2017

Opportunities and benefits for increasing transmission capacity between the US eastern and western interconnections

Armando Luis Figueroa-Acevedo
Iowa State University

Opportunities and benefits for increasing transmission capacity between the US eastern and western interconnections

by

Armando L. Figueroa Acevedo

A dissertation submitted to the graduate faculty

in partial fulfillment of the requirements for the degree of

DOCTOR OF PHILOSOPHY

Co-Majors: Wind Energy Science Engineering; Policy and Electrical Engineering

Program of Study Committee:
James D. McCalley, Major Professor
Ian Dobson
Stephen Sapp
David Keiser
Lizhi Wang

The student author, whose presentation of the scholarship herein was approved by the program of study committee, is solely responsible for the content of this dissertation. The Graduate College will ensure this dissertation is globally accessible and will not permit alterations after a degree is conferred.

Iowa State University

Ames, Iowa

2017

DEDICATION

This work is dedicated to my family. Elvira, Luis, Amanda and Arivel: Thank you for your understanding, patience and love.

TABLE OF CONTENTS

LIST OF FIGURES

Page

LIST OF TABLES

LIST OF ACRONYMS

AEMO	Australian Energy Market Operator
AEO	Annual Energy Outlook
B2B	Back-to-back HVDC
BA	Balancing Authority
BPA	Bonneville Power Authority
CAISO	California Independent System Operator
CAPEX	Capital Expenses
CGT-Plan	Co-optimized Generation and Transmission Plan
CO2	Carbon Dioxide
DSIRE	Database of State Incentives for Renewable Energy
EI	Eastern Interconnection
EIA	Energy International Agency
EPA	US Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operation & Maintenance
GAMS	General Algebraic Modeling System
GEP	Generation Expansion Planning
HVAC	High-voltage Alternate-Current
HVDC	High-voltage Direct-Current
ISO	Independent System Operator

LCC	Line-commutated converter
LP	Linear Programming
MILP	Mixed-integer Linear Programming
MISO	Midcontinent Independent System Operator
MTON	Metric Ton
NE	North East
NE-ISO	New England Independent System Operator
NERC	North American Reliability Council
NPV	Net-present value
NY-ISO	New York Independent System Operator
RPS	Renewable Portfolio Standard
RSG	Reserve Sharing Group
RSG	Reserve Sharing Group
RTO	Regional Transmission Operator
SPP	Southwest Power Pool
SW	South West
TEP	Transmission Expansion Planning
US	United States
VOM	Variable Operation & Maintenance
VSC	Voltage-sourced converter
WI	Western Interconnection

NOMENCLATURE

INDEXES

y/Ny	Year/Planning horizon
g/Ng	Node/Total number of nodes
s/Ns	Operating block/Total number of operating blocks
h/Nh	Generation technology/Total number of generation technologies
t/Nt	Transmission technology/Total number of transmission technologies

SETS

E	Set of energy blocks
P	Set of peak-load blocks
G	Set of RSGs peaking
G'	Set of RSGs not peaking

DECISION VARIABLES

P	Generation dispatch
C^{New}	New generation capacity
C^{Ret}	Retired generation
C	Cumulative generation capacity
TC^{New}	New transmission capacity
TC	Cumulative transmission capacity
RR^{+}	Regulation-up reserve
RR^{-}	Regulation-down reserve
CR	Contingency reserve
Θ_i	Voltage phase angle (sending)

Θ_j	Voltage phase angle (receiving)
B	Branch flow

PARAMETERS

CAPEX	Generation investment cost
IC	Transmission investment cost
FOM	Fixed O&M cost
VOM	Variable O&M cost
DECOM	Decommissioning cost
HR	Heat-rate at full-load
FC	Fuel cost
Δs	Block duration
ξ	Discount factor
r	Discount rate
D	Demand
C^{Exist}	Existing generation capacity
CF	Capacity factor
CC	Capacity credit
PRM	Planning reserve margin
α	1-minute net-load variability (up)
β	1-minute net-load variability (down)
γ	Contingency reserve requirement
$rr^{1\text{-}min}$	Ramp rate in MW/min
X	Reactance
T^{Max}	Maximum transmission capacity

LR	Learning rate
FOR	Forced outage rate

ACKNOWLEDGMENTS

I would like to express my gratitude to my advisor, Dr. James D. McCalley, for giving me the opportunity to be part of Wind Energy Science, Engineering and Policy (WESEP) program at Iowa State University and for his guidance throughout the past four years. I would also like to thank the members of my thesis committee: Ian Dobson, Stephen Sapp, David Keiser, and Lizhi Wang for their guidance and support throughout the course of this research.

Furthermore, I would like to thank Dr. Ali Jahanbani-Ardakani (ISU), Dr. Hussam Nosair (ISU), Abhinav Venkatraman (ISU), Dale Osborn (Retired; Previously with MISO), Aaron Bloom (NREL), Josh Novacheck (NREL), and the rest of the technical review committee for their feedback during the course of the Interconnection Seam Study. Also, I would like to thank Anne Kimber, the Electric Power Research Center (EPRC), and the National Science Foundation (NSF) for their financial support during my PhD.

I would also like to acknowledge my former advisor and friend, Agustín Irizarry, from the University of Puerto Rico at Mayagüez, for his teaching and advice during the past eight years. Finally, I would like to thank my friends, colleagues, the department faculty and staff for making my time at Iowa State University a wonderful experience.

ABSTRACT

Historically, the primary justification for building wide-area transmission lines in the US and around the world has been based on reliability and economic criteria. Today, the influence of renewable portfolio standards (RPS), Environmental Protection Agency (EPA) regulations, transmission needs, load diversity, and grid flexibility requirements drives interest in high capacity wide-area transmission. By making use of an optimization model to perform long-term (15 years) co-optimized generation and transmission expansion planning, this work explored the benefits of increasing transmission capacity between the US Eastern and Western Interconnections under different policy and futures assumptions. The model assessed tradeoffs between investments in cross-interconnection HVDC transmission, AC transmission needs within each interconnection, generation investment costs, and operational costs, while satisfying different policy compliance constraints. Operational costs were broken down into the following market products: energy, up-/down regulation reserve, and contingency reserve. In addition, the system operating flexibility requirements were modeled as a function of net-load variability so that the flexibility of the non-wind/non-solar resources increases with increased wind and solar investment. In addition, planning reserve constraints are imposed under the condition that they be deliverable to the load. Thus, the model allows existing and candidate generation resources for both operating reserves and deliverable planning reserves to be shared throughout the interconnections, a feature which significantly drives identification of least-cost investments. This model is used with a 169-bus representation of the North American power grid to design four different high-capacity wide-area transmission infrastructures. Results from this analysis suggest that, under policy that

imposes a high-renewable future, the benefits of high capacity transmission between the Eastern and Western Interconnections outweigh its cost. A sensitivity analysis is included to test the robustness of each design under different future assumptions and approximate upper and lower bounds for cross-seam transmission between the Eastern and Western Interconnections.

CHAPTER 1. OVERVIEW

1.1. Introduction

Since 1949, high-capacity inter-regional transmission lines have been built across the contiguous United States to meet reliability criteria, move low cost generation to the load centers, and maximize the benefits of load diversity (McDaniel & Gabrielle, 1965). The increasing demand for electricity in the East and West coasts, the de-regulation of the electric power industry, and the expansion of Regional Transmission Operators (RTOs) have shaped the evolution of the US electric power grid. In recent years, high-capacity transmission projects (e.g., transmission lines with voltage levels above 345-kV) have also been built from the Midwest towards the East coast and from New Mexico and Colorado to the West coast to meet increasing demand within the region, optimize the operation of local generation resources, and enhance the reliability of neighbor areas. This trend is expected to continue under the assumption that renewables will become one of the primary sources of electricity generation in years to come.

Although major wide-area AC transmission expansion above 345-kV have been built during the past 50 years, the US electric power system operates asynchronously as a whole, and limited transmission is available between the Eastern Interconnection (EI), Western Interconnection (WI) and the Texas Interconnection (ERCOT). Today's transmission capacity between the EI and WI interconnections is 1,320 MW, roughly 0.5% of the total transmission capacity (about 1,100 GW) in the US in 2016. This "cross-seam" transmission capacity is comprised of seven HVDC back-to-back (B2B) interties located at the Seams of the US grid, as illustrated in Fig. 1.1.

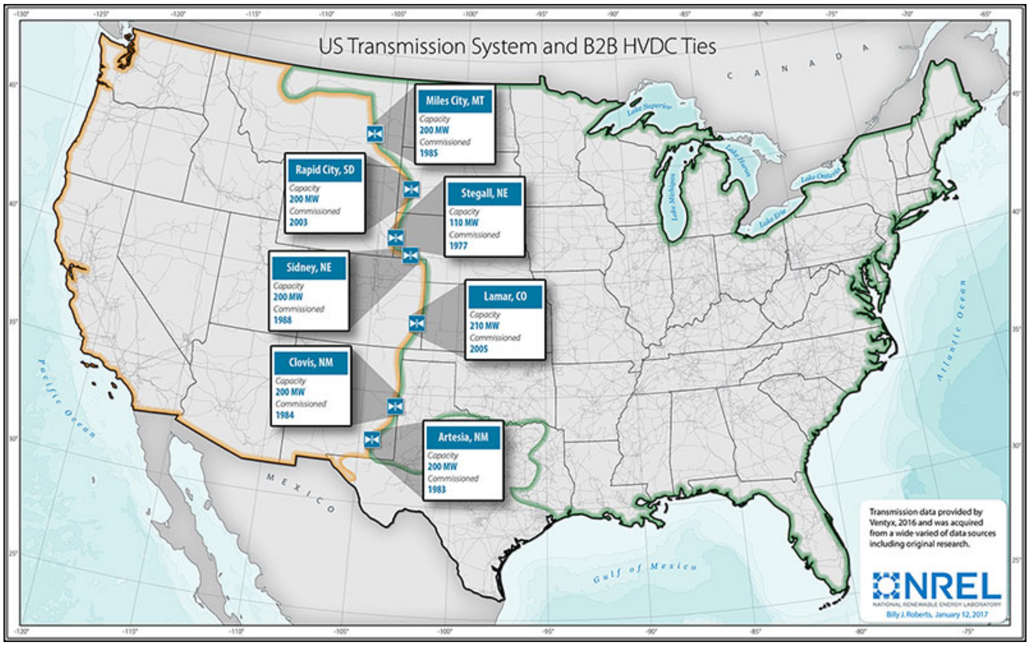

Figure 1-1: B2B HVDC Facilities between the EI and WI (Image used with permission from NREL)

There has been growing interest in strengthening the cross-seam transmission between the EI and WI as a cost-effective technological option to reduce CO_2 emissions, enhance the grid's reliability (the ability of the system to withstand the most credible set of generation and transmission contingencies) and resiliency (the ability of the system to recover from a catastrophic event, e.g. hurricane, in a short amount of time), and to facilitate the implementation of state-level renewable energy policies (DSIRE, 2017). Driven, in addition, by FERC's Order 1000 (FERC, 2016), this interest has highlighted the need for a collaborative effort towards the planning and operation of the future electric power grid.

Efforts towards the conceptualization of the idea of increasing capacity between the EI and WI have set the path for further research on wide-area transmission. Preliminary studies suggest that increasing capacity between the Eastern and Western interconnections creates economic value while keeping adequate levels of the system's reliability (Osborn, 2014), (Li & McCalley, 2015), and (Krishnan, et al., 2013). These efforts have also shown that the cost of accommodating significant amounts of renewable energy over a large footprint can be significantly reduced if additional transmission is built from the Midwest towards the East and West costs. Although increasing capacity between both interconnections will require major upgrades to the existing underlying AC transmission grid (Caspary , et al., 2015), recent studies and proposed projects (e.g., Clean Line Energy, Tres Amigas) have confirmed initial findings; that the benefits of a well-designed wide-area transmission infrastructure outweigh its costs, thus justifying further research on this topic (Li & McCalley, 2015), (Corcoran, et al., 2012).

1.2. Motivation for exploring the economics of wide-area transmission

Although there is a rich literature on the topic of wide-area transmission expansion planning, including the development of conceptual transmission overlays at the national level (McDonald, et al., 2016), (Osborn, 2014) and (Li & McCalley, 2015), little is known about the implications of net-load diversity and capacity sharing on cross-interconnection transmission. Weather-related and time-zone differences are among the principal sources of net-load diversity in continent-wide interconnections. In this work, net-load diversity is defined as the difference between the maximum net-load during the year of one area and the load of that area when a neighbor area is peaking. Figure 1.2 illustrates the concept of net-load diversity using a two-area system as an example.

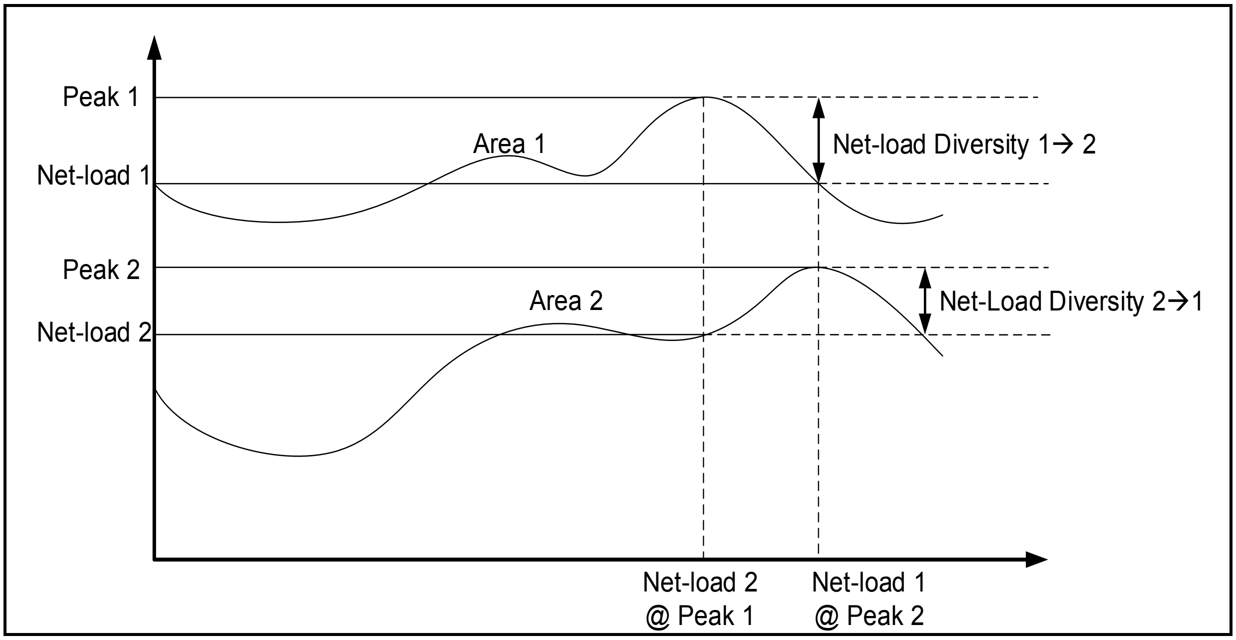

Figure 1-2: Conceptual representation of net-load diversity

In (Osborn, 2014)[1], the historical net-load diversity in the contiguous US was estimated to be 30,000 MW. These investigations provided insight on the drivers behind wide-area transmission expansion. However, the economic implications of the energy-capacity interactions on investments in generation and transmission resources when the asynchronous interconnections are allowed to share planning reserve margin (PRM) obligations and operating reserves haven't been explored. Today, new computational tools are available to combine high-fidelity models and study the effects of different modeling features (e.g., net-load diversity) on investments in transmission and other resources.

This work combines previous work on wide-area transmission and implements a design process for the development of hybrid HVDC/HVAC designs and exploration of the economic benefits of continent-wide transmission infrastructures. By characterizing net-load diversity

[1] The value of net-load diversity is derived from the generation capacity deferred by transmission. For example, a 30,000 MW of net-load diversity represents the amount of generation that will not be needed if 30,000 MW of transmission is build.

using historical load diversity data, accounting for net-load diversity and capacity sharing within a co-optimization framework, and modeling the capacity contribution of wind and solar generation during non-coincident peak-load times, this work contributes to the understanding of capacity sharing opportunities in wide-area interconnections.

1.3. Objectives of this dissertation

The overall objective is work is to develop and use an optimization model to perform long-term (15 years) co-optimized generation and transmission expansion planning, to explore the benefits of increasing transmission capacity between the US Eastern and Western Interconnections under different policy and futures assumptions. In order to achieve this goal, four wide-area transmission designs for the contiguous US were developed. These designs are characterized as follows:

- *Design 1:* No B2B upgrades: This design serves as a reference case for the three other designs. Capacity expansion of the existing B2B interties is not allowed. A CEP plan is developed for each interconnection assuming that only 1,320 MW of transmission can be transferred between the EI and WI.
- *Design 2a*: B2B upgrades: The capacities of all seven B2B interties between the EI and WI are allowed to be increased, as long as the added transmission enables economic benefits that exceed its costs.
- *Design 2b*: Upgraded seams: In addition to allowing all seven B2B interties to increase in capacity, three new HVDC lines above the existing underlying AC system and upgraded B2B interties are also allowed to be expanded.
- *Design 3*: Macro-grid overlay: This design uses the Mid-Continent Independent

System Operator (MISO) macro-grid overlay as presented in (Osborn, 2014). In this design, the existing B2B HVDC interties are not upgraded. This design is unique in its capability to withstand the loss of one "cross-seam" transmission line (N-1).

Although each design is unique from a configuration perspective, the design process adopted for this work is the same for all four designs. A graphical representation of each design is shown in Fig. 1.3. The lines internal to each respective interconnection represent the nature of expected AC transmission investment necessary to facilitate the HVDC cross-seam design. There are three particular points, relative to these diagrams, that need attention.

1. The figures indicate the locations for the highest quality wind (Midwest) and solar (South) resources in the US. The implication is not that a renewable-rich future is preferred in this study in spite of its economics; rather, it is preferred because of its economics. That is, today's existing and expected future technology costs indicate that the most economically attractive new energy investments are wind and solar, with natural gas also being in the mix in order to provide planning capacity, operational flexibility, and, depending on fuel price assumption on CO2 cost, some energy.

2. Expansion of transmission interconnections with the region of the US operated by the Electric Reliability Council of Texas (ERCOT) were not considered in this study. Although it is possible, even likely, that such expansion may offer significant benefits to EI, WI, and ERCOT, these potential benefits were not studied in this work in order to limits its scope to that achievable within the time and resources available.

3. All cross-seam transmission (existing and added) is HVDC. Cross-seam AC transmission was not considered because it would synchronize what are now two asynchronous

grids, and, causing exposure to resulting stability issues, would significantly limit the flexibility of choice in capacity and location offered by use of HVDC.

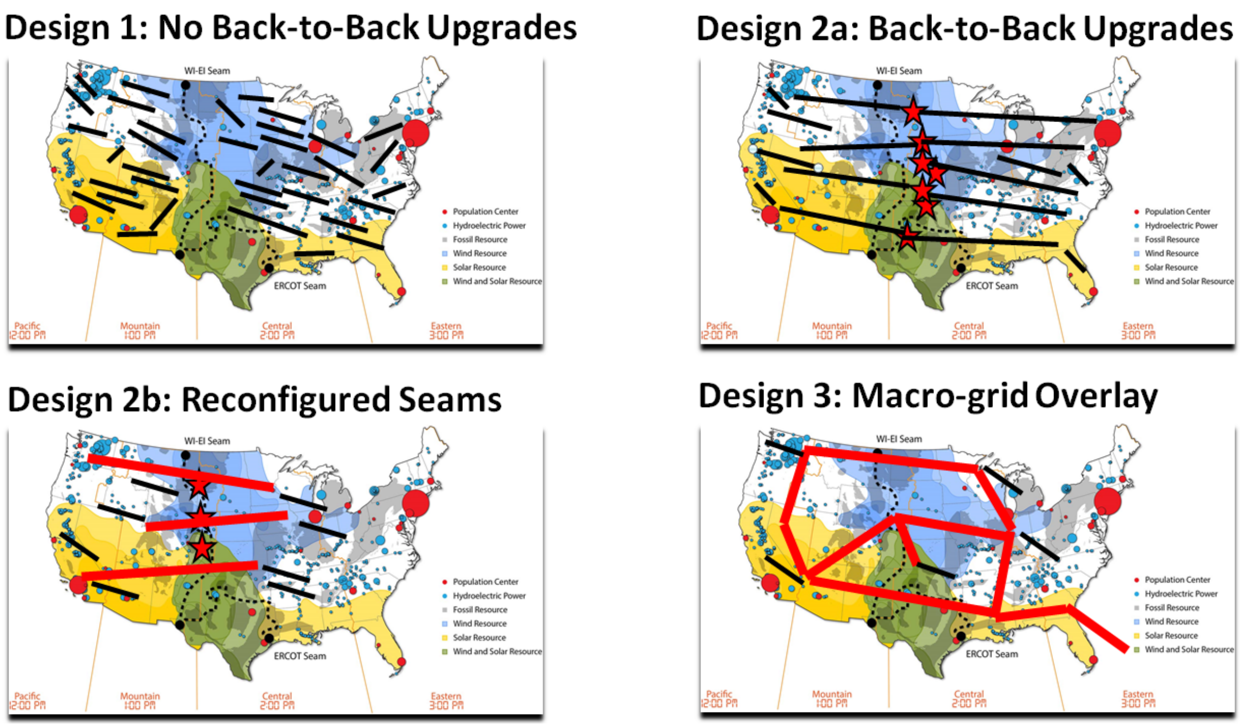

Figure 1-3: Conceptual representation of the four designs studied in this dissertation

In particular, the specific objectives of this research were to:

1) Develop an analytical CEP model that accounts for diurnal net-load diversity, annual net-load diversity, capacity sharing and deliverability, and operating reserves sharing.
2) Develop a database for the US Eastern and Western Interconnections, which include existing and candidate generation/transmission operational and investment data.
3) Develop four base designs for the US grid without and with capacity sharing opportunities, assess the implications of base assumptions on investments, and assess and compare the economic performance of the four designs.

4) Evaluate the robustness of each design by performing model-level sensitivities on the number of energy blocks, the number of peak blocks and the number of transmission candidate lines and quantify the robustness of each design to gas prices and policy uncertainties.

1.4. Organization of this dissertation

This dissertation is organized as follows:

Chapter 2: This chapter includes a review of the most relevant studies related to wide-area transmission in the US and around the world. Special emphasis is given to the studies that span the US Eastern and Western Interconnection.

Chapter 3: The formulation of the CGT-Plan used in this dissertation is presented, together with the additional features developed in this work.

Chapter 4: This chapter includes a description of the database development, design process and study framework used for the US Seams Interconnection Study.

Chapter 5: The results from base designs are described and assessed. The differences in the resulting co-optimized infrastructures designs are described.

Chapter 6: This chapter compares the results from the previous chapter under current policy conditions. Current policy, consistent with two highly influential environmental policies in place today, imposes state-by-state renewable portfolio standards (RPS) but not impose a CO_2 cost.

Chapter 7: The robustness of the model is tested in this chapter. Results are provided in terms of the impact, relative to the base designs, on generation and transmission investments.

Chapter 8: This chapter summarizes the major findings of this dissertation, and it identifies future work useful in conjunction to understand the costs and benefits of building high-capacity cross-seam transmission.

CHAPTER 2. PREVIOUS WORK ON WIDE-AREA TRANSMISSION PLANNING

This chapter includes a summary of the most recent work related to wide-area transmission planning. Special emphasis is given to studies conducted for the contiguous United States and electric boundaries. The literature review presented in this chapter includes the modeling techniques, data assumptions and major findings from each study.

2.1. Wide-area transmission studies around the world

In (Lumbreras & Ramos, 2016) and (Pache, 2015), the technical, economic, and policy aspects of achieving large amounts of wind and solar generation in Europe was studied. As part of the 2050 Pan-European Transmission System project, the authors developed an enhanced methodology to design a wide-area transmission grid capable of moving wind and solar generation across Europe. The methodology included a mixed-integer linear programming (MILP) model for the development of different transmission overlays, an algorithm to define candidate transmission lines based on congested paths, and treatment of uncertainty.

In Canada, General Electric (GE) evaluated the technical feasibility of integrating large amounts of wind generation into the Canadian electric power system (General Electric Consulting, 2016). The study concluded that 4.6-4.8 GW of additional inter-regional transmission is required to accommodate 35% of the wind penetration in Canada. Interestingly, the study concluded that for every 1 MWh of additional wind generation in Canada, energy exports from Canadian provinces to the USA increase by 0.5 MWh. Furthermore, CO_2 emissions decreased by half in the Business as Usual scenario. The study did not consider transmission expansion to the US, although it did account for the existing net-exchange transmission capacity.

The Super Smart Grid concept was proposed in (Battaglini, et al., 2009). The authors argued that combining wide-area power generation and decentralized power generation, two philosophical views of future network architectures that are usually presented as mutually exclusive, are technically and economically feasible in a future dominated by renewables. Also in Asia, Taggart et. al. (Taggart, et al., 2012) presented the Pan-Asian Energy Infrastructure, which included China, Australia, Mongolia, and Vietnam. The study evaluated the technical feasibility of connecting these countries with HVDC transmission using undersea cables. Although the authors neglected intra-regional transmission, the cost of integrating large amounts of wind and solar at each country was accounted for. Results show that savings up to $6B US dollars can be achieved at the 30% wind and solar penetration levels.

Wide-area interconnection studies have also been conducted in South Asia and Australia. One of the most relevant studies was published in (Andrew, et al., 2017). The authors proposed a 4,500 km HVDC backbone infrastructure connecting 12 contiguous Southeast Asian countries. The study concluded that a third of the 2050 demand could be met from Australian solar energy, large-scale pumped storage, and HVDC transmission. The levelized cost of electricity (LCOE) was estimated to be $0.08/kWh in 2050 in Australia and $0.077 in South East Asia. This represents a slight increase from today's prices in Australia and South East Asia's coal-dominated infrastructures. Meanwhile, in North Asia, (Bogdanov & Breyer, 2016) studied a scenario with 100% renewable generation in North Asia. One of the main findings from this study was the comparison made between a network infrastructure with high local storage deployment and one with high HVDC interregional transmission. The authors concluded that if political boundaries are neglected HVDC transmission resulted in the most economic option.

2.2. Wide-area transmission studies in the US

Wide-are planning studies in the US can be classified in two main groups: interconnection-level studies and cross interconnection-level studies. The common topic amongst these is the utilization of transmission to move wind energy from the Midwest and solar energy from the Southwest to the load centers in the East and West parts of the contiguous US. Phase 1 of the Western Wind and Solar Integration Study (National Renewable Energy Laboratory, 2014) explored the benefits of integrating 35% of renewables in the Western Interconnection. A total of 69.48 GW of new wind and 13.2 GW of new solar capacity, and 17 GW of new HVDC transmission were proposed for the 30% scenario.

Although (Ho, et al., 2015) and (Munoz, et al., 2014) focused their work on quantifying the benefits of using stochastic programming models for the WECC system, the authors also tested the modeling features that have the most impact on investment decisions. The main modeling features tested was the number of scenarios, number of candidate lines, number of operating blocks and number of buses. The authors concluded that including Kirchhoff's Voltage Law (KVL) constraints, unit commitment considerations and a larger number of candidate lines increase the fidelity of the results while keeping the simulation computationally tractable. In (WECC, 2016) a 300-bus representation of the WECC model for 10-year CEP studies was presented. The author used aggregation techniques to reduce the 2026 TEPPC model and pro-posed an algorithm based on triangulation for the filtering of transmission candidate lines. The effects of increasing wind and solar penetration in WECC by 33% on transmission requirements were explored in (Mills & Amol, 2010). The estimated cost of new transmission was between $22-34 billions. Other studies from WECC also explored the effect of achieving a $1/Watt investment cost for solar on the WECC system, concluding that $20 billion of savings were possible on an annual basis from 2010-2050 under a carbon tax assumption.

In 2010, the EIPC (Eastern Interconnection Planning Collaborative (EIPC), 2011) quantified the cost and benefits of building a 765-kV together with an HVDC overlay across the EI to accommodate higher levels of wind generation. The study used a sequential generation first, and then transmission expansion approach. More recently, Spyrou et. al. (Spyrou, et al., 2016) showed the benefits of co-optimization using a 24-bus representation of the Eastern Interconnection. In particular, the author discussed the advantages of using co-optimization models to explore the implications of building high transmission capacity between the Midwest part of the US (Midcontinent ISO and Southwest Power Pool) and the East coast. The model showed how investment decisions about different wind resources and the necessary transmission enhances the planning process. KVL constraints were considered and a 20-block representation was used to approximate production cost implications. As a follow-up study on co-optimized expansion planning using the EISPC database, You et. al. (You, et al., 2016) built upon the EIPC study to quantify the benefits of co-optimization for CEP studies. The authors found that the diversity of wind decreases the total transmission capacity requirements, and increasing the granularity of operating blocks decreases the value of new transmission on the EI. A transportation model was used to represent transmission. One of the most relevant interconnection studies conducted for the EI can be found in (Bloom, 2016). Bloom et. al. reported on the results of the Eastern Renewable Generation Integration Study (ERGIS), one of the largest studies performed for the Eastern Interconnection. In this dissertation, we make use of the datasets developed for ERGIS to represent the generation fleet of the US EI.

A sequential GEP-TEP for the contiguous US was performed in (Corcoran, et al., 2012). The authors concluded that load diversity alone does not justify major transmission expansion. The study only included load diversity as the value driver for transmission expansion and neglected the contribution of wind and solar generation. Krishnan et. al. (Krishnan, et al., 2013) quantified the benefits of building a national transmission overlay for the contiguous US. The study concluded that savings in the quarter trillion range could be achieved over a 40-year period under high renewable penetration scenarios. The authors used a sequential optimization model to expand generation and transmission. Also, the model did not consider KVL constraints, or the operational effects of renewables on reserve requirements.

At the Midcontinent Independent System Operator, Osborn (Osborn, 2016) developed an HVDC overlay for a large part of the contiguous US. The HVDC Macro-grid overlay consists of 15GW of transfer capability between the WI and EI. A single pole N-1 contingency criteria was used to guarantee the self-contingency of the design. The main value driver for the HVDC Macro-grid is the annual load diversity, and capacity sharing assumptions for planning reserve margin compliance. Li and McCalley (Li & McCalley, 2015) developed a high-fidelity transmission-planning model to study hybrid HVDC/HVAC transmission designs for the contiguous US. An algorithm based on minimum spanning tree was developed to filter candidate lines with economic and reliability potential. The authors concluded that approximately 10GW of new seam transmission was necessary to accommodate 800GW of inland wind and 200GW of solar by 2050.

2.3. Seams Interconnection Studies in the US

In the 20th century, several studies were performed to evaluate the feasibility of increasing capacity between the three main US interconnections. Although all these studies provided US regulators and decision-makers technical understanding of the benefits of increasing capacity between the Eastern and Western interconnections, optimization techniques were not mature enough at that time for evaluating the long-term economics of these options.

In 1979, Taylor (Taylor, 1979) reported on the interconnection of Eastern and Western North American Power Systems in the early 1980's. The study evaluated the transient stability performance of the integrated WI-EI system with 500 MW of transfer capability. The voltage support provided by coal- red generation units and adjacent transmission capacity were among the major findings under a 600 MW loss on the WI side together with 500 MW loss of cross-interconnection capacity. The authors recommended pursuing studying larger power transfer between interconnections.

The Western Area Power Administration (Western Area Power Administration (WAPA), 1994) studied the effects of synchronizing the EI and WI using 1 GW of bi-directional transfer capability. Finally, Abraham (Abraham, 2002) used a transportation model to identify major transmission bottlenecks and propose technological (e.g., investments) and non-technological (e.g. regulations) options to relieve them. This DOE-funded project proposed the use of market-based transmission solutions to drive investments in new transmission.

