

NEW TRANSMISSION PLANNING METHODOLOGY FOR
REQUESTING PROPOSALS FOR WIND GENERATION

BY

ANDREW L. ISAACS

A Thesis submitted to
The Faculty of Graduate Studies
In Partial Fulfillment of the Requirements for the Degree of

MASTER OF SCIENCE

Department of Electrical and Computer Engineering
University of Manitoba
Winnipeg, Manitoba

Copyright © Andrew Isaacs, 2010

Abstract

The increasing interest in renewable energy technologies during the last decade has caused conventional transmission and generation expansion planning methodologies to be strained and in some cases abandoned. This is due both to the quantity of generator interconnection requests and the constraints imposed by deregulated energy industry structures. One technique used to control the influx of renewable generation while maintaining competitive principles is a Request for Proposals (RFP). However, lack of transmission planning due to a disconnection between generation and transmission owners, difficulty in identifying viable projects, and high risk for proponents stand as obstacles to the goals of an RFP.

This research proposes a procedure which minimizes the effect of these obstacles; meeting the purchaser requirements for low price and combining conventional planning concepts with feedback from competitive structures. The general features of the method include definition of generation limits and study area, expansion plan design, transmission cost evaluation, optimal selection of requested generation levels, and final selection of successful proponents. The method is shown to be effective in creating an RFP where proponents are well-informed and provided with cost certainty to reduce bid price, buyers are able to determine end costs of their energy, and good expansion planning principles are maintained. A case study using a real system in New Mexico demonstrates these concepts.

Acknowledgements

There have been very many positive influences and people eager to help me complete this project. In particular:

I would like to thank my Advisor, Dr. Athula Rajapakse, for his excellent guidance and challenging advice, as well as the examining committee for the time taken to read this report.

I would like to extend special thanks to my employers at Electranix, who have been nothing but supportive, providing working time and financial assistance where required, expert guidance, understanding and encouragement through the long course of my graduate work.

Other supportive influences through the course of this research include Udaya Annakkage of the University of Manitoba, Gerald Brooks of GridPower Consultants, and Ron Diduch of Sequoia Energy Inc.

I would like to thank Crystal Isaacs and Jeremy Sneath for providing valuable editorial support.

This research was sponsored in part by the National Science and Engineering Research Council of Canada (NSERC), partnering with Electranix Corporation in providing an Industrial Post-Graduate scholarship.

Finally, my thanks go to my wife Crystal and daughters Raelynn and Lucy for their unfailing ability to provide perspective on the most challenging of problems, technical or otherwise.

Table of Contents

Abstract	ii
Acknowledgements	iii
Table of Contents	iv
List of Figures	vii
List of Tables	viii
Chapter 1 Introduction	1
1.1 Background	1
1.1.1 The Way Things Were: Conventional Power System Expansion Planning.....	1
1.1.2 A Problem: Transmission Expansion Planning Under Deregulation	1
1.1.3 A Solution: Request for Proposals	2
1.2 Objectives.....	3
1.3 Thesis Outline	4
Chapter 2 Background	6
2.1 Power System Planning Objectives.....	6
2.2 The Effect of Deregulation on Transmission Planning.....	7
2.3 Comparison of Deregulated and Regulated Planning Environments.....	9
2.3.1 Regulated Planning Environments	9
2.3.2 Deregulated Planning Environments	10
2.4 Conventional Transmission and Distribution Planning Concepts.....	11
2.4.1 Short Term Planning Horizon.....	11
2.4.2 Long Term Planning Horizon.....	11
2.4.3 Long Term Planning Process Level 1: Spatial Load Forecast.....	12
2.4.4 Long Term Planning Process Level 2: Transmission Planning.....	12
2.4.5 Additional Planning Process Levels: Substation and Distribution Planning..	12
2.4.6 Interconnection Queue.....	13
2.4.7 Deterministic Reliability Criteria	13
2.4.8 Probabilistic Reliability Evaluation.....	14
2.5 Recent Transmission and Distribution Planning Concepts	15
2.5.1 “Extent of Use” Cost Allocation Methods	15
2.5.2 Marginal Network Cost Allocation Methods	18
2.5.3 Centralized Deregulated Transmission Planning Methods	20

2.5.4	Project-Based Deregulated Transmission Planning Methods	22
2.5.5	Large Scale Wind Integration Studies	23
2.5.6	Competitive Renewable Energy Zones (CREZ)	24
2.6	Request for Proposals	24
2.7	Additional Background Literature	25
Chapter 3 Overview of Cluster Study Approach		26
3.1	Objective	26
3.2	Summary of Cluster Study and RFP Process	26
3.2.1	Step 1 – Define Generation Limits	26
3.2.2	Step 2 – Define Interconnection Locations and Study Area	26
3.2.3	Step 3 – Create Transmission Expansion Plans for all Levels of Generation	27
3.2.4	Step 4 – Determine Transmission Capital Costs for all Expansion Plans	28
3.2.5	Step 5 – Calculate Total Transmission Costs per MW	29
3.2.6	Step 6 – Select Optimal Amounts of Wind	29
3.2.7	Step 7 – Request for Proposals	29
3.2.8	Step 8 – Select Successful Proposals	30
3.2.9	Step 9 – Calculate Total Energy Costs to Buyer	30
3.2.10	Step 10A – Plan Rejection and Re-evaluation of Proposals	31
3.2.11	Step 10B – Plan Acceptance and Implementation	31
3.3	Introduction to Case Study	31
Chapter 4 Defining Study Parameters.....		33
4.1	Generation Limits	33
4.2	Generation Limits – Case Study	33
4.3	Study Area Selection and Interconnection Locations	34
4.4	Interconnection Locations – Case Study	35
Chapter 5 Expansion Plan Design.....		38
5.1	Expansion Plan Process and Methodology	38
5.2	Planning Study Alternative Development	42
5.3	Expansion Plan – Case Study	43
5.3.1	Expansion Plan Development	43
5.3.2	Notes on Case Study Methodology	43
5.3.3	Existing Transmission System Analysis (Alternative 0)	44
5.3.4	Alternative 1 System Analysis	46
5.3.5	Alternative 2 System Analysis	49
5.3.6	Alternative 3 System Analysis	51
5.3.7	Expansion Plan Cost Evaluation	53

5.3.8	Expansion Plan Loss Evaluation	55
5.4	Optimal Cost Breakpoint Selection – Case Study.....	58
5.4.1	Minimization of Cost per MW	58
5.4.2	Cost Breakpoint Selection	59
Chapter 6	RFP and Expansion Implementation	62
6.1	RFP Design Philosophy	62
6.2	Required RFP Elements	62
6.3	Proposal Submission – Case Study	63
6.4	Proposal Selection – Case Study.....	64
6.4.1	Rank Proposals by Price.....	64
6.4.2	Determine Energy Costs for Each Alternative	68
6.4.3	Select Alternative	72
6.5	Expansion Implementation – Case Study.....	73
6.6	Comparison Between Proposed Method and Existing RFPs	73
6.6.1	Manitoba Hydro RFP (2007).....	74
6.6.2	SaskPower RFP (2010).....	75
6.6.3	BC Hydro Clean Power Call (awarded 2010)	77
6.6.4	Hydro-Quebec RFP (awarded 2008)	78
6.7	Extension of Concepts to a Feed-in Tariff (FIT) Structure.....	78
Chapter 7	Conclusions and Future Work	80
7.1	Conclusions	80
7.1.1	The Challenge of Urgency.....	80
7.1.2	Presentation of Historical Background and State of the Art	80
7.1.3	Presentation of New RFP Methodology.....	81
7.1.4	Demonstrate RFP Methodology Using Case Study	81
7.2	Future Work	81
Chapter 8	References.....	82

List of Figures

Figure 1 - MISO Cost Allocation Table Based on Distribution Factor Methods [39]	17
Figure 2 - Process Flow Diagram - Part A.....	27
Figure 3 - Process Flow Diagram - Part B.....	28
Figure 4 - Costs for Example Transmission Expansion for Varying Wind Amounts	29
Figure 5 – Combined Wind Resource and Transmission Map for Case Study Area	32
Figure 6 – Case Study: Interconnection Queue on Transmission/Wind Map	37
Figure 7 - Expansion Planning Study Decision Process: Part 1	39
Figure 8 - Expansion Planning Study Decision Process: Part 2	40
Figure 9 - Expansion Planning Study Decision Process: Part 3	41
Figure 10 - Expansion Planning Study Decision Process: Part 4	42
Figure 11 – Case Study: Existing Transmission System Before Network Expansion	45
Figure 12 – Existing Transmission System Power Flow with 240 MW of Wind Added.	46
Figure 13 – Case Study: Network Expansion Alternative 1	47
Figure 14 – Alternative 1 PSSE Power Flow with 440 MW of Wind Added	48
Figure 15 - Alternative 1 PSSE Power Flow with Example Contingency	49
Figure 16 – Case Study: Network Expansion Alternative 2.....	50
Figure 17 - Alternative 2 PSSE Power Flow with 840 MW of Wind Added.....	51
Figure 18 – Case Study: Network Expansion Alternative 3.....	52
Figure 19 - Alternative 3 PSSE Power Flow with 1550 MW of Wind Added.....	53
Figure 20 – Case Study: Expansion Costs Varying with Installed Wind	54
Figure 21 – Case Study: Scaled Annual Wind Farm Load Duration Curve.....	56
Figure 22 – Case Study: Variation of Incremental Losses with Wind Capacity	57
Figure 23 - Case Study: Energy Costs for Transmission per MW of Installed Wind	61
Figure 24 – Case Study: Energy Costs for Alternative 1.....	69
<i>Figure 25 – Case Study: Energy Costs for Optimal Breakpoint 2</i>	<i>70</i>
Figure 26 – Case Study: Energy Cost for Optimal Breakpoint 3	72
Figure 27 - Saskatchewan Wind Resource Map Overlaying Transmission Grid	76

List of Tables

Table 1 – Case Study: Generation Limits Based on Points of Delivery	34
Table 2 – Case Study: Reference Interconnection Queue in Study Area	36
Table 3 – Case Study: Power flow Results for Existing System	45
Table 4 – Case Study: Power flow Results for Alternative 1	47
Table 5 – Case Study: Power flow Results for Alternative 2	50
Table 6 – Case Study: Power flow Results for Alternative 3	52
Table 7 – Case Study: Breakdown of Costs for Expansion Alternatives	54
Table 8 – Case Study: Dispatch Levels for Loss Evaluation.....	56
Table 9 – Case Study: Comparison of Energy Losses Using LDC and Capacity Factor .	57
Table 10 – Case Study: Unsorted Summary of Random Bid Prices by Project	64
Table 11 – Case Study: Proposals Ranked by Price, Constrained by Alternative 1	65
Table 12 – Case Study: Proposals Ranked by Price, Constrained by Alternative 2	66
Table 13 – Case Study: Proposals Ranked by Price, Constrained by Alternative 3	67
Table 14 – Case Study: Total Cost of Energy for Expansion Alternative 1	70
Table 15 – Case Study: Total Cost of Energy for Expansion Alternative 2	71
Table 16 – Case Study: Total Cost of Energy for Expansion Alternative 3	72
Table 17 – Comparison Between Manitoba Hydro RFP Process and New Method	75
Table 18 – Comparison Between SaskPower RFP Process and New Method	76
Table 19 – Comparison Between BC Hydro RFP Process and New Method	77

Chapter 1 Introduction

1.1 Background

1.1.1 The Way Things Were: Conventional Power System Expansion Planning

Traditional generation and transmission planning involved planning horizons extending as far as 20 years or more. Proposals to build new generation were relatively infrequent and an interconnection study procedure was designed to accommodate each request. This procedure involved a request by the generator to interconnect at a given location at a specified date, and the transmission provider (often also the owner of the generator) would place the request into a “queue.” Interconnection studies were then performed to evaluate the merit of the generator, assuming all generation with prior queue status would be in service.

If new transmission was required to accommodate the new generation, planners integrated these facilities into their long term plans for network development. The lead time for new transmission was often shorter or comparable to that of new generation.

1.1.2 A Problem: Transmission Expansion Planning Under Deregulation

This process was not adjusted when deregulation allowed independent power producers (IPPs), completely separated from the transmission planners, to propose large plants with in-service dates extending as little as 2 years from their interconnection request. The simplest approach to dealing with the uncertainty this introduced into the long term planning horizon was to deal with each interconnection as it came. Each interconnection was and is often still evaluated assuming all prior queue requests are in service, though sensitivity analysis is often done to help mitigate risk of projects dropping out of the queue.

Many North American utilities are beset with a lengthy interconnection queue filled mainly with wind generation interconnection applications. The sheer volume of interconnection requests, often located geographically close to one another with overlapping in-service dates, causes the traditional interconnection procedure to become

overwhelmed. Utility engineering resources are often not equipped to handle the study volume. Further, the inability of the utility to predict which of the generators will ultimately be built adds an element of uncertainty and can throw the interconnection study process into a continuing cycle of study and restudy.

1.1.3 A Solution: Request for Proposals

There are many proposed solutions to these problems. Some utilities and load-serving transmission providers use Requests for Proposals (RFP) as a tool to help control generation expansion and move past the issues with their clogged interconnection queues. A traditional RFP is issued by an energy purchaser as a statement of intent to purchase energy from one or more energy suppliers. It is assumed that competition between energy suppliers will result in the lowest possible price for energy. However, several factors present obstacles to the achievement of the goals of controlled expansion and low price:

Lack of Transmission Planning – Energy suppliers often do not understand, or do not possess the resources to effectively account for principles of transmission expansion planning, such as the limits of existing transmission infrastructure, expected load growth, generation and load balancing, and reliability concerns. Therefore, within their respective project proposal development processes, there exists limited accounting for transmission infrastructure costs, or optimal generation placement from a transmission planning point of view.

Infeasible Projects – The relatively low cost and low effort involved in submitting proposals can result in projects being proposed which may not be developed to a sufficient degree. Historically purchasers who issue RFPs are often left with “lowest price” proposals which may not in fact be feasible, since in some cases the supplier waits to “win” the RFP before developing their project in earnest and performing required due diligence. In the case where a project that has been selected is deemed to be infeasible, the buyer may be required to issue a new RFP or re-open past negotiations.

High Risk for Generators – If the energy purchaser is not willing to provide sufficient long term price certainty to the supplier, the supplier must compensate by incorporating these risks into their proposal price.

This research proposes a new methodology for issuing an RFP such that these obstacles are reduced or eliminated.

1.2 Objectives

This research accomplishes the following:

1. To present a historical background leading to the current state of the industry, as well as a summary of the current state of the transmission planning field, especially relating to renewable energy integration.
2. To present a set of steps that may be followed by an energy purchaser or transmission provider to ensure a fair and successful RFP. The process has the following characteristics:
 - a. Addresses the concerns encountered in typical RFP processes to date, including a lack of coordination with long term planning goals, infeasible “low cost” proposals, high risk and cost uncertainty for generators, and ultimate high costs for the energy purchaser.
 - b. Produces a well defined transmission expansion planning process using cluster study principles, ensuring an ultimate build-out which is reliable, effective, and informed by competitive market participants and other stakeholders.
 - c. Presents the overall energy costs to the purchaser, and allows adjustment of the purchaser’s original intent according to feedback generated throughout the process, especially with regard to the costs. In other words, if the amount of energy requested is very expensive, the process has a mechanism to alter the request size to reduce the costs.
3. To demonstrate the proposed concepts using a case study based on a transmission system and wind interconnection queue located in Northeast New Mexico.

1.3 Thesis Outline

Chapter 2 presents background information pertaining to this research. Included in this chapter is a historical perspective of the field of transmission planning, some general principles guiding traditional and modern planning, and some recent developments in the field of transmission planning, especially in response to the difficulties encountered by planners in the face of deregulation and massive increases in renewable energy penetration. This chapter concludes with a brief sampling of further literature exploring these themes, as well as presenting some examples of similar RFP processes and highlighting the differences between those processes and the one proposed here

Chapter 3 presents an overview of the cluster study process, including a high level flow diagram illustrating the steps required. The case study used to illustrate the process is introduced in this chapter.

Chapter 4 describes how to define study parameters for the RFP and cluster study process, and why this is critical to the planning process. Important parameters include limiting new generation that may be connected, which usually is less than the amount of generation available, as well as selecting the study area and good interconnection locations. This is the most difficult element of the process to do correctly, since it relies on stakeholder input outside the control of the utility planners. Sub-optimal selection of these elements could jeopardize the entire RFP procedure.

Chapter 5 presents planning study methodologies, and includes an example application of these techniques to the case study using real world systems and industrial simulation tools. In addition, this chapter presents the calculations required to select optimal transmission expansion alternatives for presentation in the RFP, based on costs.

Chapter 6 deals with the RFP itself, both suggesting elements that must be present, and highlighting philosophical goals that should guide the request. In the case study example, proposal bids are evaluated and overall costs to the energy purchaser are compared.

Chapter 7 presents challenges that require further exploration and future work that is recommended.

Chapter 8 contains a list of references used in the course of this research.

Chapter 2 Background

2.1 Power System Planning Objectives

Broadly stated, the objective of transmission and generation planning is “to provide an orderly and economic expansion of equipment and facilities to meet the future electrical demand with an acceptable level of reliability.” [1] It could be added that an additional objective is to consider non-technical societal impacts alongside the orderly, economic expansion, such as impact to the environment, cultural sensitivities, regulatory issues, competitive influences, and other factors. Individual planning objectives vary between utilities according to that specific utility’s mission and values.

In general, these objectives are common to transmission system planners:

1. *Meet Technical Criteria for Quality of Delivered Power*
This includes meeting voltage standards for spread (maximum difference between highest and lowest delivered voltages), flicker, harmonics, imbalance, etc.
2. *Provide Acceptable Continuity of Service*
Maintaining a reliable system requires that continuity of service is provided to the end customer or load (distribution systems), ensuring that the wider system is robust and able to remain stable and functional under contingency conditions (transmission systems), and that the current and future load will be adequately served (generation systems and transmission systems).
3. *Consider Future Expansion*
In order to meet forecasted load growth, transmission expansion must be planned to accommodate increased generation.
4. *Optimize Economic Benefit*
Transmission planners must evaluate the economic impacts of all expansion planning, meeting reliability requirements in the short and long term to the highest economic benefit possible.
5. *Meet Non-Engineering Criteria*
These criteria include regulatory, political, environmental, aesthetic, and others.

2.2 The Effect of Deregulation on Transmission Planning

Electricity transmission regulation developed as a science very early in the 20th century, structured such that a regulatory body would enforce the rights and responsibilities of both a power company and its customers. Regulatory bodies placed an “obligation to serve” on power companies, which required that price discrimination or other preferential treatment would not occur among customers, and that electricity rates would be controlled, based on the value of investment plus a fair and reasonable rate of return. Regulatory bodies also granted monopoly status to the power companies, protecting them from competitive forces.

Many decades of academic and regulatory effort were spent understanding how best to deliver power to an expanding population and a growing economy. “Integrated Resource Planning” and “Least Cost Planning” dominated the philosophical landscape of regulators, and transmission and generation expanded using strict and carefully monitored adherence to these philosophies. Under this regulated environment, transmission and generation expansion planning was based in principle on minimizing the cost of energy to consumers, while maintaining acceptable quality of delivered power, by forecasting the demand and expanding the power grid in an optimal fashion. The financial and reliability costs resulting from failure to meet these goals by the electricity providers was borne by the energy consumers.

In the 70’s and 80’s, due to rising fuel costs, perceived failures by power companies to accurately predict demand, and a shifting philosophical landscape favouring competition as a panacea for economic troubles, pressure increased on regulators to open up competitive markets that would allow independent generators to compete in order to meet the current and future demand [2]. Additional pressures were brought to bear by “free market” lobby groups and cultural forces in the United States which were becoming stronger in the wake of recent successes enjoyed by telecommunication deregulation efforts.

Following the restructuring efforts by the US government under the Energy Policy Act in 1992 [3] and FERC orders 888 and 889 in 1996 [4][5], there began a widespread separation between transmission providers and power generation companies. Regional Transmission Organizations (RTOs) were established to operate transmission infrastructure and administer electricity markets. Regulators allowed transmission providers to recover expansion costs incurred by the connection of new generation. The risks associated with poor demand forecasts, rising fuel costs, and other factors shifted from the consumers to the generating companies and independent power producers.

The effect this restructuring had on transmission planning was dramatic, since the organizations previously responsible for predicting demand, and planning generation and transmission expansion to meet that demand were suddenly deprived of control over where and when generation would be built. Integrated Resource Planning was no longer strictly possible without this control, and the primary objective of generating companies changed from minimizing cost to the consumers, to maximizing profit. The transmission utilities charged with planning the expansion of their respective networks found themselves faced with increased risk. Optimal expansion strategies that were complex prior to deregulation became too difficult with the added uncertainties, and were often abandoned by planners.

There remain regions of North America that are fully or partially regulated in the traditional sense. Among these are most Canadian provinces, except for Alberta and Ontario. Although the Mexican system has separate generation and transmission companies and current restructuring efforts are underway, all companies are state-owned, and private investment in energy is heavily constrained by the Mexican constitution [6]. In these regulated regions, traditional generation and transmission expansion planning methods remain in use.

A broad presentation of the State of the Art in relation to transmission expansion planning, specifically with regard to modeling of the expansion problem, is presented by in reference [7].

2.3 Comparison of Deregulated and Regulated Planning Environments

The overall goals and objectives for planners in regulated and deregulated environments, while somewhat aligned, differ in their implementations and tend to cause the power network to grow in different ways.

2.3.1 Regulated Planning Environments

A regulated planning environment will be defined here as an environment in which a central body directly controls the transmission and generation facilities (either owning the generation facilities or purchasing the power as the sole buyer), and sells the power to the load customers.

Characteristics of a regulated environment may include:

- “Vertically integrated” style of control for the various components of the utility. This implies a hierarchical structure of component parts within the company or utility, with a common owner over all parts working towards a common goal.
- Lower internal transaction costs, since the various components of the company share a common owner and goals.
- Increased control over all aspects of the system produces much lower uncertainty, and decreases the risk in investment.
- Regulated environments generally form monopolies, and hence must be controlled or limited through external regulation to protect consumers.
- Large nature of integrated or regulated utilities cause an increase in bureaucratic overhead, resulting in a large “inertia”, or rigid organizational structure, with an inflexibility that makes it difficult to rapidly respond to changing socioeconomic or political forces.
- Generation is prioritized in planning, with the assumption that whatever transmission is required can be built. Due to the regulatory structure, all investment costs can be recovered as the consumer rates are controlled proportionally to costs [8].

- May be characterized as “least-cost” planning, which considers the optimal plan to be the plan that meets present and future load requirements while minimizing investment costs [9].
- All data, such as generation plans, required return on investment, existing network data, demand forecasts, etc, is available to transmission planners [9].

2.3.2 Deregulated Planning Environments

Deregulation of the power system has occurred in many countries over the last few decades. It was believed that this would ultimately cause electricity prices to fall due to competition, and new technologies would emerge. A “deregulated” planning environment is defined here simply as an environment which separates the generation, distribution, and transmission components of the power system into separate entities. The generation providers compete with each other in an open market with the goal of maximizing their profits. Certain constraints, such as reliability, environmental, security, and economic factors are usually imposed by external regulatory bodies.

Characteristics of a deregulated environment may include:

- High level of uncertainty for transmission planners due to the lack of control over planned generation. In other words, at the time transmission construction commitments needs to be made, future generation may not be known.
- Since transmission infrastructure costs money, generators can be motivated to minimize network investments. Their profits are negatively impacted by expansion spending, and they are not concerned with meeting future load growth. In some cases, independent generators are motivated to deliberately consume all available transmission, giving themselves an advantage over potential competing market participants.
- Since transmission becomes a service for the generators, its pricing can be a major factor in expansion, and a control variable for the efficient use of transmission.
- Two main types of transmission planning approaches may be used: The first is decentralized planning by investors to determine the expansion of the

network on a per-project basis, with the fundamental motivations being normal commercial incentives. The second is a form of centralized planning which attempts to enhance the overall transmission capability [9].

- Either by the confidential nature of data in competitive markets, or by conflict of interest or other regulation, data flow from generators to transmission providers can be restricted, and flow from transmission providers to generators can be restricted by market rules and standards of conduct.
- Due to high risk, capital recovery of investment may be uncertain.
- Due to strategic influences, electricity prices in deregulated markets can be significantly higher than in regulated markets [10].

