Systems Dynamics Modeling for Understanding Transmission Investment Incentives

By

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To the Faculty of Washington State University:

The members of the Committee appointed to examine the dissertation of HUI YUAN find it satisfactory and recommend that it be accepted.

Chair

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SYSTEMS DYNAMICS MODELING FOR UNDERSTANDING TRANSMISSION INVESTMENT INCENTIVES

Abstract

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Over the past several decades the electric power industry has undergone a broad restructuring process of attempting to introduce competition and improve economic efficiency. This restructuring has liberalized the traditional vertically integrated industry by separating many traditional engineering functions from central decision-making in planning and operation. This thesis focuses on transmission investment incentives under these restructured environments, which have been a particular concern. Specifically, this work contributes the following:

1. Developed a dynamic model with information feedback. Considering the characteristics of the restructured industry, the system dynamics approach is used as a tool to model the Western Electricity Coordinating Council transmission planning process and analyze the effects of different incentives on its transmission investments. This is the first time that the system dynamics is used for transmission planning analysis.

2. Introduced methods to model transmission capacity expansion with soft constraints. In order to coordinate the contradiction between transmission expansion and investment, soft limits are utilized in the optimal transmission expansion formulation. This technique provides a systematic method to avoid alternating between over and under investment.

3. Developed a tool for studying the effects of different incentives on transmission investment. System dynamics models are constructed and simulated under different market structures. The analyses and comparisons based on the simulations help us better understand the effects of different incentives on transmission investment.

4. Proposed an improved process for transmission planning. With the developed models, the system information feedback control and complex inter-relationships between different market components can be taken more fully into consideration. The transmission planning process better reflects real system conditions. This can reduce uncertainties and allows a risk-based model for decision-making.

5. Suggests a framework for improving market design and regulations. Considering the complication of the restructured power industry, system dynamics modeling does not need to be limited to transmission planning and resource planning. It can also be used to test the effects of different policies or structures on the markets.

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NOMENCLATURE

m	the number of nodes
n	the number of areas
C_1	generation production cost parameter matrix for quadratic coefficients
$\underline{C}_2$	generation production cost parameter vector for linear coefficients
$\underline{P}$	generation active power production vector
$\underline{P}_D$	load active demand vector
$\underline{P}_L$	line active flow vector
$\underline{P}_L^{max}$	line active flow limit vector
$\underline{P}^{max}, \underline{P}^{min}$	genertor active power production upper,lower bound vector
P_i	genertor active power production at node i
$P_{D,i}$	load active power demand at node i
A	bus-unit incidence matrix
B	bus-load incidence matrix
λ	lagrangian multiplier for power balance constraint
$\underline{\pi}^+, \underline{\pi}^-$	lagrangian multiplier vector for line active flow limits
SF	shift factor matrix
LMP_e	energy term of locational marginal price
LMP_c	congestion term of locational marginal price
LMP_l	loss term of locational marginal price
$\Delta LMP_\ell(t)$	LMP difference on line ℓ at time point t
$\Delta LMP_{\ell'}$	LMP difference on line ℓ'

$P_\ell(t)$ active power flow on line ℓ at time point t

t_ℓ duration of congestion rent calculation on line ℓ

$q_{\ell'}$ quantity of allocated FTR on line ℓ'

$H_{c,\ell'}$ annual average congestion hours on line ℓ'

η load growth rate

L_ℓ length of line ℓ

υ_ℓ per MW-mile investment cost on line ℓ

τ annual loan interest rate

ρ annual profit rate

σ annual inflation rate

t_j number of years after a line's expansion

$T_{m,\ell}$ economic life of transmission investments on line ℓ in years

δ_ℓ ROE value granted to investment on line ℓ

$\Delta\delta_\ell$ ROE adders' value granted to investment on line ℓ

$\overline{LMP_i}$ annual average LMP for area i

$\overline{LMP}^{max}$ maximum annual average LMP in the system

dR alleviated annual congestion rent

AR^I annual congestion rent without transmission investment

AR^{II} annual congestion rent with transmission investment

IC initial investment costs

IG investment gain from allocated FTRs

PC present value of initial investment costs

Dedication

This dissertation is dedicated to my immediate family members: my mother, father, sister, brother-in-law, and wife. Thank you all of your love, support, and sacrifice throughout my life

CHAPTER ONE

BACKGROUND AND MOTIVATION

Because the electric power industry has been thought of as a “natural” monopoly industry, it remained vertically-integrated and centralized until recently [1]. With the development of new economic theories on power system operation [1-3], economists proposed that the generation system could be competitive and separated structurally and functionally from transmission and distribution systems. White [3] pointed out that the primary stimulus for restructuring the US electric power industry was the gap that existed in some parts of the US between the price of generation services before and after the restructuring.

The first restructuring initiative in the industry was the Public Utility Regulatory Policies Act of 1978 (PURPA) [4-5], which created a market for non-utility electric power producers by forcing traditional utilities to buy power from them. The Energy Policy Act of 1992 [6] removed obstacles to wholesale power competition in the Public Utilities Holding Company Act (PUHCA) and created a framework for a competitive wholesale electricity generation market. In order to remove impediments to competition in the wholesale electricity markets and to bring more efficient, lower cost power to customers, FERC issued Order No.888 [7] and No.889 [8] in 1996, which required all public utilities to provide Open Access Non-discriminatory transmission services to transmission customers and an OASIS (Open Access Same-time Information System) to enable customers to obtain these services. In order to improve engineering and economic efficiencies in the transmission system and correct perceived or real discrimination by transmission owners, FERC issued Order No. 2000 [9] on December 20, 1999 to encourage all transmission owners to voluntarily join Regional Transmission Organizations (RTOs). The Energy Policy Act of 2005 [10] promotes market transparency and discourages market manipulation.

Through the above mentioned processes, the originally vertically-integrated and centralized electric power industry has begun to be gradually restructured to a non-integrated and decentralized structure in the US. In many cases, the generation, transmission and distribution assets no longer reside in the same company. Accordingly, the transmission expansion process must change to reflect this restructuring. The following describes the general approach proposed in this thesis that attempts to fully incorporate market impact on planning decisions.

1.1 Transmission planning

Transmission planning is a process to find the best solutions to when, where and how much capacity should be expanded. This process occurs over some specified planning horizon and must satisfy given networks constraints. Transmission planning has had, and continues for the most part, to have the following characteristics:

- The planning process is based on a single-stage scenario analysis, which considers only one time horizon [11]-[17]. Scenario based transmission planning focuses on detailed analysis but is not responsive, which means the analysis is valid for a specific set of events. Moreover, this type of approach is a centralized decision making process. All major components in the system are specifically planned and implemented by utilities with coordination through the regional councils. This characteristic suited the electric power industry before restructuring since the industry was vertically-integrated and centralized. It does not meet the requirements of a restructured industry where critical components of the planning process, such as, generation expansion, are not under the control of the utility. With large numbers of market players, there is necessarily greater uncertainty under restructured markets. Moreover, there is no feedback in the scenario based transmission planning process. That is, the plans are made open-loop and do not respond naturally to events, or the impacts of the planning decisions, as should happen in an open market. In practice, events are also greatly affected by the previous planning decisions (the decision feedback control effects) and ignoring this effect, can easily leads to erroneous conclusions. In essence, the scenario based analysis focuses on reliability [18-22], but the market effects of risk and uncertainty are not taken into consideration.

- To provide improved decisions over time, some researchers have introduced multi-stage transmission planning, which considers more than just one time horizon in the planning process. Multi-stage planning [23-28] is a more involved process compared to the single-stage planning, but it is still not a planning process with decision feedback control since while it is staged, there is no true feedback. We refer to it as a pseudo dynamics approach.

Some researchers [29] classify the transmission planning as static or dynamic according to the treatment of the study period: the planning is static if the transmission expansion is set for a single year in the planning horizon, otherwise it is dynamic. This definition more properly classifies transmission planning as single-stage or multi-stage but not static or dynamic. We believe that a true dynamic process of planning should satisfy the following two criteria: (1) the modeled system is time-series (often in months or years); and (2) the system status evolves with time through a closed information feedback loop. This classification better reflects the characteristics of the transmission planning process in that there is information feedback over the given planning time horizon. The advantage of planning with true feedback is one of both responding better to unforeseen events and reducing future uncertainty as one expects in a feedback control system. A planning process with true feedback might be described by Fig. 1.1.

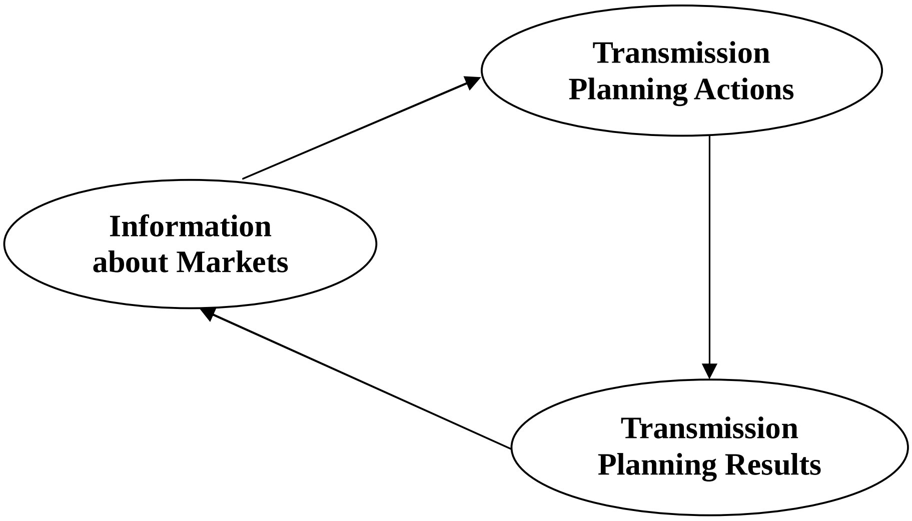

Fig. 1.1 Dynamic transmission planning process

1.2 Background on transmission investment incentives

Generally speaking, transmission investment can be categorized into the following three forms [30]:

- System-wide reliability enhancement and improved system economy. This type of investment existed long before electric power industry restructuring and still exists today. The project costs are allocated among sub-regions through a costbenefit analysis [31] and the investors recover their investment and gain profits through a cost-based rate of return.

- Voluntary transmission investment, which includes generation interconnection and load connection requests. Voluntary transmission investment is sponsored by those who will directly gain the benefits from the investment, so there is little or no incentive problem for this kind of investment. We do not consider this form of investment in this research.
- Merchant transmission investment. This relies on the existence of competitive electric power markets and a free entry to the transmission provision markets. This type of investment did not exist before the industry restructuring and only emerged with the industry restructuring. In the Locational Marginal Price (LMP)-based wholesale electricity markets, which is the primary situation in the US, the merchant transmission investors rely on the congestion rents gained through allocated Financial Transmission Rights (FTRs)/Congestion Revenue Rights (CRRs)/Transmission Congestion Contracts(TCCs) to recover their investments and make profits [32-34].

Based on the above three transmission investment mechanisms, we can state that there are two transmission investment incentives of interest: one a cost-based rate of return and the other FTR-based congestion rents. Under cost-based rate of return, the investors recover their investment and make profits through the set rate of return in the given time horizon. Investments have to be justified to the utility commissions based on local regulations. Under FTR-based congestion rent incentives, investors are allocated some quantity of FTR [35]. Through the allocated FTR, one can earn income from the congestion rent equal to the sum of the product of the FTR and the LMP differences for the allocated injection and withdrawn node pairs.

1.3 Challenges introduced by restructured markets for transmission planning

With electric power industry restructuring, the traditional transmission planning decision framework is no longer adequate. Before restructuring, the planning process only included the regulators and utilities, which can be fully overseen, but today the planning process includes the regulators, a large number of market players and, of course, consumers. These result in numerous inter-relationships that cannot be centrally managed. There are many components to the markets and more complicated inter-relationships between these components in the markets. As such, the planning process must become a more decentralized structure. Moreover, in this new structure, not all components of the system can realistically be fully considered in the planning process. Thus, there are more uncertainties, or greater unknowns, lying outside the decision process. The transmission planning process should manage these uncertainties or risks effectively.

In Figure 1.3, participants in the restructured electric power industry are categorized into three categories:

- Regulators, including Department of Energy (DOE), Federal Energy Regulatory Commission (FERC), and State governments or their agencies. Together they regulate the electric power industry and ensure fairness in the industry.
- Market Monitors, including RTOs (Regional Transmission Organizers) or ISOs (Independent System Operators). Under authority delegated from regulators, they

monitor the day-to-day system operation and the long-range planning for the wholesale electricity markets so that the markets can run safely, reliably, and economically both in the short term and in the long term.

- Market Players, including generating companies (GenCos), transmission companies (TransCos), grid companies (GridCos), load serving entities (LSEs), brokers, large customers, ordinary customers, and independent investors. In the markets, some make money through investment, service or production, and others receive service.

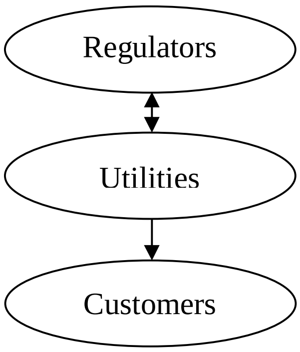

Fig1.2 The integrated structure before restructuring

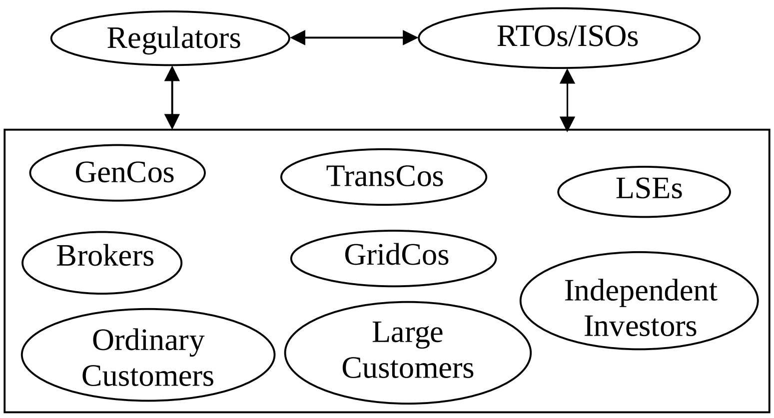

Fig 1.3 The decentralized structure after restructuring

1.4 Historical use of System Dynamics in electric power industry

System Dynamics (SD) was developed by MIT Professor Jay W. Forrester in the mid-1950s. It provides a method to understand the dynamic behavior of complex systems from a whole system point of view. This method is based on a decision framework – dynamics. It has been used for resource planning in the electric power industry. Ford [36] summarized the publications on the applications of SD to electric power till 1996, and these 33 publications are classified into 7 categories: the national model; individual companies and state agencies; Pacific Northwest hydroelectric system; electric cars and the electric utility; privatization (UK) and deregulation (USA); system dynamics models at forums or workshops; emerging areas (electricity & water). Ford [37-38] constructed SD models to simulate the general patterns of power plant construction in the restructured electric power industry. Dimitrovski, et al [39] constructed SD models based on the WECC system to simulate the interplay between the economic, technical and environmental factors in the restructured industry over a long-term horizon. Olsina, et al. [40] constructed a general model to simulate the long-term behavior of liberalized power markets.

The long-term transmission planning process for the restructured industry is far more complicated than before restructuring, with many more participants and complicated interrelationships. Through system level modeling, SD provides a powerful tool to address the transmission planning process in the post restructured industry.

1.5 Contributions of this thesis

In this research, SD is used as a tool for modeling transmission planning and to test the effects of different transmission investment incentives in the transmission planning process. The primary contributions of this thesis are outlined in the following:

- **Developed a dynamic model with information feedback –** Considering the characteristics of the restructured electric power industry, the SD approach is used as a tool to model the WECC transmission planning process and analyze the effects of different investment incentives on the WECC transmission planning. This is the first time that the system dynamics is used for transmission planning analysis.
- **Introduced methods to model transmission capacity expansion with soft constraints –** In order to coordinate the natural contradiction between transmission capacity expansion and investment on the expansion, soft limits are utilized in the optimal transmission expansion formulation. This technique provides a systematic method to avoid oscillating between over and under investment.
- **Developed a tool for studying the effects of different incentives on transmission investment –** SD models are constructed and simulated under different incentives. The analyses and comparisons based on the simulation results help us better understand the effects of different incentives on transmission investment.
- **Proposed an improved process for transmission planning –** With the developed WECC model, the system information feedback control and complex

inter-relationships between different market components can be taken more fully into consideration. With the help of detailed simulations, the transmission planning process better reflects the real system conditions after restructuring. This can reduce uncertainties and allows a risk based model for decision-making.

- **Potential for improving market design and regulations –** Considering the complication of the restructured electric power industry, the SD modeling should not be limited to transmission planning and resource planning. It can also be used to test the effects of different policies on the markets or the effects of different market structures. The restructuring of the electric power industry does not mean an elimination of regulations in this industry. As there are still many possibilities where different market players can exercise market power and manipulate the market, careful regulations are still necessary. These regulations are different from those before the restructuring in their focus on attempting to encourage competition and anticipating counter productive relationships between different market components. SD modeling provides a method to test the effects of different regulations on the market players, hopefully, leading to better regulation rules in the markets.

CHAPTER TWO

SYSTEM DYNAMICS METHODOLOGY

System Dynamics (SD) is a methodology for studying and managing complex feedback in information systems attempting to model both management and technical issues. In this chapter, this methodology will be introduced and discussed in detail.

2.1 System Dynamics definition and characteristics

SD is *a branch of control theory which deals with socio-economic systems and that branch of management science which deals with problems of controllability* [41]. SD differs from typical detailed engineering models in that it emphasizes system information feedback and the system dynamics brought by the information feedback. It is not intended as a model for detailed point predictions. The "*dynamics*" in this transmission expansion research is not traditional power system dynamics arising from system faults or disturbances but rather the "*dynamics of performance*" over a long time period. It has meanings on two fronts:

- The system is modeled as a time series and is not limited to a fixed time or equilibrium point. In another word, the model is time varying, and there is more than one equilibrium point in the dynamic equilibrium model. Though most existing electric power markets literature is based on static equilibrium models, there are still some researchers who take dynamic perspectives. Cho and Meyn [42] used a dynamic newsboy model to research the market clearing price in an electricity spots market. In order to capture the dynamic nature of power networks, Mookherjee, et al [43] proposed a general and complete model of Cournot-Nash competition on electric power networks. Garcia, et al [44] developed a simplified oligopoly model where hydro generators engage in dynamic Bertrand competition. Garcia and Shen [45] developed a dynamic oligopoly model with a stochastically growing demand to analyze the inherent tension in market-based incentives for capacity expansion where capacity additions take place over long time lags. All these researchers modeled the dynamic characteristics of liberalized electric power industry, which are inherent to the researched problems.

