expected profits) and lower risk (standard deviations) are considered more desirable than those with lower return and higher risk. The tradeoff between higher return with higher risk and lower return with lower risk is up to the risk tolerance, investment style, and personality of the decision maker.

Worse case profit is the minimal profit under all scenarios. This is a pessimistic risk measure for conservative decision makers. Similar philosophies have been used in robust optimization, in which the optimal solution is defined as the one resulting in the highest benefit under the worst case scenario.

Best case profit is the maximal profit under uncertainty, the exact opposite criterion with the worse case profit. This is an optimistic risk measure for risk-seeking decision makers.

Expected regret is the probability weighted average regret under aleatoric uncertainty. For a investment plan p^1 with profit $\pi(p^1, s^0)$, the regret associated with this investment plan is defined as the maximal possible profit loss with respect to all possible investment plans:

$$max_p\{r(p^1, p, s^0)\} = max_p\{\pi(p, s^0)\} - \pi(p^1, s^0).$$

Intuitively, the smaller the expected regret, the more likely the decision maker feels good about the selected investment plan under uncertainty

4.2.2 Assessment Layer

The assessment layer computes approximate probability distributions of a firm's profit over the planning horizon for a given investment plan. Inputs to the assessment layer include an investment plan, a set of scenarios for epistemic uncertainty, and a set of probability density functions for aleatoric uncertainty. The investment plan is passed down from the optimization layer, which uses the assessment layer as a sub-routine to assess all the investment candidates individually before it conducts a comparative analysis. The set of scenarios for epistemic uncertainty and a set of probability density functions for aleatoric uncertainty are assumed to be provided in the optimization layer.

The input epistemic uncertainty scenarios are subjectively selected in the optimization layer by the investment decision maker to reflect what they perceive as possible, and critical scenarios. The aleatoric uncertainty is assumed to be statistically characterizable using historical data. We assume that statistical characterization of the aleatoric uncertain parameters has been conducted and is readily available to the assessment layer. The outputs from the assessment layer are in the form of several quantitative indicators listed as follows:

Profit capacity ratio calculates the generator's average profit per capacity over the planning horizon. The higher the ratio, the more profitability potential for further investment. This ratio helps decision maker to identify opportunities for better investment alternatives.

Annual profit distribution illustrates the probability density function of iGENCO's annual profit. The trajectory of such distributions over the entire planning horizon provides a convenient perspective to the company's profit outlook.

Emissions indicate the environmental footprint of an investment plan. This value provides both an explanation for reward or penalty imposed by environmental regulations but also a projection of future reward or penalty as a result of potential policy changes.

Renewable generation portfolio measures the ratio of renewable electricity generation to total electricity generation from iGENCO. This is a similar indicator to total emissions.

Load curtailment is the total amount of energy-not-served due to inefficient transmission or lack of generation capability. This is a good indicator of the power system's generation adequacy and reliability.

System profit is the total profit earned by all the generation companies in the power systems. This provides a comparative benchmark for iGENCO to evaluate its profitability against its competitors.

These assessment indicators not only provide the investing decision maker with a comprehensive assessment of the investment plans, but also shed light on directions of potential improvement.

4.2.3 Operations Layer

The operations layer is a computational engine that solves a deterministic OPF for the entire planning horizon. Input parameters to the operations layer include transmission/generation capacity and availability, generators' supply function, deterministic fixed load, carbon taxes or credits, etc. These parameters are passed down from the assessment layer. The outputs of the operations layer are a sample path of the OPF solutions, which feed back to the assessment layer. The sample path includes information such as hourly dispatched generations, local marginal prices and the power flows under a given scenario path through the whole planning horizon. The OPF formulation of the operations layer includes the Kirchhoff Current and Voltage Laws, capacity constraints, and implementations of environmental policies. The detailed formulation and assumptions of the operations layer are provided in Section 4.5.1.

4.3 Case Study

Our framework is examined on a realistic network with elaborately designed investment plans and representative epistemic scenarios. The planning horizon is set to be twenty years. Several investment plans are designed to answer questions raised in generation expansion planning, such as when and where to install how much capacity. The epistemic scenarios are deliberately selected to represent a subjective generation planning environment, such as through implementation of regulations and transmission planning. Other details in the case study, such as fuel prices and load growth rate are practically defined. The case study is able to return reliable results to assess the long-term planning strategies for iGENCO in the future. Section 4.3.1 is the introduction to the test system. Sections 4.3.2 and 4.3.3 list the selective epistemic scenarios and investment plans. Section 4.3.4 illustrates the case study results.

4.3.1 Test System

We use the reduced WECC (Western Electricity Coordinating Council) 240-bus network as our test system. The 240-bus test system was developed by California Independent System Operators (CAISO) to use as a market design prototype [68]. It can be used as a realistic test system for California and WECC market. The 240-bus network evolved from previous 225-bus network by conforming topology of areas outside CAISO shown in other transmission studies. The 225-bus network evolved from a 179-bus network by conforming topologies of CAISO shown in other transmission studies. There are 138 buses within CAISO excluding HOOVER. The network is enclosed, and no energy is transmitted in and out of the system, which means the facilities like power plants and transmission lines are all located within the system. The market comprises the whole network and is assumed to be regulated by a single virtual regulator in our case study.

Figure 4.2 is the topology of the WECC network. Thick solid lines represent connections between the CAISO and neighboring, and significant transmission lines within CAISO. The shaded blocks are the areas under CAISO regulations. Each bus shown in the topology could have multiple sub-buses with various voltages. It is worthy to mention that the topology does not represent the physical geometry. The resource characteristics inherited from [68] are listed in Section 4.5.2.1.

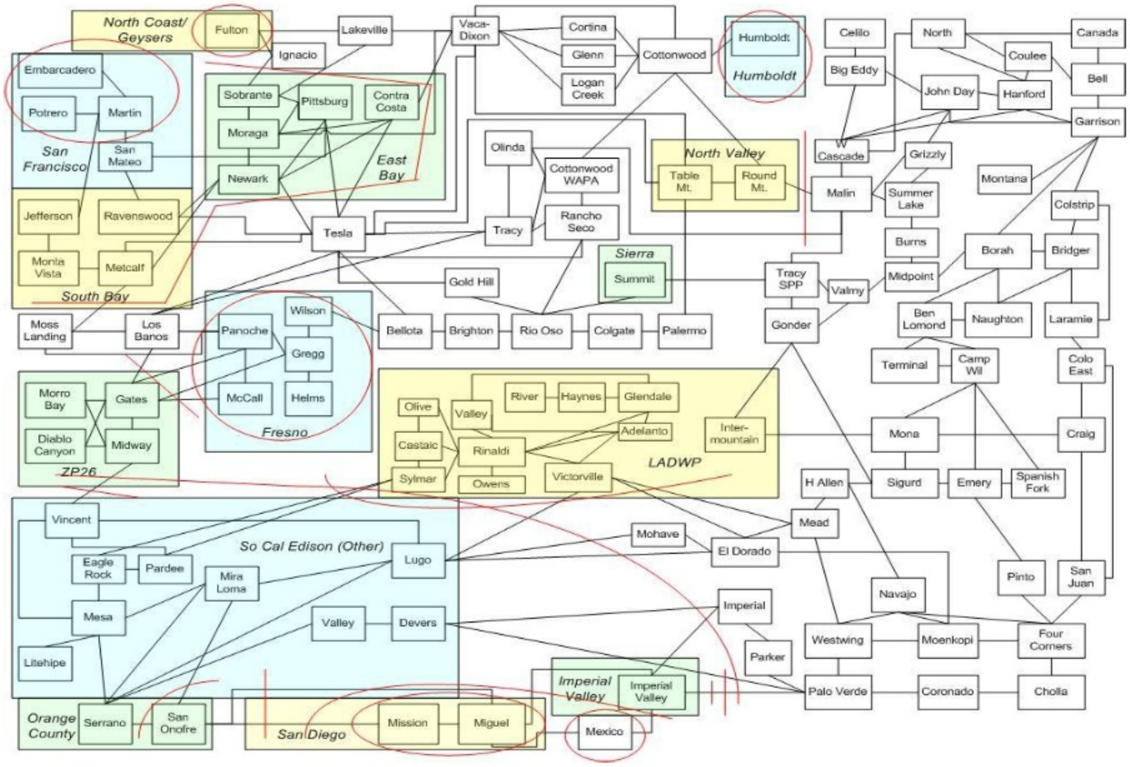

Figure 4.2 WECC 240-bus topology

4.3.2 Scenarios in Epistemic and Aleatoric Uncertainty

The hypotheses of epistemic scenarios are based on knowledge and information of the power systems, energy markets, political systems, economy, and federal and state laws or regulations. Therefore, the epistemic scenarios are inexhaustible and difficult to constitute. As a matter of fact, it takes 1,000 minutes to complete the assessment of one investment plan under one epistemic scenario, which allows for consideration of only a small number of investment candidates, each with a small number of epistemic scenarios. Moreover, some scenarios barely occur and are not worth addressing in the study.

4.3.2.1 Selection of Epistemic Scenarios

Although epistemic uncertainty is unknown in practice, it can be subjectively, but rationally and logically constituted through public reports, research and experience. We consider competitor decisions, transmission plans and implementation of environmental regulations in epistemic scenarios.

Expansion decisions of other generation companies are fabricated via guessing generation companies' investment preference. Some generator companies, who only have non-renewable generators, would be more likely to invest in renewable generators only. Some generator companies, who have existing coal power plants, would be likely to invest in gas-fired power plants to replace the high emission coal power plants and keep their reserve capability. The total investment capacity is commensurate with generator company current capacity.

Generation expansion depends on future pathways; at the same time, transmission expansion relies on locations of generators. Although there are debates between the causality or consequence between transmission expansion and generation expansion, it is agreed that one heavily influences the other. We assume the market regulator does transmission planning and pays the transmission investment cost, and the specific amount would not be discussed in the case study. Both transmission and generation expansion are estimated empirically and follow the rules in Section 4.5.3.1.

The epistemic scenarios also address the most probable environment policies during the generation planning.

The descriptions of the four selective epistemic scenarios are presented as follows:

S_0 All the generation companies except CDWR (who has large hydro only and excluding iGENCO could have more than 30% but less than 40% renewable generations to produce in the end of the planning time frame, if all their generators are at the maximal outputs. The transmission network in this scenario has 122 new transmission lines, which are built through the planning horizon. No explicit environmental policy is imposed. We take this transmission network as the baseline transmission network and this scenario as baseline scenario.

S_c A carbon tax policy is imposed on the power systems from year 9 to year 20 in the planning horizon. The carbon tax simply remains constant within a year. The carbon prices are predetermined by the equation: $(13+2(\text{year}-1))*(1.05^{2(\text{year-1})})$. Other conditions such as the generation companies'(excluding iGENCO) investment decisions and transmission network stay the same as the baseline scenario.

S_t A new transmission planning replaces the one in the baseline scenario. The investments of all the generation companies (excluding iGENCO) are the same as the baseline scenario. No environmental policy is imposed.

S$_{gc}$ All the generation companies except CDWR (who has large hydro only) and excluding iGENCO could have more than 40% renewable generations to produce in the end of the planning time frame, if all their generators are at the maximal outputs. We also keep imposing the carbon tax policy as described under S_t. The transmission network is the same as the baseline transmission network.

The baseline scenario aims to describe a moderate planning environment. Generation companies are around the boundaries of complying with preexisting policy – 33% RPS by 2020 and generally keep increasing renewable generation portfolio.

S_c is used to observe the impacts of environmental regulations. The choice of the carbon tax policy is based on the cap-and-trade program in California, which was launched in 2012 [1]. The carbon price started to be 10$/ton, became 14$/ton in early 2013 and is forecasted to reach 75$/ton in 2020 [4, 2, 46]. To simplify the modeling, the CO_2 auction mechanism is not mathematically modeled. The carbon price in 2020 under this scenario is slightly lower than the forecasting, since when the renewable generation grows up, the needs of carbon will decline, and the carbon price might be smaller than the forecasted value [44].

Under S_t, we intend to study the impacts of transmission lines on the generation expansion. The new network is intentionally designed to significantly reduce peak-hour LMPs under Plan A.