2.4. Ongoing wide-area transmission studies in the US

Today, there are several ongoing studies, e.g., (National Renewable Energy Laboratory, Ongoing) and (NREL, Ongoing) having similar objectives. The North America Renewable Integration Study (NARIS) and the Interconnect Seams Study are two studies being run in parallel with the objective of studying the optimal transmission required to maximize the use of the most economic resources in the US. This dissertation was part of the Interconnect Seams Study (NREL, 2017).

CHAPTER 3. CGT-PLAN: MATHEMATICAL FORMULATION AND MAIN MODELING FEATURES

The U.S. electric power transmission grid is arguably the single largest and most complex machine in the world. Although the process of deciding where, how much, and when new generation and transmission capacity are required to meet a particular objective involves a broad range of non-engineering disciplines, including economics and social sciences (McCalley , et al., 2013), the design processes that precedes the decision making phase is typically assessed by means of capacity expansion models (CEP). The latter helps decision makers explore the economic implications of a particular policy on investment in transmission and other resources and can also inform the planner about potential reliability issues. By minimizing the net present worth of all new transmission and generation resources, including the operating and maintenance cost, the general CEP is capable of determining the optimal combination of resources required to meet a particular objective, such as an environmental regulation, under a set of constraints (e.g. Kirchhoff's voltage and current laws, design criteria, etc.). In general, the most used CEP models can be classified as:

1. Linear programming
2. Mixed-integer linear programming
3. Dynamic programming
4. Non-linear mixed integer programming
5. Stochastic programming
6. Multi-objective
7. Economic-energy interactions

8. Integrated investment-financial

The decision of which model to use for long-term planning studies depends on the objectives of various organizations (e.g. Federal power authority, investor owned utility (IOU), regional transmission operator (RTO), municipal utility, Coop), the locational granularity requirements (e.g., nodal, zonal), the study framework (economic-based, reliability-based, financial-based, engineering-based, hybrids), among other considerations (e.g., market interactions). For example, the federal power authority may want to make decisions to maximize social welfare, while an IOU will aim at maximizing the rate of return of an investment. An example of a social welfare model is the US Energy Information Administrator (EIA) capacity expansion model. The EIA model makes use of econometric and financial concepts and provides information about existing and future trends related to the electric power industry. A common denominator in traditional CEP models is that generation and transmission are optimized sequentially. That is, generation is optimized first to identify the optimal location, and then transmission is added to optimize the operation of the generation fleet.

In recent years, the sequential approach has been challenged by the development of new programming models and algorithms (Spyrou, et al., 2016). Co-optimization models are currently being tested, where generation and transmission infrastructures are simultaneously optimized using a single analytical formulation. The economic benefits of generation and transmission co-optimization range from \$10-100 billions. In (Krishnan, et al., 2016), the authors presented a summary of the methodologies and mathematical formulations used for co-optimized expansion planning studies. In the next section, the CGT-Plan model used in this work is presented.

This chapter is organized as follows. Sections 3.1 and 3.2 include the mathematical formulation of the CGT-Plan. In Section 3.3, a description of the variability model adopted for this work is discussed, including a study to support the assumptions about reserves modeling within CEP models.

3.1. Mathematical Formulation

The general objective of a least-cost CGT-Plan model is to minimize the net-present value (NPV) of new generation technology *h* represented by the continuous decision variable C^{New}, new transmission technology *k* represented by the continuous decision variable T^{New}, retired generation represented by the continuous decision variable C^{Ret}, the production cost of generation resources, represented by the continuous decision variable P, the provision cost of regulation up, regulation down and contingency reserves, represented by variables RR^{+}, RR^{+}, and CR, and the fixed and variable operation and maintenance cost of new and existing generation resources, denoted by parameters FOM and VOM. The model is extended to multiple time periods by defining two new variables: *y*, which represents a single year, and N_y, representing the total planning horizon (15 years). The problem is formulated as a linear programming model (LP), where the NPV of two different yet related resources are simultaneously minimized within one optimization formulation. The objective function of the general multi-period CEP, for multiple regions, is given by (3.1)-(3.9).

3.2. Extended Objective Function

The objective function is further extended to account for the maturation rate, regional multipliers, and end-effects. In this work, we use the capital expenditure (CAPEX) for new generation resources to represent the total cost required to achieve commercial operation and a social discount rate to calculate the annual costs. Also, a decommission cost is included to represent the disposal of plant's equipment and cleanup of land, as shown in Eq. (3.3). In this work, the decommission cost of bulk conventional generation (several generation units aggregated into a single bus), is assumed to be negligible. Under this assumption, the retirement decision is mainly driven by the capacity factor and FOM. That is, if the NPV of a generation technology is less than the FOM, the model will identify this condition as "more economic" than keeping the technology underperforming. However, if a generation technology is able to provide capacity to meet operating and planning reserves requirements, the model will keep these for reliability considerations.

The general CEP formulation can be modified to account for end effects by assuming an infinite horizon after the last year of the simulation (perpetuity), N_y. Perpetuity is a stream of equal cash flows that occur at regular intervals and last forever. This modification guarantees that the production cost of generation technologies with low investment cost is correctly accounted for in the final years of the planning horizon.

3.3. Constraints

The objective function is subject to the following constraints. Equation (3.10) represents the nodal power balance, using a linearized DC power flow network model. The total cumulative generation capacity on each year, C_{ygh}, is included into the problem formulation as an equality constraint, as shown in (3.11), and its corresponding initialization is defined by (3.12). In order to account for the fact that wind and solar resources cannot provide full power output during some instances of time, a capacity factor inequality constraint (3.13), in terms of parameter CF, is included. Also, dispatch variable P is bounded by its minimum stable limit, as shown in (3.14). In this work, the minimum stable limit is assumed to be zero for all generation technologies. This assumption is consistent with commercial-grade GEP models. However, an additional set of constraints is included to account for the ancillary services component of the operating costs.

Equations (3.15)-(3.20) represent the operating reserves requirements as a function of load, wind and solar variability and corresponding ramp-rate constraints, as implemented in (Krishnan, et al., 2013). Finally, Eq. (3.21)-(3.22) represent the transmission constraints (KLV and thermal limit). In this dissertation, the impedances of existing paths are assumed to be constant. This assumption enhances the fidelity of the transportation model but still underperforms compared to the MILP formulation presented in (Li & McCalley, 2015). Finally, Equations (3.23)-(3.24) limit the new generation and transmission capacity and Eq. (3.25) defines all decision variables to be positive.

Minimize:

Capital Expense of New Generation Resources

$$\sum_{y}^{Ny}\sum_{g}^{Ng}\sum_{h}^{Nh}\zeta * CAPEX(h) * RM(g,h) * C_{ygh}^{New} \tag{3.1}$$

Capital Expense of New Transmission Resources

$$+\sum_{y}^{Ny}\sum_{k}^{Nk}\sum_{t}^{Nt}\zeta * IC(k,t) * RM(k,t) * T_{ykt}^{New} \tag{3.2}$$

Capital Expense of Retired Generation Resources

$$+\sum_{y}^{Ny}\sum_{g}^{Ng}\sum_{h}^{Nh}\zeta * DECOM(h) * C_{ygh}^{Ret} \tag{3.3}$$

Fuel Cost of New and Existing Generation Resources

$$+\sum_{y}^{Ny}\sum_{g}^{Ng}\sum_{s}^{Ns}\sum_{h}^{Nh}\zeta * HR^{FL}(g,h) * FC(y,g,h) * P_{ygsh} * \Delta_s \tag{3.4}$$

Regulation-Up Reserve Cost of New and Existing Generation Resources

$$+\sum_{y}^{Ny}\sum_{g}^{Ng}\sum_{s}^{Ns}\sum_{h}^{Nh}\zeta * (0.5) * HR^{FL}(g,h) * FC(y,g,h) * RR_{ygsh}^{+} * \Delta_s \tag{3.5}$$

Regulation-Down Reserve Cost of New and Existing Generation Resources

$$+\sum_{y}^{Ny}\sum_{g}^{Ng}\sum_{s}^{Ns}\sum_{h}^{Nh}\zeta * (0.5) * HR^{FL}(g,h) * FC(y,g,h) * RR_{ygsh}^{-} * \Delta_s \tag{3.6}$$

Contingency Reserve Cost of New and Existing Generation Resources

$$+\sum_{y}^{Ny}\sum_{g}^{Ng}\sum_{s}^{Ns}\sum_{h}^{Nh}\zeta * (0.2) * HR^{PL}(g,h) * FC(y,g,h) * CR_{ygsh} * \Delta_s \tag{3.7}$$

Fixed Operation and Maintenance Cost of New and Existing Generation Resources

$$+\sum_{y}^{Ny}\sum_{g}^{Ng}\sum_{h}^{Nh}\zeta * FOM(h) * C_{ygh} \tag{3.8}$$

Fixed Operation and Maintenance Cost of New and Existing Generation Resources

$$+\sum_{y}^{Ny}\sum_{g}^{Ng}\sum_{s}^{Ns}\sum_{h}^{Nh}\zeta * VOM(h) * P_{ygsh}\Delta_{s} \tag{3.9}$$

Subject to:

Power Balance (Energy Blocks)

$$\sum_{h=1}^{Nh} P_{ysgh} - \sum_{t=1}^{Nt} A^{T}(g,t)B_{yst} = D(y,s,g)\ \forall y,g,s \in S_{E} \tag{3.10}$$

Cumulative Generation Capacity

$$C_{ygh} = C_{0gh} + C_{ygh}^{New} - C_{ygh}^{Ret} \quad \forall\ y,g,h \tag{3.11}$$

Existing Generation Capacity

$$C_{0gh} = C_{0gh}^{Exist}(g,h) \quad \forall\ y,g,h \tag{3.12}$$

Maximum Output of New and Existing Generation Resources (Energy Blocks)

$$P_{ysgh} + RR_{ysgh}^{+} + CR_{ysgh} \le CF(g,h)C_{ygh} \quad \forall\ y,g,h,s \in S_{E} \tag{3.13}$$

Minimum Output of New and Existing Generation Resources

$$P_{ysgh} - RR_{ysgh}^{-} \le 0 \quad \forall\ y,g,h,s \in S_{E} \tag{3.14}$$

Regulation-Up Reserve Requirement

$$\sum_{g=1}^{G}\sum_{h=1}^{Nh} RR_{ysgh}^{+} \ge \alpha * \sigma_{NL}^{1min+} \quad \forall\ y,h,s \in S_{E} \wedge g \in G_{k} \tag{3.15}$$

Regulation-Down Reserve Requirement

$$\sum_{g=1}^{G}\sum_{h=1}^{Nh} RR_{ysgh}^{-} \geq \beta * \sigma_{NL}^{1min-} \quad \forall\, y,h,s \in S_E \wedge g \in G_k \tag{3.16}$$

Contingency Reserve Requirement

$$\sum_{g=1}^{G}\sum_{h=1}^{Nh} CR_{ysgh} \geq \gamma * D(y,s,g) \quad \forall\, y,h,s \in S_E \wedge g \in G_k \tag{3.17}$$

Regulation-Up Reserve Ramp-rate Requirement

$$RR_{ysgh}^{+} \leq rr_h^{1min} C_{ygh} \quad \forall\, y,h,s \in S_E \tag{3.18}$$

Regulation-Down Reserve Ramp-rate Requirement

$$RR_{ysgh}^{-} \leq rr_h^{1min} C_{ygh} \quad \forall\, y,h,s \in S_E \tag{3.19}$$

Contingency Reserve Ramp-rate Requirement

$$CR_{ysgh} \leq rr_h^{10min} C_{ygh} \tag{3.20}$$

Kirchhoff's Voltage Law

$$\theta_{ysgi} - \theta_{ysgj} = X_t (B_{yst}) \tag{3.21}$$

Total Transmission Capacity

$$T_{ykt} = T_{ykt}^{Exist} + \sum_{k=1}^{Nk} T_{ykt}^{New} - T_{ykt} \leq B_{yskt} \leq T_{ykt} \quad \forall\, y,s,t \tag{3.22}$$

Maximum New-Transmission Capacity

$$T_{ykt}^{New} \leq T_{ykt}^{Max} \quad \forall\, y,s,t \tag{3.23}$$

Maximum New-Generation Capacity

$$C_{ygh}^{New} \leq C_{ygt}^{Max} \quad \forall\, y,s,t \tag{3.24}$$

$$Bounds: C_{ygh}^{New}, C_{ygh}^{Ret}, P_{ysgh}, T_{ykt}^{New}, RR_{ysgh}^{+}, RR_{ysgh}^{-}, CR_{ysgh} \geq 0 \tag{3.35}$$

3.4. Modeling the effects of renewables variability on operating reserves within CGT-Plan

Assuming that forecasting errors are independent and normally distributed the total regulation up and down requirements can be represented as the square root of the sum of load, wind and solar variances. The appendix includes the linearization of Eq. (3.15) and (3.16). Figure 3-1 shows a comparison between the non-linear and linear approximation of the reserves requirements and its relationship with actual market data gathered from the BPA website. Although Krishnan's approach tends to overestimate reserves requirements, the linear approximation performs better than the non-linear relationship at higher levels of renewables.

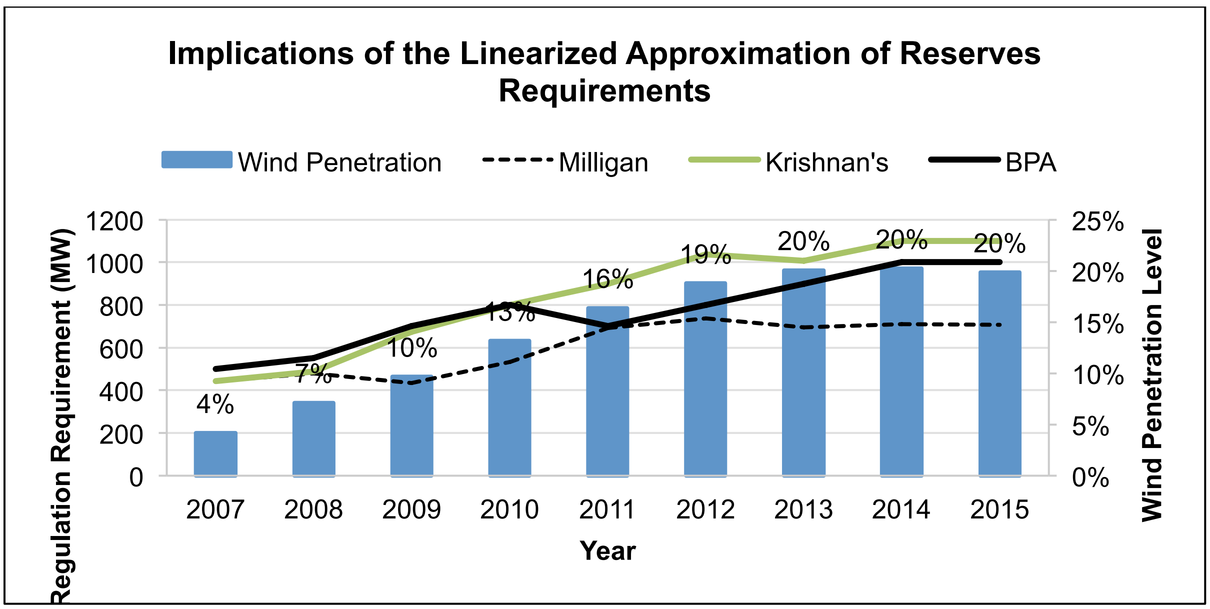

Figure 3-1: Implications of the linear approximations of reserves requirements

As observed in Fig. 3-1, the linear approximation tends to slightly overestimate the reserves requirements under the assumption that the nonlinear approach is the “correct one”. In this work, the linear approximation is adopted for the determination of the RHS of Eq. (3.15) and Eq. (3.16), under the assumption that the effect the difference (up and down) between approaches will not influence investment decisions in CEP studies at the national level.

Effects of operating reserve requirements on investment decisions

In this section, the effects of the methodology described in the previous section on generation and transmission investment decisions are explored. A 28-bus representation of the EI is used as a test case. The complete database and assumptions can be found in (Eastern Interconnection Planning Collaborative (EIPC), 2011). The 28-bus representation of the EI is shown in Fig. 3-3.

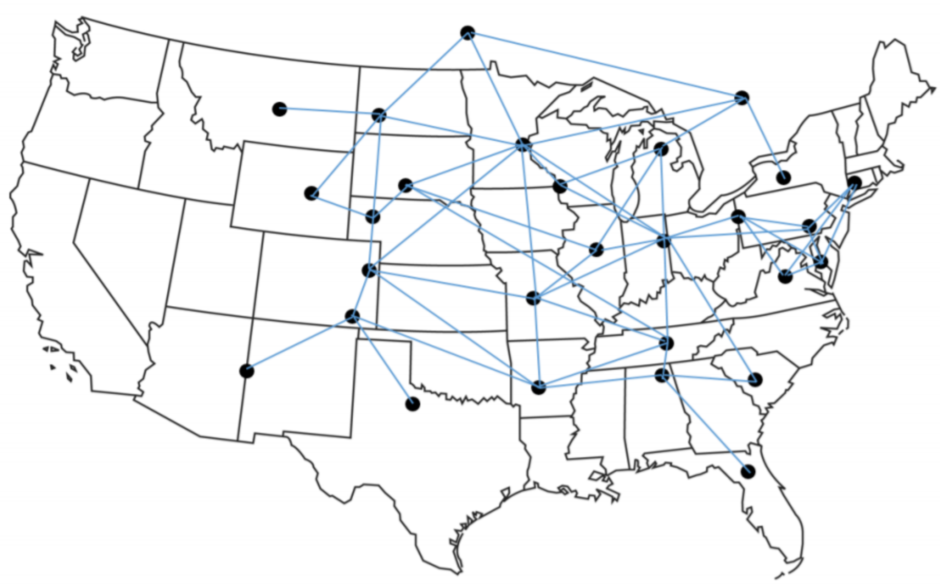

Figure 3-2: 24-bus representation of the EI grid

Benchmarking

The CGT-Plan model presented in Chapter 3 was implemented in Matlab as a Mixed-integer linear programming (MILP) model. The model was benchmarked against two other software; PLEXOS (a commercial-grade software), and JASMINE (an academic-grade software developed at John Hopkins University). Two metrics were used to verify the functionality of CGT-Plan: economics and investment decisions. All software makes use of similar basic assumptions, but the formulation and implementation techniques are proprietary information. This makes it difficult to have an exact comparison. For this reason, the benchmarking was done on a high-level basis to test the performance of CGT-Plan. Tables 3-1 and 3-2 show the economic summary and investments comparison between software. This high-level comparison confirms that CGT-Plan provide results that are consistent with PLEXOS and JASMINE. In Tables 3-3 and 3-4, a comparison between the transmission investments and retirements is shown.

Table 3-1: Economics Summary

Component	**PLEXOS**	**JASMINE**	**CGT-Plan**
Total NPV	2,465.0	2,266.0	**2,404.4**
Gen. Investment Cost	403.0	747.0	**367.5**
Tx. Investment Cost	49.6	41.0	**58.1**
Production Cost	1,173.0	1,443.0	**1,036.3**

Table 3-2: Summary of generation investments

Technology	PLEXOS	JASMINE	CGT-Plan
NGCC	251	218	**271.8**
Coal	12.0	8	**11**
CT	66	63	**83.5**
Hydro	44.0	57.3	**44.8**
Nuclear	132.1	135	**154.0**
Onshore Wind	302.9	278	**272.3**
Offshore Wind	0	0	**0**
Pumped Storage	17	17	**17.1**
DSM	151	153	**148.0**

Table 3-3: Cumulative transmission expansion

	PLEXOS	JASMINE	CGT-Plan
Total (transportation model)	71.6	112.9	**76.3**

Table 3-4: Cumulative generation retirements

	PLEXOS	JASMINE	CGT-Plan
Total	402	432	**390.1**

Cost breakdown with and without the reserves constraints

The effects of modeling operating reserves as a function of net-load variability within the CGT-Plan model on the economics are shown in Table 3-5. As expected, the objective value increases when operating reserves are accounted for. In particular, more Natural Gas Combined Cycle (NGCC) units are built, as shown in table 3-6. The reason is that NGCC is a technology option with one of the highest ramp rate and lowest operating cost.

Table 3-5: Economic summary with and without reserves constraints

Component	w/o Reserves	w/Reserves	Difference
Total NPV	2,404.4	2,426.4	**1.0%**
Generation Investment Cost	367.5	370.9	**8.0%**
Transmission Investment Cost	58.1	57.8	**(0.50%)**
Production Cost	1,036.3	1,037.4	**0.10%**
Fixed O&M Cost	306.6	306.8	**0.07%**

Table 3-6: Economic summary with and without reserves constraints (continuation)

Emission Cost	693.2	691.1	**(0.33%)**
Wheeling Charges	111.6	116.1	**4.0%**
Regulation Cost	0	6.5	**N/A**

Table 3-7: Differences by technology

Technology	**w/o-Reserves**	**w/Reserves**	**% Difference**
NGCC	271.8	278.9	**2.6%**
CT	83.5	82.6	**(1.1%)**
Onshore Wind	272.3	273.7	**0.5%**
Offshore Wind	0	0	**0%**
Transmission	76.3	76.0	**(0.4%)**

Results from this section provided two insights: 1) including operating reserves in capacity expansion planning models increases the cost and capacity requirements, thus making generation technologies with high ramping capability such as NGCC more attractive than other technologies, 2) transmission investments are decreased because of the need of each region to meet operating reserves requirements using local generation resources. The effect of lifting this assumption and allowing regions to share this reserve is studied in Chapters 5-7.

3.5. Accounting for net-load diversity and deliverability of reserves

In order to account for the deliverability of generation resources, a new set of power balance constraints are defined for the set of peak-load blocks. By adding this constraint, the model is allowed to procure the most economic generation resources and at the same time, the deliverability of these reserves is enforced. Equations (3-26)-(3-28) show the additional constraints.

Power Balance Constraint (Peak-load Blocks)

$$\sum_{g}^{Ng}\sum_{h}^{Nh} P_{ysgh} - \sum_{t=1}^{Nt} A^{T}(g,t)B_{yst} = \sum_{g}^{Ng} D(y,s,g) \;\; \forall\, s \in P \wedge G \in G' \tag{3.26}$$

Maximum Power Output of Generation Resources During Its Own Peak

$$(1-FOR(h)) * P_{ysgh} \le CC(g,h) * C_{ygh} \;\; \forall\, y, G, h, s \in P \tag{3.27}$$

Maximum Power Output of Generation Resources When A Different Regions is Peaking

$$(1-FOR(h)) * P_{ysgh} \le CF(g,h) * C_{ygh} \;\; \forall\, y, h, s \in P \wedge G \notin G' \tag{3.28}$$

An illustrative example is shown below to describe the differences between traditional modeling of PRM constraints and the approach developed in this dissertation. In Fig. 3.3, both transmission and generation resources are allowed to be build. Only the coincident peak-load block is used for the expansion planning simulation. Two other cases are included to study the effects of modeling capacity sharing within CGT-Plan. In case 1, local resources must meet the PRM requirement. The investment cost of new generation is assumed to be \$700,000/MW, and for transmission is assumed to be \$3,000,000/MW. The existing capacity of line 1-2 is 1 GW, line 2-3 is 5 GW and line 3-1 is 0 GW. Also, a load diversity value is assumed for each pair of regions. The load diversity between areas 1-2 is 6 GW, 2-3 is 6 GW and 3-1 is 8 GW. The operational, load and cost assumptions for each region are shown in Fig. 3.3. Table 3-8 shows a summary of the results. As expected, no transmission is built in the first two cases. In case 1, the regional PRM is a hard constraint and using transmission is not an investment option. Although building new transmission is an option in Case 2, is more economical to build new generation in the area with the cheapest production cost. When load diversity is accounted for, and when deliverability is enforced, the model makes use of new transmission to facilitate capacity sharing between areas. Figures (3.4)-(3.6) show the resulting power flows for each Case.

Table 3-8: Summary of results (3-bus system)

Examples	**Planning Cost (B$)**	**New Gen**	**New transmission**
Case 1	9.8517	14,000 MW	-
Case 2	8.4517	12,000 MW	-
Case 3	1.8094	-	5,000 MW

Figure 3.3 shows a conceptual representation of the 3-bus test system. It includes the operational and cost data associated with each bus. The investment options are: local CT generation and new transmission.

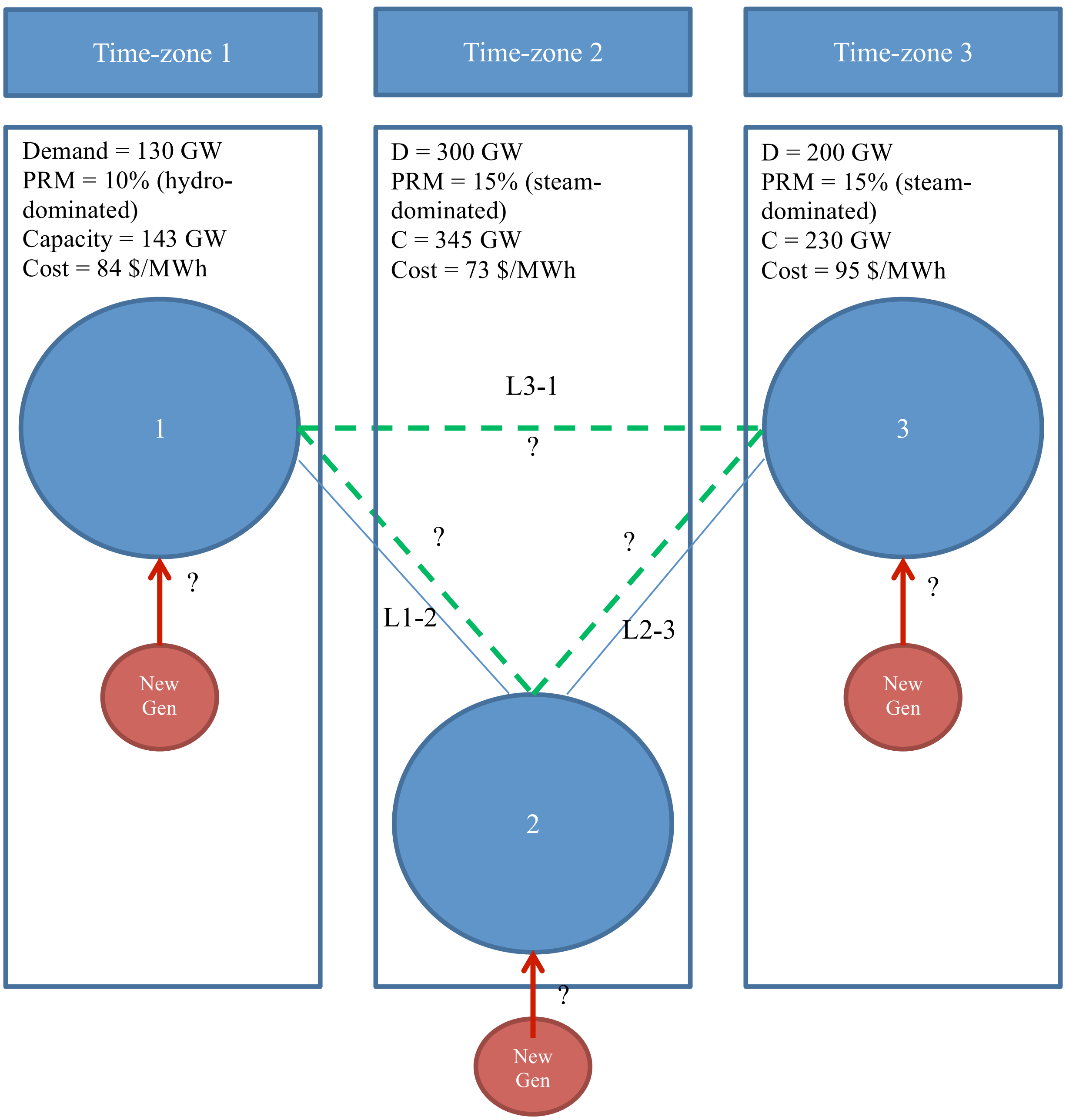

Figure 3-3: 3-bus Test System

The resulting power flow of Case 1 is shown in Fig. (3.4). The low production cost of Area 2 makes it a net exporter and all areas comply with their own PRM requirements using local generation resources.

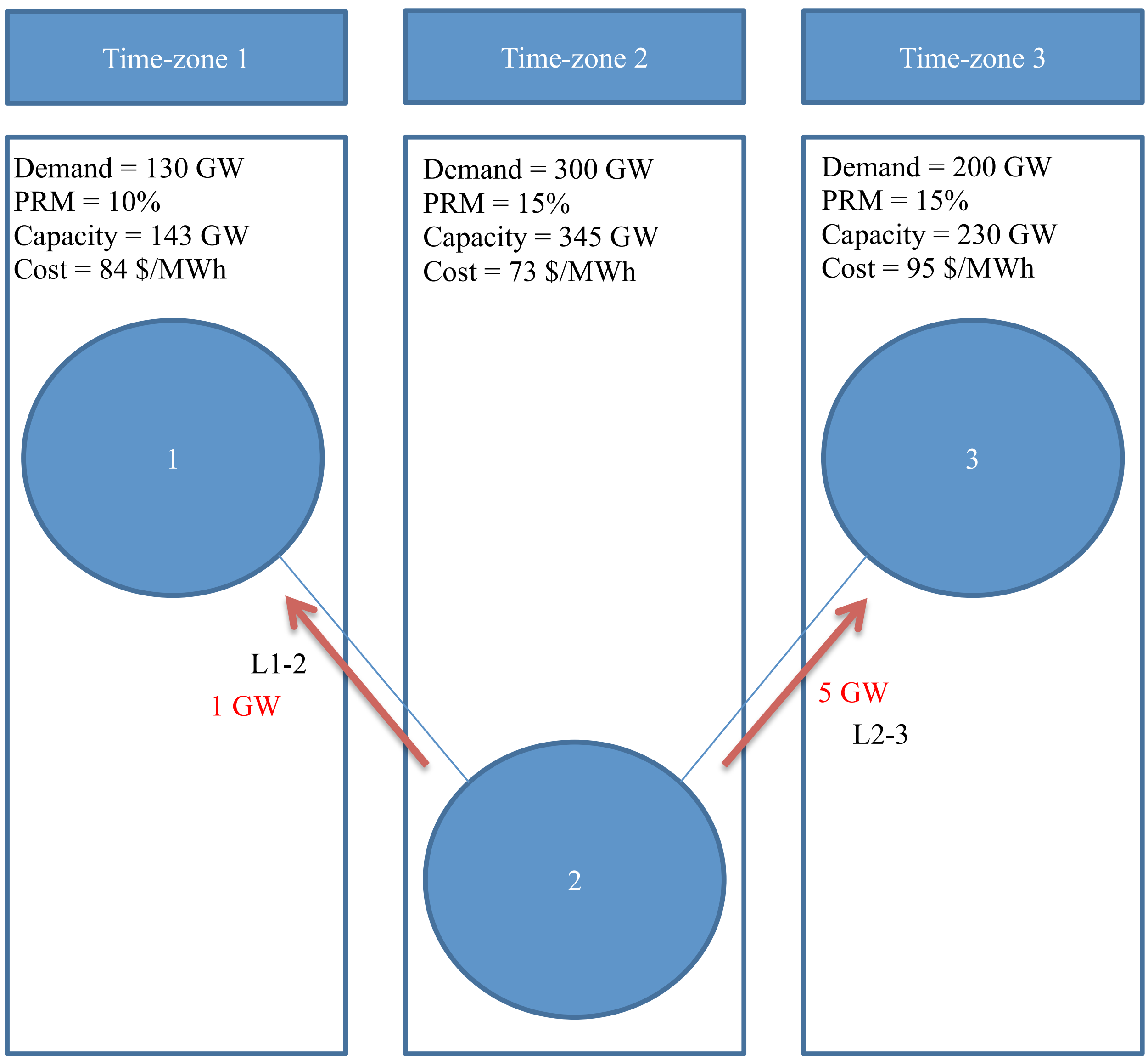

Figure 3-4: Case 1: Capacity sharing is disabled

When areas 1, 2, and 3 are allowed to share reserves, the power flow patter remains the same, but the total planning cost is reduced. This is due to the fact that the deliverability of the PRM is neglected and the operating condition corresponds to a coincidental peak-load.