- The system has a closed-loop information-feedback control mechanism and any decision will cause a reaction in subsequent decisions. In SD, the system status changes with time through the closed-loop information-feedback that is characteristic of, and embedded into, the system.

The following two figures describe two different models: one is an engineering model for the power system frequency control; and the other is a SD model for the long-term transmission planning. In the two figures, we can see that although both engineering model and SD model have feedback, there is not a referenced destination value as input in the SD model. Also whether the information feedback control is positive or negative, depends upon the causal loop inherent to the SD model.

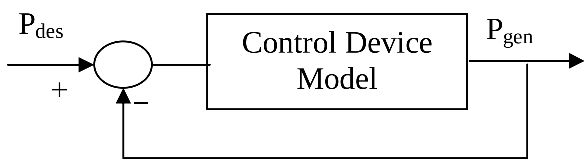

Fig 2.1 Structure of engineering model for power system frequency control

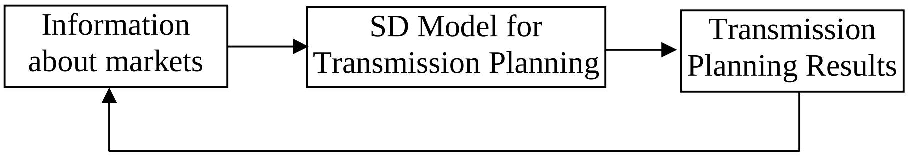

Fig 2.2 Structure of system dynamics model for transmission planning

SD, as used in this research, is a methodology of feedback system analysis and control for the long-term transmission expansion under different policies (investment recovery incentives) in the restructured electric power industry. It deals with the time-varying interactions between different parts of the transmission expansion system over a specified time of study.

2.2 Advantages and disadvantages of SD

The advantages of System Dynamics include the following:

- It provides a methodology to investigate a high level system description with feedback. SD is not a tool to build a detailed model and the purpose of SD modeling is not for point prediction but rather insight into overall performance. For a power system with thousands of buses and transmission lines, the model will not represent these components in detail. Instead, a simplified model with several lumped areas connected by equivalent tie-lines will be developed.
- It provides a methodology to capture the characteristics of a complex, nonlinear information-feedback control system. The inter-relationship between any two components in a modern system is often nonlinear. For a system with a large number of such components, it is very difficult to describe as a single nonlinear function. Even if some nonlinear functions are formulated to describe such a

system, with some simplifications, it is still very difficult to solve these models. SD provides a methodology to formulate a model that includes important components in the system and by some rules that capture their relationships. Through the modeling of such a system, the simulation results will reflect the characteristics of the system evolving over time.

- It provides a methodology for policy or structure judgment in an information-feedback control system through experiments. In a SD model, a new policy or a new system structure can be included in the model. The model simulation results will reflect the effects of the new policy, or the new system structure on the system, which helps judge a policy or a system structure.

The disadvantages of SD are as follows:

- The model builder must have a fairly good understanding of the system being researched and its characteristics. Because the SD model is based on high level abstractions rather than a detailed description of the system, the modeler must have enough information and insight to describe the system. Otherwise, the model will not capture the actual system characteristics and the simulation results will simply misinform the policy maker.
- The SD modeling tends to be system specific or case by case. It is generally difficult to build a general model that could be reused like a function, such as, load flow in the power system.

- The SD modeling does not suit detailed research on large scale problems. It does provide insight into the system from the system level but not insight at say the bus level for a power system with thousands of buses.

The electric power industry after restructuring is clearly a complex information-feedback control system. For example in the transmission planning problem of concern in this thesis, the congestion rents in the markets will be affected by transmission capacity expansion in the system. In turn, the rents will affect the transmission expansion due to transmission investment recovery. If this feedback interaction is ignored and the policy is based on an analysis without considering this interaction for the transmission expansion, it is very likely that there will be insufficient congestion rent for transmission expansion investment recovery. SD provides a methodology to test the effects of different policies (transmission investment recovery incentives) on a researched system. Hence, we can better manage system development as well as future uncertainties and financial risks.

2.3 Analysis tools

SD is chosen as a tool for our long-term transmission planning analysis to address the following concerns: unexpected outcomes arising from ignoring feedback and management of uncertainty and risk. In order to better understand the effects of system feedback control on system performance, a simple example is given. In this example, it is assumed that a product is produced to meet the market demand. If the production is more than the market demand, then the extra product goes into inventory; or else the product from inventory will make up the gap between production and demand. This example is realized by the SD software, Vensim. Two Vensim models are built: one is the case without feedback; and the other is with feedback. Fig. 2.3 and Fig. 2.4 show these two Vensim models separately.

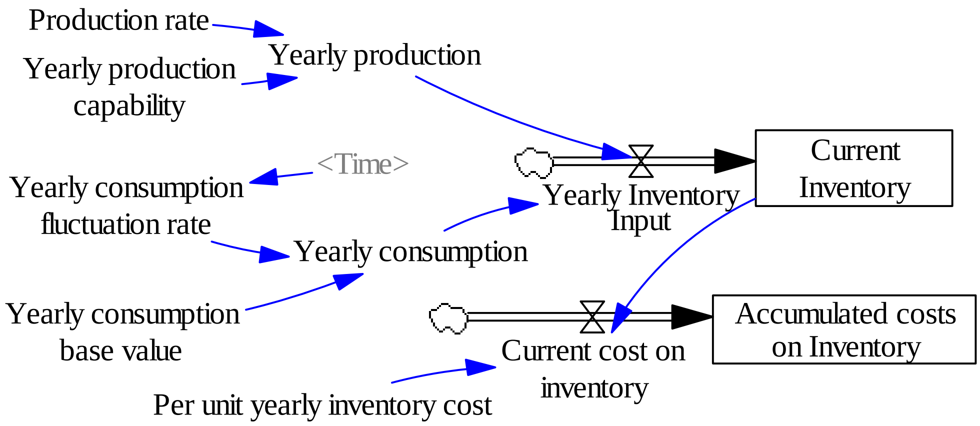

Fig. 2.3 The Vensim model for system inventory cost - without feedback

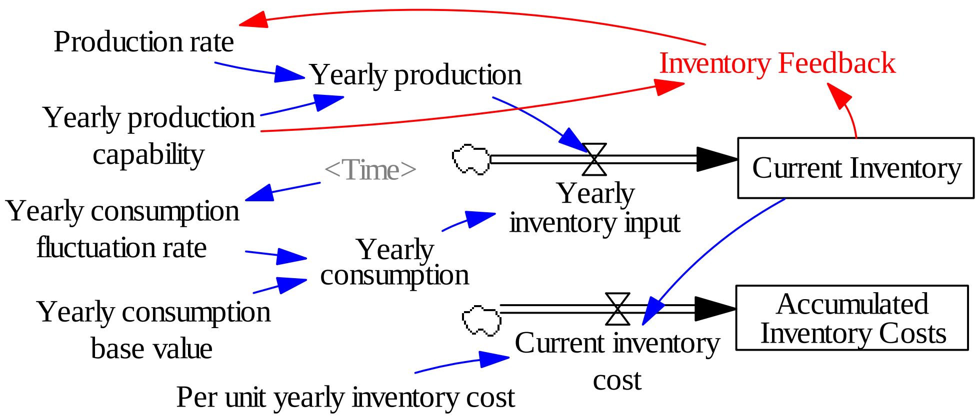

Fig. 2.4 The Vensim model for system inventory cost - with feedback

The simulation horizon is set to 50 years. An integration step of 1/2 year is chosen to solve the Delay Differential Equations (DDEs) by means of the Euler algorithm in the Vensim model. The feedback comes from the **Current Inventory** in the model. Here, we just want to show the effects of feedback control, so fairly simple feedback control logic is utilized in this model. In the case without feedback the production rate is constant, while in the case with feedback it depends on the **Current Inventory** values: when inventory can meet the market demand, the production rate is set to zero; or else it is the same value as in the case without feedback. Fig. 2.5 and Fig. 2.6 separately show the **Current Inventory** over time for the case without and with feedback. Fig. 2.7 and Fig. 2.8 separately show accumulated costs over time for the case with and without feedback. Fig. 2.5 – Fig. 2.8 clearly show that the inventory and the inventory costs in the case with feedback are much lower than those in the case without feedback. Fig. 2.9 and Fig. 2.10 better illustrate this observation. The Ratio in Fig. 2.9 and Fig. 2.10 is defined as

$$Ratio = \frac{simulation\ results\ from\ the\ case\ without\ feedback}{simulation\ results\ from\ the\ case\ with\ feedback} \tag{2.1}$$

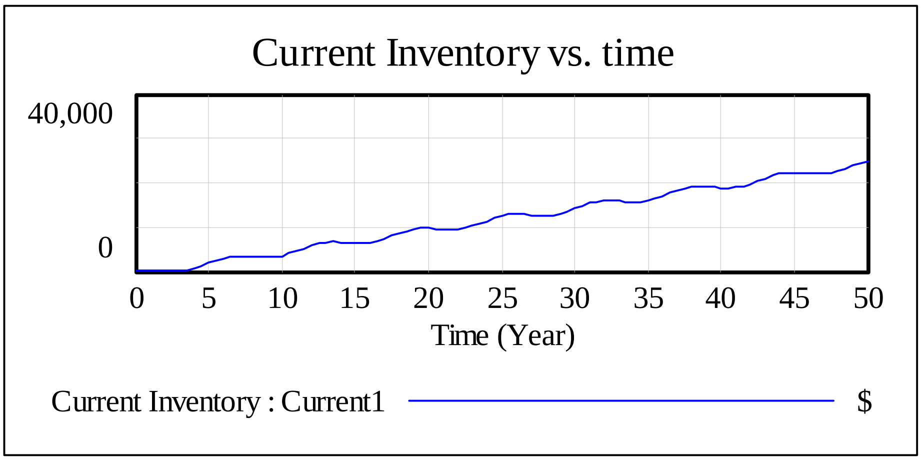

Fig. 2.5 Current inventory over time - without feedback

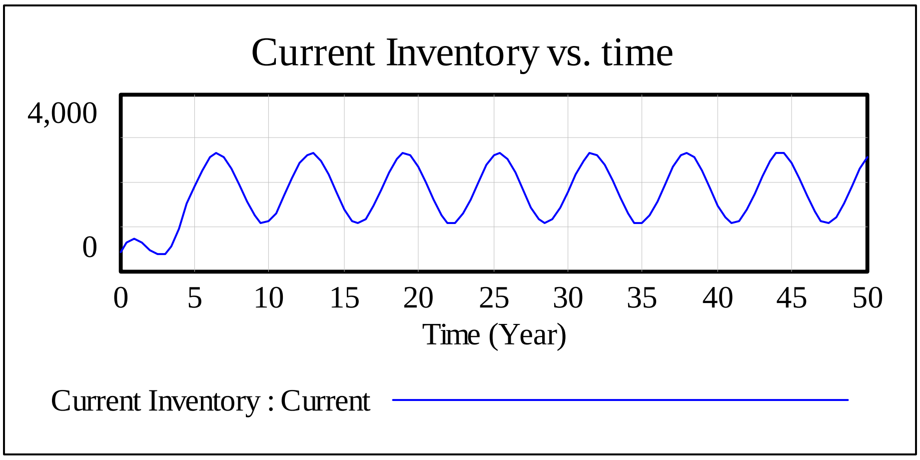

Fig. 2.6 Current inventory over time - with feedback

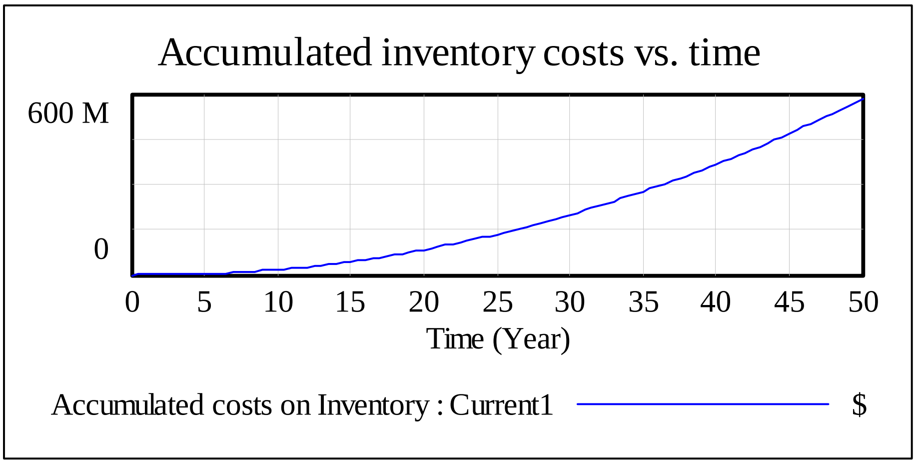

Fig. 2.7 Accumulated inventory costs over time - without feedback

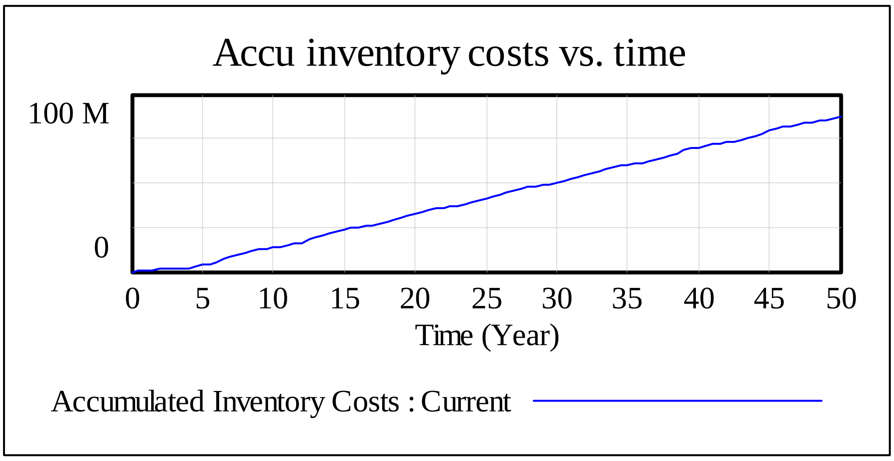

Fig. 2.8 Accumulated inventory costs over time - with feedback

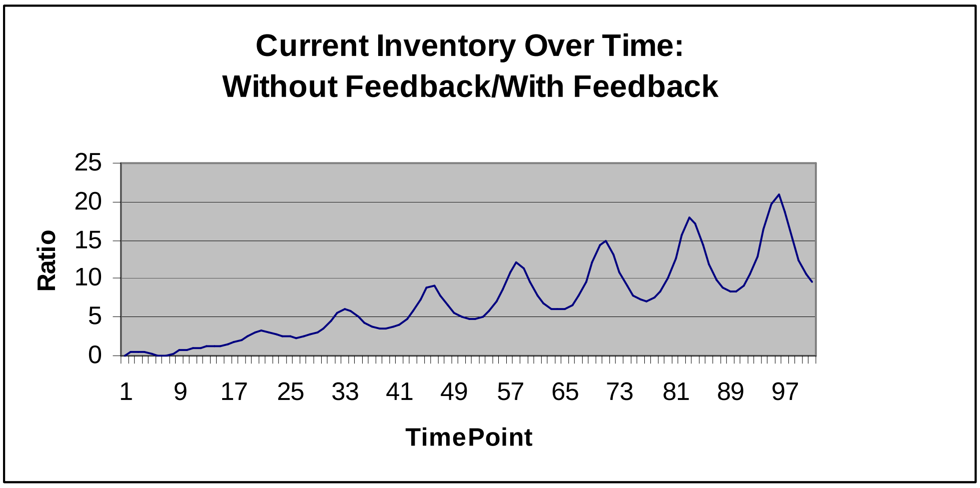

Fig. 2.9 Current Inventory Comparison between the cases with and without feedback

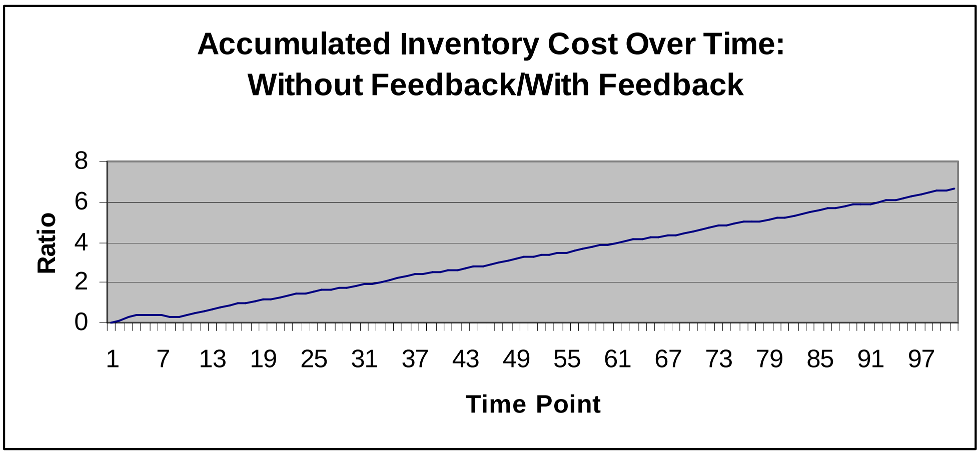

Fig. 2.10 Accumulated Inventory Cost Comparison between the cases with and without feedback

There are several commercial software systems specifically designed for the building and use of SD models, including DYNAMO, DYSMAP, iThink/STELLA, PowerSim and Vensim. The SD software provides a graphically oriented front end for the development of SD models: stock and flow for the modeling with the mathematical equations implemented through dialog boxes accessible from the stock and flow diagrams, so that the model is clean, simple and easy-to-follow. This characteristic can be easily seen in the SD modeling example realized by Vensim in Fig. 2.3 and Fig. 2.4. Modeling through flow diagrams provides a good means for communication. Still, this kind of software provides only simple mathematical functions, such as *abs*, *sin*, *min* and *max*, and does not allow for more analytical descriptions. Among commercial software, Vensim is the only one to allow external function calls. Thus, one can combine user-defined functions in the model and provide more advanced relationships, including optimization [46]. In this transmission investment research, since a number of complex computations are required, such as DC-OPF, optimal expansion, and so on, Vensim is chosen.

CHAPTER THREE

MODEL DEVELOPMENT

This chapter introduces the overall model development and describes in detail the modeling assumptions.

