Functional Unbundling of Special Protection Systems as a Required Interconnected Operating Service in a Deregulated Environment

by

John K. Earle P.Eng.

B.Sc. Eng. University of New Brunswick, 1992

A Thesis Submitted In Partial Fulfillment
of Requirements for the Degree of

Master of Science in Engineering

in the Graduate Academic Unit of
Electrical and Computer Engineering

Supervisors:	Hill, Eugene F., BScE, MScE (UNB), PhD (NC State), EE
	Mobarak, Mohamed., BScE (Alexandria), MScE (UNB), DSc (California), PhD (UNB), NB Power
Examining Board:	Colpitts, Bruce, BScE, MScE, PhD (UNB), EE, Chair
	Taylor, James Hugh, BSc, MSc (Rochester), MPh, PhD (Yale), EE
	Doraiswami, Rajamani, BEE (VJI, Bombay), MEE (IIS, Bangalore), PhD (Johns H), EE
External Examiner:	Rogers, Robert J., BSc (Alta), MASc, PhD (Wat), ME

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ABSTRACT

With the evolution of the power systems to the new world of deregulation, the regulated monopoly structure is being removed. The goal is to increase efficiency and reduce prices by creating a competitive environment. As the components of the integrated power system are unbundled a need arises to appropriately cost all components required for power transactions to take place.

One such component identified within this thesis is the special protection systems. The special protection systems are introduced as a required service for effectively increasing the transfer capability on the interconnections while maintaining system security and reliability.

During the course of this work, the special protection systems involving generation rejection are theoretically investigated and economically evaluated in terms of their operation and benefits in a deregulated marketplace.

ACKNOWLEDGMENTS

The success of this thesis can be contributed to the interactions and the contributions of many highly skilled people.

The author wishes to express special gratitude to Dr. Eugene Hill who has provided a wealth of knowledge coupled with tremendous patience, understanding and devotion of many hours to its successful completion. Special acknowledgment to Dr. Mohamed Mobarak who initiated this work and provided continual support and technical guidance concerning the special protection systems and the many issues involved in deregulation.

This work involved many meetings with engineers from several groups within NB Power, all of whom have given freely of their time and knowledge. I would particularly like to thank the following people:

William K. Marshall for providing insight into the complexities of the transmission tariff structures and the costing of services.

Glenn Brown for providing information on the occurrences of generation rejection, including input into the operation of the special protection systems.

Wayne Davies, David Fewkes, and Roger Thompson of the Generation business unit for providing information and background on the costing considerations of generation rejection.

David Daley for providing historical information from the energy control center on hours of arming for generation rejection.

Lloyd Denton for allowing me the use of his computer and his years of experience.

A final note of thankful appreciation goes to my wife, Dana, for her love, patient and understanding.

LIST OF ACRONYMS

ATC	-	Available Transfer Capability
CBM	-	Capacity Benefit Margin
DPL	-	Dedicated Path Logic
ED	-	Economic Dispatch
EOH	-	Equivalent Operating Hours
GR	-	Generation Rejection
FCTTC	-	First Contingency Total Transfer Capability
FERC	-	Federal Energy Regulatory Commission
HQ	-	Hydro Quebec
HVdc	-	High Voltage direct current
IOS	-	Interconnected Operating Services
ISO	-	Independent System Operator
LR	-	Load Rejection
CMP	-	Central Maine Power
NB	-	New Brunswick
NE	-	New England
NERC	-	Northeast Electric Reliability Council
NOPR	-	Notice of Proposed Rulemaking
NPCC	-	Northeast Power Coordinating Council
NS	-	Nova Scotia
NUG	-	Non-Utility Generation
PEI	-	Prince Edward Island
SCADA	-	Supervisory Control and Data Acquisition
SPS	-	Special Protection Systems
TCT	-	Transmission Cross-Tripping
TRM	-	Transmission Reliability Margin
TTC	-	Total Transfer Capability

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1. INTRODUCTION

1.1 GENERAL BACKGROUND INFORMATION

Electric power systems are beginning a new era with the onset of deregulation. Competition in power generation is the way of the future as utilities will no longer control the market. In the deregulated structure, the emphasis will be on lowering prices and improving the quality and reliability of the power being purchased.

Under the regulated monopoly structure, electric utilities were motivated to provide reliable services. This motivation was created by enabling the utilities to recover their costs for improving the system by putting these costs in their rate base. In addition to the recovery of costs, the utilities received a return on their investment; therefore, by increasing their rate base the utilities effectively increased their return. This is known as the traditional "rate base/rate of return" regulation [1]. In this type of regulated structure, reliability was ensured because the utilities had the incentive to improve the system.

Traditional reliability analysis was based on two attributes of reliability, namely adequacy and security, which were considered equally important and were the main focus of any reliability analysis.

> "Adequacy is a measure of the ability of the power system to supply the electric power and energy requirements of the customers within component ratings and voltage limits, taking into account planned and unplanned outages of system components. Adequacy measures the capability of the power system to supply the load in all steady states in which the power system may exist" [2].

> "Security is a measure of the electric power system to withstand sudden disturbances such as electric short circuits or unanticipated sudden outage of system components (together with consideration of operating constraints)" [2].

NB Power is currently in the process of developing their procedures for implementing an interconnected transmission network philosophy that can be used in a deregulated marketplace. Anything that is not efficient or cost effective will not be acceptable in a market-driven competitive structure. NB Power Chairman Dr. Frank Wilson announced ". . . the utility will be split into four separate business units in anticipation of a deregulated marketplace. The units will consist of Generation, Wires (transmission and distribution), Marketing (customer service and external marketing), and Services (human resources, administration; and engineering and finance/information systems)" [3]. The work in this thesis has been completed under the premise that functional unbundling of the New Brunswick Power system is going to take place. The Wires Company will be assumed as the regulated body, and Generation the independent and competitive entity.

1.2 HISTORICAL EVOLUTION OF THE NB POWER NETWORK

Power wheeling has been a reality in New Brunswick since the early 1970's when the Eel River HVdc Link to Hydro Quebec and the 345 kV New England interconnection were installed. This enabled power to be transferred between Hydro Quebec, New Brunswick and New England. In the mid 1970's additional 345 kV lines were put in place in southern NB, and the 345 kV interconnection to Nova Scotia was completed. Because the transfer capability from New Brunswick to Nova Scotia was dependent on a single 345 kV tie-line, there was a concern that the sudden loss of the Nova Scotia 345 kV tie-line could result in power swings on the New England tie-line, and possible separation from New England.

Following an analysis of this scenario a recommendation was made that a Type I Special Protection System be put in place.

Special protection systems are a form of if-then logic, at two levels. First, if certain operating conditions exist on the power system, then the SPS is armed and ready to initiate pre-defined action. An example of these operating conditions might be the level of power flow on one of the interconnections. Second if certain events occur on the power system while the SPS is armed, then the SPS initiates the specified action. For example, if a heavily loaded interconnection opened, then the specified action might be to trip a designated generator. (The types and functionality of the special protection systems will be discussed further in Chapter 3).

Referring back to the operating conditions initially described in this section, the first SPS employed on the NB Power system was a Type I SPS involving generation rejection. If a fault occurred on the system leading to power swings going above or below specified limits, then one or more of the on-line generating units (such as Coleson Cove) would be tripped to reduce the transient power level.

With the completion of the 345 kV ring around the province, the construction of the Belledune coal-fired 600 MVA unit, and the incorporation of additional Special Protection Systems, it became possible to increase the export flow level across provincial boundaries[4].

1.3 LITERATURE REVIEW

The literature review has revealed an underlying theme, that utilities are changing. In reference [1] an example is given where three long standing US customers, General Motors, Ford Motor Company, and Chrysler, are involved in multi-year contracts with electric suppliers in which they are to be reimbursed for low quality electric power, and in return they sign a multi-year contract promising not to buy power from anyone else. This example illustrates how traditional reliability and power quality are being adapted into the new era of deregulation [1]. The paper goes further to address power quality and reliability. It characterizes power quality as ". . . any occurrence manifested in voltage, current, or frequency deviation that results in failure of electronic equipment" [1]. The paper attempts to redefine reliability in terms of power quality, and the collection of vital statistics through the use of sophisticated monitoring.

Reliability is a general term encompassing all the measures of the ability of the system, generally given as numerical indices, to deliver electric energy to all points of utilization within acceptable standards and in the amounts desired. Reliability or the concept of a reliable system has been evolving over the past sixty years. One of the first papers on reliability was by W. J. Lyman in 1933. Lyman gave the following statement on power-system planning [5]: "Three of the most vital problems around which the fabric of future planning is woven are forecasting, the relation between load and capacity and fixed replacements." Lyman's paper in 1933 was followed by papers from S. A. Smith Jr. in 1934 [6], and P. E. Benner [7] also in 1934. All three of these papers considered probability analysis with respect to the need for spare generator capacity or reserve margin planning [2, 8].

Over the years there have been numerous papers and studies on reliability. As a result, the definition and vital importance of reliability analysis became abundantly clear. In 1988, an application guide was published by the CIGRÉ (Conférence International des Grands Réseaux Électriques) Study Committee 38 outlining the various reliability methodologies[9]. Over the next few years a CIGRÉ task force was brought together with the goal of comparing the various power-system reliability methodologies on an operating power-system. NB Power was chosen as the power-system to be evaluated by the eight different groups using a variety of software packages. The software was based on either

State Enumeration or Monte Carlo methodologies. In 1992, the methods and the results were compared in a document called "Power System Reliability Analysis Volume 2" [2].

Past conventional reliability analysis attempted to come up with one or more figures of merit. However, it did not deal directly with costs associated with transmission enhancements, which improved reliability, or transmission costs in an unbundled system. In a deregulated environment, transmission costing becomes very important. It becomes part of the revenue stream for the Wires business unit.

One of the papers on transmission pricing/costing [10], outlines the distinction between transmission pricing and costing. The paper states ". . . it is important to realize that pricing of transmission services, although a technical issue, is not an engineering problem. Engineering analysis deals mainly with determining the feasibility and the cost of providing transmission services, and is only one of many considerations in the overall process of pricing transmission services." The paper gives the basic concepts used in transmission cost analysis. It introduces methodologies such as the contract path, rolled-in embedded costs, postage stamp method, and the MW-mile method in terms of cost based transmission pricing and it suggests how economic efficiency may be achieved [10].

In reference [11], a methodology for determining the costs associated with power wheeling over the transmission networks is described. The paper looks at methods of allocating the costs involved in maintaining and operating the transmission network in the deregulated environment. The method they propose is based on the impacted MW-mile method [12]. The impacted MW-mile method is a flow based pricing methodology for the transmission network. It considers incremental costs of transmission services reflecting the actual measured use of the network.

The impacted MW-mile method is a non-traditional pricing method. In conventional practice there are three methods namely: 1) contract path, 2) rolled-in embedded costs, and 3) the postage stamp method. The impacted MW-mile method abandons these three methods, considering them outdated. The method allows new transactions to take place until any additional commitments would cause the reliability limits to be exceeded. The transaction would take place on a first-come first-served basis, and the system condition would be updated after each transaction. It considers firm and non-firm service and incorporates an impact factor into the pricing mechanism. One of the most important attributes of this method is that it encourages transmission improvement resulting in improved reliability, as pricing is based on system impact and loading of the transmission lines. By improving the system the impact is diminished and prices are reduced. Customers pay for the improved network; however, they benefit from the fixed costs for improved capacity. The computer models used for reliability studies have been incorporated into the impacted MW-mile pricing method[10]. Dispute resolution, as outlined in [9], is accomplished by cooperative game theory. This scheme employs a nucleus to minimize a maximum regret of each participant involved. The paper gives the results of research still only in the proposal stage.

The main focus of this thesis is two fold; 1) introducing, for the first time, the Special Protection Systems (SPS) as an interconnected operating service, and 2) costing of the SPSs, since cost breakdowns are required in the unbundled power systems. One of the only papers found on the topic of special protection systems is by D.R. Cowbourne and P.M. Murphy from Ontario Hydro[13]. In this paper special protection systems are presented as a cost saving mechanism enabling power produced at the Bruce Nuclear Power plant to reach the customers without building additional transmission facilities. The generation capability of the Bruce facility was increased with the construction of four additional generation units. However, the approval and construction of new transmission facilities lagged behind, creating a dilemma for Ontario Hydro. It was found that a fault on the transmission network could result in instabilities at the plant or possibly overloading the remaining transmission lines. This restriction forced the Bruce plant to be limited in the amount of power they could transmit out of the plant (approximately half the available output). As a result of the reduced plant output, power would have to be made up from fossil generation at about four times the operating costs. The solution was to introduce a special protection system at the Bruce facility, which would reject (trip) up to two generating units upon the occurrence of a fault, thereby allowing the facility to operate at full output without violating the limitations of the transmission system [13].

A second paper [14] was found which was concerned with the reliability of special protection systems. This paper stresses the need for the design of special protection systems to meet stringent reliability standards. This paper outlines the reliability concerns associated with the Ontario Hydro system, and provides a methodology for reliability assessment of the special protection systems.

1.4 NATURE OF THE PROBLEM

In the historical electric utility the common transactions were imports, exports, purchases, and sales - all carried out by one integrated company. In the proposed unbundled structure, the common transactions of the Wires company will be and "wheeling across" and "wheeling out. Relative to the Generation company, wheeling across will be totally transparent to them and wheeling out may very well involve a competing power producer.

In the unbundled open access world the Wires company (controlled by the Independent System Operator (ISO)) must treat all transmission users equally and fairly. Thus, this has lead to three new concepts [17].

a) The Wires company must post, on the Open Access Same-time Information System (OASIS), the point-to-point available transfer capability (ATC) remaining after it supplies all native or in-province load.

b) The Wires company must post, on OASIS, the transmission tariff for all power transfers.

c) Specifically in the New Brunswick context, in the newly proposed unbundled structure there is a need to place an appropriate cost on the required services associated with power wheeling such as the Special Protection Systems (SPSs) (and other Interconnected Operating Services) that are essential if power transactions are to take place.

The SPSs are required for system security when the power flow on the interconnected transmission lines will be above the voltage, thermal, or stability limits following a contingency. When the level of power flow on the interconnected transmission lines is high, SPSs are vital to the security of the network. For example, when the exports of power to New England exceed a certain level the security of the New Brunswick Power system is at a threshold. Any power in excess of this level will put the system in a vulnerable and unsecured state. However, with the implementation of special protection schemes, NB Power has been able to substantially raise the flow limit on the New England tie-line and still maintain high standards of reliability and system security.

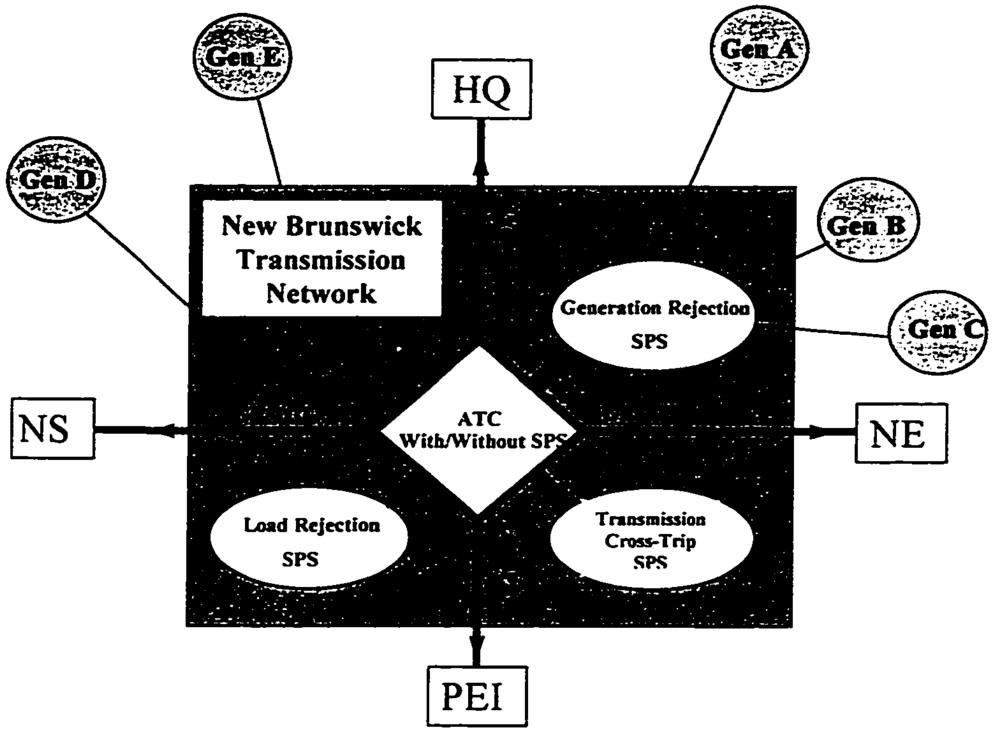


Figure 1-1 Representation of Fundamental Problem

Figure 1-1 shows a representation of the fundamental problem. If an SPS in the Wires Company requires that a particular generator be tripped, then this service must be purchased from the generation supplier. Any services required from the unregulated generation suppliers within NB must be contracted for by the transmission provider. The ATC will be posted for the interconnections as shown in Figure 1-1: Hydro Quebec, New England, Nova Scotia, and Prince Edward Island. The ATC is dependent upon the incorporation of SPSs into the transmission system.