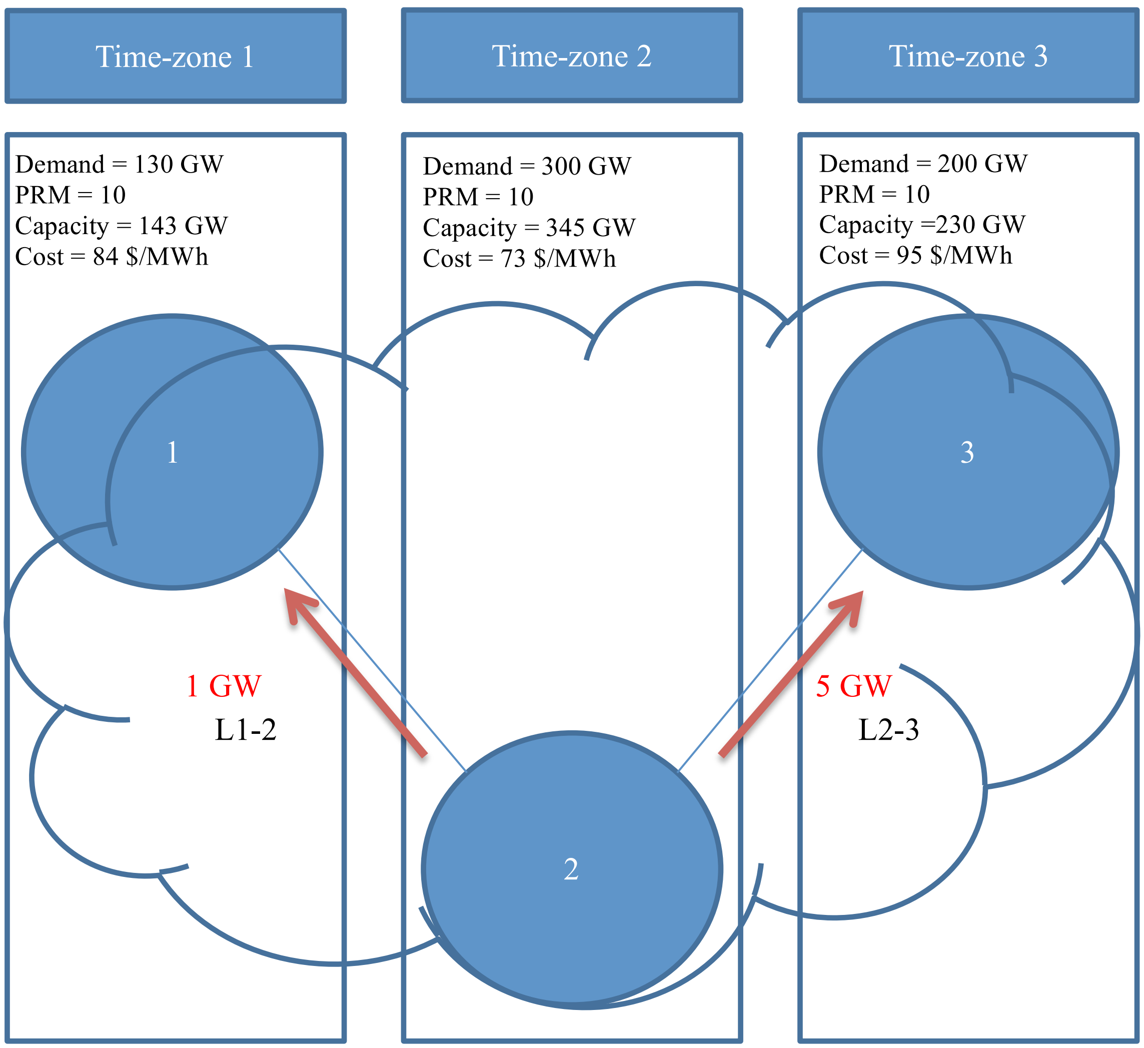

Figure 3-5: Capacity sharing is enabled

The inclusion of load diversity and deliverability allows area 2 to increase its export capability and reduces the overall planning cost. The new transmission displaces the generation that was built in Cases 1 and 2.

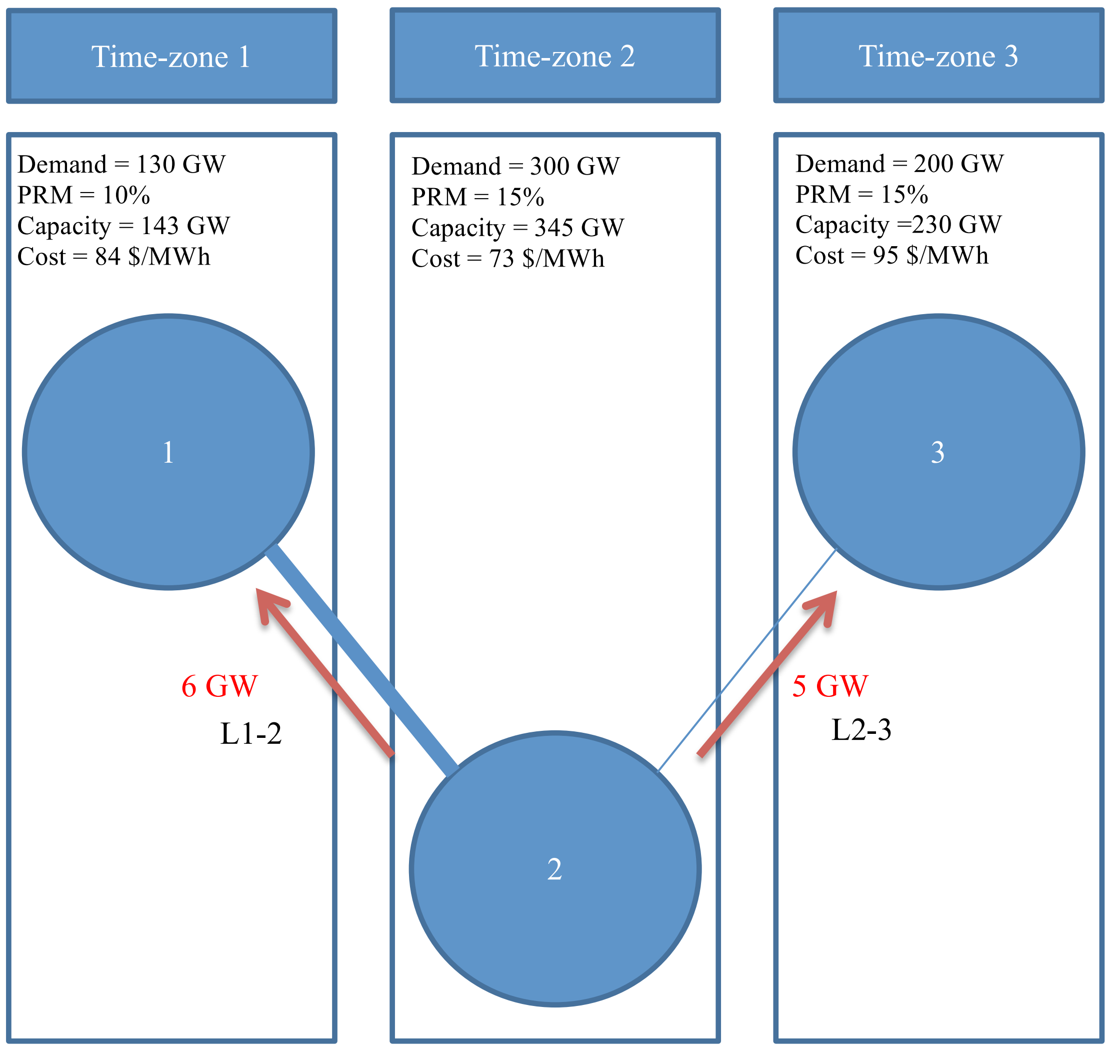

Figure 3-6: Case 3: Capacity sharing is enabled and net-load diversity is accounted for

Table 3.7 shows the economic and investment summary for each case. Case 3, which accounts for load diversity, deliverability and capacity sharing results in the lowest planning cost. Three main conclusions can be drawn from the illustrative example presented in this section:

1. Accounting for load diversity facilitates capacity sharing during non-coincident peak load times.
2. Generation capacity required to meet future PRM obligations is displaced when the planning reserve constraint is defined without deliverability.
3. The model guarantees that capacity will be delivered.
4. The model accounts for both the energy and capacity requirements.

The CGT-Plan software developed in this dissertation accounts for the three modeling features presented in this chapter: operating reserves requirements, capacity sharing during non-coincident peak-load times and deliverability of planning reserves. A 168-bus representation of the contiguous US is presented in the following chapter. This industry-vetted model is used to illustrate the modeling features discussed in this chapter and quantify the economic benefits of increasing transmission capacity between the EI and WI. Assumptions about data sources, forecast data, and cost data are also included in the subsequent chapter.

Table 3-9: 3-bus test system summary

		Case1	Case2	Case3
Investment	G1	4 GW	-	-
	G2	5 GW	12 GW	-
	G3	5 GW	-	-
	L1-2	-	-	5 GW
	L2-3	-	-	-
	L3-1	-	-	-
Dispatch	G1	129 GW	129 GW	127 GW
Dispatch	G2	306 GW	306 GW	329 GW
Dispatch	G3	195 GW	195 GW	220 GW
Cost		9.8517 B$	8.4517 B$	1.8096 B$
EENS (N-1)		0	0	0

CHAPTER 4. STUDY FRAMEWORK, DATA ASSUMPTIONS, AND DESIGN PROCESS

The study framework adopted for designing the four infrastructures defined in Chapter 1 consisted of the following four primary tasks:

1. Development of a CEP model for the contiguous US.

2. Development of typical operating blocks to approximate the production cost and account for the diurnal net-load diversity between regions.

3. Development of typical peak-load conditions to account for annual net-load diversity.

4. Selection of candidate transmission lines using a simple, yet effective, algorithm based on a static CEP model.

A robustness analysis is included to test the assumptions about the number of energy blocks, peak-load blocks and their effect on transmission candidate lines.

4.1. Database Development

This section summarizes assumptions on conditions significantly influencing electric generation and transmission investment and the associated cost for the US between the years 2024 and 2038. In addition, this section includes the assumptions on which the "initial" conditions are based (these are the conditions for the year 2024). An overview summary of these 2024-2038 assumptions is provided in Section. There are 17 specific assumptions. These are shown in Table 4-1.

Table 4-1: Summary of assumptions

#	Attribute	Assumptions (2024-2038)
1	RPS	DSIRE
2	CO_2 policies	\$3/MTON/year starting from 2024
3	Real discount rate	5.7%
4	Inflation	3%
5	Demand growth	EIPC for EI; E3 for WI
6	DG growth	AEO 2016
7	Forced generation retirements	EIPC for EI; JHU/WECC for WI
8	Planned generation builds	Include only those w/ signed interconnection agreements, consistent with ERGIS/LCGS
9	Fuel cost forecasts	AEO 2016: Hi Gas
10	Generation investment base costs	NREL ATB 2016
11	Gen investment cost regional multipliers	EIPC for EI; WECC for WI
12	Capacity reserve requirement	12%-18%, varies by region
13	Technology maturation rates	NREL ATB
14	Transmission technologies available for investment	DC: 500,600,800kV for LCC; others for VSC AC: 345, 500, 765 kV
15	Transmission base costs	Black & Veatch 2014 WECC Report
16	Transmission investment cost regional multipliers	EIPC for EI; Black & Veatch 2014 Terrain Multipliers for WI
17	Time Slices	15 energy time slices; 4 peak time slices

Existing generation portfolio

Conventional generation, hydro, and load data corresponding to year 2024 was gathered from NREL. Typical capacity factors (CF) and forced outage rate (FOR) values for conventional existing generation resources were extracted from the EIA. Each conventional existing generator is energy-limited by its capacity factor and capacity limited by a weighted averaged forced outage rate.

Initial 335-bus model of the US grid

Western Interconnection Model

Gaussian elimination was used to create a reduced network equivalence of the TEPPC 2026 power flow case. 260 buses were selected and preserved, to preserve some of the key paths in the WECC region, as defined in TEPPC 2026. Gaussian elimination creates fractional mapping, such that load and generation of an eliminated bus is distributed in fractions to the preserved buses. The fractional mapping was used to relocate load of eliminated buses in fractions, whereas the highest fraction was selected to relocate generation of eliminated buses integrally. Dr. Hussam Nosair developed the code and the 260-bus model for the WI.

Eastern Interconnection Model

The network topology of the Eastern Interconnection was gathered from the Midcontinent Independent System Operator (MISO). A total of 61 buses representing control areas and/or balancing authorities and 7 buses representing existing B2B ties with WECC were defined. The software TARA was used to calculate transfer limits between connected buses under N-1 conditions. Finally, equivalent impedance was estimated for each interface based on knowledge of voltage level connecting each pair of regions. We assumed that the transmission infrastructure in 2024 would comply with minimum design standards. Figure 4-1 shows the 335-bus representation of the contiguous US.

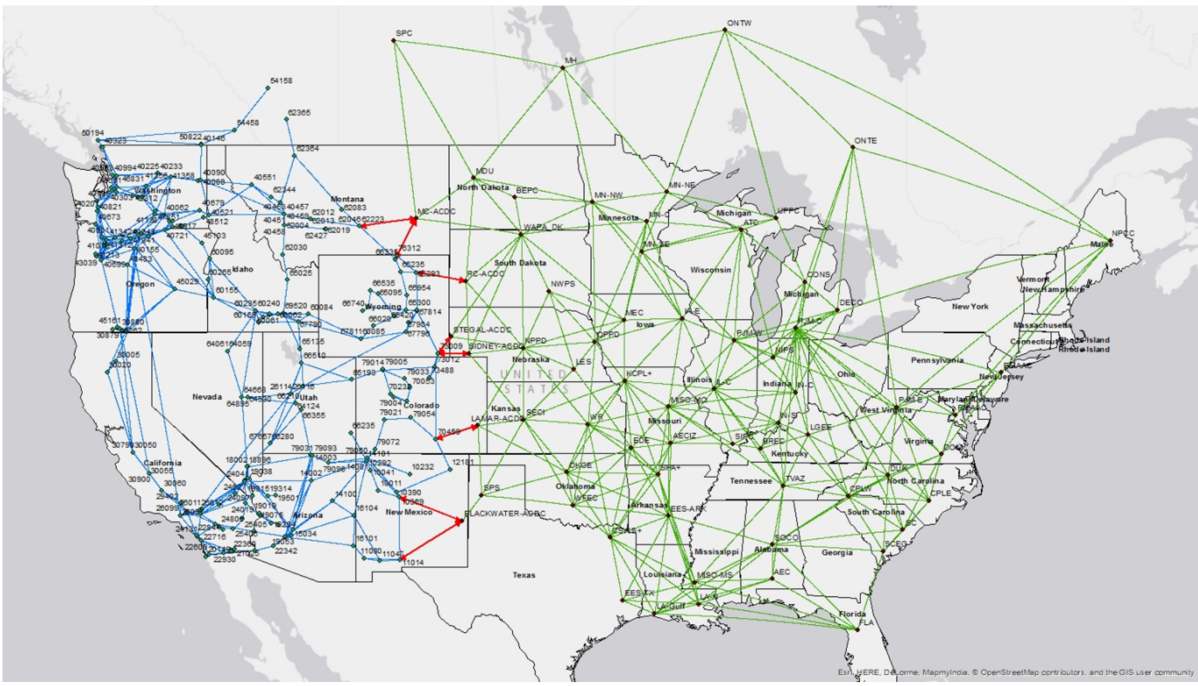

Figure 4-1: Initial 335-bus representation of the US grid

Reduced 169-bus model of the US grid

In order to improve the computational time, an additional reduction was performed to the WI model. Figure 4-2 shows the reduced 101-bus WI model. The 61-bus EI model shown in Fig. 4-3 was preserved.

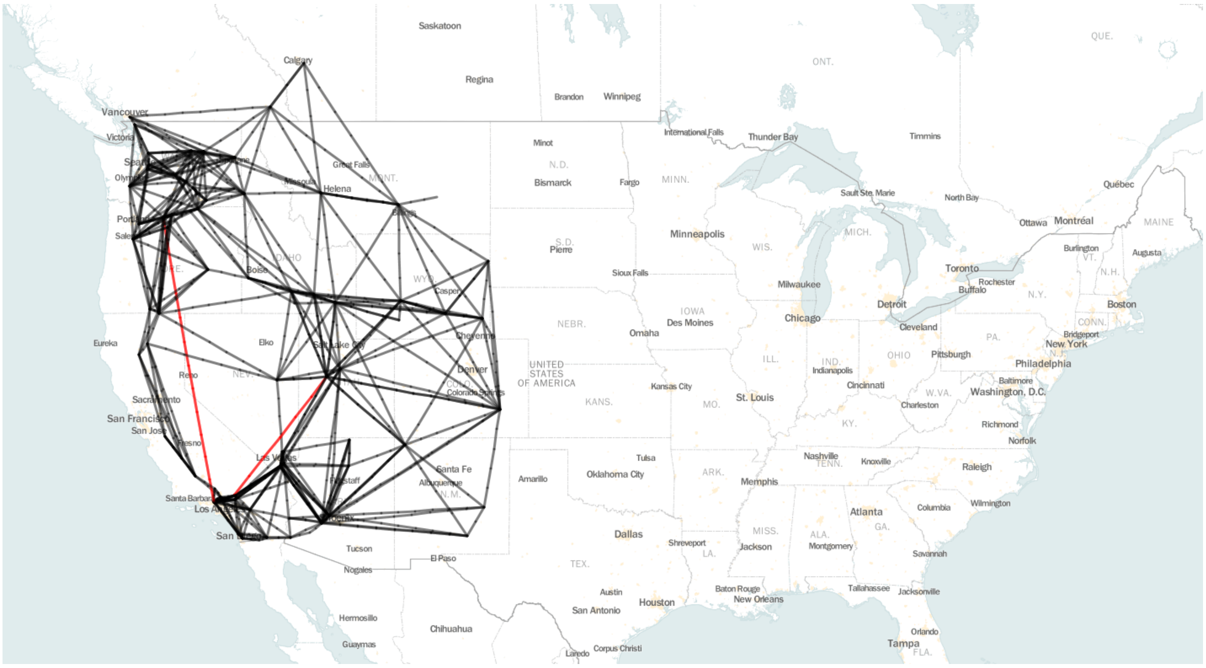

Figure 4-2: Aggregated model of the WI

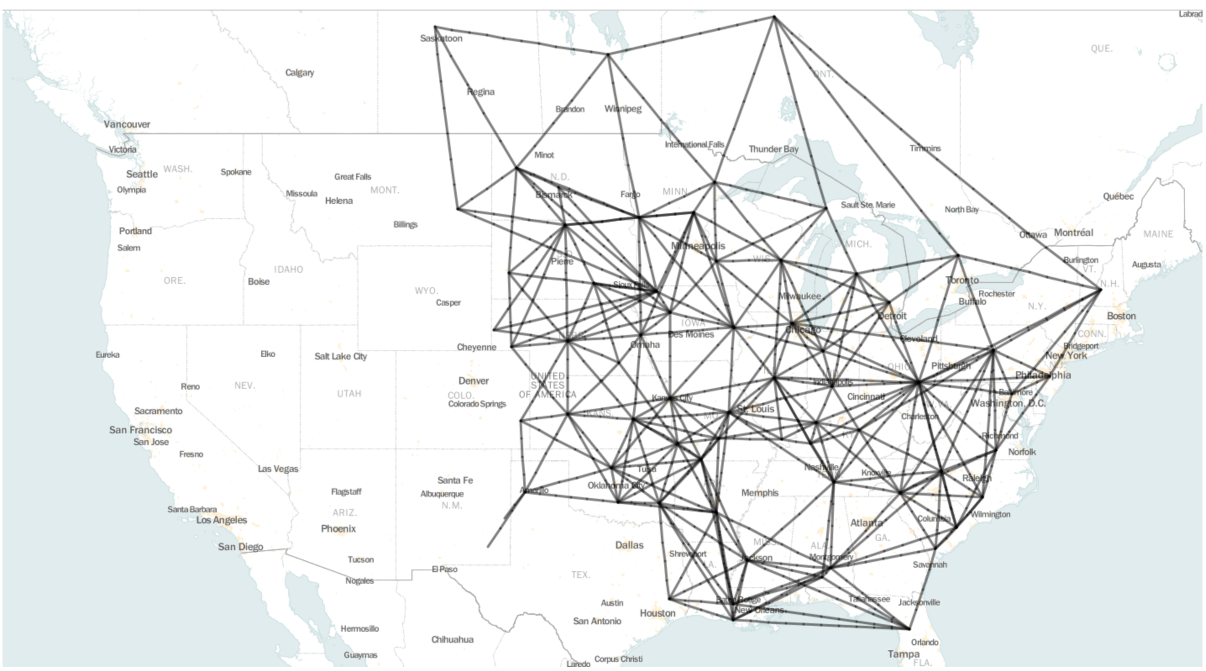

Figure 4-3: Aggregated model of the EI

Wind and Solar Profiles

Hourly wind, solar, and hydro shapes were provided from NREL. The wind profiles make use of the newly developed WindToolkit, which includes more than 100,000 locations for the contiguous US. A unique feature of this database is that all profiles correspond to 100-m towers. The use of wind profiles adjusted to 100-m results in more sites with good resource potential, as shown in Fig. 4-4. Solar profiles were gathered from NREL.

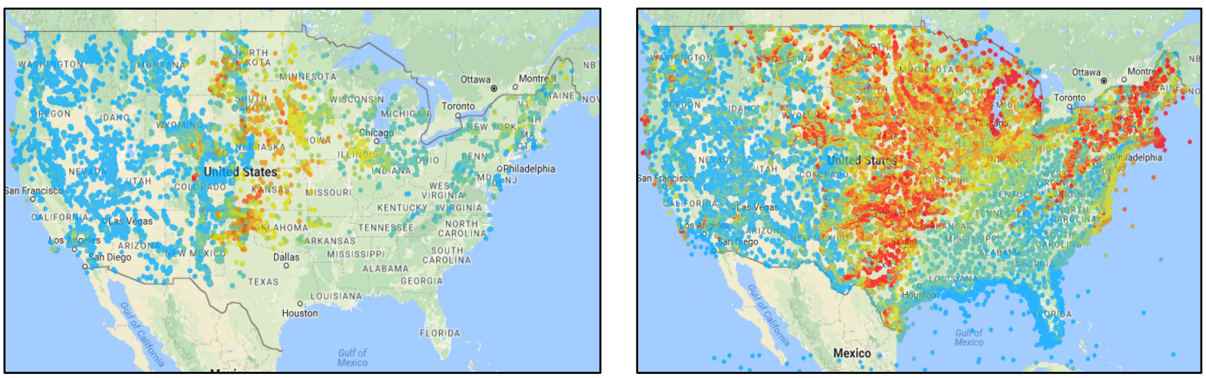

Figure 4-4: 80-m vs.100-m Wind Sites

Clustering of wind and solar sites

The process developed for grouping wind and solar sites was based on using GIS mapping information to map wind and solar sites to the closest CEP bus. Figure 4-5 shows the wind and solar clusters used to approximate the resource potential within each region. This data was then used in the CGT-Plan model as a parameter to limit the amount of wind and solar investments on a per bus basis. The process used the minimum-distance algorithm and a fixed radio of 30 miles to differentiate between buses.

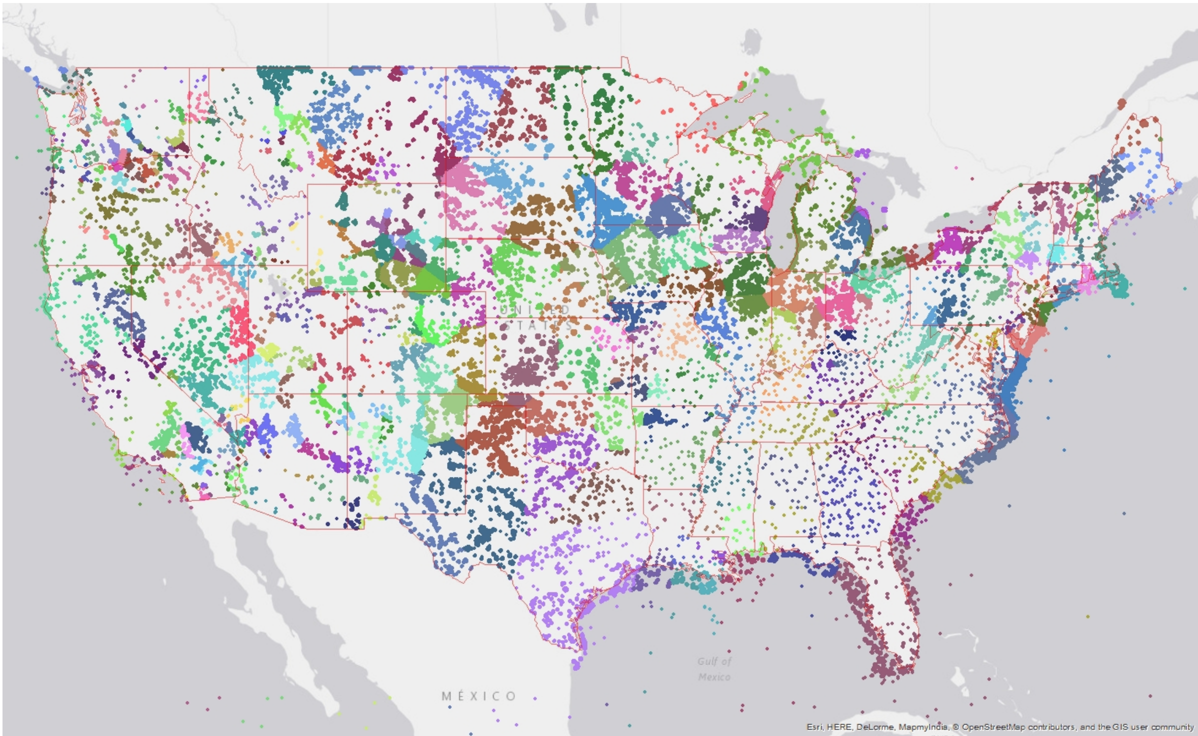

Figure 4-5: Wind/Solar Clustering

Renewable Portfolio Standard (RPS)

A state level renewable portfolio standard (RPS) is used for this study. The information about RPS targets and the contribution requirements from each renewable generation technology was gathered from (DSIRE, 2017), as shown in Fig. 4-6. Two additional steps were required to map state-level RPS percentages to the corresponding bubble. The following list describes the mapping and allocation process:

1. The geographical location of each bubble was used to map group of bubbles with its corresponding state.

2. The RPS requirement for each state was broken down into n-years, where n represents the difference in the number of years between the year of the RPS target and the first year

of the planning horizon (2024). For example, the state of CA has a 50% RPS requirement by 2030. This requirement was broken down into 7 RPS requirements that increase linearly at 3% per year starting with 33% in 2024 and ending with a 50% in 2030. It is also assumed that years in the planning horizon beyond the RPS target will have a fixed RPS requirement, equivalent to the RPS target.

3. The RPS requirement is modeled as an equality linear constraint at the state level. Each group of bubbles within a state is required to generate a specific percentage of the total demand with renewable resources. Fig. 7 includes the RPS allocation by year.

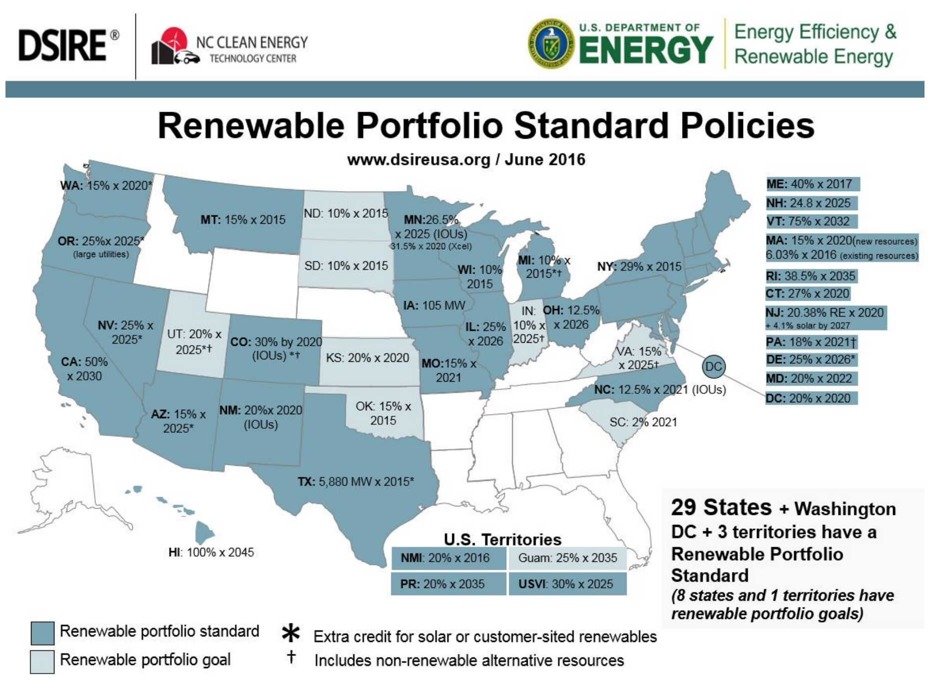

Figure 4-6: RPS Map per State

RPS by State (Ref: http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2014/11/Renewable-Portfolio-Standards.pdf)															
State	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
WA	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
OR	3%	7%	10%	13%	17%	20%	23%	27%	30%	33%	37%	40%	43%	47%	50%
CA	33%	36%	39%	42%	44%	47%	50%	50%	50%	50%	50%	50%	50%	50%	50%
NV	23%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
MT	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
UT	18%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
AZ	13%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
CO	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
NM	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
ND	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
SD	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
KS	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
OK	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
MN	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
MO	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
WI	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
IL	21%	23%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
IN	8%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
MI	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
OH	9%	11%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
NY	7%	14%	21%	29%	36%	43%	50%	50%	50%	50%	50%	50%	50%	50%	50%
VA	13%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
NC	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
SC	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%

Figure 4-7: Allocation of RPS per year

CO2 Tax Policy

Carbon tax is assumed to be along the lines of Initiative-732 by the state of Washington, which proposed to impose a carbon tax of $3/MMTCO$_2$/yr. Even though the initiative was rejected, it provides a direction in which carbon taxes may be headed and remains a good model for other states to try and replicate.

Real Discount Rate

Taking a cue from the Regional Energy Deployment System (ReEDS) by NREL, real discount rate is assumed at 5.7%.

Inflation

Inflation is assumed at 3%, consistent with assumptions made in the NREL Renewable Electricity Futures Study.

Demand Growth

The expected rate of demand growth and peak demand growth were obtained in percentages from EIPC modeling assumptions for the EI and from E3 for the WI (Eastern Interconnection Planning Collaborative (EIPC), 2011). Data for the EI was available per NEEM region (Table 4-2) which was then mapped to the MISO 68-bus model. Similarly, data for the WI was available per state (Fig. 4-9), which was then mapped to the 101 WI buses. Mapping between the MISO 68-bus model and NEEM regions, and between 101 WI buses and the western states was performed by inspection, by overlaying a map of the buses on a NEEM regions/western states map, respectively.

Distributed Generation (DG) Growth

Distributed generation (DG) is assumed to be a constant parameter that increases at a fixed rate, consistent with the 2016 Annual Energy Outlook (AEO). Generation capacity of renewable-based DG is assumed to increase at rate of 6.9% per year, and 2.4% per year is assumed for natural gas DG as shown in Fig.8.