3.1 Modeling objectives

From an SD modeling point-of-view, an elaborate and accurate model has little meaning if it relates to behavior that is of no practical consequence to the system or if it depends greatly on parameters that cannot be reasonably found. On the other hand, a simple and even inaccurate model may be tremendously valuable if it yields even a little understanding of the reasons for success and failure of an approach [47]. The objective of our system dynamics model is not for point prediction but for system characteristic performance. By better understanding the characteristics of an information-feedback on transmission investment and congestion, more suitable incentives (policies) will be found and hence better decisions could be made in the long-term transmission expansion. The overall objective of the modeling is to improve the long-term transmission planning in a large system, such as, the WECC (Western Electricity Coordination Council). The first and most important requirement of the model is that it should capture the overall characteristics of the system performance. Thus, the standard for evaluating the SD model will be less on precision and more on capturing the characteristics of the system. For the WECC system model in this research, the network will be based on DC-OPF. If the model can simulate the area generation output, line flow directions and values, line flow congestion patterns and hours, and the resulting LMP differences in different seasons within some reasonable error ranges, then the model will be claimed to be valid.

3.2 Modeling structure

Based on the previous discussion, the developed model will be simplified based on the following assumptions:

1) **The modeled system, WECC, is assumed to be run as an LMP based wholesale electricity market**. Today, WECC is an organization to promote the reliability and coordinated planning of interconnected electric power system in provinces of Alberta and British Columbia, Canada, the northern portion of Baja California, Mexico, and all or portions of the 14 western states in between. In WECC there is only one ISO – CAISO which provides services for the wholesale electricity markets in the California area. In this research, we assumed that eventually there will be a wholesale electricity market covering the bulk of the WECC area, which will be an LMP based market. This market will be operated by some future RTO.
2) **Transmission upgrade or expansion is congestion-driven**. We know that traditionally the objective of transmission upgrades or expansion is either to maintain or improve system reliability or to promote system economy. In the restructured electric power industry, there are much more electric power transactions in the wholesale electricity markets, and hence there are more possibilities for congested lines and over longer time periods. According to [48] in the eastern interconnection system, the congestion rent will be over $10 billion in 2011 high fuel price case, which is 5.1% of the total cost of served load. In the PJM interconnection RTO, its

total congestion costs increased by $271 million or 15 percent, from $1.846 billion in calendar year 2007 to $2.117 billion in calendar year 2008 [49]. This research is focused on alleviating transmission congestion, and so the transmission upgrade or expansion is congestion-driven. The expectation is that this will improve reliability and reduce costs indirectly.

3) **A year will be represented by some small set of typical days**. In general, the time horizon for long-term transmission planning spans decades, accurate data does not exist to describe every day in a year for such a study. In addition, such a simulation would be computationally intractable. Most electric power systems have a characteristic that their loading and operating conditions change with seasons. In the transmission planning process, the planners generally care about the peak load condition, since the power flow under such circumstance most closely reaches the OTC (Operating Transfer Capabilities). So in this research, each season is represented by a typical day with the highest loading conditions according to the historic data and a fixed daily load curve.

4) **The large power system is represented by a limited number of areas and equivalent tielines between these areas**. The modern electric power system often includes hundreds of generators and thousands of transmission lines, and it is not feasible to build a detailed SD model to describe each generator, load and transmission line in the system. Moreover, it is unnecessary to build such a detailed model according to the objectives of the research. In this work, the WECC will be grouped into seven areas with interties reflecting actual flows in the system. More

detailed models are certainly possible but they should not at the level of individual lines or buses.

5) **The relationship between interarea line flows and the area power injections will be approximately linear**. An approximation will be used to describe the relationship between the interarea flows and area power injections. This will be based on sensitivities from a large scale model but not strictly a load flow calculation. The need for a special approach arises due to the need to allow transmission expansion in terms of equivalent line reactance and line lengths to impact future flow patterns. Details are given in Appendix A.
6) **There is some physical time delay for the commission of expanded transmission lines.** The lifecycle of a major transmission line project includes choosing transmission routes, public information meetings, open houses and public outreach, regulatory review, environmental review, real estate issues, construction, and commission. The length of this lifecycle is project dependent and changes from project to project.
7) **Miscellaneous data**. The developed model requires extensive parameter data for investment return, area load growth, generation costs, construction costs, construction lag time, operations and maintenance fees, and so on. Details are provided in Appendix B.

SD modeling, as used in our research, is a methodology of feedback system analysis and control for the long-term transmission expansion under different policies (investment recovery incentives) in the restructured electric power industry. It deals with the time-varying interactions between different parts of this industry over a specified time of study. The SD models are composed of four different sub-models as shown in Fig. 3.1.

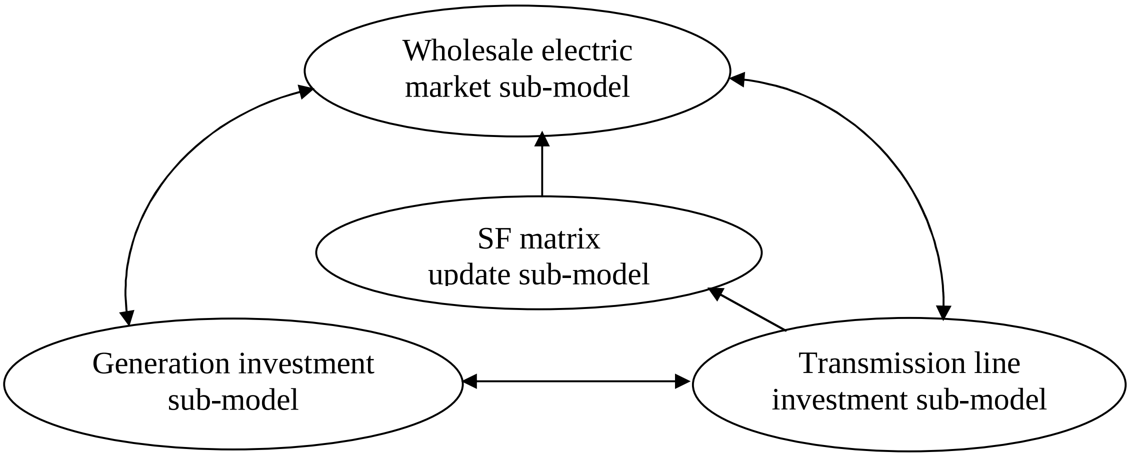

Fig. 3. 1 Structure of SD models for transmission planning

The arrows in Fig. 3.1 represent the flow of information between different sub-models. The function of each sub-model is as following:

1) **Wholesale electric market sub-model:** it models the function of wholesale competitive electric markets. GenCos submit their bids in the markets, and the markets are cleared by calculated LMPs based on our DC-OPF model.
2) **SF matrix update sub-model:** it updates the SF (Shift Factor) matrix whenever there are some upgrades or expansions on transmission lines in the modeled system. The SF matrix is a sensitivity matrix that is used to describe the relationship between power flows on transmission lines and power injections on nodes. The SF matrix is linear in our research.

3) **Transmission line investment sub-model:** it models the transmission line investment process under different investment incentives in the restructured industry, including investors' judgments, decisions, construction and commission activities.

4) **Generation investment sub-model:** it models the generation investment process under the restructured industry. The purpose of our research is to investigate the dynamic transmission investment process, but not both the generator and transmission investment dynamics in a competitive market. Here, we assume some reasonable generation investment behavior and suggest the conclusion drawn for transmission investment from such models remains sound. Specifically, we assume that the generation investment is proportional to the area annual average LMPs that are modeled in the wholesale electric market sub-model and ignore the typical boom-and-bust behavior of such investment. The generation investors will observe area LMPs in the markets through OASIS (Open Access Same-time Information System) and then calculate each area's annual average LMP. With these values, they can make their investment decisions accordingly. This is a reasonable assumption about generation investment since in the actual LMP based markets, generator investors' investment is basically based on the value of LMPs. Let the system reference annual generation capacity increase rate be ξ, and the corresponding increase rate for each area is $S_i\xi$. S_i is a generation capacity increase adjustment coefficient for each area, which is calculated in (3.1) based on the annual average LMP in each area.

$$S_i = \overline{LMP_i} \Big/ \overline{LMP}^{max} \tag{3.1}$$

where $i = 1, 2, ..., n$, and n is the number of areas. $\overline{LMP_i}$ is the annual average LMP for area i, and $\overline{LMP}^{max}$ is the maximum annual average LMP in the whole system, which is defined as

$$\overline{LMP}^{max} = max(\overline{LMP_1},\ ...,\ \overline{LMP_n}) \tag{3.2}$$

3.3 Transmission investment incentives

The following describes transmission incentives from FTR-based congestion rents for merchant investments and cost-based ROE (Rate-of-return On Equity) for regulated investments.

3.3.1 FTR-based congestion rent

Merchant transmission investment is financed through FTRs issued by the RTOs/ISOs as entitlements to congestion rents. Financial Transmission Rights provide holders the rights to receive financial benefits derived from use of transmission capacity. They can hedge transmission price risk caused by volatile LMP. For merchant transmission investors, long-term FTRs provide incentives for them to invest in transmission assets. There are two configurations for FTRs: Point-to-Point Financial Transmission Rights (PTP-FTRs) and Flowgate Financial Transmission Rights (FG-FTRs), and two financial treatments: obligations and options [50-52]. Obligations grant the right holders to receive congestion revenues when they are positive and to pay congestion revenues when they are negative. Options grant the right holders only to receive congestion revenues when they are positive, but right holders do not need to pay congestion revenue when they are negative. PTP-FTRs are defined from a source (injection) to a sink (withdrawn) with a MW quantity. FG-FTRs represent the rights to collect congestion rent by a portion of the capacity over a particular transmission flowgate in a specified direction. There has been considerable debate on the advantages and disadvantages of PTP-FTRs and FG-FTRs concerning their liquidity, complexity and market power issues [see for example 53-56]. In practice, electricity markets often use a hybrid model to include both approaches [57].

A flowgate can be a line, a transformer, or a set of lines and transformers with a certain limit. The capacity of FG-FTRs is determined by physical factors associated with the defined flowgates, e.g., thermal limits or stability limits. The payment to FG-FTRs holders is equal to the product of the shadow price of the flowgate in the specified direction. Because the shadow price is non-zero only when transmission congestion occurs on the flowgate, FG-FTRs are always greater than or equal to zero. Fig. 3.2 – Fig. 3.3 clearly shows the difference between PTP-FTRs and FG-FTRs.

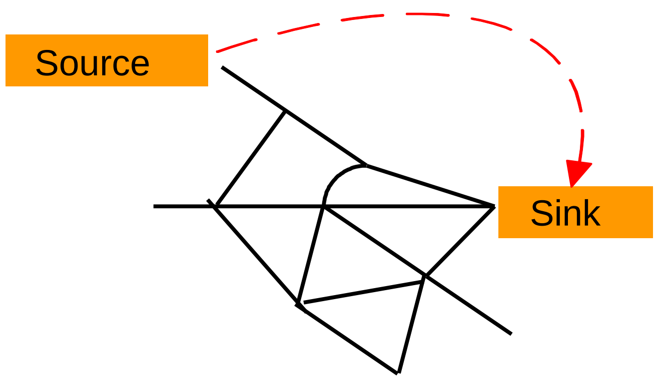

Fig. 3.2 Illustration of PTP-FTRs

Based on the above analysis, we have these types of financial transmission rights: PTP-FTR Obligations, PTP-FTR Options, and FG-FTR Options. For PTP-FTR holders, the revenue obtained can be expressed by either

$$PTP-FTR\ Obligation\ Revenue = (LMP_{sink} - LMP_{source})P_{PTP-FTR} \tag{3.3}$$

or

$$PTP-FTR\ Option\ Revenue = |LMP_{sink} - LMP_{source}|P_{PTP-FTR} \tag{3.4}$$

where LMP_{sink} and LMP_{source} are the LMP values on the sink and source nodes separately, and $P_{PTP-FTR}$ is the quantity of PTP-FTRs allocated to FTR holders.

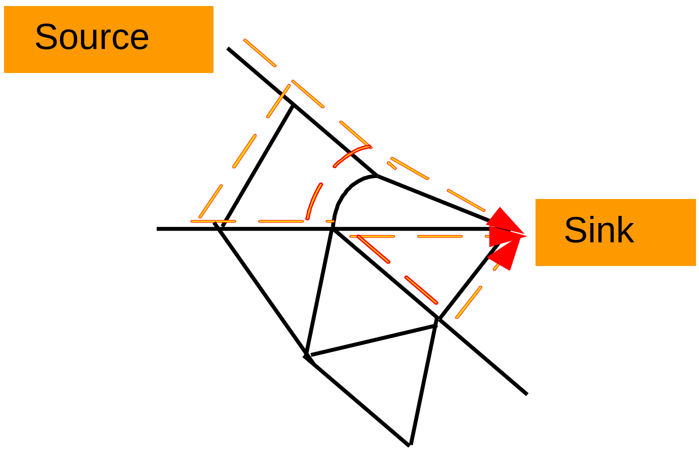

Fig. 3.3 Illustration of FG-FTRs

For FG-FTR Options holders, the revenue can be calculated by

$$FG-FTR\ Option\ Revenue = \sum_i \lambda_i P_{FG,i}{}^{cap} \tag{3.5}$$

where λ_i is the shadow price corresponding to path *i* in the defined flowgate. It is greater than zero when power flow along the flowgate is congested, otherwise it is zero. $P_{FG,i}{}^{cap}$ is the power transfer capability of path *i* along the specified direction in the defined flowgate, which depends on the thermal limits or stability limits of this path.

The feedback control loop for FTR based investment recovery incentives is described by the causal loop diagram depicted in Fig. 3.4. This shows how an increase in capacity or in transfers will negatively impact the investment return to a transmission owner. For any FTR based incentives, the biggest shortcoming is this contradiction between the purpose and the means to realize it. The purpose of transmission expansion is to alleviate congestion in the transmission system but the transmission investment recovery relies on the congestion rent, i.e., the congestion itself.

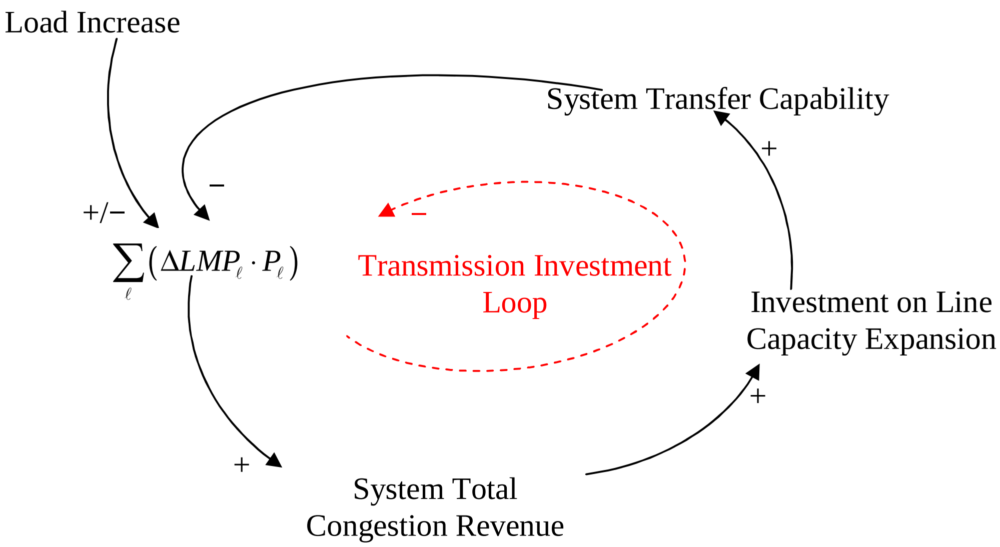

Fig. 3.4 The causal loop of FTR-based congestion rent incentives

For a severely congested system where there are adequate congestion rents, there is no problem with such an incentive initially, since there is sufficient payment for transmission investment recovery. As time goes by, if transmission lines are continuously expanded and the congestion rent decreases in the system, there will eventually be insufficient congestion rent to support investment recovery. It is not possible for such a simple incentive to completely eliminate system congestion.

Although there are three types of FTRs, we only consider PTP-FTRs Options in this research. This consideration will not affect the effectiveness of conclusions that will be drawn from our research, since it only impacts the quantity of the congestion rents transmission investors will gain from allocated FTRs but does not change the inherent negative transmission investment feedback control loop depicted in Fig. 3.4.

Another important issue in FTRs formulation is revenue adequacy. Revenue adequacy means that the revenue collected with locational prices in the dispatch should at least be equal to the payments to the holders of FTRs in the same period [55]. A process named simultaneous feasibility test (SFT) guarantees the revenue adequacy for the allocated FTRs to transmission investors. This feasibility test evaluates the ability of the system to remain within normal ratings, including first contingency conditions, with the data input for the nominated FTRs. In this research, we model the WECC system as a lumped seven-area and ten tieline system and only consider the congestion rents on these equivalent area tielines. Actually there are many other congested lines within each aggregated area, which are not researched. Compared to the total congestion rents in the WECC system, the congested rents collected from the ten equivalent tielines in our lumped system may be only a small percentage of the total value. So there is no revenue adequacy issue in our research, since if there are insufficient payments to the transmission investors from the ten equivalent tielines in our lumped system, we assume that congestion rents within the aggregated areas will supplement the inadequate payments.

The investors' decision on a transmission investment is based on their judgment on the profitability of the investment. We define investors' decision rule on FTR-based merchant transmission investment below. Assume that investors invest in transmission line ℓ, and the FTR granted for their investment is allocated on line ℓ' then

$$\begin{aligned}
&\sum_{t=1}^{t_j}\left(q_{\ell'}\left|\Delta LMP_{\ell'}\right|H_{c,\ell'}\left(1+\eta\right)^{t}\right)\geq q_{\ell'}L_{\ell}\upsilon_{\ell}\left(1+\tau\right)^{t_j}\left(1+\rho\right)\left(1+\sigma\right)\\
&s.t.\\
&\qquad t_j\leq T_{e,\ell}
\end{aligned}\tag{3.6}$$

In (3.6), $q_{\ell'}$ is the quantity of allocated PTP-FTR Options on line ℓ' to merchant transmission investors who invest on line ℓ. $\Delta LMP_{\ell'}$ is the LMP difference on line ℓ', $H_{c,\ell'}$ is the annual average congestion hours on line ℓ', η is the load growth rate, L_{ℓ} is the length of line ℓ, υ_{ℓ} is the per MW-mile transmission investment cost on line ℓ, τ is the annual loan interest rate, ρ is the annual profit rate, σ is the annual inflation rate, t_j is the number of years after a transmission investor's decision on investment, and $T_{e,\ell}$ is the economic life of transmission investment on line ℓ in number of years.

In (3.6), the left hand side is the predicted accumulated congestion rent from the allocated FTR in year t_j and the right hand side is the value of investment costs in year t_j, which equals the initial value of investment costs that is converted to the year t_j. If (3.6) can be satisfied, investors will make the investment to upgrade or expand line ℓ by $q_{\ell'}$ MW.