In the historical integrated power system, the Special Protection Systems were simply part of normal operating equipment. They had a cost, but no value was assigned to them. In the unbundled power system the initial focus was almost exclusively on their value. For the company with a business opportunity it surely was financially advantageous if one or more of the SPSs on the Wires system produced an effective wheeling across capability of 700 MW rather than 400 MW. For the power producer, whether the Generation company or an independent producer, a wheeling out opportunity of 700 MW has greater value than a 400 MW wheeling out opportunity.

These ideas of whether the SPSs should have a cost or value, or some combination, have lead to the research investigations of this thesis.

1.5 OBJECTIVES OF THE THESIS

As functional unbundling of the power system proceeds, there is a need to identify and cost all the components and services that have been taken for granted in the monopoly structure. It becomes extremely significant that all required services and components are identified and costed to ensure their availability in the open access marketplace.

The objectives of this thesis are:

1. Describe the nature of the Special Protection Systems.
2. Within the open access context, define Available Transfer Capability and illustrate how SPSs can increase the ATC.
3. Theoretically illustrate the action of SPSs within the power system.
4. Identify SPSs as a service in the deregulated utility.
5. Contrast, and compare, cost and value of the SPS initiated generation rejection service from the perspective of fundamental economic theory.
6. Determine the capital cost of the SPSs.
7. Develop a methodology for costing the services provided by SPSs

1.6 OUTLINE OF THE THESIS

The outline of this thesis is presented in such a way to enable the reader to gather an understanding of the many issues involved in the deregulation and operation of the New Brunswick power utility. In chapter one, background material and the literature review provide a description of the nature of the problem to illustrate the issues to be addressed throughout this thesis.

Chapter 2 Available Transfer Capability

This chapter introduces one of the new areas in the deregulated environment, namely, available transfer capability (ATC), which will be posted for the interconnections between New Brunswick and its neighboring utilities. This chapter illustrates the importance of considering all aspects of power transmission in determining the available transfer capability of each interconnection.

Chapter 3 Enhanced Power System Control

In this chapter reliability and stability are considered with respect to the available transfer capability and the incorporation of special protection systems which enable the ATC to be substantially increased without adversely affecting the reliability and stability of the network. The incorporation of special protection systems is shown as a method of enhancing the systems capability, while deferring the building of new transmission facilities.

Chapter 4 Special Protection Systems

In this chapter functional unbundling, of the many services required to operate the transmission network, are investigated. Special protection systems are identified as an interconnected operating service required for network stability when the available transfer capability is increased above its otherwise expected limit. The special protection systems are evaluated as a mechanism to maintain system stability in the event of a disturbance.

Chapter 5 Basic Economic Theory Relating to SPSs

In this chapter basic economic theory is utilized to investigate the cost and value of providing generation rejection as an interconnected operating service required for maintaining network stability when operating the interconnections at a level which would otherwise be beyond the reliability limits. Economics is used to distinguish between the cost of providing a service, and the value of having the service available. Additionally, the future aspects of competition are explored, with focus on the possible sources of generation rejection and the procedures involved in modifying the special protection systems.

Chapter 6 Generation Rejection SPS Service Cost

In the near future NB Power will have a regulated transmission or Wires business unit. The cost plus rate-of-return required to operate the transmission system must be recovered. Network stability support has been identified by NB Power, as a cost in the functional unbundled system. The result of these events is a requirement for the cost to the wires business unit for stability support to be recovered. Part of the cost of providing network stability support is the generation rejection service charge which will be paid to the suppliers of this service. This chapter identifies the costs and provides examples of how the value may be determined. It utilizes the theoretical aspects of economics outlined in chapter 5 and provides numerical values that can be considered as an indication of the cost and the value of the generation rejection services supplied in-part by the NB Generation business unit.

Chapter 7 Conclusions and Recommendations

This chapter summarizes the thesis and gives recommendations for future work.

2. AVAILABLE TRANSFER CAPABILITY (ATC)

The outline of this chapter is structured to start with individual power system components, then proceed to the interconnected system, and finally to consider operational aspects of the interconnected system.

2.1 TRANSMISSION CAPACITY

The term capacity is used throughout the power industry to describe the specific rating of power system equipment. Transmission capacity can be characterized by the rating/limit of the transmission element or component. The capacity is usually related to the thermal properties of that element/component. The thermal capacity limit can be broken down into two categories, short-term and long-term limits. Intuitively, we know that things take time to heat; therefore, the destructive thermal temperatures created by the I^2R losses in the transmission lines take time to reach the critical temperatures that will cause damage. For most transmission lines the thermal time constant is of the order of several minutes, implying that the short-term thermal capacity limit will be greater than the long term limit. The thermal capacity rating of a transmission line is generally only applicable for a short line (150 - 300 km) because the voltage and stability limits for a long line will dominate over its thermal limit [15, 16].

2.2 TRANSFER CAPABILITY

> "Transfer capability is a measure of the ability of the interconnected electric system to reliably move or transfer power from one area to another over all transmission lines (or paths) between those areas under specified system conditions"[16].

Transfer capability is normally expressed in MW's and is dependent upon the direction of power flow. The transfer capability from one area (which could be a power pool, region, individual system) to another area is directional. The transfer capability from, for example, Nova Scotia to New Brunswick is not necessarily the same as the transfer capability from New Brunswick to Nova Scotia. The criteria of the individual areas in terms of reliability and stability play a major role in determining the limits on the transfer capability. Transfer capability is computed based on assumed operating conditions and computer simulations of the network. The calculation of transfer capability is dependent on the actual system condition; incorporating projected customer demands, generation dispatch, system configuration, base scheduled transfers, and system contingencies [16]. When calculating the transfer capability consideration must be given to the inherent system limitation, such as the voltage and stability limits.

The voltage limits on a transmission line set the maximum and minimum operating limits, since transmission line voltages decrease when the lines are heavily loaded and increase when lightly loaded. As a result the minimum voltage will establish a maximum power level and the maximum voltage will establish the minimum power level. The static or stability limits (see Chapter 3.0) are set for a long line by the line inductance creating current and power limits, which usually dominant over the thermal limits.

The most critical contingencies are determined during the process of calculating the transfer capability by evaluating the network in terms of which facilities or facility outages are most restrictive to that transfer being considered. These critical contingencies may vary depending on the system condition.

The system condition is based on the current operating state, which is identified for a certain time period. In determining the system condition the following are considered; customer demand, generation dispatch, system configuration, and the base scheduled transfers. It must be recognized that the calculation of transfer capability is based on projections of the near future network configuration. The system studies are performed off-line where load flow and stability analysis are performed and the system condition is established. This off-line determination of the system condition can only be classified as an indication of the actual system condition which may vary as the system configuration changes. The system condition in the planning horizon may not truly represent the system condition in the operating horizon. Thus, the posted transfer capability must contain a margin, to account for variation of the parameters of the system conditions. These changes in system conditions may be caused by other systems that impact the area, parallel path flows, maintenance outages, sudden loss of generation or transmission, and the dynamic response of the interconnected system[16].

2.3 INTRODUCTION TO ATC CONCEPTS

The Federal Energy Regulatory Commision (FERC)) has produced numerous sets of rules for the deregulated environment. As part of the FERC requirements, each utility/power pool must produce a transmission tariff for costing their transmission networks. The fundamental purpose is to develop cost-of-service rates for providing transmission access. The tariffs attempt to place a value on operating and maintaining the transmission networks. The regulatory agencies will not permit prices for transmission service to exceed the cost-of-service plus a rate-of-return. It is believed that the market will provide the incentives for optimal use and expansion of the networks to facilitate the power transactions [17, 18].

The control of the transmission network will fall under the jurisdiction of an independent system operator (ISO) who will control the power flow and regulation of the power network. The ISO will be responsible for system reliability and posting the available transfer capability for the interconnections.

The North American Electric Reliability Council (NERC) was responsible for producing the framework for determining the available transfer capabilities of the interconnected transmission networks. NERC had the task of considering all of the factors required in the calculation process of ATC, which include the rules provided by the regulatory agencies such as the Federal Energy Regulatory Commission (FERC) and the Northeast Power Coordinating Council (NPCC) [16].

2.4 AVAILABLE TRANSFER CAPABILITY DETERMINATION

> ATC (Available Transfer Capability) is defined by NERC as being ". . . a measure of the transfer capability remaining in the physical transmission network for further commercial activity, over and above already committed uses"[16].

The calculation of available transfer capability becomes very important when considering power transfers across large geographical areas because of the near instantaneous response of the system to disturbances. After determining the total transfer capability, secure operation of the network can be ensured by subtracting an amount of transfer capability to accommodate uncertainties in system conditions (i.e., Transmission Reliability Margin)[16].

ATC is computed using the following three variables:

TTC - "Total Transfer Capability is defined as the amount of electric power that can be transferred over the interconnected transmission network in a *reliable* manner while meeting *all* of a specific set of defined pre- and post-contingency system conditions"[16].

TRM - "Transmission Reliability Margin is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions"[16].

CBM - "Capacity Benefit Margin is defined as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements" [16].

ATC = TTC - TRM - Σ (existing transmission commitments (which include retail customer service) and CBM) [16]

2.4.1 TOTAL TRANSFER CAPABILITY

The Total Transfer Capability (TTC) is defined as the amount of electric power that can be transferred reliably between any two areas, based on all of the following conditions. These are taken directly from reference [16].

1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits,

2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit.

3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

4. With reference to condition 1 above, in the case where pre-contingency facility loadings reach normal thermal ratings at a transfer level below that at which any first contingency transfer limits are reached, the transfer capability is defined as that transfer level at which such normal ratings are reached.
5. In some cases, individual system, power pool, sub-regional, or regional planning criteria or guides may require consideration of specified multiple contingencies, such as the outage of transmission circuits using common towers or right-of-ways, in the determination of transfer capability limits. If the resulting transfer limits for these multiple contingencies are more restrictive than the single contingency considerations described above, the more restrictive reliability criteria or guides must be observed.

During the studies in which all of the above conditions are being considered, TTC is defined as follows [16]:

TTC = Minimum of {Thermal Limit, Voltage Limit, Stability Limit}

The limiting factor can change as the system operating conditions vary. Therefore, the limit on TTC may be set by one facility or another, or it may change from one type of limit to another for any facility, as illustrated in Figure 2-1.

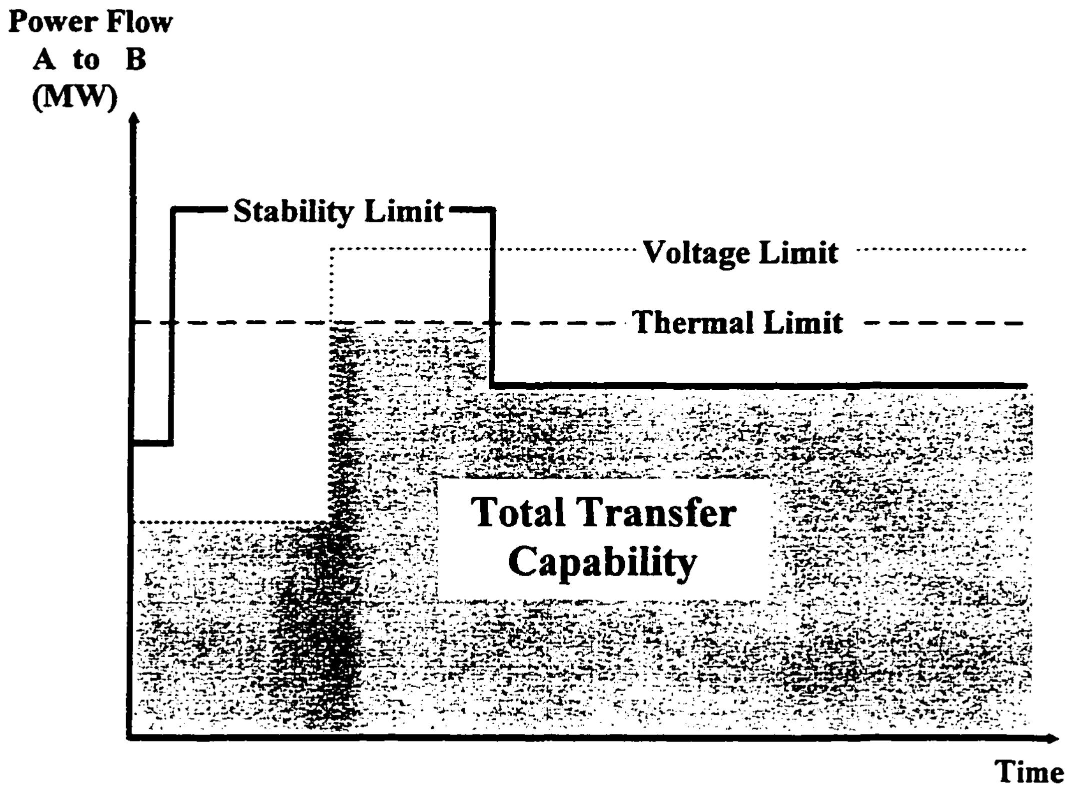


Figure 2-1 Limits to Total Transfer Capability

As illustrated in Figure 2-1, the shaded area represents the TTC or Total Transfer Capability. Since the system is continually changing with time the limiting factor also changes with time [16].

For simple illustrative purposes, in the following sections, suppose that a TTC=400 MW has been determined with no special protection systems.

2.4.2 TRANSMISSION RELIABILITY MARGIN

It is clear that the determination of TTC has been based on a myriad of assumptions, and projections of system conditions. However, ultimately these determinations must recognize that actual system conditions may change considerably from the assumed ones. Therefore, Transmission Reliability Margin

(TRM) is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

Two simple illustrations follow:

a) If TTC was determined with:

   i. Projected customer demands at peak load levels
   ii. Generation dispatch easily controlled
   iii. Contingencies at the N-2 level

   then an acceptable value of TRM might be:

   TRM = 75 MW

b) If TTC was determined with:

   i. Average load conditions
   ii. Generation dispatch heavily influenced by voltage and stability requirements
   iii. Contingencies at the N-1 level only

   then an acceptable value of TRM might be:

   TRM = 200 MW

2.4.3 CAPACITY BENEFIT MARGIN

Electric utilities must operate with a generation reserve, that is generation which is on-line or quickly available and not yet used, equal to the largest on-line unit. Historically it has gone by the name "spinning" and "10-minute" reserve.

For smaller utilities with one or more large generators, a portion of the spinning reserve has often been provided by the interconnections. (Of course the converse is true in that smaller utilities could not install high capacity generators unless they had significant interconnections).