2.4 Conventional Transmission and Distribution Planning Concepts

2.4.1 Short Term Planning Horizon

Short term planning horizons are mainly driven by lead time required for installation of new equipment, while ensuring that standards and criteria are met in the process of supplying customer load. It is very project oriented, leading usually to a set of separate projects each pertaining to a specific need in the system. The short term planning horizon is dependent on the situation, but would usually be in the 5 year range.

2.4.2 Long Term Planning Horizon

Long term planning is an internal planning step which has an output of a short-term course of action. Long term planning is beneficial mainly because it allows the short term decisions to be placed in the context of a minimum cost network designed to meet long term goals. This type of planning is less concerned with lead time, and more concerned with ensuring that the decisions together have a low present worth cost.

The long term planning process must also consider the uncertainty involved in planning far into the future. Ideally, a long term plan will be developed to confront the most likely eventualities for the system in question. This is called multiple-scenario planning. An alternative to multi-scenario planning is to develop a single plan which is based on average or probabilistic models of all the possible combinations of load growth. This is

not recommended due to the fact that it often results in poor performance and high cost [1], not due to the probabilistic nature of the analysis, but due to the inability of this method to anticipate multiple futures which may differ widely from each other.

2.4.3 Long Term Planning Process Level 1: Spatial Load Forecast

Long term planning in the traditional regulated sense is driven by the assumption that future loads will increase. This is generally outside the control of the utility, but is required to make good decisions. Spatial forecasts are usually produced for 1, 2, 3, 5, 7, 10, 15, and 20 years ahead, and for transmission purposes may use higher spatial load resolutions on the order of 25 square miles. The spatial load forecast sets goals for load location, amount, type, reliability, and service requirements that the future system must meet, and should be consistent with corporate planning, which projects sales and revenues for the utility.

2.4.4 Long Term Planning Process Level 2: Transmission Planning

The high voltage transmission grid planning component is done in conjunction with the generation plan, and is often coordinated using a power pool or system operator. The goals for high voltage transmission planning are less concerned with individual customer demand, and more concerned with stability of the system as a whole, and freedom for generation dispatch. The spatial load forecast that has been developed is used by distribution and substation planners, who in turn provide lumped substation load information to the transmission planners.

The inputs to the transmission planning process are: corporate rate and revenue forecasts, corporate goals, guidelines and criteria, and the generation/power pool plan. The output of the transmission planning process is the list of authorized short range projects and a forecast of long range projects.

2.4.5 Additional Planning Process Levels: Substation and Distribution Planning

Substation planning provides the interface between transmission and distribution planning, and is mainly a subset of distribution planning.

2.4.6 Interconnection Queue

Many North American utilities have for many years used an interconnection queue that consists of a list of generators and loads which are requesting interconnection to the main grid. Traditional study procedures dictate that each subsequent interconnection request assumes previous interconnection applications are in service ahead of them. Following these procedures with many concurrent wind generators creates a large risk that when one of the generators in the queue is removed for any reason, subsequent studies become invalid, creating additional study burden on the utility engineering resources by forcing study iterations or complete re-studies.

2.4.7 Deterministic Reliability Criteria

The type of criteria used to evaluate the reliability of a transmission plan or existing transmission system are common across much of the world. “Deterministic” implies a set of defined parameters or rules with no randomness or probabilistic attributes. Another way to state this could be that every element in the transmission network is assigned an equal probability of failure, and probability of failure is consequently ignored (although some level of probability may be used to differentiate severity of different event groups).

An example set of rules used for many years was prescribed by the North American Electric Reliability Corporation (NERC) [17]. These rules include standards for resource and demand balancing, communications, critical infrastructure protection, emergency preparedness, maintenance, interchange scheduling, and interconnection reliability, transmission planning, and many others. Their “Transmission Planning” standards in particular are often referred to as “deterministic reliability criteria”, and include the following general principles:

- When all facilities are in service (no contingencies), the system must operate stably, thermal and voltage limits must be within ratings, and there must be no cascading outages or curtailment of firm transfers.
- When an event occurs resulting in the loss of a single element (such as a transmission line or generator), the system must operate stably, thermal and voltage limits must be within ratings, and there must be no cascading outages

or curtailment of firm transfers. This criteria is commonly referred to as the “N-1” criteria, where any one out of N total elements may be suddenly lost with no adverse effects on network safety or reliability.

- When an event occurs resulting in the loss of two or more elements, all limits must still be respected, stability must be maintained with no cascading outages, but firm transfers may be curtailed in a controlled fashion.
- For very severe catastrophic events (such as the loss of a substation or all the lines on a right of way), NERC proscribes careful (inter-regional if necessary) study and evaluation of risk and consequences.

The NERC rules are currently under review, and these deterministic criteria will soon be refined and expanded upon [18], but the essence of what they are trying to accomplish will remain the same.

2.4.8 Probabilistic Reliability Evaluation

Deterministic Planning, and more specifically the use of N-1 and similar criteria to benchmark reliability, has a few weaknesses [19]. First, the consequences of failure are analyzed, but their probabilities are usually ignored. Secondly, multiple component failures (and associated probabilities) are excluded from consideration. In other words, even a very severe outage is inconsequential if it is so unlikely it can be ignored. Conversely, a mildly severe outage can become problematic if it occurs regularly.

Probabilistic planning attempts to use probabilistic reliability assessment to identify the risk levels associated with traditional deterministic methods. Reference [20] presents an example of how various expansion plans may be evaluated using arbitrary and individual probabilistic reliability criteria at each bus in the system. Although probabilistic planning techniques are not widely adopted in practice, the theoretical concepts are mature, and interest in developing this expertise within transmission utilities has been increasing.

2.5 Recent Transmission and Distribution Planning Concepts

2.5.1 “Extent of Use” Cost Allocation Methods

The following represents a high level survey of various transmission cost allocation methodologies currently in use or under industry examination. The principle source for this list is Shahidehpour et al. [11].

Postage Stamp Rate Method: This method allocates charges to a specific transmission user based on the average embedded cost of all the area transmission facilities and the amount of power the user desires to transmit. Features are: useful for allocating fixed transmission costs among firm transmission users, charges are independent of transmission distance or actual loading caused by transaction, and there are no powerflow calculations required.

Contract Path Method: This method assigns transmission use to transmission paths that may disregard the actual electron flows. Postage stamp rate methods are then applied.

MW-Mile Method (Line by Line Method): Costs are calculated by calculating incremental power flows on every line, and multiplying the number of new MW flowing on each line by the length of the lines. A dollar per MW-mile is assigned, and the costs are determined. Features are: allocation of charges based on actual usage, requires DC powerflow, and guarantees full recovery of transmission costs.

Unused Transmission Capacity Method: This method attempts to recover costs by proportionally sharing the entire cost of the line among the users based on their transmission use, but regardless of whether the line is being used to capacity. Features are: recovery of all costs, may not be equitable to those with a small use of an underutilized facility, does not motivate efficient use of transmission system.

MVA-Mile Method: AC powerflow is used to calculate both real and reactive power flow contributed by a transaction, and applying MW-mile concepts for obtaining a price.

Counter Flow Method: This method argues that only transactions adding to the net flow on a transmission line should be charged, and if power is “backed off” on a line, that should be credited. This may be difficult to keep track of and arrange payments in practice, but does provide motivation for optimal placement of generation with respect to transmission.

Distribution Factor Methods: These methods provide efficient ways of determining transmission usage for use in MW-mile calculations. Types of distribution factors are Generation Shift Distribution Factors (GSDF), Generalized Generator Distribution Factors (GGDF), and Generalized Load Distribution Factors (GLDF). GSDF methods use DC powerflow techniques to calculate the incremental use on a transmission line due to some change in generation or load dispatch. The second two types of distribution factors are based on the total use of the transmission line rather than just the incremental use.

For example, $D_{l,r}$ (GGDF) is the fraction of power flowing on a line l due to the reference bus in the system:

$$D_{l,r} = \frac{\text{Power flow on a line caused by reference generator}}{\text{Total generation in the system}} \quad (2.1)$$

$D_{l,i}$ is the fraction of power flowing on line l due to generator i and is calculated as:

$$D_{l,i} = D_{l,r} + \text{Fraction of power flowing on a line caused by specific generator} \quad (2.2)$$

The total power flowing on line l due to total generation in the system, $Flow_l$ is obtained by:

$$Flow_l = \text{sum of all } D_{l,i} * G_i \quad (2.3)$$

The Midwest ISO (MISO) uses DF methods, as follows [39]:

“The Network Upgrades cost for a Group Study will be allocated based on the MW impact from each project on the constrained facilities in the base case. With all Group Study projects in the base case, all thermal constraints will be identified and a distribution factor from each project on each constraint will be obtained. Finally, the cost will be allocated based on the pro rata share of the MW contribution on all constraints from each project.”

This principle is illustrated in Figure 1.

Constraint	MW contribution from Project x	MW contribution from Project y	MW contribution from Project z
c1	x1	y1	z1
c2	x2	y2	z2
c3	x3	y3	z3
cn	xn	Yn	Zn
Total MW contribution on constrained facilities from project x equals: $X = x1+x2+x3+...+xn$			
Total MW contribution on constrained facilities from project y equals: $Y = y1+y2+y3+...+yn$			
Total MW contribution on constrained facilities from project z equals: $Z = z1+z2+z3+...+zn$			
Total MW flowing on all constraints from Group Study projects = X+Y+Z			
Project x's share on the total NU cost = $X/(X+Y+Z)$			
Project y's share on the total NU cost = $Y/(X+Y+Z)$			
Project z's share on the total NU cost = $Z/(X+Y+Z)$			

Figure 1 - MISO Cost Allocation Table Based on Distribution Factor Methods [39]

Bialek's and Kirschen's Tracing Methods: These tracing methods are sophisticated distribution factor methods which are capable of accounting for actual transmission usage of a particular energy transaction.

The principle behind Bialek's method is that of proportional sharing [11][12]. It recognizes that all power flows out of a node may be defined in terms of the flows into a node; that nodal inflows are shared proportionately between nodal outflows. Using Bialek's tracing algorithm, it is possible to determine what portion of each load in the system is supplied by each generator. And what portion of power flow on each line is created by each generator and load transaction. The method can equally well handle AC or DC powerflows (real and reactive power), and may be adapted to assign losses to generation or load.

Kirschen's tracing method is similar in underlying principle (proportional sharing), and in outcome (determination of generator/load contributions to line flows), but differs in approach, relying instead on a recursive algorithm working on a system of domains, commons, and links [11][13].

The principle weakness (aside from moderate complexity) of both Bialek and Kirschen's methods is that the computation done to determine line usage is dependent on operational conditions, and does change as the power flow in the network changes. As well, inherent in each of the two algorithms are assumptions which can cause the transmission usage by a particular generator to be zero. However, both of these methods may be extremely useful in fairly allocating transmission costs to the true users of the network.

2.5.2 Marginal Network Cost Allocation Methods

Reference [14] describes comparative analysis of 3 network cost allocation methods, differing from the "extent of use" type methods described above, and used mainly for determining the complementary charge necessary to recover the transmission costs not accounted for by strict marginal transmission pricing. Note that marginal network revenues are defined as:

$$\text{Marginal Network Revenues} = \sum_k p_k(d_k - g_k) \quad (2.4)$$

where p is price, d is demand, and g is the generation at a given node k . Hence the complementary charge for line l is equal to:

$$CC_l = \max \{ \text{Annual Cost}_l - NR_l, 0 \} \quad (2.5)$$

where NR is the marginal annual revenue of line l .

Marginal Participation Factors: The complementary charge is allocated according to “extent of use”. The incremental use of each corridor by a particular generator or load is calculated as a yearly usage index (using a 1MW incremental injection) for every scenario over the course of one year. It is critical that the system generation dispatch responds optimally when load or generation is increased when using this method. This method may be applied either to a corridor/path or to an individual line.

$$U_{kc} = \sum_{\substack{c \\ |F_{ce}^k| - |F_{ce}| > 0}} (|F_{ce}^k| - |F_{ce}|) \times P_{ke} \times D_e \quad [MW^2h] \quad (2.6)$$

where:

- F_{ce} represents the power flow of corridor c at scenario e
- F_{ce}^k represents the power flow of corridor c when the consumption or generation of agent k at scenario e is increased by 1MW
- P_{ke} represents the power consumed or generated by agent k
- D_e represents the duration of scenario e
- U_{kc} represents the usage factor of agent k over corridor c

The marginal participation factor of agent k over corridor c is:

$$\text{Part}_{kc} = \frac{U_{kc}}{\sum_k U_{kc}} \quad (2.7)$$

Mean Participation Factors: Mean participation factors attempt to assign the participation factors to each agent by splitting optimal power flows on corridors or lines according to simple proportionality. This method is simpler, but is more arbitrary due to its simplification of the electrical network to a “water-pipe” analogy.

Benefit Factors: The main criterion used when assigning complementary charges using benefit factors is the benefit that each network element provides to each agent. It is computationally intensive, and requires simulation over one year with the corridor in service, and again without the corridor in service, and then the calculation of a participation factor using the incremental benefit provided to the agent (revenue for generator and reduction in energy prices for consumers).

$$Part_{kc} = \frac{B_{kc}}{\sum_k B_{kc}} \quad [B_{kc} > 0] \quad (2.8)$$

where:

B_{kc} represents the benefit of agent k resulting from corridor c

The acknowledged problems with this method are potential for ambiguity in relation to what constitutes “benefits”. As well, the method only works for the addition of new lines.

The advantages and disadvantages of each of these three methods are summarized in [14] with the authors concluding that the benefit method is the best for reasons of providing correct economic signals for all agents, being based on sound economic and physical principles, and lowest amount of required data.

2.5.3 Centralized Deregulated Transmission Planning Methods

Even though deregulation has placed the specifics of generation expansion (and in some cases transmission expansion) in the hands of private industry, there remains room for regulators to supervise the process. The extent to which this is done can determine the optimality of the resulting expansion, and if carefully done can provide a fair market environment.

Reference [8] proposes a planning process or decision making procedure which allows robust plans to be created in the face of uncertainty, such as that which is presented in a deregulated transmission environment. This method was implemented on a large expansion planning study encompassing six Central American countries, with a large degree of uncertainty involved. The procedure is summarized as follows:

1. *Problem formulation* – Problem formulation involves identification of the available options, the uncertainties involved, and a set of quantifiable attributes which reflect the main stakeholder objectives to be fulfilled.
2. *Simulation to measure Attributes* – One of the primary attributes used was the strength of the system, which may be best measured using transfer capability. Other attributes could be construction costs, fuel cost, reliability, emissions, return on equity, ground level concentrations of pollutants, all of which may be measured using simulation or calculation tools.
3. *Decision Analysis: Risk and Robustness* – Risk may be measured in several ways, but in this context it was quantified using exposure. Exposure was explained as follows: How great is the regret (regret being defined as the difference between the value of an attribute for a given plan and the value of that attribute for the optimal plan) when a particular plan is chosen, and an adverse “future”, or set of outcomes for that plan occurs? What are the futures that are adverse, and what is the probability that those futures could occur?

A plan is considered robust if the regret is zero for a particular plan for all futures (ie. The plan is optimal). If there is no robust plan, a choice must be made between the available plans. A plan may be chosen based on a number of strategies: Minimizing maximum regret, minimizing average regret, maximizes maximum benefit, or others depending on risk tolerance.

A different procedure for dealing with the uncertainty associated with a deregulated environment is presented in reference [12]. It has been applied to major transmission expansion in Brazil, and this could be a very useful general procedure, or at least starting place, for transmission planners searching for fair ways to expand their networks in the face of uncertain costs and (especially) generation expansion. The steps applied are summarized as follows (the procedure summarized here is further generalized from the specific Brazilian case presented):

1. Design a reference system based on traditional or best information available.
2. Estimate costs of proposed reference system.
3. Simulate the allocation of expansion costs to all the generators included in the reference plan. Estimate transmission tariffs to be assigned to each generator interested in connecting.
4. Provide transmission cost allocation estimate to each candidate generator, and request proposals for interconnection contracts, or carry out an auction for new generation contracts.
5. Given results of the auction or RFP, construct a new transmission expansion plan. The costs of this expansion plan will be the actual costs. In Brazil, the transmission expansion was also placed up for auction, resulting in a huge growth in private transmission providers.
6. The difference between the actual costs and the estimated costs are absorbed by the consumers, or put into the “rate base” of the transmission utility.

It is noted in [10] that it must be possible to quantify the benefits associated with the reference plan as well as the costs associated with the expansion, so that any proposed expansion plan by transmission companies may be compared in a fair way.

2.5.4 Project-Based Deregulated Transmission Planning Methods

The uncertainty associated with deregulation has caused some utilities or transmission authorities to revert to a simple form of planning which essentially neglects the long term or horizon plan, and focuses on the generation that requires immediate interconnection. Assuming that reliability standards have been adhered to in a rigorous fashion throughout

the process, the danger of this approach involves the risk of a long term expansion which is sub-optimal.

In general, this type of planning can be treated as an aspect of short-term transmission planning, unconcerned with the timeline of circuit installation, but concerned with the optimization of a single new expansion. This is a part of all transmission planning strategies (in the form of interconnection studies) to determine compliance with a reliability criteria, but in some cases becomes the primary planning strategy, especially where the utility or transmission provider is unable to, or uncertain how to deal with uncertainty involved in long term planning under deregulation. The problem is especially difficult in areas where large wind resources exist, and many wind developers are proposing to build wind generator facilities within a relatively short time.

2.5.5 Large Scale Wind Integration Studies

In recent years, several very large planning studies have been undertaken, spanning the entire eastern interconnection, western interconnection, and Texas, and including input from stakeholders representing all aspects and regions of the transmission system as technical review committees [21] - [24]. Common elements from these studies include:

1. Stakeholder input from wind developers, RTO/ISO planners, NERC, and other stakeholders to ensure the relevance of results.
2. Proposals for large scale transmission enhancements, including 765kV AC lines and HVDC ties. In general, it is presumed that a more robust connection between control areas will increase wind penetration capability, especially in the Midwest where vast renewable resources exist with minimal load. In these cases, cost of transmission is assumed to be cheaper than curtailment or energy storage.
3. Studies correlating wind resource with market price differentials to optimize transmission expansion (capacity factor plays a role here).
4. Varying levels of overall wind penetration for various forecast years, along with economic feasibility analysis.

These studies are important for providing federal regulators with the technical planning background needed to drive their renewable energy policies.

2.5.6 Competitive Renewable Energy Zones (CREZ)

Several states in the US have issued policies which allow transmission providers to build transmission ahead of renewable generation, passing the planning risk forward to rate-payers. An example of this type of policy is Senate Bill 20 passed by the Texas State Legislature in 2005, which allows the creation of designated high resource areas (called Competitive Renewable Energy Zones (CREZ) and supporting high capacity transmission corridors to these areas [21]. Among other requirements, the Bill had the following requirements for the Texas Public Utilities Commission (PUCT):

The commission, after consultation with each appropriate independent organization, electric reliability council, or regional transmission organization: (1) shall designate competitive renewable energy zones throughout this state in areas in which renewable energy resources and suitable land areas are sufficient to develop generating capacity from renewable energy technologies where sufficient; (2) shall develop a plan to construct transmission capacity necessary to deliver to electric customers, in a manner that is most beneficial and cost-effective to the customers, the electric output from renewable energy technologies in the competitive renewable energy zones;

These policies have been effective in interconnecting large wind resource areas to load areas in a coordinated and well-planned fashion. Other examples of CREZ type initiatives include SB-07-100 (State of Colorado) [25], and FERC order 119 FERC 61,061 for the California ISO.

2.6 Request for Proposals

A further method to introduce large amounts of wind into a deregulated or regulated planning environment is to issue a Request for Proposals (RFP) for energy. This has been popular in recent years as a way to choose the most economic projects from among many applicants. A more detailed discussion of RFP philosophy, as well as a comparison between existing methods and the method proposed here is shown in Section 6.6.

2.7 Additional Background Literature

A broad survey of power system planning basic concepts, including a comprehensive reference list, is available as a reading course report in reference [27], and a primary text for power systems planning basic theory is reference [28]. A literature survey showing many recent publications on the topic of transmission planning, along with classification of papers is found in reference [29]. Several source papers on planning using probabilistic reliability criteria are references [30] and [31]. A discussion of the problem of transmission being built before wind generation is available is shown in reference [32], and a discussion of the interconnection concerns associated with wind generation is reference [33]. Reference [34] highlights some challenges faced by ERCOT in planning under a deregulated environment. References [35] and [36] present a very interesting history of transmission and generation regulation and deregulation in North America. Reference [37] compares different transmission cost allocation methods, with reference [38] exploring marginal pricing in more depth with a view to examine cost recovery.

Chapter 3 Overview of Cluster Study Approach

3.1 Objective

The objective in defining a cluster study methodology is to define a process which planners or transmission authorities may follow in obtaining wind energy from multiple generation providers in a fair and economical way, adhering to transmission planning principles of reliable power delivery in a sustainable fashion. The process shown here represents discrete steps which may be used together or separate as an aid to planners tasked with designing an RFP to this end.

3.2 Summary of Cluster Study and RFP Process

The flow diagram shown in Figure 2 graphically illustrates the proposed process. Each element of the flow diagram is described briefly in the following sections, and elaborated on fully in the remaining chapters along with example applications based on a case study.

3.2.1 Step 1 – Define Generation Limits

Determine the maximum amount of total wind or other renewable energy sources for consideration, based on forecasted load data, maximum total system renewable energy penetration, and other area specific bounds on project acceptance into the cluster study.

3.2.2 Step 2 – Define Interconnection Locations and Study Area

Propose a study region based on interconnection requests, stakeholder meetings, and available geographical wind data. The acceptable size of the region will be dependent on the maximum total amount of wind generation acceptable. The final definition of the interconnection locations should be a specific point on the existing or planned transmission system, and any deviation from this point by a proposed project should consider the costs required to reach this point. On a case by case basis, it may be determined by planners that proposed interconnection locations are not substantially different from the locations defined by them.

This step will require significant judgement on the part of the planner, and considerable up-front study effort. In particular, the allocation of wind between interconnection

locations should be chosen carefully such that the best wind resource is used to the fullest extent, so as to avoid issuing iterations of the request for proposal.

3.2.3 Step 3 – Create Transmission Expansion Plans for all Levels of Generation

Create transmission expansion alternatives at varying levels of wind, such that any amount of wind may be connected up to the maximum determined in Step 1. For example, one expansion plan may be created to connect a small amount of wind, another to connect more wind, and another to connect the maximum amount of wind. Each alternative expansion plan must satisfy the traditional deterministic reliability criteria.