3.3.2 Cost-based Rate-of-return On Equity

Merchant transmission investment alone is unlikely to produce sufficient investment in transmission expansion. As a result [33, 58], regulatory involvement in transmission investment is essential. Under the ROE regulation, variable costs are treated as expenses and passed directly into rates, while capital costs are computed by identifying prudently incurred capital investment, and assessing the allowed rate of return on this investment that will allow a firm to raise capital. For ROE based transmission investment recovery, the return depends on the decisions of government institutions or/and regulatory organizations such as ISOs and RTOs.

1) **Cost-based ROE without adders**. This is the more typical case for transmission investment with cost-based ROE incentives. This regulated investment in transmission assets is based on the granted ROE for cost recovery and profit making. The feedback control loop for ROE without adders incentives is described by the causal loop diagram depicted in Fig. 3.5. From this figure, we can see that the investment in transmission capacity expansion will result in negative feedback to alleviate system congestion rents. As long as there is sufficient ROE to support the transmission expansion, it is possible to completely eliminate the congestion in such a system. The investment decision rule on cost-based ROE incentives without adders is

$$\delta_\ell \geq \tau + \rho + \sigma \tag{3.7}$$

where δ_ℓ is the ROE value granted to investors who make investment on line ℓ to expand its capacity. Based on (3.7), as long as the granted ROE value is greater than or equal to the summation of loan interest rate, inflation rate and profit rate, investors will make investment on transmission line ℓ to improve the transfer capability.

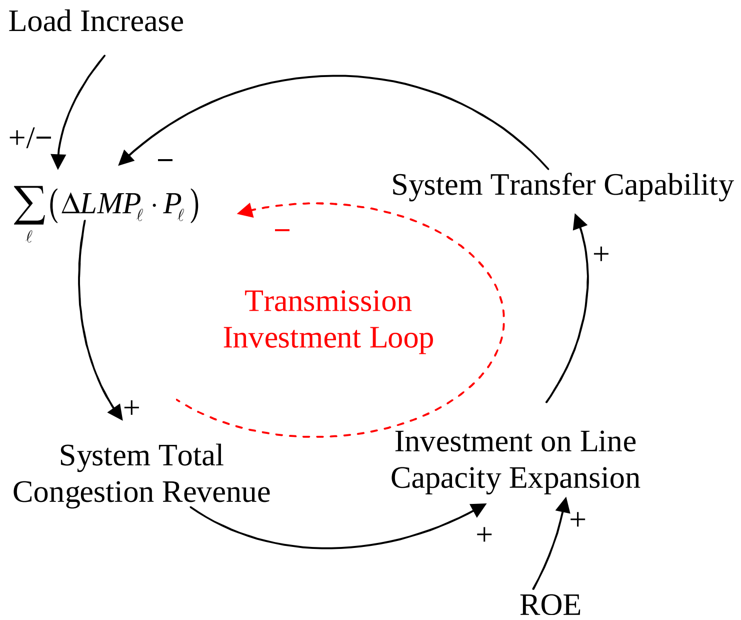

Fig. 3.5 The causal loop for cost-based rate-of-return on equity incentives without adders

2) **Cost-based ROE with performance-based adders**. In order to promote investments on transmission infrastructure, FERC [59] has proposed performance-based adders for the cost-based ROE to provide a performance-based rate (PBR). Although the effect of this adder on transmission investment is still under debate [59-61], FERC [59] believes that the development of PBR measures may represent a long-term approach for the industry and the commission to pursue and hence they encourage development of PBR proposals. Figure 3.6 depicts the causal loop of transmission system investment incented by ROE plus ROE adders. The ROE adders could be positive or negative depending on the performance of the investment. ROE adders are decided case-by-case.

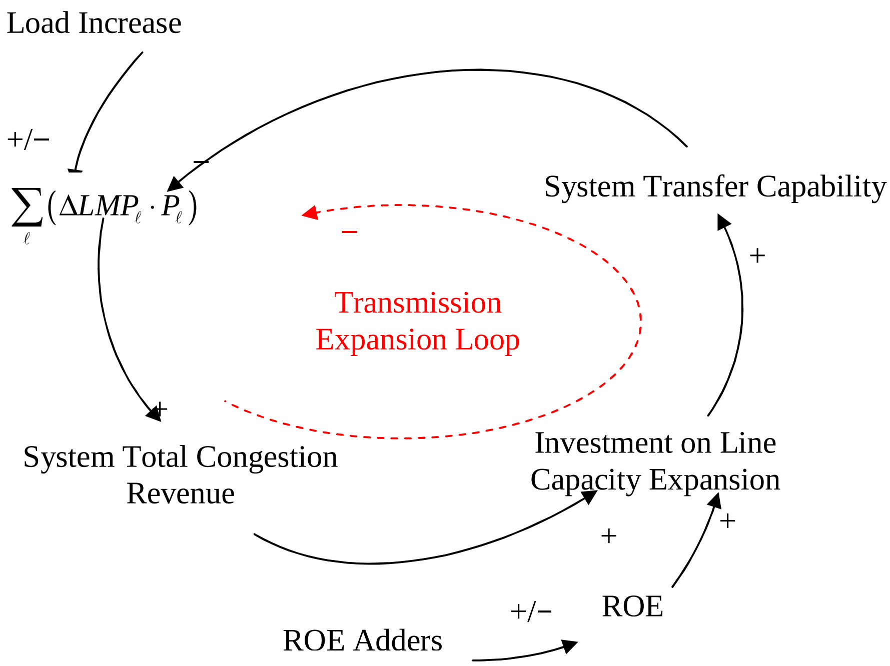

Fig. 3.6 The causal loop of cost-based rate of return incentives with adders

In our research, we research two ways to determine the ROE adders. One assumes only an ROE adder $\Delta\delta_{\ell}$ as in (3.8) that depends on the value of system congestion rents alleviation brought by transmission investments. The other assumes that there is the same ROE adder $\Delta\delta_{\ell}$ but at the same time the transmission upgraded or expanded capacity ΔP_{ℓ}^{cap} will also be adjusted by increasing the percentage of $\Delta\delta_{\ell}$ as in the following

$$\Delta\delta_{\ell} = min(\Delta\delta^{max}, dR_{\ell}/R) \tag{3.8}$$

$$\Delta P_{\ell}^{C'} = \Delta P_{\ell}^{C}(1+\Delta\delta_{\ell}) \tag{3.9}$$

where $\Delta\delta^{max}$ is the maximum allowed ROE adder granted to investors in the system, dR_{ℓ}

is the alleviated annual congestion rent by investing in line ℓ's expansion, R is the system annual congestion rent, $\Delta\delta_\ell$ is the ROE adders granted to investors who invest on line ℓ, ΔP_ℓ^C is the initial optimal capacity upgrade or expansion on line ℓ, and ΔP_ℓ^C is the optimal capacity upgrade or expansion on line ℓ adjusted by ROE adders.

The investment decision rule on cost-based ROE incentives with adders is

$$\delta_\ell + \Delta\delta_\ell \geq \tau + \rho + \sigma \tag{3.10}$$

Based on (3.10), as long as the granted ROE plus its adder's value is greater than or equal to the summary of loan interest rate, inflation rate and profit rate, investors will invest in transmission line ℓ to improve the transfer capability.

CHAPTER FOUR

MODELING NODAL PRICING AND TRANSMISSION RELIABILITY

For the reduced WECC power system model, the primary concern is the interarea power flows and congestions on the interties. The objective of the SD modeling is to capture the characteristics of the long-term transmission expansion for the interarea tie-lines under different investment recovery incentives. Thus, the nodal prices are needed for each area at each time point of the study. For the large modeling reduction needed for a system like WECC, there is simply no way to create a meaningful full AC-OPF model. A DC-OPF should provide sufficiently precise results to serve this purpose. In addition, a method is proposed to relate these nodal pricing and congestion calculations to reliability considerations.

4.1 Nodal pricing

Nodal pricing is a method of determining nodal prices in which market clearing prices are calculated in the competitive wholesale electricity markets. The nodal price or Locational Marginal Price (LMP) is the cost to serve the next MWh of load at a specific location, using the lowest bidding cost of all available generation, while observing all transmission limits. Nodal price theory was first formulated by Schweppe, et al. [62]. This theory constitutes the basis of the current wholesale electricity markets in the U.S. The LMP can be decomposed to three components [63]. Although the decomposition is really a mathematical artifice rather than a physically meaning reality, it still helps one to better understand the LMP and contributes to understanding market management. Let

$$LMP = LMP_{energy} + LMP_{congestion} + LMP_{losses} \tag{4.1}$$

where LMP_{energy} is the marginal cost of energy, $LMP_{congestion}$ is the marginal cost of congestion and LMP_{losses} is the marginal cost of losses. The main advantages of using an LMP mechanism are that it:

(1) increases the transparency of the true costs of serving load by location;
(2) provides a consistent methodology to price transmission and energy across market time frames;
(3) provides price signals for developing new generation in preferred locations;
(4) provides some information for transmission expansion.

The disadvantages of LMP are also numerous, however, and include:

(1) high volatility arising from bidding strategies and numerous possible congestion patterns in practical wholesale electricity markets;
(2) troublesome properties that are counter intuitive to good engineering practice. For example, the LMP difference on uncongested lines may be caused by other lines. Also, reinforcing a line according to the LMP difference may reduce the transfer capabilities of the system. Moreover, the LMP difference may be negative along the power flow directions. These counter-intuitive properties result from the looped transmission network and Kirchhoff's Laws for power flows. Unlike generation investment, where LMP typically provides a transparent price signal, the signal to transmission investment is obscured because of these properties.

A general LMP formulation and calculation are given in [64]. In our research, the system is linearized and transmission losses are ignored. Let's consider a standard formulation of the DC-OPF with quadratic generation bidding functions

$$\begin{aligned}
& \min \ \underline{P}^T C_1 \underline{P} + C_2{}^T \underline{P} \\
& s.t. \\
& \sum_{i=1}^{m} P_i = \sum_{i=1}^{m} P_{D,i} && : \quad \lambda \\
& \underline{P}_L = SF(A\underline{P} - B\underline{P}_D) \le \underline{P}_L{}^{\max} && : \quad \underline{\pi}^{+} \\
& -\underline{P}_L = -SF(A\underline{P} - B\underline{P}_D) \le \underline{P}_L{}^{\max} && : \quad \underline{\pi}^{-} \\
& \underline{P}^{\min} \le \underline{P} \le \underline{P}^{\max}
\end{aligned} \tag{4.2}$$

where C_1 is the matrix for quadratic coefficients in generation production function, $\underline{C}_2$ is the vector for linear coefficients in generation production function, $\underline{P}$ is generator active power output vector, P_i is generator active power output on bus *i*, $P_{D,i}$ is the active load on bus *i*, $\underline{P}_L$ is the line active power flow vector, $\underline{P}_L{}^{max}$ is the line active power flow limit vector, $\underline{P}^{min}$ is generator active power output lower limit vector, $\underline{P}^{max}$ is generator active power output upper limit vector, *A* is bus-unit incidence matrix, *B* is bus-load incidence matrix, *SF* is shift factor matrix, *m* is the total number of buses in the system, *i* is the bus number, λ is the dual variable for the power equality constraint, $\underline{\pi}^{+}$ is the dual variable vector for the line active power flow constraint in the reference direction, $\underline{\pi}^{-}$ is the dual variable vector for the line active power flow constraint in the opposite reference direction.

For a DC power flow model, transmission losses are ignored so that the LMP and its decomposition can be calculated by

$$LMP = LMP_{energy} + LMP_{congestion} = \lambda - SF^T(\pi^+ - \pi^-) \quad (4.3)$$

and

$$LMP_{energy} = \lambda \quad (4.4)$$

$$LMP_{congestion} = -SF^T(\pi^+ - \pi^-) \quad (4.5)$$

In the present six major RTOs/ISOs in the US, five of them, PJM Interconnection, New York ISO (NYISO), ISO New England (ISO-NE), Midwest ISO (MISO), and California ISO (CAISO), are LMP based wholesale electricity markets, and the remaining one, ERCOT, will transform to this kind of market in 2010. In order to determine LMPs that accurately reflect physical operation of the power system, most RTOs/ISOs, including PJM interconnection, ISO-NE, MISO, and CAISO, calculate ex-post LMPs to clear the wholesale electricity markets. The ex-post LMP calculation is formulated as an incremental optimization problem around the operating point. This strategy helps to mitigate market power since GenCos trying to manipulate prices will be screened out for eligibility to set the price. Only NYISO calculates ex-ante LMPs to clear the markets, and it claims that the ex-ante LMPs are consistent with the real-time market dispatch signals and hence more efficient.

4.2 Transmission expansion with system reliability considerations

In our research, the objective of transmission investment is to alleviate system congestion. In order to reach this goal, it is necessary to define a metric to measure the system congestion level. The System Congestion Rent (SCR) is used and defined as the sum of the product of the absolute value of LMP difference, the active power flow, and the duration on all transmission lines in the system.

$$SCR = \int_{0}^{t_\ell} | \Delta LMP_\ell(t) \cdot P_\ell(t) | \, dt \qquad (4.6)$$

where $\Delta LMP_\ell(t)$ is the LMP difference on line ℓ at time *t*, t_ℓ is the duration of active power flowing on line ℓ and ℓ is system line number. Similarly, considering system reliability in transmission investment requires a metric. There are three common reliability metrics [65]:

- *n-k* criterion
- Loss of Load Probability (LOLP)
- Loss of Energy Expectation (LOEE) or equivalently Loss of Energy Probability (LOEP)

In our research, the *n-1* criterion is chosen as the reliability metric, since the other two are difficult to define within the SD model. Because the model is a lumped WECC system, the tielines are equivalences for the actual interties. The utilization of *n-1* criterion becomes a decrease in line capacity by some percentage but not a disconnection. The total provided load is used as a proxy to measure the reliability level assuming this reflects a *n-1* criterion.

$$RI = \sum_{i} P_{load,i} \tag{4.7}$$

where *RI* is the metric to measure system reliability level and $P_{load,i}$ is active load value at bus *i*.

In the SD model, the optimal capacity expansion on a transmission line ℓ is calculated based on one of the following three strategies:

- **Strategy 1 (Hard limit expansion)**: In this strategy, the optimal capacity expansion on line ℓ is calculated by relaxing this line's power flow limit in the DC-OPF. That is:

$$\begin{aligned}
&min \;\; \underline{P}^T C_1 \underline{P} + C_2{}^T \underline{P} \\
&s.t. \\
&\sum_{i=1}^{m} P_i = \sum_{i=1}^{m} P_{D,i} \\
&\;\; \underline{P}_L \leq \underline{P}_L{}^{\max} \\
&-\underline{P}_L \leq \underline{P}_L{}^{\max} \\
&\underline{P}^{\min} \leq \underline{P} \leq \underline{P}^{\max} \\
&P_\ell^{\max} = \infty
\end{aligned} \tag{4.8}$$

where P_ℓ^{max} is the power flow limit on line ℓ , which is to be relaxed. From this optimization problem, the recommended capacity by strategy 1 will eliminate congestion on line ℓ to flow P_ℓ. Let P_ℓ^C be line ℓ's initial capacity and ΔP_ℓ^C be the optimal line capacity expansion based on the minimum capacity needed to alleviate congestion. Then there is a need for

$$\Delta P_\ell^C = P_\ell - P_\ell^C \tag{4.9}$$

Such a solution provides an optimal capacity expansion relative to current system operating conditions. We define it as hard limit optimal expansion.

- **Strategy 2 (Hard margin expansion)**: We seek approaches to modify the calculated hard limit optimal expansion ΔP_{ℓ}^{C}, because the expansion ΔP_{ℓ}^{C} only considers current transmission congestion and does not take into consideration the possible future line flow increases. In order to take into account the future operation conditions and improve system reliability, we allow some fractional margin increase, say κ ($0<\kappa\le 1$), for the optimal line capacity expansion. Based on this assumption, we obtain the expression below

$$\Delta P_{\ell,m}{}^{C} = (1+\kappa)\left(P_{\ell} - P_{\ell}^{C}\right) \tag{4.10}$$

- **Strategy 3 (Soft limit expansion)**: If we simply allow some percentage margin κ for optimal line capacity expansion as in strategy 2, this can easily result in over investment. Here we define a third strategy based on a soft limit. In this strategy, we use a soft constraint to provide a systematic trade-off between reliability and needed investment. The detailed mathematical formulation for the soft optimal expansion begins from the DC-OPF problem with hard limits in (4.2). Define a function to describe the degree of satisfaction α ($0\le\alpha\le 1$) with the capacity expansion ΔP_{ℓ}^{Cap} on line ℓ:

$$\alpha = \begin{cases} 0 & , \ \Delta P_\ell^{Cap} \le \Delta P_\ell^{C} \\ \dfrac{1}{\kappa}\left(\dfrac{\Delta P_\ell^{Cap}}{\Delta P_\ell^{C}} - 1\right), & \Delta P_\ell^{C} \le \Delta P_\ell^{Cap} \le (1+\kappa)\Delta P_\ell^{C} \\ 1 & , \ (1+\kappa)\Delta P_\ell^{C} \le \Delta P_\ell^{Cap} \end{cases} \tag{4.11}$$

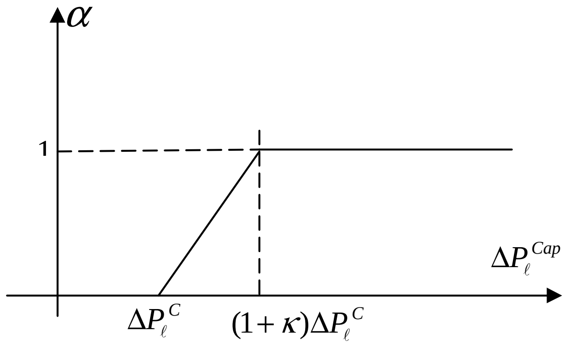

Fig. 4.1 Satisfaction with expansion on line ℓ

where κ ($0 < \kappa \le 1$) is again the capacity margin to improve system reliability. We convert this satisfaction, or membership, function to the following optimization problem with $\alpha \ge y$

$$\begin{aligned} & \max \ y \\ & s.t. \\ & \quad 0 \le \mathrm{y} \le 1 \\ & \quad \mathrm{y} \le \frac{1}{\kappa}\left(\frac{\Delta P_\ell^{Cap}}{\Delta P_\ell^{C}} - 1\right) \end{aligned} \tag{4.12}$$

or equivalently

$$\begin{aligned} & \min \ -y \\ & s.t. \\ & \quad 0 \le \mathrm{y} \le 1 \\ & \quad \mathrm{y} \le \frac{1}{\kappa}\left(\frac{\Delta P_\ell^{Cap}}{\Delta P_\ell^{C}} - 1\right) \end{aligned} \tag{4.13}$$