In the deregulated industry, the responsibility for providing operating reserve will reside with the ISO. Therefore Capacity Benefit Margin (CBM) is defined as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

A simple example illustrates this. If

i. The largest operational generator is 500 MW
ii. The ISO depends on interconnection for 25 % of the operating reserve.

then:

$$CBM = 500 \times 0.25 = 125 \text{ MW}$$

2.5 SIMPLE ILLUSTRATIVE EXAMPLE

Based on the illustrations of section 2.4, the ATC without SPSs can be calculated as follows:

$$ATC = TTC - TRM - CBM$$
$$ATC = 400 - 75 - 125$$
$$ATC = 200 \text{ MW}$$

3. ENHANCED POWER SYSTEM CONTROL

3.1 INTRODUCTION TO POWER SYSTEM STABILITY

In the steady state operation of a power system, continuous balance is required between the mechanical input power and the electrical output or load. However, the load in an electrical network is forever changing because customers' lights, appliances, and machines cycle on and off. As a result the mechanical energy input to the prime mover of the generators connected to the network must continually change to follow these load variations. The mismatch between the mechanical and electrical energy causes fluctuations in the frequency and voltages in the network. To correct this problem control systems such as governors and automatic voltage regulators are incorporated into the network[15].

The steady state condition of a synchronous generator is achieved when its mechanical input power equals its electrical output power (neglecting losses). Restated[19]:

Mechanical Power Input = Electrical Power Output

If the system or synchronous machine suffers a disturbance such as a fault, the above equation will require another term: [19]

Mechanical Power Input = Electrical Power Output + Acceleration Power

There are three types of stability: 1) Steady-State, 2) Transient, and 3) Dynamic [20]:

1. Steady-state stability ". . . refers to a system's ability to withstand *small* changes or disturbances from the equilibrium state without the loss of

synchronism between two or more synchronous machines in the system "[18].

2. "Transient stability is the ability of the system to remain in synchronism (prior to the action of governor control) following a system disturbance" This is often referred to as first or "initial swing" stability) [20].

3. "Dynamic Stability is the ability of a power system to remain in synchronism after the "initial swing" (transient stability period) until the system has settled down to the new steady-state equilibrium condition" [20].

3.2 SWING EQUATION LEADING TO EQUAL-AREA CRITERION

Power system stability analysis is very complex because of the detailed machine electrical model, the mechanical model of the turbine-generator, the detailed models of the system controllers, and finally because of the thousands of variables that are involved when many machines are simulated.

However, for understanding and explanatory purposes, one of the concepts used to illustrate stability is the equal-area criterion. Fortunately this simple concept can be used to illustrate the action of SPSs in maintaining stability.

The swing equation (1) is used to describe rotor dynamics in transient stability studies. It relates the internal torque to the net accelerating torque of the rotor of a synchronous machine[15].

$$J\frac{d^2\theta}{dt^2} = T_a \quad \text{Nm} \tag{1}$$

where:

$J\dfrac{d^2\theta}{dt^2}$ - inertial torque

T_a - accelerating torque in Nm

The accelerating torque T_a in Nm can be represented as follows:

$$T_a = T_m - T_e \tag{2}$$

where:

T_m - driving mechanical torque

T_e - retarding or load electrical torque

The angular position of the rotor θ is given with respect to a stationary reference point.

This form of the rotational dynamics is the classical one. Power system engineers developed this equation in a specific way.

Relative to power:

a) Work with power rather than torque
b) Express power on a per unit basis

Relative to speed:

c) Work with electrical radians per second rather than mechanical radians per second
d) Express electrical speed in per unit
e) Express electrical speed as a deviation about a synchronously revolving reference frame

Relative to angle:

f) express the electrical angle in radians

g) Define this angle with respect to a synchronously revolving reference frame

After taking these steps, the following equations are obtained[15].

$$\frac{2H}{\omega_o}\left[\frac{d^2\delta}{dt^2}\right] = P_m - P_e \tag{4}$$

where [15]:

$P_e = P_{max} \sin\delta$

H is a newly defined inertia constant with units in seconds

ω_0 is the base electrical speed in electrical radians/second

δ is the angular position of the rotor with respect to a synchronously revolving reference frame

Multiplying both sides of equation (4) by $\frac{2d\delta}{dt}$ it can be put in the following form [15]:

$$2\frac{d\delta}{dt}\frac{d^2\delta}{dt^2} = \frac{\omega_o(P_m - P_e)}{H}\frac{d\delta}{dt} \tag{5}$$

and finally[15]:

$$\frac{d\delta}{dt} = \sqrt{\int_{\delta_o}^{\delta} \frac{\omega_o(P_m - P_e)}{H} d\delta} \tag{6}$$

It is necessary to make two points:

1. If following a disturbance the machine does not momentarily return to synchronous speed, then by definition it loses synchronism and becomes unstable. Also by definition the machine returns to synchronous speed when the angle δ stops changing. That is:

$$\frac{d\delta}{dt} = 0 \tag{7}$$

From equation (6) this means that the square root, and the integral itself, equals zero[15].

$$\frac{\omega_o}{H}\int_{\delta_0}^{\delta}\left(P_e - P_m\right)d\delta = 0 \tag{8}$$

2. During a disturbance a machine initially experiences either an acceleration or a deceleration. If it initially experiences an acceleration, then to remain stable it must subsequently experience a deceleration (and vice versa). Consequently, one part of the integral of equation (8) is positive and one part is negative. Therefore, it is desirable to break the integral into two regions[15].

$$\int_{\delta_0}^{\delta_1}\left(P_m - P_e\right)d\delta = \text{area } A_1 \tag{9}$$

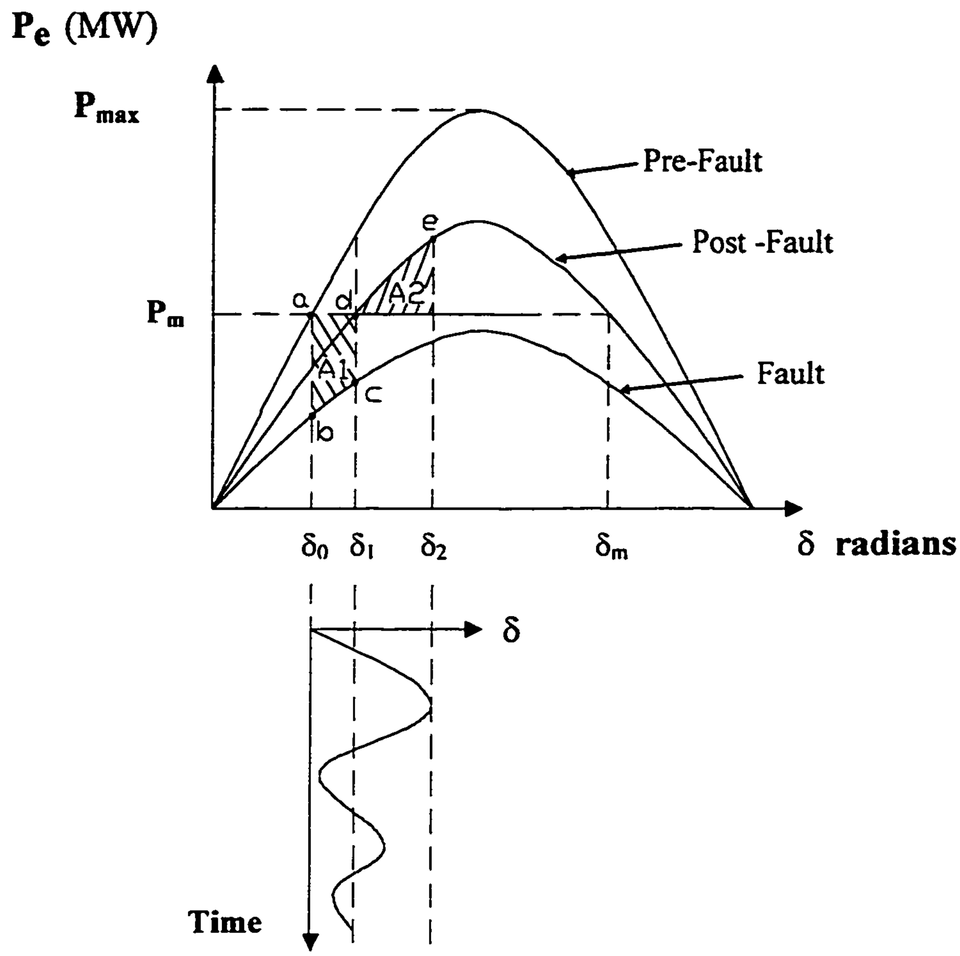
(assume $P_m > P_e$ so this is acceleration)

$$\int_{\delta_1}^{\delta}\left(P_m - P_e\right)d\delta = \text{area } A_2 \tag{10}$$

(assume $P_m < P_e$ so this is negative or deceleration)

A typical illustration of the equal-area criterion is that of a single generator operating through two parallel transmission lines (pre-fault P_e curve). A fault occurs on one of the parallel lines inhibiting the ability of the lines to transfer power (fault P_e curve).

The protective relaying and circuit breakers act to remove the faulted line leaving one transmission line in service (post-fault P_e curve).



Stability is lost when area A1 > A2.

Figure 3-1 Equal Area Criteria

When the fault occurs the electrical power is reduced (to the fault P_e curve) while the mechanical power input is assumed constant at P_m. This creates the accelerating area A_1. When the faulted line is removed at angle δ_1 , the ability to transmit electrical power is increased (to the post-fault P_e curve). This starts to create a decelerating area A_2. If it is possible to find a decelerating area A_2 at least as big as the accelerating area A_1, before the limiting angle δ_m is reached, then the system is transiently stable. It should be noted that if damping were not present the angle would continue to oscillate unabated). Practical power systems have inherent damping as illustrated on the δ verses time graph.

If power is being transferred at a level close to this steady state stability limit and the system suffers a disturbance the resulting power swings, created by the power angle fluctuations within the machines connected to the system, may push the level of power transfer above the stability limit and cause the system to become unstable [20].

An important factor affecting the transient stability is the time required to clear the fault. An example of how special protection schemes can improve the transient stability of the power network is illustrated in Figure 3-2. This example illustrates how the equal-area criteria can be used to analyze the operation of special protection systems involving generation rejection. Generation rejection in this example is used as a method for maintaining the system stability when a large load is lost within the sending area (New Brunswick).

3.3 APPLICATION OF EQUAL-AREA CRITERION TO SPS ACTIVITY

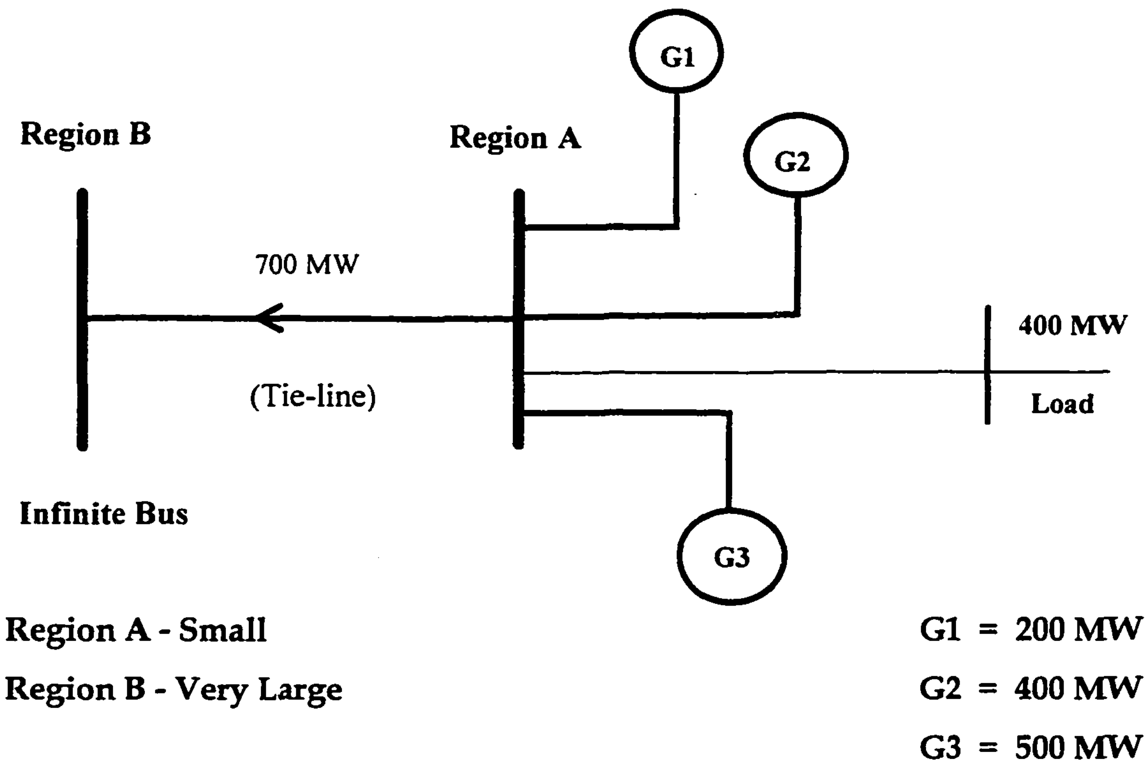


Figure 3-2 Generation Rejection Example

3.3.1 INITIAL STEADY-STATE

Three generators in Region A are producing a total generation of 1100 MW, with a load in Region A of 400 MW. The difference of 700 MW is being transferred over a tie-line. The tie-line transfer capability is

$$P_{tie} = 1060 \sin \delta \ \text{MW}$$

δ is the angle by which the rotors of the Region A generators are ahead of the Region B bus (which is considered to be an infinitely strong bus). The system is clearly stable.

3.3.2 LOSS OF LOAD IN REGION A

The original tie-line flow of 700 MW causes the tie-line to operate at an initial operating point **a.** that is at angle δ_o, as shown in Figure 3-3. The sudden loss of 400 MW of load in Region A (and assuming that no control action takes place in the governors of Region A) means that the entire 1100 MW of power will try to flow across the tie-line to Region B. However, this is impossible since the tie-line has a maximum capability of 1060 MW, at $\delta = 90^o$.

As shown in Figure 3-3 if no action is taken it is not possible to achieve a balance between the tie-line flow and the mechanical power supplied to the generators.

3.3.3 GENERATION REJECTION BY SPS - PART 1

Because the mechanical power supplied to the generators is greater than the power flow across the tie-line; the generators are in an acceleration mode and momentarily speed up causing the angle δ to increase.

While the angle δ is increasing from δ_o, as a result of a logic signal based on the loss of load the Special Protection System trips off Generator 3 thus decreasing by 500 MW the power being attempted to be sent across the tie-line.

Prior to the time that Generator 3 is tripped off, the accelerating energy area A1 is being formed. There are inherent time delays in the sensing, in the logic signal transmission, and in the actual time that it takes to open the circuit breaker to trip the generator. Assume that the generator angle has reached δ_1 at point **b** when Generator 3 is tripped. This completes the formation of the accelerating energy area A1. It represents the excess kinetic energy of the remaining Region A generators.

After Generator 3 trips off, the mode changes from acceleration to deceleration because the 600 MW of mechanical power available to the generators is far less than the tie-line flow at angle δ_1. However, because of the excess kinetic energy Region A continues to swing from point **b** at angle δ_1 to point **c** at angle δ_m from area A2.

Area A2 is a decelerating area. It is possible to find a decelerating area A2 equal in size to the accelerating area A1, then $\frac{d\delta}{dt} = 0$ and the generators are again momentarily at synchronous speed, and Region A is stable.