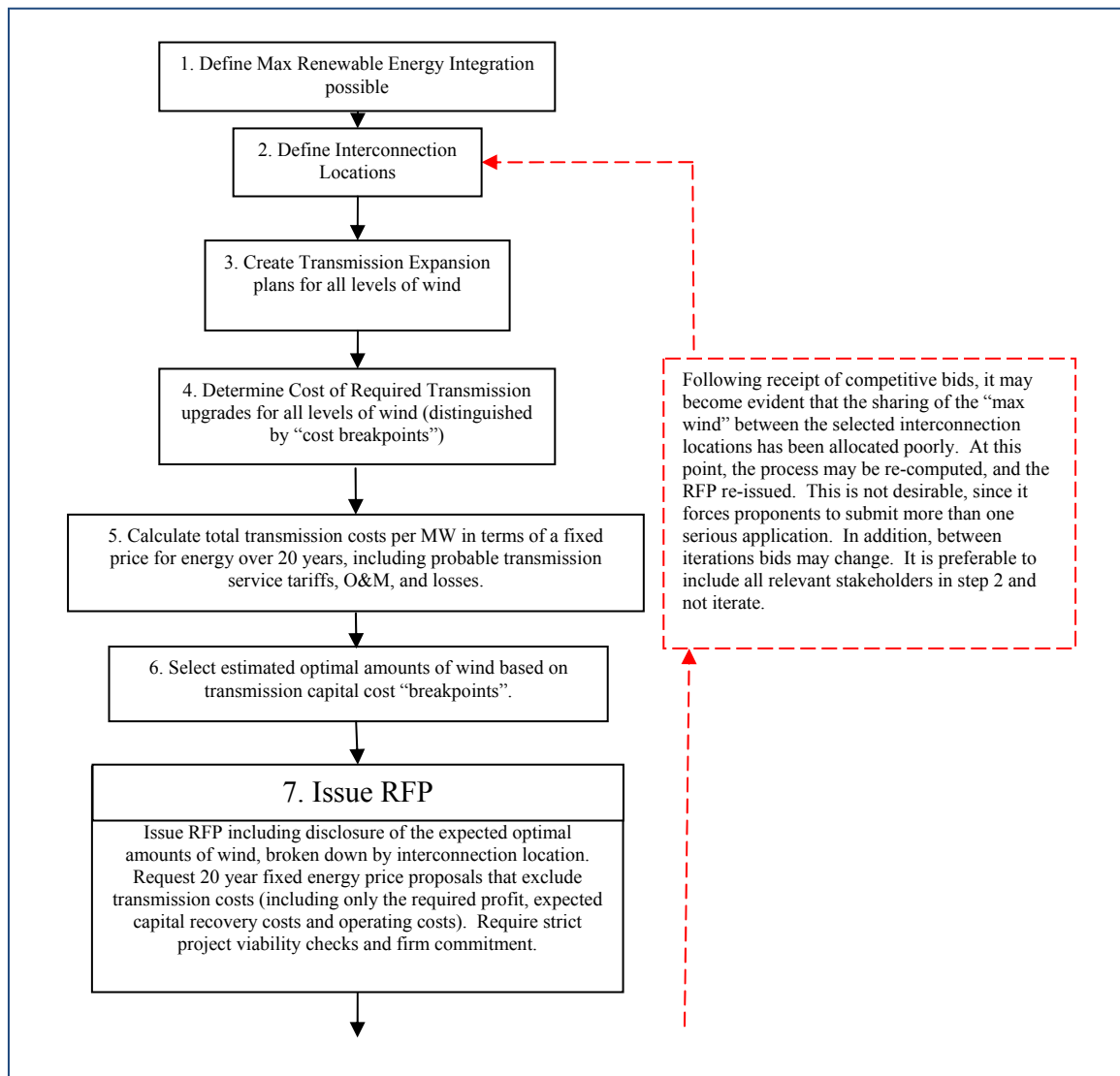


Figure 2 - Process Flow Diagram - Part A

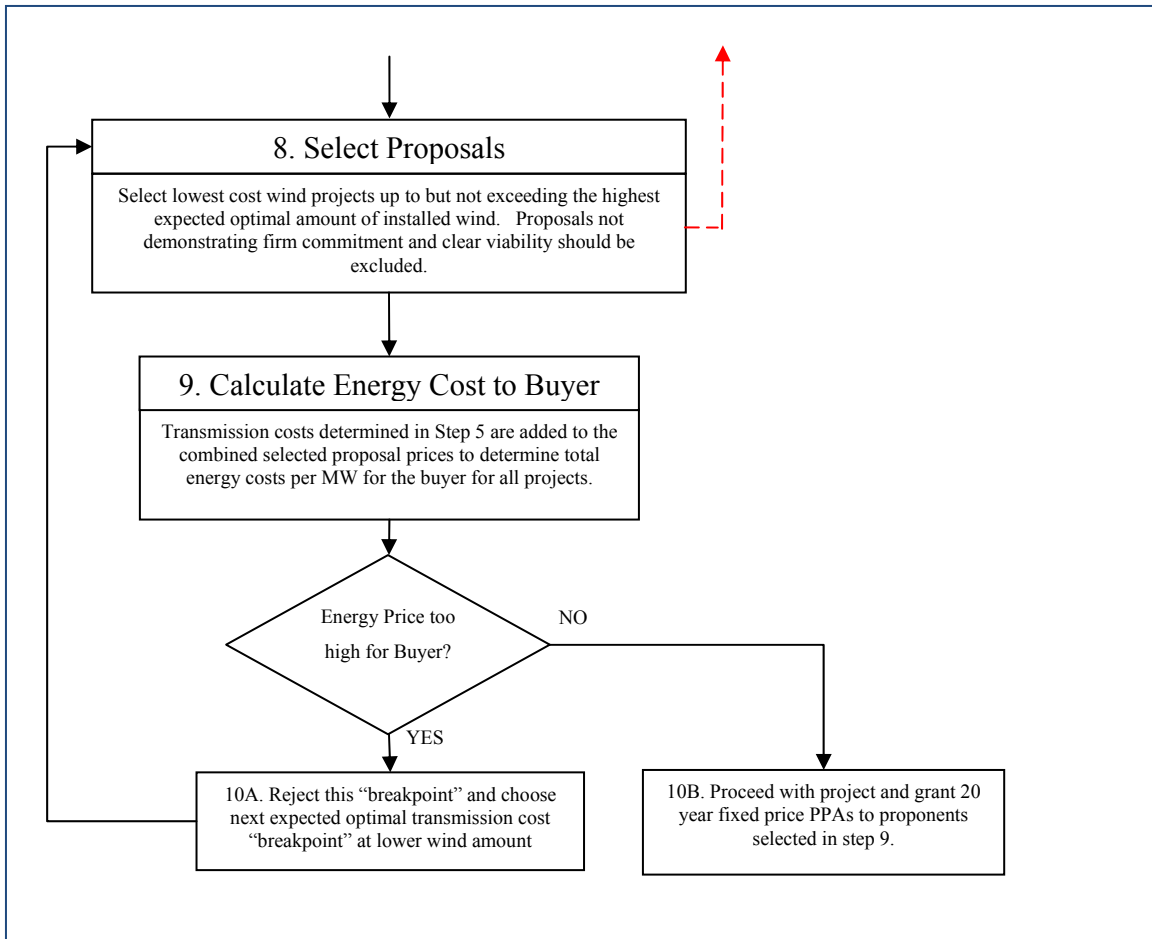


Figure 3 - Process Flow Diagram - Part B

3.2.4 Step 4 – Determine Transmission Capital Costs for all Expansion Plans

As the amount of interconnected wind increases, the cost of the transmission facilities required to accommodate the wind will generally increase in a step-wise fashion (see example in Figure 4). Each new “step” represents a new transmission expansion alternative, determined to be optimal for that range of interconnected generation, based on traditional planning methodologies, or using available optimization tools. The width of each “step” represents the amount of wind that may be interconnected before the plan must be abandoned for a more expensive plan. (For example, a new transmission line may accommodate anywhere from 100 MW to 200 MW of new wind) The height of each step represents the cost for that alternative.

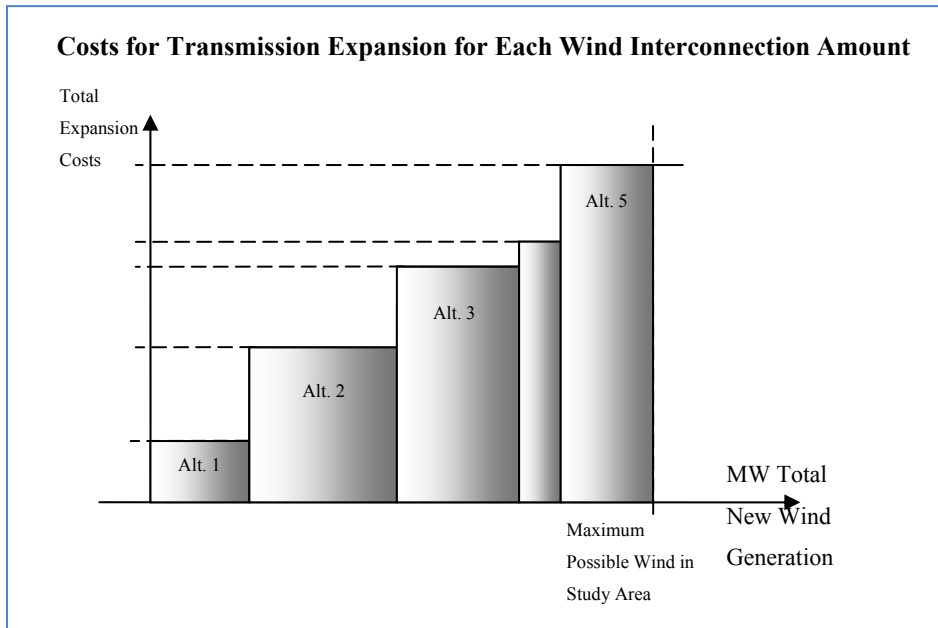


Figure 4 - Costs for Example Transmission Expansion for Varying Wind Amounts

3.2.5 Step 5 – Calculate Total Transmission Costs per MW

Transmission costs must be calculated on a “per MW” basis for the entire range of possible wind capacity. Costs include initial capital costs for lines, substations, and associated support equipment (all of which are calculated in Step 4), as well as continuing costs such as operation and maintenance, tariffs, and losses. This will result in a stepped chart as described in Step 4.

3.2.6 Step 6 – Select Optimal Amounts of Wind

Step 5 and Step 6 are closely linked. Based on the chart produced in Steps 4 and 5, clear ranges for optimal use of the transmission should emerge. These will tend to use the new network upgrades to near their capacity.

3.2.7 Step 7 – Request for Proposals

Issue the RFP including disclosure of the expected optimal amounts of wind, broken down by interconnection location. Request 20 year fixed energy price proposals that exclude transmission costs (including only the required profit, expected capital recovery costs and operating costs). Require strict project viability checks and firm commitment. Disclosure of pre-determined estimated optimal amounts of wind allows proponents to

size their projects appropriately. Very large projects may be excluded if an optimal breakpoint with little total wind is chosen.

Queue priority in the cluster study will be abandoned, and all cluster participants will be treated equally. This is to avoid the incentive for applicants with poor queue position to deliberately opt out of the study in order to be “bumped up” in front of the cluster study. The only purpose for the queue would be to help evaluate the best interconnection locations, although it may be used as an additional sorting criterion if needed.

3.2.8 Step 8 – Select Successful Proposals

Select lowest cost wind projects up to but not exceeding the highest expected optimal amount of installed wind. Proposals not demonstrating firm commitment and clear viability should be excluded. It will be unlikely that the size of the combined lowest price proposals will exactly match the expected optimal amount of wind. This will require some judgement on the part of the transmission planner.

Following receipt of competitive bids, it may become evident that the sharing of the “max wind” between the selected interconnection locations has been allocated poorly. At this point, the process may be re-computed, and the RFP re-issued. This is not desirable, since it forces proponents to submit more than one serious application. In addition, between iterations bids may change. It is preferable to include all relevant stakeholders in step 2 and not iterate.

3.2.9 Step 9 – Calculate Total Energy Costs to Buyer

Transmission costs determined in Step 5 are added to the combined selected proposal prices to determine total energy costs per MW for the buyer for all projects. This cost will be the long-term marginal cost of generation, and will fully recover all costs of transmission infrastructure.

3.2.10 Step 10A – Plan Rejection and Re-evaluation of Proposals

If the total energy costs for the breakpoint with the highest amount of wind proves to be too high, this “breakpoint” should be rejected and the next largest optimal transmission cost “breakpoint” at lower wind amount selected. Step 9 is then repeated.

3.2.11 Step 10B – Plan Acceptance and Implementation

If total energy costs for the “optimal breakpoint” are acceptable to the purchaser, the plan is implemented and formal studies are undertaken. 20 year fixed price PPAs are granted to the applicants selected in step 8, and differences in cost between implementing the final plan and the proposed costs may be absorbed by the utility. This provides a high level of certainty for the participants, thus stimulating study participation.

3.3 Introduction to Case Study

To clearly illustrate all concepts in the aforementioned steps, a case study will be used. The case study uses a large area in Southeast Colorado and Northeast New Mexico (Figure 5). This area is known to have very good wind resources, and due to the sparse population the transmission grid is very weak (weak in the sense of low short circuit capacity, far distance to inertia providing generation, large induction loads, and radial configurations). The Tri-State OAIT OASIS interconnection request queue listed 57 active interconnection requests for this area as of September 1, 2008, with requested generation interconnection capacity totalling several times the historic peak area load. This condition is representative of many locations in the US, and presents a suitable example of a system in need of creative planning in order to add significant wind resource in a reliable and economic fashion.

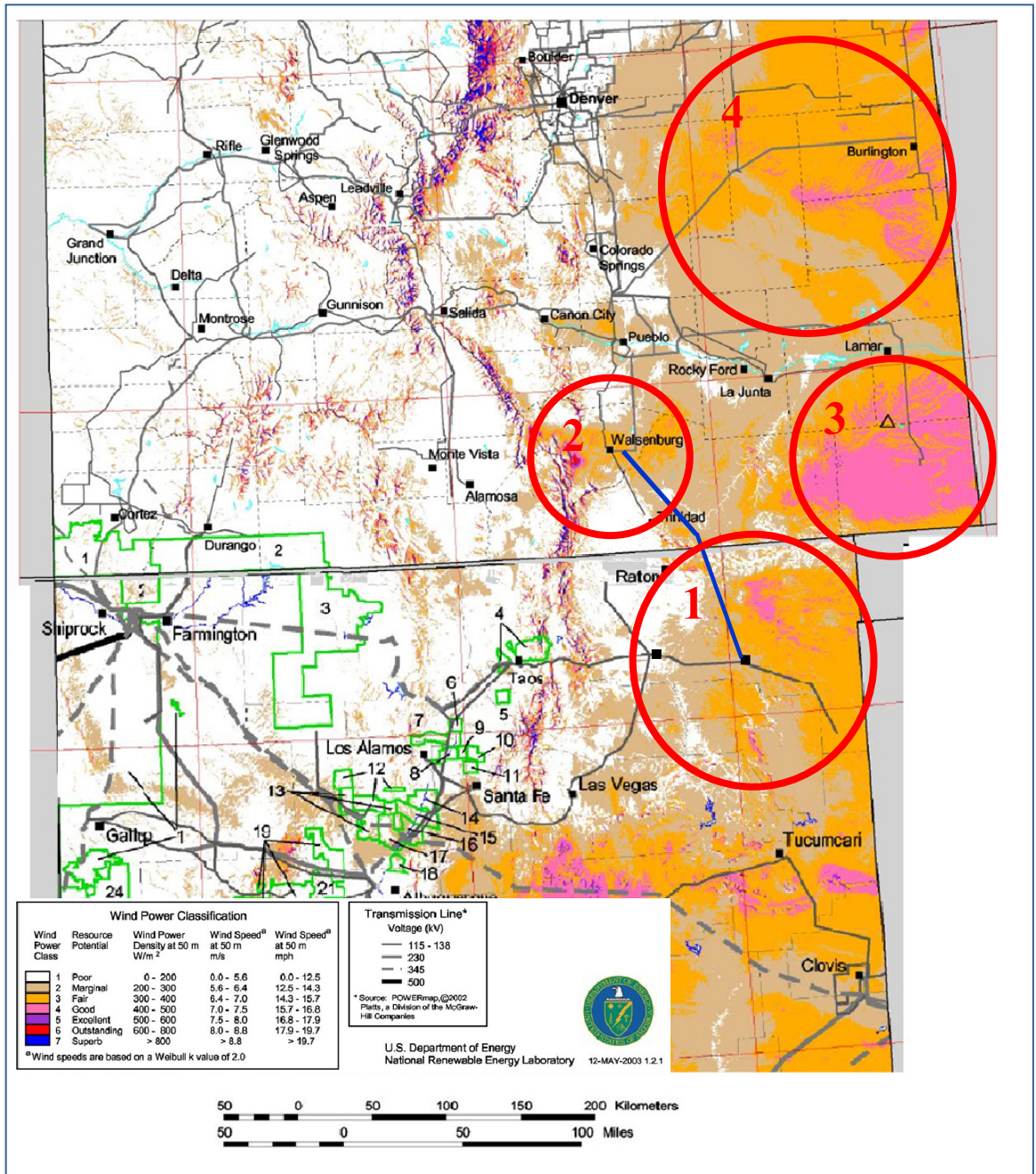


Figure 5 – Combined Wind Resource and Transmission Map for Case Study Area

Chapter 4 Defining Study Parameters

4.1 Generation Limits

The first task for any planning endeavour is to determine the need for generation, traditionally analyzed in a resource adequacy study. Conventional planning methodology assesses projected regional load growth and ensures that sufficient generation capacity will be in service at the required future time to meet the load.

From a purely physical point of view, if the capacity of all the interconnection requests exceeds forecasted peak load, it will be impossible to interconnect them all and operate them at their capacity simultaneously. Therefore it is crucial to select a limit for the total generation to be interconnected. This should be based on large regional requirements (state or inter-state), considering all feasible load centers and power delivery points. The maximum amount of wind generation should be examined to quantify system impact on neighbouring regions or ties. Additionally, the amount should be reasonable from the standpoint of deliverability, especially given the “non-firm” nature of wind resources. Total penetration of variable resources cannot be unlimited, and current industry rules-of-thumb indicate that wind providing 20% of peak load may be a practical limit, though any such high levels incorporated into real systems must overcome significant challenges and often are required to rely heavily on ties to neighbouring systems (eg. Denmark, Gotland [40]).

The result of this stage of work must be a maximum total generation level, and clear point of delivery locations for the entire amount of generation.

4.2 Generation Limits – Case Study

For our case study, the point of delivery is assumed to be flexible, but generally west to the San Juan, Four Corners area for export to California and Arizona markets, southwest to the Albuquerque area, and north to the Denver area load.

The Public Service of Colorado (PSCo) is a utility which is responsible for serving the Denver area load. PSCo’s total peak load was slightly less than 8000 MW for 2008 [15]. Public Service of New Mexico (PNM) projects their peak load at something less than 2500 MW for 2012 [16]. It is unknown by the author how much power may be realistically exported to the west from the Four Corners/San Juan/Shiprock regions in addition to the capacity already used up, but for the purpose of this analysis we will assume the incremental value is approximately 500 MW.

The case study will only consider wind in the vicinity of areas marked 1 and 2 on the map in Figure 5. Since we must assume that there are other study areas which require new generation to be accommodated in addition to areas 1 and 2 (Reference areas 3 and 4 in Figure 5), we will assume an optimistic value of 10% penetration for serving existing load (half of the 20% rule of thumb number, assuming other renewable integration efforts are simultaneously considered by other processes), and all of the available export capacity. This yields a total amount of 800 MW to the PSCO region, 250 MW to the PNM load, and 500 MW of export, for a combined generation level of 1550 MW of power. This is the “maximum total wind” for the purpose of this example, and the dispatch schedule for creating and modifying power flow models. These totals are summarized in Table 1.

Table 1 – Case Study: Generation Limits Based on Points of Delivery

Amount of Generation Displaced (Total of 1550 MW)	Location of Displaced Generation
800 MW	PSCO/Denver Load Area
250 MW	PNM Load
500 MW	Export West from San Juan

4.3 Study Area Selection and Interconnection Locations

Selection of study area and interconnection locations is simultaneously the most important and most difficult step in this process. In a purely deregulated environment, the selection of the interconnection location and size of the generator must be left

completely up to the competitive process. It is at this stage where some of that control must be removed from the “free market” and returned to the regulating body or transmission companies. Consequently, care must be taken to ensure that input is considered from all stakeholders, including land owners, environmental groups, geographical wind data, location of existing transmission, and a host of other factors. There has been good work already done on this subject, implemented as Renewable Energy Zones and similar initiatives (Refer to chapter 2.5.6). One tool that may be of additional use in selecting interconnection points is the existing interconnection queue. If the existing interconnection requests are superimposed on a wind resource map along with transmission, common locations often emerge. For this task, Geographic Information Systems (GIS) tools would be of great assistance.

The end result of this stage of work is a preliminary set of clearly defined interconnection locations, subject to change following the expansion plan design.

4.4 Interconnection Locations – Case Study

The Tri-State OAIT OASIS interconnection request queue listed 57 active and valid (considered real by transmission authority) interconnection requests as of September 1, 2008. This is used as the reference queue. There are 11 active requests in the vicinity of the 230 kV transmission line connecting Walsenburg substation in Colorado with Gladstone substation in New Mexico which were selected for consideration. These are shown in order of request date in Figure 6 on page 37 as areas 1 and 2, and are summarized in Table 2.

Table 2 – Case Study: Reference Interconnection Queue in Study Area

Relative Order	Queue Reference #	Amount and Type of Generation (Group 1)	Amount and Type of Generation (Group 2)
1	TI-04-1214	120 MW Wind	
2	TI-06-0828	300 MW Wind	
3	TI-07-0222	50 MW Wind	
4	TI-07-0301	500 MW Wind	
5	TI-07-0305		250 MW Wind
6	TI-07-0510	120 MW Wind	
7	TI-07-0611B		300 MW CT
8	TI-07-0816	200 MW Wind	
9	TI-08-0103		210 MW Wind
10	TI-08-0403		200 MW Wind
11	TI-08-0515	200 MW Wind	
Total Generation in Group		1490 MW	960 MW
Total generation limited proportionally by Max Wind		940 MW	610 MW

These two areas are distinct from an interconnection impact perspective, but not separated enough geographically to assume they do not electrically impact one another. From Figure 6, it is also possible to see how a high wind resource area near existing transmission attracts interest from wind developers. All in service dates are assumed to be “as soon as possible”, given that usually transmission infrastructure schedules lag behind generator plant construction schedules.

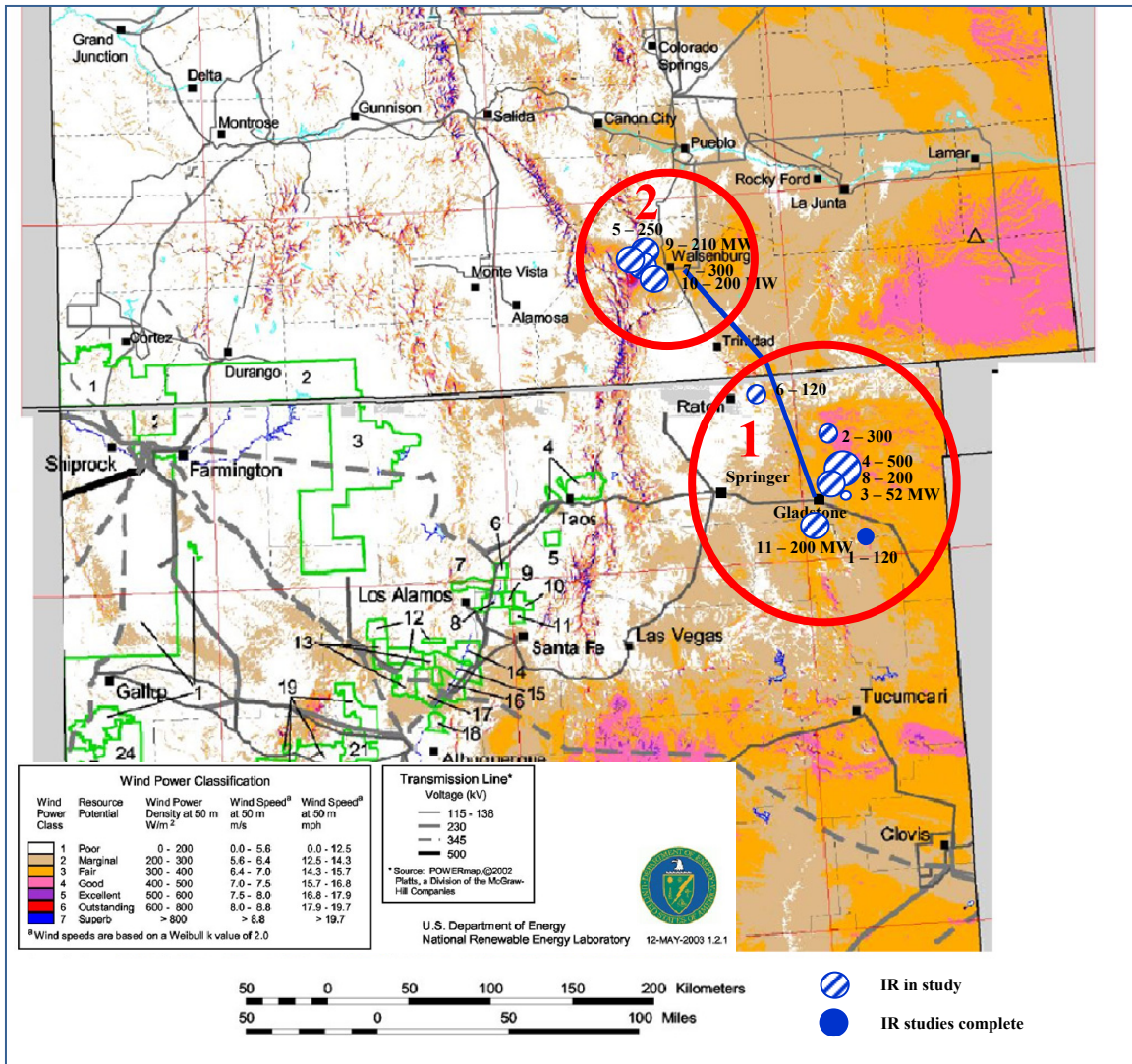


Figure 6 – Case Study: Interconnection Queue on Transmission/Wind Map

For the case study, proponents may select between two interconnection locations based on interconnection request density in the reference queue. The first interconnection location is at the Gladstone 230 kV substation, roughly central to “Group 1” shown in Figure 6. The second location is at the Walsenburg 230 kV substation, roughly central to “Group 2” shown in Figure 6.