Combining the DC-OPF and the optimization problem corresponding to soft constraints, a multi-objective optimization problem is formulated

$$\begin{aligned}
& \min \begin{pmatrix} \underline{P}^T C_1 \underline{P} + C_2{}^T \underline{P} \\ -y \end{pmatrix} \\
& s.t. \\
& \qquad \sum_{i=1}^{m} P_i = \sum_{i=1}^{m} P_{D,i} \\
& \qquad \underline{P}_L \le \underline{P}_L{}^{\max} + \Delta \underline{P}^C \\
& \qquad -\underline{P}_L \le \underline{P}_L{}^{\max} + \Delta \underline{P}^C \\
& \qquad \underline{P}^{\min} \le \underline{P} \le \underline{P}^{\max} \\
& \qquad 0 \le \mathrm{y} \le 1 \\
& \qquad \mathrm{y} \le \frac{1}{\kappa}\left(\frac{\Delta P_\ell{}^{Cap}}{\Delta P_\ell{}^{C}} - 1 \right) \\
& \qquad \Delta P_\ell^C \le \Delta P_\ell^{Cap} \le (1+\kappa)\Delta P_\ell^C
\end{aligned} \tag{4.14}$$

where $\Delta \underline{P}^C = \begin{pmatrix} 0 \\ ... \\ 0 \\ (1+\kappa)\Delta P_\ell^C \\ 0 \\ ... \\ 0 \end{pmatrix}$ and the satisfaction functions for $\underline{P}^T C_1 \underline{P} + C_2{}^T \underline{P}$ and

-y are

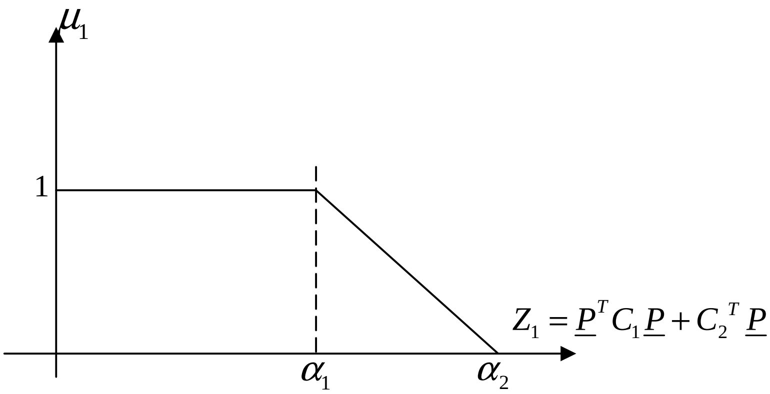

Fig. 4.2 Satisfaction function for $\underline{P}^T C_1 \underline{P} + C_2^T \underline{P}$

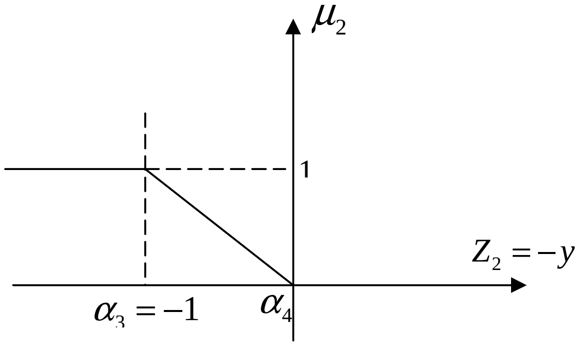

Fig. 4.3 Satisfaction function for $-y$

$$\mu_1 = \begin{cases} 1, & Z_1 \le \alpha_1 \\ \dfrac{\alpha_2 - Z_1}{\alpha_2 - \alpha_1}, & \alpha_1 \le Z_1 \le \alpha_2 \\ 0, & \alpha_2 \le Z_1 \end{cases} \tag{4.15}$$

$$\mu_2 = \begin{cases} 1, & Z_2 \le \alpha_3 \\ \dfrac{\alpha_4 - Z_2}{\alpha_4 - \alpha_3}, & \alpha_3 \le Z_2 \le \alpha_4 \\ 0, & \alpha_4 \le Z_2 \end{cases} \tag{4.16}$$

Here $\alpha_1 = \underline{P}^T C_1 \underline{P} + C_2^T \underline{P}$ and $\underline{P}$ are solutions from the DC-OPF problem (4.2).

$\alpha_2 = \underline{P}^T C_1 \underline{P} + C_2^T \underline{P}$ and $\underline{P}$ are solutions from the following quadratic optimization problem

$$\begin{aligned}
&min \quad \sum_j \left(\frac{P_{line,j}}{P_{line,j}{}^{max} + \Delta P_{line,j}{}^{C}} \right)^2 \\
&s.t. \\
&\qquad \sum_{i=1}^{m} P_i = \sum_{i=1}^{m} P_{D,i} \\
&\qquad \underline{P}_L \le \underline{P}_L{}^{\max} + \Delta \underline{P}^C \\
&\qquad -\underline{P}_L \le \underline{P}_L{}^{\max} + \Delta \underline{P}^C \\
&\qquad \underline{P}^{\min} \le \underline{P} \le \underline{P}^{\max}
\end{aligned} \tag{4.18}$$

with

$$\Delta P_{line,j}{}^{C} = \begin{cases} \Delta P_\ell^C, & j = \ell \\ 0, & otherwise \end{cases} \tag{4.19}$$

Finally, the soft-constrained optimal expansion problem objective becomes $max \cdot min\ (\mu_1, \mu_2)$. Let $\gamma = min\ (\mu_1, \mu_2)$, so the $max \cdot min$ problem is converted to this maximization problem

$$\begin{aligned}
&max \quad \gamma \\
&s.t. \\
&\qquad \sum_{i=1}^{m} P_i = \sum_{i=1}^{m} P_{D,i} \\
&\qquad \underline{P}_L \le \underline{P}_L{}^{\max} + \Delta \underline{P}^C \\
&\qquad -\underline{P}_L \le \underline{P}_L{}^{\max} + \Delta \underline{P}^C \\
&\qquad \underline{P}^{\min} \le \underline{P} \le \underline{P}^{\max} \\
&\qquad 0 \le \mathrm{y} \le 1 \\
&\qquad \mathrm{y} \le \frac{1}{\kappa} \left(\frac{\Delta P_\ell^{Cap}}{\Delta P_\ell^C} - 1 \right) \\
&\Delta P_\ell^C \le \Delta P_\ell^{Cap} \le (1+\kappa) \Delta P_\ell^C
\end{aligned} \tag{4.20}$$

$$\gamma \le \frac{\alpha_2 - \underline{P}^T C_1 \underline{P} + C_2^{\,T} \underline{P}}{\alpha_2 - \alpha_1}$$

$$\gamma \le \frac{\alpha_4 + y}{\alpha_4 - \alpha_3}$$

$$0 \le \gamma \le 1$$

In (4.20), the unknowns are $\underline{P}$, ΔP_ℓ^{Cap}, y, and γ. The solution ΔP_ℓ^{Cap} is the optimal capacity expansion calculated based on the soft constraints. After obtaining this solution, the system reliability index RI will be calculated. The process is summarized in the flowchart shown in Fig. 4.4. The calculated reliability level RI considering the transmission expansion plan will be compared with the reliability level of the initial system to evaluate the system reliability change. If reliability worsens with this transmission expansion plan, this expansion will be abandoned. The complete screening process is given in the flowchart shown in Fig. 4.5. In this flowchart, system congestion set { K_1, K_2, ... K_ℓ, ..., K_L } includes all congested lines and is arranged in the order of the quantity of congestion rents. L is the total number of congested lines.

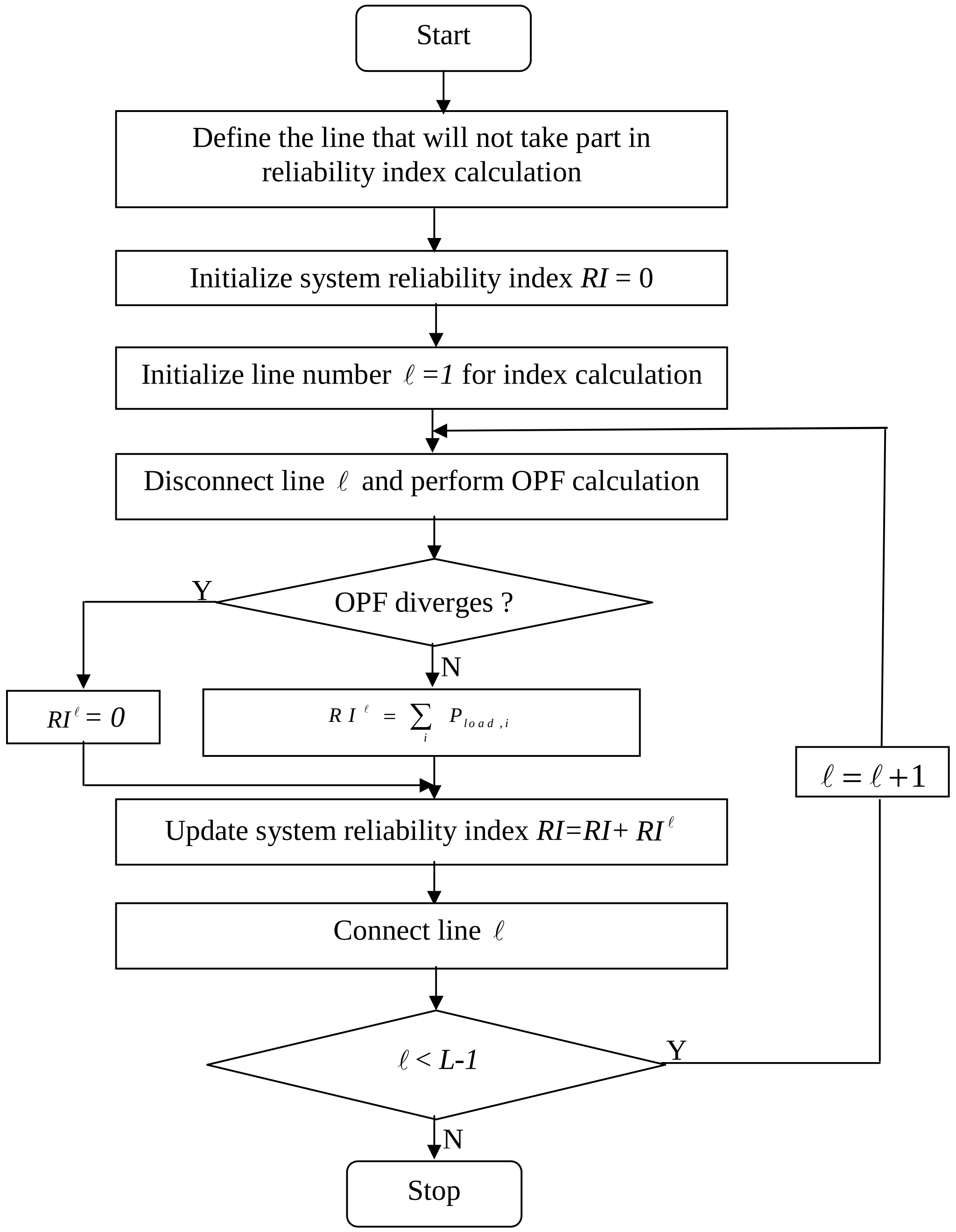

Fig. 4.4 Flowchart of system reliability index calculation

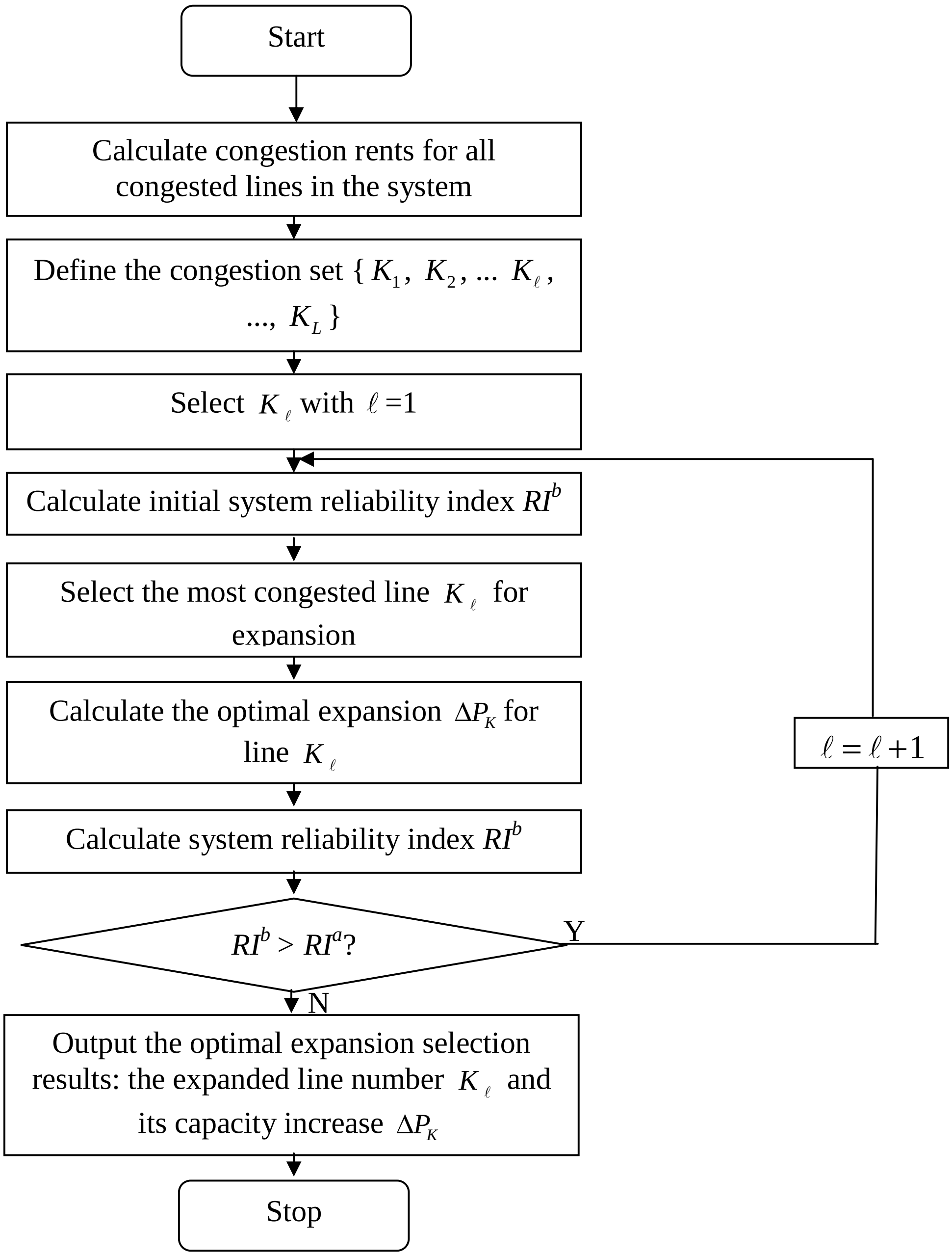

Fig. 4.5 Flowchart of transmission expansion with system reliability considerations

CHAPTER FIVE

NUMERICAL SIMULATIONS

This chapter evaluates different transmission investment incentives using the developed WECC SD models. We investigate two types of transmission investments: merchant transmission investment and regulated transmission investment. From the social welfare point of view, the purpose of these two transmission investments is to mitigate system congestion rents caused by insufficient transmission capacities. With the mitigation of system congestion rents, cheaper generation units can produce more electric power while the congestion rents paid by consumers will be reduced. Eventually the social welfare should improve. From the transmission investors' point of view, the purpose for both merchant and regulated investment is to make a profit. The focus here is on the practical impacts of different incentives on transmission investments and congestion mitigation.

The SD models are based on a simplified, lumped WECC system. First, the methodology to formulate a useful simplified WECC system is introduced. The WECC is divided into four subregions: NWPP, RMPA, AZ/NM/SNV, and CA/MX. The correspondence between these subregions and states is given in Table 5.1. This four subregion WECC system is depicted in Fig. 5.1. The subregion of CA/MX is the main load pocket and the electricity price there is the most expensive. There is a significant amount of inexpensive hydro-energy in NWPP, especially in Washington and Oregon. In wet seasons, electric power flows primarily from NWPP to CA/MX; and in dry seasons, the flow tends to be from AZ/NM/SNV and CA/MX to NWPP. The bulk power transactions between these areas often cause congestion on the transmission lines with flow limits primarily determined by security. In order to investigate the impacts of investment incentives and long-term dynamic transmission planning on system congestion mitigation, we re-divide the original four subregion WECC system into a seven area system splitting NWPP into Canada, WA/OR and the remaining part of NWPP, and splitting CA/MX into NCA and SCA. These areas are connected by ten equivalent tielines. A more detailed model is certainly possible but one is limited by the available data for subsystems. For example, the possible new locations for generation and new load growth are not known with bus level specificity.

Table 5.1 Subregion and State correspondence for four subregion WECC system

Subregion	**States Comprised**
AZ/NM/SNV (Arizona)	Arizona, most of New Mexico, the western part of Texas, southern Nevada, and a portion of southeastern California
CA/MX (California)	Most of California and the northern portion of Baja California, Mexico
NWPP (Northwest)	Washington, Oregon, Idaho and Utah, British Columbia and Alberta, and portions of Montana, Wyoming Nevada and California
RMPA (Rockies)	Colorado, eastern Wyoming, and portions of Western Nebraska and South Dakota

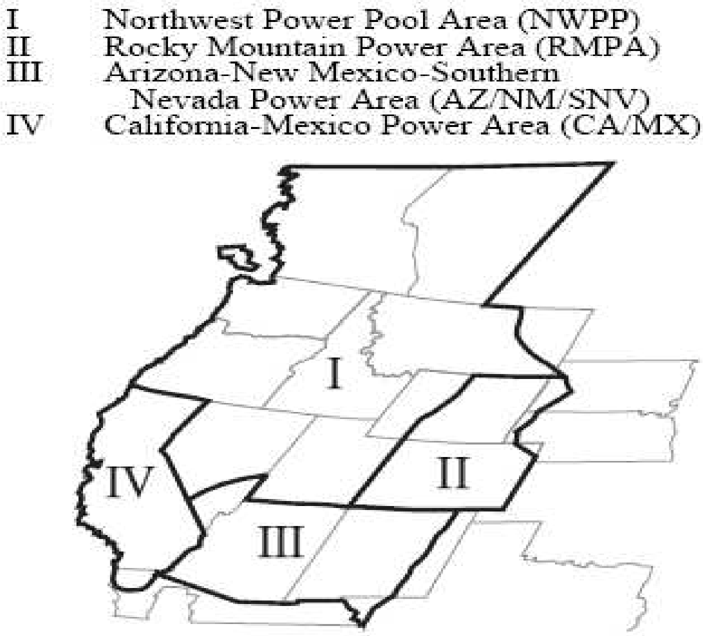

Fig. 5.1 WECC four subregion diagram

Table 5.2 Area and State correspondence for seven area WECC system

Area number	**Area name**	**States Comprised**
1	WA/OR	Washington and Oregon
2	RM	Colorado, eastern Wyoming, and portions of Western Nebraska and South Dakata
3	SW	Arizona, most of New Mexico, the western part of Texas, southern Nevada, and a portion of southeastern California
4	SCA	The southern portion of California and the northern portion of Baja California, Mexico
5	NCA	Northern portion of California
6	Remaining of NWPP	Idaho and Utah, , and portions of Montana, Wyoming Nevada and California
7	Canada	British Columbia and Alberta

For the seven-area WECC system, the correspondence between these areas and states comprised them is given in Table 5.2. Fig. 5.2 shows the WECC seven area geographic divisions. Fig. 5.3 is the one-line diagram for the lumped WECC seven-area and ten-tieline system. In this figure, the arrows on the lines represent the reference power flow directions on the equivalent area tielines.