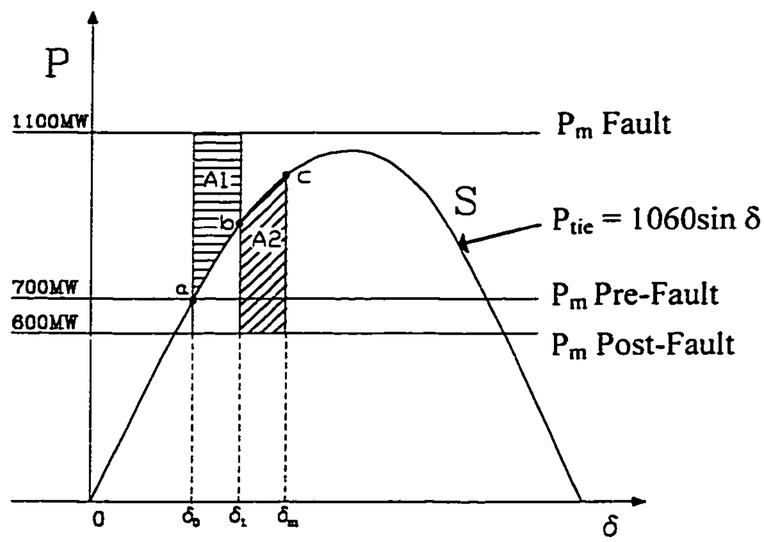


Figure 3-3 Recovery of System

A1 - accelerating energy due to excess mechanical power resulting from loss of load.

A2 - decelerating energy resulting from rejecting a generator.

3.3.4 GENERATION REJECTION BY SPS - PART 2

At angle δ_m (point **c**) the speed deviation is momentarily zero, but the mode is strong deceleration. Consequently the Region B generators start to slow down. This causes the generator angle to decrease to δ_f (as shown in Figure 3-4) where there is a momentary balance between mechanical power to the generators and electrical power flow across the tie-line. This forms the decelerating area A3.

However, because the speed of the Region B generators is slow, the angle continues to decrease. The generators now enter an acceleration mode. The angular swing continues until the speed deviation momentarily goes to zero at angle δ_3 at point **d**. This forms the accelerating area A4. If the damping forces where not present, the Region B generators would continue to swing between δ_3 and δ_m indefinitely. However, a new operating point **e** is finally reached as the damping forces within the system reduce the power swing (as illustrated in Figure 3-4).

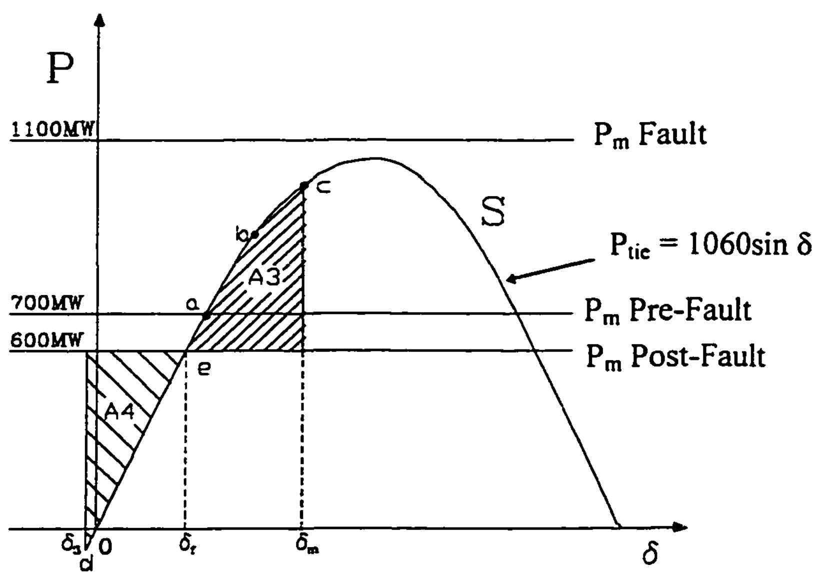


Figure 3-4 Performance following System Recovery

A3 - decelerating energy resulting from:

a) less mechanical power to Region A due to generator 3 tripping

b) excess electrical power flow across tie-line.

A4 - accelerating energy required to match A3

In [21] analysis of system disturbances has shown that the required corrective actions in most cases, are those actions closely matching the counterpart of the actual disturbance. For example if load is lost then generation is rejected, or if generation is lost then load shedding may be required.

3.4 FURTHER INTRODUCTION TO SPECIAL PROTECTION SYSTEMS

Special Protection Systems are logic schemes controlling network components based on action/reaction criteria. Sometimes referred to as remedial action schemes, SPSs are designed to operate (trip or remove from service) key components within the system under a carefully defined system condition [22]. SPSs have become widely utilised as a result of the desire to increase inter-area and intra-area power transfers without building new transmission facilities. SPSs are a relatively inexpensive means to increase transfer capability without building additional facilities. The incorporation of SPSs into the transmission network allows for increased power transfers without sacrificing system stability or reliability.

	Type I	Type II	Type III
Impact	Potential for inter-area impact	Potential for inter-area impact	Potential for local impact only
Initiation	Initiated by normal contingencies	Initiated by extreme contingencies	Initiated by normal or extreme contingencies

Table 3-1 Type of SPS Schemes

The Type I SPS is classified [33] as the most important in terms of system security because it is designed to function under normal contingencies. Normal contingencies are those involving the loss of a single network component such as a transmission line. Normal contingencies have the highest probability of occurrence. Extreme contingencies occur less frequently, as a result the Type II SPS does not require the high reliability through redundancy as does Type I. The Type III SPS has a lower risk than does Types I and II because it has local effect only, and thus the redundancy requirement is not as crucial.

The functions of the SPSs are as follows: [23]

GR - Generation Rejection or Reduction is a protection system designed to trip or reduce pre-selected generation or HVdc import not directly involved in clearing the fault from the power system, in response to certain contingencies or abnormal system conditions.

TCT - Transmission Cross-Tripping is a protection system designed to trip an element of a power system because of an event on another part of the system during an abnormal condition.

LR - Load Rejection is a protection system designed to trip load following the loss of a major supply to the area.

O - Other.

To place a cost on the service provided by the special protection system, we must investigate the functionality and benefits in terms of transmission improvement through increased power transfer capabilities, reliability, and system security.

Special Protection Systems are very system specific requiring reliable communication equipment and highly reliable logic circuitry. The available transfer capability of an interconnected system can be increased by the implementation of an SPS or multiple SPSs. However, because they are vulnerable to failure there is a need to inform the system operator of the use of SPSs. To establish criteria and guidelines for their operation, it may be necessary to have back up or redundant SPSs to cover such a scenario.

3.5 PROTECTIVE RELAYS AND SPECIAL PROTECTION SYSTEMS

Conventional protective relays sense faults such as short circuits and act to remove the faulted equipment from service. The specific objective is to remove the faulted equipment in order to protect it from damage. On the other hand, special protection systems act in response to an abnormal system condition, to improve the system condition as a whole.

4. SPECIAL PROTECTION SYSTEMS

4.1 INTRODUCTION TO FUNCTIONAL UNBUNDLING

Functional unbundling of any electric utility must be broken down into stages. In the first stage services must be identified and singled out as to whether they will fall under the transmission, generation or marketing business units. The services must be classified and costs must be allocated to the business unit supplying the service in question. If the services are not well defined in this first stage of deregulation, the result could be that uneconomic transactions will appear and services will be provided without compensation.

In the next stage the business units may become independent from one another, and be on their own to survive in an open deregulated marketplace. The only regulated entity will be the transmission network, controlled by the ISO. The ISO is responsible for acquiring the supply of necessary services to ensure system reliability and security. This will enable the ISO to post the ATC for transactions with a confidence in the ability of the system to survive any normal contingencies.

4.2 REQUIRED SERVICES IN AN UNBUNDLED SYSTEM

During the early development phase of deregulation, the U.S. Federal Energy Regulatory Commission requested utility feedback with respect to identifiable required services under deregulation. The responses varied widely, with one institution proposing 39 identifiable required services [17].

FERC assimilated these and eventually issued Order 888 [17] in which they would require each control area to supply six basic services which have become known as Ancillary Services.

4.2.1 ANCILLARY SERVICES

> "Ancillary Services are defined as: Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice" [24].

The six Ancillary Services are as follows: [25]

1. Scheduling, System Control and Dispatch
2. Reactive Power Supply and Voltage Control
3. Regulation and Frequency Response
4. Energy Imbalance
5. Operating Reserve - Spinning
6. Operating Reserve - Supplemental

There was concern within the electric utility industry that the six Ancillary Services did not provide for all operational aspects of open access and competition including the Interconnected Operating Services (IOS). As a result a Working Group was formed to study and develop strategic initiatives to address reliability/security in the deregulated environment. The criteria used by the Working Group in determining the IOS were as follows: [26]

1. Does the function provide for reliability?
2. Does the function facilitate open access and/or enable markets?
3. Does the function provide equity?

4.2.2 INTERCONNECTED OPERATING SERVICES (IOS)

The result of the IOS WG's efforts is the definition of twelve services which are practical to unbundle, necessary to ensure system reliability, will ensure open-access and/or enable markets, and simultaneously maintain an equitable allocation of costs: [27]

1. Regulation
2. Load Following
3. Energy Imbalance
4. Operating Reserve - Spinning
5. Operating Reserve - Supplemental
6. Backup Supply
7. System Control
8. Dynamic Scheduling
9. Reactive Supply and Voltage Control from Generation Sources
10. Real Power Transmission Losses
11. Network Stability Services from Generation Sources
12. System Blackstart Capability

Note: These services are not new, they have always been provided; however, the IOS WG has found that it is necessary for these services to be unbundled to provide for deregulation. The definition of each service can be found in Appendix C.

4.2.3 SPSs AS AN INTERCONNECTED OPERATING SERVICE

Some utilities are small, others are radially connected to the North American grid with only one interconnection, and yet others are strongly connected, and therefore transfer capability is not a major problem. For this reason, SPSs do not appear as a separate item in the above lists. They are, however, inherently a part of IOS #11 Network Stability Services from Generation Sources.

> "Network Stability Services from Generation Sources—under certain regional operating and planning conditions—may be required to maintain system reliability and to ensure equity by avoiding cost shifting. If these services are required, they must be identified and specified by an Operating Authority based on regional or inter-regional conditions" [27].

Utilities with many interconnections relative to their size, such as NB Power, have unique characteristics that create a high dependence on special protection systems to increase transfer capability and improve reliability and security of their networks.

In 1996, the IOS WG formulated six questions in an attempt to verify the necessity of each of the IOS's [28]. In order to show how SPSs fit under the deregulated structure, this section attempts to answer these questions for an SPS scheme which arms specified generators for possible generation rejection (GR). The answers are given based on research and input from discussions with engineers from NB Power who are involved in deregulation.

1. Is the service required for system security or to achieve an equitable allocation of costs?

   System security is the motivation for GR. It is designed to trip or reject selected generators on the occurrence of a fault or outage of a transmission line which creates instability in the network. The GR SPS rejects the generating unit and removes inertia from the system enabling the system to return to a new secure and stable operating condition. The GR SPS achieves an economic benefit by providing extra transfer capability where it would not exist without the SPS. This extra transfer capability could only be realized by adding a transmission line or lines or incorporating the SPS. In order to be able to operate at the enhanced transfer level, the transmission supplier must purchase this service from the selected generating units.

2. What are the technical requirements for the service?

   On-line generation appropriately located and of sufficient magnitude, when rejected at the proper time with the appropriate speed, should produce the desired shift in power flow and in system inertia required for system security and stability. Logic circuitry must be in place and line loading and status must be monitored, and during a disturbance signals must be sent to the generators for rejection.

3. In what time frame must the service be provided?

   The generation must be on-line and armed when the power transfer on the interconnection, or transmission line in question is above a predefined limit. The actual rejection is almost instantaneous when the triggering disturbance occurs.

4. How is the generation rejection service measured?

   There are several measures:

   - Value of the increased transfer capability which would be otherwise unavailable.
   - Improved system reliability and/or security by providing the course of action in case of a disturbance.
   - Cost savings in comparison to building new transmission lines which in the deregulated structure must be paid for at commercial rates. These costs must be paid for by the native customers.
   - Inconvenience and lost revenue incurred by the generating company.
   - Enhanced business opportunities created by increased ATC

5. Can the service be self-provided or must it be purchased?

   It is possible in some instances for the service to be self-provided by the wheeling entity. The generator/generators armed for the rejection must be studied through off-line analysis and their operation proven effective in terms of system security and reliability under a wide range of operating conditions. The generator location and rejection magnitude are crucial for the correct performance of the SPS.

6. Obligations/ Provider of Last Resort

   Where the increased transmission capacity is requested and/or needed the transmission provider must offer to supply the service or arrange for this service on behalf of the transmission customer[28].

   The alternative to the generation rejection SPS is building new transmission lines, a long and expensive endeavor, which may not be feasible in some cases. However, the benefits of a new transmission line are reduced losses along with the added stability and reliability.

4.3 NEW BRUNSWICK SPSs

The transfer capability limits have been defined for NB Power through extensive system studies carried out over a number of years. The maximum transfer capability to Nova Scotia or New England is 700 MW, with the maximum simultaneous transfer of up to 1100 MW. These limits have been made possible by incorporating special protection systems into the network to fulfill the security and reliability requirements set forth by the regulatory agencies.

The 700 MW limit to NS has been established based on thermal overload of key transmission lines and low voltage in the Moncton Area, whereas the 700 MW NE transfers limit results from stability problems. The 1100 MW simultaneous transfer limit NB to NS and NB to NE is a result of stability limitations. If the 1100 MW limit is to be raised, then more than one of the

Coleson Cove thermal units, or equivalent, would have to be prepared for rejection [4].

4.3.1 ROLE OF SPSs IN DEVELOPMENT OF TRANSFER LIMITS IN NB

In order to determine the maximum or Total Transfer Capability (TTC) from New Brunswick to one of its neighboring control areas, the following three steps need to be followed [4]:

Note: The transfer levels are determined assuming a 100 MW export to Prince Edward Island in all cases.

1. Transfer from NB is increased until the steady-state stability limits are marginally violated. This represents the TTC for that transaction.
2. Applying the N-1 criteria by removing key network elements within NB one at a time to develop transfer curves, representing the maximum allowable post contingency transfers for the different scenarios.
3. Do transient stability studies, which are carried out for the following three scenarios:
   a) consider the pre- and post-contingency states by examining the transient response of the system.
   b) consider the different power transfer capability levels and the Special Protection System requirements at each transfer level.
   c) consider inter-area impact on the 345 kV tie line between New Brunswick and New England under certain contingencies

4.3.2 IMPACT OF SPSs ON TRANSFER CAPABILITIES

The NB Power network has limitations on the transfer capabilities of its interconnections which are illustrated graphically in Figures 4-1 & 4-2 [4]. These figures illustrate the total transfer capabilities of the interconnections with New Brunswick. It should be noted, that these transfer limits result from the incorporation special protection systems. The total transfer capability is determined by investigating the N-1 criteria, which considers the loss of any single element or facility and the ability of the system to remain stable thereafter. If the SPSs were removed from the system the transfer capabilities would be substantially reduced.