Chapter 5 Expansion Plan Design

5.1 Expansion Plan Process and Methodology

Expansion planning is a wide field of expertise, highly dependent on regional regulatory environments. This chapter focuses primarily on the engineering and study components of the process. Chapter 2 presents some philosophical and contextual background to set up the technical study aspects presented here.

In order to fulfill the deterministic reliability criteria discussed in Section 2.4.7, a decision tree such as that shown in Figure 7 through Figure 10 may be used. This decision tree is a partial result of study work done for EPRI [41]. The use of this decision tree is illustrated for a generation interconnection type of planning exercise. It is critical to note that at all points, engineering judgement presides and is crucial in making this process efficient and effective.

1. Select analysis tool – (Refer to Figure 7) In general, unless specific conditions determine the need for higher levels of study detail such as electromagnetic transient type studies (eg. PSCAD/EMTDC [42]), PSS/E or similar conventional powerflow and transient stability tools are adequate at this stage.
2. Obtain data – Data requirements for this study include:
 - a. Network data (steady state & dynamic)
 - b. Detailed study area boundary and load or sink locations
 - c. Manufacturer specific generator plant models
 - d. Known trouble conditions or contingencies which will stress the system
 - e. Detailed deterministic reliability criteria for the area being considered
3. Develop models – (Refer to Figure 8) Contingency processing tools and complete “before and after” steady state and dynamic models must be created and configured to automatically identify thermal, steady state voltage, voltage delta, loadability, and stability issues.
4. Identify concerns – (Refer to Figure 9 and Figure 10) Depending on the nature of the issues encountered, various mitigation alternatives may be implemented to

handle problems which arise. In the case of massive amounts of generation being added, it is not possible to avoid construction of new transmission lines, but additional measures may be implemented to minimize expense, such as managing VAR flow and paying close attention to voltages throughout the expansion planning process.

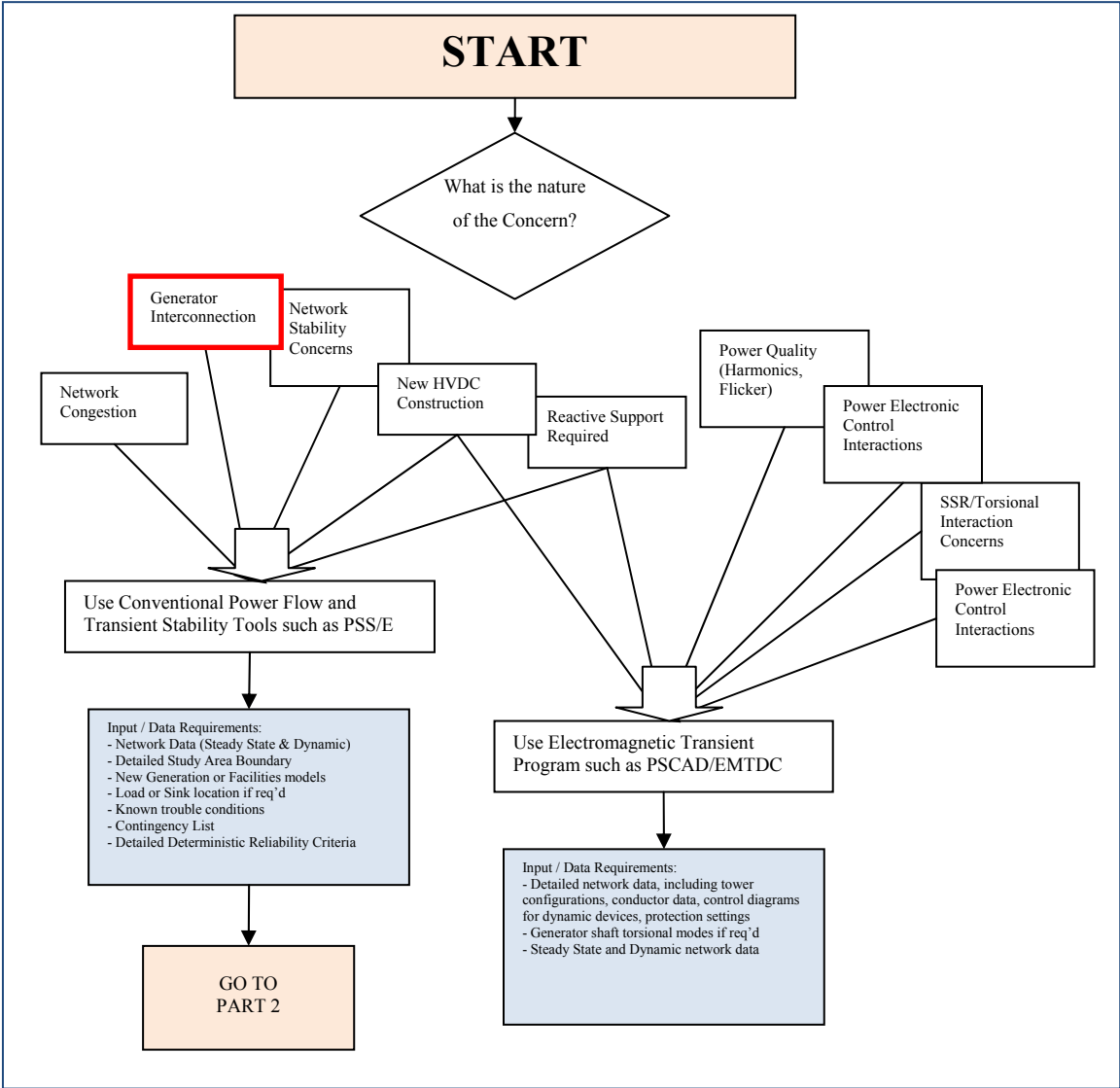


Figure 7 - Expansion Planning Study Decision Process: Part 1

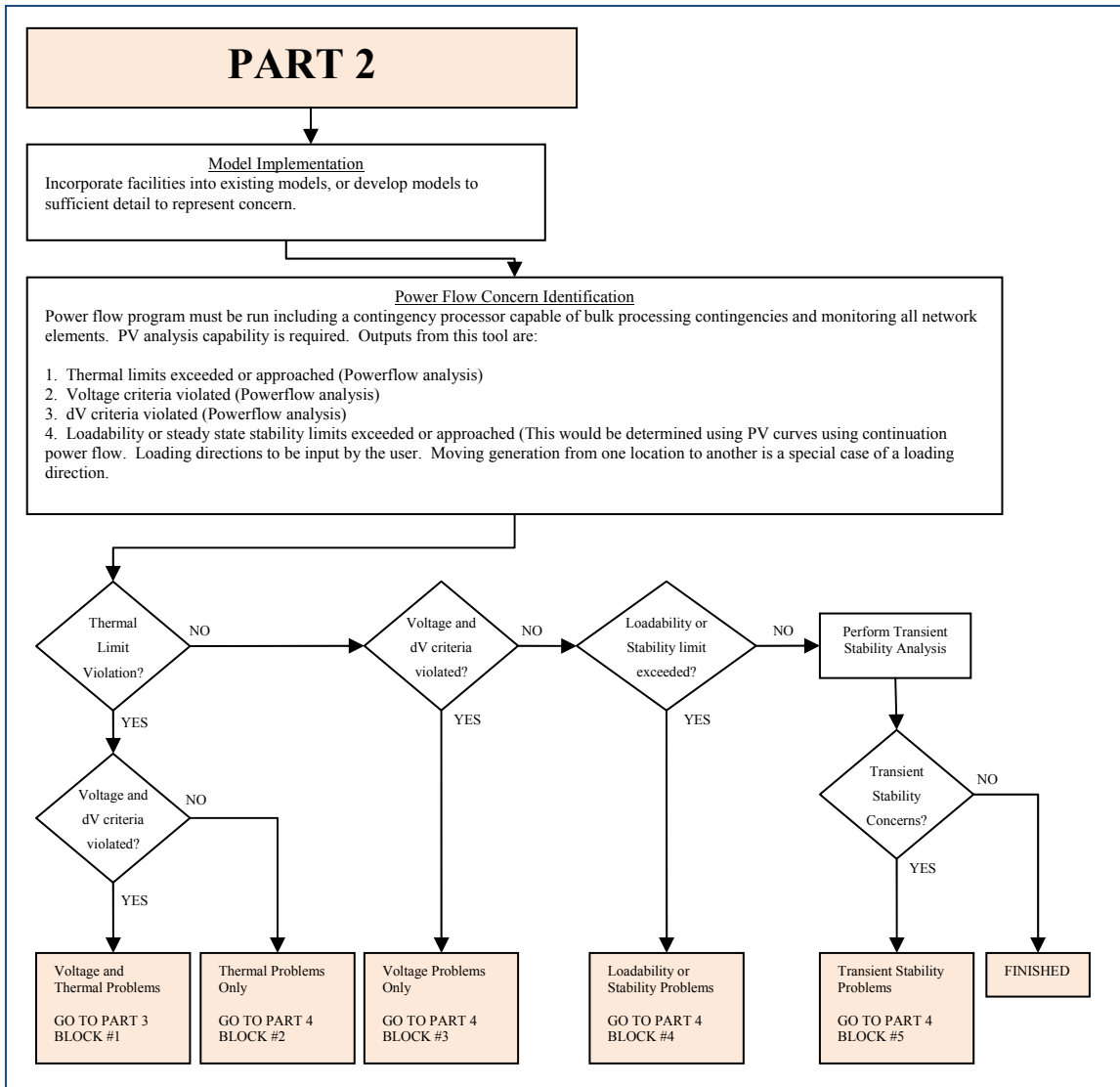


Figure 8 - Expansion Planning Study Decision Process: Part 2

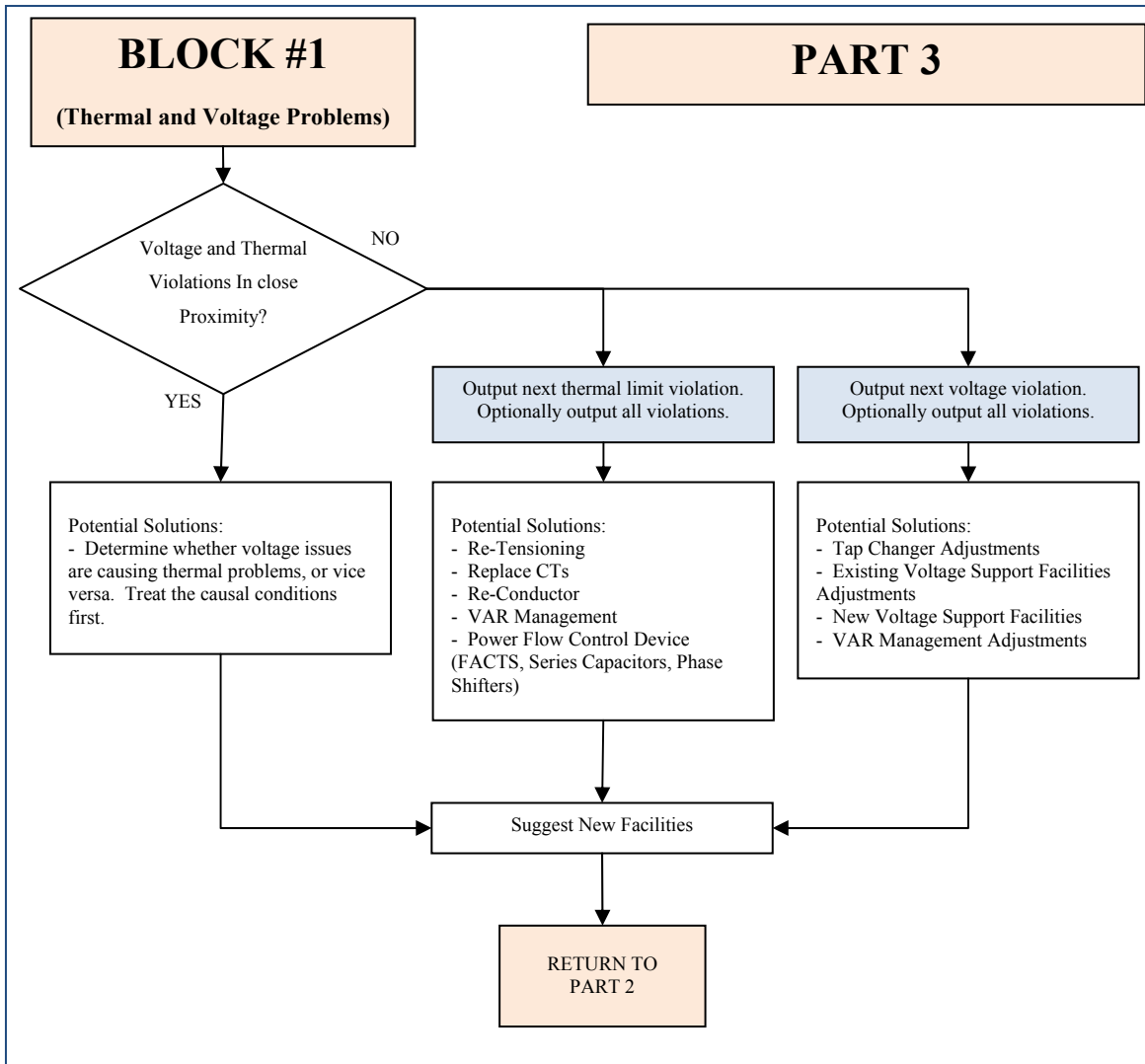


Figure 9 - Expansion Planning Study Decision Process: Part 3

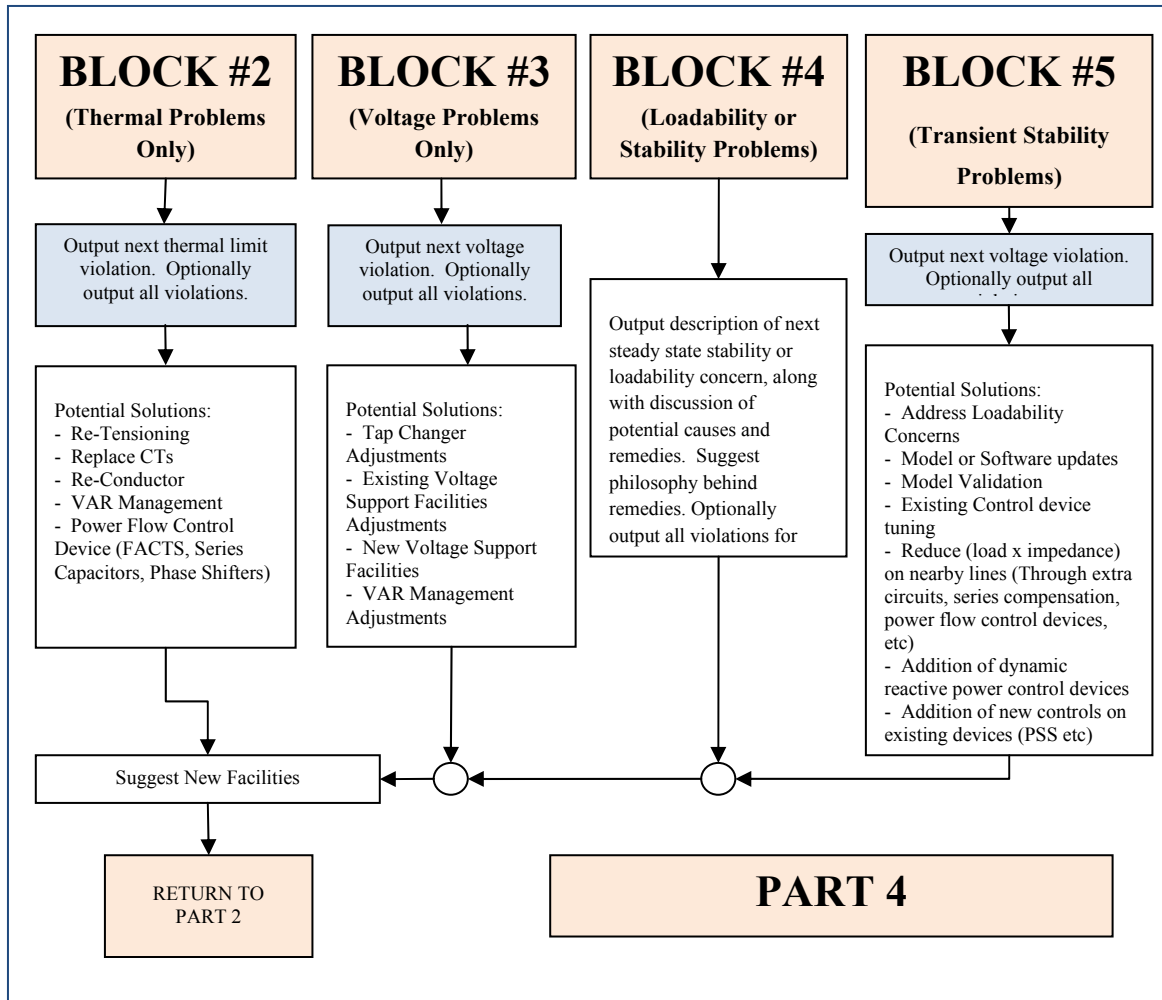


Figure 10 - Expansion Planning Study Decision Process: Part 4

5.2 Planning Study Alternative Development

Given the maximum amount of wind allowed for the cluster study (determined in Chapter 4), transmission expansion alternatives must be created for every level of new wind injection up to that amount. As the amount of interconnected wind increases, the cost of the transmission facilities required to accommodate the wind will generally increase in a step-wise fashion, as shown in the example in Figure 4. Each new “step” represents a new transmission expansion alternative, determined to be optimal for that range of interconnected generation, based on traditional planning methodologies (5.1), or using available optimization tools. Each alternative expansion plan must satisfy the traditional deterministic reliability criteria. The width of each “step” represents the amount of wind

that may be interconnected before the plan must be abandoned for a plan incorporating larger infrastructure upgrades.

5.3 Expansion Plan – Case Study

In order to demonstrate the planning concept, complete expansion plans were developed for the case study area using commercial planning tools (PSS/E) and network data obtained under a non-disclosure agreement (NDA) with the Western Electricity Coordinating Council (WECC). Costing data was made available by Electranix Corporation.

5.3.1 Expansion Plan Development

The planning process identified in Section 5.2 was used to identify steady state thermal constraints and severe voltage criteria violations associated with upgrades at each wind injection level. Transient stability and short circuit considerations were not examined for this case study. Final outcomes of this process are reported here, as the process itself is iterative in nature, and flexible according to the judgement of the transmission planner.

As increasing amounts of wind are injected at the chosen locations, more network expansion is required. Several alternatives were identified which correspond to increasing wind interconnection. These alternatives were selected based on many factors, including consultation with utility planning engineers, formal system impact analysis performed in the region, and best engineering judgement guided by the procedures outlined in Section 5.2. Simplified graphical representation of the chosen expansion alternatives are shown in Figure 11, Figure 13, Figure 16, and Figure 18. Tables showing summaries of the power flow analysis leading to the upgrade alternatives are shown in Table 3 through Table 6.

5.3.2 Notes on Case Study Methodology

The specific tool used to perform the analysis was PSSE version 32. Individual powerflow cases were developed using the aforementioned assumptions. A set of contingency processor (PSS/E's contingency processor tool is called ACCC) files was

developed based on experience working in the area, ensuring that all nearby transmission lines were accounted for, and setting criteria according to local rules. Once preliminary network upgrade designs were tested using “manual” PSSE powerflow runs, the designs were subjected to more rigorous ACCC analysis. For each alternative, ACCC output for cases representing the system before the wind is added was compared to output for cases representing the system after the wind was added. A further comparison to a case with “too much” wind was performed to illustrate where the limit for the upgrade alternative was reached. Any further upgrades or corrections identified by ACCC analysis were implemented in the cases, and ACCC analysis was repeated for those cases.

5.3.3 Existing Transmission System Analysis (Alternative 0)

Figure 11 is a high level diagram of the area transmission system prior to the addition of wind. The proposed wind project area is connected to load areas via a 115 kV network and a single 230 kV line. The existing network can accommodate the 240 MW of wind generation proposed in the interconnection queue, but any additional wind requires upgrading to avoid overloading the 115 kV network to the west and south of the project area (Table 3). A simplified PSSE “slider” diagram is shown in Figure 12 to illustrate the actual power flow in this region.