S_{gc} is designed to observe the market outcomes when other generation companies are optimistic about renewable technology. A renewable generator with cheap operation cost is likely to enter into the market every hour, and earn more profit. For some given hours, generation companies may produce less electricity due to intermittency of renewable resources. Thus, generation companies with more non-intermittent nonrenewable technologies may be able to provide electricity supply and become competitive in the market. LMPs are usually high during those hours, and generation companies with a significant nonrenewable energy supply may be profitable due to intermittency. It is quite interesting to study the investment strategies when the outer environment is ambitious and confident in renewable technologies. It makes more sense to have implementation of a mandatory policy if the majority believes in renewable technologies. Thus, the carbon tax policy is implemented.

4.3.2.2 Makeup of Aleatoric Scenarios

Distribution fitting models are built upon the features of the uncertainty. For example, generator outage is usually modeled as binomial distribution. Among renewable resources, wind is mostly studied. Peer literatures showed that Weibull distribution was widely to model wind speed [26, 42, 61, 76]. Brownie motion and time series method were also used to model wind uncertainty [27, 28, 55]. In order to acquire robust and reliable fitting parameters, a large data set is required to simulate the distribution.

Wind outputs are both temporally and spatially correlated. Moreover, the electricity demand and the wind output are correlated as well. Therefore, it is difficult to develop a suitable fitting distribution fundamentally. Additionally, due to the limitation of the data, we are not able to fit the distribution via statistical approaches. As a consequence, we manipulate the existing data and generate a set of reasonable aleatoric scenarios. In the data file, we have only one year hourly time-varying electricity loads and generations. The outputs themselves must follow certain distributions if any exist. Therefore, the complex correlations discussed before have been reflected in the outputs. In the case study, renewable generation and electricity demand uncertainty are considered in the aleatoric uncertainty. The aleatoric scenarios used in the case study are made up through the process described in Section 4.5.3.2. Decision makers are welcome to use their own scenario generation methods and apply to our framework. The framework's applicability is independent of the scenario generation methodologies.

4.3.3 Candidate Investment Plans

California RPS program requires investor-owned utilities (IOU), electric service providers, and community choice aggregations to increase procurement from eligible renewable energy resources to 33% of total procurement by 2020 [3]. It is one of the most ambitious RPS in the United States. Currently, California's three large IOUs reached 19.9% renewable power in 2012. Pacific Gas and Electric (PG&E) served 19.3%, San Diego Gas and Electric (SDG&E) served 20.3% and Southern California Edison (SCE) served 20.6 % under their own generation portfolios. Therefore, renewable energy investment is the priority among all investment options. To keep the system's reliability and reserve capacity, nonrenewable generator investments are also inevitable in the long-term planning.

Generally, generation companies need to consider both environmental factors and their own conditions to make smart investment choices. Generation companies look at their current generator portfolios and estimate their financial conditions, and are also supposed to have rational suppositions on other generation companies' strategic behaviors. The profitability of investments is restricted by investments of other generation companies.

We select the largest generation company in the data set as iGENCO for our case study. Although it resembles PG&E, our case study results do not necessarily reflect any reality with the company, since numerical results from our case study are obtained using various assumptions. iGENCO is assumed to have rational and reasonable perceptions of other market players' decision-making on investments and operations, based on analysis of available public reports. All the generation companies follow the generator expansion rules listed in Section 4.5.3.1. The following lists the five selective investment plans in the case study:

Plan A iGENCO has about 32.8% renewable generations to produce if all its generators are at the maximal outputs in the end of the planning time frame. All the types of possible technologies are invested in with appropriate capacities according to historical data at the proper time. For example, geothermal and biomass generators are unlikely assigned with high capacities.

Plan B iGENCO can have about 50% renewable generation to produce if every generator is at its maximal output in the end of the planning time frame. New renewable generators in Plan A scale up their installed capacities, while new nonrenewable generators scale down their installed capacities. The total generation in the end of the planning time frame keeps almost the same compared to Plan A, if generators operate at their maximal outputs.

Plan C All the invested generators in Plan A are brought forward one year ahead.

Plan D New renewable generators are all switched to wind generators with comparable total generation outputs, and installed in possible locations under the expansion rules.

Plan E New generators in Plan A are switched locations arbitrarily without violating the expansion rules.

Plan A is also called the baseline investment plan. iGENCO does moderate investments in all possible generator technologies.

Plan B is designed to observe the renewable generation profitability. This plan answers the question of how much to invest in renewable generations. The renewable generators is not cost competitive with regards to the investment cost, but inversely very economic with respect to the operations cost. Thus, the renewable generations are easier to get accepted in energy markets. At the same time, cheap electricity supply from renewable generations has a locational marginal price (LMP) reduction effect, and the profit might not be higher as expectation. There lie in other issues due to the uncertainty of the renewable generations as well. The profit variance is likely to increase, and the investment plan's robustness will likely decrease.

Plan C is selected to study the question of when to invest. Earlier investment comes with earlier earnings. With regard to the time value of money, it seems more worthy to make earlier investment. However, generators are depreciated earlier and lose profits in the future. This plan helps analyze the tradeoffs.

Plan D is designed to study the technology options and mix of investments. Different types of technology have their own advantages. For example, biomass generators are expensive, but supply stably; wind generators are cheap, but supply low during the daytime when the load is high. We examine the impacts of the technology selections by extremely switching all the renewable technologies to wind.

Plan E is aimed to study the locational impacts of new generators. Generally speaking, investments in high LMP buses look promising to earn higher revenue. However, if other generation companies perceive the business opportunity and invest in the same buses, LMPs might be reduced and hence the revenue, or iGENCO loses market share due to cost competency.

A "case" is defined as one plan under an epistemic scenario. There are twenty cases in total to show us the impacts from other companies' decisions, transmission topology, environmental regulation, investment time, and choices of technologies on various investment plans. In all the cases, the supply is greater than the electricity demand at any hour.

4.3.4 Results

Hourly economic dispatch is run on the test system for 364 days per annum through the whole planning horizon. Five plans of iGENCO under four epistemic scenarios are extensively evaluated, assessed and compared via criteria and indicators mentioned in the framework. They provide insights of the generation planning in complex power systems under uncertainty.

4.3.4.1 iGENCO Study Profit Performance Statistics

Table 4.3 iGENCO study profit performance statistics (billion $)

	Plan A		Plan B		Plan C		Plan D		Plan E	
S_0	34.43	0.3893	34.69	0.3903	34.84	0.4000	34.32	0.4058	33.42	0.3889
	54.65	22.09	54.96	21.96	55.38	22.43	55.24	21.22	54.14	20.98
S_c	45.88	0.4514	46.80	0.4494	46.00	0.4557	45.18	0.4582	44.62	0.4496
	69.31	30.01	70.03	30.55	69.37	30.29	68.57	29.14	68.71	28.56
S_t	30.44	0.2853	35.39	0.2818	36.06	0.2895	34.20	0.2749	34.19	0.2711
	45.47	20.16	49.30	23.97	50.38	24.64	48.18	22.97	48.4	22.90
S_{gc}	50.11	0.5921	50.53	0.6010	50.31	0.5990	49.62	0.5935	48.81	0.5890
	81.03	29.87	81.45	29.77	81.28	30.18	79.95	29.45	79.95	28.28

Every plan has four profit performance statistics under an epistemic scenario, which are shown in a two-by-two matrix. Expected value is in the upper left corner; standard deviation is in the upper right corner; the highest present value of profit (billion $) over 20 years is in the lower left corner; the lowest present value of profit (billion $) over 20 years is in the lower right corner. The following are the observations found in the table:

- Plan A performs significantly differently from other plans under S_t. The transmission plan under S_t was especially designed for Plan A to increase the system's efficiency. When the system adds an appropriate transmission line, cheaper generators, via the new pathway, can supply the sink buses. In our case study, iGENCO loses a large portion of profits in Plan A, because LMPs are reduced significantly compared to S_o due to efficient use of cheap generation. For other investment plans, the generators are not placed in the proper places with proper capacities with respect to the new transmission plan, therefore, the new transmission plan is not able to reduce LMPs significantly. The evidence in the case study supports the saying that the performances of generation and transmission plans are highly interactional.

- The profits are higher under cases with the carbon tax policy. The carbon tax policy adds additional costs in operations of fuel-fired generators. Since the marginal generators are usually fuel-fired, local marginal prices increase, correspondingly. The revenues of generators, partially depending on the differences between LMPs and regular operations costs, increase.

- Variances are the highest under S_{gc}, the second highest under S_c, the third highest under S_0, and finally the lowest under S_t. Basically, the variance increases with deepening renewable energy penetration in the system, due to energy intermittency. It is very interesting to see that S_t has the lowest variance. A well-designed transmission network can efficiently transport the renewable generations with complementary outputs to sink node, and reduce the uncertainty from renewable energy intermittency, which is the reason of variance reduction in Plan A. Complementary output means when some renewable generators operate at their low capacity factors, others operate at their high capacity factors, such as wind and solar generators at nearby locations. However, in other plans, it is because of the reduced production of renewable energy. Table 4.14 provides supporting evidence.

- Generally, consistent with intuition, the larger the variance, the larger the difference between the minimal and maximal profits of plans under an epistemic scenario.

- With regards to the maximal profits, they are much higher under S_{gc} than S_c, although their minima are subtly different. Because the ordinary market prices follow a hockey stick shape, the slope of price with respect to demand is sharp after some turning point. If we treat intermittent renewable generations as negative demand, the net demand is defined as the original real electricity demand plus the negative demand. The change of the net demand will result in change of prices, thus profits. If the net demand is greater than the demand at the turning point on the demand-price curve, slight change of net demand will lead to significant changes of prices and profits, otherwise subtle changes of profits. The maximal profits happen under aleatoric scenarios with higher net demand where LMPs climb up owing to lacking of renewable generation supply. Under maximal profit aleatoric scenarios, the net demand under S_{gc} is larger than under S_c, since S_{gc} has more renewable generation unavailable under those scenarios. As a result, maximal profits are much higher under S_{gc} than S_c. Similar analysis is applicable for subtle differences between minimal profits. In summary, the maximal profits occur when renewable generators are at low outputs; the minimal profits take place when the renewable generators are at high outputs.

- Optimal solutions change according to the weighting of epistemic uncertainty and optimization philosophies. The weights (probabilities) of epistemic scenarios are not statistically definable, and decision makers assign subjective weights. Optimal plans differ under different weights, for example, if S_t weighs one, the optimal plan is Plan C, if S_{gc} weighs one, the optimal plan is Plan B. On the other hand, the optimal plan is Plan C if decision maker wants to maximize minimal profit, while Plan E outperforms other plans if decision maker prefers a small variance plan. Thus, from the profit performance statistics, there does not exist a dominant optimal plan. Our framework evaluates all the statistics to help the decision maker compare the investment plans comprehensively.

- We observe the renewable energy's two counter effects. One is increasing LMPs due to lacking intermittent energy supply, and the other is reducing LMPs due to low operating cost.

4.3.4.2 iGENCO Expected Regret and Its Standard Deviation

Table 4.4 iGENCO expected regrets (billion $)

	Plan A	Plan B	Plan C	Plan D	Plan E
S_0	0.3949	0.0308	0.00403	0.5128	1.475
S_c	1.0142	0	0.9239	1.8526	2.2519
S_t	7.5431	0.7883	0	2.4031	1.9149
S_{gc}	0.5798	0	0.4082	1.2408	1.8382

Table 4.4 shows the expected regrets in all cases. It measures the potential profit loss under uncertainty. A robust plan is not volatile under uncertainty and inclined to have small regrets. We have the following findings:

- Plan A has the largest expected regret, which accounts for 24.5% of its expected profit under S_t, consistent with its lowest expected profit. The least expected regret of Plan A occurs under S_o. The expected regrets in orders, from minimum to maximum are under S_t, S_o, S_{gc}, S_c, consistent with the orders of the difference between Plan A's mean profits in the same epistemic scenarios. Expected regrets are found closely related to the mean values in other plans too. Mean profits are positively related to the expected regret orders in our case. Usually, the profit with larger mean profit will have less regret.

- Plan B has no regrets under S_c and S_{gc}. It implies that it is better to invest in more renewable energy under a carbon tax policy. The carbon tax policy is indeed an efficient policy to promote renewable resources from economic perspective. The expected regrets of Plan B under S_o and S_t are the second smallest compared to other plans, and less than 5% of Plan B's expected profits. As a matter of fact, with more than 60% probability, no regret happens under S_o. Plan B is a relatively robust plan under considered epistemic scenarios.