Details on developing SD models for such a lumped WECC system are given in Appendix A and B. The different transmission investment incentives will be tested on these reduced models. The initial simulation time for the SD models starts at calendar year 2004. Typical parameters for the SD models are given in Table 5.3. In order to observe long-term system dynamics under different transmission investment incentives, the simulation horizon is set to 20 years. An integration step of 0.25 hours is chosen to solve the Delay Differential Equations (DDEs) by means of the Euler algorithm in the Vensim model. In the SD models, a year is represented by four different seasons: spring, summer, fall, and winter. Each season is represented by a typical day in this season. Hence a year will be represented by four days in the SD models.

The lifecycle for the transmission line projects includes preparation, application, review, construction and commission. In our SD models, this lifecycle is assumed to be 2 years. For investors' investment recovery, the economic life of transmission investments is assumed to be 20 years. In WECC's 10-year coordinated plan from 2005 to 2015 [66], the projected average annual compound peak demand growth rates under adverse hydro conditions from 2005 to 2015 are 2.1% in the summer season and 1.9% in the winter season. Based on this WECC planning data, the system annual load growth rate in our Vensim SD models is set to be 2.0%. Based on the analysis on area generation investments in Chapter 4, the base annual generation increase rate is set to be 2% to match load growth. Again, this is to isolate generation from transmission investment.

Table 5.3 Base economic parameters for WECC SD models

Parameter	**Value**
Initial time point	Calendar year 2004
Planning horizon	20 years
Integration time step	0.25 hours
Time for construction	2 years
Economic life of transmission investments	20 years
Number of days to represent a year	4 days
Annual profit rate	10%
Annual loan interest rate	7%
Annual inflation rate	2.5%
Annual load increase rate	2%
Base annual generation increase rate	2%
Transmission line construction cost	$1075 per MW-mile
Capacity expansion margin for strategy 2	20%

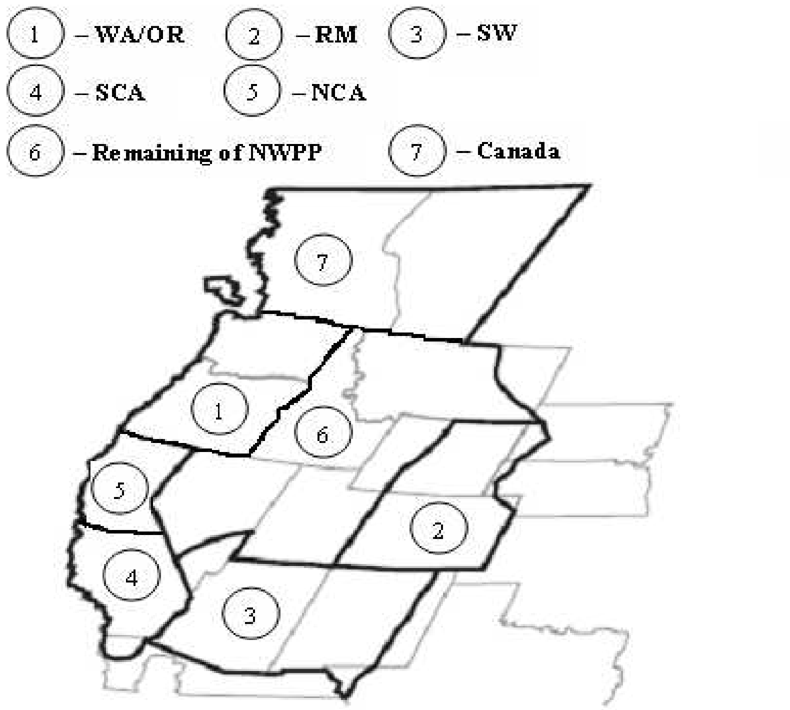

Fig. 5.2 WECC seven area diagram

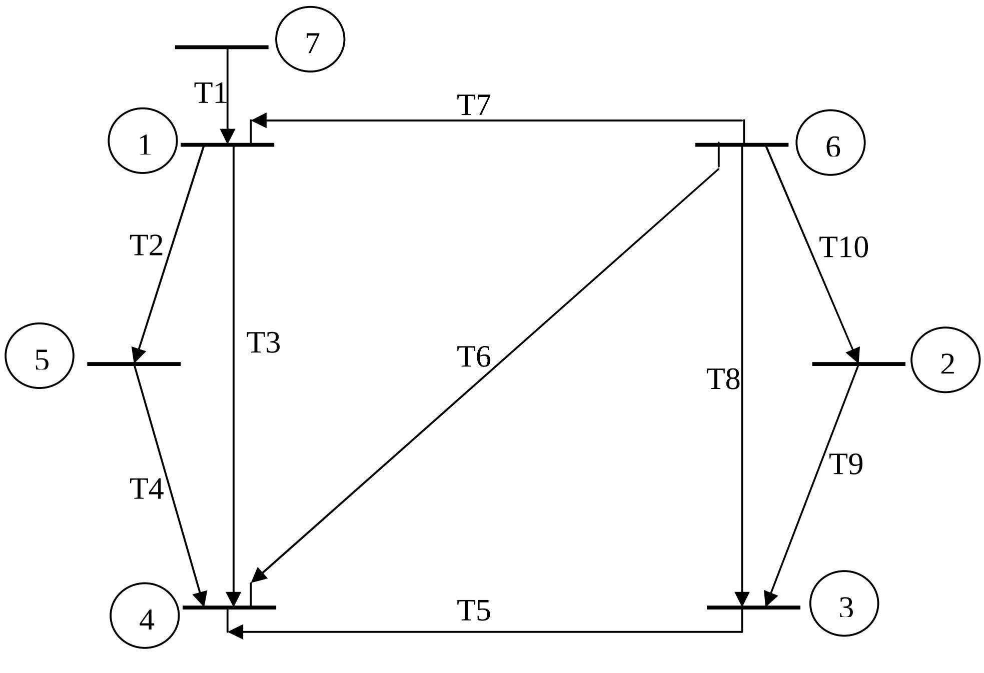

Fig. 5.3 Lumped WECC one-line diagram

5.1 FTR-based incentives

Merchant transmission investors rely on allocated FTRs to recover investment and make profit. There are three types of FTRs in the US LMP-based electricity markets: PTP-FTRs Options, PTP-FTRs Obligations, and FG-FTRs Options. We will only consider PTP-FTRs Options in our SD models. As discussed in Chapter 3.3.1, this consideration will not affect the appropriateness of conclusions we will draw for the FTR-based transmission incentives. For transmission investors, we assume they use a linear prediction for the revenues possible from allocated PTP-FTRs Options. We also assume that the PTP-FTRs Options are allocated to transmission investors based on the following two criteria:

1) The quantity of allocated FTRs $q_{\ell'}$ is equal to the increased transmission capacity on line ℓ through transmission investments.

2) The location of allocated FTRs lies in the most congested line ℓ' in the system after transmission capacity expansion on line ℓ.

With these assumptions, the investors' decision on transmission investments will be based on the judgment on the below (see also (3.6)).

$$\begin{aligned} &\sum_{t=1}^{t_j}\left(q_{\ell'}\left|\Delta LMP_{\ell'}\right|H_{c,\ell'}\left(1+\eta\right)^{t}\right)\geq q_{\ell'}L_{\ell}\upsilon_{\ell}\left(1+\tau\right)^{t_j}\left(1+\rho\right)\left(1+\sigma\right) \\ &s.t. \\ &\qquad t_j \leq T_{e,\ell} \end{aligned} \tag{5.1}$$

Only if (5.1) is satisfied will participants invest in transmission. In (5.1), $q_{\ell'}$ is the quantity of allocated PTP-FTRs Options on line ℓ' for transmission investors who invest on line ℓ, $\Delta LMP_{\ell'}$ is the LMP difference on line ℓ' with line ℓ's capacity expansion. $H_{c,\ell'}$ is the annual average congestion hours on line ℓ', η is the system load growth rate, L_{ℓ} is the length of line ℓ, υ_{ℓ} is the per MW-mile investment cost on line ℓ, τ is the bank annual loan interest rate, ρ is the annual profit rate investors require for the investment on line ℓ, σ is the annual inflation rate, t_j is the number of years after investors make investment decision on line ℓ, and $T_{e,\ell}$ is the economic life of the merchant transmission investments on line ℓ in years.

5.2 ROE-based incentives

Regulated transmission investors rely on granted ROE to recover their investments and make profits. Under the ROE regulation, variable costs are treated as expenses and passed directly into rates, while capital costs are computed by identifying prudently incurred capital investment and assessing the allowed rate of return on this investment to allow the firm to raise capital. In order to promote investments on transmission infrastructure, FERC allows increasing ROE values through adding some ROE adders [59]. These adders are decided case-by-case. In our research, the purpose of regulated transmission investments is to mitigate system congestions. We assume the allowed ROE δ has been decided by a reliability organization to provide enough support for investment cost recovery. The investment judgment is based on the inequality (5.2) below

$$\delta \geq \tau + \rho + \sigma \tag{5.2}$$

If ROE δ is greater than or equal to the summary of loan interest rate τ, profit rate ρ, and inflation rate σ, there will be investment. There may be an additional ROE adder $\Delta\delta$ to be granted to regulated transmission investors with ROE, the investment judgment then becomes

$$\delta + \Delta\delta \geq \tau + \rho + \sigma \qquad (5.3)$$

Similar to the case without an ROE adder, if (5.3) is satisfied, then there will be investment.

5.3 Economic metrics for the effects of transmission investments

In order to measure the efficiency of different transmission investment incentives, we define two metrics: alleviated system congestion rent *dR* and congestion alleviation efficiency (*ICAE*). Conceptually, *dR* is an index to measure the capability of a transmission incentive and transmission expansion strategy to alleviate system congestion rents – the higher the value, the more effective the expansion. Equation (5.4) defines *dR* as the difference of the system congestion rents between the case without transmission expansion and the case with transmission expansion over the entire transmission planning time horizon. In (5.4) AR^{I} is the system congestion rent without transmission expansion, and AR^{II} is the system congestion rent with transmission expansion.

$$dR = AR^{I} - AR^{II} \qquad (5.4)$$

ICAE is defined as the ratio of alleviated system congestion rent and the transmission upgrade or expansion to the initial investment cost *IC*.

$$ICAE = {dR}/{IC} \tag{5.5}$$

ICAE means how much system congestion rent will be eliminated by per unit investment cost in the simulated time horizon, say $10 billions system congestion rent will be eliminated by $1 million transmission investment in 20 years. This is an index to measure the economic efficiency of transmission investment from the perspective of system performance. A larger *ICAE* means higher efficiency in reducing system congestion rents for a given investment in transmission assets.

5.4 Simulation scenarios definition

In chapter 4.2, we defined three optimal transmission expansion strategies to eliminate transmission line congestions: Strategy 1-hard limit expansion, Strategy 2-hard margin expansion, and Strategy 3-soft limit expansion. We also investigate three transmission investment incentives: PTP-FTRs Options for merchant transmission investments, ROE for regulated transmission investments, and ROE+adders for regulated transmission investments. Combining these optimal transmission expansion strategies and transmission investment incentives results in nine different scenarios as detailed in Table 5.4.

Table 5.4 Combination of transmission investment strategies and incentives

Transmission Expansion Strategies	Transmission Investment Category		
	Merchant Investment	Regulated Investment	
	PTP-FTRs Options	ROE	ROE+adders
Strategy 1	Scenario 1	Scenario 4	Scenario 7
Strategy 2	Scenario 2	Scenario 5	Scenario 8
Strategy 3	Scenario 3	Scenario 6	Scenario 9

5.5 Economic analysis

In this section, we present simulation results and analysis from our SD models for nine scenarios.

- **Scenario 1 simulation results**

In this scenario, merchant transmission investors realize hard expansion on most congested lines in the system and rely on allocated PTP-FTRs Options to recover investment and make profit.

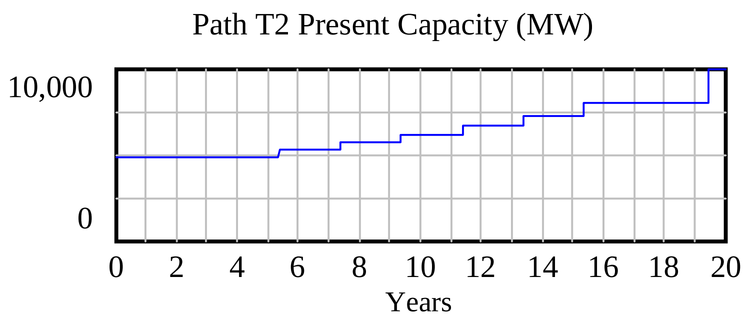

Fig. 5.4 Path T2 capacity change under scenario 1

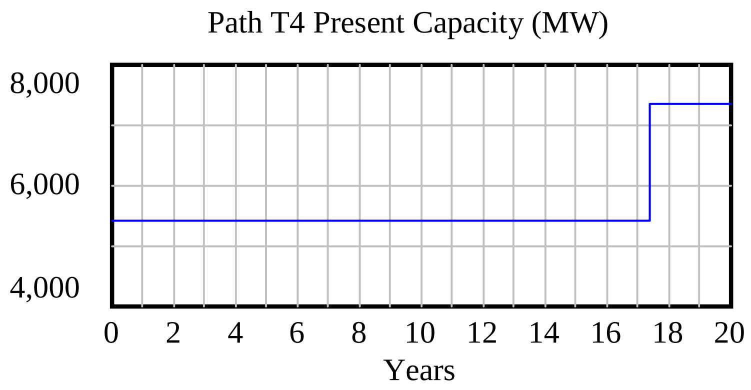

Fig. 5.5 Path T4 capacity change under scenario 1

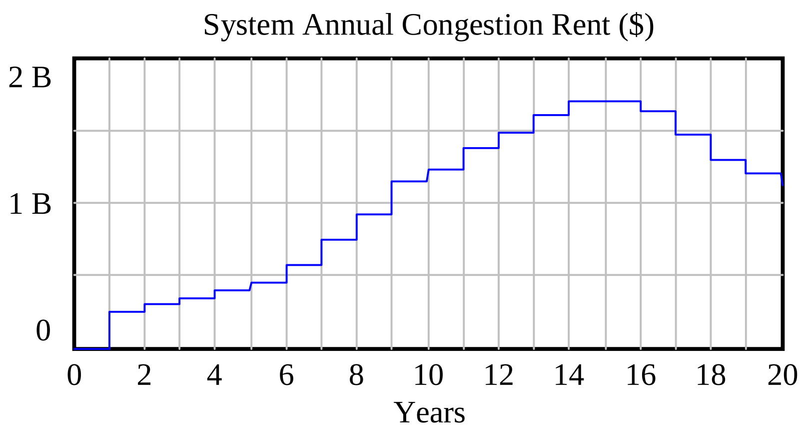

Fig. 5.6 System annual congestion rent change under scenario 1

- **Scenario 2 simulation results**

In this scenario, merchant transmission investors use hard margin expansion on most congested lines in the system and rely on allocated PTP-FTRs Options to recover investment and make profit.

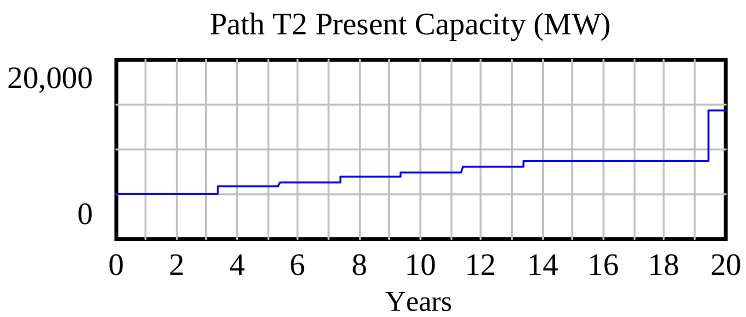

Fig. 5.7 Path T2 capacity change under scenario 2

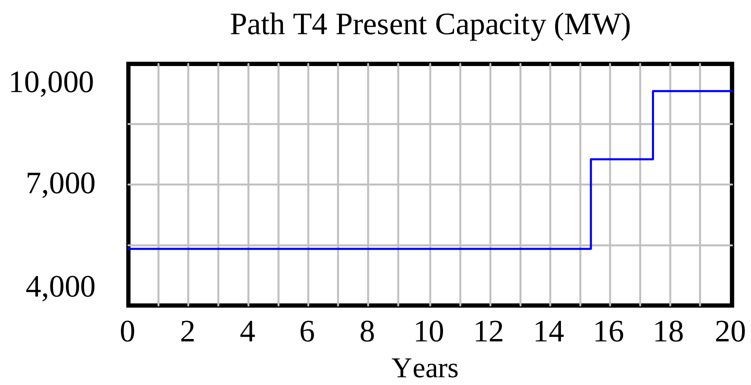

Fig. 5.8 Path T4 capacity change under scenario 2

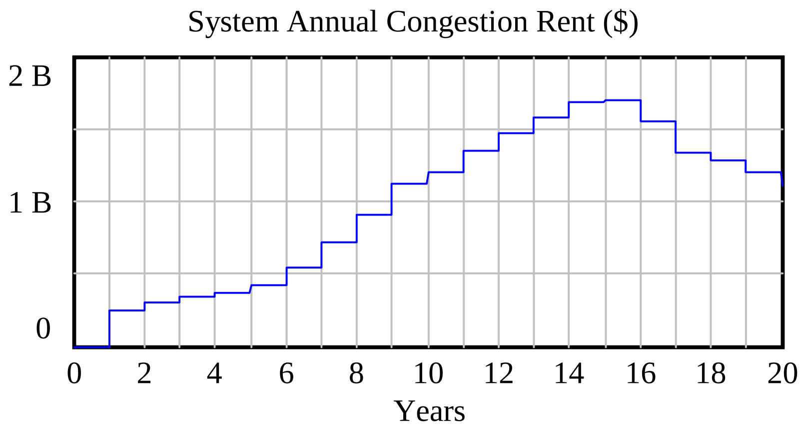

Fig. 5.9 System annual congestion rent change under scenario 2

- **Scenario 3 simulation results**

In this scenario, merchant transmission investors use soft limit expansion on most congested lines in the system and again rely on allocated PTP-FTRs Options to recover investment and make profit.