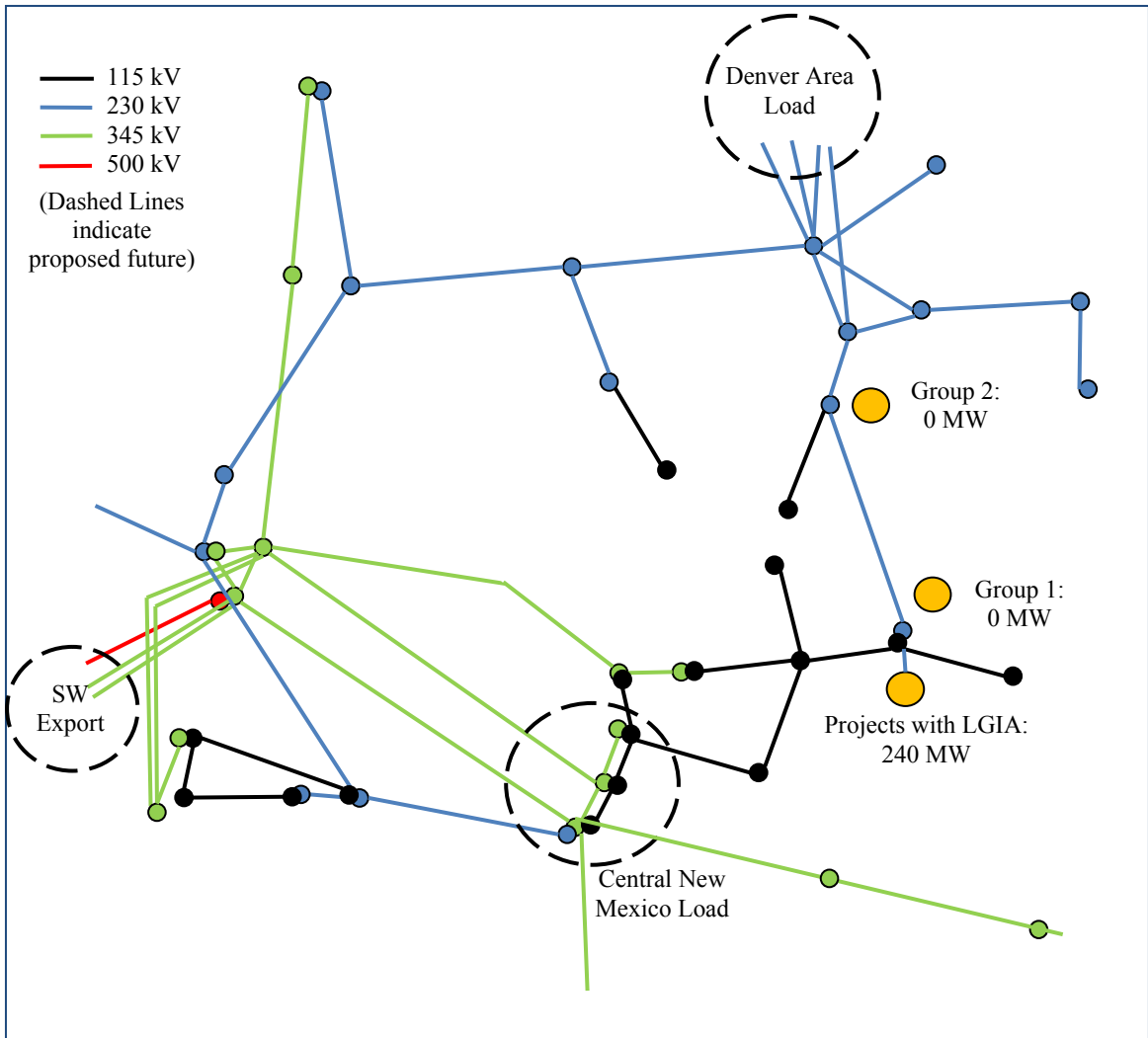


Figure 11 – Case Study: Existing Transmission System Before Network Expansion

Table 3 – Case Study: Power flow Results for Existing System

Contingency	Overloaded Element	Branch Rating (MVA)	Branch Loading (%)			Voltage Concerns
			0 MW wind	240 MW wind	270 MW wind	
Case 1 (No network upgrades, 240 MW of wind)						
Gladstone - Walsenburg 230 kV	Springer - Gladstone 115 kV	169	54	97	114	None
Walsenburg 115/239 kV TF 1	Walsenburg 115/239 kV TF 2	100	69	98	102	None

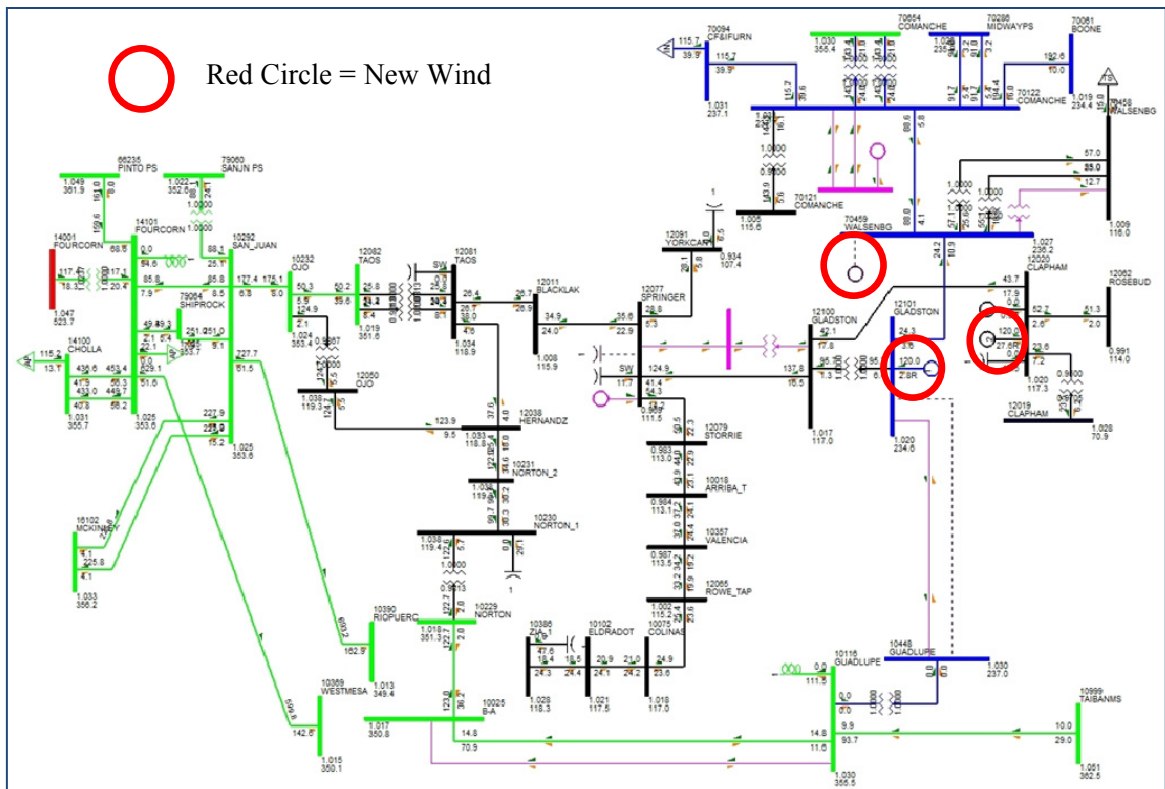


Figure 12 – Existing Transmission System Power Flow with 240 MW of Wind Added

5.3.4 Alternative 1 System Analysis

If 150 MW of wind is added to interconnection location 2 (in addition to the amount that the existing system can handle), and an additional 50 MW to interconnection location 1 (corresponding to Section 4.4), Figure 13 depicts what mitigation would be required to handle this generation. The precise split of generation chosen here is based on informal iterative power flow studies. The 115 kV thermal and stability constraint is avoided by building additional voltage support and a new 115 kV parallel circuit. Voltage support is provided by an SVC sized to ensure no dV criteria violations occurred when the transmission path west was interrupted. Switched capacitors may be used as a cheaper alternative mitigation for this dV concern. A transformer overload in the north was discovered and mitigated by adding a parallel transformer. This set of network upgrades is assumed to be “Alternative 1”, and requires the specific breakdown of generators between interconnection locations to be respected.

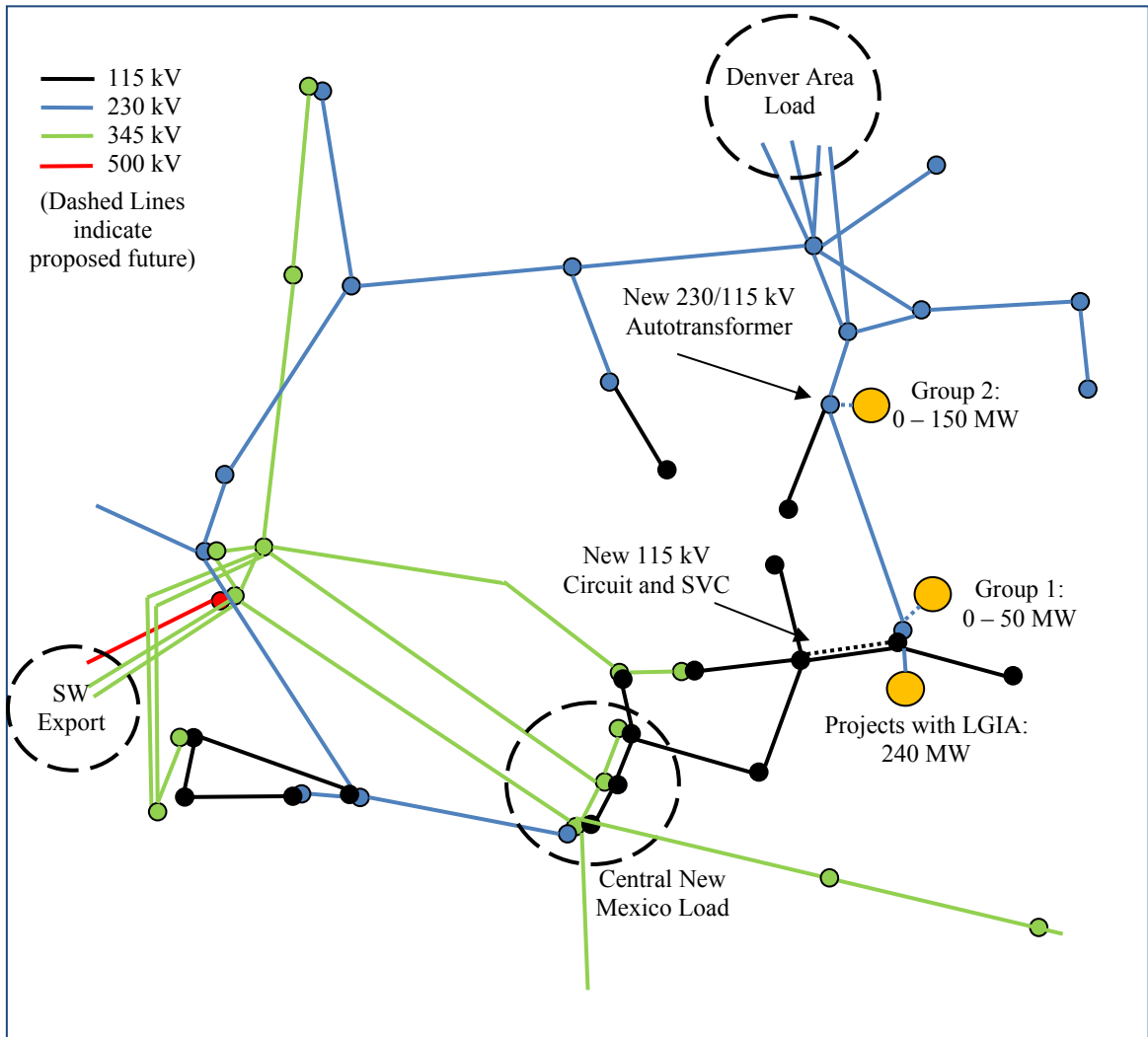


Figure 13 – Case Study: Network Expansion Alternative 1

Table 4 – Case Study: Power flow Results for Alternative 1

Contingency	Overloaded Element	Branch Rating (MVA)	Branch Loading (%)			Voltage Concerns
			240 MW wind	440 MW wind	470 MW wind	
Case 2 (Alt 1 upgrades added, 440 MW of wind)						
Springer - Black Lake 115 kV	115 kV Path south from Springer	110	76	100	106	Low voltage at Springer and south along path to Valencia
Clapham - Gladstone 115 kV	Gladstone 115/230 kV TF	110	69	97	104	None
Note that the existing cross-trip between Comanche - Walsenburg and Walsenburg - Gladstone must be disabled						
Note that if one of the 2 circuits between Gladstone and Springer trips, the second must trip with it to avoid overloading						

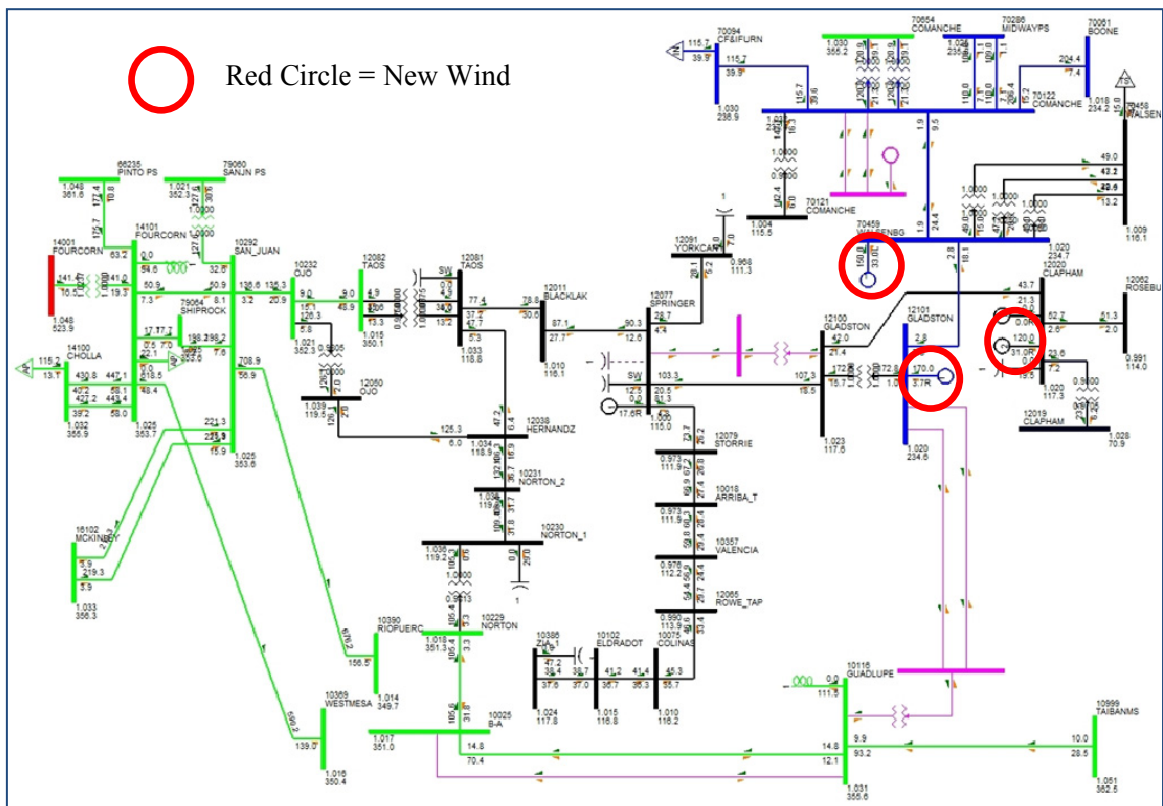


Figure 14 – Alternative 1 PSSE Power Flow with 440 MW of Wind Added

The ACCC analysis for this alternative (summarized in Table 4) indicated that low voltage was a concern for contingencies on the 115 kV system west of Springer. Figure 15 shows an example of how the PSSE slider tool can be used to help understand problem areas. In Figure 15, a contingency has been applied west of Springer which causes under-voltages to occur (shown in blue) throughout the 115 kV network, particularly south of Springer 115 kV.

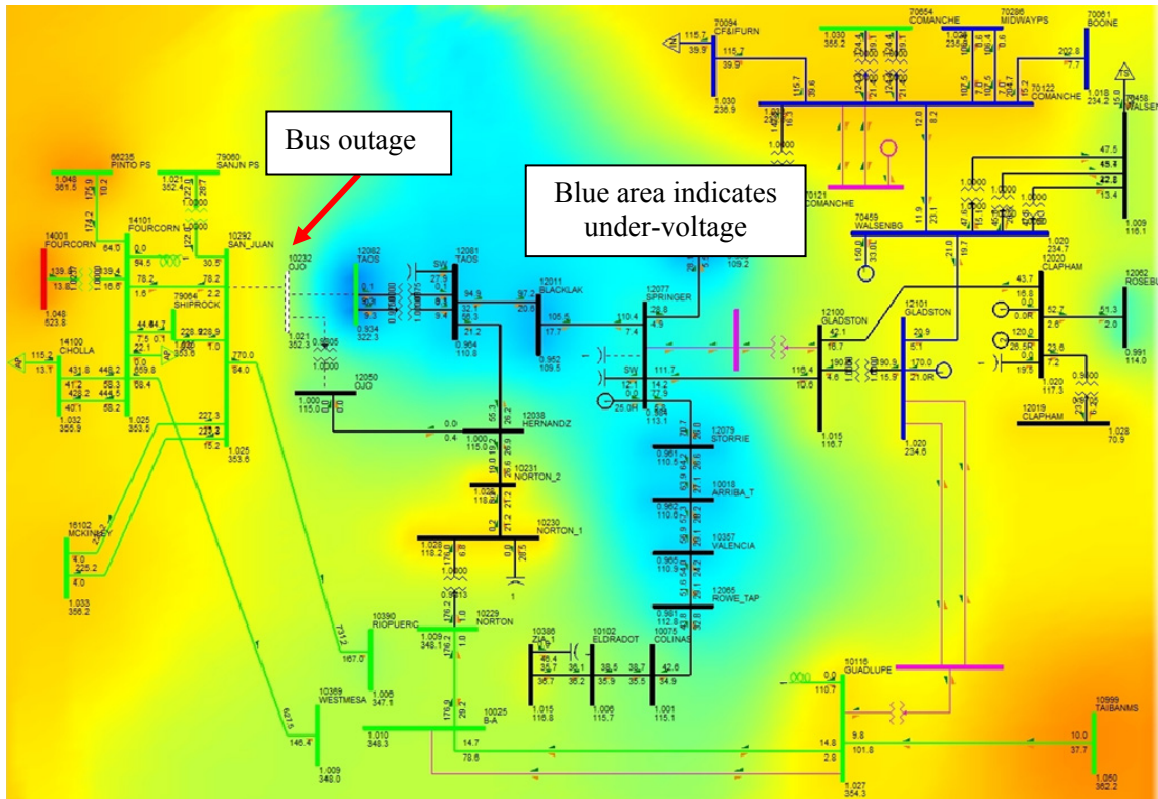


Figure 15 - Alternative 1 PSSE Power Flow with Example Contingency

5.3.5 Alternative 2 System Analysis

Increasing the total installed wind at both interconnection locations requires more substantial high voltage transmission upgrades, including a parallel 240 kV path south from interconnection location 1, and a twinned 345 kV circuit west to the Central New Mexico load area (Figure 16). Associated substation and transformation equipment is required. Additional minor upgrades are required in the north, but the 115kV new circuit required for Alternative 1 is not required for Alternative 2. Table 5 summarizes the constraints demonstrated by the ACCC analysis for this alternative and Figure 17 shows the PSSE power flow in a simplified “slider” diagram.

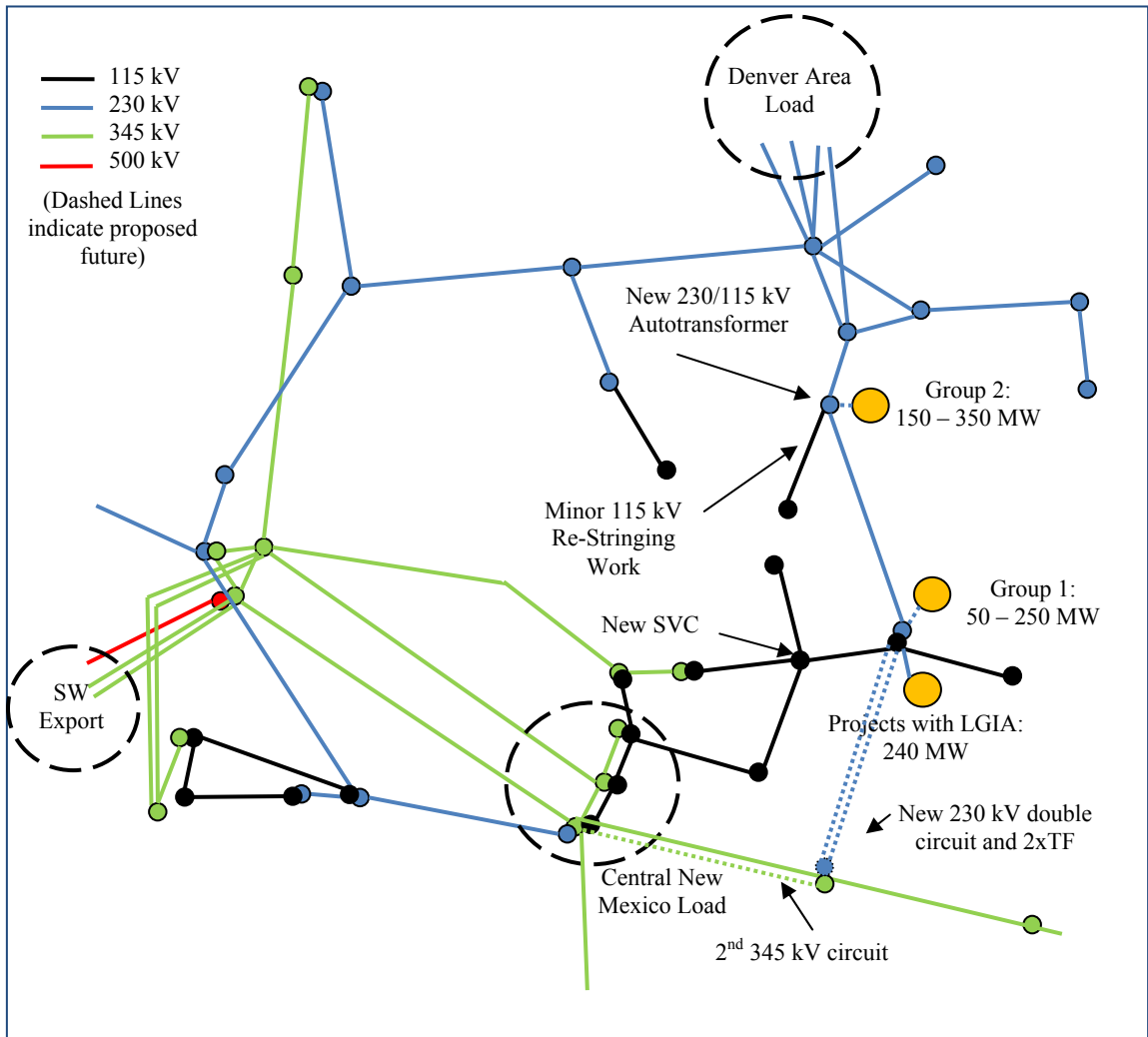


Figure 16 – Case Study: Network Expansion Alternative 2

Table 5 – Case Study: Power flow Results for Alternative 2

Contingency	Overloaded Element	Branch Rating (MVA)	Branch Loading (%)			Voltage Concerns
			440 MW wind	840 MW wind	950 MW wind	
Case 3 (Alt 2 upgrades added, 840 MW of wind)						
Gladstone - Guadalupe 230 kV	Springer - Gladstone 115 kV	169	60	90	102	None
Note that the existing cross-trip between Comanche - Walsenburg and Walsenburg - Gladstone must be disabled						

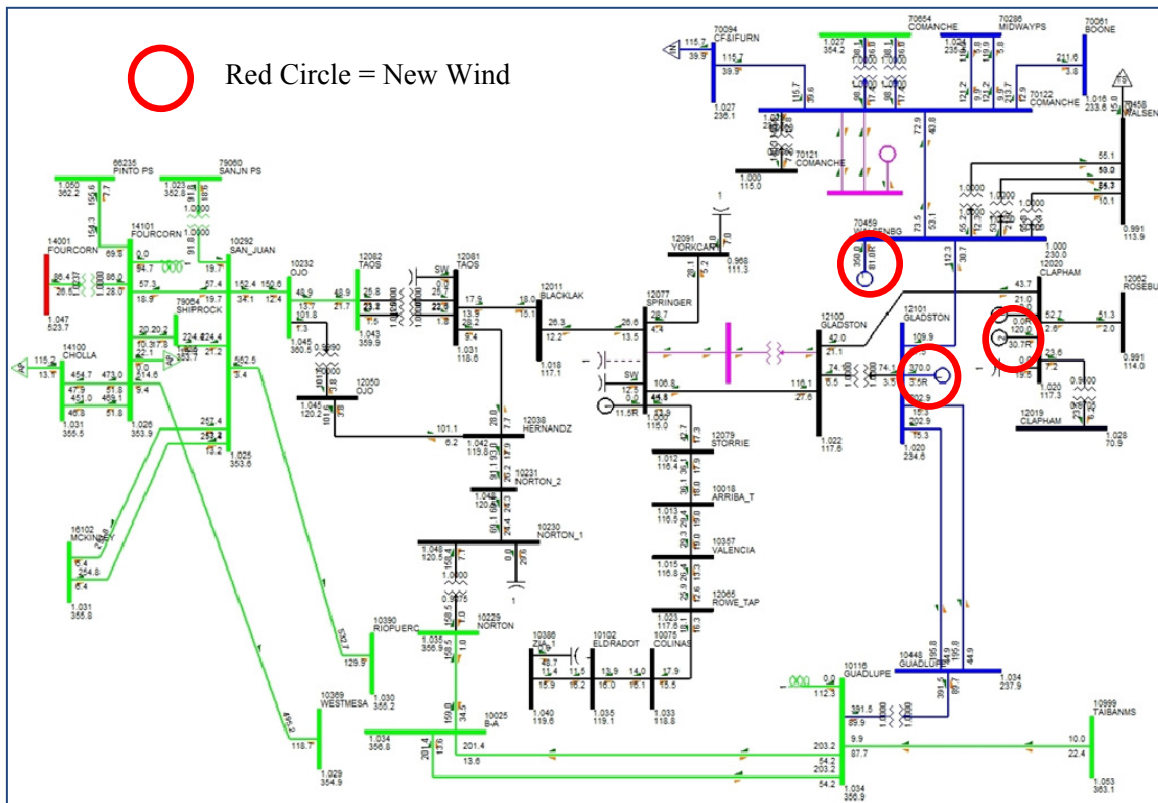


Figure 17 - Alternative 2 PSSE Power Flow with 840 MW of Wind Added

5.3.6 Alternative 3 System Analysis

Further increasing the total wind generation to 1550 MW requires a phase shift transformer to prevent excess power from flowing into the weak 115 kV network west of interconnection point 1 (at this wind injection level, directing power out of this 115 kV line by adding circuits out of the area is not enough to prevent overload of the 115 kV network, and a new phase shifter is required), and a new 230 kV double circuit to the north of interconnection point 2 to bypass a weaker 230 kV path (Power flow illustrated in Figure 18, with ACCC constraints shown in Table 6). The 230 kV line between location 1 and 2 is not required to be twinned, but it is critical that generation is split correctly between the two locations. This point is important when final costing is done, because it may be tempting for the planner to take a different balance of projects from location 1 and 2 based on cost. If this is done, Alternative 3 must be re-evaluated with the revised dispatch.