- Plan C has no regrets under S_t. Expected regret under S_o is the second smallest compared to other plans. Besides the reason of network topology, regrets of Plan C imply that early investments can lead to smaller regrets, due to early seizing the market share.

- Plan D has large expected regrets under all the epistemic scenarios, which mean the wind-only investment is volatile. There is no other technology to compensate the intermittency of wind outputs, regrets occur when wind generators operate at their low profiles.

- Plan E has large expected regrets under all the epistemic scenarios. The switch of generators to unprofitable buses reduces the profits (supporting evidence in Table 4.7).

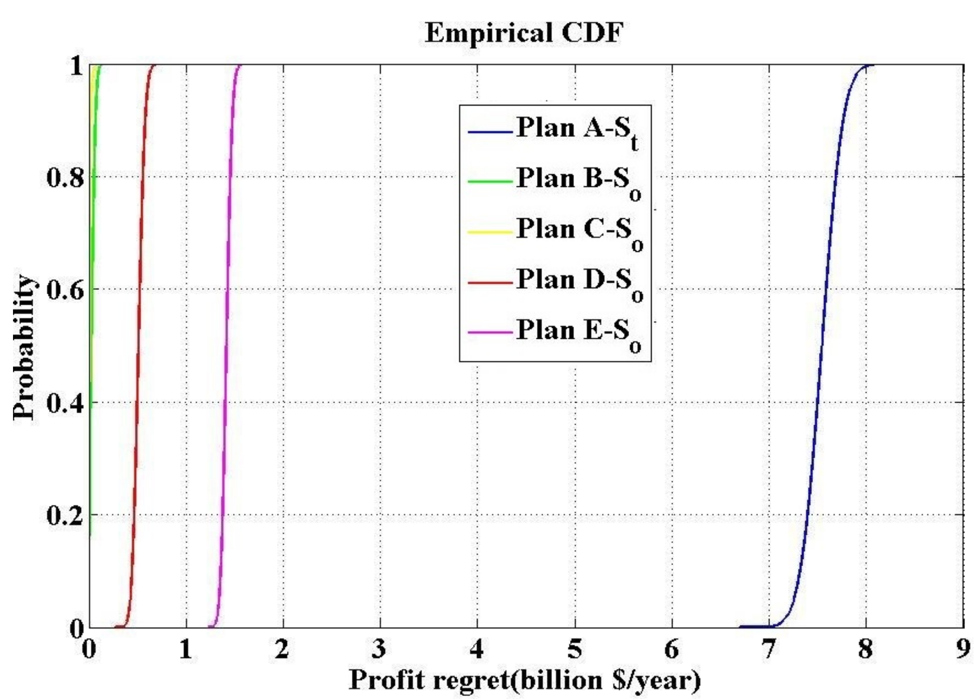

Figure 4.3 regret cumulative density functions under the worst epistemic scenarios

Figure 4.3 is the regret cumulative density functions when the plans are under their worst epistemic scenarios. The worst epistemic scenario is defined as the scenario where the least profit occurs. There are sharp climbs in the regret cumulative density functions, since the coefficients of variation (defined as standard deviation divided by mean) are small. The regret cumulative density functions of Plan B and Plan C under S_o are very closed, but not identical. We also find that the epistemic scenario where minimal profit happens may not he the one with the highest regret. For example, Plan E has the "worst" (largest expected) regret curve under S_c, but the minimal profit occurs under S_o.

Besides the optimization criteria, decision makers also look into the assessment indicators of the plans for future improvement. Results of six assessment indicators are provided as follows.

4.3.4.3 iGENCO Annual Profit Distribution

Figures 4.4 to 4.8 are vivid visions of iGENCO annual profit performance under both epistemic and aleatoric uncertainty. The following are some findings and discussions:

- Generally, the probability density functions of annual profits are bell shaped, which is because of our assumptions of aleatoric uncertainty. The density functions cannot be fit as any well-known distributions.

- Under S_c or S_{gc}, the annual variances are larger than under S_o and S_t, which are consistent with the relationships of total profit variances. As the time goes by, there are more and more renewable generations, and the variances have growing trends.

- The annual profit performances under uncertainty are very helpful information to modify the candidate plans. For example, the variance increment is an indication of profit vulnerability in particular years. The reason could be from the system or the plan itself. Modifications would be made to alleviate the drawbacks. In another instance, the profits increase a lot compared to the previous year and it is because with a new generator available, decision makers can increase investments; if it is because there are fewer ongoing investments, decision makers can look ahead a few more years to see whether the profits have a downward trend, which implies the investments are still necessary for future profits.