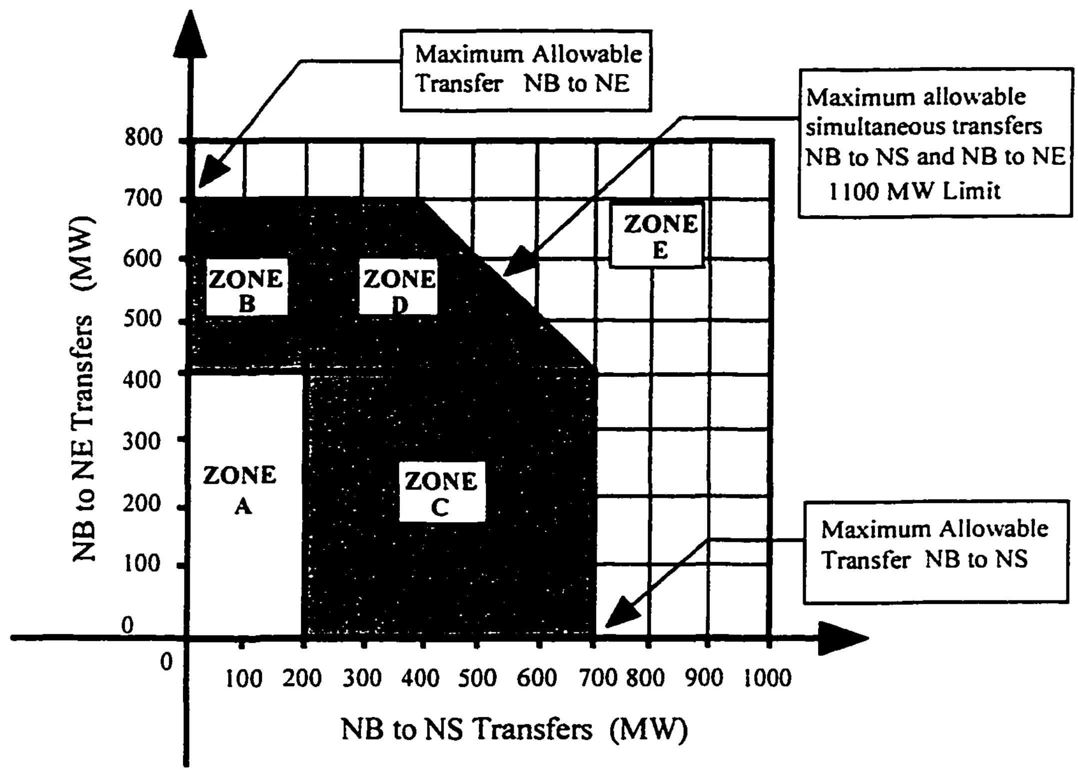


Figure 4-1 Simultaneous Power Transfers (NB to NE and/or NS)

Figure 4-1 illustrates the interrelationship between the NB to NE and the NB to NS interconnections. Zone A represents the theoretical operating area where no SPSs are required. Zone B represents the operating area where SPSs # 11 and 12 are required. Zone C represents the operating area where SPS # 106 is required. Zone D represents the operating area where all three type I SPSs are required. Zone E is considered as an unacceptable operating area. (Note: the numbered SPSs are in Appendix A).

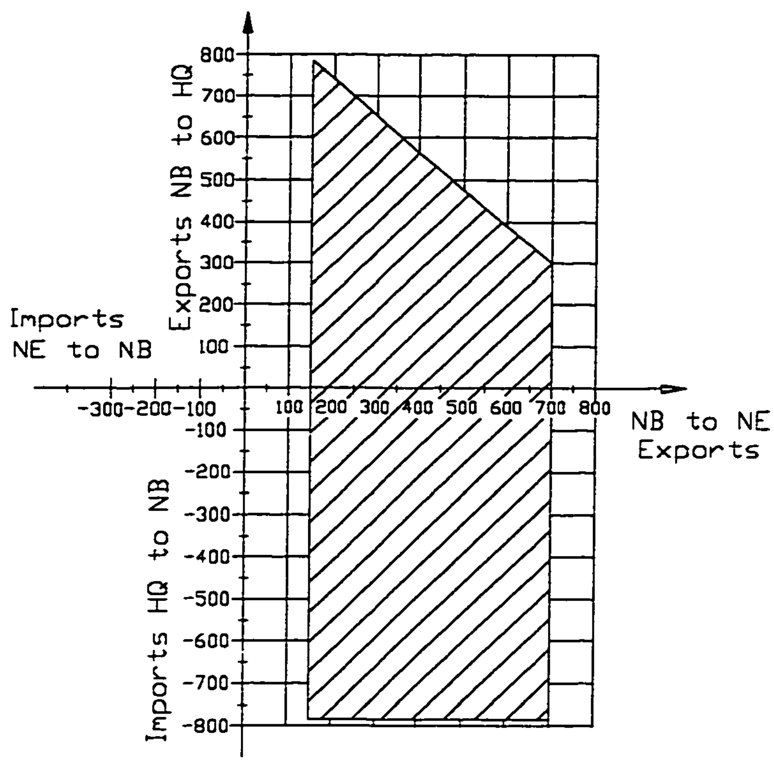


Figure 4-2 Simultaneous Power Transfers (NB to NE and to/from HQ)

The shaded operating area in Figure 4-2 involves special protection systems. This particular transfer capability plot is currently undergoing revision and updating. Within the shaded area, three SPSs are required: SPS # 11, 12, and 106.

4.3.3 DETAILS OF NEW BRUNSWICK SPSs

In appendix A, three Tables: I, II, and III are provided as information. They contain the Type I and Type III SPSs currently in use throughout the New Brunswick Power system. For the purposes of this thesis, only the SPSs involving generation rejection are considered as they are outside the control of the regulated transmission company[4].

5. BASIC ECONOMIC CONSIDERATIONS RELATING TO SPSs

In the deregulated electric utility all services must be separately identified, and financially evaluated. It is important to realize that not all facilities are considered as direct parts of the transmission system, however their existence is crucial for the reliable operation of the power system. One such service is the network stability support provided by the special protection systems. This service is crucial to the reliability and security of the interconnections when they are heavily loaded. This service has been supplied in the regulated system for years with no charge.

In analyzing the financial aspects of supplying the SPS-initiated generation rejection service, basic economic theory has been utilized. Reference [10] has placed the financial aspects in the clearest of perspectives. It says that "... it is important to realize that pricing of transmission services, although a technical issue, is not an engineering problem. Engineering analysis deals mainly with determining the feasibility and the cost of providing transmission services, and is only one of many considerations in the overall process of pricing transmission services".

In the deregulated marketplace it is important to re-evaluate the costing structure. In terms of NB Power, the Wires business unit (under the control of the system operator) will be considered as the regulated entity. This is similar to the fully deregulated system where the transmission system is regulated and under the control of the ISO.

It is useful to state two basis elements of economics:

a) It is an exercise in engineering economics to determine the cost of providing the SPS services.

b) It is quite another matter to determine the value and/or pricing of the SPS services. One possibility is to set the price at what the market will bear. Another possibility might be to examine enhanced business opportunities for associated enterprises, with a consequent sharing of profits. Clearly the determination of pricing is in the marketing domain, and may involve a negotiating process either implied or direct.

5.1 COST

The cost of a service can be subdivided into two categories:

a) Embedded cost

b) Actual service cost

5.1.1 EMBEDDED COST OF SPSs

The sensing, logic, and communication hardware/software must be part of the Wires business unit transmission system. Therefore these costs are absorbed as part of the embedded transmission cost.

The embedded cost includes:

1. Software - SCADA interfaces and software logic settings, displays.
2. Hardware - hardwired logic, relay.
3. Communication systems - microwave links for sending required arming and trip signals.
4. Contingency plans - selecting and deselecting units for arming and rejection
5. Engineering person hours - hours and years spent in design and optimization of the SPS schemes.

5.1.2 ACTUAL SERVICE COST

Normally the logic of the SPSs demands that a generator be tripped or rejected at infrequent intervals.

The actual service cost of the generation rejection supplier includes :

a) Loss-of-life (thermal stress to the machine's rotor or turbine shaft)
b) Replacement energy
c) Loss of firm contracts
d) Increased down time for maintenance, and increased maintenance
e) Risk of major damage from full load rejection

5.2 VALUE

The value of any service is considered as the worth that a person or persons attach to the service. Thus, the value of the service is inherent not in the service itself but in the regard that a person or persons has for it. Market value is the most common measure of value because it is what the service is worth to someone else. A service may be worth more to the person who uses it than it is to those who supply that particular need. The actual cost of providing the service may have little or no relation to its value [29, 30, 31].

Value is a subjective concept. This thesis suggests that there are three ways to establish a value for the SPS system and services.

1. Value based on global transmission cost.

   In this section one charge is used for all power transactions. This charge applies for all in-province and interconnection power transfers.

The value of the SPS will be based on the transmission costs per kW-yr for the additional transfer capability made possible by the incorporation of the SPSs. This can be calculated by identifying the yearly revenue required for owning and operating the additional capacity on the transmission network including operation and maintenance, capital, and depreciation.

For any service that it provides, either with its own facilities or as a purchased service, the Wires business unit as owner of the transmission system is allowed to recover cost plus a rate-of-return [32]. That is, the Wires business unit could recover the embedded costs and the actual service costs associated with any generation rejection services, which they might purchase.

2. Value based on an equivalent transmission line.

The provider of generation rejection services might argue that such services are much more valuable than the actual service cost. For example, if the generation rejection service allows the Wires business unit to carry out a wheeling across transaction on the interconnection at twice the otherwise possible value, then the provider of the generation rejection services could logically argue that such services had the value of a second transmission line. On this basis, the generation rejection service provider might price its services to the Wires business unit at a value much higher than the actual service cost.

3. Value based on enhanced business opportunities.

The argument is similar here. If the provider of generation rejection services allows an enhanced business opportunity such as a wheeling across transaction of 700 MW, than the provider of the generation rejection services could logically argue for some split of the profits resulting from the enhanced business opportunity. On this basis, the generation rejection service provider might price its services to the Wires business unit at a value much higher than the actual service costs.

5.3 ADDITIONAL ASPECTS OF PURCHASING GR SERVICES

Referring to Figure 1-1 it can be seen that the New Brunswick transmission system is highly interconnected, and the ATC is dependent upon the special protection systems. The required generation rejection arming level of the SPSs is proportional to the amount of power being exported from NB over the tie-lines.

It should be noted, in reference to Figure 4-1 (Simultaneous Power Transfer (NB to NE and/or NS), that the theoretical SPS arming level of 400 MW is marginally acceptable. The actual arming for SPS-initiated generation rejection takes place below this level, at approximately 200 MW. NB Power actually arms the generation for rejection at the 200 MW level to allow for uncertainties in the system condition. This may be viewed as the reduction in ATC related to TRM and CBM (as illustrated in the simple example in Chapter 2). A TTC of 400 MW with no special protection systems results in:

$$ATC = TTC - TRM - CBM = 400 - 75 - 125 \qquad = 200 \text{ MW}$$

In this section sources of generation rejection other than those of the NB generation business unit will be investigated. Five different possible transaction and generation arming requirements will be investigated. Of these five, two of the possibilities are existing, the other three are hypothetical. However with future uncertainty about the exact nature of the developing competition structure, all possibilities must be examined.

5.3.1 EXISTING GENERATION REJECTION ISSUES

Currently, the NB Power system has been divided into business units. The Wires business unit controls the transmission network and the Generation business unit controls all NB generation. As a result, the cost to the Wires Business unit will come from what the Generation business unit may charge for supplying the generation rejection service. In this section the required arming level is investigated with respect to the HVdc ties with Hydro Quebec.

1) Wheeling out of New Brunswick and the reliance on the HVdc as part of the required generation rejection arming level.

   The required generation rejection arming level can be supplied in-part by the ISO. When power is being transferred from Hydro Quebec to New Brunswick, the ISO can send a signal to block the HVdc. This will stop the import power flow from Hydro Quebec, which has the same effect as tripping a generator in New Brunswick.

   Hydro Quebec and New Brunswick have systems in place to block the HVdc, based on any major disturbance occurring in either province. Both sides of the HVdc link are prepared under the N-1 requirement to survive the loss of the HVdc link. As a result, the control of the HVdc blocking schemes falls under the control of the system operator or ISO in the future. This allows the ISO to utilize the HVdc as part of the special protection systems with the remainder supplied by the Generation business unit or independent generators.

2) Hydro Quebec wheeling across New Brunswick to New England.

   In this scenario the required generation rejection arming level is substantially reduced because the HVdc blocking provides a major portion of the required arming level.

5.3.2 FUTURE GENERATION REJECTION ISSUES

In the future the control of the New Brunswick transmission network may fall under the control of an Independent System Operator (ISO). With respect to generation, the individual generation units may become independently owned and operated. In this case the individual unit owners could submit bids based on their cost and what they may consider their generation is worth as a source of generation rejection.

It may be the case that the future power transactions in, out, and through the province could create new special protection issues resulting in modification of the generation rejection arming requirements. The supply of generation rejection service may become competitive and external suppliers may wish to be considered as a source of generation rejection. Three such possibilities follow:

1) An external generation supplier selling power to New Brunswick, who requests to be considered as a source of generation rejection.

   If the external generator is connected to the New Brunswick transmission network then providing generation rejection may have little or no effect on its operation. In this case the generator can supply the generation rejection service as a business opportunity to aid in the recover of the units costs.
   If this unit becomes a wheeling entity, then it can be a self supplier of the required generation rejection, in full or in part depending on the required levels.

2) A generator in Nova Scotia selling power to New Brunswick, or wheeling across to a neighboring system, may want to supply all or part of the required generation rejection.

   This may be possible in the future, and could be used to lower the transmission tariff which they will pay for wheeling in NB.

3) Generation rejection service being self-supplied by the wheeling entity.

If the wheeling entity has been approved as a source for generation rejection and has the capability to be a self provider then this entity may be given a reduced tariff for their transactions.

All power transactions in or through New Brunswick will be controlled by the regulated Wires company. The ISO is responsible for reliability and system security. Therefore, the ultimate discussion of what is required will be under the control of the ISO. Any changes to the existing SPS logic or the addition of new sources of generation rejection must be approved by the ISO in New Brunswick and must also be approved by the Northeast Power Coordinating Council (NPCC). Detail of the NPCC SPS review procedure are provided in Appendix F [33].

6. GENERATION REJECTION SPS SERVICE COST

A transmission system with many interconnections would normally experience a host of possible transactions. For simplicity, this thesis will consider SPS costing limited to identifying the cost and the value of providing an effective increase of 300 MW in the total transfer capability on the New Brunswick to New England interconnection (that is, from 400 to 700 MW). When considering SPSs involving generation rejection in NB, this interconnection is the major focus since the SPS logic is directly linked to the power transfers and ATC. If the SPSs are removed from this interconnection the TTC would reduce to 400 MW and the ATC could be as low as 200 MW depending on the TRM and CBM as indicated in Chapter 2. For this reason the value will be determined at the 400 MW and the 200 MW levels.

This chapter will consider the costing of special protection systems from the different stages of deregulation. In the introductory section of this thesis, NB Power's deregulation efforts have been described as breaking the utility into business units. The Wires business unit will be assumed to take the role of regulated Wires company under the control of the independent system operator (ISO). The generation company will be considered as one single entity which controls all in-province generation.

The special protection systems have been identified as the interconnected operating service (IOS) number 11 (Network Stability Services from Generation Sources) [27]. Therefore, the following cost and value calculations will be constructed under this premise.

6.1 DETERMINATION OF THE EMBEDDED COST OF THE SPSs

The actual cost of the sensing, logic, and communication hardware/software for the overall power system has been absorbed by the integrated system. As a result it is considered as an embedded cost. Therefore, such costs will simply be absorbed in the transmission tariff. The partial embedded costs associated specifically with the SPS are calculated as follows:

Estimated cost of the actual hardware and logic circuitry:	$ 300,000
Two man-years of engineering and overhead at $ 70 per hour:	$ 291,200
Total cost:	$ 591,200

We must first project this cost into the future at a 2.5 % inflation rate, assuming a 20 year life for the electronic components.

$$\text{Revenue required considering inflation} = \$591200\ (1 + 0.025)^{20}$$

$$= \$\,968{,}750$$

The uniform sinking fund calculated at 7.5 % interest will be [34, 37]:

$$\text{USF Factor} = \left(\frac{i}{(1+i)^{n} - 1}\right)$$

$$\text{USF} = \left(\frac{0.075}{(1+0.075)^{20} - 1}\right) * \$968{,}750 \qquad = \$\,22{,}371 \ / \text{ year}$$

This cost provides insight into the savings using SPSs compared to building a new transmission line. The cost of building a new transmission line will be investigated further on in this chapter.

6.2 ACTUAL SERVICE COST CALCULATIONS

In this proposal transfer payments from the NB Power Wires business unit to the Generation business unit are recommended for the use of the NB generation as part of the SPS schemes required to supply the network stability service. This involves determining the contribution to the 300 MW increase in TTC resulting from the incorporation of the NB generation rejection into the functioning of the SPSs.

To determine the cost for the generation rejection service, thermal generating units were considered, as they are the most expensive in terms of the complexities in forced outages.