It should be noted that following the implementation of the Alternative 3 upgrades, the limit to the amount of new wind is now not constrained by transmission, but by the “max wind” value selected in chapter 4.2.

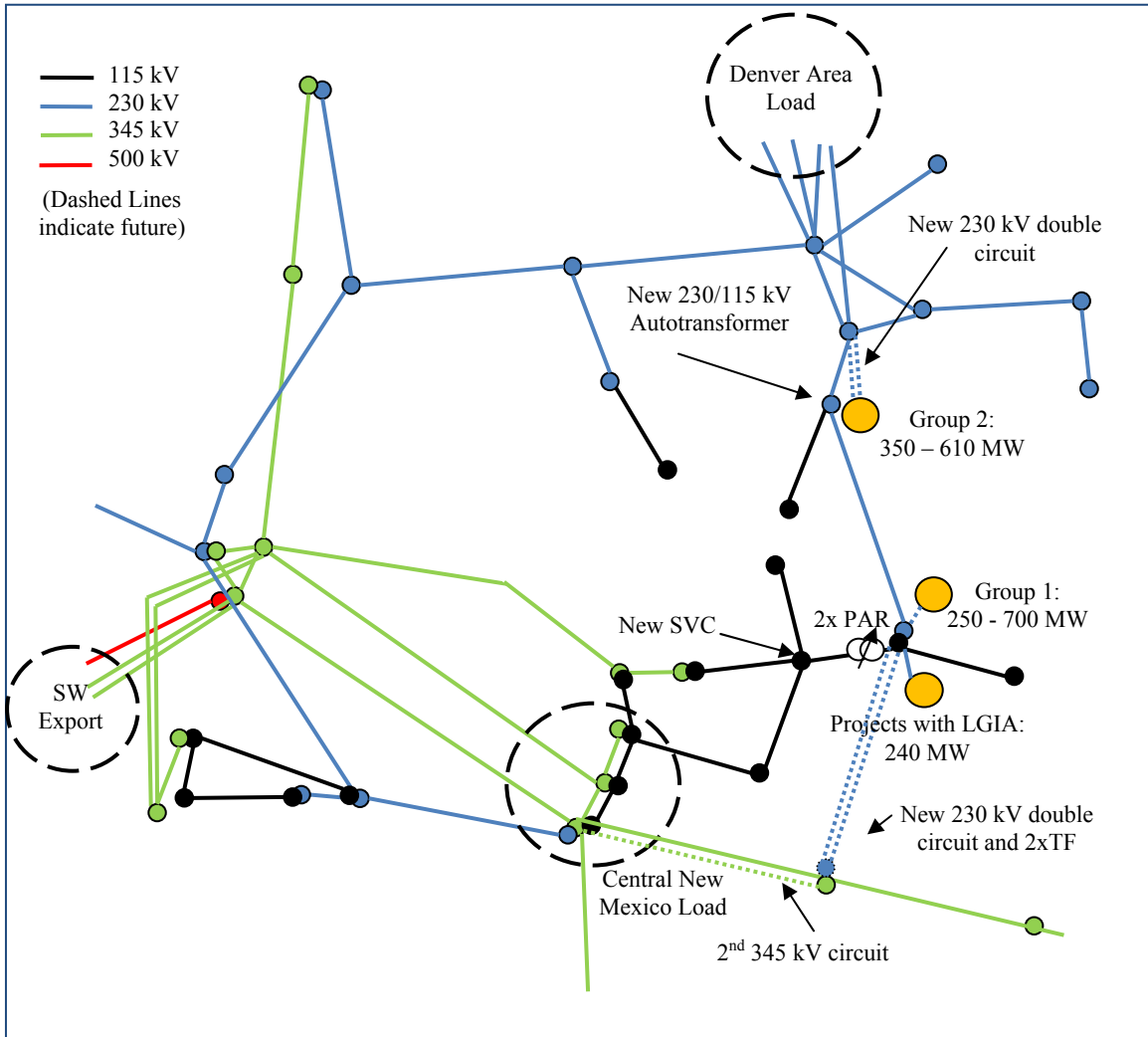


Figure 18 – Case Study: Network Expansion Alternative 3

Table 6 – Case Study: Power flow Results for Alternative 3

Contingency	Overloaded Element	Branch Rating (MVA)	Branch Loading (%)		Voltage Concerns
			840 MW wind	1550 MW wind	
Case 4 (Alt 3 upgrades added, 1550 MW of wind)					
N/A	N/A	N/A	N/A	N/A	None
Note that the existing cross-trip between Comanche - Walsenburg and Walsenburg - Gladstone must be disabled					

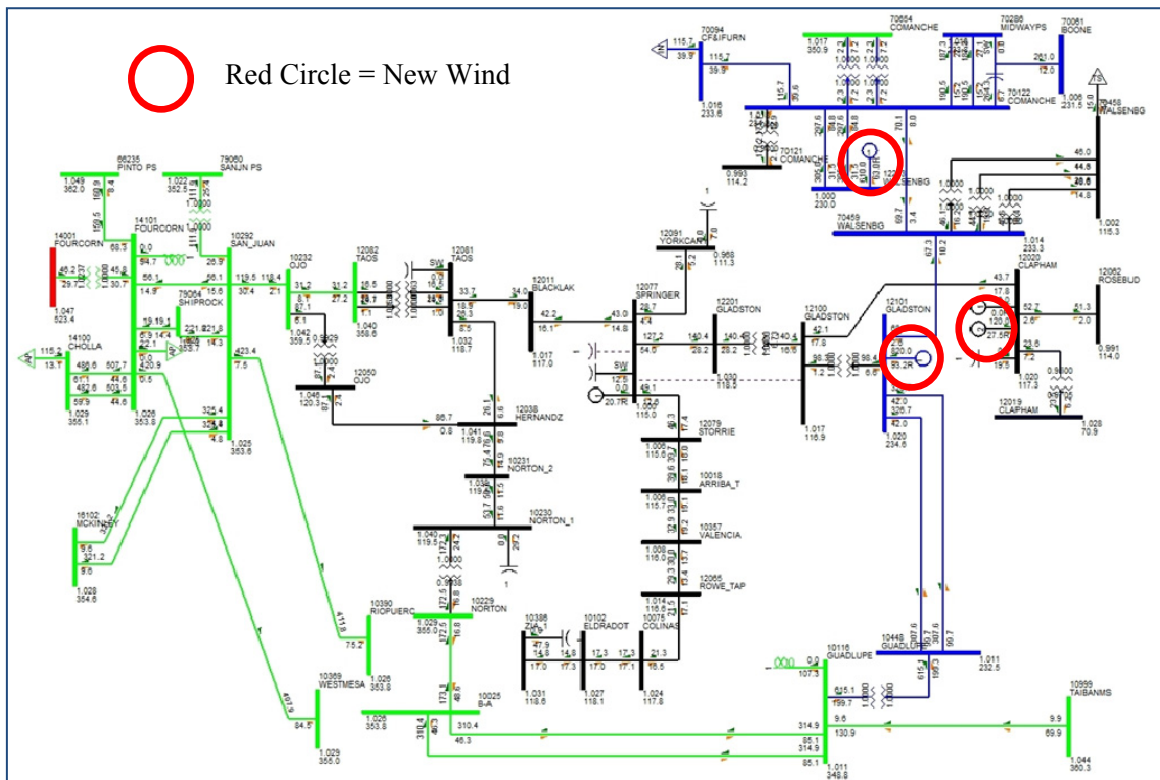


Figure 19 - Alternative 3 PSSE Power Flow with 1550 MW of Wind Added

5.3.7 Expansion Plan Cost Evaluation

Table 7 shows the calculated costs for each expansion alternative, and Figure 20 shows the infrastructure cost as a function of installed capacity. Costs in these tables are in 2009 dollars, and based on per unit costing data provided by Electronix Corporation. They account for terrain, permitting and environmental considerations, and short line multipliers.

Table 7 – Case Study: Breakdown of Costs for Expansion Alternatives

Total Wind for Alternative	Wind loc. 1	Wind Loc. 2	Dispatch	Mitigation Required	Mitigation Details	est. Cost (2009) (\$M USD)
Existing System (Alternative 0)						
240 MW	240	0	Denver 240	none (existing system)	N/A	N/A
Total Cost Existing System						0.00
Alternative 1						
440 MW	290	150	San Juan 200 Denver 240	2nd 115 kV cct bw Gladstone and Springer	32 miles new towers ACSR 954 Conductor	21.11
				25 MVAR SVC at Springer	+/- 24 MVAR AMSC DVAR	3.50
				new transformer at Walsenburg	100 MVAR	3.33
Total Cost Alternative 1						27.94
Alternative 2						
840 MW	490	350	Export 200 San Juan 200 Denver 440	double cct 230 kV bw Gladstone and Guadalupe	110 miles 2x1113 KCMIL	237.99
				2x345/230kV transformers at Guadalupe	2x600MVA Autotransformer	14.60
				2nd circuit from Guadalupe to B-A	92 miles 2x1272 kcmil, single new circuit	140.12
				3rd transformer at Walsenburg	100 MVAR	3.33
				25 MVAR SVC at Springer	+/- 24 MVAR AMSC DVAR	3.50
				re-conductor 115 kV cct b/w stem and pueb	10 miles re-stringing	4.95
Total Cost Alternative 2						404.50
Alternative 3						
1550 MW	940	610	Export 500 Denver 800 San Juan 250	2x 230kV cct radial bw Wals wind and Comanche	51 Miles at 444 MVA, 2x cct 1x1113kcmil	72.53
				2xPAR set to 140 MW at Gladstone 115 kV	Based on 300 MVA 345 kV	18.95
				double cct 230 kV bw Gladstone and Guadalupe	110 miles 2x1113 KCMIL	237.99
				2x345/230kV transformers at Guadalupe	2x600MVA Autotransformer	14.60
				3rd transformer at Walsenburg	100 MVAR	3.33
				2nd circuit from Guadalupe to B-A	92 miles 2x1272 kcmil, single new circuit	140.12
25 MVAR SVC at Springer	+/- 24 MVAR AMSC DVAR	3.50				
Total Cost Alternative 3						491.04

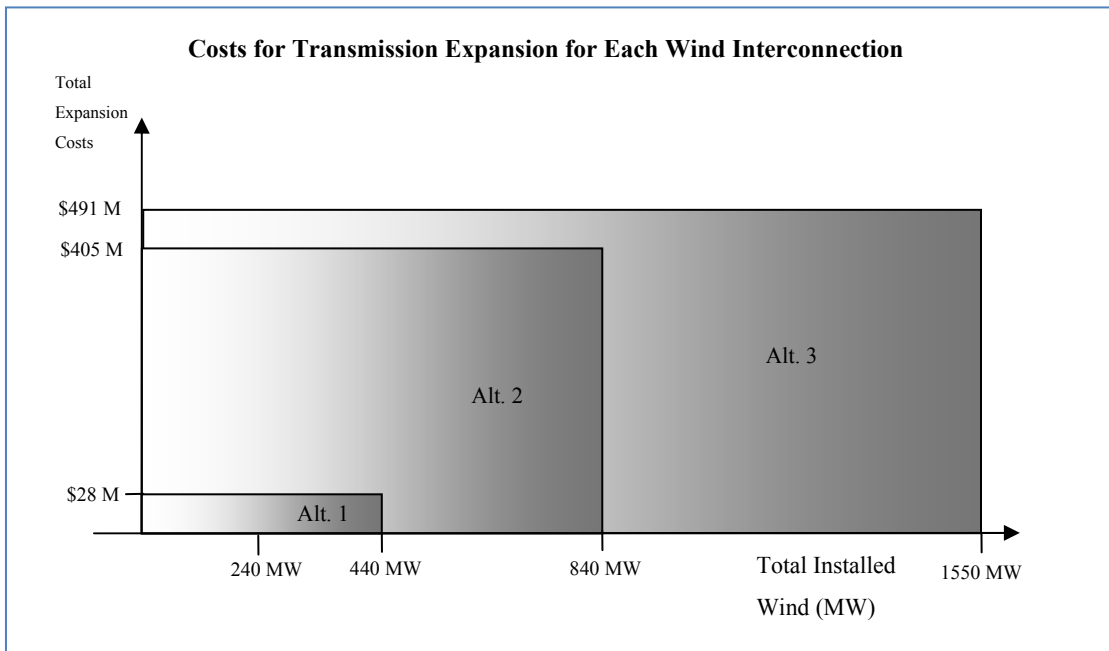


Figure 20 – Case Study: Expansion Costs Varying with Installed Wind

5.3.8 Expansion Plan Loss Evaluation

In order to determine the incremental losses imposed on the system by the addition of wind and associated transmission network upgrades, a system wide loss evaluation was performed for various increments of wind generation, up to the maximum level used in the case study. This cost aspect can be considered as part of the expansion plan design, but it is noted that precise quantification of the costs of losses are difficult, and heavy reliance upon this aspect is not recommended.

A load duration curve (LDC) was generated using actual 10 minute historical wind data from a commercial site in Saskatchewan (far from study area but representative of real wind data) and was applied to all wind in the case study (Figure 21). Nine dispatch scenarios were modelled in PSS/E, reflecting a linear increase in wind at both interconnection locations and generation backed down evenly from all three dispatch locations (Table 8). For each dispatch scenario, total real power losses across the entire Western Interconnection (WECC) were measured (Figure 22).

Table 9 and Figure 22 present a comparison between two methods for calculating energy losses for wind. One method uses the LDC to evaluate losses according to time spent generating at various wind levels. The second method assumes that the wind farms are generating all year round at a constant level, equal to the predicted capacity factor for the plants. The second method requires much less computation, but is found to be fundamentally incorrect, due to the non-linear increase in system losses as the wind generation increases.

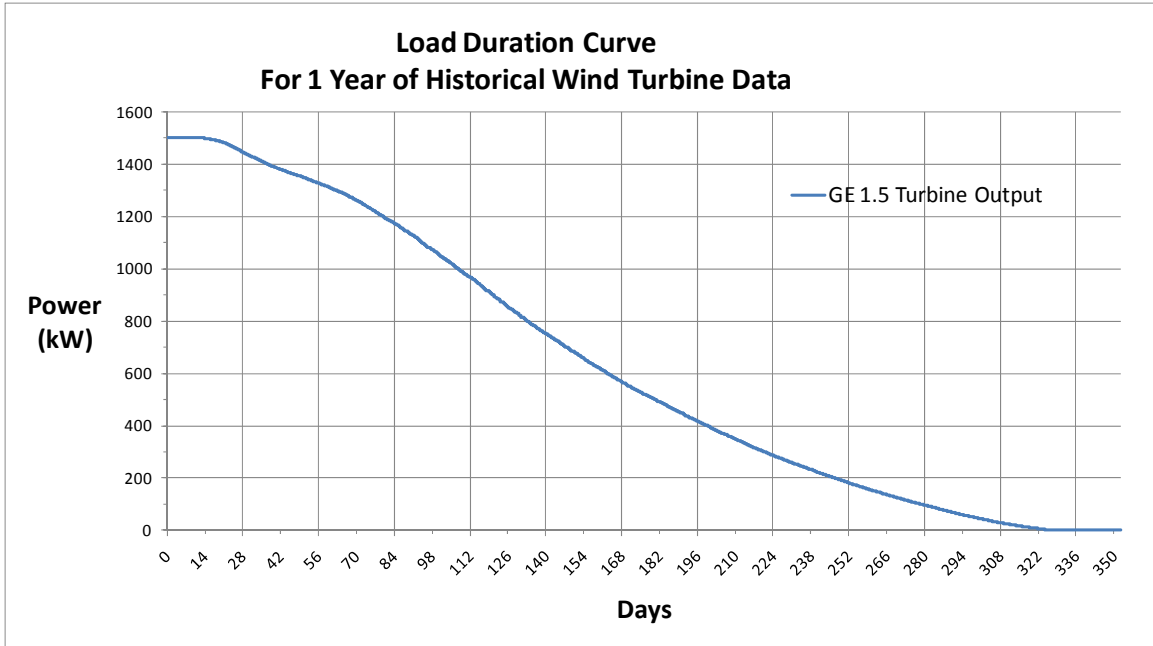


Figure 21 – Case Study: Scaled Annual Wind Farm Load Duration Curve

Table 8 – Case Study: Dispatch Levels for Loss Evaluation

Table for linear Generation Dispatch						
Change in Existing Generation Dispatch				Wind Output		
SJ	Denver	AZ	total	Loc. 1	Loc. 2	Total
250	800	500	1550	940	610	1550
218	697	435	1350	819	531	1350
185	594	371	1150	697	453	1150
153	490	306	950	576	374	950
121	387	242	750	455	295	750
89	284	177	550	334	216	550
56	181	113	350	212	138	350
24	77	48	150	91	59	150
0	0	0	0	0	0	0

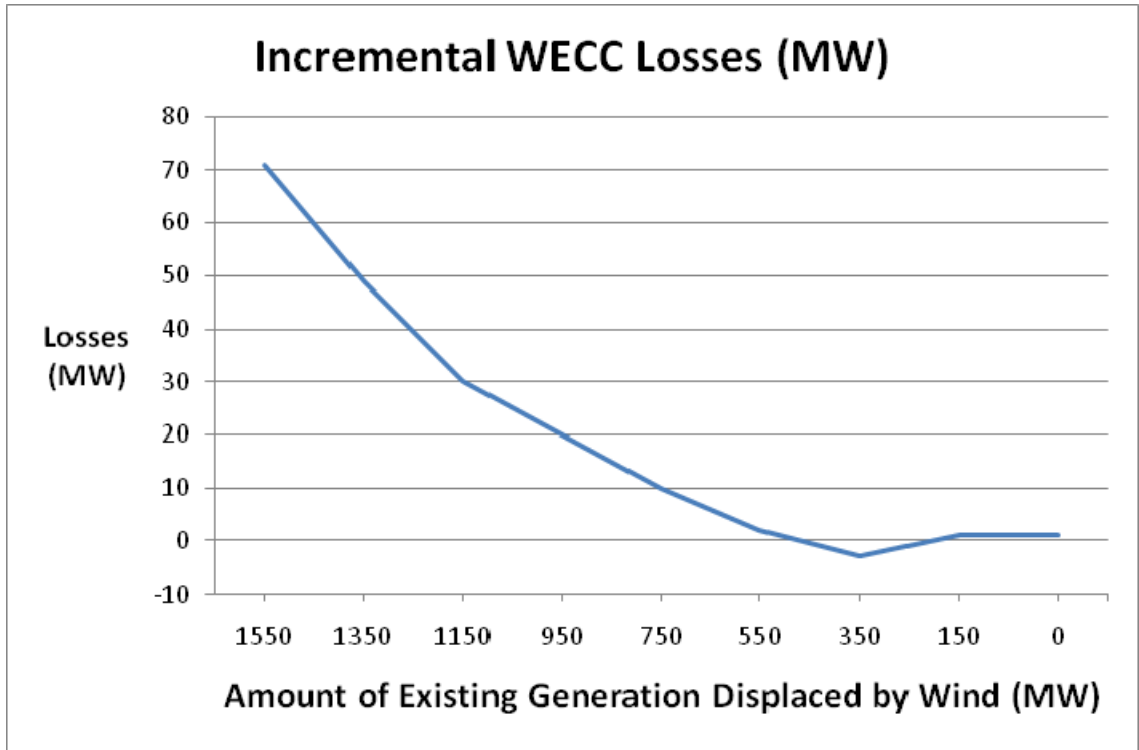


Figure 22 – Case Study: Variation of Incremental Losses with Wind Capacity

Table 9 – Case Study: Comparison of Energy Losses Using LDC and Capacity Factor

Total Wind (MW)	Incremental Losses (MW)	Wind Turbine Avg Power (kW)	Days per year (from Wind LDC)	Energy in Losses (MWh)
1550	71	1500	14	23856
1350	49	1306	46	54096
1150	30	1113	32	23040
950	20	919	24	11520
750	10	726	26	6240
550	2	532	31	1488
350	-3	339	39	-2808
150	1	145	50	1200
0	1	0	103	2472
Total Annual Energy in Losses (kWh)				121104
Total Annual Energy in Losses using capacity factor of 0.40 (kWh)				35040

Note: Capacity factor calculation uses loss value for 620 MW (interpreted from Figure 22 characteristic) of wind generation, which corresponds to 40% of full rated capacity.

Several things are worth noting about these calculations:

1. The simpler calculation based on a single loss calculation when the total wind is generating at its capacity factor value is different from the more thorough technique applying the generator load duration curve, and is therefore not an acceptable approach in this case.
2. Since the generation is replacing existing coal resources, changes in losses are generally only dependent on the difference in physical distance between the new and old generation sources from the existing load. The case study used here does not show an appreciable difference in total losses until near the highest levels of wind.
3. The real system would not necessarily use the same dispatch assumptions in real time as those used for this calculation, and the calculation of precise numbers for losses attributable to the new wind would be highly controversial and difficult to obtain.
4. This loss analysis was performed only for the highest level of wind (Alternative 3). Similar results would be expected for lower wind level Alternatives.

Due to these notes, and particularly note 3 above, the loss calculation was not included in the overall cost calculations. However, the annual energy losses are notable and should be considered by the energy purchaser as indicative of potential lost resource.

5.4 Optimal Cost Breakpoint Selection – Case Study

5.4.1 Minimization of Cost per MW

Optimal breakpoints are selected such that the “Cost per MW” for transmission is minimized. This accounts for the probable effect of increased economy of scale resulting in lower energy prices with more wind. Since the desired end result is to purchase a significant amount of wind power, the very low cost alternatives that effectively use up the existing available transmission capacity (but only connect small amounts of wind) should be considered only after higher wind levels are discarded as being too expensive.

5.4.2 Cost Breakpoint Selection

For the case study considered here, the energy cost per MW of installed wind for transmission was calculated as shown:

$$C_T = \frac{1}{10} \left(\frac{NUPM + OMPM}{CF} + TTPM \right) \quad (5.1)$$

Where:

- C_T = Component of energy costs required for transmission [cents/kWh]
- NUPM = Network upgrade costs per hour per installed MW [\$/hr/MW]
- OMPM = O&M costs per hour per installed MW [\$/hr/MW]
- TTPM = Transmission tariffs per hour per installed MW [\$/hr/MW]

Note: Representing the cost of using existing transmission facilities between the interconnection point and the point of power delivery, the transmission tariffs per hour per installed MW (TTPM) was assumed to be \$6.28/hr/MW. This value is based on information obtained from Sequoia Energy for typical transmission service fees over the project lifetime for a 100 MW wind farm in Northeast New Mexico with a point of delivery in the Denver area. The value also assumes that 40% of the transmission capacity would be purchased on a “firm” basis, and 60% on a “non-firm” basis.

- CF= Capacity Factor (assumed to be 35%)
- Note that the 1/10 factor represents a conversion from dollars/MWh to cents/kWh

Network upgrade costs per hour per installed MW (NUPM) is obtained as

$$NUPM = CCPM \cdot r \cdot \left[1 - \frac{1}{(1+r)^p} \right]^{-1} \quad (5.2)$$

Where:

- r is the discount rate, assumed to be 6%
- p is the number of payment periods, equal in total to the project life (assumed to be 20 years, expressed as hours).
- CCPM = Network upgrade capital cost per installed MW [\$/MW], which is obtained from

$$CCPM = \frac{CC_{alt}}{IC} \quad (5.3)$$

- IC = Installed wind capacity
- CC_{alt} = Network upgrade capital cost for the expansion alternative. The expansion alternative capacity must greater than or equal to IC

The O&M costs per hour per installed MW (OMPM) is calculated as:

$$OMPM = \frac{CCPM * OM}{8760} \quad (5.4)$$

Where:

- OM = Annual O&M as percent of Capital Cost

When the C_T values are calculated at every value between 0 MW and the full allowed installed wind capability (1550 MW), Figure 23 may be constructed to visualize what ranges of installed wind are optimal from a transmission costs standpoint.

Optimal ranges are selected in this case study as the installed amounts slightly smaller than the levels which trigger a new set of transmission upgrades (Alternative 1, 2, and 3). For each alternative, the installed wind is allowed to be reduced by up to 100 MW. Therefore, if alternative 1 is selected, the minimum cost equals = 0.91 cents/kWh at 440 MW of installed wind, and allowing a reduction of up to 100 MW, the optimal range from 340-440 MW was selected. Applying similar guidelines to Alternative 2 and Alternative 3 yield optimal ranges of 740 MW – 840 MW, and 1450 – 1550 MW respectively.