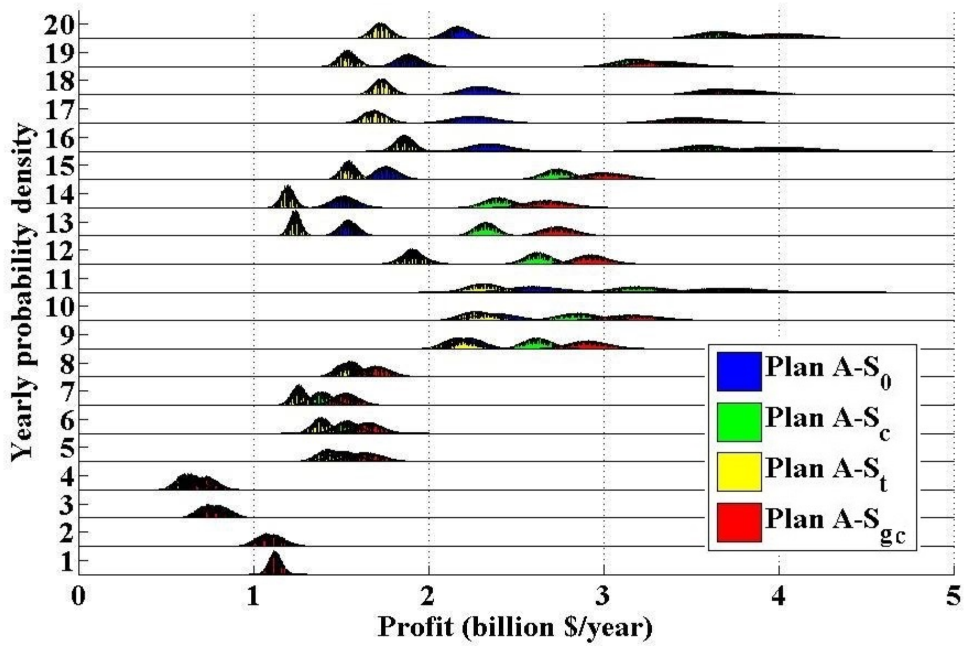

Figure 4.4 Annual profit distribution of Plan A

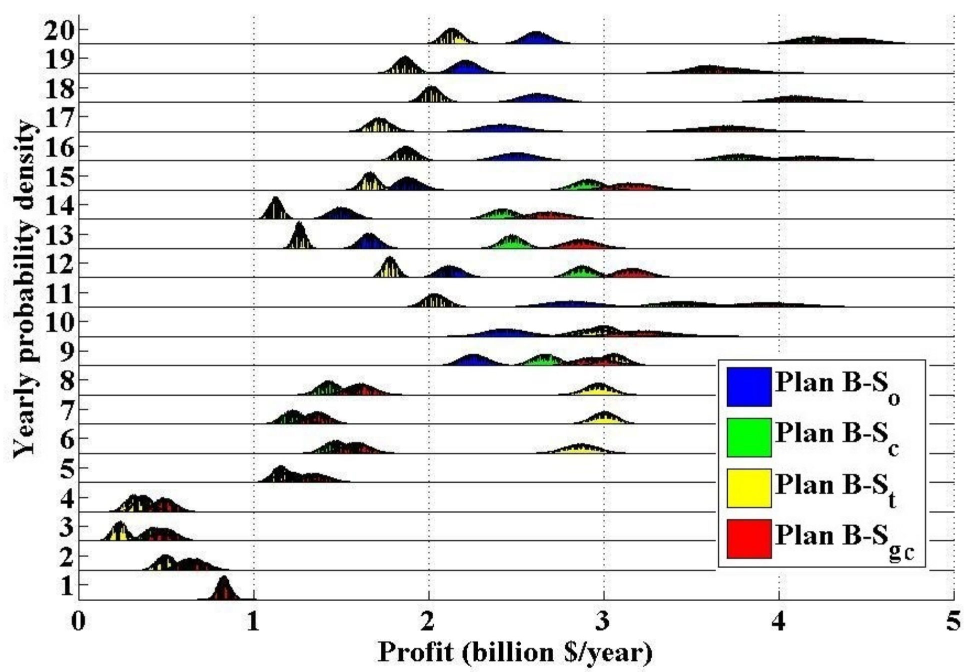

Figure 4.5 Annual profit distribution of Plan B

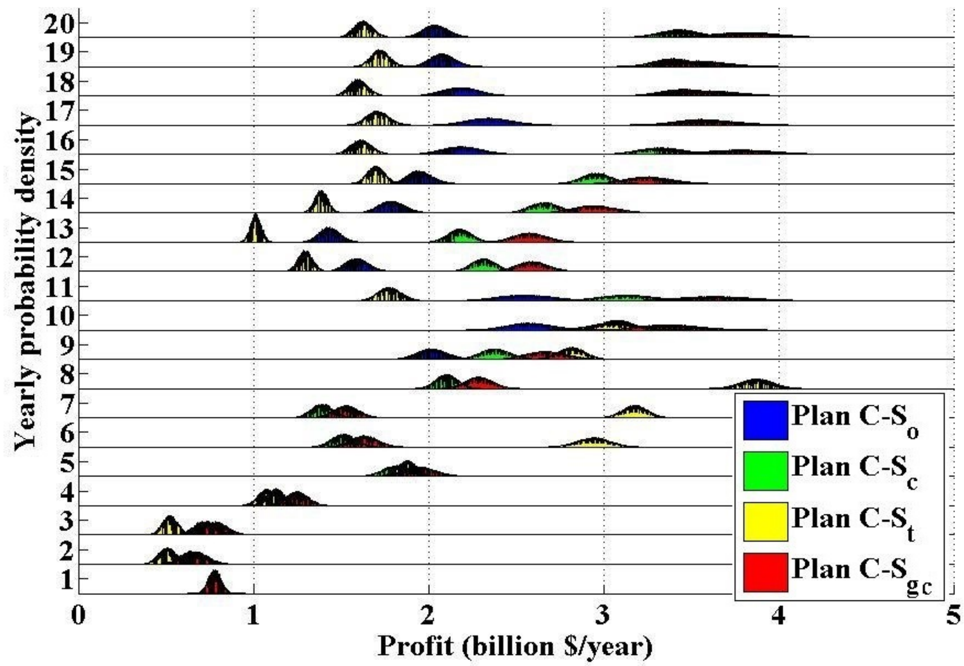

Figure 4.6 Annual profit distribution of Plan C

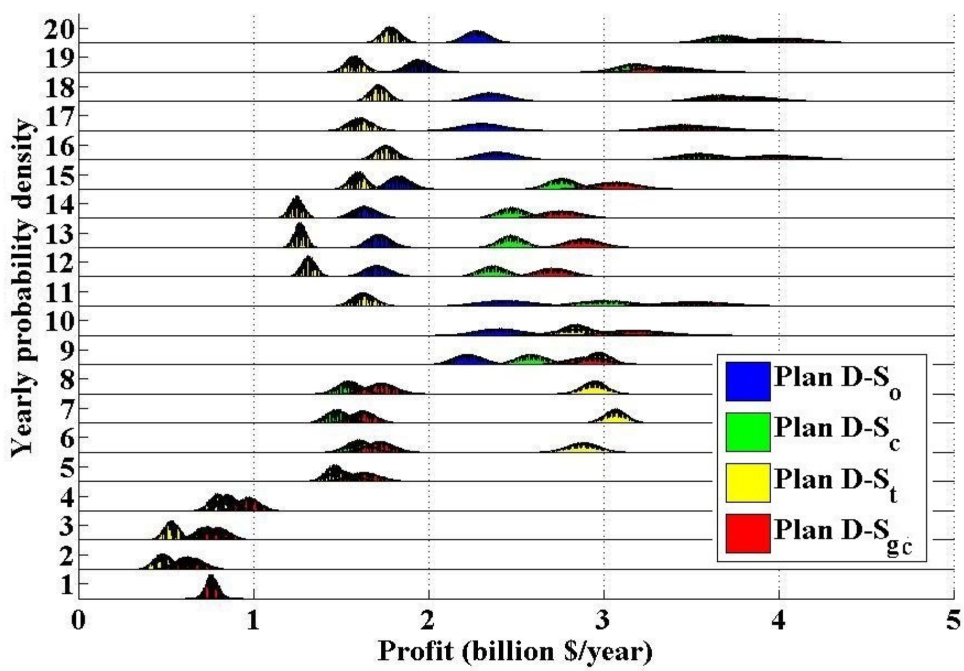

Figure 4.7 Annual profit distribution of Plan D

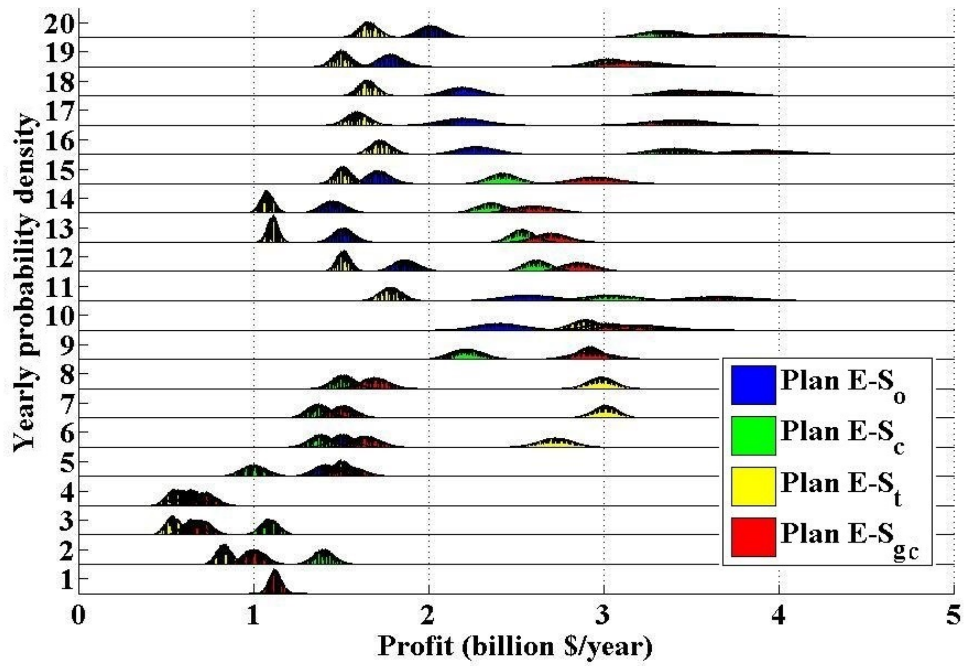

Figure 4.8 Annual profit distribution of Plan E

4.3.4.4 Profit Capacity Ratio

All the new generators are in the market at some hours, however, not all of them are always profitable. Some generators actually come with negative profits. Although we do not consider generator retirement in our case study, this indicator is able to give us some clues to retire certain generators and help decision makers adjust the investments toward a better solution empirically.

Profit capacity ratio is defined as

$\frac{\text{total revenues of the generator} - \text{total operational cost of the generator} - \text{total investment cost of the generator} \cdot \frac{\text{active years}}{20}}{\text{capacity}}$. The money is all presented in year 1's value. Total investment costs include costs occur outside the planning time frame. Active years are the available years of generator during the planning horizon. For the existing generators, we assume they are new generators available at year one to obtain their profit capacity ratios.

Tables 4.5 to 4.9 are generator profit capacity ratios of new generators from all plans. Characters B, E, G, H, N, S, and W before the numbers in the generator names, represent biomass, geothermal, gas-fired small hydro, nuclear, solar and wind power plants. The number in the generator name represents the year the generator becomes available. The characters after the number are short names of generator buses. Usually, they are the first two or three characters of the bus names, with the exception of "SM" which means SANMATEO. For example, “B8FU” means biomass generator, built at bus FULTON, beginning to produce electricity in year 8. The generator names in Plan A are exactly the same in Plan B, but their capacities are different. The name is not unique in Plan C. The tables supply evidences for the follow findings and discussions:

Plan A

1. Generator profit capacity ratios are similar under S_{gc} and S_c, and in most cases, greater under S_{gc} than S_c. Ratios are similar under S_o and S_t, and in most cases, greater under S_o than S_t. Ratios under S_{gc} and S_c are greater than under S_o and S_t. These findings are consistent with iGENCO expected total profits. The higher the profit capacity ratio, the larger the profit.
2. “B2TE” has negative profit in S_t and S_o and positive profits in other epistemic scenarios. Compared to other generators in the same location, it is not cheap, since it is invested early and depreciated a lot. Moreover, biomass generator has about four times investment cost than gas-fired generators. However, under S_c and S_{gc}, the carbon tax policy increases “B2TE” cost competitiveness by adding extra costs on gas-fired generators and leads to profitability.
3. “E11TE” has an extremely high ratio under S_{gc} and S_c. In fact, geothermal generator has a higher profit capacity ratio than other generators in the same epistemic scenarios. It is due to geothermal generator’s characteristics of constant supply and zero fuel cost.
4. Ratio of “D7HU” is negative under all the epistemic scenarios. However, “D14HU” is positive. It means the technology type and location are fine, but the time to install “D7HU” should be postponed, or the capacity of “D14HU” should be reduced if “D7HU” is profitable before the appearance of “D14HU”. Similar analysis can be done on “S14ME” and “S3ME”.
5. Ratios of wind generators in TELSA are less than in PITTSBURGH, and these ratios in PITTSBURGH are less than in MESA CAL (except for “W19ME”). The wind technology investment in less profitable areas is recommended to move to more profitable areas.
6. The evidence suggests that it is more profitable to have generators available around the mid period during the planning horizon. For example, “W8PI” and “W10ME” are more prof-

itable than other wind generators in the same locations. It is because around mid-periods, the electricity demands increase to require significant investments, and the renewable generations are not high in the energy market yet. Renewable technology investments with low operations cost around mid-periods are likely to gain more market share and profits. Wind technology with relatively low levelized investment cost, zero-fuel cost and extremely low operating cost, are a competitive choice.

Plan B Plan B has the same generator names, therefore, their technology types, available years, and locations are the same, but their capacity is not. Plan B has more renewable and less nonrenewable generations than Plan A.

1. It is very interesting to see that generator profit capacity ratios in Plan B have similar relationships as observed from one to five in Plan A. For most generators, the values are close too, with slight reductions in generation with high variability and small increase in generation with low variability. The generations with high variability lose profit due to low outputs or inefficient utilization of high outputs at some hours. With investment in storage technology, the condition can be improved.
2. Generally, generator profit capacity ratios are higher in Plan B than Plan A under S_t.
3. Besides the negative ratios mentioned in Plan A, "W3TE" also has negative ratio under S_t. Actually, generator bus TELSA has lower LMPs in Plan B than Plan A. Thus, "W3TE" has lower revenues and negative ratios. iGENCO is suggested to reduce investments in TELSA.

Plan C

1. "D6HU" becomes worse than in Plan B, because early investment has higher investment costs.
2. "B5RO" is a new negative generator under S_t compared to Plan B, because of low LMPs. Biomass technology is not easily profitable due to its operations costs and high investment costs without policy intervention.

Plan D

1. LMPs are reduced by mass of installations of wind generators in TELSA, and lead to negative ratios of "W2TE" and "W3TE". There are intense price competitions in TELSA, since generation companies made numerous investments in this bus. LMPs in this bus are

low. We will suggest retiring old generators or reducing renewable technology investments in this bus.

Plan E 1. "D7SM" has negative ratios under all the epistemic scenarios, since it has relatively high operating cost in generator bus SANMATEO. Decision maker can consider moving this generator to ROUND MT where gas-fired generator can have positive profits under all the scenarios.

2. "B2FU", "W2TE" and "B5TE" also have negative profits under S_t due to less cost competitiveness.

Table 4.5 New generator profit capacity ratios of Plan A (million $)

Generator	S_0	S_c	S_t	S_{gc}	Generator	S_0	S_c	S_t	S_{gc}
B8FU	3.27	6.10	2.59	6.42	B5PI	1.81	3.84	1.34	4.13
E5FU	6.47	8.75	5.93	9.00	B19PI	1.18	2.21	1.17	2.22
G17FU	2.52	4.59	2.07	4.58	G12PI	2.71	4.76	2.11	5.18
W3TE	0.23	0.06	0.17	0.55	B5HU	1.25	3.02	0.84	3.42
D19TE	0.89	1.70	0.85	1.85	D7HU	–0.29	–0.29	–0.29	–0.28
D8TE	2.77	4.18	2.04	4.91	D14HU	3.30	5.80	2.49	6.29
B2TE	–0.06	1.17	–0.37	1.41	B15HU	3.49	6.35	2.89	6.52
E11TE	8.81	12.50	8.29	12.39	B3SM	0.93	2.60	0.50	2.92
G4TE	1.49	2.07	1.03	2.62	B8SM	3.23	6.06	2.60	6.39
D10MC	2.98	4.92	2.18	5.80	B6SM	2.33	4.62	1.80	4.96
G15MC	3.53	6.23	2.63	6.71	D1PO	0.97	1.12	0.72	1.53
B6MC	2.41	4.81	1.88	5.39	D9PO	2.84	4.48	2.09	5.23
D19MC	1.09	2.05	0.84	2.28	G6PO	1.85	2.77	1.37	3.40
G5MID	1.91	2.80	1.49	3.89	G12PO	2.76	4.86	2.02	5.31
D10MID	3.17	5.40	2.22	6.97	D8ME	2.35	3.90	1.72	4.99
G15MID	3.80	6.72	2.33	8.18	S4ME	2.15	3.16	1.91	3.32
B3MID	1.35	3.24	0.89	4.15	S14ME	3.97	5.77	3.30	5.98
B6RO	1.38	3.19	0.70	3.30	W5ME	2.40	3.34	2.11	3.59
G8RO	2.58	4.02	1.59	4.64	W15ME	3.23	4.65	2.49	4.82
E7RO	7.62	10.35	6.52	9.94	W10ME	3.42	4.87	2.91	5.18
B14RO	3.34	6.08	2.39	5.58	W19ME	1.04	1.56	0.74	1.58
H13SU	5.07	7.32	4.39	7.05	G1SM	0.89	1.10	0.60	1.52
H3SU	3.18	4.27	2.83	4.37	G4SM	1.49	2.07	1.06	2.62
W2PI	1.09	1.66	0.97	1.71	G8SM	2.44	3.81	1.81	4.45
W8PI	2.56	3.61	2.35	3.64	G12SM	2.76	4.84	2.06	5.26
W17PI	1.89	2.84	1.83	2.67	B12SM	3.98	7.40	3.32	7.51

Table 4.6 New generator profit capacity ratios of Plan B (million \$)