Many hours have been spent in discussion with the engineers from the Generation business unit[38]. These discussions have uncovered the extremely complex nature, and wide range of possible costs, of providing this service. Full load tripping of a thermal generator can cause severe damage to the unit. The resulting cost can vary from hundreds of thousands to tens of millions depending on the damage. Ideally a generating unit is put on line and remains at full load without disturbance. This would maximize the unit's expected life. However, if the unit is continually cycled its life will be reduced accordingly. Planned cycling of the unit imposes less damage than unplanned full load tripping. If a unit is taken off line suddenly, when operating at full load, the components of the machine can suffer stresses which can dramatically reduce the unit's expected life[15].

Data has been gathered for the 345 kV tie-line between New Brunswick and New England. This data was collected from researching the past three years of Monday peak loading sheets (as illustrated in Appendix D).

Results:

Percentage of transfers above 400 MW	= 35.6 %
Average of loads actually above 400 MW	= 115.9 MW
Percentage of transfers above 200 MW	= 74.6 %
Average of loads actually above 200 MW	= 210.7 MW
Average monthly peak exports	= 447 MW

These values were confirmed as an accurate estimation by system operators at the Energy Control Center, where it was found that for 1996/97 the tie-line was above 400 MW for 2724 hrs out of 8760 hrs/year or approximately 31.1% of the time, at an average loading above 400 MW of 105.6 MW.

The Monday report data is used throughout the calculations because it considers the past three years whereas the Energy Control Center data is only for 1996/97, which was considered to be lower than average in terms of the actual power transfers to New England.

Investigation of the disturbances on this tie-line have revealed that over a 14 year period there were 9 disturbances that resulted in SPS-initiated generation rejection. This implies that generation rejection occurs on average 0.65 times per year due to SPS activity.

Through conversation with NB Power engineers [38], typical costs for generation have been established. Based on all NB generation the average estimated cost is $ 45 / MWH. This is broken down into three components.

Operation and Maintenance	=	$ 10 /MWH
Capital and Depreciation	=	$ 20 /MWH
Fuel	=	$ 15 /MWH

6.2.1 LOSS-OF-LIFE (THERMAL STRESS TO THE MACHINE ROTOR)

The thermal stresses resulting from generation rejection or full load tripping can cause loss-of-life to the generating unit. Thermal generating units have stress-life curves relating the expected unit life in hours to the projected life with thermal stress considerations.

Generator rejection imposes a high thermal stress on the turbines because of variation of temperatures in the metal of the machine turbine shaft and rotor. These stresses can result in severe damage to the machine.

If power is being exported over a tie-line and a fault occurs, causing the line to open resulting in generation rejection, it can take minutes, hours, or even days for the generator to come back on-line. If the faulted line is restored quickly, the rejected units may be brought back on-line in minutes. Many utilities have designed their units such that, following being rejected, the unit continues to run supplying the unit auxiliaries. In this case the unit may be brought back on-line - within 15 to 30 minutes [15].

Typical information has been gathered, from discussion with NB Power engineers [38], for a medium (350 MW) thermal generating unit and it was found that the average yearly data is as follows:

Yearly Average	Typical Thermal Unit
Actual Operating hours	6000
Number of Cold Starts	7
Number of Warm/Hot Starts	35
Equivalent Operating Hours	6980

Table 6-1 Average Yearly Data for a Typical Thermal Unit

The equivalent operating hours (EOH) are based on the running hours and the number of cold and warm/hot starts. The following equation, provided by NB Power engineers [38], is used to calculate the EOH.

$$\text{EOH} = \text{Actual Operating Hours} + 40 \text{ Hours for each Cold Start} + 20 \text{ Hours for each Warm/Hot Start.}$$

The type of start i.e. Cold, Warm, or Hot is dependent on the actual down time of the unit.

If we use 30 years as the expected life, then:

Average Over 30 Years	Typical Thermal Unit
Actual Operating hours	180000
Number of Cold Starts	210
Number of Warm/Hot Starts	1050
Equivalent Operating Hours	209400

Table 6-2 Typical Thermal Unit 30 Year Data

Next if we consider the reduced life of the unit from being cycled:

$$\text{Percent loss-of-life} = \left(1 - \frac{180000}{209400}\right) * 100\% \qquad = 14.0\ \%$$

Years of reduced life = 30 year * 14% = 4.2 years

From Table 6-3 there are 210 cold starts and 1050 warm/hot starts, which implies 29400 equivalent operating hours related to cycling the unit.

It has been determined, based on historical data, that there are 0.65 occurrences of SPS-initiated generation rejections per year. Extrapolating this average over 30 years, 19.5 rejections are expected. Assume that ½ of the SPS-initiated generation rejections result in cold starts and ½ result in warm/hot starts.

Cold Start EOH	9.75 * 40	= 390 hr
Warm/Hot Start EOH	9.75 * 20	= 195 hr
Total EOH for generation rejection		= 585 hr

The loss of unit life attributed to SPS-initiated generation rejection can be calculated as follows:

$$\text{Percent loss-of-life} = \left(\frac{585}{209400 - 180000}\right) * 100\% \qquad = 2.0\%$$

Years of loss-of-life = 2.0% * 4.2 years = 0.084 years

The unit loses 0.084 years of capital and depreciation recovery due to SPS-initiated generation rejection over its 30 year life. This can only be made up through a charge for SPS activity.

The overall cost structure quoted earlier was based on an average plant capacity factor of 58 %. Continuing with a unit rated at 350 MW:

Revenue required to recover capital and depreciation =

$20/MWH * 8760 hours/yr * 58% * 350 MW = $ 35,565,000 /year

Revenue required over 30 years to recover loss-of-life =

$35,565,000/year * 0.084 years = $ 2,987,460

We must first project this cost into the future at the 2.5 % inflation rate, assuming that the unit is half way through its life or at 15 years.

$$\text{Revenue required considering inflation} = \$2{,}987{,}460\ (1+0.025)^{15}$$

$$= \$\,4{,}326{,}733$$

The uniform sinking fund calculated at 7.5 % interest will be [34];

$$USF = \left(\frac{i}{(1+i)^n - 1}\right)$$

$$USF = \left(\frac{0.075}{(1+0.075)^{15} - 1}\right) * 4{,}326{,}733 \qquad = \$165{,}659\ /\ \text{year}$$

This represents $165,659 per year cost for lost capital and depreciation resulting from SPS-initiated generation rejection causing loss-of-life.

6.2.2 REPLACEMENT ENERGY OR LOST OPPORTUNITY COST

For a thermal unit, the typical cost has been approximated by NB Power engineers [38] as $10,000 for a Cold start, and $5000 for a Warm/Hot start. Taking the worst case of a Cold start:

Restart (Cold Start) = $10,000

If we assume that when a (350 MW) generating unit is rejected the time required to re-synchronize is 8 hours. The replacement energy or lost opportunity cost can be calculated based on a system marginal energy cost, estimated (by NB Power engineers [38]) at $30/MWH.

Replacement energy or lost opportunity cost =

marginal energy cost - fuel cost = $ 30/MWH - $15/MWH

= $ 15 /MWH

Replacement Power Cost = 350 MW * 8 Hr * $ 15 /MWH

= $ 42,000

The total cost is the replacement energy plus the restart cost.

Total Costs = $ 52,000

Based on the historical value of 0.65 generation rejections per year:

Replacement energy cost per year = $ 33,800 /year

6.2.3 LOSS OF FIRM CONTRACTS

There exists a potential for loss of firm contracts if the generating unit has a higher than normal possibility of being tripped as a result of the SPS action. Presently, however, the actual generation rejections only occur 0.65 times per year, therefore the cost in terms of lost contracts can be ignored. If in the future the number of generation rejections per year increases, then the cost may become significant.

6.2.4 INCREASED DOWN TIME FOR MAINTENANCE

Maintenance of the generation units is related to the operating hours, and the operating hours are influenced by the number of cold and hot starts. As deregulation proceeds the interconnection power transfer levels are unknown, however an increase is expected. Additionally, reliability and system security are becoming a focus with unknown effects resulting from deregulation.

It was found in the investigation of a typical thermal generating unit that the number of starts, Hot and Cold, was on average 42 per year, whereas the generation rejected related starts are 0.65 per year. This implies that only 1.55% of the unit's cycling is related to SPS activity.

Assuming that the 14% increase in EOH corresponds to a 14% increase in the Operation and Maintenance cost, then[38]:

SPS related O&M = 350MW * 8760 hr/yr * 58% * $10/MWH * 14% * 1.55%

= $ 38,589 / year

6.2.5 RISK OF MAJOR DAMAGE FROM FULL LOAD REJECTION

In discussion with engineers from the Generation business unit, it was estimated that there is a 0.1 percent chance that during a full load rejection of a thermal unit there will be major damage such as turbine generator runaway which can result in damage to the turbine shaft or rotor.

From discussion with NB Power engineers [38], it was found that the actual costs for replacing the a major rotational component in a thermal plant (such as the generator rotor or turbine high pressure cylinder) can vary anywhere from $1 million to $25 million depending on many factors. Therefore, for illustrative purposes we will assume $15 million to replace the rotational component of a thermal generator which has suffered thermal stress resulting in-part from full load generation rejection.

For an inspection of the generating unit to ascertain the damage the typical cost is $ 350,000 and it takes approximately 6000 hours for the inspection and repairs. Assuming the unit is 350 MW the cost for replacement power and the inspection would be:

Assuming replacement energy cost = marginal energy cost - fuel cost

$ 30 /MWH - $15 /MWH = $ 15 /MWH

Replacement Power = 350 MW * 6000 hr * $ 15 /MWH

= $ 31,500,000

Inspection = $ 350,000

Replacement of the Rotor = $ 15,000,000

Total Cost = $ 46,850,000

Risk of major damage = 0.1% * 0.65 /year * $ 46,850,000

= $30,453 /year

This represents $30,453 per year cost for exposing the generating unit to risk of major damage resulting from SPS-initiated generation rejection.

Table 6- 3 provides a summary of cost considerations for a typical 350 MW thermal generator taking part in SPS-initiated generation rejection.

Cost Component	Actual Cost/year
Loss-of-life	**$ 165,659**
Replacement energy or lost	**$ 33,800**
Loss of firm contracts	**0**
Increased maintenance	**$ 38,589**
Risk of major damage	**$ 30,453**
Total cost	**$ 268,501**

Table 6-3 Actual Cost of Generation Rejection Service

6.3 VALUE CONSIDERATIONS

As outlined in chapter 5, three ways of establishing the value of the special protection systems and the required services will be investigated.

6.3.1 VALUE BASED ON GLOBAL TRANSMISSION COST

In this section one charge is investigated for all power transactions. The value of the SPS will be based on the transmission charge per kW-yr. This can be calculated by identifying the yearly revenue required for owning and operating the transmission network. This includes operation and maintenance, capital, and depreciation.

From conversations with NB power engineers [38] the cost of owning and operating the transmission network has been estimated at between 75 and 95 million dollars per year. An average cost of 85 million will be assumed, which will be required to service an assumed forecasted load for 1997/98 of 2700 MW, this includes an average monthly peak of the in-province and the New England to New Brunswick interconnection [35, 36].

An estimate of the transmission tariff can be calculated based on these numbers as follows[36]:

$$\text{Transmission Tariff} = \frac{\text{Revenue Required}}{\text{Usage}}$$

$$= \frac{\$85{,}000{,}000 / \text{year}}{2700\text{MW}} \qquad = \$\,31.5\ /\text{kW-yr}$$

Considering the average monthly peak exports of 447MW, as given in section 6.2, we can calculate the yearly cost for of the New England to New Brunswick tie-line.

Interconnection Cost = 447MW * $ 31.5/kW-yr = $ 14,080,500/year

Next, considering the value of the transfers above 400 MW upper limit without SPSs under ideal conditions.

Average peak transfers above 400 MW = 447 MW - 400 MW

= 47 MW

Value based on global transmission cost = 47 MW * $ 31.5/kW-yr

= $ 1,480,500 /year

If we consider the ATC = 200 MW without SPSs, which reflects the actual situation with an operating margin to cover uncertainties, then:

Average peak transfers above 200 MW = 447 MW - 200 MW

= 247 MW

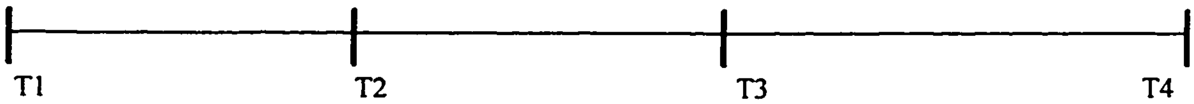
Value based on global transmission cost = 247 MW * $ 31.5/kW-yr

= $ 7,780,500 /year

6.3.2 VALUE BASED ON AN EQUIVALENT TRANSMISSION LINE

The equivalent transmission line required to replace the SPSs must be built all the way from NB (Point Lepreau) to NE (Maine Yankee), a distance of approximately 200 Miles. This is required because the first contingency, loss of one transmission line at any point before Maine Yankee, would not remove the stability problems in New Brunswick.

Point Lepreau ----- Orrington ------------- Maxcy's -------------- Maine Yankee



Assume an average cost of $400,000/mile for building the new transmission line.

The termination costs are estimated as follows:

T1 = $ 6 Million   T2 = $ 4 Million   T3 = $ 4 Million   T4 = $6 Million

The total cost of the equivalent transmission line is therefore approximately:

Total cost = 200 miles * $ 400,000 /mile + Termination cost

Total cost for the 200 mile line = $ 80 million + $ 20 million

= $ 100 million

The uniform capital recovery of this cost at 7.5 % interest will be [34, 37];

$$\text{UCR} = \left(\frac{0.075(1+0.075)^{35}}{(1+0.075)^{35}-1}\right) * 100{,}000{,}000 \qquad = \$\,8{,}148{,}291\ /\text{year}$$

The Operation and Maintenance costs are approximately 3% [38]:

Operation and Maintenance costs = 3% of $ 8,148,291 /year

= $244,449 /year

Thus, the total revenue requirement for recovery of the cost of the new line is

Total revenue requirement = $8,148,291 /year + $244,449 /year

= $ 8,392,740 / year.

It was found from Figure E-1 (in Appendix E) that at average monthly peak exports of 447 MW, the line losses were approximately 18 MW. With the second line, the line loading would be half or 223.5 MW and the losses are only 14 MW, therefore the loss savings are 4 MW with the introduction of the new line.

Using the generation cost of $ 45/MWH the loss savings can be calculated as follows:

Loss savings at 350 MW = 4 MW * $ 45 / MWH * 8760 hr
= $ 1,576,800 /year

The required cost for recovering the yearly capital and depreciation costs $8,392,740 /year less the loss savings is:

The total cost for second transmission line = $ 8,392,740 - $ 1,576,800
= $ 6,815,940 / year

Assuming the SPS provides half the value of the new transmission line, then the value of the SPS-initiated generation rejection service would be:

Value based on equivalent transmission line = $ 6,815,940 /2
= $ 3,407,970 /year

6.3.3 VALUE BASED ON ENHANCED BUSINESS OPPORTUNITIES

It was determined that, under ideal system conditions, it is theoretically possible to have transfers at the 400 MW level without SPSs. However, in the new deregulated environment there arises a requirement to restrict the transfers by the transmission reliability margin (TRM). When the TRM is applied to the TTC of 400 MW, the ATC will be reduced to approximately 200 MW to provide for uncertainty in system conditions. Historically, even though the term TRM had not yet been formally defined, the SPSs have been armed at the 200 MW level to provide for system reliability in such an event.

An assumed approximate markup on the historical power transaction on the NB to NE tie-line is $ 5 /MWH [38].

(a) Theoretical Operating Level of 400 MW.

Even though it is far too advantageous to the wheeling parties, nevertheless it is useful to calculate the profit they would have to share assuming that SPSs were not required until the 400 MW level was reached.

From the past three years of Monday peak power transfer reports, it was determined that the tie-line loading was above 400 MW, 35.6 % of the time and the average of the loads actually above 400 MW was 115.9 MW

For the SPS arming level at 400 MW :

Profit = 115.9 MW * 35.6% * 8760 hr/year * $ 5/MWH

= $ 1,807,205 /year

(b) SPSs Required and Armed at 200 MW.