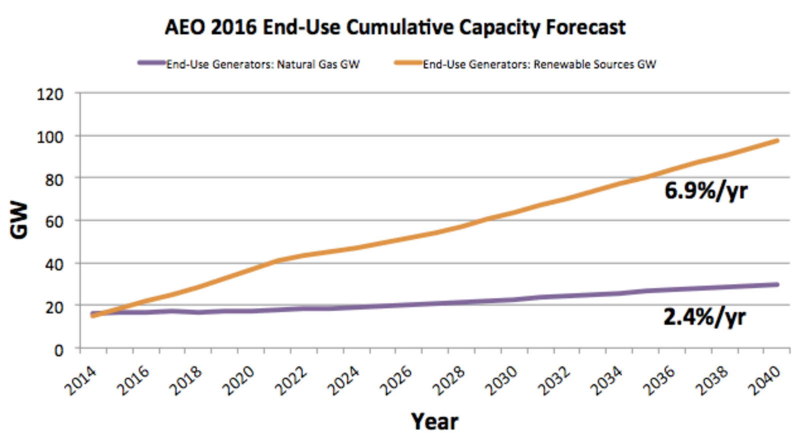

Figure 4-8: DG Growth Rate

Table 4-2: Demand growth assumptions for the EI

NEEM Region	2020-2050 Peak Demand Growth Rate	2020-2050 Demand Growth Rate
AZ_NM_SNV_Coal	1.31%	1.31%
ENT	0.53%	0.53%
ERCOT	0.65%	0.65%
FRCC	1.24%	1.24%
MAPP_US	0.78%	0.78%
MISO_IN	0.61%	0.61%
MISO_MI	0.79%	0.79%
MISO_MO_IL	0.82%	0.82%
MISO_W	0.78%	0.78%
MISO_WUMS	0.66%	0.66%
NE	0.78%	0.78%
NEISO	0.12%	0.00%
NonRTO_Midwest	0.49%	0.49%
NP15	1.00%	1.00%
NWPP_Coal	0.94%	0.94%
NYISO_A-F (Note A)	0.51%	0.51%

Table 4-3: Demand growth assumptions for the EI (continuation)

NYISO_G-I (Note A)	0.85%	0.85%
NYISO_J-K (Note A)	0.88%	0.88%
PJM_E	0.67%	0.67%
PJM_ROM	0.67%	0.67%
PJM_ROR	0.61%	0.61%
RMPA	1.27%	1.27%
SOCO	0.81%	0.81%
SP15	1.00%	1.00%
SPP_N	0.91%	0.91%
SPP_S	0.64%	0.64%
TVA	0.49%	0.49%
VACAR	0.96%	0.96%
ALB	1.41%	1.41%
BC	0.96%	0.96%
IESO	0.68%	0.67%
MAPP_CA	0.78%	0.78%

Western Region	2008 Peak (MW)	2020 Peak (MW)	%	2008 Load (GWh)	2020 Load (GWh)	%
AB	8,570	10,695	1.9%	59,910	75,526	1.9%
AZ	20,560	27,607	2.5%	97,454	136,953	2.9%
BC	9,950	11,521	1.23%	56,877	67,444	1.43%
CA	62,946	73,738	1.3%	298,945	345,566	1.2%
CFE	1,645	2,716	4.3%	8,942	15,521	4.7%
CO	11,041	14,382	2.2%	67,582	85,707	2.0%
MT	1,620	1,888	1.3%	10,293	11,994	1.3%
NM	3,290	4,324	2.3%	19,913	25,692	2.1%
NV	1,737	2,173	1.9%	10,351	12,895	1.8%
NW	29,395	34,656	1.4%	177,186	208,898	1.4%
UT	10,157	13,696	2.5%	55,546	70,499	2.0%
WY	2,526	3,534	2.8%	14,579	21,139	3.1%
Total WECC	163,436	200,930	1.7%	877,576	1,077,835	1.7%

Figure 4-9: Peak load growth rate

4.2. Development of energy blocks

In order to capture the diurnal diversity of wind, solar, hydro and load, all time-series are shifted to a common time zone and a 5-block representation of a typical 24-hour period is used for production cost approximations. This approach is an adaptation from (Short, et al., 2011). In this work, we use the Eastern Standard Time (EST) zone as the reference. An average load, wind, solar, and hydro capacity factors, and a capacity requirement above net-load to account for regulation and contingency reserves requirements characterize each block. Three seasons were defined to capture the annual variation of wind, solar, hydro and load: winter (November, December, January, February), summer (May, June, July, August), and shoulder (March, April, September, October). These two assumptions led to the development of energy blocks which capture the diurnal net-load diversity across the different time zones in the contiguous US. Figure 4.10 shows a conceptual representation of the energy blocks.

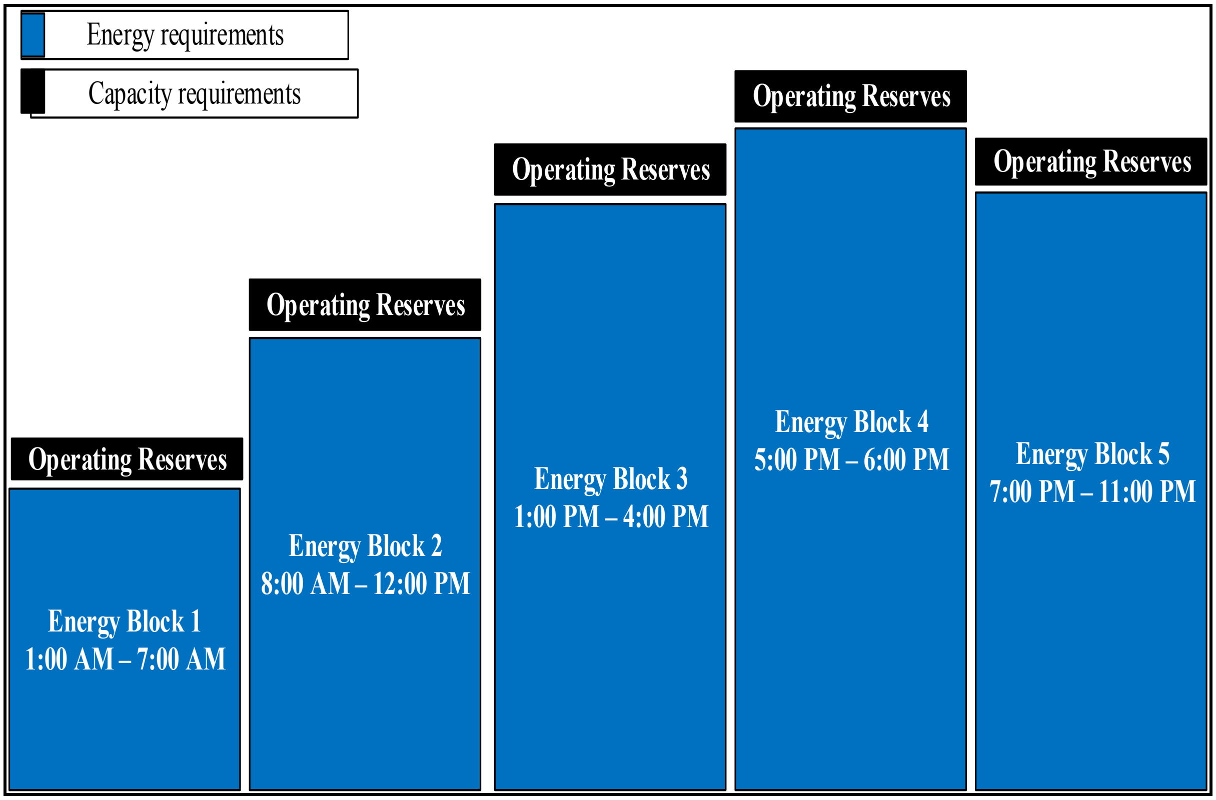

Figure 4-10: Average energy flow (Base Design)

4.3. Development of peak blocks

One-hour duration, non-coincident peak-load blocks are defined for each reserve-sharing group (RSG) within an interconnection. The number of RSGs plus one determines the total number of blocks. The last block represents the coincident peak net-load hour of the year for the entire grid. Each peak-load block P is characterized by the peak-load of the RSG that is peaking, an expected load for all others RSGs that are not peaking, a capacity credit for the RSG that is peaking and an expected capacity factor for all other RSGs that are not peaking. Also, a planning reserve margin above peak is enforced on each RSG peaking. The margin of this reserve is different for each region and depends on the regulations of each region, as defined by NERC. A proportional-based mechanism is proposed in this work to allocate load diversity amongst CEP buses. The total capacity that a region can contribute towards another region's peak is allocated based on load factors. Mathematically, the load diversity is included in the CEP formulation as follows. Once the peak-load date and time of each peaking region are identified, the demand of all other RSG (sometime referred as "the rest of the world") can be assumed to be the demand of these when a single RSG is peaking (1 hour).

The approach used in (Osborn, 2014) to calculate the historical minimum load diversity between RSG is used in this work. A description of the methodology is included below.

1. RSGs are defined based on some desired criteria (e.g. ownership, geographical location, RTO).

2. Net-load is aggregated for each RSG and shifted to a common time zone.

3. The difference between the peak load of a particular RSG and each individual RSG is determined. This difference is defined as net-load diversity (NLD).

4. The process is repeated for all interconnections.

5. The minimum NLD between interconnections is saved and defined as bilateral net-load diversity (BNLD).

The process is repeated for every year and the minimum of the 9-year available database is saved and defined as the minimum bilateral net-load diversity

(MBNLD). A proportional-based mechanism is proposed in this work to allocate load diversity amongst CEP buses. The total capacity that a region can contribute towards another region's peak is allocated based on load factors. Mathematically, the load diversity is included in the CEP formulation as follows.

Alternatively, a representative year can be used to parameterize Eq. (28). Once the peak-load date and time of each peaking region are identified, the demand of all other RSG (sometime referred as "the rest of the world") can be assumed to be the demand of these when a single RSG is peaking (1 hour). In Section 4.2, a comparison between these two approaches is presented. Furthermore, sensitivity about the total number of hours used for the load diversity calculations is presented.

4.4. Reduction of transmission candidate lines

A static CEP model was used to filter candidate lines with economic potential. The method consists of the following steps:

- Step 1: Run a static CG&T-Plan assuming 2024 conditions.
- Step 2: Run a static CG&T-Plan assuming 2032 conditions.
- Step 3: Run a static CG&T-Plan assuming 2038 conditions.

The set of candidate lines to be used in the full simulations is the union of Steps 1-3.

4.1 Software development

The illustrative and motivating examples presented in this Chapter were developed using a Mixed-Integer Linear Programming (MILP) model developed in Matlab. Given the complexity of the modeling requirements for the Seams Interconnection Study, the Dr. Jahanbani-Ardakani implemented the CGT-PLAN model presented in this chapter in GAMS. The author of this dissertation assisted during the coding stage, and contributed as described below:

1. Included a set of constraints to cap the total amount of investments for the planning horizon and on a per year basis.

2. Modified the code to a static CGT-Plan for the determination of candidate lines (more on this in the next chapter).

3. Modified the code and corresponding input file to change the number of energy and peak-load blocks.

CHAPTER 5. CO-OPTIMIZED BASE DESIGN RESULTS WITH CAPACITY SHARING

5.1. Introduction

This chapter includes the results from the Base Designs. The assumptions that are unique of this design are:

Assumption 1: The regions, as illustrated in Fig. 5-1, are allowed to share capacity to meet their own PRM obligations.

Assumption 2: A national 3$/MTON/year carbon tax is assumed.

Assumption 3: No state-level RPS is enforced.

The rest of this chapter is organized as follows. Section 5-2 includes the fundamental results. These include an economic summary and an infrastructure comparison between designs. Finally, Sections 5-3 to 5-7 include a discussion of each Design.

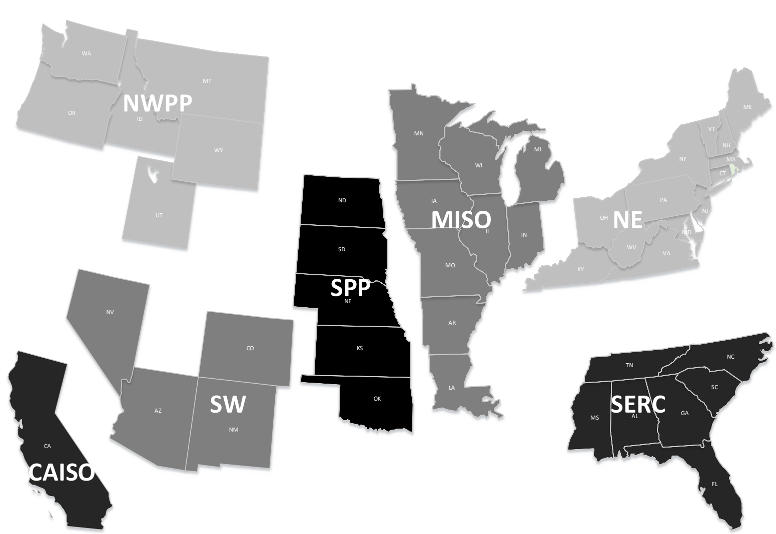

Figure 5-1: Definition of FERC regions

5.2. Fundamental Results

Table 5-1 shows the economic results for each design. A breakdown of the objective value is included. The performance of each design is compared against Design 1 and it is included in the "Delta" column.

Table 5-1: Economic Summary

ECONOMICS NPV $B	Design 1	Design 2a	Delta	Design 2b	Delta	Design 3	Delta
Line Investment Cost	61.21	73.89	12.68	74.88	13.67	80.1	18.89
Generation Investment Cost	704.03	703.32	-0.71	696.99	-7.04	700.51	-3.52
Fuel Cost	753.8	738.98	-14.82	737.3	-16.5	736.12	-17.68
Fixed O&M Cost	455.6	450.2	-5.4	448.95	-6.65	450.23	-5.37
Variable O&M Cost	64.5	63.9	-0.6	64.27	-0.23	64.39	-0.11
Carbon Cost	171.1	164.2	-6.9	162.6	-8.5	162.5	-8.6
Regulation-Up Cost	33.29	31.63	-1.66	29.96	-3.33	26.63	-6.66
Regulation-Down Cost	4.76	4.52	-0.24	4.29	-0.47	3.81	-0.95
Contingency Cost	24.41	23.19	-1.22	21.97	-2.44	19.52	-4.89
Total Non-Transmission Cost (Orange)	2,211.49	2,179.94	-31.55	2,166.33	-45.16	2,163.71	-47.78
15-yr B/C Ratio (Orange/Blue)	-	-	2.48	-	3.30	-	2.52
Perpetuity (post-2038 Op) Cost	61.21	73.89	12.68	74.88	13.67	80.1	18.89

The most relevant economic-related finding is that all designs "pay by themselves". This is shown in the Benefit/Cost ratio row. The benefits are defined as the summation of all "delta" terms except the transmission investment cost. The cost (denominator) is defined as the transmission delta. The major value driver is fuel cost, but other components such as the carbon cost and operating reserves also influence the value of each design. Design 3 outperforms other designs, although the difference is small.

When looking at the total emissions (Fig. 5-2), there is not a significant difference between designs. Designs 2a and 2b outperform Design 3 in the early years, but then, Design 3 results in less CO2 emissions. This is mainly driven by solar investments in the EI when the capacity of the macro-grid increases.

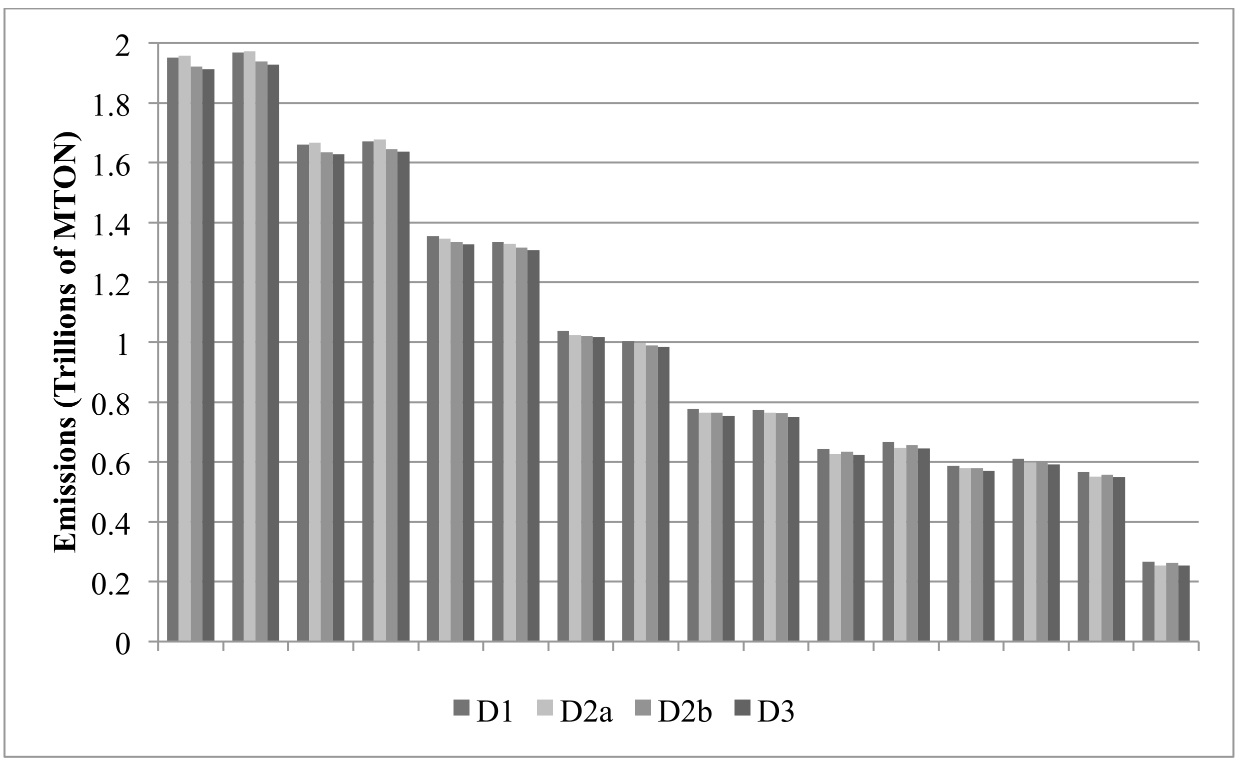

Figure 5-2: Base Designs - CO2 Emissions

In terms of retirements, Design 3 shows a higher amount of gas and oil retirements, compared to Designs 2a and 2b. The ability of Design 3 to "displace" generation capacity required to meet PRM on a continent-wide level result in more retirements, and a low "creditable capacity" during peak-load times, resulting in more transmission. Table 5-2 is included to supports the latter statement. The total creditable capacity is defined as the difference between the invested capacity (de-rated by the capacity contribution of each technology) and the total retirements in year 2038.

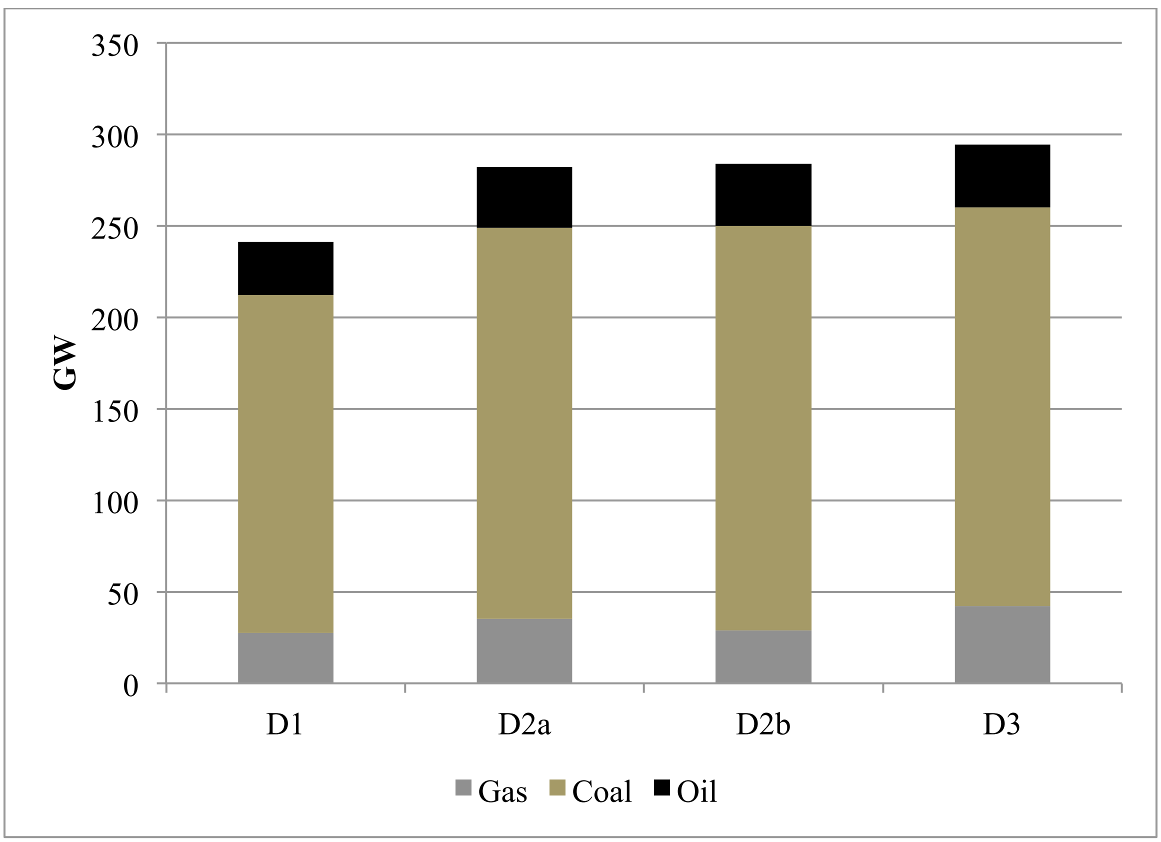

Figure 5-3: Base Designs - Total Retirements

Table 5-2: Creditable Capacity

Design	Total Creditable Capacity (MW)	Delta (MW)	Cross-Seam HVDC Transmission (MW)	Deferred Generation/ HVDC
D1	838,487	-	N/A	N/A
D2a	809,471	(29,016)	21,045	1.37876
D2b	792,015	(46,472)	39,073	1.18936
D3	794,095	(44,391)	20,349	2.18148

5.3. Design 1: No B2B Upgrades

A geo-map showing new generation and transmission investments is shown in Fig. 5-4. Under the assumption that only 1.4 GW of transfer is allowed between the EI and WI, each interconnection must supply their load using local generation resources. Major wind investments are observed in the Midwest and West side of the US Seam. The wind resource in both regions is extremely high, e.g. capacity factors above 45%, resulting in high investments to supply energy needs. In addition, a significant amount of transmission is observed from wind resources to load centers (e.g., Iowa to Illinois, Minnesota to Chicago, Wyoming to Colorado, and from SPP to SERC. A breakdown of the total generation and transmission investments is shown in table 5-3.

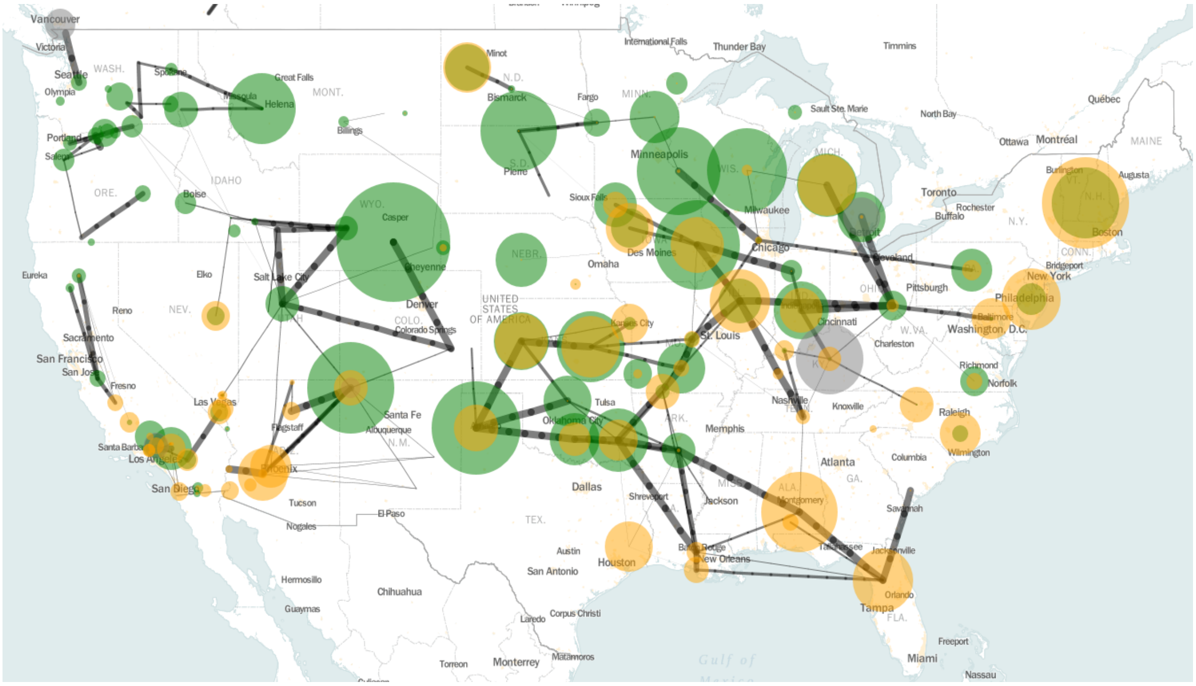

Figure 5-4: Design 1 - Total Generation and Transmission Investments

Table 5-3: Summary of new investments (Design 1 - Base)

Technology	MW
Transmission AC	228,853
Transmission DC	0
Wind	385,804
Solar	176,906
Gas	37,289

5.4. Design 2a: B2B Upgrades

In Design 2a, all 7 back-to-back HVDC interties are allowed to be expanded, as shown in Fig. 5-5. Major AC transmission in SPP is required to enable high capacity transfer between the EI and WI using existing B2B interties. A total of 25.6 GW of new B2B capacity characterizes this design. In terms of generation resources, the results show that increasing capacity in the B2B ties results in more wind investments and less solar in the Eastern Interconnection, as shown in Table 5-4. The breakdown of HVDC capacity per B2B intertie is shown in Table 5-5.

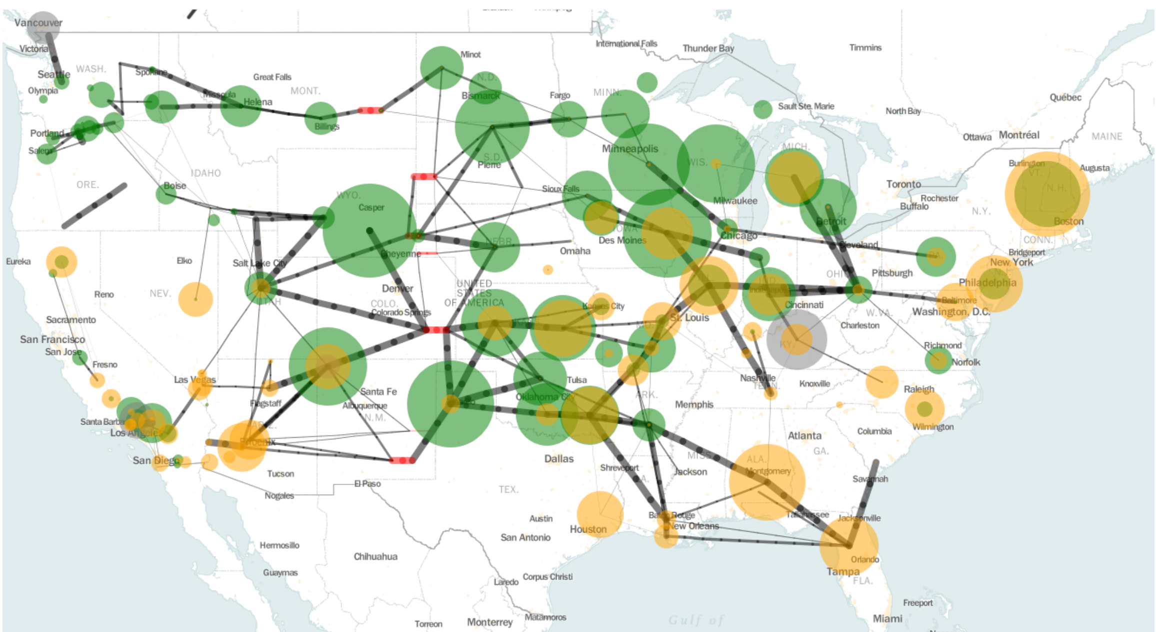

Figure 5-5: Design 2a - Total Generation and Transmission Investments

Table 5-4: Summary of new investments (Design 2a - Base)

Technology	MW
Transmission AC	251,317
Transmission DC	25,698
Wind	392,463
Solar	171,967
Gas	35,575

Table 5-5: Total new capacity for each B2B intertie

B2B Facility	MW
BLACKWATER-ACDC	198.7
EDDYACDC	2694.6
LAMAR-ACDC	9330.8
MC-ACDC	2756.7
RC-ACDC	3966.1
SIDNEY-ACDC	907.6
STEGAL-ACDC	5843.3

5.5. Design 2b: Upgraded Seams

Figure 5-6 shows the result from Design 2b. The main difference between this and Design 2a is the addition of three wide-area HVDC lines on top of the 7 B2B interties. Tables 5-6 and 5-7 show the total generation and transmission investments. The major finding of this design is that the addition of 27 GW of HVDC transmissions above the existing B2B ties results in a decrease in B2B investments and a decrease in AC transmission requirements. This results is consistent with the general idea that HVDC reduces the need for AC transmission when a large footprint is considered.

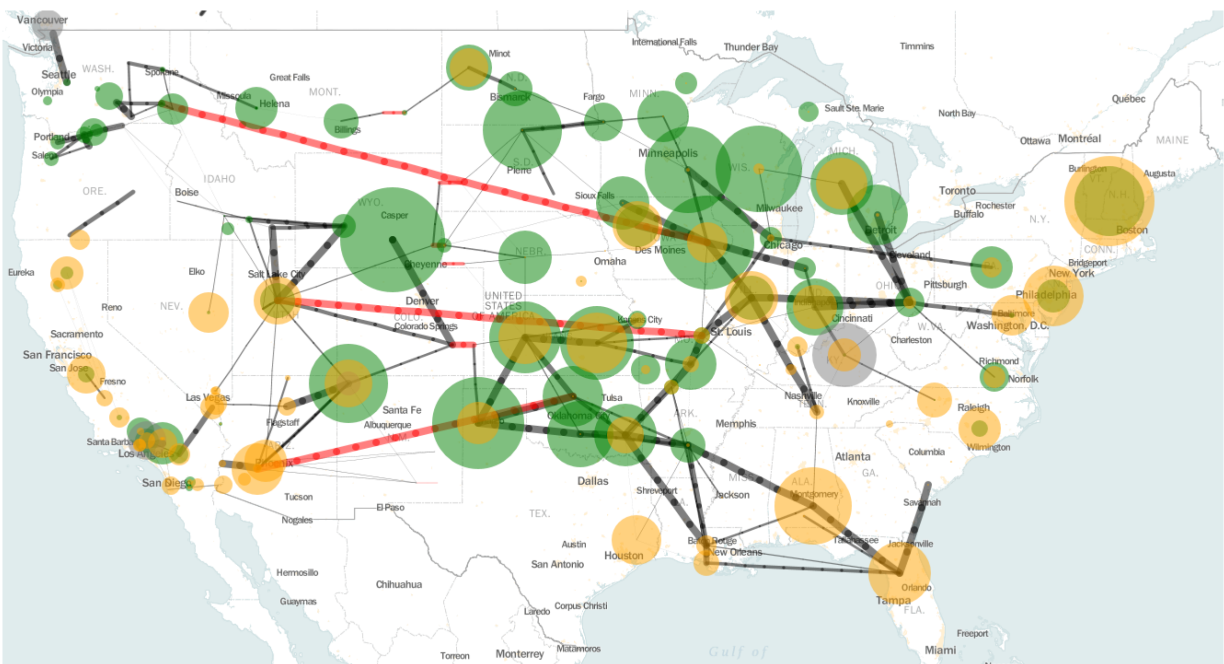

Figure 5-6: Design 2b - Total Generation and Transmission Investments

Table 5-6: Summary of new investments (Design 2b - Base)

Technology	**MW**
Transmission. AC	234,770
Transmission DC	35,936
Wind	393,233
Solar	172,081
Gas	34,685

Table 5-7: Total HVDC investment in Design 2b

B2B Facility	**MW**
BLACKWATER-ACDC	34.4
EDDYACDC	138.4
LAMAR-ACDC	2074.9
MC-ACDC	1119.4
RC-ACDC	1389.0
SIDNEY-ACDC	1054.9
STEGAL-ACDC	1681.9
Cross-Transmission HVDC	3×9481.3

5.6. Design 3: Macro-grid overlay

Finally, Figure 5-7 shows the new investments resulted from Design 3. The total amount of generation and transmission investments is shown in Tables 5-8 and 5-9. The main difference between Design 3 and the rest is its ability to displace generation required to meet future PRM (as presented in table 5-2) and reduce the AC transmission required to upgrade the existing B2B ties. A unique feature of this design is that all HVDC lines have the same capacity, a characteristic that allows the macro-grid to withstand the loss of one HVDC line and still be able to operate under emergency conditions. Under base assumptions, Design 3 outperforms other designs in terms of economic and reliability.