Generator	S_0	S_c	S_t	S_{gc}	Generator	S_0	S_c	S_t	S_{gc}
B8FU	3.26	6.07	3.28	6.40	B5PI	1.80	3.81	2.58	4.11
E5FU	6.46	8.72	8.46	8.97	B19PI	1.17	2.18	1.16	2.19
G17FU	2.49	4.54	2.06	4.55	G12PI	2.72	4.74	2.12	5.18
W3TE	0.21	0.57	–0.17	0.53	B5HU	1.26	3.02	2.25	3.43
D19TE	0.88	1.67	0.84	1.82	D7HU	–0.29	–0.29	–0.29	–0.27
D8TE	2.76	4.16	1.41	4.88	D14HU	3.31	5.80	2.47	6.32
B2TE	–0.06	1.15	–1.07	1.40	B15HU	3.48	6.32	2.85	6.51
E11TE	8.78	12.44	8.17	12.31	B3SM	0.93	2.59	2.30	2.91
G4TE	1.49	2.07	0.06	2.62	B8SM	3.23	6.03	3.10	6.36
D10MC	3.02	4.97	2.03	5.88	B6SM	2.33	4.60	3.35	4.94
G15MC	3.55	6.23	2.58	6.75	D1PO	0.99	1.13	1.68	1.55
B6MC	2.43	4.83	3.83	5.41	D9PO	2.86	4.50	2.18	5.26
D19MC	1.08	2.02	0.85	2.27	G6PO	1.87	2.79	2.35	3.42
G5MID	1.99	2.90	2.85	4.02	G12PO	2.78	4.88	2.02	5.34
D10MID	3.28	5.53	1.86	7.15	D8ME	2.43	3.99	1.29	5.11
G15MID	3.86	6.80	2.31	8.32	S4ME	2.16	3.16	1.65	3.33
B3MID	1.41	3.31	1.77	4.24	S14ME	3.96	5.75	3.10	5.96
B6RO	1.34	3.12	0.21	3.25	W5ME	2.36	3.28	1.93	3.50
G8RO	2.55	3.96	0.91	4.59	W15ME	3.16	4.50	2.20	4.61
E7RO	7.55	10.24	5.73	9.83	W10ME	3.37	4.77	2.54	5.04
B14RO	3.31	6.02	2.29	5.53	W19ME	0.98	1.44	0.66	1.40
H13SU	5.07	7.31	4.36	7.05	G1SM	0.90	1.11	2.10	1.54
H3SU	3.19	4.27	2.95	4.37	G4SM	1.51	2.08	3.02	2.64
W2PI	1.09	1.65	1.39	1.70	G8SM	2.45	3.81	2.32	4.45
W8PI	2.54	3.59	2.42	3.62	G12SM	2.77	4.84	2.08	5.28
W17PI	1.87	2.81	1.81	2.64	B12SM	3.98	7.38	3.33	7.50

Table 4.7 New generator profit capacity ratios of Plan C (million $)

Generator	S_0	S_c	S_t	S_{gc}	Generator	S_0	S_c	S_t	S_{gc}
B7FU	2.88	5.45	3.44	5.79	B4PI	1.41	3.24	2.19	3.54
E4FU	5.90	7.97	7.86	8.22	B18PI	2.15	4.01	2.11	3.83
G16FU	3.20	5.65	2.46	5.58	G11PI	2.65	4.57	1.96	5.07
W2TE	0.00	0.33	–0.33	0.30	B4HU	0.87	2.47	1.83	2.86
D18TE	1.63	3.07	1.53	3.13	D6HU	–0.33	–0.33	–0.33	–0.32
D7TE	2.57	3.73	1.07	4.47	D13HU	3.29	5.74	2.38	6.34
B1TE	–0.51	0.60	–1.38	0.83	B14HU	3.59	6.58	2.93	6.84
E10TE	9.01	12.57	8.13	12.63	B2SM	0.43	1.94	1.58	2.25
G3TE	1.28	1.72	0.12	2.25	B7SM	2.86	5.41	3.18	5.77
D9MC	2.95	4.67	2.48	5.59	B5SM	1.88	3.96	3.16	4.30
G14MC	3.63	6.37	2.65	6.97	D0PO	0.83	0.91	1.40	1.27
B5MC	1.99	4.17	3.69	4.73	D8PO	2.73	4.15	2.25	4.94
D18MC	1.90	3.54	1.51	3.84	G5PO	1.63	2.37	2.25	2.98
G4MID	1.77	2.48	2.33	3.47	G11PO	2.67	4.64	1.88	5.17
D9MID	2.99	4.98	2.09	6.52	D7ME	2.11	3.38	1.24	4.43
G14MID	3.93	6.93	2.37	8.42	S3ME	1.68	2.60	1.28	2.76
B2MID	0.82	2.54	0.99	3.38	S13ME	4.26	6.14	3.34	6.39
B5RO	0.89	2.52	–0.18	2.66	W4ME	2.12	2.98	1.78	3.21
G7RO	2.33	3.52	0.75	4.19	W14ME	3.45	4.95	2.60	5.15
E6RO	6.87	9.34	5.17	8.99	W9ME	3.27	4.65	2.62	4.96
B13RO	3.27	6.02	2.21	5.65	W18ME	1.85	2.73	1.34	2.82
H12SU	5.16	7.39	4.42	7.24	G0SM	0.69	0.82	1.68	1.19
H2SU	2.79	3.78	2.55	3.88	G3SM	1.28	1.72	2.59	2.25
W1PI	0.81	1.32	1.05	1.37	G7SM	2.24	3.37	2.57	4.02
W7PI	2.38	3.33	2.36	3.38	G11SM	2.68	4.63	1.94	5.12
W16PI	2.37	3.51	2.20	3.28	B11SM	3.84	7.19	3.13	7.38

Table 4.8 New generator profit capacity ratios of Plan D (million $)

Generator	S_0	S_c	S_t	S_{gc}	Generator	S_0	S_c	S_t	S_{gc}
W8TE	1.17	1.78	0.91	1.70	W5ME	2.28	3.16	1.90	3.36
W5TE	0.64	1.08	0.18	1.03	W19ME	0.97	1.42	0.67	1.38
G17FU	2.65	4.77	2.13	4.82	G12PI	3.01	5.15	2.21	5.65
W3TE	0.23	0.59	–0.20	0.56	W5ME	2.28	3.16	1.90	3.36
D19TE	0.95	1.78	0.88	1.96	D7HU	–0.29	–0.29	–0.29	–0.26
D8TE	3.25	4.75	1.48	5.60	D14HU	3.49	6.03	2.57	6.59
W2TE	0.01	0.34	–0.37	0.31	W15ME	3.09	4.38	2.20	4.46
W11TE	1.41	2.11	1.33	1.98	W3ME	1.73	2.44	1.42	2.61
G4TE	1.81	2.44	0.10	3.06	W8ME	2.94	4.12	2.39	4.37
D10MC	3.23	5.20	2.11	6.17	W6ME	2.53	3.50	2.11	3.73
G15MC	3.68	6.39	2.67	6.92	D1PO	1.15	1.31	1.79	1.77
W6TE	0.83	1.32	0.44	1.27	D9PO	3.21	4.91	2.29	5.76
D19MC	1.10	2.05	0.88	2.30	G6PO	2.16	3.11	2.52	3.82
G5MID	1.89	2.73	3.03	3.82	G12PO	2.99	5.15	2.10	5.66
D10MID	3.13	5.26	1.87	6.83	D8ME	2.29	3.77	1.32	4.86
G15MID	3.71	6.54	2.34	7.98	W4ME	2.02	2.81	1.68	3.00
W3TE	0.23	0.59	–0.20	0.56	W14ME	3.30	4.67	2.39	4.76
W6TE	0.83	1.32	0.44	1.27	W5ME	2.28	3.16	1.90	3.36
G8RO	3.04	4.57	1.05	5.30	W15ME	3.09	4.38	2.20	4.46
W7TE	1.02	1.56	0.69	1.50	W10ME	3.30	4.64	2.53	4.88
W14PI	2.87	4.19	2.64	4.08	W19ME	0.97	1.42	0.67	1.38
W13PI	2.90	4.23	2.68	4.16	G1SM	1.09	1.32	2.22	1.80
W3TE	0.23	0.59	–0.20	0.56	G4SM	1.79	2.40	3.20	3.03
W2PI	1.20	1.78	1.44	1.85	G8SM	2.83	4.26	2.46	5.00
W8PI	2.72	3.80	2.47	3.88	G12SM	3.02	5.17	2.16	5.67
W17PI	1.95	2.92	1.84	2.76	W12PI	2.91	4.21	2.65	4.18

Table 4.9 New generator profit capacity ratios of Plan E (million $)

Generator	S_0	S_c	S_t	S_{gc}	Generator	S_0	S_c	S_t	S_{gc}
B8TE	2.59	4.91	1.46	5.15	B5TE	1.30	3.00	–0.14	3.25
E5TE	6.79	9.11	4.28	9.24	B19TE	0.95	1.80	0.95	1.80
G17TE	2.38	4.36	2.08	4.26	G12TE	2.76	4.81	2.13	5.25
W3TE	0.22	0.58	–0.17	0.54	B5SM	1.93	4.01	3.31	4.33
D19FU	0.96	1.83	0.83	1.97	D7SM	–0.29	–0.29	–0.29	–0.26
D8FU	2.91	4.34	2.77	5.08	D14SM	3.32	5.80	2.54	6.06
B2FU	0.48	1.99	2.03	2.28	B15SM	4.20	7.57	3.51	7.37
E11FU	8.66	12.00	7.88	12.43	B3SM	1.02	2.70	2.36	3.02
G4FU	1.57	2.17	3.51	2.71	B8SM	3.34	6.19	3.08	6.50
D10HU	2.90	4.80	1.88	5.59	B6SM	2.42	4.73	3.38	5.05
G15HU	3.43	6.06	2.52	6.39	D1PO	1.02	1.18	1.67	1.59
B6HU	1.71	3.69	2.37	4.10	D9PO	2.92	4.58	2.12	5.32
D19HU	1.03	1.95	0.83	2.15	G6PO	1.93	2.86	2.33	3.49
G5MID	1.88	2.76	2.69	3.85	G12PO	2.79	4.90	1.99	5.34
D10MID	3.18	5.44	1.73	7.01	D8ME	2.34	3.90	1.35	5.02
G15MID	3.88	6.90	2.26	8.38	S4ME	2.14	3.16	1.74	3.33
B3MID	1.33	3.23	1.65	4.14	S14ME	3.99	5.81	3.26	6.05
B6RO	1.45	3.26	0.21	3.39	W5PI	1.91	2.69	2.22	2.73
G8RO	2.69	4.15	0.89	4.79	W15PI	2.63	3.87	2.44	3.69
E7RO	7.71	10.00	5.75	10.04	W10PI	2.79	3.98	2.50	3.99
B14RO	3.33	6.05	2.28	5.57	W19PI	0.73	1.12	0.74	1.11
H13SU	5.08	7.34	4.37	7.11	G1MC	0.78	0.98	2.43	1.45
H3SU	3.21	4.30	2.95	4.42	G4MC	1.46	2.04	3.48	2.69
W2TE	0.00	0.32	–0.34	0.29	G8MC	2.39	3.81	2.48	4.60
W8TE	1.15	1.75	0.94	1.67	G12MC	2.87	5.05	2.01	5.70
W17TE	1.02	1.52	1.03	1.35	B12MC	4.16	7.75	3.26	8.27

4.3.4.5 iGENCO Emissions

Table 4.10 shows expected iGENCO's total emissions in all cases. "Expected" is with respect to the aleatoric uncertainty. The following are the observations from the table:

- Counter-intuitively, emissions are larger under S_c than in S_o and further increased under S_{gc}. Actually, the system's total CO_2 emissions under S_c are less than under S_o. iGENCO produces more emissions by generating nonrenewable energy to compensate for the intermittent supply of renewable generators of other generation companies. It also means the system's results are not positively related to individual generation company's results.

Table 4.10 Expected iGENCO's total emissions (million ton)

	Plan A	Plan B	Plan C	Plan D	Plan E
S_0	193.45	149.58	201.84	195.69	197.81
S_c	195.29	150.34	203.60	197.65	199.37
S_t	178.71	140.47	187.69	182.11	181.32
S_{gc}	198.74	155.11	207.91	200.94	205.16

- Compared to other epistemic scenarios, emission reductions under S_t are significant due to increasing efficiency of renewable energy deliverability in Plan A, and due to generation reductions in other plans.

4.3.4.6 iGENCO Renewable Generation Portfolio

Table 4.11 iGENCO renewable generation portfolios (%)

	Plan A	Plan B	Plan C	Plan D	Plan E
S_0	30.82	40.97	31.09	29.28	29.45
S_c	31.15	41.23	31.43	29.56	29.79
S_t	31.34	41.13	31.24	29.20	29.43
S_{gc}	30.94	40.95	31.18	29.58	29.42

Table 4.11 shows iGENCO renewable generation portfolios under twenty cases, which are average renewable generations divided by average total generations through the whole planning horizon. Emissions and renewable generation portfolio are two distinct assessment indicators for decision makers. Emissions tell how much the polluting resources are, and renewable generation portfolio tells us how percentage of eligible renewable energy. The findings are summarized in the following:

- Generally, renewable generation portfolios are higher under S_c than S_{gc} and S_o. The carbon tax policy increases the usages of renewable generators with not-low operations cost, such as biomass. At the same time, under S_{gc}, iGENCO produces more nonrenewable generation to compensate for renewable intermittent outputs from other generation companies, and hence reduces its own renewable generation portfolios.