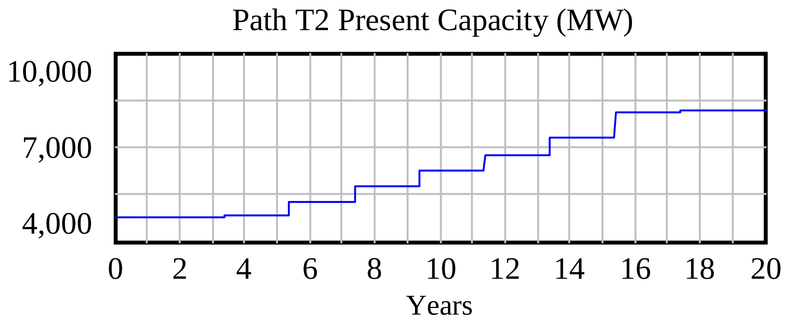

Fig. 5.10 Path T2 capacity change under scenario 3

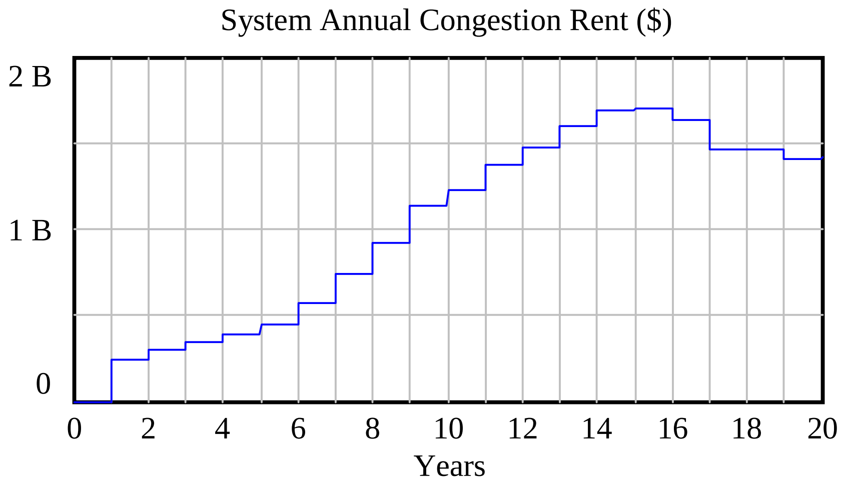

Fig. 5.11 System annual congestion rent change under scenario 3

- **Scenario 4 simulation results**

In this scenario, regulated transmission investors use hard expansion on most congested lines in the system and rely on ROE granted by regulators to recover investment and make profit.

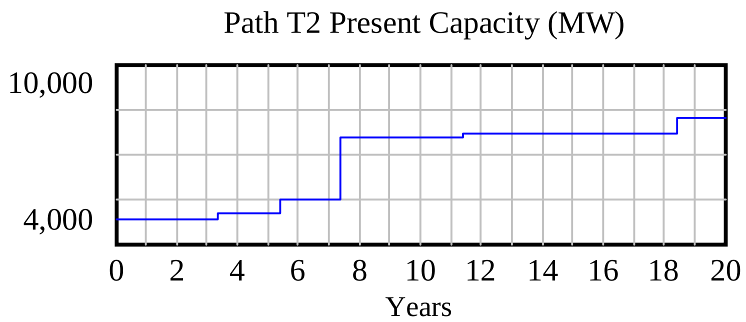

Fig. 5.12 Path T2 capacity change under scenario 4

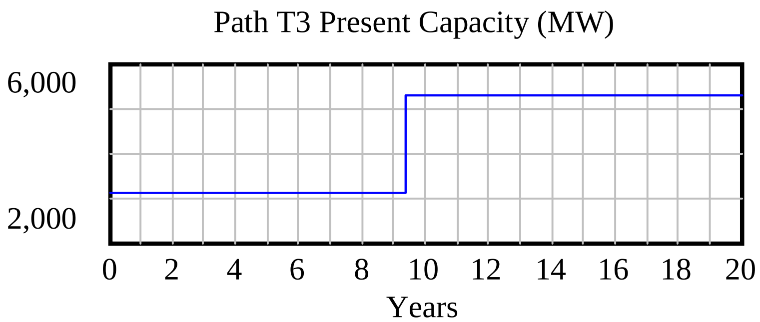

Fig. 5.13 Path T3 capacity change under scenario 4

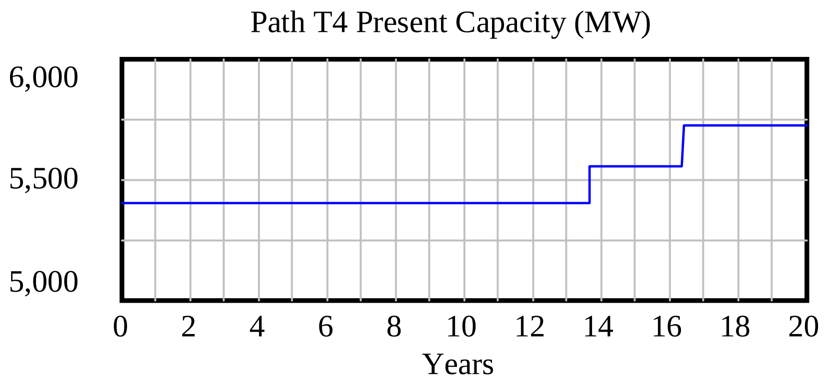

Fig. 5.14 Path T4 capacity change under scenario 4

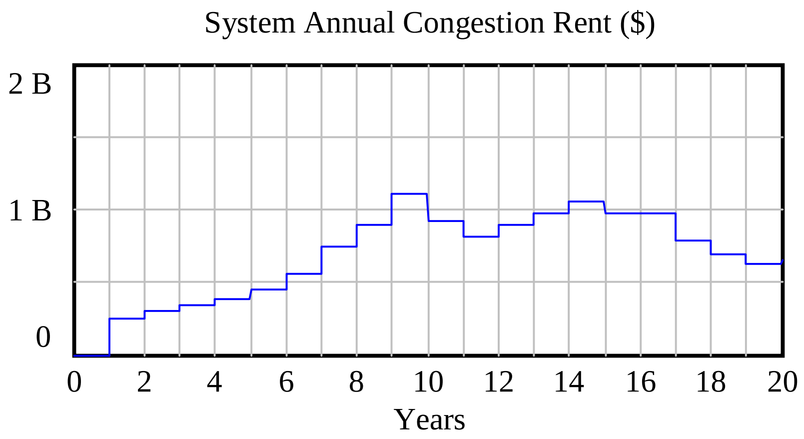

Fig. 5.15 System annual congestion rent change under scenario 4

- **Scenario 5 simulation results**

In this scenario, regulated transmission investors use hard margin expansion on most congested lines in the system and rely on ROE granted by regulators to recover investment and make profit.

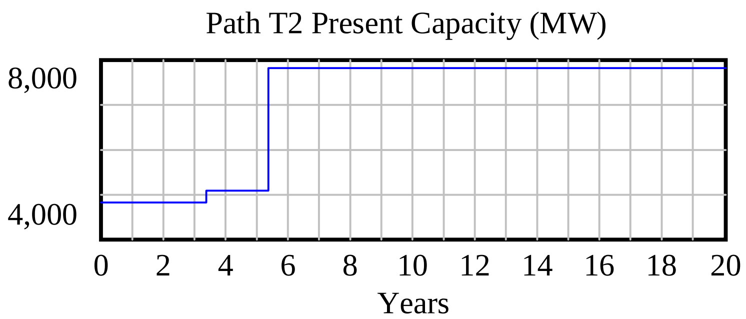

Fig. 5.16 Path T2 capacity change under scenario 5

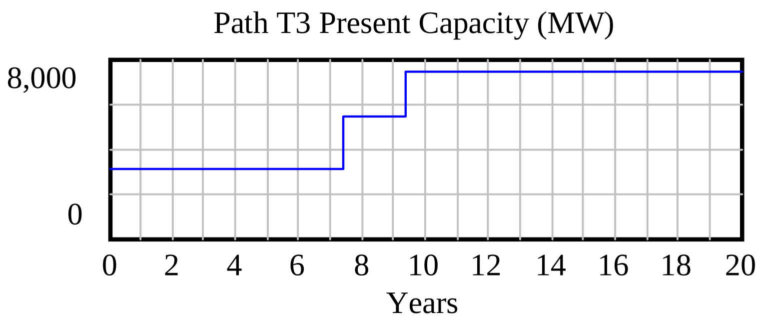

Fig. 5.17 Path T3 capacity change under scenario 5

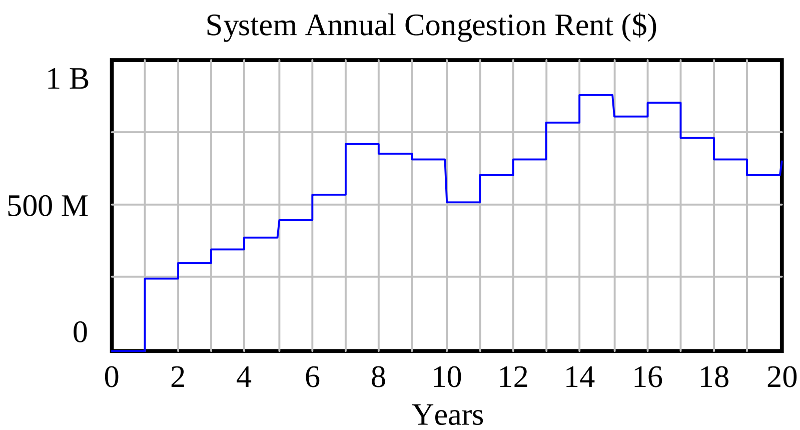

Fig. 5.18 System annual congestion rent change under scenario 5

- **Scenario 6 simulation results**

In this scenario, regulated transmission investors use soft limit expansion on most congested lines in the system and rely on the ROE granted by regulators to recover investment and make profit.

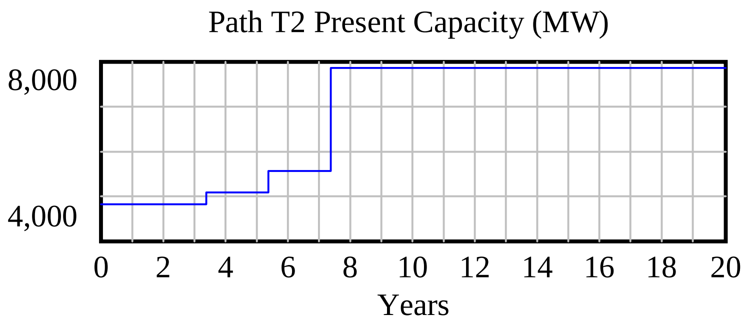

Fig. 5.19 Path T2 capacity change under scenario 6

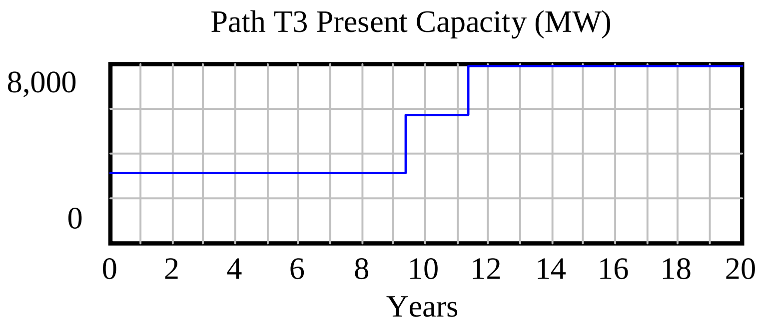

Fig. 5.20 Path T3 capacity change under scenario 6

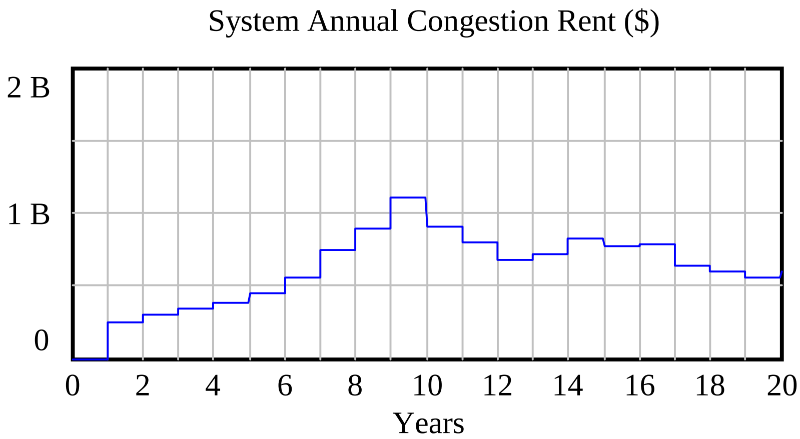

Fig. 5.21 System annual congestion rent change under scenario 6

- **Scenario 7 simulation results**

In this scenario, regulated transmission investors use hard expansion on most congested lines in the system and rely on ROE with an adder granted by regulators to recover investment and make profit.

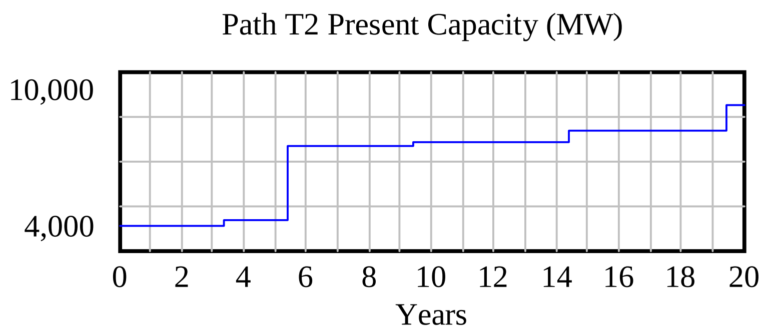

Fig. 5.22 Path T2 capacity change under scenario 7

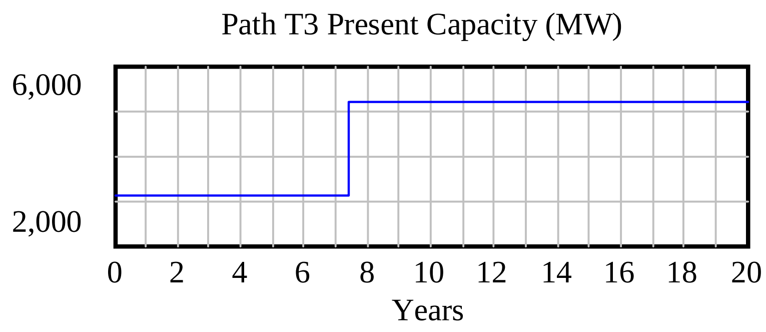

Fig. 5.23 Path T3 capacity change under scenario 7

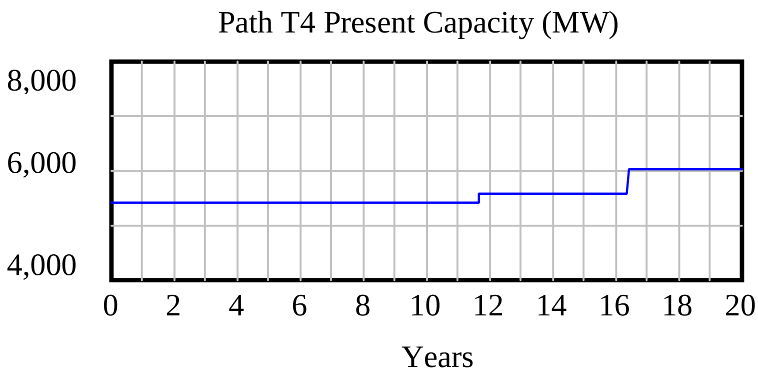

Fig. 5.24 Path T4 capacity change under scenario 7

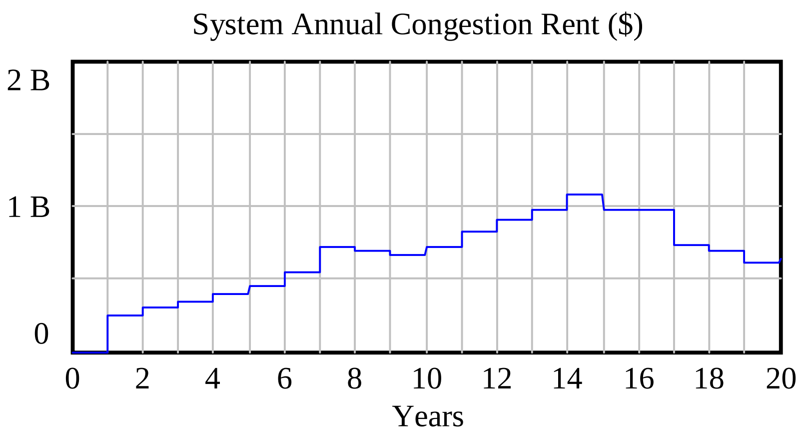

Fig. 5.25 System annual congestion rent change under scenario 7

- **Scenario 8 simulation results**

In this scenario, regulated transmission investors use hard margin expansion on most congested lines in the system, and rely on ROE plus an adder granted by regulators to recover investment and make profit.