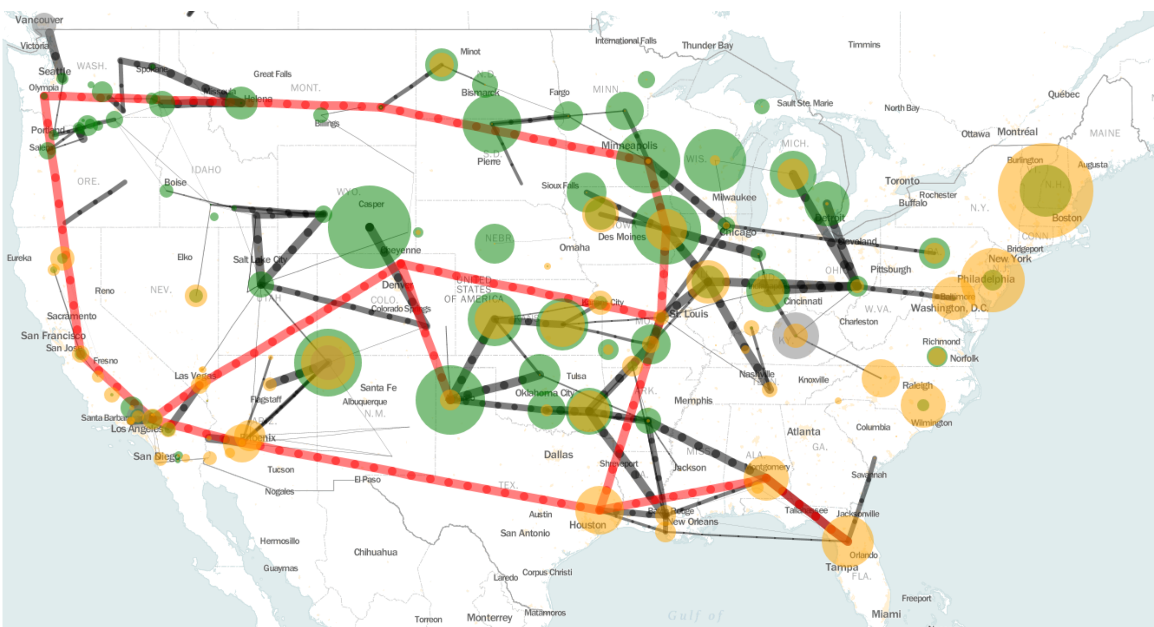

Figure 5-7: Total Generation and Transmission Investments

Table 5-8: Total investments by technology (Design 3 - Base)

Technology	MW
Tx. AC	195,128
Tx. DC	125,824
Wind	392,769
Solar	169,638
Gas	37,951

Table 5-9: New HVDC investments

HVDC	MW
Capacity/segment	8,389.5
Total capacity	15×8389.5

5.7. Robust AC upgrades

Figure 5-8 shows the lines with investments above 0 GW of capacity that were observed in every design. These are referred to as "robust AC upgrades". As observed in the previous sections, lines connecting major wind hubs with load centers are built on every design. Figure 5-9 illustrate the concept of robust AC line investments, but only lines which capacity is above 1 GW are considered. In this case, major AC transmission is observed from MN and IA to the North-East coast and from SPP to the South-East region of the US.

On the WI side, robust AC upgrades occur near the load centers. These include California, Washington, Utah and Colorado.

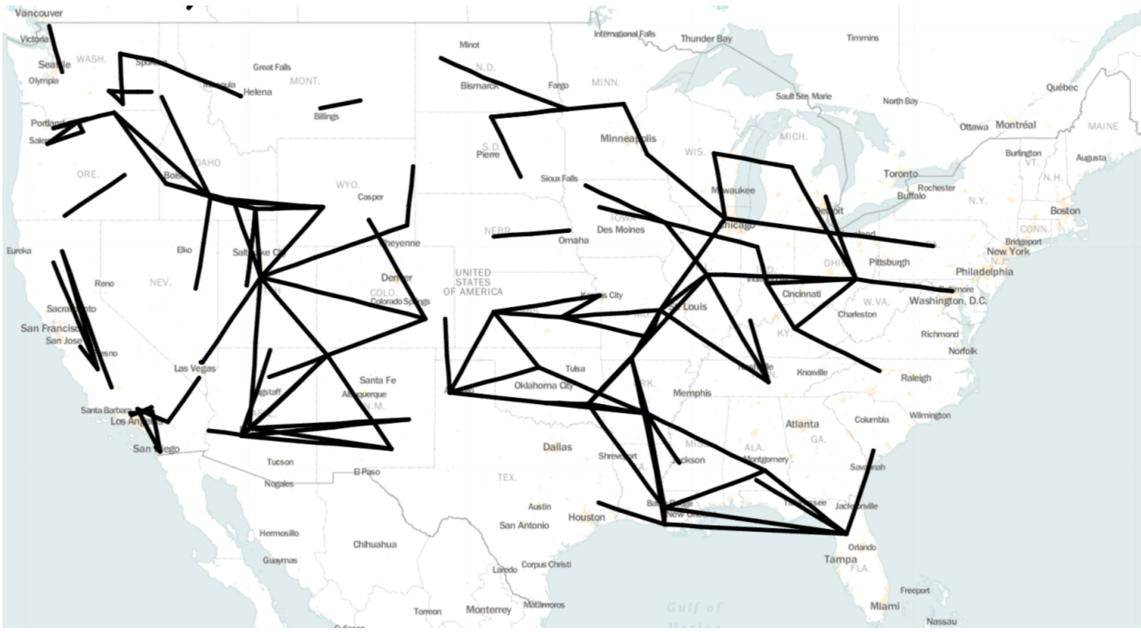

Figure 5-8: Robust AC transmission investments (>0 GW)

Figure 5-9: Robust AC transmission investments (>1 GW)

5.8. Power flow maps

In order to support the discussion presented in the previous section, a power flow map for the three peak-load blocks and one for the energy block of Designs 2a and 3 are included. Figures 5-10 to 5-14 show the power flow maps related to Design 3. As it can be seen from the maps showing how the power flow across the US when each of the RSG is peaking, the value of capacity sharing results in major HVDC transmission for Design 3 and major AC upgrades within SPP in Design 2a. Although the energy flow map in both Designs show that most of the time the power flows from the WI to the EI, during peak-load times, power flows will be determined by the demand level of neighbor regions when a particular region is peaking. These maps confirm the value of net-load diversity from a co-optimized CEP framework.

Design 1

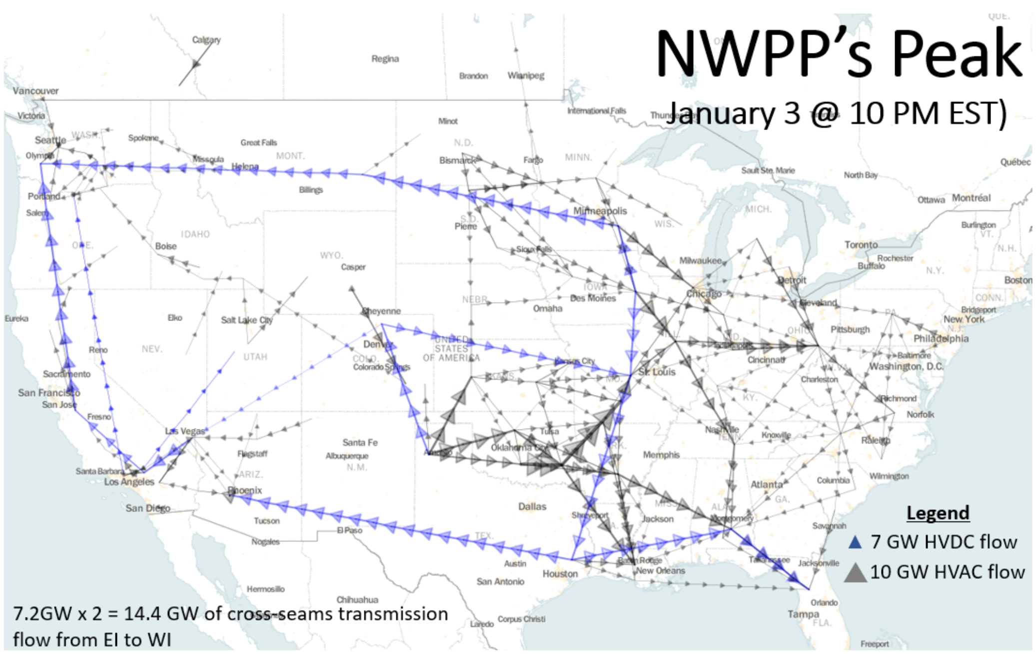

Figure 5-10: Power flow during NWPP's peak (Base Design)

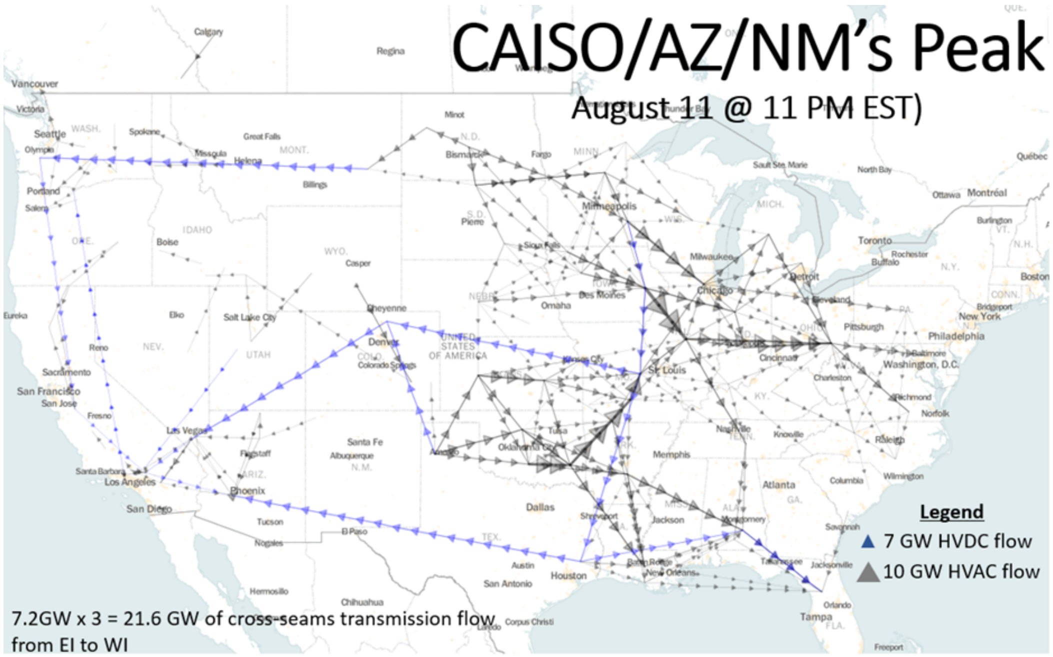

Figure 5-11: Power flow during CAISO's peak (Base Design)

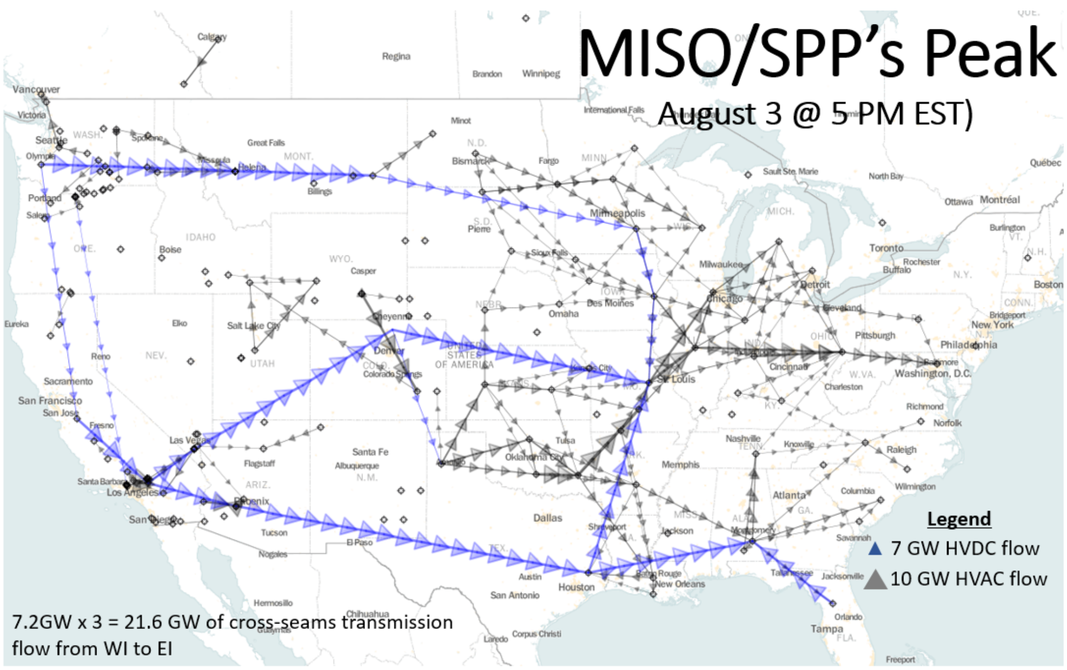

Figure 5-12: Power flow during MISO's peak (Base Design)

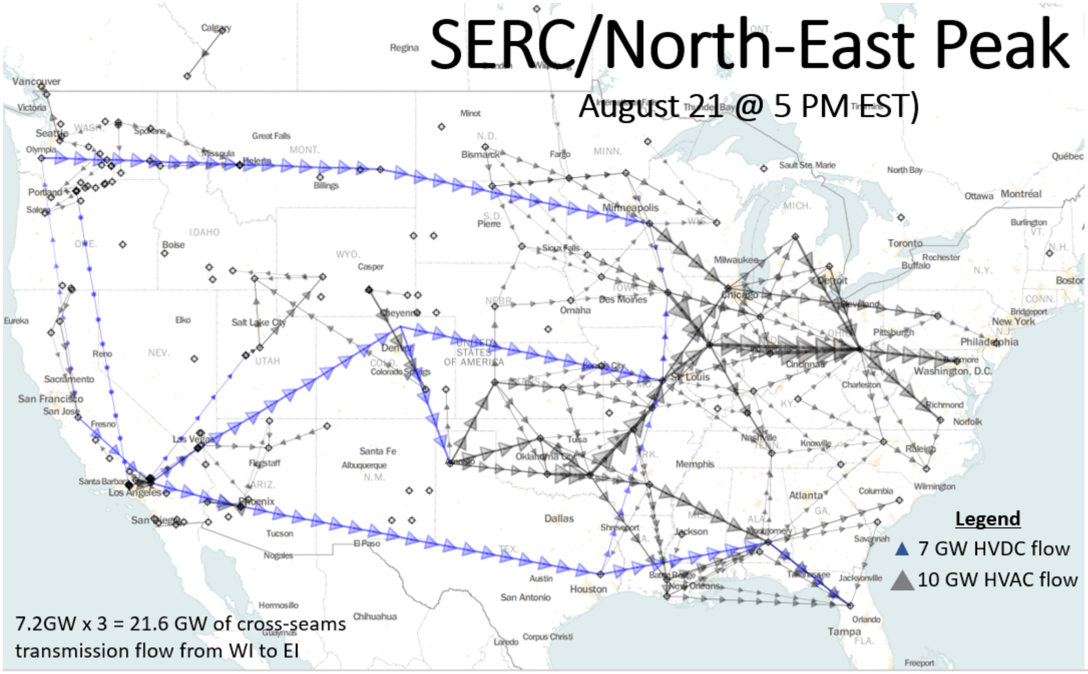

Figure 5-13: Power flow during SERC's peak (Base Design)

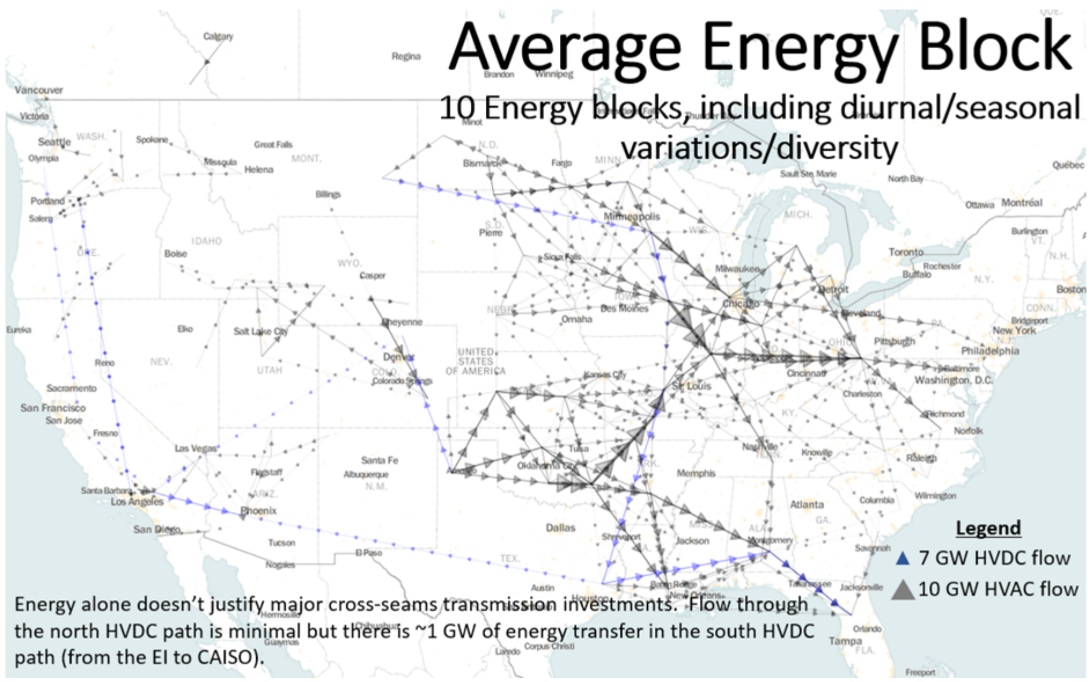

Figure 5-14: Average energy flow (Base Design)

Design 2a

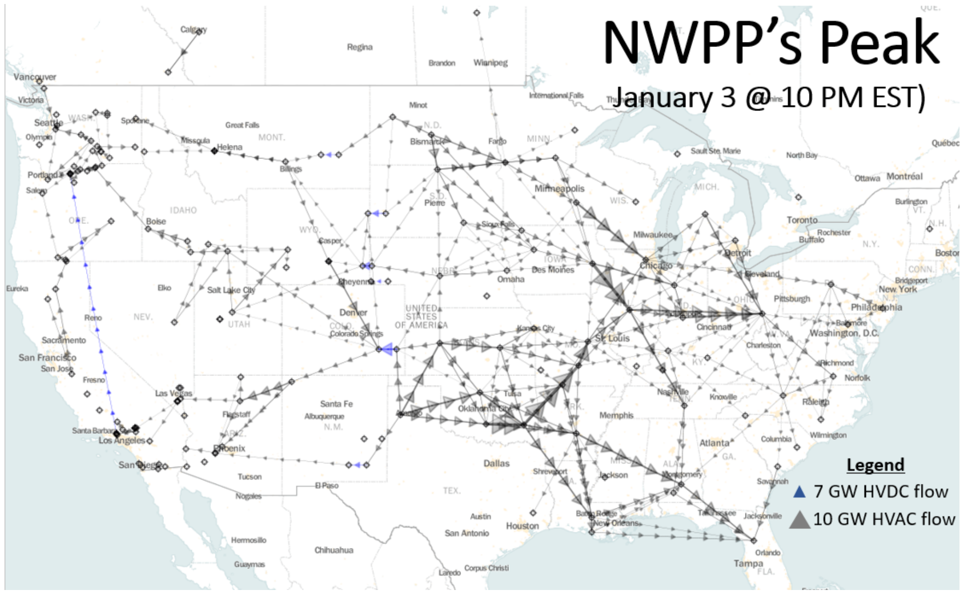

Figure 5-15: Power flow during NWPP's peak (Base Design)

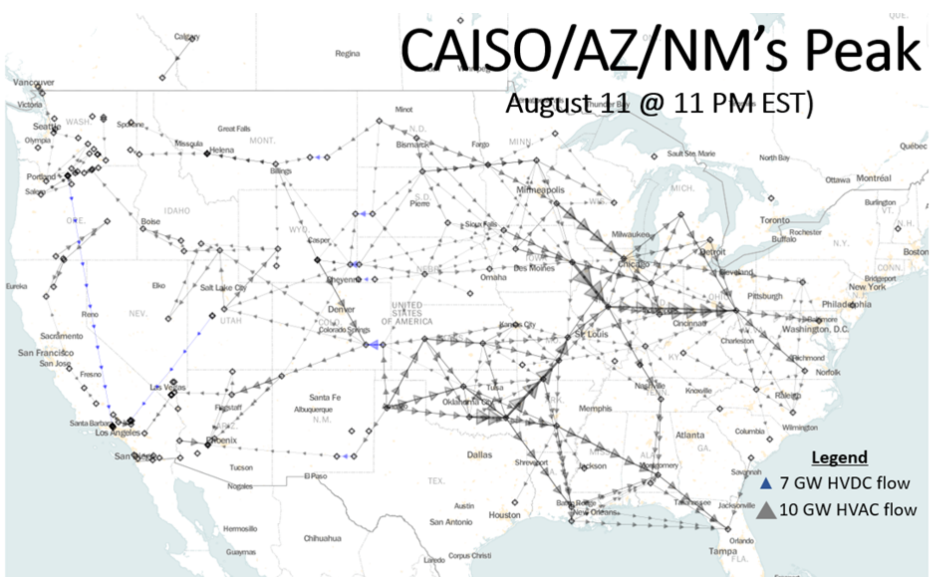

Figure 5-16: Power flow during CAISO's peak (Base Design)

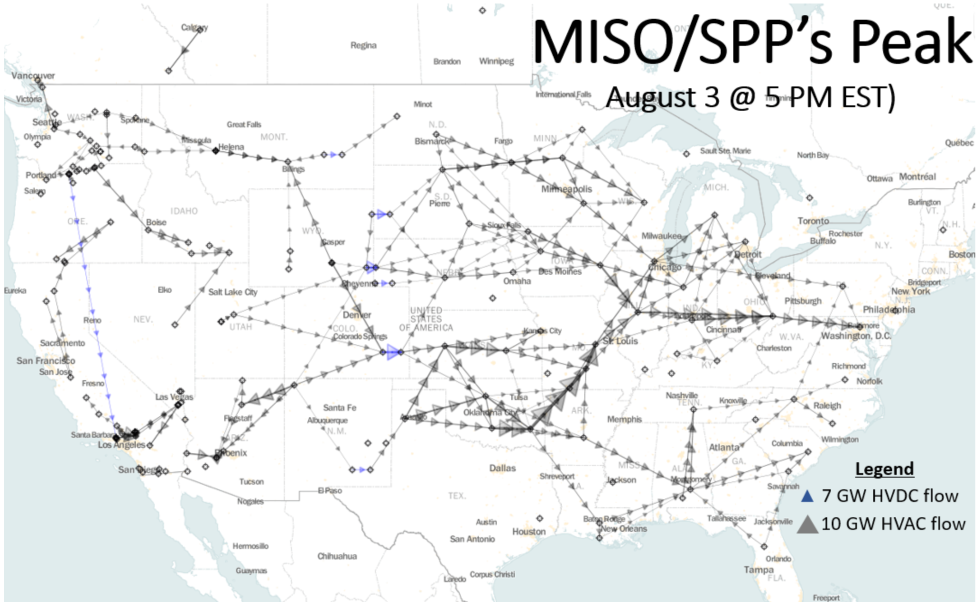

Figure 5-17: Power flow during MISO's peak (Base Design)

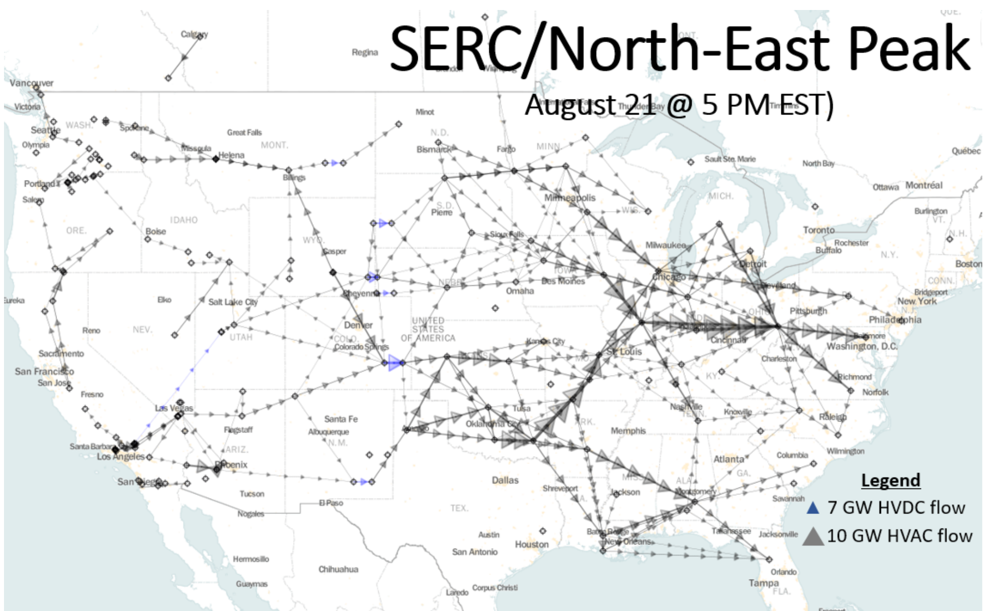

Figure 5-18: Power flow during SERC's peak (Base Design)

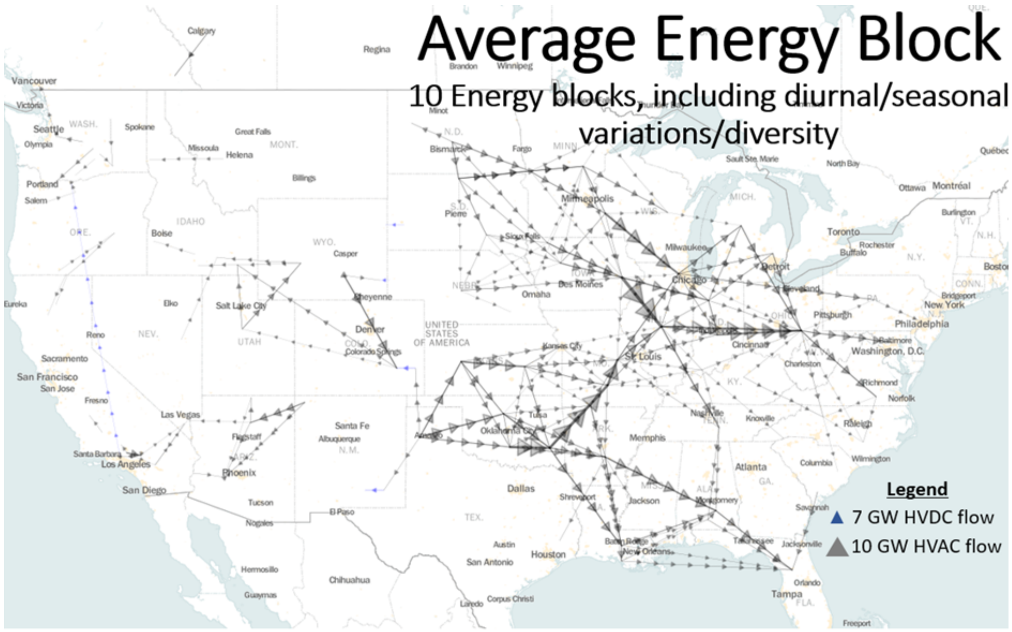

Figure 5-19: Average energy flow (Base Design)

5.9. Summary

In this chapter, results from the Base case for each design were compared. Under a $3/MTON/year carbon tax policy and if RSGs are allowed to share reserves to meet PRM obligations (this will require a policy change) and operating reserves requirements (this will require a market modification), all designs pay for themselves and are above FERC's suggested 1.25 minimum for interregional transmission lines. From an economic perspective, Design 3 outperforms other designs.

CHAPTER 6. CO-OPTIMIZED DESIGNS UNDER CURRENT POLICY ASSUMPTIONS

6.1. Introduction

In this chapter, a co-optimized CEP is developed for all four designs under the following assumptions:

1. **Assumption 1**: State-level RPS is enforced as shown in Fig. 6-1.
2. **Assumption 2**: No carbon tax
3. **Assumption 3**: RSGs are allowed to share reserves to meet operating reserve requirements and PRM obligations.

The rest of this chapter is organized as follows. A summary of the economic results and performance metrics are included in Section 2. Section 3-6 includes the results that are unique to each design. Finally, a robustness AC transmission plot is included in Section 7 to compare with Base design assumptions.

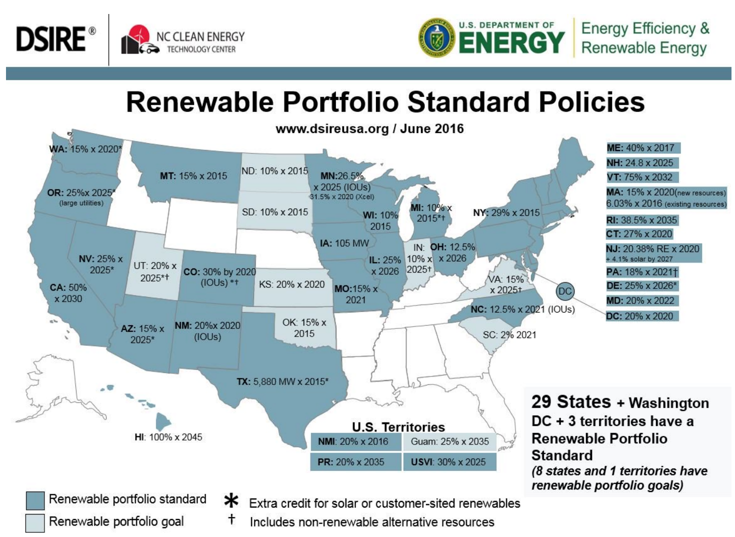

Figure 6-1: RPS by State

6.2. Fundamental Results

Table 6-1 shows the breakdown of the objective function for all four designs. One of the major findings from this case is that although all designs pay for themselves, the B/C ratio is below FERC's suggested minimum (1.25) for interregional transmission lines for Designs 2b and 3. These results confirm that cross-seam transmission using HVDC is economically viable even under current policy conditions.