- Renewable generation portfolios are significantly smaller in Plan D and Plan E than other plans. Plan D has wind technology as single renewable resource. Surplus wind energy is not injected into grid. Plan E moves renewable generators from efficient areas to less efficient areas, such as "W10ME" to "W10PI", and reduces renewable energy production.

- Plan B has higher renewable portfolios compared to other plans under the same epistemic scenarios, it is because Plan B has more renewable capacities essentially. The highest renewable generation portfolio appears in Plan B under S_c.

- The reason why Plan A under S_t has higher renewable portfolio than under S_o is because the new transmission plan reduces congestions and delivers more clean energy. For other plans, renewable generation portfolios under S_t might be higher or lower than under S_o, depending strongly on the efficiency of energy delivery. It may fail to transmit the renewable energy at their peak outputs, or fail to deliver the nonrenewable energy when loads are at peaks.

- There are no distinct correlations between emissions and a renewable energy portfolio. The clean energy might not be defined as renewable energy, such as large hydro. For this reason emissions might be a better index to describe cleanness of the systems.

4.3.4.7 Expected System's Total Profit and Profit Difference

Table 4.12 Expected system's total profit (billion $)

	Plan A	Plan B	Plan C	Plan D	Plan E
S_0	350.54	351.43	351.95	363.77	352.38
S_c	491.50	492.74	493.21	505.13	493.56
S_t	334.96	341.58	340.63	345.44	340.37
S_{gc}	547.57	548.54	550.46	565.54	550.20

Table 4.12 shows expected system's total profits in all the cases. Table 4.13 shows the revenue differences with respect to Plan A under all the epistemic scenarios from iGENCO and non-iGENCO entities. The last row is the investment cost difference of all plans with respect to Plan A. The values in the brackets are the profit differences of iGENCO between other plans and Plan A. The findings and discussion are presented as follows:

- Plan D has the highest system's total profits under all the epistemic scenarios, but Plan D is not thought highly of from iGENCO's point of view, based on previous optimization criteria and

Table 4.13 Expected system's total profit difference (billion \$)

	Plan A	Plan B	Plan C	Plan D	Plan E
S_0 iGENCO	0	4.0169 (0.26)	0.2119 (0.41)	0.8565 (-0.09)	-1.01 (-1.01)
S_0 non iGENCO	0	0.63	1.00	12.373	2.85
S_c iGENCO	0	4.6769 (0.92)	-0.0781 (0.12)	0.2465 (-0.7)	-1.26 (-1.26)
S_c non iGENCO	0	0.32	1.59	14.33	3.32
S_t iGENCO	0	8.7069 (4.95)	5.4219 (5.62)	4.7065 (3.76)	3.75 (3.75)
S_t non iGENCO	0	1.67	0.05	6.72	1.66
S_{gc} iGENCO	0	4.1769 (0.42)	0.0019 (0.2)	0.4565 (-0.49)	-1.3 (-1.3)
S_{gc} non iGENCO	0	0.55	2.69	18.4	3.93
Investment Cost	0	3.97569	-0.1981	0.9465	0

assessment indicators.

- Positive revenue difference with negative or less profit difference means that the generators are in need but the investment costs are high. We may suggest iGENCO keeping investing in the same capacities in the same locations but change to technologies with less investment costs (The operating cost should still be lower than marginal cost at the generator buses.) For example, by looking at Plan B, we could consider replace small hydro power plants with geothermal plants.

- If the revenue difference of iGENCO is significantly less than revenue difference of non-iGENCO, it might be because of the lack of renewable generation in some hours, specifically Plan D in our case study. Since the revenue is determined by multiplication of LMP and generation, the effective wind generation is really low in iGENCO and loses profit opportunities. One way to modify Plan D is trying to increase generation. We may suggest replacing the wind technology with other technologies that can have significant outputs at hours when wind cannot.

4.3.4.8 Curtailment

Table 4.14 Expected system's total curtailment (million MWh)

	Plan A	Plan B	Plan C	Plan D	Plan E
S_0	8.7437	8.8711	8.5069	9.6178	8.8281
S_c	8.8054	8.9338	8.5774	9.6943	9.2048
S_t	7.7196	22.306	20.595	23.888	22.014
S_{gc}	11.579	11.779	11.397	13.094	11.742

Table 4.14 shows expected system's total curtailment in all the cases. The curtailment is less than 5% at any hour during the whole planning horizon. Other findings are listed as follows:

- Plan B has larger curtailments than other plans, and curtailments are all the largest under $S_{g\backslash}$. These results imply that the intermittency of renewable generation causes curtailment increments in our case study. The results can be improved if the renewable generators are connected to storages.
- Plan A has the smallest curtailment under S_t. The new transmission plan is specifically designed for Plan A, and does not perform well under other plans with regard to curtailment.

4.3.4.9 Result Summary

The plans are elaborately designed to answer key questions raised in generation expansion planning, which are the investment time, location, technology and capacity of generator. Plan A is a moderate baseline plan. Base on Plan A, we observe the evidence that performances of transmission and generation planning are highly interactional. Plan B increases investments in renewable generation, significantly reduces the emissions and increases the renewable energy portfolios. Luckily, the profit variances do not significantly increase in Plan B. It is because the resource mix of renewable generators. A lot of generators with stable outputs, such geothermal, small hydro and biomass generators are considered. Plan C invests in all the generators one year earlier. It increases CO_2 emissions due to early depreciations of generators. It also increases the renewable generation portfolio, since there is less competition in renewable energy if the renewable generators are invested in earlier. Plan D studies impacts of the technology of generators. Compared to Plan A, wind energy is not fully delivered to the grid and results in less renewable energy portfolio and more emissions. Plan E switches the generators to unprofitable locations and reduces the profits. Generally speaking, performances of all the plans are similar in epistemic scenarios, and there is no absolute winner considering multiple optimization criteria.

The most direct effect of the carbon tax policy on current power systems is to increase the operations cost of generations. Consequentially, it increases the system's LMPs. Generation companies must increase the market shares of low-operations-cost generations to gain more benefit from higher LMPs.

Finally, the carbon tax policy plays a role as indirect incentives in renewable technology investment. With the most renewable generator investments, Plans B has the highest profits among all the plans when the systems are imposed on the carbon tax policy.

Two counter effects of renewable generation are observed. One is to lower LMPs due to low operations cost of renewable generation. The other is to increase LMPs during the hours that renewable generations are at their low outputs.

4.4 Conclusion and Discussion

4.4.1 Conclusion

Structured investment planning model using the three-layer framework with explicit quantification of uncertainty and representation of environmental regulations is tested via a practical case study. The case study analysis answers a wide range of questions related to the impacts of the penetration of renewable energy, implementation of environmental policies, and the expansion/improvement of the transmission grid. Specifically, in the case study, we use a 240-bus WECC network to test our framework of generation expansion under both aleatoric and epistemic uncertainty. The framework is able to produce a set of practically oriented results of direct benefit to decision makers, by providing insightful guidance for decision robustness and improvement. The carbon tax policy is found able to lead to higher profits. The potential improvements of existing plans are discussed based on the assessment indicators. The counter effects of renewable generation make the results more complicated, in which case it is hard to find a absolute winner under multiple optimization criteria.

4.4.2 Discussion

The novel framework can benefit many agencies. Related agencies could gain the insights into the planning strategies/investment decisions from the framework that involves multiple market players and entities. This research will bring about major benefits to generation/transmission companies, investors, ISOs/RTOs or regulatory agencies, equipment vendors, as well as power consumers in the following ways:

- The framework develops practical approaches to the determination and modification of investment strategies that comply with environmental policy requirements and considers explicitly their associated sources of uncertainty. Such approaches will be of valuable benefit to investors and generation/ transmission companies that undertake such decisions. For example, the decision problem formulation will be able to quantify the appropriate timing and impacts of generator retirements. Moreover, the approach will also be able to determine the most appropriate generation technologies for the replacement of the units that are retired.

- ISOs/RTOs will be able to use the methodology to gain new insights into decision process for investment in new technologies, the investment vs. retirement evaluation when a retrofit is required for an existing resources to remain compliant with environmental regulations, and the impacts of various components of the investment decision process on the system's reliability and market performance. ISOs/RTOs or regulatory agencies will be provided with an approach capable of providing a quantitative evaluation of the environmental policies.
- Vendors will find the analytic framework proposed useful to estimate the market growth in future years and to align their offerings in line with the investment preferences of the decision makers.
- Electricity consumers will benefit directly by the case study results and findings of the market outcomes for future participation in demand-side management programs.

In the framework, there exist two major limitations. On one hand, the computational time is the most difficult obstacle. In our case study, in order to keep the resolution, we run the OPF for every single hour through twenty years. It requires too much time to search through a continuous domain of generation investment decisions and epistemic uncertainty. We only select a few representative candidate plans to conduct sensitivity analysis in selective epistemic scenarios. On the other hand, in order to study the impacts of intermittency of renewable generation and load uncertainty, numerous scenarios under aleatoric uncertainty should be generated from appropriate fitted distributions. However, since only 8760-hour data is available, it is impossible to fit the spatial and time correlation or distribution of wind generation and/or other renewable generation, and load. Therefore, we have to make some harsh assumptions on the approach of scenario generations.

In the future, resolution of the case study will be sacrificed for increment of investment action domain. The action domain would be continuous. The operational layer would run the OPF through representative hours only. The optimization layer would intelligently modify their investment decisions dynamically referring to the assessment results. The decision makers could reassess the existing plan by referring to realized events.

4.5 Appendix

4.5.1 Assumptions and Formulation in the Operations Layer

Nomenclature

Sets:

$\mathscr{I}$	set of nodes (buses), $i, j \in \mathscr{I}$
$\mathscr{M}$	set of generation companies, $m \in \mathscr{M}$
$\mathscr{G}$	set of types of generation technologies, $g \in \mathscr{G}$
$\mathscr{G}^{\mathrm{s}}$	set of types of storage technologies, $g^{\mathrm{s}} \in \mathscr{G}^{s}$
$\mathscr{L}$	set of transmission lines, $l \in \mathscr{L}$. $l(o,i,j)$ contains line's "from" node i,"to" node j information and identification number o for overlapped lines.
$\mathscr{L}^{1}$	set of transmission lines to be constructed, $l^{1} \in \mathscr{L}^{1}$
$\mathscr{H}$	set of hours, $h \in \mathscr{H}$
$\mathscr{Y}$	set of years, $y \in \mathscr{Y}$

Parameters:

γ_l	susceptance of line l. (S)
F_l	transmission capacity of line l. (MW)
n^{G}_{migy}	generation expansion decision binary variable, if n^{G}_{migy} =1, generator of technology g located at node i would be expanded by generation company m and in service in year y. We assume n^{G}_{migy} =1 for existing generators, and n^{G}_{migy} =0 for retired generators. (NA)
Ω	payment for not-served energy. (\$/MWh)

Δh	minimal time interval, Δh = 1 hour. (hour)
$C^{\mathrm{s}}_{mig^{s}y}$	storage operating cost of technology g^{s} owned by generation company m at node i in period y. (\$/MWh)
η_{mighy}	capacity factor of technology g owned by generation company m at node i at hour h in period y. (NA)
$\varsigma_{mig^{s}y}$	charging/discharging efficiency of technology g^{s} owned by generation company m at node i in period y. (NA)
G_{migy}	capacity of technology g owned by generation company m at node i in period y. (MW)
E_{migy}	emission rate of technology g owned by generation company m at node i in period y. (ton/MWh)
A_{y}	emissions cap under the cap-and-trade policy in period y. (ton)
C_{migy}	operations cost of technology g owned by generation company m at node i in period y. (\$/MWh)
V_{ihy}	electric vehicle load before demand-side management at node i at hour h in period y. (MW)
C^{t}_{igy}	tax (carbon price)(positive) or subsidy (negative) of technology g at node i in period y. (\$/ton)
$S^{\min}_{mig^{s}y}$	minimal state of technology g^{s} owned by generation company m at node i in period y. (MWh)
$S^{\max}_{mig^{s}y}$	maximal state of technology g^{s} owned by generation company m at node i in period y. (MWh)
$DSM_{i,y}$	load ratio that is subject to demand-side management at node i in period y. (NA)
a^{G}_{migy}	service status of generator g owned by generation company m at node i in period y. If a^{G}_{migy} =1 (0), the generator is in (out of) service. (NA)
a^{L}_{ly}	service status of transmission line l in period y. If a^{L}_{ly} =1 (0), the transmission line is in (out of) service. (NA)

n^{L}_{ly}	transmission expansion decision binary variable, if $n^{\mathrm{L}}_{ly}=1$, line l would be available in year y. We assume $n^{\mathrm{L}}_{ly}=1$ for existing transmission lines, and $n^{\mathrm{L}}_{ly}=0$ for retired transmission lines. (NA)
S_{liy}	node-arc incident element of line l starting from node i in period y. (NA)
Q_{ihy}	electricity load before demand-side management at node i at hour h in period y. (MW)

Decision variables:

q^{s}_{mighy}	electricity supply by technology g owned by generation company m at node i at hour h in period y . (MW)
q^{d}_{ihy}	real electricity demand at node i of technology g at hour h in period y. (MW)
f_{lhy}	power flow in line l at hour h in year y. (MW)
θ_{ihy}	voltage angle of node i at hour h in period y. (radius)
$s^{\mathrm{c}}_{mig^{\mathrm{s}}hy}$	storage charging quantity of technology g^{s} owned by generation company m at node i at hour h in period y. (MWh)
$s^{\mathrm{d}}_{mig^{\mathrm{s}}hy}$	storage discharging quantity of technology g^{s} owned by generation company m at node i at hour h in period y. (MWh)
$\mathrm{s}_{mig^{\mathrm{s}}hy}$	storage state of technology g^{s} owned by generation company m at node i at hour h in period y. (MWh)
q^{fix}_{ihy}	fixed demand at node i at hour h in year y. (MW)
q^{flx}_{ihy}	flexible demand after demand-side management at node i at hour h in year y. (MW)
r_{ihy}	not-served load at node i at hour h in year y. (MW)

This section delineates the fundamental assumptions and generalized formulations in the operations layer.