This means that any wheeling above 200 MW is an enhanced business opportunity, and the resultant profits would have to be shared.

From the past three years of Monday peak power transfer reports, it was determined that the tie-line loading was above 200 MW, 74.6% of the time and the average of the loads actually above 200 MW was 210.7 MW

If we consider the ATC with SPSs (200 MW) then:

Profit = 210.7 MW * 74.6% * 8760 hr/year * $ 5/MWH

= $ 6,884,580 /year

6.4 SUMMARY OF COST AND VALUE CONSIDERATIONS

Tables 6-4 and 6-5 provide a summary of the cost and the value of using the special protection systems to increase the ATC on the New Brunswick to New England interconnection. In some cases two numbers are provided which indicate the value calculated with and without special protection systems.

Table 6-4 illustrates the cost and Table 6-5 the value of the SPSs to the Transmission company and the Generation company. An average value of approximately $ 4 million per year has been determined. It is recommended that

50% of this value or $2 million per year be paid to the Generation company for providing the interconnected operating service #11; (Network stability services from generation sources). The NB Wires business unit should pay the NB generation business unit $2 million per year for providing this services as part of the special protection systems, which enables the ATC to be increased to the 700 MW level without building a second transmission line.

Cost Component	Cost to	$/year	$/kW-yr	$/MWH
Partial embedded cost	**Transmission Company**	22,371	0.05	0.00571
Actual cost for SPS-initiated generation rejection	**Generation Company**	268,501	0.6	0.06857

Table 6-4 Summary of Value Consideration

Value Component	Value to	$/year	$/kW-yr	$/MWH
Value based on global transmission cost **ATC= 400 MW No SPS** **ATC = 200 MW No SPS**	**Transmission Company**	1,480,500 7,780,500	3.312 17.406	0.3781 1.987
Value based on equivalent transmission line	**Transmission Company**	3,407,970	7.624	0.7203
Value based on enhanced business opportunity **ATC = 400 MW No SPS** **ATC = 200 MW No SPS**	**Generation Company**	1,807,205 6,884,580	4.04 15.40	0.4615 1.7581
Average value	**Transmission and the Generation Companies**	4,272,151	9.557	1.091

Table 6-5 Summary of Value Consideration

Note:

a) The $ / kW-yr are based on the average monthly peak exports of 447 MW.

b) The $ / MWH conversion is $\left(\frac{1000}{8760} * \frac{\$}{\text{kW-yr}}\right)$

7. CONCLUSIONS AND RECOMMENDATIONS

7.1 CONCLUSIONS

The primary objectives of this thesis were 1) introduce and identify, for the first time, special protection systems as an interconnected operating service, 2) cost this service based on the actual service cost or on the value of this service in a open-access marketplace. The service has been classified as network stability support supplied by generation sources through special protection systems.

Special protections systems have been theoretically investigated as a means of increasing the available transfer capability on the interconnections while maintaining the systems reliability. In the deregulated marketplace power wheeling will become commonplace and will be dependent on the posted available transfer capability (ATC) of the interconnections. ATC has been defined and the dependence on SPSs has been demonstrated for the NB Power system.

The capital cost of providing the SPS services has been calculated and is found to be insignificant when compared to the alternative (building a new transmission line). The actual cost of supplying the SPS-initiated generation rejection has also been found to be substantially less than the value of the increased transfer capability produced by the incorporation of SPSs. Three methods of determining the value of the SPSs are presented and an average value of $ 4,272,151/year was found. This is the average value of the SPSs to the transmission and the generation companies. It is recommended that the generation company receive 50% of this value in the form of transfer payments from the NB Wires business unit to the NB Generation business unit.

7.2 RECOMMENDATIONS

As illustrated by this thesis, functional unbundling of even one service is a very complex task. In the regulated monopoly structure all services had been provided and the cost recovered; however, their cost and or value have never been identified on an individual basis. It will become more important, as deregulation proceeds, to identify these costs and the value of all services so that any unregulated entity will be able to recover all costs, enabling them compete in the open-access marketplace.

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APPENDIX A

NB SPSs with Potential for Inter-Area Impact Initiated by Normal Contingencies - Type I

Type	Function	Identification	Initiating Condition	Action(s) Resulting	Reason for Installation	Comment, Explanation	SPS #
I	GR	Keswick - Orrington	Any system disturbance resulting in greater than a 950 MVA flow out of Keswick on L3001. Coincident with above normal system frequency.	Trip selected units at Coleson, Mactaquac, Beechwood, and/or reduce import level via HVdc (Madawaska).	To prevent overload tripping of L3001.	Known as Keswick GCX SPS.	11
I	GR	Keswick - Orrington	NB - Maine flows swing above 650 MW and 200 MVAR on L3001.	Trip 200 MW of generation at Dalhousie, Mactaquac or reduce Eel River HVdc by 200 MW.	System stability. When Chester SVC is unavailable.	Known as Keswick Power Relay (KPR SPS). Only armed when Chester SVC is out-of-service.	12
I	GR/TCT	Southeast NB - Dedicated Path Logic	Any 3 pole opening of 345 kV lines between Coleson Cove - Salisbury or Bathurst - Salisbury	Trip selected generation and/or crosstrip Nova Scotia ties	System stability and area low voltage.	Armed when NB transmission flows exceed pre-defined levels	106

Table I New Brunswick Special Protection Systems [4]

APPENDIX A

NB SPSs with Potential for Local Impact
Only Initiated by Normal/Extreme Contingencies - Type III

Type	Function	Identification	Initiating Condition	Action(s) Resulting	Reason for Installation	Comment, Explanation	SPS #
III	GR	Mactaquac - Transformer	Loss of the Keswick 345/138 kV transformer or loss of the Keswick 138 kV buses #1 and #2	Trip selected units at Mactaquac	Prevent overload of 138 kV system		3
III	GR	Mactaquac-Keswick	Loss of a 138 kV line between Mactaquac and Keswick.	Partial shutdown of selected units at Mactaquac	Prevent overload of the remaining line.		4
III	GR	Keswick - Orrington	Loss of export on 345 kV line 3001 (Keswick - Orrington) combined with the Keswick frequency being above 60.3 Hz.	Trip selected generation at Mactaquac, Coleson, Dalhousie, Beechwood, Reduce Hvdc import at Eel River and Madawaska.	System stability. When Chester SVC is unavailable.	Maintain system stability following separation of the Maritimes from the interconnected system.	5
III	GR	Eel river - Bathurst	Loss of the 230 kV line 2103.	Reduce Eel River Hvdc import.	System stability, and preventing overload of 138 kV system when the 345 kV path is out of service.		6

Table II New Brunswick Special Protection Systems [4]

APPENDIX A

NB SPSs with Potential for Local Impact
Only Initiated by Normal/Extreme Contingencies - Type III

Type	Function	Identification	Initiating Condition	Action(s) Resulting	Reason for Installation	Comment, Explanation	SPS #
III	GR	Matapedia - Eel River	Loss of 230 kv lines 2101 or 2102 (Eel river - Matapedia).	Reduce Eel River Hvdc import.	To prevent overload on the remaining line.		14
III	TCT	NB - NS	Total exports from NB to NS exceeds 100 MW and 345 kV line 3006 opens.	Trip remaining 138 kV tie lines between NB and NS	To force NB/NS separation such that the 138 kv lines are not overloaded.		15
III	O	1190/1215 Thermal Overload	Thermal overload of 138 kV line 1190 or 1215	Close Moncton 69 kv bus tie circuit switcher, start PEI combustion turbines and initiate PEI load shedding.	Thermal overload protection of Salisbury-Moncton- Memramcook lines	If actions do not eliminate the overload of the NB-PEI ties will be tripped.	116

Table III New Brunswick Special Protection Systems

APPENDIX B

Occurrences of Generation Rejection related to the NB - NE 345kV tie line. [39]

1) Nov 16,1994

Event: While, exports to NE at 630 MW maintenance of a relay on L388 caused an accidental trip of the line. Frequency peaked at 60.31 and dropped to 59.34 Hz before the governors got it turned around.

Result: Generation Rejection Madawaska 395 MW
Eel River runback from 330 MW to 50 MW
Maritimes left deficient 205 MW

2) July 23,1993

Event: Lightning strike near Orrington while exporting 240 MW. Frequency peaked at 60.33 Hz and stabilized at 60.16 Hz

Result: Generation Rejection Madawaska (97 MW)
Mactaquac U3 (36 MW) leaving 107 MW surplus.

3) July 24, 1990

Event: Line to ground fault on L3001

Result: SPS tripped or rejected Madawaska (102 MW),
Dalhousie (206 MW), and Beechwood (68 MW)
Frequency peaked at 60.31 Hz.

4) Jan 27, 1988

Event: Relay maintenance on L388 caused it to trip while NB was exporting 620 MW. Maine 115 kV lines tripped on overload leaving 110 MW Bangor load on L3001.

Result: SPS tripped Coleson 1 (340 MW) to halt the frequency rise at 60.31 Hz.
Dalhousie 1 (105 MW tripped 3 ½ minutes later to dip to 59.87 Hz).

Occurrences of Generation Rejection related to the NB - NE 345kV tie line.

5) June 11,1986

Event: Mistake while calibrating Keswick fault recorder tripped line L3001 at 685 MW export.

Result: Generation Rejection:
Madawaska HVdc (380 MW)
Mactaquac 4 (85 MW),
Beechwood 2 & 3 (50 MW)
Eel River runback from 280 MW to 150 MW
Frequency rise was halted at 60.32 Hz.

6) Sept 20, 1985

Event: Wave trap phase-to-phase fault at Keswick while line L3001 was at 685 MW export.

Result: Generation Rejection
Madawaska HVdc (355 MW) stopped itself due to control problems and the SPS tripped Beechwood 2 (20 MW) and Eel River runback by 230 MW from 330 Mw to 100 MW. Resulting in an 80 MW surplus which was handled by the governors, frequency rise was halted at 60.44 Hz.

7) Jan 10, 1985

Event: Wiring mistake on protection panels at Orrington caused a 3 phase trip at end while L3001 was exporting 580 MW.

Result: SPS scheme reacted properly to trip Coleson 1 (305 MW) and runback Eel River by 160 MW. Resulting Surplus 115 MW which was handled by the governors, frequency rise halted at 60.41 Hz.

Occurrences of Generation Rejection related to the NB - NE 345kV tie line.

8) June 13, 1984

Event: Orrington fault recorder technician and bad protection fuse resulted in a false trip and breaker failure action on line while carrying 586 MW.

Result: SPS tripped the following units;
2 Mactaquac units (185 MW)
2 Beechwood units (78 MW)
Eel River was reduced by (165 MW)
Frequency rise was limited to 60.57 Hz.

9) July 14, 1983

Event: L3001 tripped 3 pole (because Orrington recloser was off) when the line contacted a green belt tree near Orrington. The tie-line was operating at 582 MW.

Result: SPS reduced HVdc Eel River from 330 to 80 MW
Tripped Coleson Cove (174 MW)
Mactaquac (14 MW)
Frequency rise was limited to 60.62 Hz.

APPENDIX C

GLOSSARY

All definitions contained in this Glossary are exerted from the NERC "Glossary of Terms" August, 1996 and the IOS WG's Final report [17, 28].

Ancillary Services
Interconnected Operations Services (IOS) identified by FERC Order 888 as necessary to effect a transfer of electricity between purchasing and selling entities and which a Transmission Provider must include in an open access transmission tariff. The six FERC Ancillary Services are: (Definitions adapted from FERC Order 888.) [17]

1. **Energy Imbalance** Energy Imbalance service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance service obligation.

2. **Operating Reserve: Spinning Reserve** Spinning Reserve service is needed to serve load immediately in the event of a system contingency. Spinning Reserve service may be provided by generating units that are on line and loaded at less than maximum output. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve service obligation.

3. **Operating Reserve: Supplemental Reserve** Supplemental Reserve service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve service may be provided by generating units that are on-line but unloaded, by quick-start generation or by curtailable load. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve service obligation.

4. **Reactive Supply and Voltage Control from Generating Sources** In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities (in the Control Area where the Transmission Provider's transmission facilities are located) are operated to produce (or absorb) reactive power. Thus, this service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the Region and consistently adhered to by the Transmission Provider. Reactive Supply and Voltage Control from Generation Sources service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System.

5. **Regulation and Frequency Response** Regulation and Frequency Response service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response service obligation.

6. **Scheduling, System Control, and Dispatch** This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator.

Interconnected Operations Services Working Group (IOS WG) has identified the following required services, which have been taken directly from reference [17].

1. **Regulation** The provision of adequate generation response capability, under AGC, in an effort to continuously balance Control Area supply resources with minute-to-minute load variations in order to meet NERC Control Performance Standards
2. **Load Following** The provision of the generation and interchange capability needed to meet the hour-to-hour and daily load variations not covered by Regulation service.
3. **Energy Imbalance** Energy imbalance is the mismatch between the energy schedule(s) at the point of receipt (POR) or point of delivery (POD) and the actual metered energy flow at the POR or POD within a Control Area's boundaries, over a given period of time. The Energy Imbalance service is the provision by the Control Area to supply the deficit energy or absorb the excess energy involved in such mismatches and applies to both load and generation.
4. **Operating Reserve - Spinning** The provision of generation capacity synchronized to the system that is unloaded, is in excess of the quantity required to serve current and anticipated demand, is able to respond immediately to serve load, and is fully available within ten minutes. Operating Reserve - Spinning is typically managed by a Control Area and is used following a contingency to meet the Disturbance Condition requirements of NERC.
5. **Operating Reserve - Supplemental.** The provision of (1) generation capacity not necessarily synchronized to the system but capable of serving demand and (2) interruptible load that can be removed from the system; both within ten minutes. Operating Reserve - Supplemental is typically managed by a Control Area and is used following a contingency to help meet the Disturbance Condition requirements of NERC.
6. **Backup Supply** Backup Supply is electric generating capacity used: (1) to replace an outage of generation or the failure to deliver generation due to an outage of transmission sources; and/or (2) to cover that portion of the customer's load that exceeds its generation. Capacity (planning) reserves, installed capacity obligations, or capacity (planning) reserve sharing agreements are common mechanisms to provide Backup Supply.
7. **System Control** Comprises the integration activities required to ensure the reliability of the North American Interconnections, to minimize transmission constraints, and to coordinate restoration activities following a contingency or disturbance.
8. **Dynamic Scheduling** The service that provides for the real-time metering, telemetering, computer software, hardware, communications, engineering, and administration required to electronically move a portion or all of the "watt type" services associated with generation or load out of the Control Area to which it is physically connected and into a different Control Area. This is not the service to match load and generation within a Control Area.

9. **Reactive Supply and Voltage Control from Generation Sources** The provision of reactive power from generation sources, to support transmission system operations, including the ability to continually adjust transmission system voltage in response to system changes.
10. **Real Power Transmission Losses**. Replacement of energy losses and the capacity to supply those losses on the Transmission Provider's transmission system associated with transmission service.
11. **Network Stability Services from Generation Sources Procurement**, operation and maintenance of special equipment, devices, software or systems that are required at generating plants to enable the Transmission Provider or Control Area to meet NERC, Regional, or sub-regional reliability requirements. Examples include power system stabilizers (PSS) and dynamic braking resistors.
12. **System Blackstart Capability**. The ability of a generating unit or station, during a system restoration, to go from a shutdown condition to an operating condition and start delivering power without assistance from the electric system.