Table 6-1: Economic Summary

ECONOMICS NPV $B	Design 1	Design 2a	Delta	Design 2b	Delta	Design 3	Delta
Line Investment Cost	23.50	26.69	3.19	31.50	8.00	37.70	14.20
Generation Investment Cost	493.60	494.70	1.10	492.50	-1.10	494.20	0.60
Fuel Cost	855.10	852.70	-2.40	851.20	-3.90	845.60	-9.50
Fixed O&M Cost	416.40	415.60	-0.80	413.70	-2.70	413.80	-2.60
Variable O&M Cost	81.00	81.10	0.10	81.20	0.20	81.20	0.20
Carbon Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Regulation-Up Cost	31.60	30.97	-0.63	31.13	-0.47	30.02	-1.58
Regulation-Down Cost	45.10	44.20	-0.90	44.42	-0.68	42.85	-2.26
Contingency Cost	23.90	23.42	-0.48	23.54	-0.36	22.71	-1.20
Total Non-Xm Cost (Orange)	2,011.7	2,010.6	-4.01	2,007.5	-9.01	2,001.5	-16.34
15-yr B/C Ratio (Orange/Blue)			1.26		1.13		1.15
Perpetuity (post-2038 Op) Cost	850.12	833.12	-17.00	822.07	-28.05	807.62	-42.51

The emissions per year for all four designs are shown in Fig. 6-2. The same interrelationships between designs observed in the base designs are also shown in the Current Policy designs. Although no carbon tax is enforced in this case, both the state-level RPS and the low LCOE for wind and solar reduces CO_2 emissions in the 15-year time frame. Figure 6-3 shows the retirements by design.

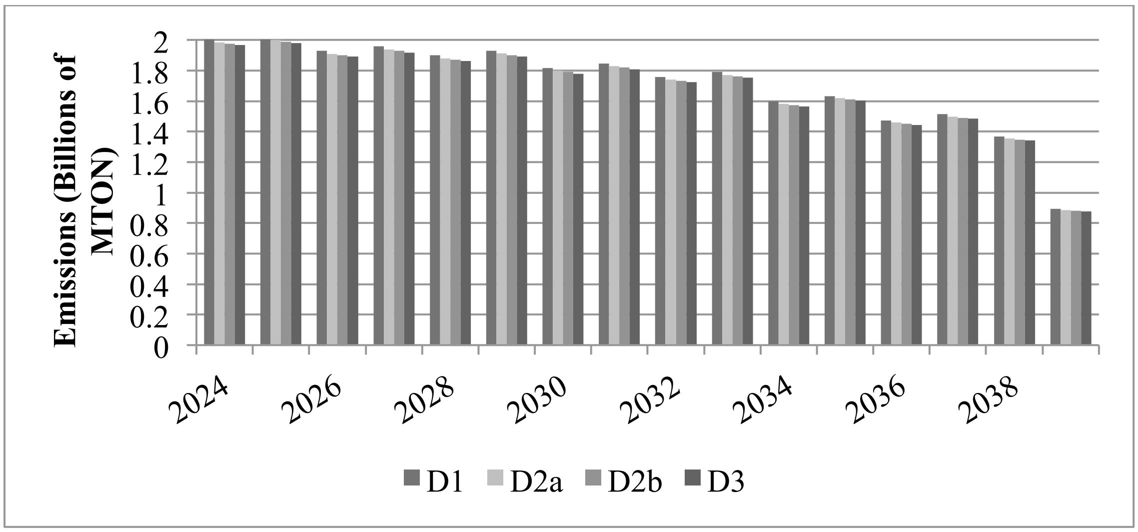

Figure 6-2: Emissions by year (Current Policy)

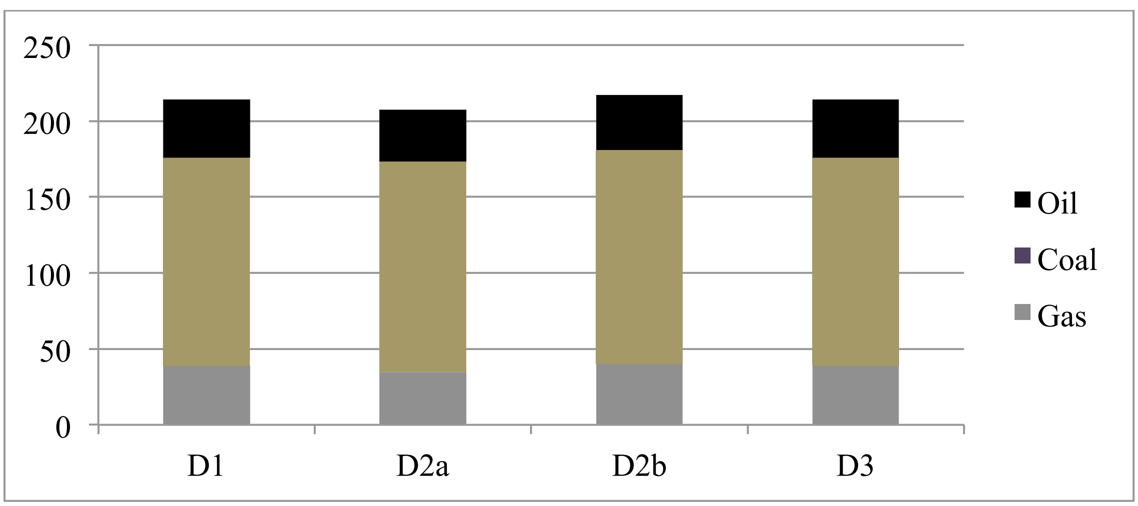

Figure 6-3: Retirements by technology (Current Policy)

6.3. Design 1: No B2B Upgrades

Figure 1-4 shows the generation and transmission investments of Design 1. In contrast to the Base Design 1, when the RPS is imposed on a state-wide level (Current Policy), rather than on a National level, the model identifies solar as more economic than the wind plus transmission option. The reason is that each state must comply with a particular percentage of renewable generation, and this limits the amount of export capability. Table 6-2 and 6-3 include the total amount of generation and transmission builds.

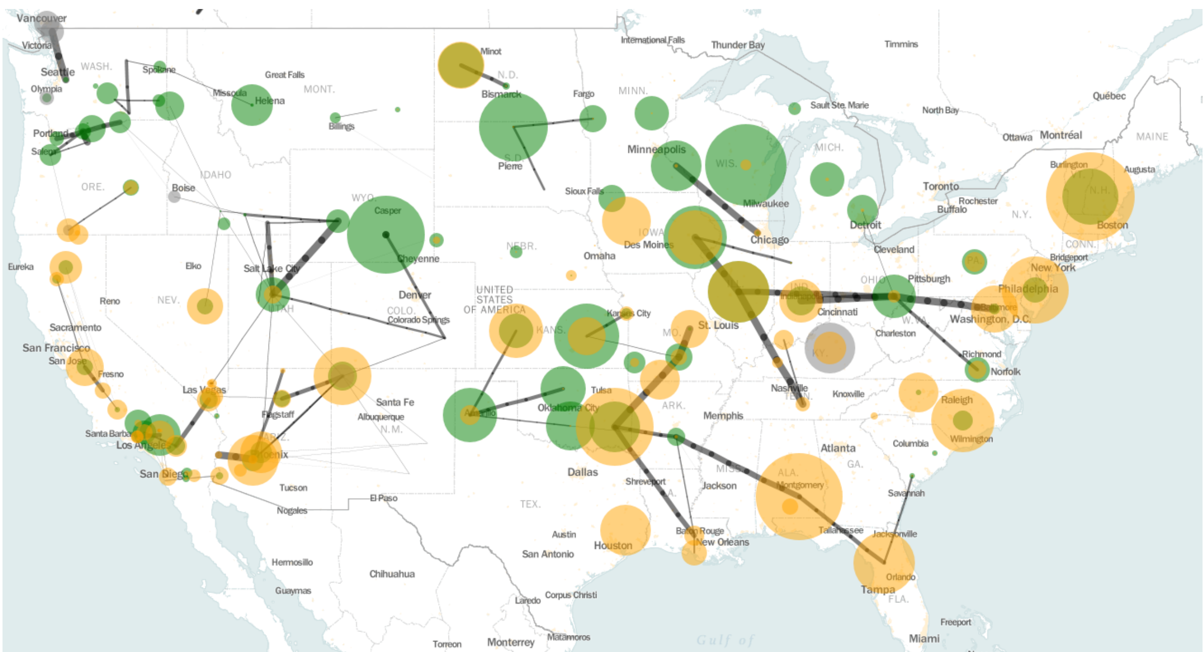

Figure 6-4: Design 1: No B2B Upgrades (Current Policy)

Table 6-2: Summary of investments: Design 1 (Current Policy)

Technology	**MW**
Transmission AC	92,344
Transmission AC	0
Wind	225,581
Solar	209,744
Gas	27,381

6.4. Design 2a: No B2B Upgrades

In Design 2a, a significantly decrease in B2B investments is resulted in this scenario, compared to the Base Design. More solar is invested near the coasts in both interconnections. This is consistent with the RPS map shown in Fig. 6-1. The model is building wind and solar resources in states with high RPS (e.g., NY, CA, and WA). The secondary effect of allowing this constraint is a reduction in Seams transmission and a higher long-term planning cost. Tables 6-3 and 6-4 show a breakdown of the total investments per technology.

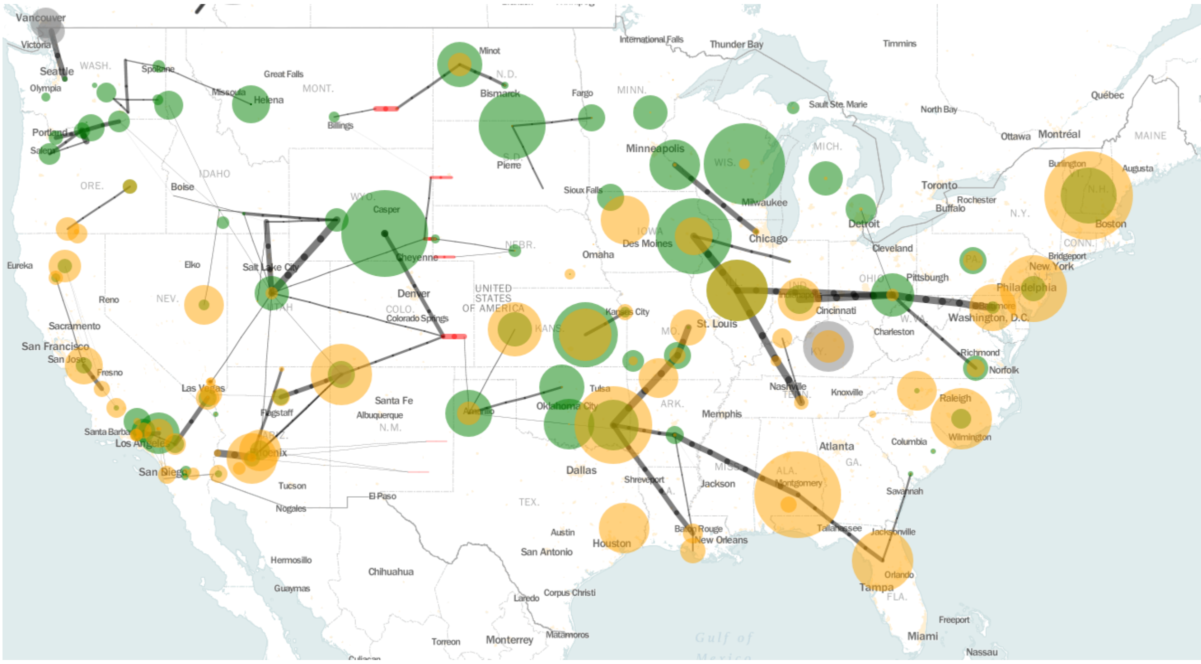

Figure 6-5: Design 2a: B2B Upgrades (Current Policy)

Table 6-3: New investments: Design 2a (Current Policy)

Technology	**MW**
Transmission AC	94,798
Transmission AC	6,682
Wind	229,499
Solar	202,095
Gas	27,268

Table 6-4: New investments: Design 2b (Current Policy)

B2B Facility	MW
BLACKWATER-ACDC	114.5
EDDYACDC	198.9
LAMAR-ACDC	1355.0
MC-ACDC	1,634.9
RC-ACDC	1,009.4
SIDNEY-ACDC	851.2
STEGAL-ACDC	1,518.4

6.5. Design 2b: Upgraded Seams

A similar generation investment pattern is observed in Design 2b. However, more solar is observed in locations Tables near the HVDC terminals.

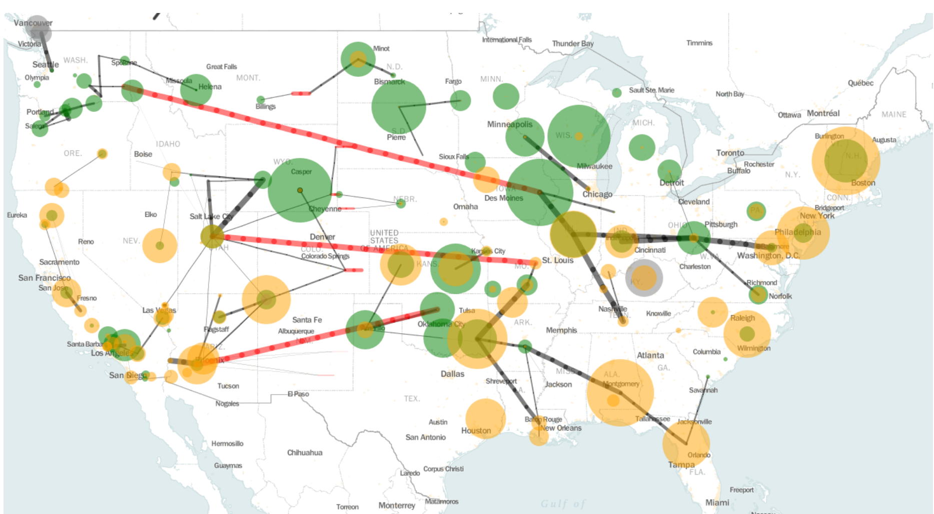

Figure 6-6: Design 2b: Upgraded Seams (Current Policy)

Table 6-5: Total Investments - Design 2b (Current Policy)

Technology	**MW**
Transmission AC	89,391
Transmission AC	20,661
Wind	232,021
Solar	201,828
Gas	25,883

Table 6-6: Total HVDC investments - Design 2b (Current Policy)

B2B Facility	**MW**
BLACKWATER-ACDC	93.8
EDDYACDC	176.3
LAMAR-ACDC	1021.3
MC-ACDC	1774.7
RC-ACDC	915.8
SIDNEY-ACDC	848.8
STEGAL-ACDC	1493.6
Cross-Tx. HVDC/line	4,779.0

6.6. Design 3: Macro-grid overlay

The macro-grid overlay also shows high solar investments near the HVDC terminals when the state-level RPS is enforced. Tables 6-7 and 6-8 show the total investments by technology. Although a significant decrease in HVDC is observed compared to the base design, the model still identifies economic potential for 3.5 GW/per segment of new HVDC transmission.

Table 6-7: Total HVDC investments - Design 3 (Current Policy)

HVDC	MW
Capacity/segment	3,861

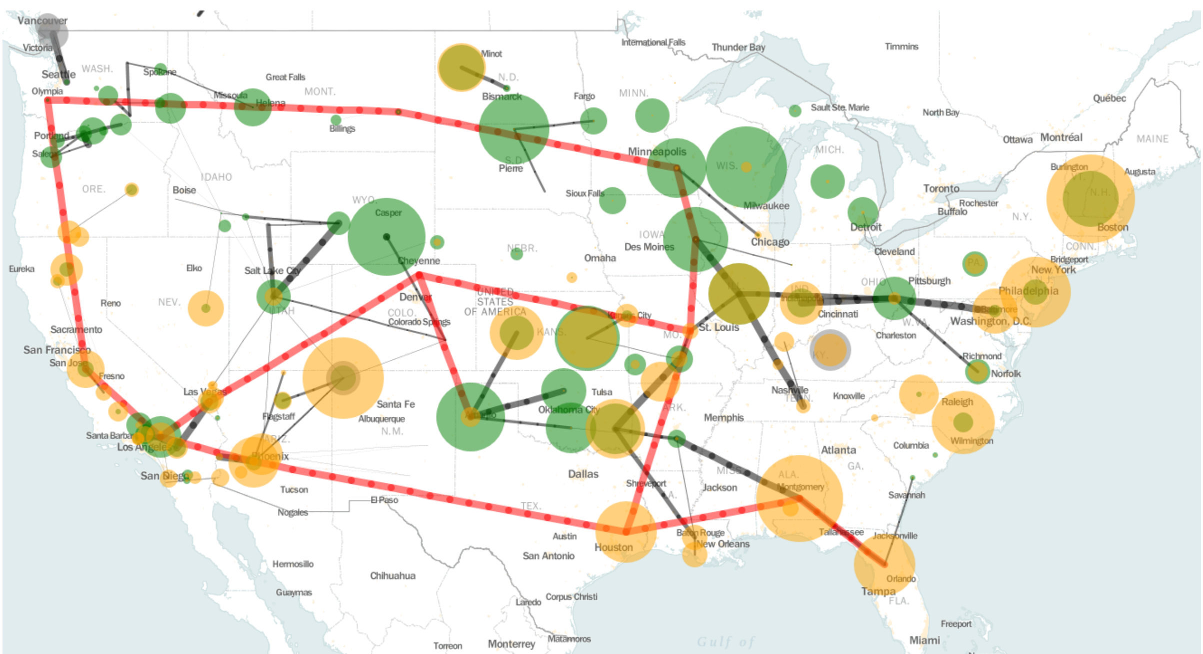

Figure 6-7: Total Generation and Transmission Investments

Table 6-8: Total Investments - Design 3 (Current Policy)

Technology	MW
Transmission AC	84,075
Transmission DC	57,915
Wind	229,683
Solar	208,960
Gas	26,323

6.7. Robust AC transmission

The robust AC transmission lines above 0 GW and 1 GW are included in Figs. 6-8 and 6-9. The number of robust AC upgrades significantly reduces compared to the Base designs. This is mainly driven by the high solar investments (local generation resource) near the load centers of each interconnection. An interesting observation from these plots is the identification of major AC upgrades going from the Midwest to the East coast and near the load centers in the Western Interconnection. This results suggests that under both current policy and base design conditions, these transmission lines have high economic potential.

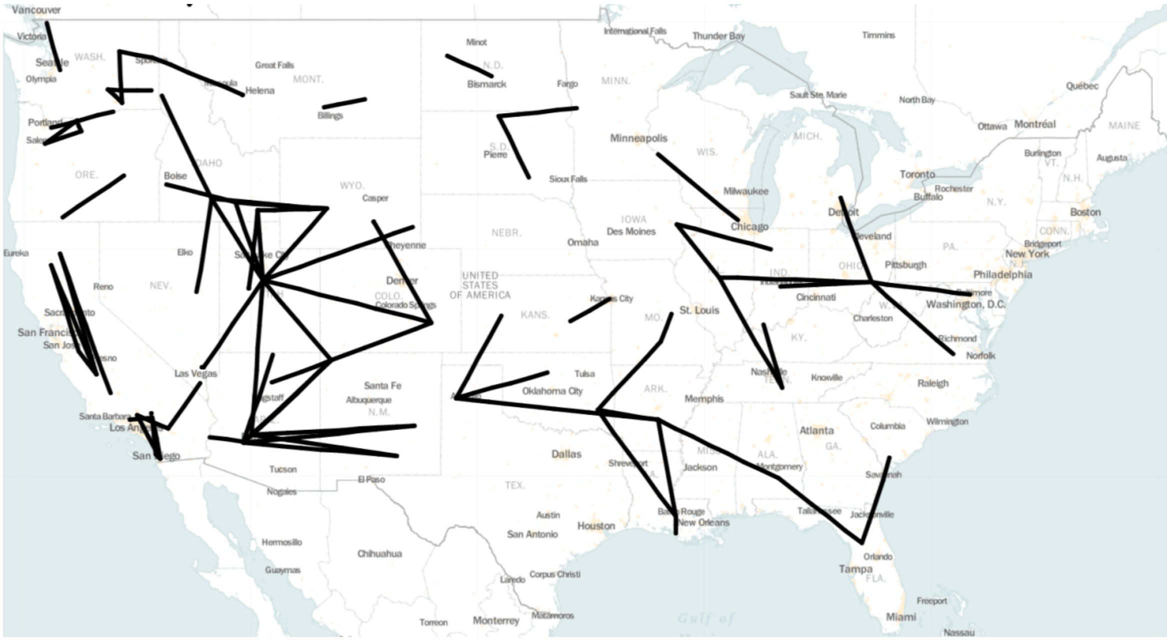

Figure 6-8: Robust AC upgrades (capacity > 0 GW)

Figure 6-9: Robust AC upgrades (capacity > 1 GW)

Finally, the creditable capacity of each design is included in Table 6-9. This table confirms the value of capacity sharing and net-load diversity when HVDC lines on top of the AC system are built.

Table 6-9: Creditable Capacity (Current Policy)

Design	Total Creditable Capacity (MW)	Delta (MW)	Cross-Seam HVDC Transmission (MW)	Deferred Generation/ HVDC
D1	857,500	N/A	N/A	N/A
D2a	846,000	-11,500	7,000	1.6
D2b	822,500	-35,000	20,000	1.8
D3	830,100	-27,400	58,000	0.47

6.8. Summary

In this chapter, results from the Current Policy case for each design were compared. Under a \$0/MTON/year carbon tax policy and state-level RPS enforcement, all designs pay for themselves, but only Design 2a is above FERC's suggested 1.25 minimum for interregional transmission lines. From an economic perspective, Design 2a outperforms other designs.

CHAPTER 7. ROBUSTNESS OF CO-OPTIMIZED BASE DESIGNS

7.1. Introduction

The following sensitivities were performed to test the robustness of each design under futures uncertainties:

1. Low Gas Sensitivity
2. No Carbon Tax Sensitivity
3. RPS
4. No Sharing
5. Number of blocks

These sensitivities are compared against base design conditions. That is, a 3$/MTON carbon tax is imposed at the national level and the state-level RPS is neglected. In order to better understand the effect of future sensitivities on investments, a graphical representation of the contiguous US grid divided in sub-seams is included. These sub-seams are defined based on their distance from the EI-WI seam (dashed line in red). A description of each sub-seam in included below:

- Western Interconnection
  - W3 sub-seam: Covers the states located near the Pacific coast (California, Nevada, Oregon, and Washington)
  - W2 sub-seam: Covers the states located in the Mountain Standard time-zone (Utah, Arizona, Montana).
  - W1 sub-seam: Include states near the EI-WI seam (Colorado, New Mexico, Montana).

- Eastern Interconnection
  - E3 sub-seam: Cover the states near the EI-WI seam (North Dakota, South Dakota, Kansas, Arkansas, Oklahoma).
  - E2 sub-seam: Includes the states of Minnesota, Iowa, Illinois, Missouri, Wisconsin, and New Orleans.
  - E1 sub-seam: Cover the states in the US East coast.

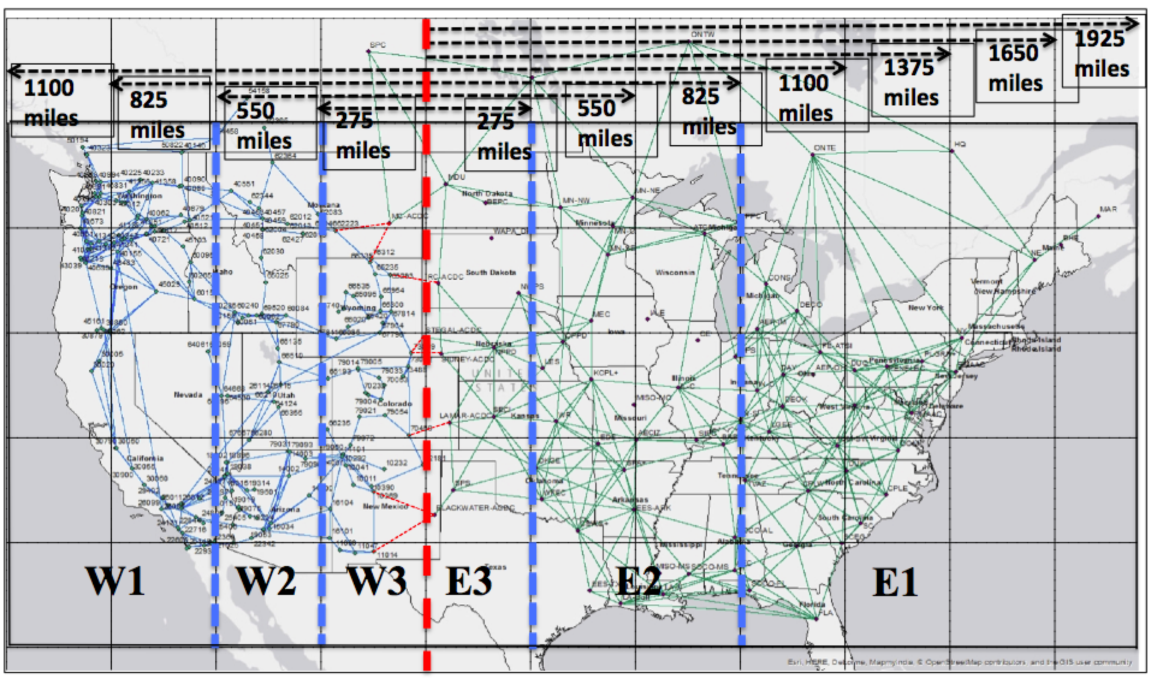

Figure 7-1: Conceptual Representation of Sub-Seams

7.2 Design 1: No B2B Upgrades

This section includes include the differences in generation expansion between sensitivities, compared to the base design. Figure 7-2 illustrate the changes in wind, solar and gas investments when each RSG must comply with the PRM obligation using local resources.