4.5.1.1 Assumptions in the Operations Layer

The main function of the operations layer is to execute market clearing and return comprehensive market outcomes under all the scenarios generated in the assessment layer. We do not explicitly model unit commitment of generators, but use lossless DC power flows to obtain market outcomes. The system operator is fabricated to regulate the whole WECC system, including the market and transmission network. In the operations layer, we assume all the information in the market is complete and known by the system operator. There is no entry or exit of new or existing market players. Generation companies are not charged for penalty payments of energy-not-served. All the generation companies submit their true supply pairs (price, capacity) to the system operator, where the price is operations cost (including fuel cost) and the capacity is the maximal capacity times the capacity factor. Each generator can only submit one pair of bid in an hour. If generation companies have candidate expansion plans, they would be reflected in the form of new supply pair. The transmission network, electricity demand, carbon tax, fuel prices etc. are known parameters, but subject to scenarios in the operations layer.

4.5.1.2 Formulation in the Operations Layer

In this section, economic dispatch problem is formulated using DC power flows. For notation simplicity, we define a power flow incident matrix S_{liy}. For transmission line $l = l(o,i,j)$, S_{liy} =-S_{ljy}=$a^{\mathrm{L}}_{ly}n^{\mathrm{L}}_{ly}$. In this way, the element values of the incident matrix would be updated subject to scenario, but the dimensions are predefined and will not change. The number of rows is equal to the total number of existing and candidate transmission lines. The number of columns is the number of buses.

The detailed economic dispatch problem is formulated in Equations (4.1) to (4.14). The system operator collects the supply and demand bids from generation companies and load serving entity (LSE), and executes the economic dispatch. We use linearly approximated power flows, and the problem is linear when the investment plans and scenarios are known. We assume that the economic dispatch is done hourly.

The formulation of hourly economic dispatch in period y is written as:

$$\min \quad (\textstyle\sum_{migh}(C_{migy}+C^{\mathrm{t}}_{igy})q^{\mathrm{s}}_{mihy}+\sum_{mig^{\mathrm{s}}h}C^{\mathrm{s}}_{mig^{\mathrm{s}}y}(s^{\mathrm{c}}_{mihg^{\mathrm{s}}y}+s^{\mathrm{d}}_{mihg^{\mathrm{s}}y})+\Omega\sum_{ih}r_{ihy})\cdot\Delta h \tag{4.1}$$

$$\text{s.t.} \quad \textstyle\sum_{mg}q^{\mathrm{s}}_{mighy}+r_{ihy}-q^{\mathrm{d}}_{ihy}-\sum_{mg^{\mathrm{s}}}(s^{\mathrm{c}}-s^{\mathrm{d}})=\sum_l S_{liy}\cdot f_{lhy},\forall i,h \tag{4.2}$$

$$f_{lhy}=\gamma_l(\textstyle\sum_i S_{liy}\theta_{ihy}),\forall l,h\in\mathscr{L}, \tag{4.3}$$

$$-\pi\leq\theta_{ihy}\leq\pi,\forall i,h \tag{4.4}$$

$$-F_l\leq f_{lhy}\leq F,\forall l,h\in\mathscr{L}, \tag{4.5}$$

$$q^{\mathrm{S}}_{mighy}\leq a^{\mathrm{G}}_{migy}n^{\mathrm{G}}_{mig}\eta_{mighy}G_{migy},\forall m,i,g,h \tag{4.6}$$

$$s_{mig^{\mathrm{s}}(h+1)y}\leq s_{mig^{\mathrm{s}}hy}+(\varsigma_{mg^{\mathrm{s}}i}s^{\mathrm{c}}_{mig^{\mathrm{s}}hy}-(\varsigma_{mg^{\mathrm{s}}i})^{-1}s^{\mathrm{d}}_{mig^{\mathrm{s}}hy})\cdot\Delta h,\forall m,i,h,g^{\mathrm{s}} \tag{4.7}$$

$$S^{\min}_{mig^{\mathrm{s}}}\leq s_{mig^{\mathrm{s}}hy}\leq S^{\max}_{mig^{\mathrm{s}}},\forall m,i,h,g^{\mathrm{s}} \tag{4.8}$$

$$q^{\mathrm{d}}_{ihy}=q^{\mathrm{fix}}_{ihy}+q^{\mathrm{flx}}_{ihy},\forall i,h \tag{4.9}$$

$$q^{\mathrm{fix}}_{ihy}=(1-DSM_{ih})(Q_{ihy}+V_{ihy}),\forall i,h \tag{4.10}$$

$$\textstyle\sum_h q^{\mathrm{flx}}_{ihy}=DSM_{iy}\sum_h(Q_{ihy}+V_{ihy}),\forall i \tag{4.11}$$

$$\textstyle\sum_{migh}E_{migy}q^{\mathrm{s}}_{mighy}\Delta h\leq A_y \tag{4.12}$$

$$q^{\mathrm{d}}_{ihy},q^{\mathrm{s}}_{mighy},s^{\mathrm{c}}_{mig^{\mathrm{s}}hy},s^{\mathrm{d}}_{mig^{\mathrm{s}}hy}\geq 0,\forall i,g,h \tag{4.13}$$

$$\theta_{ihy},f_{lhy}\ \text{free},\forall l,i,h \tag{4.14}$$

- The terms in the objective function are, respectively, operations cost and carbon tax or subsidy, storage operations cost, and load curtailment payment. The energy-not-served is subject to a penalty payment. In order to be compatible with fuel price growth, the penalty cost is set to be as the 1.5 times the highest operations cost (including the carbon price if there is any).

- Equation (4.2): power balance between supply and demand at node i at hour h in period y. Left hand side is the net power injection at node i expressed in terms of power supply and demand at node i, and the right hand side is the net injection expressed in terms of power flows, which is Kirchhoff's Current Law. The hourly time-varying electricity demand is inelastic to the electricity price without demand-side management.

- Equation (4.3): power flow through line $l=(o,i,j)$, which is Kirchhoff's Voltage Law.

- Equation (4.4): voltage angle constraint at node i. The voltage angle cannot exceed $[-\pi, \pi]$.
- Equation (4.5): transmission capacity constraint, which is given and would be fixed through the planning horizon. We do not consider the depreciation of the line capacity. Incident matrix S and Equation (4.3) would ensure the flow in outage or non-existing line l is zero.
- Equation (4.6): maximal power generation from generator (m,i,g). Both a^{G}_{migy} and n^{G}_{migy} has to be 1 in order to supply power, either $a^{\mathrm{G}}_{migy} = 0$ or $n^{G}_{migy} = 0$, the generator does not supply any power.
- Equation (4.7): storage state at hour h, it is determined by the previous hour state and charging and discharging quantities at hour h.
- Equation (4.8): maximal and minimal storage state at hour h.
- Equations (4.9)-(4.11)formulate the demand-side management. The load is decomposed into flexible load q^{flx} and fixed load q^{fix} in Equation 4.9. The flexible load q^{flx} is subject to demand-side management in Equation 4.11. Equation 4.10 is the amount of hourly fixed load.
- Equation (4.12): total CO_2 emissions from the generators are subject to the cap-and-trade policy. Since the trading profit or cost of CO_2 emission allowances is internal from the system operator's point of view, we do not consider the trading profit or cost in the objective function.
- Equations (4.13) and (4.14) define the decision variable domains.

Equations (4.1) to (4.14) are generalized to accommodate many possible modifications, such as maintenance scheduling, N-1 contingency analysis, cap-and-trade policy and so on.

We do not model fuel transportation, and the fuel resources are assumed to be infinite. In our case study, we focus on the generator technology, and do not consider the maintenance, element outages, demand-side management and storages. DSM_{iy} and storage capacities are all set to be zero. The emission cap is infinity. The service status and outage status parameters are all equal to one.

4.5.2 Data in the Case Study

This section introduces the resource characteristics inherited from [68] and parameters used in the case study.

4.5.2.1 Resource Characteristics

Existing system conditions are represented as in year 2004, and future conditions as in year 2015. The resource characteristics, to be continuously used in our case study, are as follows:

- Hourly time-varying load profiles for 21 areas in the whole system are provided in 2004, as well as load of California Department of Water of Resources (CDWR). It also includes the load participation factor of all the buses. All the areas have exclusive buses.

- Hourly time-varying profiles for wind and solar resources are aggregated to the buses in the network for both current and future time frames. There are three aggregated wind areas and one solar area within CAISO. Meanwhile, there are thirteen aggregated wind areas and four solar areas (one in the future time frame) outside CAISO.

- Hourly time-varying profiles for geothermal and biomass resources are aggregated within CAISO. Biomass outside CAISO is aggregated into generic renewable resources. The geothermal output is assumed to be 80% of maximal capacities.

- If there is no dominant renewable resources and total capacity is limited, the renewable resources are modeled as generic renewable energy with 70% capacity factor.

- Gas-fired generator is modeled as a dispatchable by using heat rate.

- Coal gasification-fired generator is modeled as gas-fired generation. There is no coal generator within CAISO, although CAISO might have ownership of coal-fired generators located outside CAISO.

- There are two nuclear sites within CAISO and two outside CAISO, modeled as 85% to 100% of capacity.

- Optimal scheduling or dispatch of hydroelectric generation is complex due to various water flows. The hourly time-varying profile was obtained from PLEXOS simulation. We continue to use the PLEXOS results of hydroelectric generation in our case study. In other words, we do not look into optimal scheduling of the large hydro power plants in our case study.

Besides the resource characteristics listed above, the data file also includes ownership of generators within CAISO. Generators outside CAISO are aggregated to buses in both current and future time frames. The generators specifications contain ownership, capacity, heat rate, resource type, capacity factor, and location. Transmission line specifications include from-bus, to-bus, capacity and impedance (The transformer is modeled as transmission line). Generally, the transmission lines from 20kV to higher voltages are with infinite capacities; lines between higher voltages have larger capacities than lines between lower voltages. It could be multiple overlapping transmission lines connecting two buses. Generator ownership outside CAISO is modeled as "WECC". Generator ownerships within CAISO are PG&E, WESC, CDWR, NCPA, SCEC, SDG&E, PASA, MISC, SMUD, WAPA, SCEM, ECI, RESI, CPCO, TEK, CCSF, DETM, MDSC, NCVU, and SCVU.

4.5.2.2 Parameters

In order to accommodate the environmental study, emission rate is added to generator specifications. The emission rate from the same type of generators is not differentiated. Renewable resources are all carbon clean. Emissions from biomass technologies are not considered as environmental polluted emissions. Similar to emission rate, fuel prices are not differentiated among the same type of technologies. Parts of heat rates are given in the data file, and the other missing heat rates are assigned as Table 4.15 shows. The assigned heat rates only depend on the types of technology. Table 4.15 lists the emission rates, fuel prices and investment costs of new generators derived from [14, 75].