APPENDIX D

Monday Peak Tie-line Power Transfer Level (New Brunswick - New England)

Date	NE	Date	NE	Date	NE	Date	NE
97/06/10	527	96/06/24	419	95/06/12	361	94/06/13	121
97/06/03	438	96/06/17	430	95/06/05	314	94/06/06	171
97/05/27	362	96/06/10	373	95/05/29	317	94/05/30	91
97/05/20	321	96/06/03	431	95/05/23	323	94/05/24	152
97/05/12	357	96/05/27	338	95/05/15	642	94/05/16	105
97/05/05	262	96/05/21	362	95/05/08	594	94/05/09	82
97/04/28	426	96/05/13	360	95/05/01	662	94/05/02	148
97/04/21	558	96/05/06	348	95/04/24	597	94/04/25	112
97/04/15	545	96/04/29	378	95/04/18	387	94/04/18	-145
97/04/08	697	96/04/22	509	95/04/10	638	94/04/11	163
97/04/01	384	96/04/15	503	95/04/03	400	94/03/28	284
97/03/24	322	96/04/09	470	95/03/27	424	94/03/21	183
97/03/17	224	96/04/01	542	95/03/20	404	94/03/14	375
97/03/18	224	96/03/25	190	95/03/13	425	94/02/28	325
97/03/10	323	96/03/18	199	95/03/06	428	94/02/21	339
97/03/03	421	96/03/11	0	95/02/27	73	94/02/14	295
97/02/24	182	96/03/04	494	95/02/20	452	94/02/07	163
97/02/17	274	96/02/26	422	95/02/13	379	94/01/31	-65
97/02/10	446	96/02/12	526	95/02/06	35	94/01/24	61
97/02/03	461	96/02/05	466	95/01/30	424	94/01/20	86
97/01/27	0	96/01/29	539	95/01/23	573	94/01/17	-58
97/01/20	547	96/01/22	196	95/01/16	413	94/01/20	86
97/01/13	426	96/01/15	120	95/01/11	36	94/01/07	-40
97/1/6	336	96/01/08	115	95/01/09	304	94/01/10	-47
96/12/31	360	96/01/02	45	95/01/03	335		
96/12/30	650	95/12/27	166	94/12/28	367		
96/12/16	608	95/12/18	227	94/12/19	382		
96/12/09	428	95/12/11	321	94/12/12	398		
96/12/02	615	95/12/04	302	94/12/05	355		
96/11/25	52	95/11/27	187	94/11/28	369		
96/11/18	0	95/11/20	154	94/11/21	502		
96/11/12	82	95/11/06	86	94/11/14	330		
96/11/04	329	95/10/30	268	94/11/07	367		
96/10/28	290	95/10/23	267	94/10/31	259		
96/10/21	-40	95/10/16	260	94/10/24	347		
96/10/15	60	95/10/10	235	94/10/17	232		
96/10/07	-52	95/10/02	299	94/10/11	222		
96/10/08	169	95/09/25	352	94/10/03	256		
96/09/30	14	95/09/18	337	94/09/26	297		
96/09/16	328	95/09/11	335	94/09/19	287		
96/09/09	336	95/09/05	329	94/09/12	288		
96/09/03	417	95/08/28	353	94/08/29	695		
96/08/26	555	95/08/21	371	94/08/22	671		
96/08/19	538	95/08/15	249	94/08/15	659		
96/08/12	622	95/08/14	62	94/08/08	679		
96/08/05	696	95/07/31	367	94/07/25	537		
96/07/29	448	95/07/24	477	94/07/11	674		
96/07/22	459	95/07/17	485	94/07/04	82		
96/07/15	422	95/07/10	227	94/06/27	446		
96/07/08	417	95/06/26	327	94/06/20	443		
96/07/01	620	95/06/19	417	94/06/13	106		

Table D-1 Monday Peak Power Transfers from NB to NE [38]

APPENDIX E

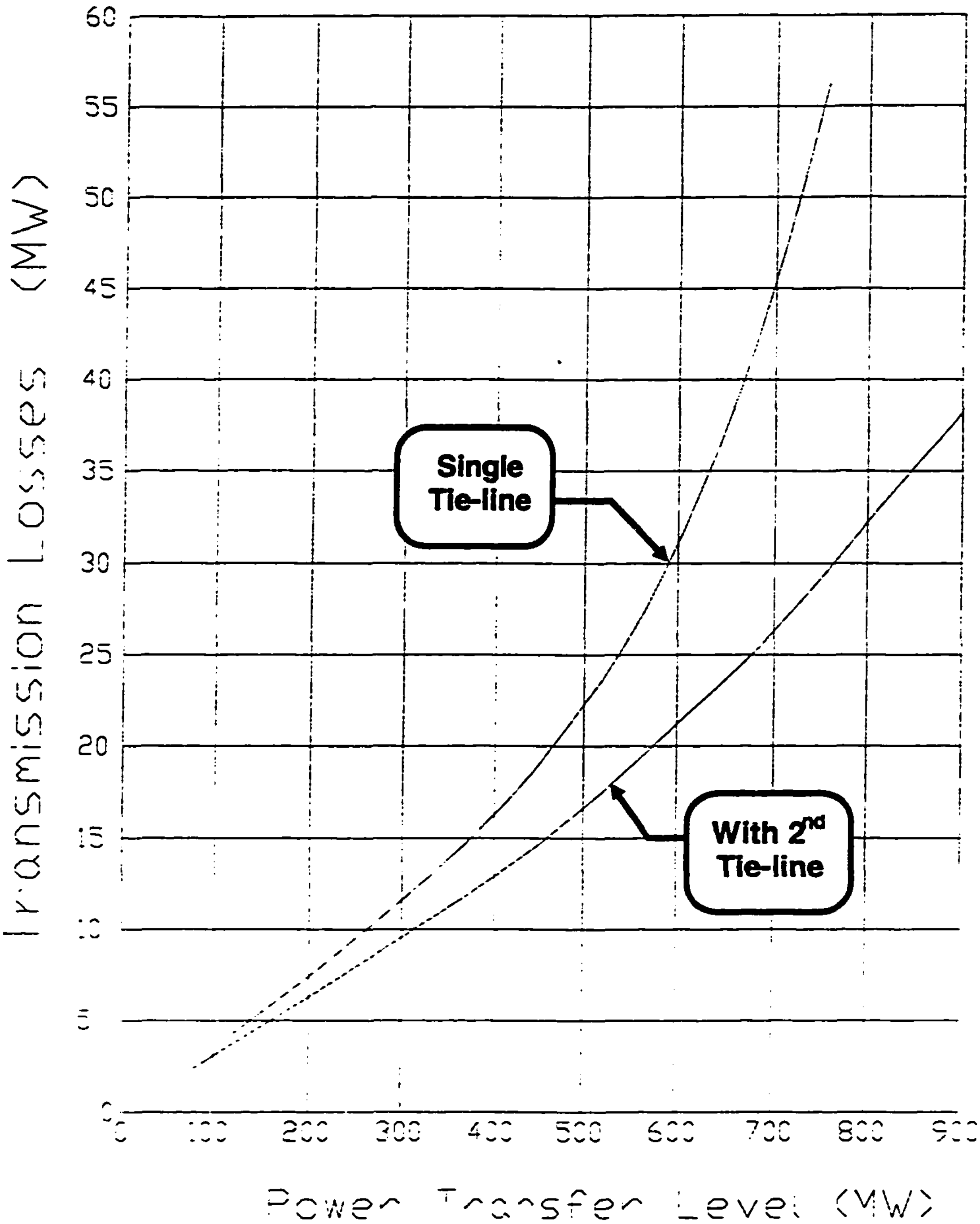


Figure E-1 Quadratic Transmission Losses Curves [40]

APPENDIX F NPCC SPS Review Procedure

NPCC has a procedure for the review of new or modified special protection systems. Any new SPS, or modification to an existing SPS such as the addition of new sources of generation rejection, must be studied and approved by the ISO and proposed to the following committees [33]:

TFCP	-	Task Force in Coordination of Planning
TFSS	-	Task Force on System Studies
TFCO	-	Task Force on Coordination of Operation
TFSP	-	Task Force on System Protection
RCC	-	Reliability Coordinating Council

The NPCC, SPS modification procedure is given in the form of the flow diagram illustrated in Figure 5-1 [33].

PROCEDURE FOR NPCC REVIEW OF NEW OR MODIFIED BULK POWER SYSTEM SPECIAL PROTECTION SYSTEMS

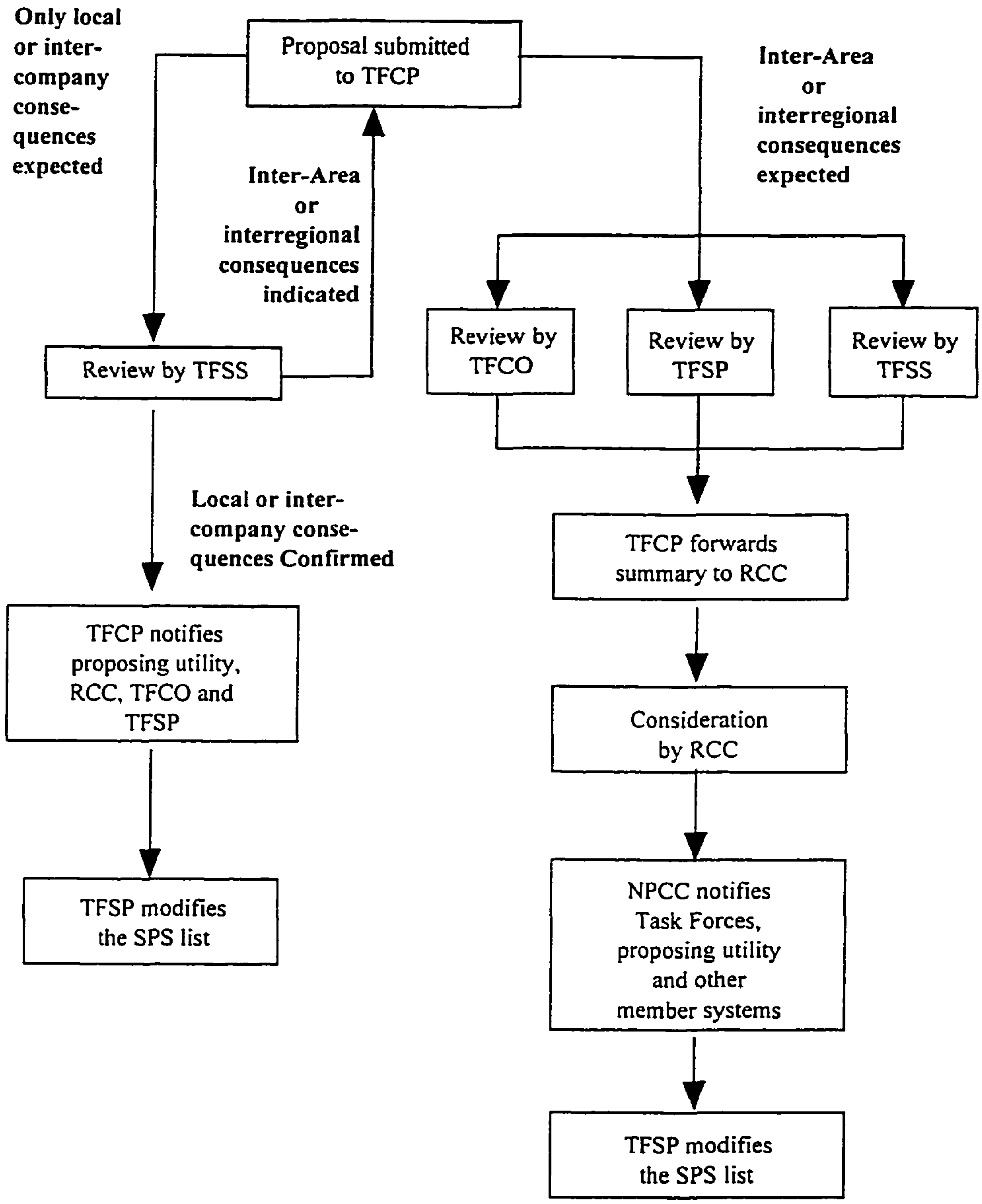
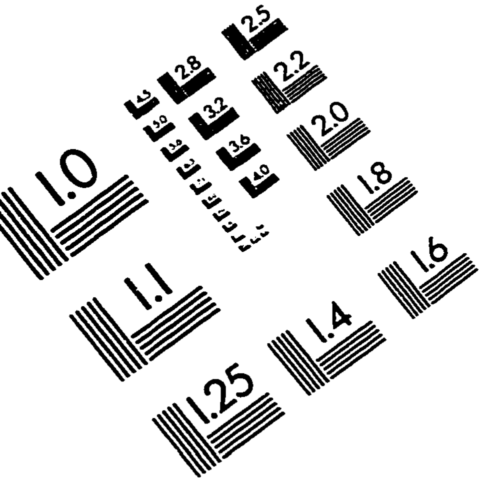


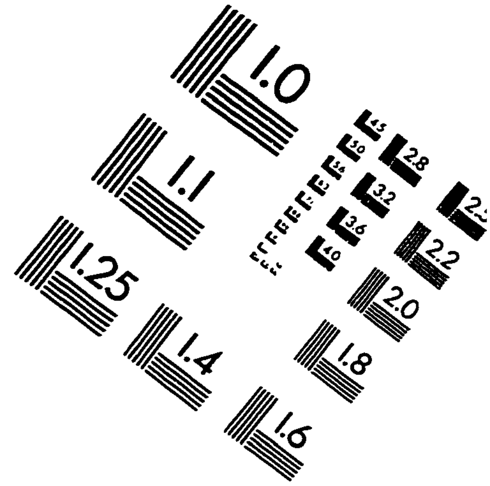
Figure F-1 NPCC SPS Modification Procedure

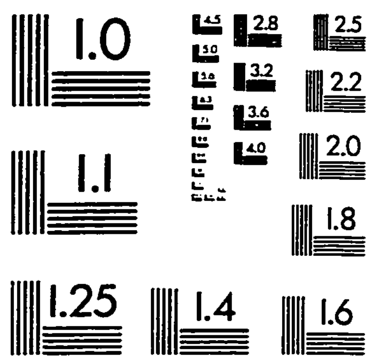
VITA

Candidates full name:	John Kyle Earle P. Eng.
Place of Birth:	Saint John, N.B.
Date of Birth:	January 27, 1965
Address:	561 Westmorland Road Saint John N.B. Canada E2J - 2G6
Educational Institutions:	University of New Brunswick Fredericton N.B., Canada Bachelor of Science in Engineering Electrical Engineering (1992)
	New Brunswick Community College Saint John N.B., Canada Diploma in Electronic Engineering Technology (1987)

IMAGE EVALUATION TEST TARGET (QA-3)







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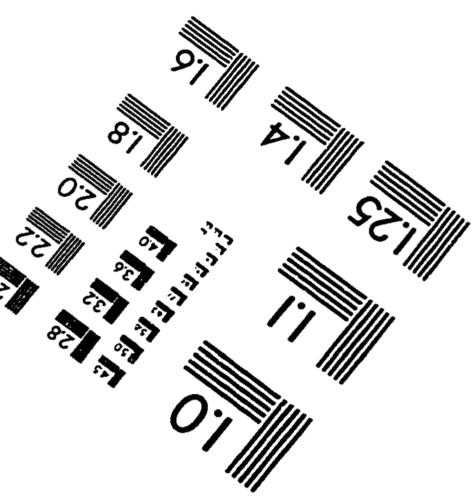
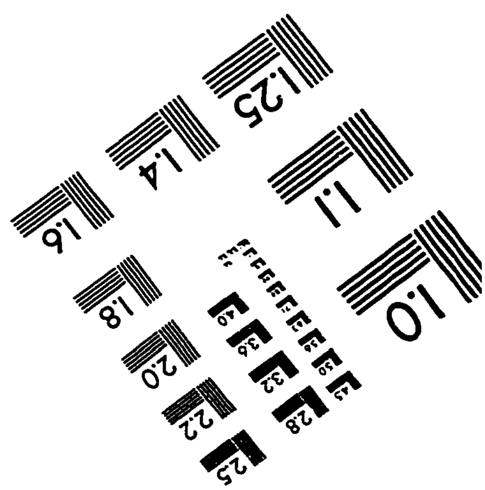
6″





APPLIED IMAGE, Inc
1653 East Main Street
Rochester, NY 14609 USA
Phone: 716/482-0300
Fax: 716/288-5989