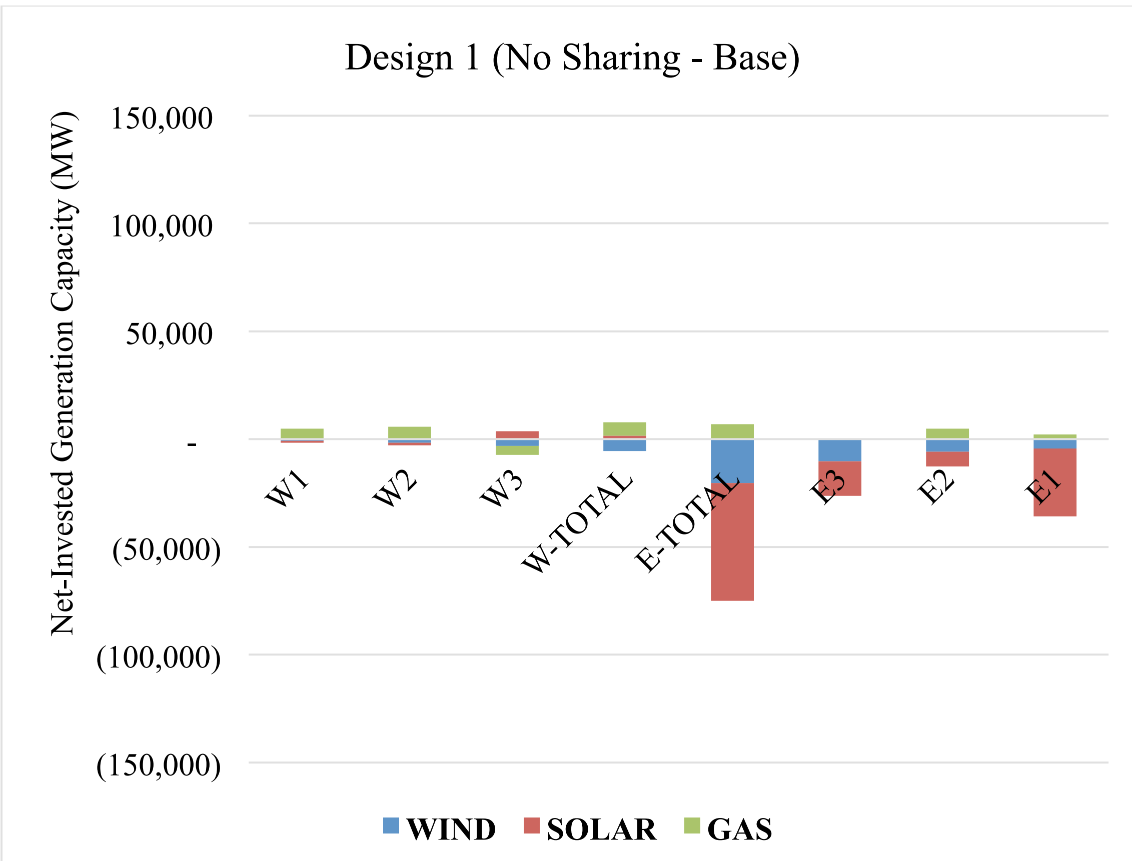

Figure 7-2: Design 1 - No Sharing

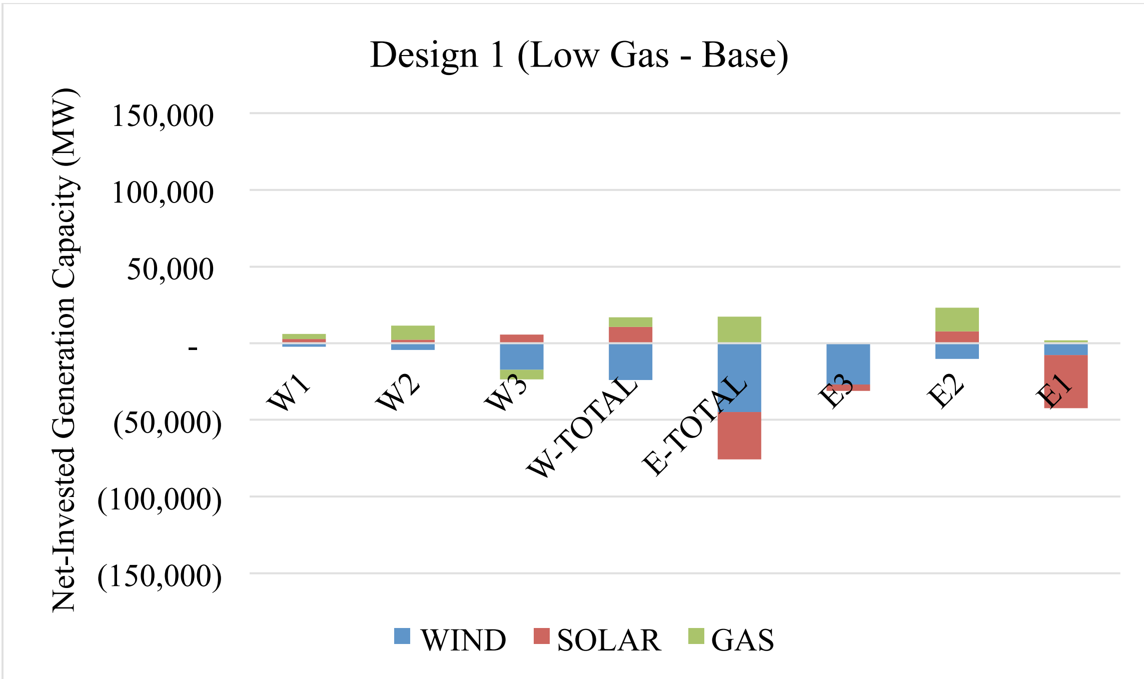

Figure 7-3: Design 1 - Low Gas

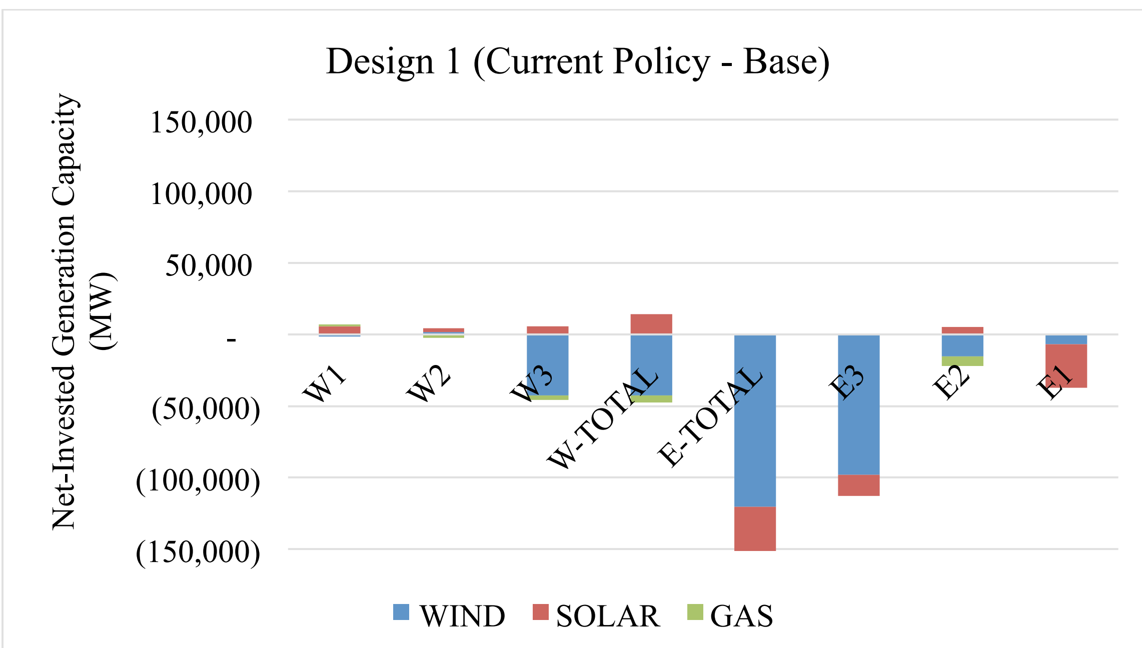

Figure 7-4: Design 1 - Current Policy

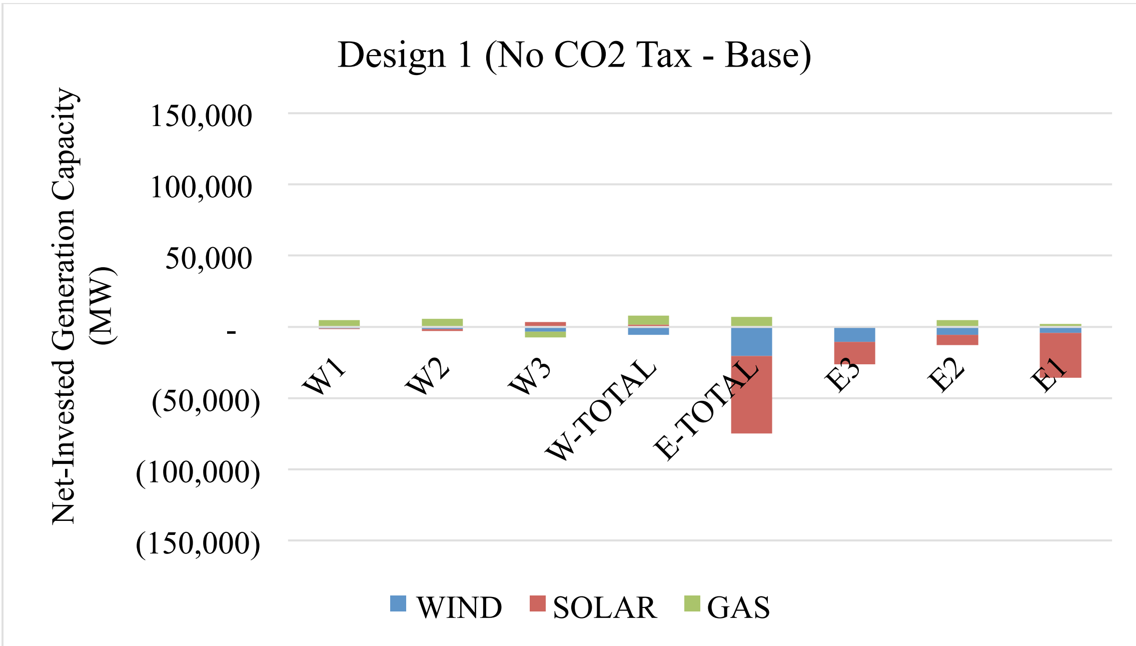

Figure 7-5: Design 1 - No CO2 tax

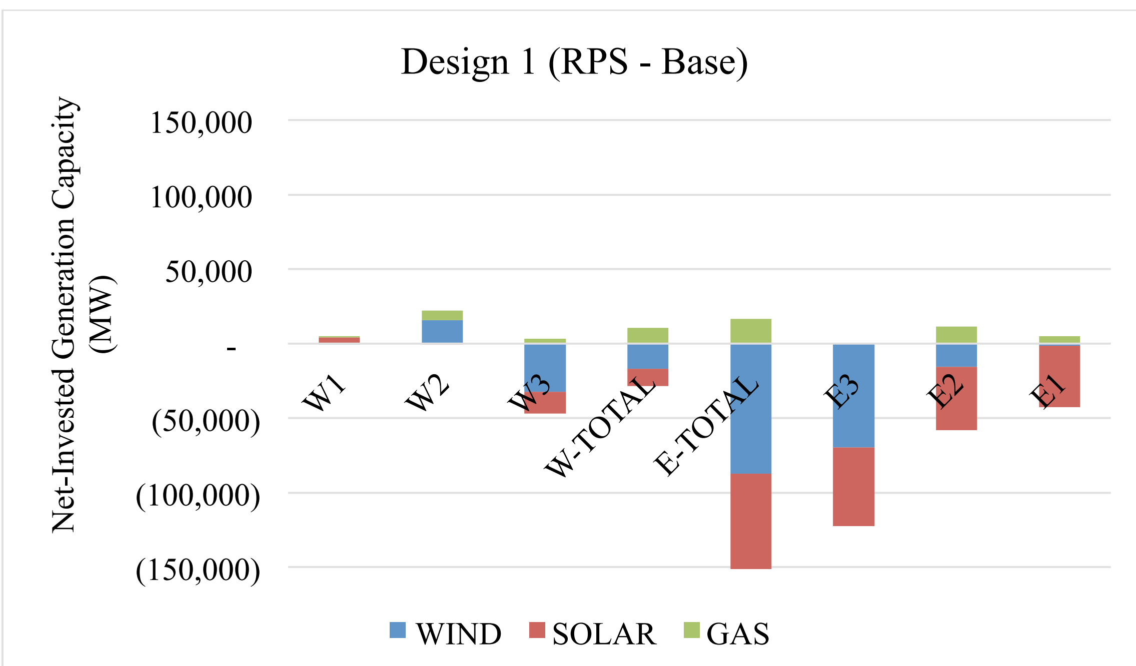

Figure 7-6: Design 1 - RPS

7.3 Design 2a: B2B Upgrades

This section includes include the differences in generation expansion between sensitivities, compared to the base design. Figure 7-2 illustrate the changes in wind, solar and gas investments when each RSG must comply with the PRM obligation using local resources.

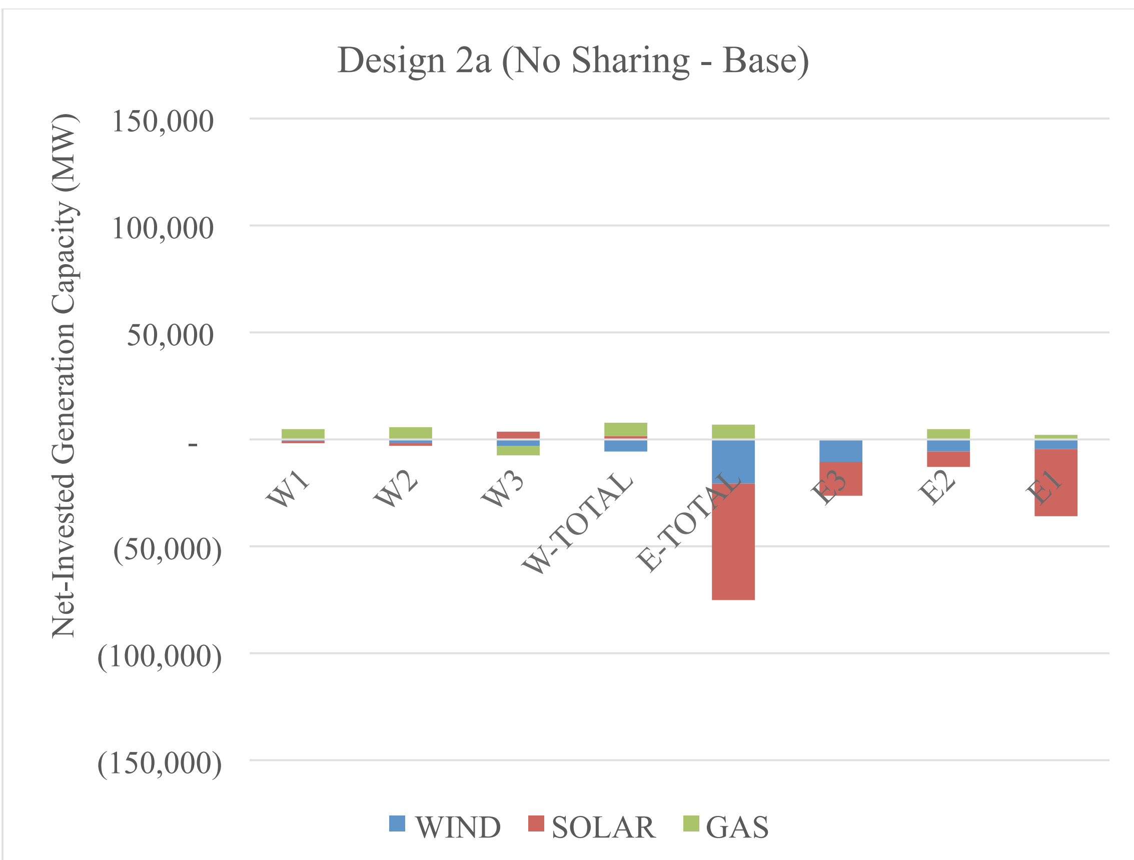

Figure 7-7: Design 2a - No Sharing

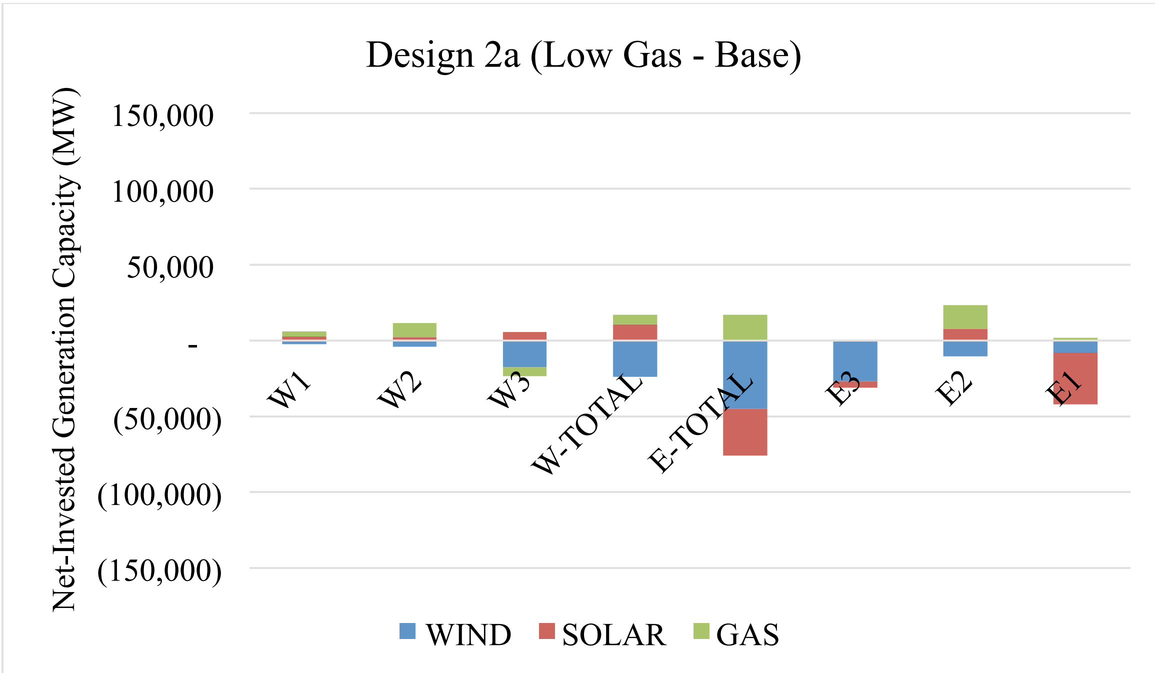

Figure 7-8: Design 2a – Low Gas

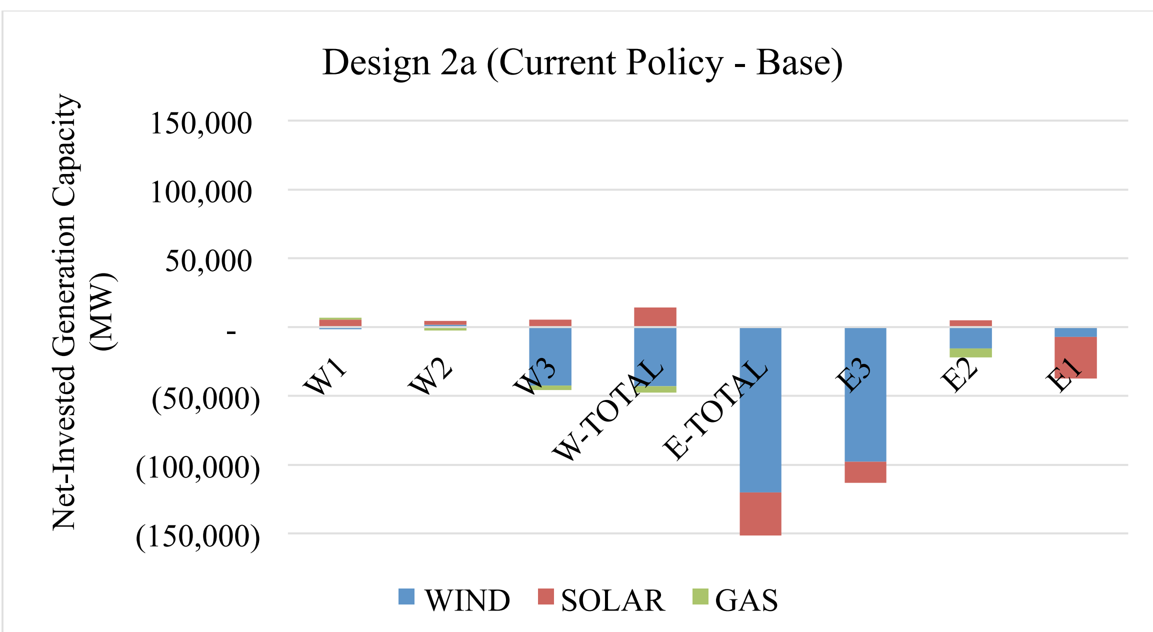

Figure 7-9: Design 2a - Current Policy

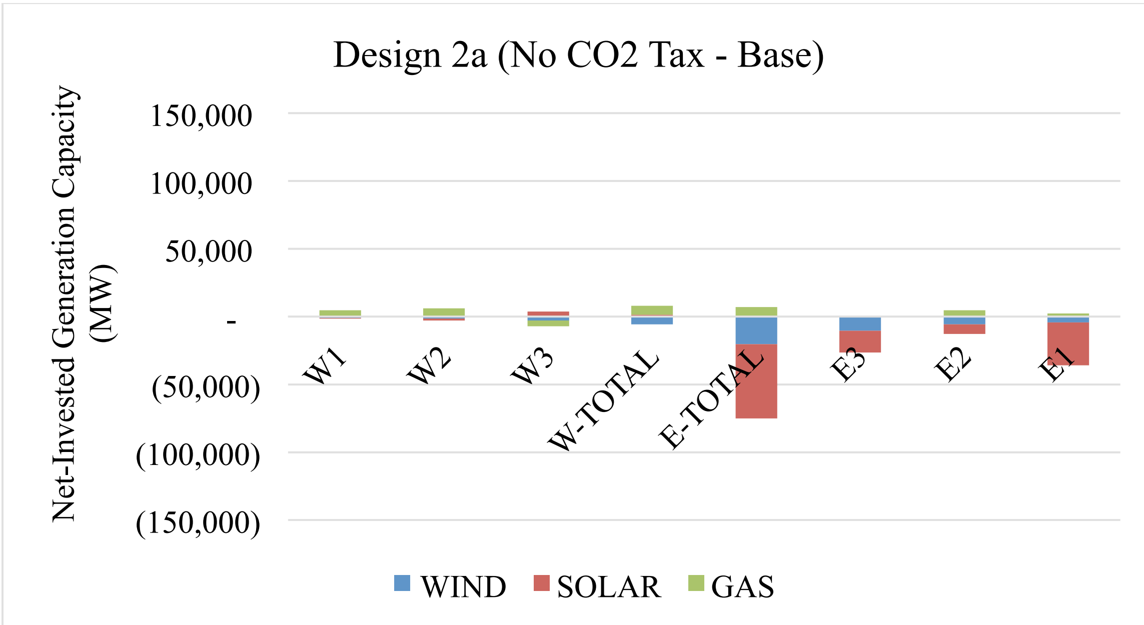

Figure 7-10: Design 2a - No CO2 Tax

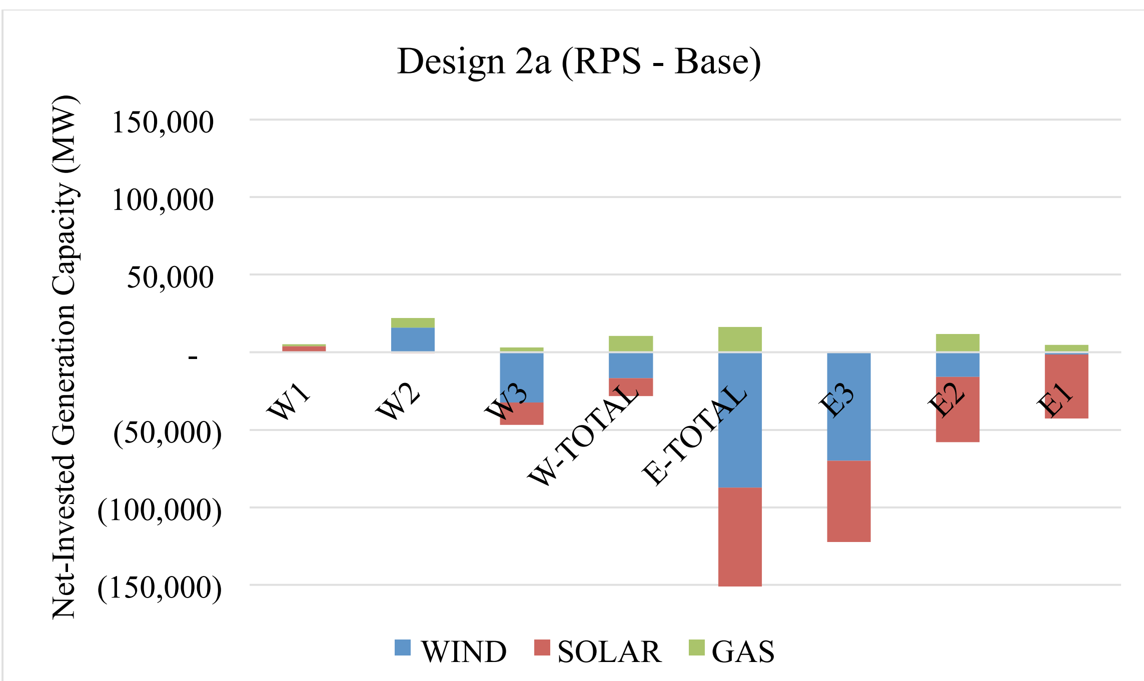

Figure 7-11: Design 2a - RPS

7.4 Design 2b: Upgraded Seams

This section includes include the differences in generation expansion between sensitivities, compared to the base design. Figure 7-2 illustrate the changes in wind, solar and gas investments when each RSG must comply with the PRM obligation using local resources.

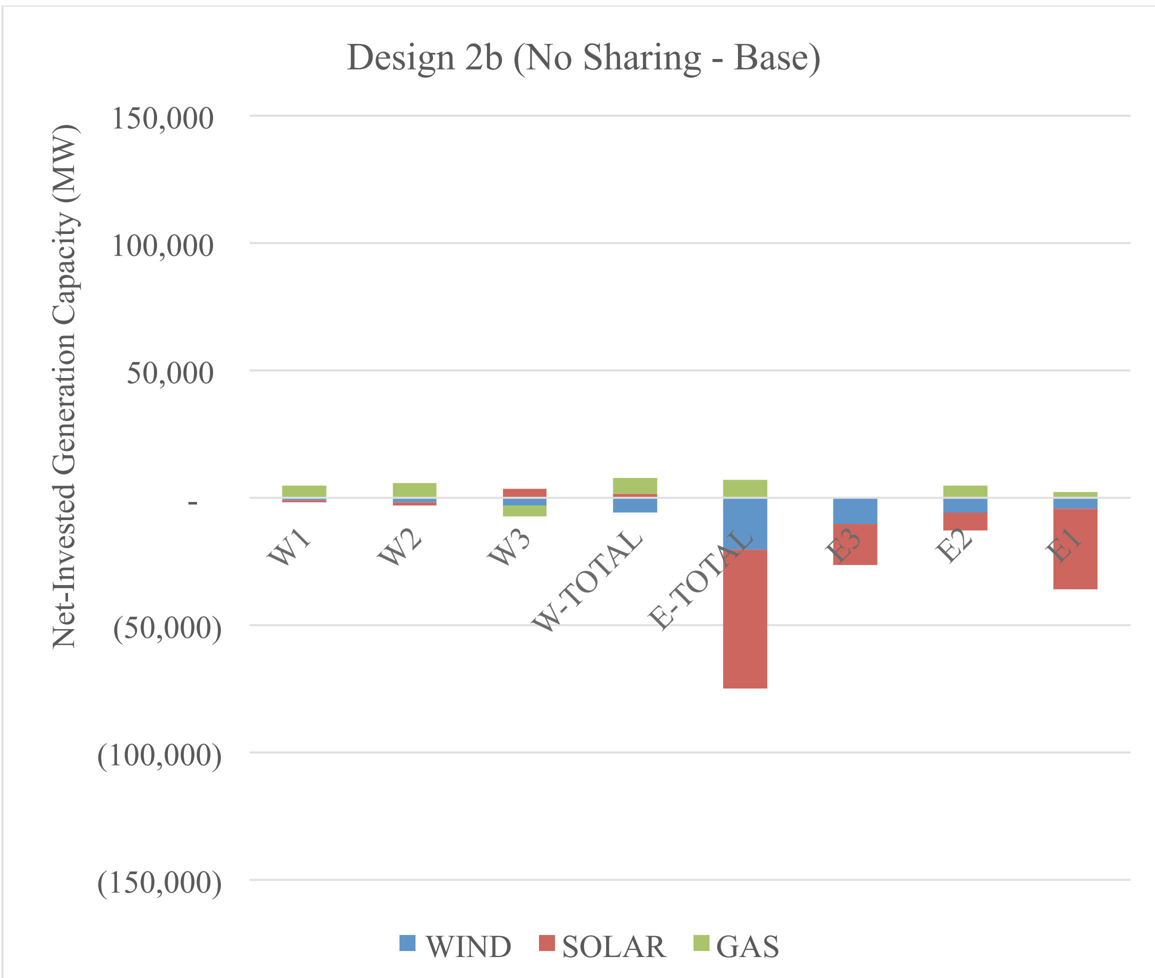

Figure 7-12: Design 2b - No Sharing

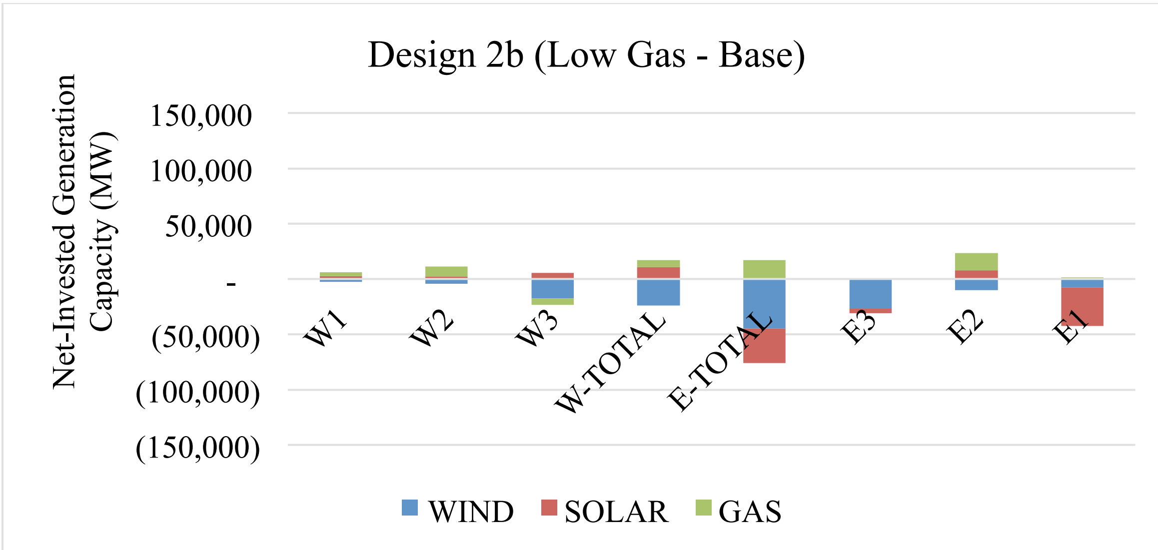

Figure 7-13: Design 2b - Low Gas

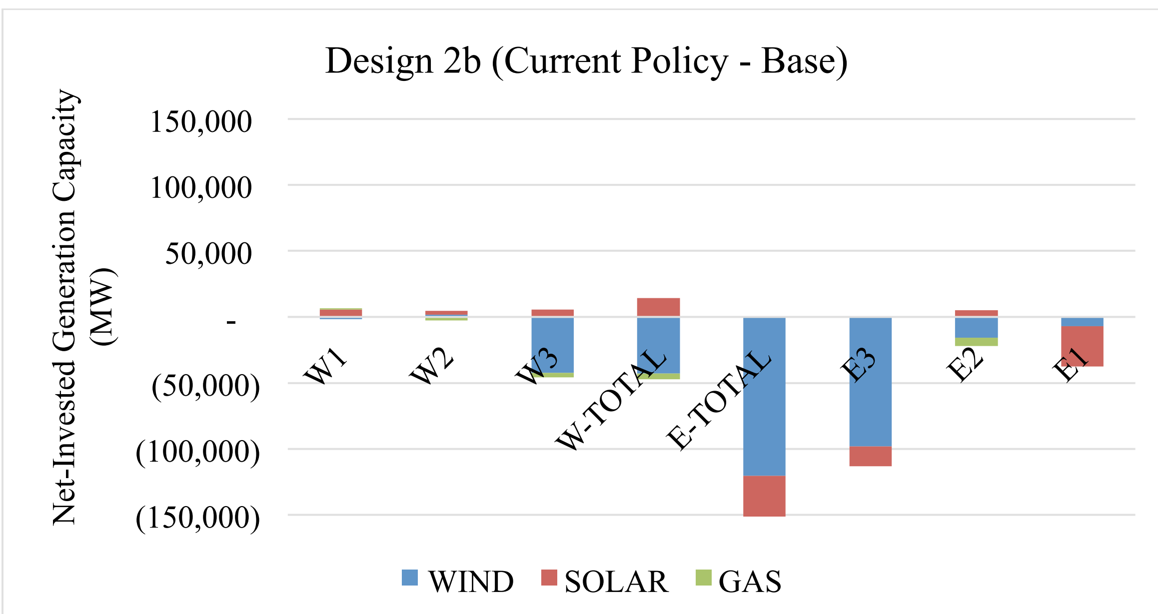

Figure 7-14: Design 2b - Current Policy

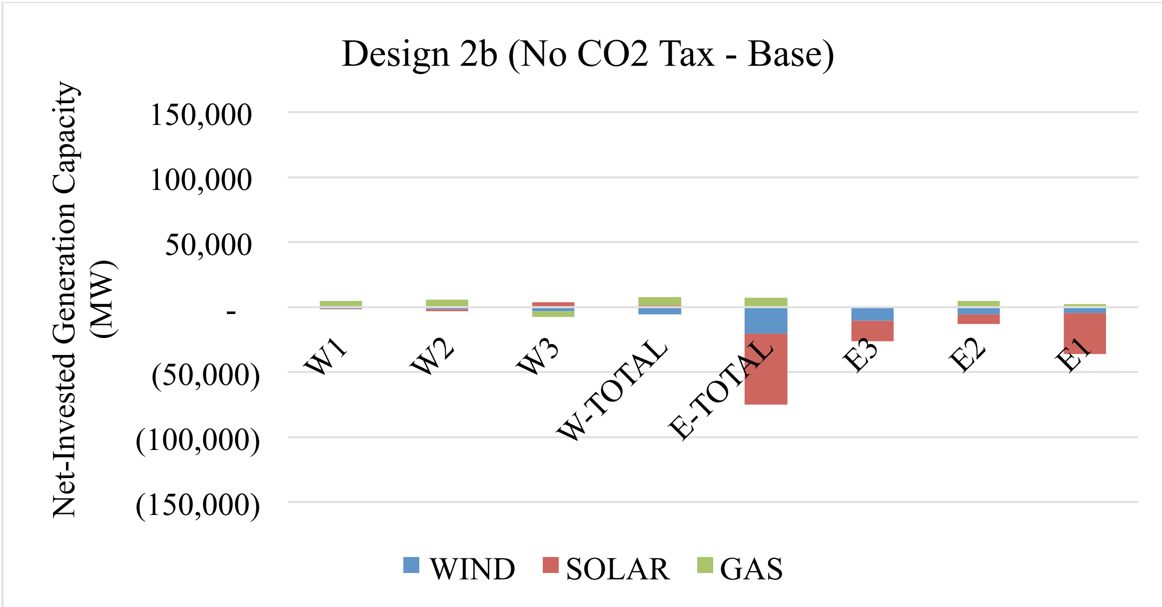

Figure 7-15: Design 2b - No CO2 Tax

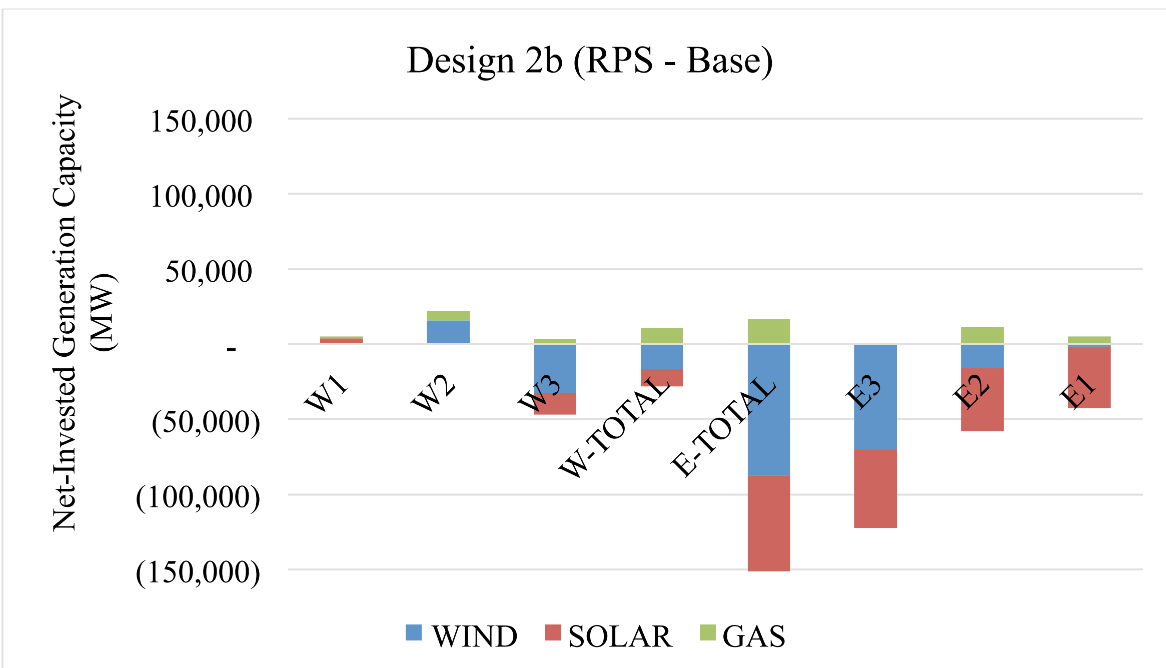

Figure 7-16: Design 2b - RPS

7.5 Design 3: Macro-grid Overlay

This section includes include the differences in generation expansion between sensitivities, compared to the base design. Figure 7-2 illustrate the changes in wind, solar and gas investments when each RSG must comply with the PRM obligation using local resources.