In addition to the above, we have the following assumptions on the parameters:

- Since most new generators' life-times are longer than twenty years, the retirement of generator is not considered. Lacking of remaining life times of existing generators, we assume existing generators are new at the beginning of the planning. Generators do not retire, but their capacities are depreciated.

Table 4.15 Emission rates, heat rates, fuel prices and investment costs of technologies

Generator	Emission rate (kg/MWh)	Heat rate (MMBTU/MWh)
Geothermal	0	34.69
Dual-fuel	440	6.7
Small hydro	0	0
Gas	400	7.2
Wind	0	0
Biomass	0	9.646
Nuclear	0	10.5
Dist. oil	758	16.03
Coal	1020	9.79
Solar	0	0
Generic renewable	0	0
Generator	Fuel price ($/MMBTU)	Invest. cost (million $/MW)
Geothermal	0	3.24
Dual-fuel	4.5	0.55
Small hydro	0	2.00
Gas	4.0	0.78
Wind	0	1.51
Biomass	1.6	2.50
Nuclear	0.75	2.82
Dist. oil	13.23	1.45
Coal	1.5	1.54
Solar	0	3.00
Generic renewable	0	2.00

- Transmission line capacity is constant through the planning horizon.
- Generation capacity is geometrically depreciated 5% annually.
- Generator's emission rate is geometrically depreciated 5% annually.
- Electricity demand increases linearly 1% annually.
- All the fuel prices increase geometrically 5% annually, but coals are 10%.
- Variable O&M cost geometrically increases by 5% annually.
- Heat rate linearly increases by 5% annually.
- Capacity factor of the same type of generator is identical at the same bus and the same time. The first year's capacity factors are derived from the given data. The hourly capacity factors of

biomass, geothermal, generic renewable, hydro, wind and solar are equal to the generation outputs divided by 125%, 115%, 135%, 120%, 100% and 110% of the maximal outputs, respectively.

- The discount rate is 5%.
- We assume the planning horizon started in 2004 and will end in 2023.

4.5.3 Scenario Generation

This section introduces the rules, processes and assumptions when we generate scenarios in the case study.

4.5.3.1 Expansion Rules

Candidate transmission line investment can be invested on the existing routes or new routes satisfying the following rules:

- New transmission lines rarely cross long physical horizon, unless there are existing routes. Most candidate line investments are within areas, a few of them are inter-area.
- New lines can be built between the same voltages or 230kV to 115kV, 345kV and 500kV, and 345kV to 500kV.
- The technology parameters such as impedance and capacity use the existing technology data. For example, the system operator plans to build a new line between Bus A and Bus B. They are both 230kV. Then the operator should look for all the existing lines with both ends at 230kV, and use one of the technologies as new line technology.

Generation expansion rules are:

- New generators can only be installed in existing generator buses (buses with existing generators). Buses with WECC generators in the future could also be viewed as generator buses.
- Candidate generators could be small hydro ($\leq$ 30MW), nuclear, wind, solar, geothermal, dual-fuel, gas, biomass, distilled oil and generic renewable. Renewable generators are small hydro ($\leq$ 30MW), biomass, geothermal, wind, solar, and generic renewable generators.

- The investments of the same technology of small generator in the same year are aggregated into one big generator of the same technology in the same year.

- The generator investment cost is equally distributed through the construction time. The investment decisions include generator types, capacities, locations and starting times. Other content like emission rate, construction lead time, variable O&M cost and capacity factor are determined by the generator technology and location.

- The final generation growth rates of every generation company consist with the total load growth rate. For example, if the load grows by 20% in year 20, the total generation expansion is also about 20%.

4.5.3.2 Makeup Process of Aleatoric Scenarios

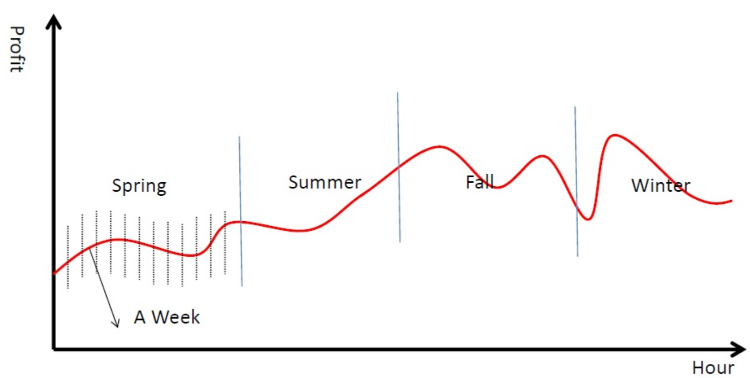

Figure 4.9 Aleatoric scenario makeup process 1

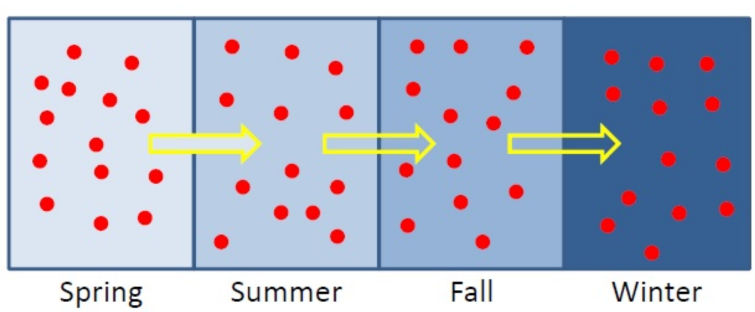

Figure 4.10 Aleatoric scenario makeup process 2

We assume the electricity loads or renewable generations among seasons are independent. A week is the minimal unit for temporal correlations of loads and renewable intermittency. A season is decomposed into thirteen non-overlapping weeks. We also assume electricity loads or renewable generations among the non-overlapping weeks are independent and follow the same distributions if there exists any. Finally, we make up scenarios under aleatoric uncertainty in the following way:

1. Firstly, as Figure 4.9 shows, we decompose a year into four seasons, and each season includes 13 weeks. We pick one week at a time from the 13 weeks, and repeat 13 times to make one sub-scenario. If 13 weeks are numbered from one to thirteen, by using polynomial theorem, distinguished sub-scenario probability follows equation $\frac{(\sum_i n_i)!}{\prod_i (n_i)!}$. n_i is the number of week i being selected. The sum of n_i in our case is thirteen. The number of distinguished sub-scenarios follows equation $\frac{(n+m-1)!}{n!(m-1)!}$. n is the number of selections, and m is the number of options in each selection. Both of them are thirteen. There are 5200300 sub-scenarios in a season.

2. Secondly, as Figure 4.10 shows, each red dot represents an independent sub-scenario in the corresponding season. Then we choose one sub-scenario from each season sequentially to compose a scenario to represent a whole year in the operations layer. In total, it is 5200300^4 scenarios in a year. Those scenarios are viewed as realizations of statistical uncertainty with equal probabilities.

CHAPTER 5. CONCLUDING REMARKS

In the liberalized energy market, independent generation companies compete to maximize their own profits from proper operations and expansion decisions. The optimal decisions are subject to uncertainty from the rapidly changing power system infrastructures and lack of perfect information from other market entities' decision-making. The three topics in the dissertation are presented to shed light on the generation expansion decision-making under the impacts of environmental regulations and various resources of uncertainty. To elaborate these three topics, the dissertation first compares the existing environmental regulation with the unimplemented ones to gain economic insights of regulation implementations and generation company's strategic behaviors. It then continues by proposing a new framework and conducting a realistic case study to assess the investment candidates under uncertainty.

In the first publication, presented in Chapter 2, unimplemented carbon tax (subsidy) policies are used to compare with the cap-and-trade policy implemented in the U.S. with respect to their effectiveness and efficiency. Seven types of tax variations are considered in the content. The oligopoly generation company's competitions are modeled by using Nash game theory. A bilevel formulation is proposed, in which the upper level is formulated to find the most efficient policy to be compared with, and the lower level models the investment and operation strategies of generation companies under the policies. The problem is reformulated into a single level problem with complementarity constraints. The framework is tested on a five bus network to demonstrate comparisons against criteria. It shows that the most efficient carbon price is the cost difference between renewable and nonrenewable generators. The cost is the sum of the levelized investment cost and operations cost. The subsidy value is higher than the tax price due to the demand elasticity. This work attains a fundamental finding that the uniform carbon tax and the cap-and-trade price are equal when the emission cap is tight. These findings are good guidance for the environmental regulation decision makers to implement the carbon tax in the future power systems. The first part of the dissertation does not capture the dynamics of the emissions and energy markets, and the small test system is not able to present the complexity of the real power systems. Therefore, the formulation is extended to include more realistic details in the markets. Firstly, the model is expanded to multi-period expansion planning. Secondly, the emissions can be banked for future use or resale, which is similar to RGGI cap-and-trade programs. Thirdly, generator construction lead-time is also considered to study the time effect to comply with the policies. We adopt the bilevel structure in the first publication, while modifying them with three aforementioned extensions, and test the model on a 30-bus network. Taking into account the time variable, we examined four variations of the carbon tax policy. Some of the results are similar to the single period case. The results also show that none of the policies is better than others under all criteria. The carbon prices or subsidies decrease when the renewable generation increases. The first two publications serve as a preliminary study on implementation of the carbon tax policy on the power systems. The economic impacts of the environmental regulations are quantified via predefined comparison criteria. However, the model relies on a strict assumption that all the market players have a full grasp of information of the power systems, including the future decision-makings from other players. This assumption is impossible to achieve in reality. The generation expansion decision serves as means to comply with the regulations. The details of generation expansion planning are not well addressed, such as diversity of technology, fuel price, and technology depreciation. The variability and intermittency of the renewable energy are not depicted either. The profit vulnerability under uncertainty is not discussed either. In next paper, with consideration of the aforementioned deficiencies, the focus of the study shifts its focus to generation expansion planning under uncertainty.

The last part of the dissertation is targeting on an individual generation company and looking for the insights of investment decision-makings under a changing environment. The third paper propose a novel three-layer framework to assess investment candidates under uncertainty with respect to assessment indicators and optimization criteria, also provide suggestions on potential improvements of candidate plans. The bottom operations layer runs the DCOPF; the middle assessment layer not only evaluates the investment candidates based on assessment indicators, but also gives suggestions on potential plan improvement; the top optimization layer discusses the decision maker's preferred tradeoff criteria between risk and return in terms of expected profits and their variance, expected regret and so on. The framework serves as a brand new toolbox for individual generation companies to pursue a robust and profitable long-term generation expansion plans under uncertainty. The sources of uncertainty are categorized into epistemic uncertainty and aleatoric uncertainty, and we are the first to apply different methodologies to tackle with them in the generation expansion planning problem. A realistic case study is conducted on WECC 240-bus test system for a twenty-years planning horizon, with practical and detailed considerations of the power systems, including the temporal and spatial correlation among the loads and renewable resource outputs under transmission network constraints, specifications of generators, and implementations of environmental regulations. The results present useful guidance for generation expansion planning. The evidences in the case study indicate that the carbon tax policy could stimulate investments in renewable technology due to increasing LMPs and reducing regrets. The investors generally benefit from the renewable generator investments in current power systems. The results help the investors dispel doubts on the drawback of high renewable generator investment cost is dominant rather than its low operating cost. The analysis also includes general discussion about how to improve the existing plans by the nature of the generators and the interactions of competitors. In addition, the outcomes demonstrate the trade-offs between risk and return in terms of various optimization criteria, and give more insightful and comprehensive information of the optimal decisions to improve the decision robustness. The framework is not constrained by the scenario generation methodologies, and the formulation in the operations layer is generalized to include considerations of storage, demand-side management, the cap-and-trade policy, element outages and maintenance scheduling. However, the framework is very time-consuming to solve and can only be applicable on predefined investment plans. The framework makes suggestions on investment candidate improvement, but does not reassess the modified plans. For future research, representative time intervals will be selected to represent the whole planning horizon and save computational time. The optimization layer will modify the plans based on the assessment layer's feedbacks and start reevaluation process. The assessment layer will be modeled as agent with artificial intelligence, which would be the major difficulty in the future work.

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