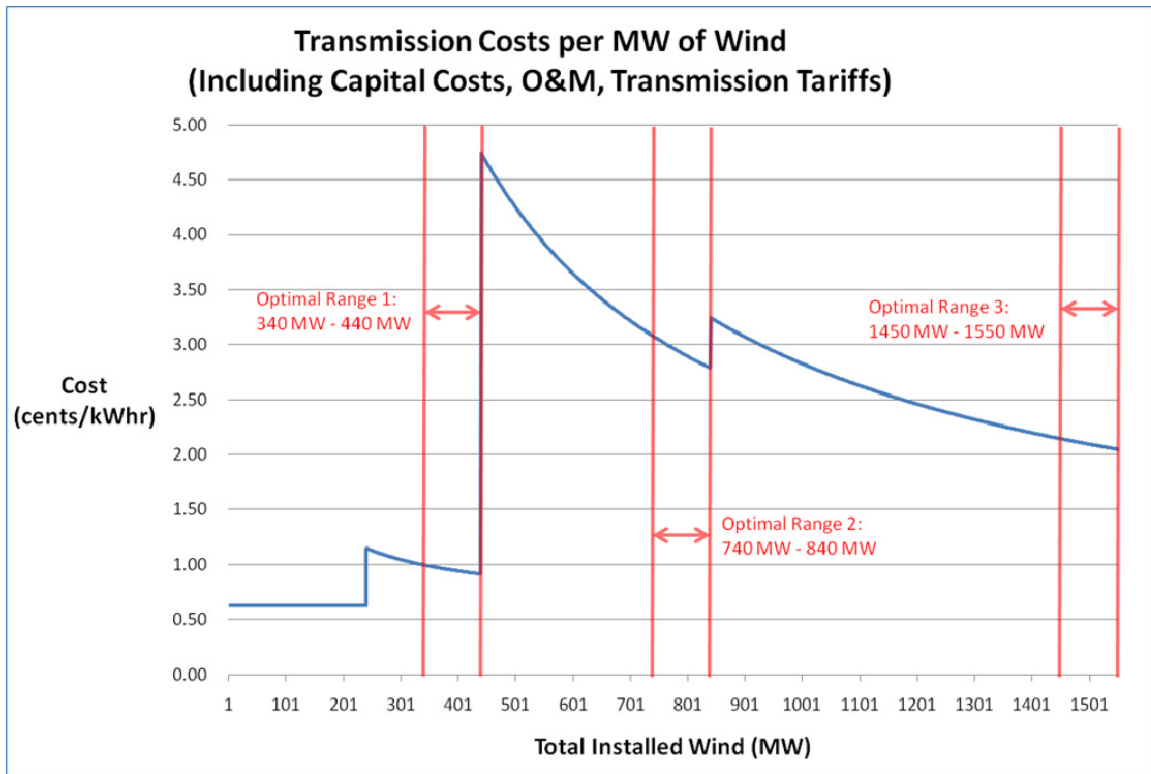


Figure 23 - Case Study: Energy Costs for Transmission per MW of Installed Wind

Chapter 6 RFP and Expansion Implementation

6.1 RFP Design Philosophy

Design of a Request For Proposals (RFP) must be undertaken with care, ensuring that interested parties are treated fairly and respectfully, without undue financial burden. A high level of commitment and a high standard of proposal must be required of applicants, and purchasers likewise must be prompt and fair, clearly communicating the process and reasoning behind decisions.

6.2 Required RFP Elements

The following elements should be present in an RFP of this nature. A recent request for proposals issued by Canadian transmission utility SaskPower elaborates on several of these requirements [46]:

- Full disclosure of planning study results to this point in the cluster study process, especially including optimal cost breakpoints as shown in the case study example (Section 5.4.2). Expected interconnection points and proposed upgrades for each alternative should be clearly indicated.
- It is assumed for this process that the energy purchaser is the party issuing the RFP, and therefore applicants need not supply proof of a willing customer, such as a Power Purchase Agreement (PPA).
- The proposal price should be framed in terms of a desired fixed payment for energy over the course of the project life (for example, 20 years). All costs for transmission should be excluded from this payment price.
- It is not required that proposals match the interconnection points determined in the cluster study exactly, but it should be made clear that deviations from the interconnection points may not match the overall expansion plan philosophy, and may require additional costs to be built into the bid such that the project may be fairly compared with other projects (for example, radial connection circuits to the expected points of interconnection). In some cases, small changes to the points of interconnection may not impact overall expansion plans, but this is a risk in any proposal.

- Proven site control (land-owner commitment to allow access to the land in the project area) should be required of Applicants.
- One year of meteorological wind data for the site in question should be provided by the applicant. This ensures adequate wind resource at the particular applicant site. In addition, expected plant capacity factor and annual energy production should be calculated [46].
- Clear indication of the capabilities of the applicant to build and operate a wind plant as proposed should be provided by the applicant, in the form of a minimum prior experience of the applicant in developing power projects, and details on applicant personnel [46].
- Financial capability should be demonstrated by the applicant [46].
- Clear description of all pertinent interconnection requirements that will be imposed upon successful applicants should be provided. For example, the voltage control and reactive power capabilities required of generators should be well defined so that proponents may obtain correct equipment costing information. Proposals should include the details of how these requirements will be met.
- Clear explanation of the process being followed should be provided, including a warning to applicants that large proposals may not be eligible if smaller expansion alternatives are chosen.

6.3 Proposal Submission – Case Study

Having been provided with expected interconnection locations and the motivation behind the “optimal breakpoints”, the applicants have enough information to submit proposals for interconnection. In the case study under examination, the important aspects of each proposal (assuming all the items required in Section 6.2 are adequate) are the bid price, which excludes transmission costs, and the interconnection location.

For the purposes of the example in question, it is assumed that all the queued projects shown in Section 4.4 are among the applicants. Five additional projects are added to simulate new projects enticed by the elimination of the old queue system. In the example, bid prices were assigned to each project somewhat randomly (but

representatively), and are shown in Table 10. The proposed interconnection location for each bid is chosen as the closer of the two selected locations. Three proposals have been randomly selected as being “incomplete”, and are rejected for not meeting the requirements in Section 6.2.

Table 10 – Case Study: Unsorted Summary of Random Bid Prices by Project

Unsorted Proposals with Random Bid Prices Assigned				
Queue Reference	Amount of wind	Wind Location	Proposed Price (cents/kWh)	Project Development
TI-07-0222	51 MW	1	12.53	Complete
TI-07-0301	500 MW	1	8.01	Complete
TI-07-0305	250 MW	2	9.24	Complete
TI-07-0510	120 MW	1	8.53	Complete
TI-07-0611B	300 MW	2	7.89	Incomplete
TI-07-0816	200 MW	1	9.01	Complete
TI-08-0103	210 MW	2	9.65	Complete
TI-08-0403	200 MW	2	9.22	Complete
TI-08-0515	200 MW	1	8.74	Complete
Not in Queue	320 MW	1	8.87	Incomplete
Not in Queue	150 MW	1	9.11	Complete
Not in Queue	100 MW	2	7.98	Complete
Not in Queue	150 MW	2	7.87	Incomplete
Not in Queue	120 MW	1	8.88	Complete

6.4 Proposal Selection – Case Study

6.4.1 Rank Proposals by Price

After the incomplete proposals are rejected, the remaining proposals are ranked according to bid price. Each interconnection location is constrained to maximum levels of new wind injection, as defined by the planning study. These maximums are applied for each connection alternative.

The projects are selected from lowest price to highest, until the maximum amount of wind has been reached for each interconnection location for that expansion alternative. Some proposals which are priced very low may still be rejected at some expansion levels

due to the maximum amount of wind allowed for that particular alternative at that location.

Alternative 1

Selecting the viable bids in Table 10 according to lowest cost first, and considering the maximum allowed generator size by location, yields Table 11.

Beginning with the existing 240 MW at location 1, we are then able add up to 50 additional MW to location 1 and up to 150 MW at location 2 to bring the totals at each location up to the locational maximums of 290 MW and 150 MW (determined in the planning studies for Alternative 1). In this alternative, the only viable project for wind location 1 is TI-07-0222, which, though high priced, is small enough to remain below the maximum total wind allowed at location 1.

This stage of the process may require discretion on the part of the planners, especially when project sizes do not fit well into the overall expansion plans originally designed. After these bids have been tabulated in this fashion (Table 11) it may become evident that the “optimal breakpoints” will require adjustment (for example “Optimal Breakpoint 1” could be reduced to 340 MW from 440 MW, discarding the expensive 51 MW smaller project.)

Table 11 – Case Study: Proposals Ranked by Price, Constrained by Alternative 1

Alternative 1					
Queue Reference	Proposed Price (cents/kWh)	Amount of wind	Wind Location	Cumulative Total Loc. 1 (MW)	Cumulative Total Loc. 2 (MW)
Existing	9	240 MW	1	240	0
Not in Queue	7.98	100 MW	2	240	100
TI-07-0222	12.53	51 MW	1	290	100
Maximum Total Allowed at Each Location (MW)				290	150

Alternative 2

For Alternative 2, selection of the lowest cost bids by location yields Table 12. More generation is allowed at each location, and consequently the larger, more economical projects may be selected for this alternative. The very large (500 MW), very low cost project may not be selected, as neither interconnection location can accommodate that amount of power injection.

Table 12 – Case Study: Proposals Ranked by Price, Constrained by Alternative 2

Alternative 2					
Queue Reference	Proposed Price (cents/kWh)	Amount of wind	Wind Location	Cumulative Total Loc. 1 (MW)	Cumulative Total Loc. 2 (MW)
Existing	9	240 MW	1	240	100
Not in Queue	7.98	100 MW	2	240	100
TI-07-0510	8.53	120 MW	1	360	100
Not in Queue	8.88	120 MW	1	480	100
TI-07-0305	9.24	250 MW	2	480	350
Maximum Total Allowed at each Location (MW)				490	350

Alternative 3

For Alternative 3, the very large, low cost projects may now be selected to good economic effect (Table 13). However, the amount of generation required to reach the third optimal range is so large that several more expensive bids are still required at location 2 (TI-07-0403 and TI-07-0305). It will be seen in the final stage of this process that the increasing bid price tends to cancel out economies of scale in transmission expansion for Alternative 3 in this case study.

Table 13 – Case Study: Proposals Ranked by Price, Constrained by Alternative 3

Alternative 3					
Queue Reference	Proposed Price (cents/kWh)	Amount of wind	Wind Location	Cumulative Total Loc. 1 (MW)	Cumulative Total Loc. 2 (MW)
Existing	9	240 MW	1	240	100
Not in Queue	7.98	100 MW	2	240	100
TI-07-0510	8.01	500 MW	1	740	100
Not in Queue	8.74	200 MW	1	940	100
TI-07-0305	9.22	200 MW	2	940	300
TI-07-0305	9.65	250 MW	2	940	550
Maximum Total Allowed at each Location (MW)				940	610

It may become evident that the lowest cost projects are concentrated at one location. For example, a mild cost bias is evident in the case study, as location 1 bids tend to be slightly lower in price compared to location 2. This could be due to a slightly better wind resource at location 1. This can indicate that the initial allocation of wind resource and selection of interconnection points was incorrect or sub-optimal. In the case study this could mean that transmission expansions would have been better designed to accommodate more wind at location 1, and less at location 2.

At this stage, it would be possible to discard the proposals and re-visit the initial study parameters, requiring a new expansion plan design and a new RFP (feedback path indicated in red dashed line in Figure 2). This is an undesirable course of action, since the delay involved would be substantial, and there is no guarantee that a new iteration would actually result in lower costs, since market conditions would probably change, and bids would certainly change. Unless the price imbalance between locations is extremely large, it is recommended that no further iterations be done.

In the case study, the price imbalance between location 1 and location 2 is minimal, and we proceed assuming that the initial study parameters and location maximums are adequate.

6.4.2 Determine Energy Costs for Each Alternative

Once the bids are ranked to determine which projects are best suited to each expansion plan, the costs of transmission are rolled into the costs presented by each project proposal to determine cost of energy to the purchaser for that alternative. The cost is determined as follows:

$$ECP = C_T + C_B \quad (6.1)$$

- ECP = Cost of energy for the proposal [cents/kWh]
- C_T = Component of energy costs required for transmission, selected as the cost of transmission at the final selected total amount of wind [cents/kWh]
- C_B = Bid costs for the proposal [cents/kWh]

Plotting the bids selected for each alternative against the varying wind capacity results in Figure 24 (Alternative 1), Figure 25 (Alternative 2), and Figure 26 (Alternative 3). The dots show the actual costs for each bid, accounting for the transmission upgrades required for all the combined bids. It is important to note that the MW value for each bid may not be reduced since the proposals are for a fixed amount of generation, not a range of generation. Each chart also shows the final weighted average energy cost for each alternative, determined as follows.

$$EC_{alt} = \sum_{i=1..n} \frac{ECP_{i,alt} * Cap_{i,alt}}{\sum_{i=1..n} Cap_{i,alt}} \quad (6.2)$$

Where:

- EC_{alt} = Cost of energy for selected alternative
- i = Individual project in selected transmission upgrade alternative.
- alt = Transmission upgrade alternative
- $Cap_{i,alt}$ = Capacity of individual project i in MW, for selected transmission upgrade alternative
- ECP_i = Energy Cost for project i

Application of this method to the case study yields the final costs shown in Table 14 (Alternative 1), Table 15 (Alternative 2), and Table 16 (Alternative 3). It is important to note that for each expansion alternative, all the capacity must be utilized at each interconnection point (i.e. you may not arbitrarily reduce the total amount of wind purchased in order to avoid a very high priced project). This is because the network upgrades are designed to have a balanced injection between the interconnection points. It may be possible to inject all of the power at one location with a very large plant, for example, but the planning studies would need to be revisited to determine whether the proposed network upgrades could sustain the unbalance of power injections between the interconnection sites.

Alternative 1 Energy Cost Calculation

Figure 24 shows the energy costs per project for network expansion alternative 1. The new projects from Table 11 are shown in addition to the projects in the existing plan.

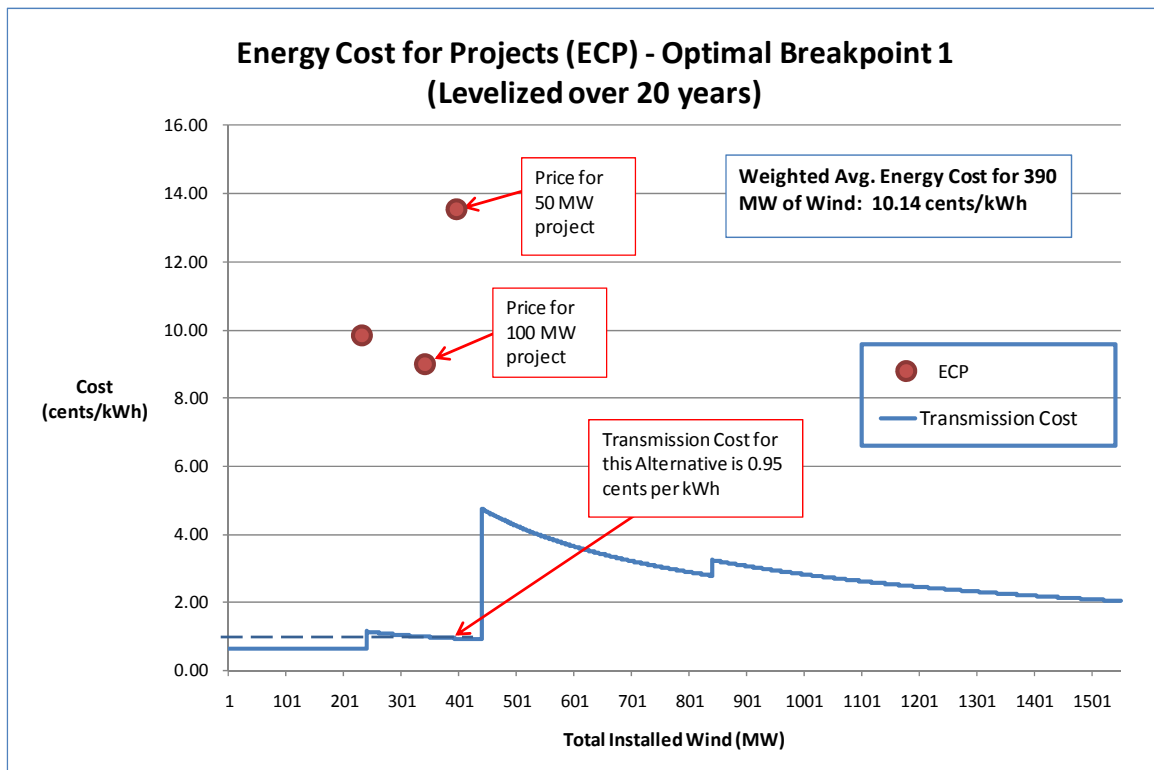


Figure 24 – Case Study: Energy Costs for Alternative 1

Table 14 summarizes the project costs and shows the calculated weighted average energy cost to be 10.14 cents/kWh. This price is the overall long term price that the energy purchaser would pay for energy if 390 MW of wind power were purchased.

Table 14 – Case Study: Total Cost of Energy for Expansion Alternative 1

Transmission Expansion Alternative 1				
Project Designation (i,alt)	Cap(i,alt) (MW)	SUM(Cap(i,alt)) (MW)	ECP (cents/kWh)	EC(alt) (cents/kWh)
1,1	240	390	9.95	10.14
2,1	100		8.93	
3,1	50		13.48	

Alternative 2 Energy Cost Calculation

Figure 25 plots the ECP and shows the projects selected for Alternative 2 in Table 12.

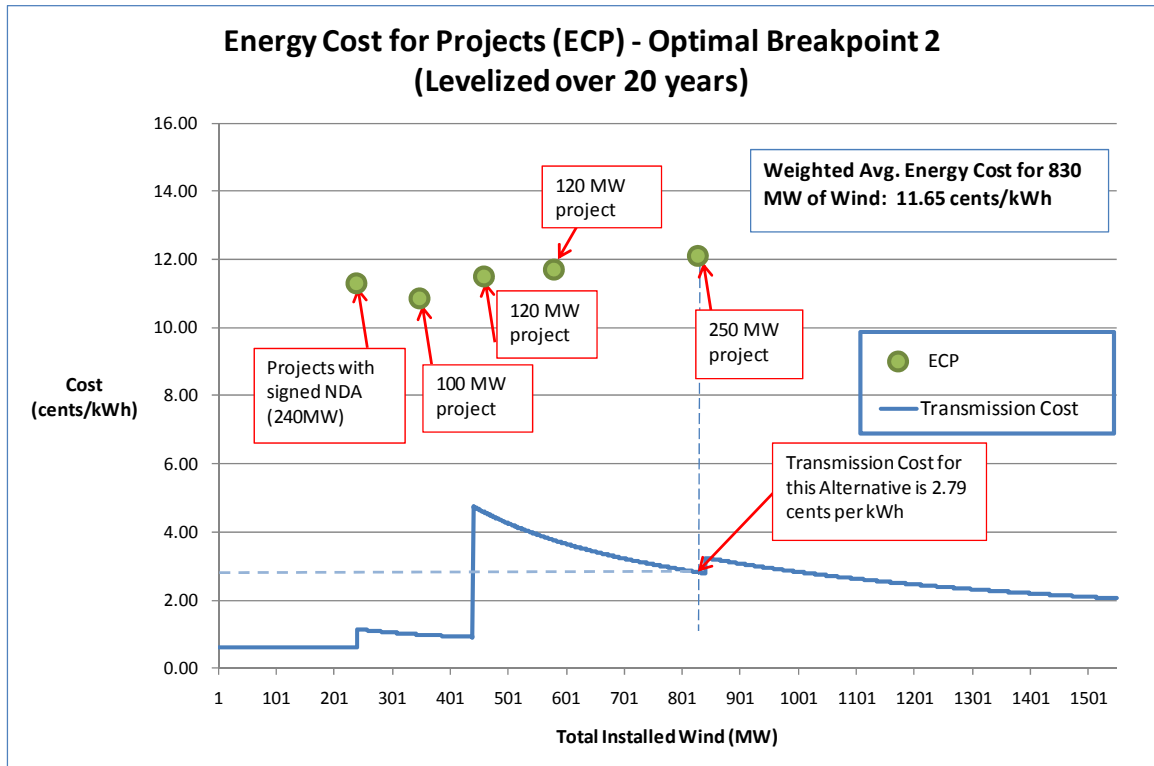


Figure 25 – Case Study: Energy Costs for Optimal Breakpoint 2

Table 15 shows the effect of these transmission upgrades on the cost of energy. Since this alternative includes a very substantial set of network upgrades, the weighted average energy cost to the purchaser increases from Alternative 1 to 11.65 cents/kWh.

Table 15 – Case Study: Total Cost of Energy for Expansion Alternative 2

Transmission Expansion Alternative 2				
Project Designation (i,alt)	Cap(i,alt) (MW)	SUM(Cap(i,alt)) (MW)	ECP (cents/kWh)	EC(alt) (cents/kWh)
1,2	240	830	11.19	11.65
2,2	100		10.77	
3,2	120		11.32	
4,2	120		11.67	
5,2	250		12.03	

Alternative 3 Energy Cost Calculation

Figure 26 and Table 16 extend the ECP and weighted energy calculations to Alternative 3. Due to the large total amount of power required, the largest and lowest cost proposals are now available for selection, and the full effect of “economy of scale” in transmission upgrades is evident. The cost of energy based on the weighted average of individual projects is calculated to be 10.90 cents/kWh, compared to 11.2 cents/kWh for alternative 2. This is not as substantial a drop as might be expected, mainly because the decreasing cost of transmission due to economies of scale is offset by the increasing price of bids which must be accepted to meet the total energy requirements.

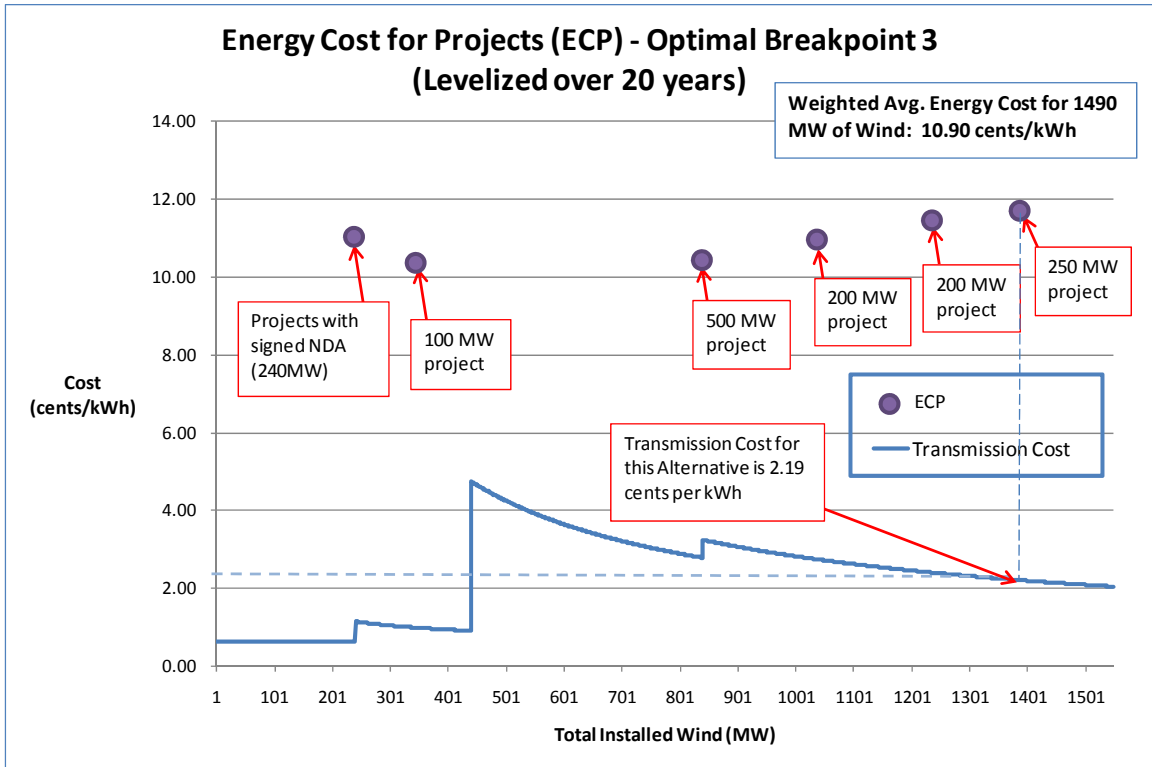


Figure 26 – Case Study: Energy Cost for Optimal Breakpoint 3

Table 16 – Case Study: Total Cost of Energy for Expansion Alternative 3

Transmission Expansion Alternative 3				
Project Designation (i,alt)	Cap(i,alt) (MW)	SUM(Cap(i,alt)) (MW)	ECP (cents/kWh)	EC(alt) (cents/kWh)
1,3	240	1490	11.19	10.90
2,3	100		10.17	
3,3	500		10.20	
4,3	200		10.93	
5,3	200		11.41	
6,3	250		11.84	

6.4.3 Select Alternative

Once the energy costs for each alternative are clear, it will fall to the purchaser to finalize the selection of the expansion alternative, and award power purchase agreements to successful proponents. In the example case presented here, the overall energy cost for

each level of wind is not substantially different. However, it is clear that the economy of scale in network expansion equipment required for Alternative 3, as well as the freedom to accept large, low cost generation bids presents a cost advantage over the Alternative 2 plan. Alternative one is the cheapest alternative since it takes advantage of existing transmission capacity, however the low cost must be set against the much smaller amount of wind ultimately connected.