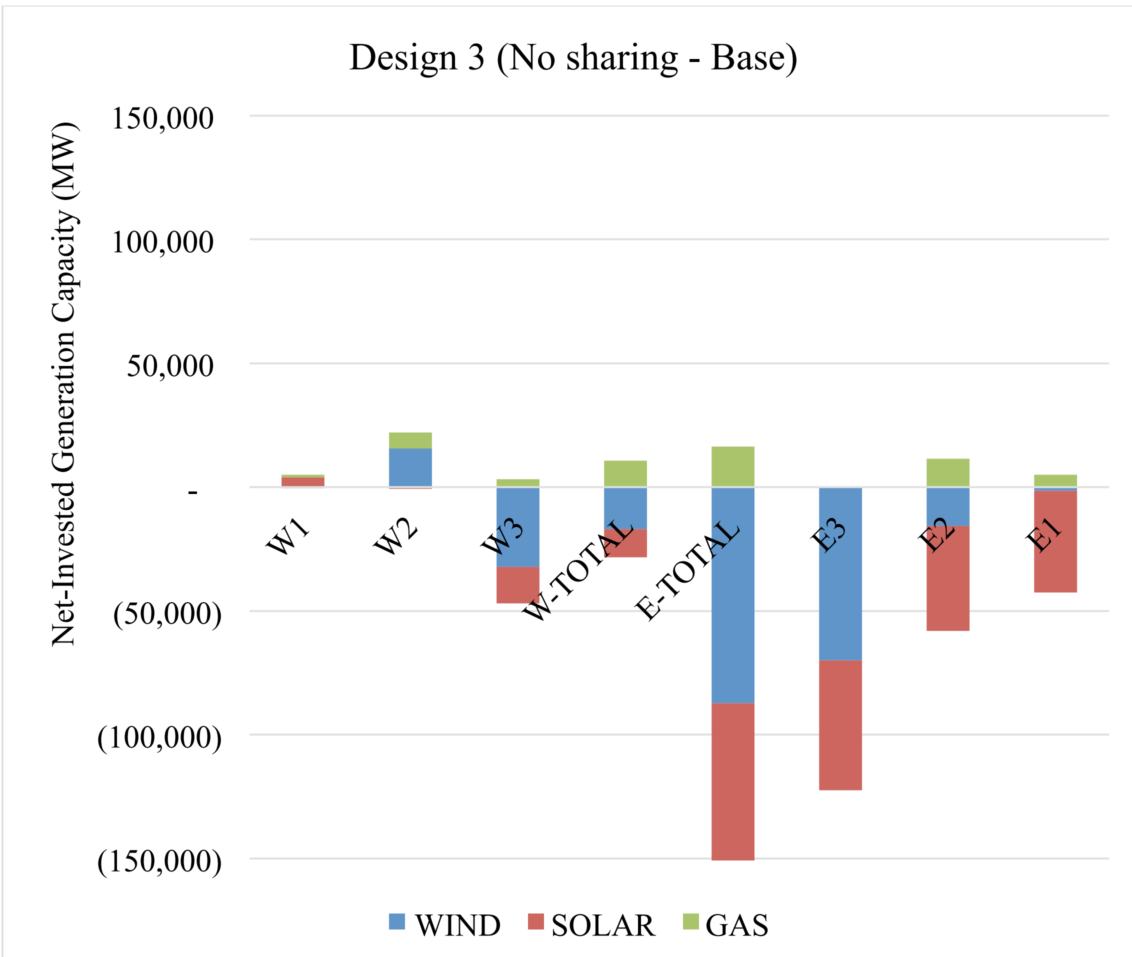

Figure 7-17: Design 3 - No Sharing

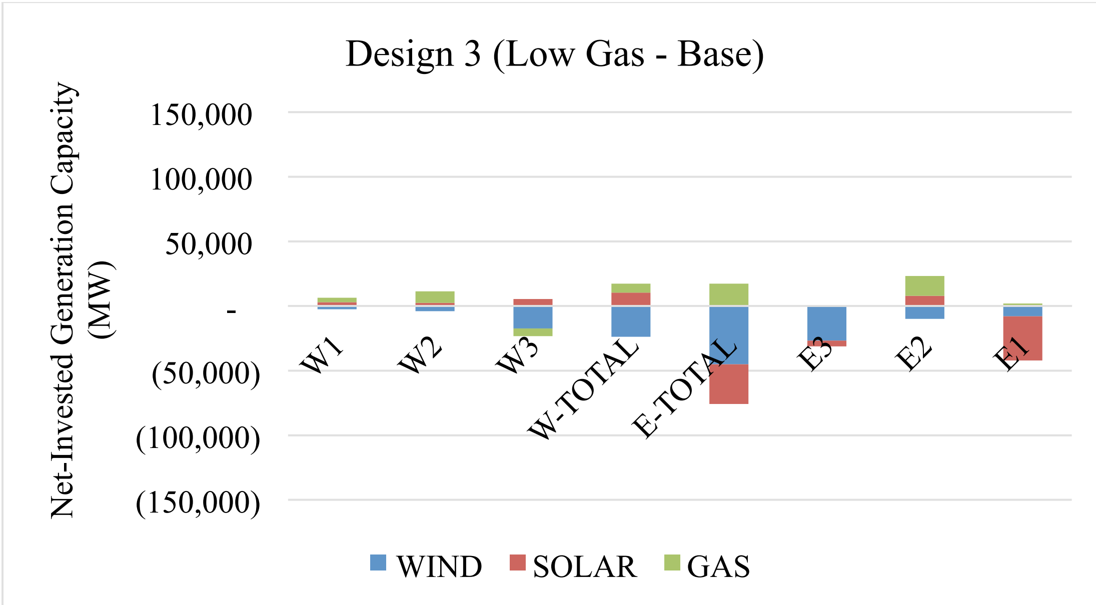

Figure 7-18: Design 3 - Low Gas

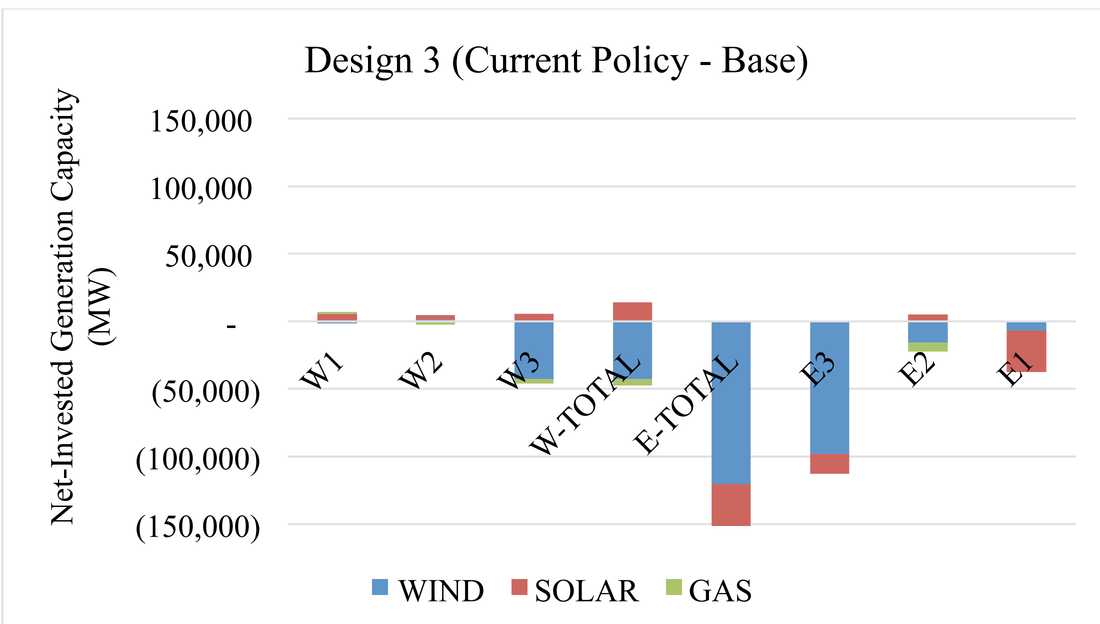

Figure 7-19: Design 3 - Current Policy

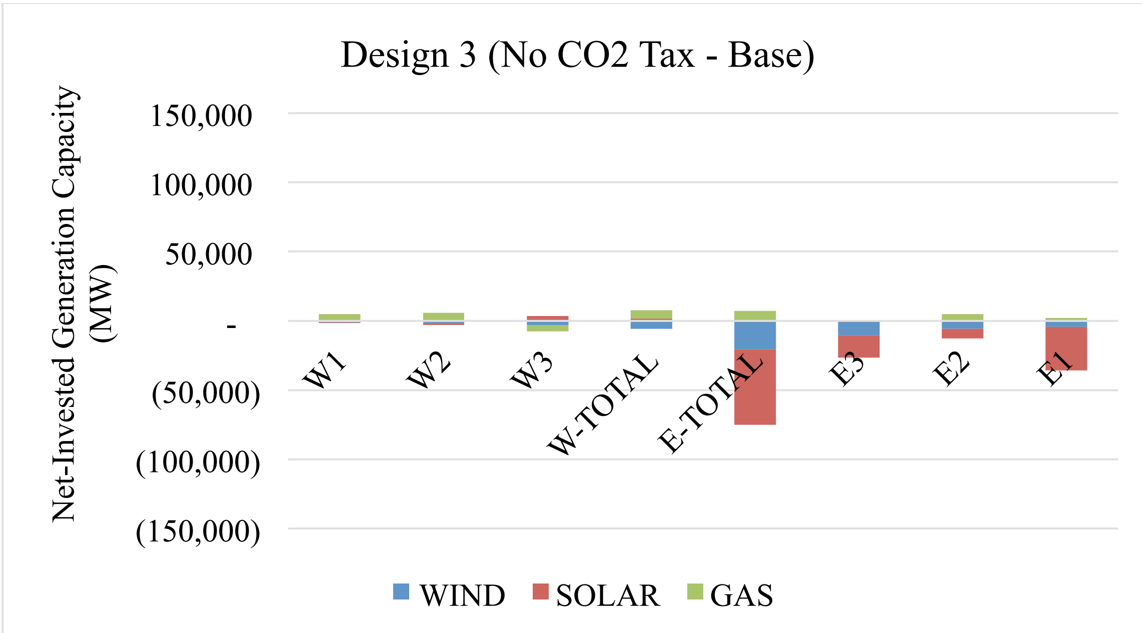

Figure 7-20: Design 3 - No CO2 Tax

7.6 Summary

In terms of transmission investments, each policy influences cross-seam transmission between the EI and WI in a different way. Cross-seams transmission between the EI and WI ranges between 7GW to 37GW as shown in Fig. 7-25. This results suggests that it is economic to increase the existing capacity between the EI and WI by 5 times and as high as 37 times.

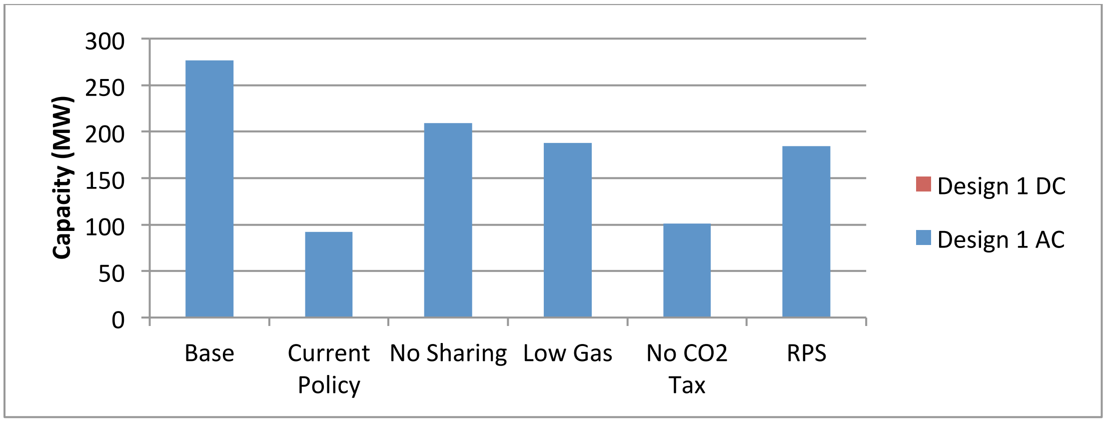

Figure 7-21: Transmission Upgrade per Sensitivity - Design 1

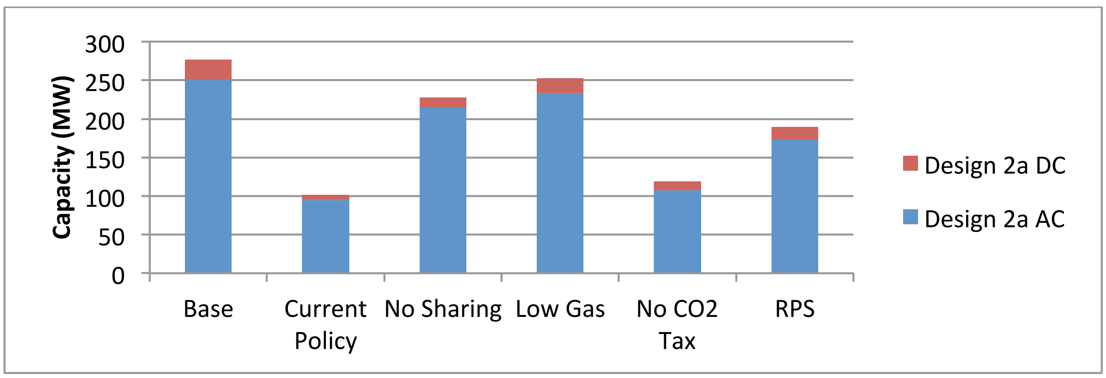

Figure 7-22: Transmission Upgrades per Sensitivity - Design 2a

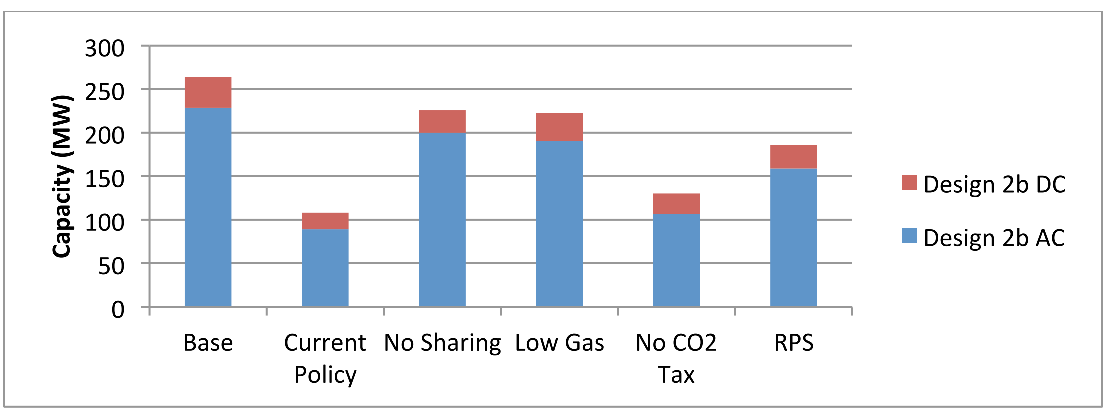

Figure 7-23: Transmission Upgrades by Sensitivity - Design 2b

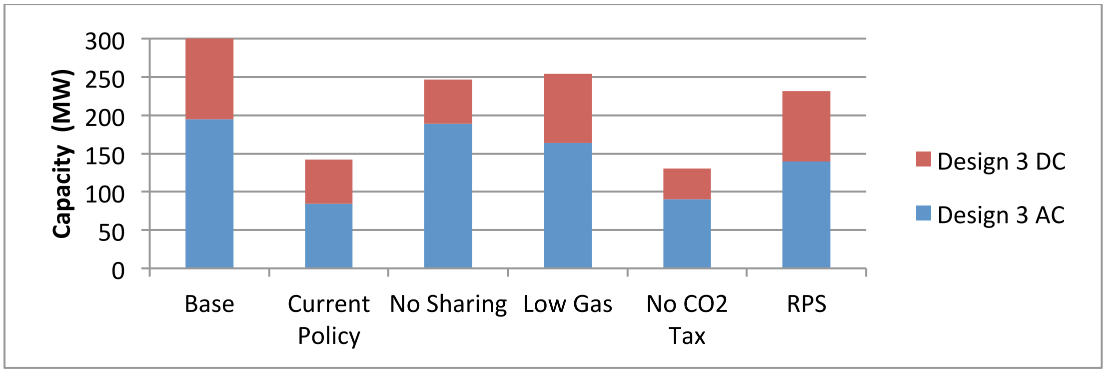

Figure 7-24: Transmission Upgrade per Sensitivity - Design 3

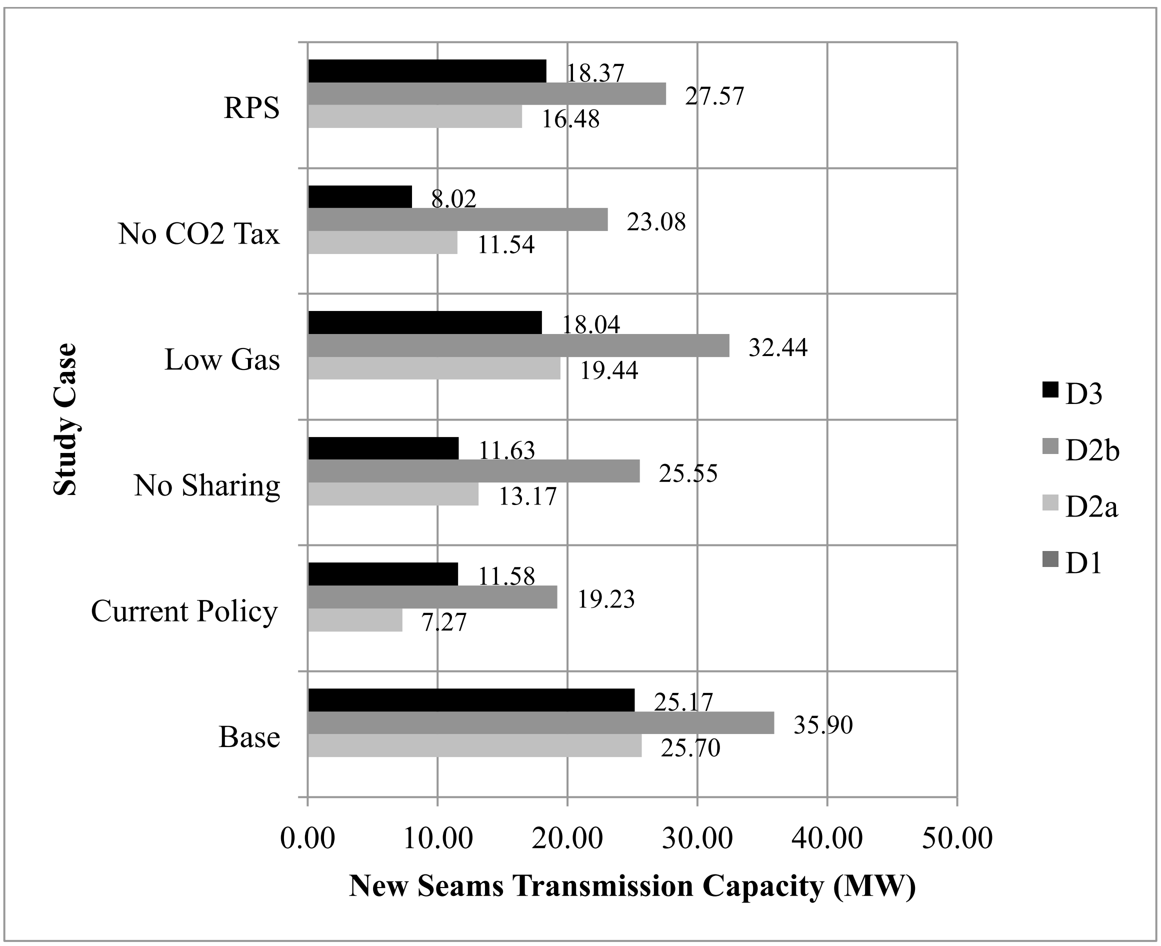

Figure 7-25: Range of Cross-Seams Transmission Capacity

CHAPTER 8. CONCLUSIONS

This dissertation explored the economic benefits of increasing transmission capacity between the EI and WI. Although the "cross-seam" transmission capacities observed in all four designs are sensitive to policy considerations, the sensitivity analysis showed that all designs pay for themselves in 15-years (B/C above 1). Furthermore, it was proven that capacity sharing creates economic value and drives HVDC investments regardless of future assumptions. The expectation that renewables will achieve much lower CAPEX and better performance (100-m wind towers and more efficient solar PV panes) in the next 20 years suggests that connecting the EI and WI using HVDC will be economically feasible in the near future.

The contributions of this dissertation are:

1) Development of an analytical CEP model that accounts for diurnal load diversity, annual load diversity, wind diversity, solar diversity, capacity sharing and operating reserves sharing.
2) Development of an industry-vetted database for the US Eastern and Western Interconnections, which include existing and candidate generation/transmission operational and investment data.
3) Development of four base designs for the US grid without and with capacity sharing.
4) Evaluated the robustness of each design by performing model-level sensitivities on the number of energy blocks, peak blocks and transmission candidate lines and quantify the robustness of futures uncertainties.

5) Assessed and analyzed the implications of future sensitivities on co-optimized investment decisions.

This work can be extended as follows:

1) Computational time: Decompose the formulation of the CGT-Plan using Bender's decomposition, or other methods suitable for large-scale models.
2) Transmission Expansion Planning (TEP) model: Re-formulate the CGT-Plan model as a MILP to account for the effects of changing impedances.
3) Generation Expansion Planning (GEP) model: Extend the retirements formulation to account for the lifetime of existing generation resources.
4) Capacity Credit: Include a dynamic capacity credit constraint to account for the changes in capacity contribution of wind/solar resources as a function of renewable penetration levels.

REFERENCES

Abraham, S., 2002. *National Transmission Grid Study.*

Andrew, B., Joachim, L. & Anna, N., 2017. Asia Pacific Super Grid: Solar electricity generation, storage and distribution.. *GREEN,* 2(4), pp. 189-202.

Battaglini, A., Lilliestam, J., Haas, A. & Patt, A., 2009. Development of SuperSmart Grids for a more efficient utilization of electricity from renewables sources.. *Journal of Cleaner Production,* 17(10), p. 9110918.

Bloom, A., 2016. *Eastern Renewable Integration Study.*

Bogdanov, D. & Breyer, C., 2016. North-East Asian Super Grid for 100% renewable energy supply: Optimal mix of energy technologies for electricity, gas and heat supply options.. *Energy Conversion and Management,* Volume 112, pp. 176-190.

Caspary , J., McCalley, J. D. & Sandars, S., 2015. *Proposed Eastern Interconnection and Western Electricity Coordinating Council Seams Study.*, CIGRE.

Corcoran, B. A., Jenkings, N. & Jacobson, M. Z., 2012. Effects of aggregating electric load in the United States. *Energy Policy,* 46(3), pp. 399-416.

DSIRE, 2017. [Online] Available at: http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2017/03/Renewable-Portfolio-Standards.pdf [Accessed 12 September 2017].

Eastern Interconnection Planning Collaborative (EIPC), 2011. *Formation of Stakeholder Process and Regional Plan Integration.*

FERC, 2016. *Order No. 1000 - Transmission Planning and Cost Allocation.* [Online] Available at: https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp [Accessed September 2017].

General Electric Consulting, 2016. *Pan-Canadian Wind Integration Study.*

Ho, J. et al., 2015. *Planning Transmission for Uncertainty: Applications and Lessons with the Western Interconnection.*

Kishore, T. S. & Singal, S. K., 2014. Optimal economic planning of power transmission: A review.. *Renewable and Sustainable Energy Reviews,* Volume 39, pp. 949-974.

Krishnan, V. et al., 2013. Modeling Operational Effects of Variable Generation within National Long-term Infrastructure Planning Software. *IEEE Transactions on Power Systems,* 28(2), pp. 1308-1317.

Krishnan, V. et al., 2016. Co-optimization of electricity transmission and generation resources for planning and policy analysis: review of concepts and modeling approaches. *Energy Systems,* 7(2), pp. 297-332.

Krishnan, V., McCalley, J., Lemos, S. & Bushnell, J., 2013. Nation-wide transmission overlay design and benefits assessment for the US. *Energy Policies,* Volume 56, pp. 221-232.

Li, Y. & McCalley, J. D., 2015. Design of a High Capacity Inter-Regional Transmission Overlay for the US. *IEEE Transactions on Power Systems,* January, 30(1), pp. 513-521.

Lumbreras, Sara, L., Banez-Chicharro, F. & Panche, C., 2015. *Modular Development Plan of the Pan-European Trnamission System 2050: Enhanced methodology to design optimal grid architectures for 2050.*

Lumbreras, S. & Ramos, A., 2016. The new challenges to transmission expansion planning. Survey of recent practice and literature review.. *Electric Power Systems Research,* May, Volume 134, pp. 19-29.

McCalley , J., Ryan , S., Sapp, S. & Testfasion, L., 2013. *Decision models for bulk energy transportation networks*.

McCalley, J. D. & Krishnan, V., 2014. A survey of transmission technologies for planning long distance bulk transmission overlay in US. *International Journal of Electric Power & Energy Systems,* Volume 54, pp. 559-568.

McDaniel, G. H. & Gabrielle, A. F., 1965. Load Diversity-Its Role in Power System Utilization. *IEEE Transactions on Power Apparatus and Systems,* 84(7), pp. 626 - 635.

McDonald, A. E. et al., 2016. Future cost-competitive electricity systems and their impact on US CO2 emissions. *Nature Climate Change.*

Mills, A. & Amol, R., 2010. Exploration of resource and transmission expansion decisions in the Western Renewable Energy Zone Initiative.. *Energy Policy.*

Munoz, F. D., Hobbs, B. & Kasina, S., 2014. An Engineering-Economic Approach to Transmission Planning Under Market and Regulatory Uncertainties: WECC Case Study.. *IEEE Transactions on Power Systems,* January, 29(1), pp. 307-317.

National Renewable Energy Laboratory, 2014. *The Western Wind and Solar Integration Study Phase 2.*

National Renewable Energy Laboratory, Ongoing. *North American Renewable Integration Study.* [Online] Available at: http//www.nrel/gov/analysis/naris.html [Accessed 11 September 2017].

NREL, 2017. *Interconnections Seams Study.* [Online] Available at: https://www.nrel.gov/analysis/seams.html [Accessed 1 November 2017].

Osborn, D., 2014. *HVDC for System Expansion-East and West.* [Online] Available at: https://www.ieee-pes.org/presentations/gm2014/PESGM2014P-002402.pdf

Osborn, D., 2016. *Designing self-contingent HVDC systems with the AC systems.* Boston, IEEE, pp. 1-4.

Pache, 2015. *Enhanced pan-European transmission planning methodology.* Denver, IEEE, pp. 1-5.

Short, W. et al., 2011. *Regional Energy Deployment System (ReEDS).*

Spyrou, E., Hobbs, B., Johnson, R. & McCalley, J. D., 2016. What are the benefits of co-optimizing transmission and generation investment? Eastern Interconnection Case Study. *IEEE Transactions on Power Systems,* pp. 1-10.

Taggart, G., James, G., Dong , Z. & Russell, C., 2012. The Future of Renewables Linked by a Transmission Asian Grid. *IEEE Transactions on Power Systems,* 100(1), pp. 348-359.

Taylor, C., 1979. *Interconnection of Eastern and Western North American Power Systems in the Early 1980's.*

WECC, 2016. *Accompanies WECC Draft 2034 Reference Case.*

Western Area Power Administration (WAPA), 1994. *East/West AC Intertiew Feasibility Study.*

You, S., Hadley, S. W., Shankar, M. & Liu, Y., 2016. Co-optimizing generation and transmission expansion with wind power in large-scael power grids: Implementation in the US Easter Interconnection.. *Electric Power Systems Research,* Volume 133, pp. 209-218.

APPENDIX: LINEARIZATION OF THE REGULATION RESERVES INEQUALITY CONSTRAINT

Under the assumption that forecasting errors of wind, solar, and load at the continent level are independent and normally distributed, the standard deviation of the net-load can be approximated as shown in Eq. (A-1).

$$\sigma^{NL} = \sqrt{(\sigma^L(t))^2 + (\sigma^W(t))^2 + (\sigma^S(t))^2} \qquad \text{(A.1)}$$

where σ^L is the standard deviation of load at year t, σ^W is the standard deviation of wind at year t, and σ^S is the solar standard deviations at year t. The linear approximation presented in (Krishnan, et al., 2013) is defined as:

$$\sqrt{L^2 + W} \approx L + \frac{W}{2L} \qquad \text{(A.2)}$$

The variance of load, wind, and solar can be defined as:

$$\sigma^L(t)^2 = (\sigma^L(t-1))^2 \times (1 + \gamma(t))^2 \qquad \text{(A.3)}$$

$$\sigma^W(t)^2 = (\sigma^W(0))^2 \times \frac{CapW}{CapW(0)} \qquad \text{(A.4)}$$

$$\sigma^S(t)^2 = (\sigma^S(0))^2 \times \frac{CapS}{CapW(0)} \qquad \text{(A.5)}$$

where $\gamma(t)$ is the load growth load per year, $(\sigma^W(0))^2$ is the standard deviation of wind in year t=0, $(\sigma^S(0))^2$is the standard deviation of solar in year t=0, $CapW$ is the nameplate capacity of wind in year t=0, $CapS$ is the nameplate capacity of solar in year t=0. Assuming that:

$$\sigma^L = L \qquad \text{(A.6)}$$

$$\sigma^S(t)^2 + \sigma^W(t)^2 = W \qquad \text{(A.7)}$$

Equations A.6 and A.7 can be substituted into A.1 and a linear relationship is achieved. The above linearization was developed in collaboration with Dr. Ali Jahanbani.