For example, if in the case study being considered, Alternative 3 had been finally selected (1550 MW of wind generation, with an expected transmission expansion cost of approximately \$491M), the costs for the proposed upgrades could exceed the estimated costs by 10%, or \$49M. This cost should be paid by the energy purchaser, since it is theoretically offset by the lower bids obtained through the provision of cost certainty to the proponents.

6.5 Expansion Implementation – Case Study

Once the alternative has been selected, it falls to the transmission authority to build the network expansions. The final cost of the expansions (and the required expansions themselves) may differ from the initial expected costs determined in the expansion planning phase of the process. If this is the case, the difference in cost must be absorbed by the transmission utility (which may then pass the difference in cost through to their rate-payers). If the cost is higher, the difference in cost should not be passed through to the generation proponents, since this negates the “low-risk” advantage obtained by providing long term cost certainty, and may cause initial bids to rise to counter this risk. If the cost is lower, the overall price of energy to the purchaser simply falls, and there is no impact to the generator proponents.

6.6 Comparison Between Proposed Method and Existing RFPs

Many RFP’s have been issued for renewable energy in the past 10 years, and they have common elements, some of which are elaborated in Section 6.2. The key advantage of the method proposed here lies in the combination of competition and regulation, and the degree to which transmission planning informs the process. Three example real-world

RFPs issued in the last 5 years are presented here for comparison with the proposed method.

6.6.1 Manitoba Hydro RFP (2007)

The mechanisms for a group study and RFP in Manitoba, Canada are found in reference [47]. At the time this RFP was issued (2007), there were several interested parties in the existing interconnection queue at advanced stages in the interconnection process. These parties were forced to relinquish their queue position in order to participate in the RFP process, and since the only purchaser of power in Manitoba was Manitoba Hydro (regulated environment), no real choice was left to these parties except to abandon their queue position and participate in the RFP process. Table 17 illustrates some key similarities and differences between the process proposed here and the one followed by Manitoba Hydro.

Table 17 – Comparison Between Manitoba Hydro RFP Process and New Method

RFP features in common with or similar to proposed method	RFP features differing from proposed method
Exploratory transmission study was done ranking transmission interconnection points according to price. The study was published and proponents were encouraged to consider them when making proposals.	The amount of wind under consideration was low in comparison to this method (300 MW, chosen for political reasons), and so substantial new transmission was not considered, beyond minor costs for interconnecting equipment (corresponding to the first “optimum” breakpoint in the process proposed here). This would not have worked if the amount of interconnected power were doubled or tripled, and tended to preclude large projects with possibly good economics being considered, since they would require new transmission.
Stakeholder meetings and information sessions were held, although these meetings were informative rather than for the purpose of obtaining planning information	Insufficient project viability checking was performed, resulting in a low priced project with insufficient financial capabilities. The end result of this process resulted in Manitoba Hydro being forced to partially finance the project, at a reduced project size (138 MW, awarded March 2010) from the initial RFP
	No transparent and competitive method existed to reduce project size if the proposal costs proved too high
	Very low cost of entry (\$25) encouraged bids. This is not necessarily a problem, provided sufficient project viability checking is in place

6.6.2 SaskPower RFP (2010)

SaskPower in Saskatchewan, Canada recently issued a request for qualifications for vendors, in anticipation of an RFP for wind [46]. This process is ongoing, and includes some very progressive measures to optimize the process. Table 18 illustrates some key similarities and differences between the process proposed here and the one being used by SaskPower.

Table 18 – Comparison Between SaskPower RFP Process and New Method

RFP features in common with or similar to proposed method	RFP features differing from proposed method
<p>Transmission map overlaying wind resource map was provided to stakeholders and proponents (see Figure 27) to assist in helping to identify where the most viable project locations would be.</p>	<p>The amount of wind under consideration was low in comparison to this method (175 MW, chosen probably based on available transmission capabilities, and corresponding to the first optimum breakpoint in the process proposed here), and so new transmission was not considered, beyond minor costs for interconnecting equipment. This would not have worked if the amount of interconnected power were doubled or tripled.</p>
<p>Project powerflow data was provided to interconnection customers to perform feasibility studies through the use of consultants. This increased the likelihood of viable projects being proposed</p>	<p>No method to alter the plan to reduce energy costs exists in this method.</p>

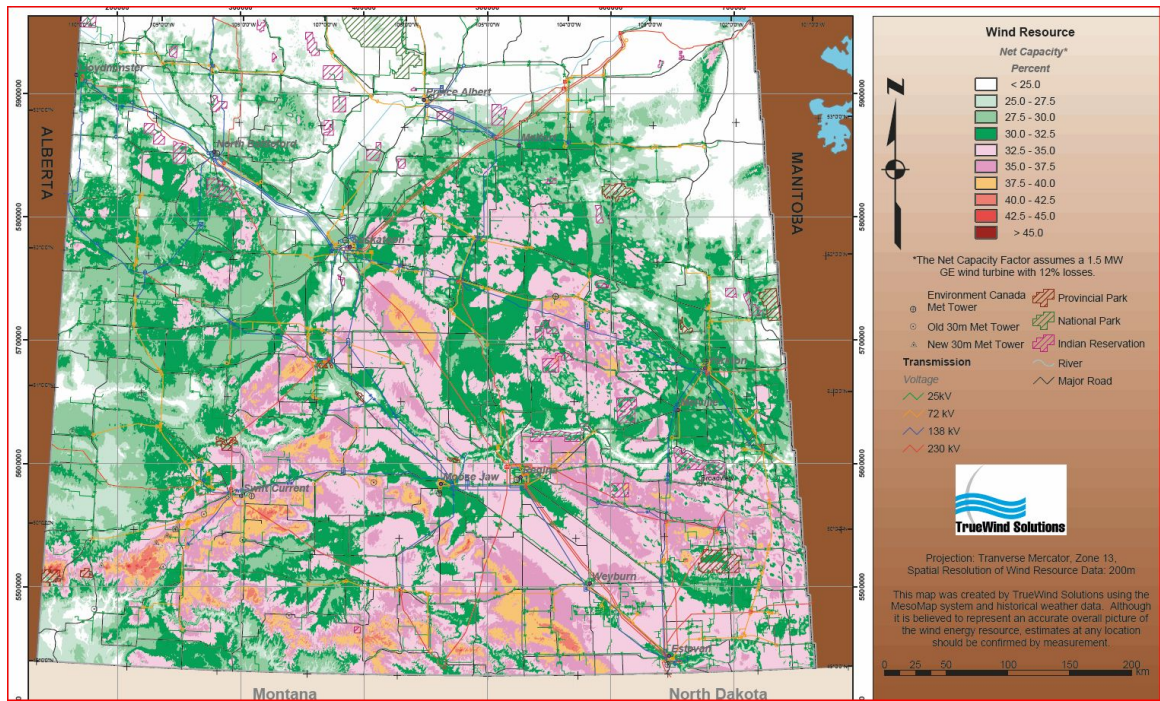


Figure 27 - Saskatchewan Wind Resource Map Overlaying Transmission Grid

6.6.3 BC Hydro Clean Power Call (awarded 2010)

On August 3, 2010, BC hydro has released a document outlining their approach to an RFP process [48]. This process has many things in common with the one proposed here, and demonstrates that concepts such as adjusting final RFP according to calculated energy costs, extensive stakeholder meetings, and others are valid and work in practice. The main difference between the BC process and the process proposed here is a focus on allowing the proposals to stand alone with regards to transmission. The additional focus on small hydro resulted in many small projects being proposed in a wide, geographically diverse area, which did not lend itself to planning large transmission infrastructure expansions to interconnect multiple large wind plants. The result of this difference in focus discourages large (possibly very low cost) applications, but has the advantage of using up all the transmission capacity available in the existing system.

Table 19 – Comparison Between BC Hydro RFP Process and New Method

RFP features in common with or similar to proposed method	RFP features differing from proposed method
Proposed interconnecting large amounts of renewable energy, although the energy was diversified between wind, storage hydro, run-of-river, and waste heat plants. The maximum amount of renewable energy was chosen to meet future load growth requirements	Network or transmission upgrades were considered on a standalone basis, causing the costs to interconnect each project to be calculated as part of that project’s energy cost, except where projects happened to be situated next to each other. This resulted in 27 relatively small projects being proposed and accepted, as these projects tended to use up available transmission capacity. If centralized transmission planning was done, larger and more economic projects may have been proposed.
BC Hydro reserved the right to reduce the total amount of energy purchased if the price proved too expensive. This was done in fact, announced August 3, 2010.	Focus on small hydro does not lend itself to pre-defined resource areas which may be well served by large transmission expansions.
BC hydro initiated extensive stakeholder information sessions, and accepted feedback on their process to build into their process.	
Calculated weighted average costs for energy for all successful proponents and revised overall wind amount based on these costs.	

6.6.4 Hydro-Quebec RFP (awarded 2008)

In October 2005, a request for bids was set out by Hydro-Quebec, and in May of 2008, Hydro-Quebec issued awards for 2000 MW of new wind and transmission. This process was not examined in detail, but examination and comparison of the detailed process would be beneficial, as it parallels the process proposed here and has been successful in implementation. The final average cost of energy for these projects was expected to be 10.5 cents per kWh, broken down into 8.7 cents/kWh for wind energy, 1.3 cents/kWh for transmission upgrades, and 0.5 cents/kWh for network balancing service costs. These costs are in line with the estimated costs in the method proposed here.

6.7 Extension of Concepts to a Feed-in Tariff (FIT) Structure

As a mechanism to encourage wind generation development and increase penetration levels of wind in existing networks, feed-in tariffs have been shown to be successful ([43] - [45]). Feed-in tariffs are loosely defined as fixed energy prices guaranteed over the lifetime of the project and set by the transmission provider or utility such that the generator can expect reasonable profit. However, conventional FIT mechanisms may have high costs with uncertain cost recovery for energy purchasers, and conventional expansion planning principles may be set aside in favour of rapid development constrained only by market players.

To address this problem, additional constraints may be placed on this mechanism such that the transmission provider, investor owned utility (IOU), or other energy purchaser has control over the amount of wind interconnected, the approximate location of the new generation, and the eventual build-out of necessary transmission infrastructure to accommodate forecasted load growth. The first constraint is a prescribed maximum amount of wind, chosen based on projected load growth and renewable energy targets (“Limited Constraint”) as described in Chapter 4.1. The second constraint is an approximate energy injection location or set of locations (“Locational Constraint”) as described in Chapter 4.3. Each of these locations may be accorded separate tariffs, or differing fixed energy purchase offers.

Although this system represents a certain amount of “re-regulation”, competitive behaviour is expected via two means. First, projects proposing to interconnect via this mechanism are treated on a first-come, first-serve basis, and any proposal considered must have a fully developed project and provide certainty that the project is viable over the lifetime of the agreement. Second, the tariff or price structure that is eventually offered may prove to be too low for any IPP to make a profit, and the utility will have to re-structure their offer. Energy pricing and interconnection location (considering available renewable resource and stakeholder feedback) are therefore extremely important to the success of this approach.

The advantage of this method over the RFP method detailed in this work is that the transmission provider may have more direct control over precisely how much renewable generation is connected at each selected location, via control over the FIT offer price. Once planners have determined how much power they would like at each location, the key challenge is to set an offer price, such that the goals of IPP participation and lowest overall energy prices are simultaneously obtained. An iterative offer structure that starts at a low offer price and increases until sufficient generation is available may be one way to optimize this approach.

Chapter 7 Conclusions and Future Work

7.1 Conclusions

7.1.1 The Challenge of Urgency

A significant challenge in undertaking this work relates to the genuine urgency of the problem. Utilities across North America are beset by pressures on their generator interconnection processes. The resulting transmission planning shortfalls have real and immediate economic, legal, and political ramifications that require fast and creative responses. Consequently, when this work began nearly 3 years ago, the regulatory landscape was in a considerably different state from today. Since 2007, major interconnection queue reform efforts have been implemented in many parts of North America, particularly in those areas with the most pressing problems, such as California and many Midwestern control regions (including the Tri-State G&T region upon which the case study is based). Staying abreast of these rapidly changing and adapting policy landscapes is challenging, especially when trying to maintain a course of academic research which speaks to these issues in a helpful manner.

The overall objective of this research is to present all the steps of the proposed methodologies in a clear way, such that any portion that is useful may be extracted, and the overall method may be adapted according to local constraints, whether regulatory or otherwise. The end goal is to re-introduce sound planning practices into deregulated environments.

7.1.2 Presentation of Historical Background and State of the Art

This research presents a substantial body of background information, particularly in the field of power systems expansion planning. It also provides historical context leading to the current state of difficulty faced by transmission planners when incorporating large amounts of renewable energy into the electrical network.

7.1.3 Presentation of New RFP Methodology

This research presents a set of steps and procedures that may be followed to implement an RFP, such that the following goals are met:

- a. Obstacles to conventional RFP processes are overcome, including poor quality proposals, lack of coordination with long term transmission planning, and unnecessarily high costs to the energy purchaser
- b. RFP process is informed by and based upon good expansion planning principles
- c. RFP process provides a means to control energy costs if they exceed the initial expectations of the energy purchaser

7.1.4 Demonstrate RFP Methodology Using Case Study

An example implementation of the proposed methodology was conducted based upon a real transmission system. A transmission expansion plan and RFP was designed for a transmission system in New Mexico, successfully determining the costs of three varying levels of wind energy over a 20 year period. Loss evaluation and economy of scale due to bulk transmission expansion were evaluated, allowing the RFP issuer to ultimately select the amount of wind energy that meets their generation requirements at an acceptable cost.

7.2 Future Work

The following continuing work would be beneficial in furthering the understanding of how to manage the large influx of renewable generation.

- Demonstrate the extension of this work to a FIT structure as discussed in Chapter 6.6.4 using a case study, and compare this extension to the work contained here.
- Review recent industry efforts and adjust the concepts proposed here accordingly.
- The transmission cost allocation methods described in Chapter 2.5.1 (and in particular Bialek or Kirschen's tracing algorithms) should be applied to a case study such as this to determine the correct costs allocated to the proponents at each interconnection location (not only based on proportional project size). This involves adapting either of these two algorithms to a very large set of network data, and could be helpful in determining whether the selected locations are optimal, and how much wind should connect to each, given a proposed expansion.

Chapter 8 References

- [1] H. L. Willis, Power Distribution Planning Reference Book, 2nd ed., Boca Raton, Florida: CRC Press, 2004.
- [2] Energy Information Administration, US DOE, “Public Utility Holding Company Act of 1935: 1935-1992”, January 1993
- [3] US Federal Act, “Energy Policy Act”, 102nd Congress H.R.776.ENR, 1992
- [4] United States of America Federal Energy Regulatory Commission, “Promoting wholesale Competition Through Open Access, Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities”, Order number 888, April 24, 1996
- [5] United States of America Federal Energy Regulatory Commission, “Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct”, Order number 889, April 24, 1996
- [6] R. Fuentes, “Mexico’s Energy Dilemma: Resource Nationalism v. Market Liberalisation” (Oxford Energy Comment March 2007)
- [7] G. Latorre, R.D. Cruz, J.M.Areiza, and A. Villegas, “Classification of Publications and Models on Transmission Expansion Planning” (IEEE Trans. Power Syst., vol. 18, No. 2, pp. 938-945, May 2003)
- [8] T. De la Torre, J.W. Feltes, T.G. San Roman, H.M. Merrill, “Deregulation, Privatization, and Competition: Transmission Planning Under Uncertainty”, IEEE Trans. Power Syst., vol 14, No. 2, pp 460-465, May 1999
- [9] Z.Xu, Z.Y.Dong, K.P.Wong, “Transmission Planning in a Deregulated Environment”, IEE Proc.-Gener. Transm. Distrib., Vol. 153, No. 3, May 2006
- [10] A. Minoia, D.Ernst, M.Dicorato, M.Trovato, M.Ilic, “Reference Transmission Network – A Game Theory Approach”, IEEE Trans. On Power Syst., vol 21, No 1, pp 249-258, Feb 2006
- [11] M.Shahidehpour, H.Yamin, Z.Li, Market Operations in Electric Power Systems: Forecasting, Scheduling, and Risk Management, Wiley-IEEE Press, March 2002
- [12] J.Bialek, “Tracing the flow of electricity”, IEE Proc. – Gener. Transm. Distrib., Vol. 143 No. 4, July 1996

- [13] D.Kirschen, S.Ahmed, G.Strbac, “Allocating Transmission System Usage on the Basis of Traceable Contributions of Generators and Loads to Flows”, IEEE Trans. On Power Systems, Vol. 13, No. 2, pp 527-534, May 1998
- [14] I.J.Peres-Arriaga, F.J.Rubio-Oderiz, “Marginal Pricing of Transmission Services: A Comparative Analysis of Network Cost Allocation Methods”, IEEE Transactions on Power Systems, Vol. 15, No. 1, pp 448 – 454, Feb. 2000
- [15] PSCO Oasis posting of Forecasted and Actual loads, 9/19/2008.
- [16] PNM E-IRP Document 2008-2028, published September 16, 2008
- [17] NERC, “Reliability Standards for Bulk Electric Systems of North America”, November 2009
- [18] NERC, “TPL-001-1 Draft 5”, January 6, 2010
- [19] W. Li, P. Choudhury, “Probabilistic Transmission Planning”, IEEE Power & Energy., Vol. 5, No. 5, pp. 46-53, Sept/Oct 2007
- [20] J. Choi, T. Tran, A.A.El-Keib, R.Thomas, H. Oh, R. Billinton, “A Method for Transmission System Expansion Planning Considering Probabilistic Reliability Criteria”, IEEE Trans. Power Syst., vol 20, No. 3, pp 1606-1615, Aug 2005
- [21] ERCOT System Planning, “Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas”, December 2006
- [22] M.Milligan, D.Lew, D.Corbus, R.Piwko, N.Miller, K.Clark,G.Jordan, L.Freeman,B.Zavadil,M.Schuerger, “Large-Scale Wind Integration Studies in the United States: Preliminary Results”, Conference Paper NREL/CP-550-46527, Sept 2009.
- [23] NREL, Enernex Corporation, Technical Review Committee, “Eastern Wind Interconnection and Transmission Study (EWITS)”, January 2010
- [24] MISO,PJM,SPP,TVA,MAPP, “Joint Coordinated System Planning Study (JCSP)”, 2008, www.jcspstudy.org
- [25] Senate Bill 07-100, “Concerning measures to ensure the adequacy of Colorado’s electric transmission infrastructure, and, in connection therewith, requiring utilities to designate energy resource zones and authorizing expedited cost recovery for the construction of transmission facilities.” (State of Colorado, 2007)

- [26] Federal Energy Regulatory Commission, "Order Granting Petition for Declaratory Order (California ISO renewable energy trunkline order)." (119 FERC 61,061, docket EL07-33. Available: www.caiso.com/1bee/1bee7d3b3b4do.doc 2007, April)
- [27] A.Isaacs, "Current Research Issues in Electrical Engineering ECE 7440-T02, Power Systems Planning", University of Manitoba, April 9, 2008.
- [28] R.L.Sullivan, "Power System Planning", McGraw-Hill, 1977
- [29] G. Latorre, R.D. Cruz, J.M.Areiza, and A. Villegas, "Classification of Publications and Models on Transmission Expansion Planning", IEEE Trans. Power Syst., vol. 18, No. 2, pp. 938-945, May 2003.
- [30] R. Billinton, M.P.Bhavaraju, "Transmission Planning Using a Reliability Criterion, Part I: A Reliability Criterion", IEEE Trans. Power Apparatus and Sys., Vol PAS-89, No. 1, pp 28-34, Jan 1970
- [31] R. Billinton, M.P.Bhavaraju, "Transmission Planning Using a Reliability Criterion, Part II: Transmission Planning", IEEE Trans. Power Apparatus and Sys., Vol PAS-90, No. 1, pp 28-34, Jan 1971
- [32] R. Piwko, R. DeMello, R. Gramlich, W. Lasher, D.Osborn, C.Dombek, K.Porter, "What Comes First?" (IEEE Power & Energy., Vol. 5, No. 6, pp. 68-77, Nov/Dec 2007)
- [33] R.Zavadil, N.Miller, A.Ellis, E. Muljadi, E. Camm, B. Kirby, "Queuing Up: Interconnecting Wind Generation into the Power System", IEEE Power & Energy., Vol. 5, No. 6, pp. 47-58, Nov/Dec 2007
- [34] S.R.Jones, "ERCOT Experience with Transmission Operating and Planning Criteria in a Competitive Environment", IEEE, 1999
- [35] Utility Consumers' Action Network, "Enron's Meltdown: The History of Regulation in the Energy Industry", February 2007
- [36] "The Restructuring of the Electric Power Industry: A Capsule of Issues and Events" (National Energy Information Center, Energy Information Administration, 1997)
- [37] E.J.Rubio-Oderiz, I.J.Perez-Arriaga, "Marginal Pricing of Transmission Services: A Comparative Analysis of Network Cost Allocation Methods", IEEE Trans. On Power Systems, Vol. 15, No.1, pp 448-454, Feb 2000

- [38] I.J.Perez-Arriaga,F.J.Rubio,J.F.Puerta,J.Arceluz,J.Marin, "Marginal Pricing of Transmission Services: An Analysis of Cost Recovery", IEEE Trans. On Power Systems, Vol. 10, No.1, pp 546-553, Feb 1995
- [39] Midwest ISO, "Business Practice Manual – Draft Manual 15", 2008
- [40] L.Soder,L.Hofmann,A.Orths,H.Holttinen,Y.Wan,A.Tuohy, "Experience From Wind Integration in Some High Penetration Areas", IEEE Trans. On Energy Conversion, Vol.22, No.1, pp 4-12, Mar 2007
- [41] A.Isaacs, D.A.Woodford, U.Annakkage,D.Zhou, EPRI Planning Tool Reference, 2009
- [42] Commercial Software EMT Tool (website: <https://pscad.com/products/pscad/>)
- [43] L.Butler,K.Neuhoff, "Comparison of Feed in Tariff, Quota and Auction Mechanisms to Support Wind Power Development", The Cambridge-MIT Institute, 2004
- [44] W.Rickerson,F.Bennhold,J.Bradbury "Feed-in Tariffs and Renewable Energy in the USA – a Policy Update", May 2008
- [45] A. Campoccia, L. Dusonchet, E. Telaretti, and G. Zizzo, "Financial Measures for Supporting Wind Power Systems in Europe: A Comparison between Green Tags and Feed-in Tariffs", IEEE International Symposium on Power Electronics, Electrical Drives, Automation and Motion, 2008
- [46] Request for Qualifications – Wind Power Facility, Saskpower Inquiry NO CO/670
- [47] Manitoba Hydro, "Manitoba Hydro Open Access Interconnection Tariff", Issued Dec 12, 2003, rev. Dec 13, 2007.
- [48] BC Hydro, "Clean Power Call Request for Proposals – Report on the RFP process", August 3, 2010, available on website: http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/acquiring_power/2010q3/cpc_rfp_process_report.Par.0001.File.CPC_RFP_Process_Report_August_3_2010.pdf