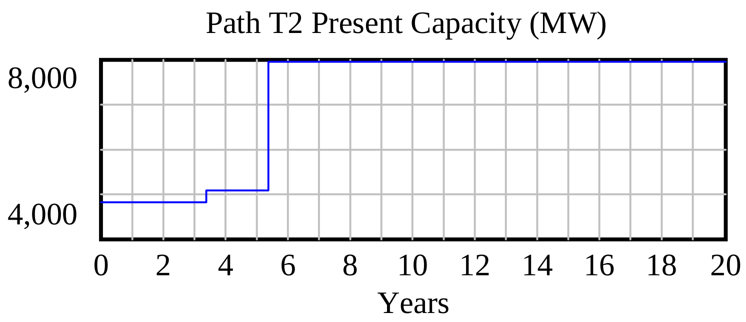

Fig. 5.26 Path T2 capacity change under scenario 8

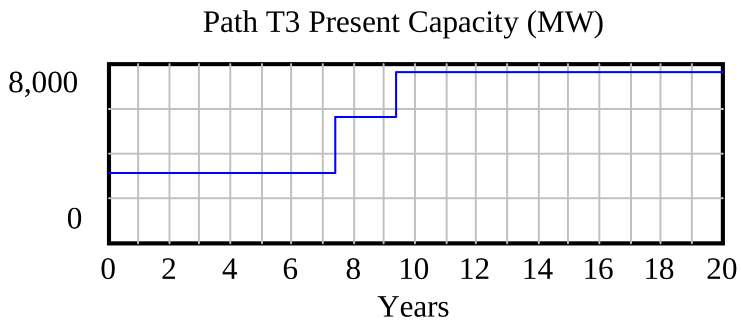

Fig. 5.27 Path T3 capacity change under scenario 8

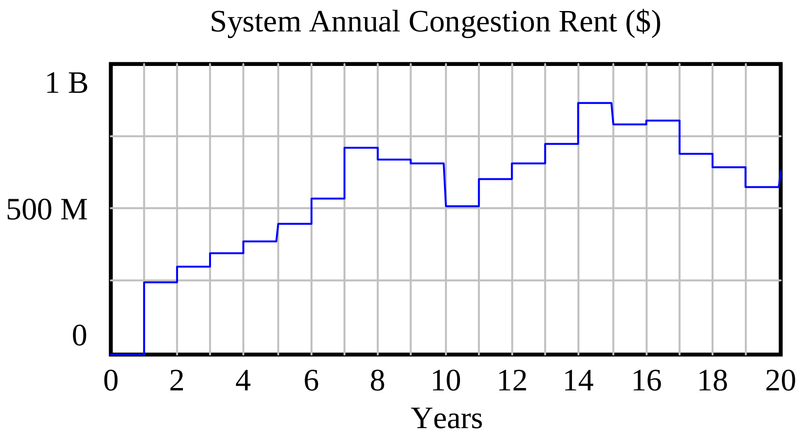

Fig. 5.28 System annual congestion rent change under scenario 8

- **Scenario 9 simulation results**

In this scenario, regulated transmission investors use soft limit expansion on most congested lines in the system and they rely on ROE plus an adder granted by regulators to recover investment and make profit.

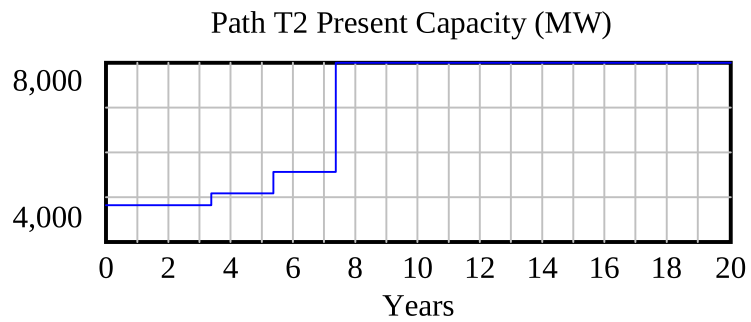

Fig. 5.29 Path T2 capacity change under scenario 9

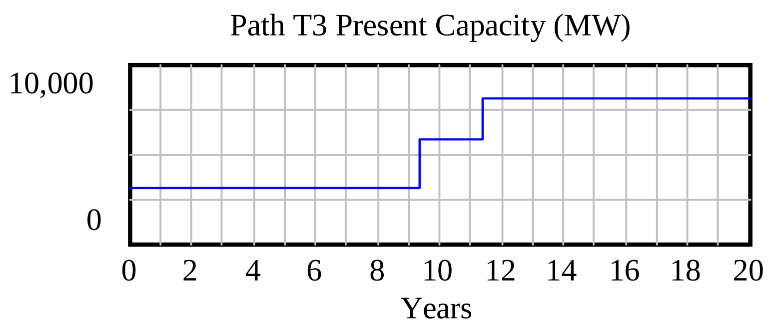

Fig. 5.30 Path T3 capacity change under scenario 9

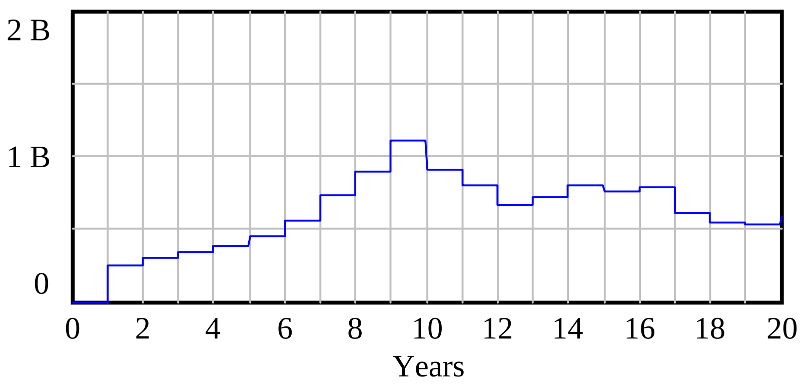

Fig. 5.31 System annual congestion rent change under scenario 9

5.5.1 Economic simulation results analysis

The following summarizes the simulation studies under nine different scenarios. The initial investments *IC*, alleviated system congestion rent *dR*, and investment congestion alleviation efficiency *ICAE* are calculated for all scenarios. Table 5.5 summarizes these calculations. ΔP^{cap} is the path capacity increase in each of the scenarios.

Table 5.5 Simulation results for different scenarios

Scenarios	ΔP^{cap}			***IC***	***dR***	***ICAE***
	T2	T3	T4			
Scenario 1	5039	0	1922	0.444	1.11	2.50
Scenario 2	9510	0	3918	0.865	1.61	1.8613
Scenario 3	3374	0	0	0.181	0.47	2.5967
Scenario 4	3376	2189	319	2.201	7.67	3.4848
Scenario 5	3006	4320	0	4.090	10.04	2.4548
Scenario 6	3075	4782	0	4.514	9.13	2.0226
Scenario 7	4044	2110	605	2.191	8.56	3.9069
Scenario 8	3140	4501	0	4.262	10.27	2.4097
Scenario 9	3174	4954	0	4.676	9.29	1.9867

*Units: ΔP^{cap} in MW; *IC*, *dR* in billion dollars

From the figures for each scenario and Table 5.5, we observe that

- The system annual congestion rent does not generally decrease quickly with transmission capacity expansion. The impact of transmission capacity expansion on system congestion rent must be observed over a sufficiently long time span. Without modeling the information feedback, one would not be able to observe this type of behavior. This shows one example where static and multi-stage planning approaches could be misleading in the impacts of transmission investment potentially leading to poor decisions based on a single snap shot of current congestion rents.
- From the alleviated system congestion rent *dR* point of view, Scenario 8 has the best performance. The alleviated system congestion rent by Scenario 8 is $10.27 billion. This is $9.8 billion more than that for Scenario 3, which reduces system congestion rent the least among all scenarios. Scenario 5 performs nearly as well as Scenario 8 with only $0.23 billion more in congestion rent.
- From the investment congestion alleviation efficiency (*ICAE*) point of view, Scenario 7 performs best. The *ICAE* for Scenario 7 is 3.9069, which is 2.0456 more (or 48%) than the worst performing Scenario 2. *ICAE* for Scenario 4 performs nearly (89%) as well as Scenario 7.
- For merchant transmission investment incentivized by allocated PTP-FTRs Options (Scenario 1 ~ Scenario 3), Scenario 2 (hard margin expansion strategy) mitigates $1.61 billion in congestion rents. This is the best strategy

from the perspective of system congestion rent mitigation. The highest transmission investment economic efficiency comes from Scenario 3 (soft limit expansion strategy) at 2.5967. This is the best strategy from the perspective of economic efficiency of transmission investment.

- For ROE with/without adders based on regulated transmission investment (Scenario 4 ~ Scenario 9), ROE with adders Scenarios are better than ROE without adders in both system congestion rent alleviation and economic efficiency of transmission investment.
- For ROE without adders based regulated transmission investment (Scenario 4 ~ Scenario 6), Scenario 5 (hard margin expansion strategy) performs best in alleviating system congestion rents. Scenario 4 (hard limit expansion strategy) has the highest economy efficiency of transmission investment.
- For ROE with adders based regulated transmission investment (Scenario 7 ~ Scenario 9), Scenario 8 (hard margin expansion strategy) performs best in alleviating system congestion rents. Scenario 7 (hard limit expansion strategy) has the highest economy efficiency of transmission investment.

5.6 Sensitivity Analysis

In order to understand the behavioral boundaries of the modeled WECC system and to test the robustness of different transmission investment incentives, sensitivity simulations are performed. In the sensitivity simulations, a few model parameters are selected and varied over a specified range during the simulations. Based on these

Table 5.6 Parameter settings for sensitivity analysis

Parameters	**Minimum value**	**Maximum value**	**Distribution**
Time for construction (years)	0	5	Uniform
Annual loan interest rate	5%	15%	Uniform
Annual profit rate	5%	15%	Uniform

simulation results, we analyze the impacts on transmission investments and system congestion rents, and the robustness of modeled system.

Three parameters for sensitivity analysis are "time for construction", "annual loan interest rate" and "annual profit rate". The detailed parameter settings are given in Table 5.6. The reasons we selected these parameters are: 1). time delay often plays an important role in SD models; 2) Bank loan interest rate and investors' profit rate play important roles in transmission investment decisions. These parameters will randomly change between the given minimum and maximum values according to defined probability distributions. For the defined nine scenarios in Table 5.4, each parameter will be changed and simulated for sensitivity analysis.

In the following figures for simulation results, the sensitivities are shown as confidence bounds. In the simulation results, only path T2~T4's capacity will change with the different parameters, and all other paths' capacities do not change. So we only show path T2 ~ T4's capacity and system annual congestion rents in the following simulation results.

- **Scenario 1 simulation results**

In this scenario, merchant transmission investors make hard limit expansion on most congested lines in the system, and they rely on allocated PTP-FTRs Options to recover their investments and make profits.

- Sensitivity simulation results for time for construction.

From the simulation results, we can see that path T2 is sensitive to the time for construction; path T3 is not sensitive to this parameter, and path T4 is sensitive to this parameter after the 17th year. System annual congestion rent is not particularly sensitive to this parameter.

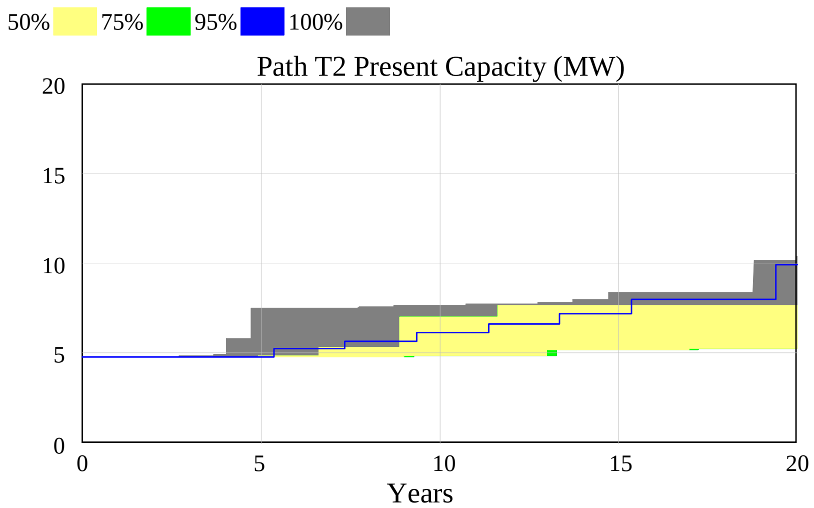

Fig. 5.32 Sensitivity of Path T2 expansion to time for construction under scenario 1

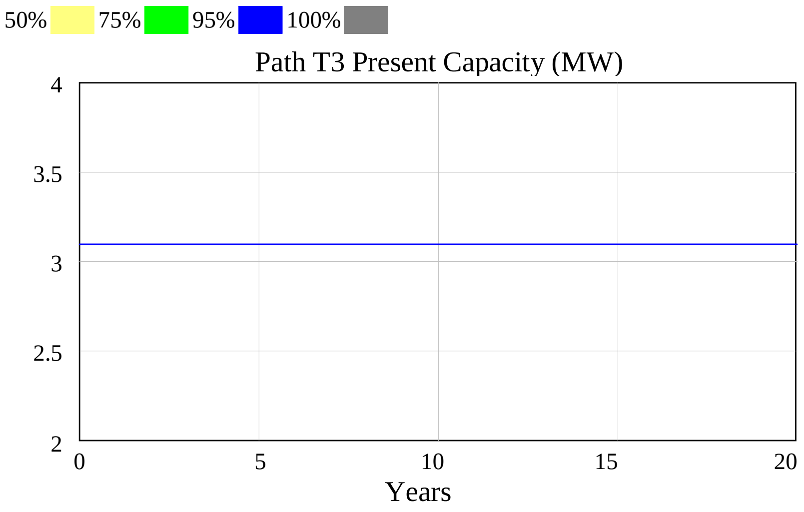

Fig. 5.33 Sensitivity of Path T3 expansion to time for construction under scenario 1

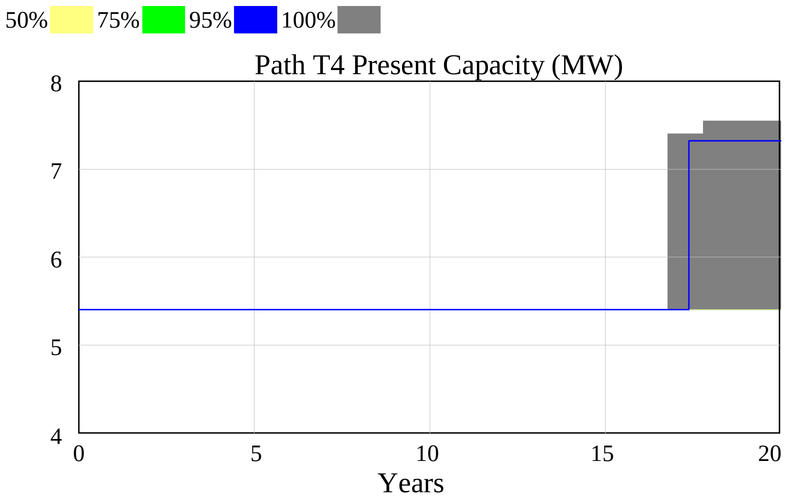

Fig. 5.34 Sensitivity of Path T4 expansion to time for construction under scenario 1

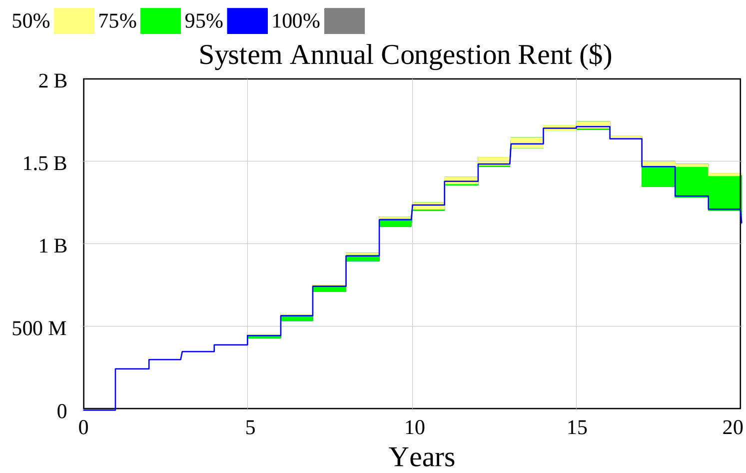

Fig. 5.35 Sensitivity of system annual congestion rent to time for construction under scenario 1

- Sensitivity simulation results for annual loan interest rate

From the simulation results, we can again see that path T2 is sensitive to the annual loan interest rate; path T3 is not sensitive to this parameter, and path T4 is sensitive to this parameter after the 17th year. System annual congestion rent is not particularly sensitive to this parameter.

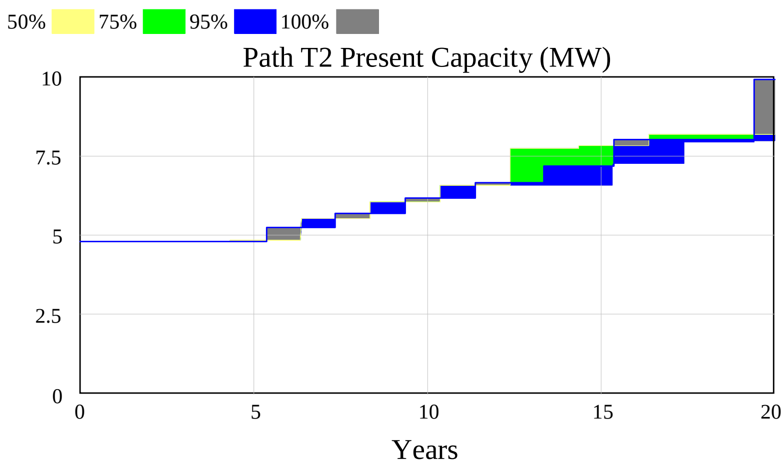

Fig. 5.36 Sensitivity of Path T2 expansion to annual loan interest rate under scenario 1

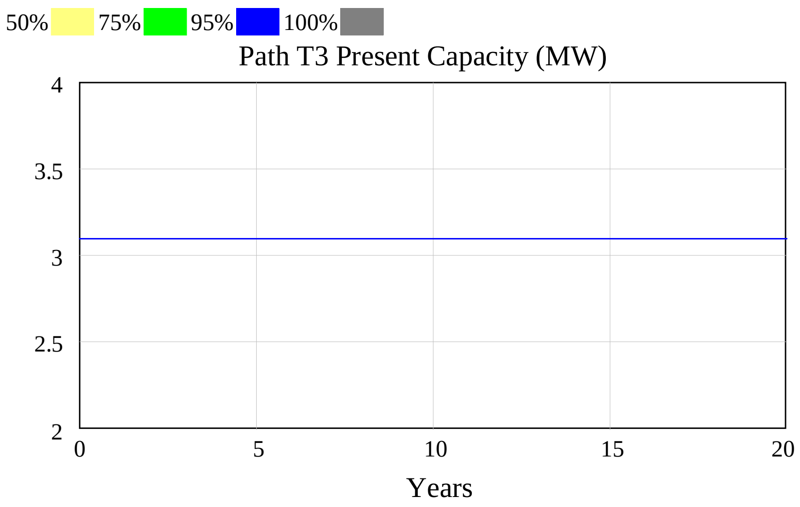

Fig. 5.37 Sensitivity of Path T3 expansion to annual loan interest rate under scenario 1

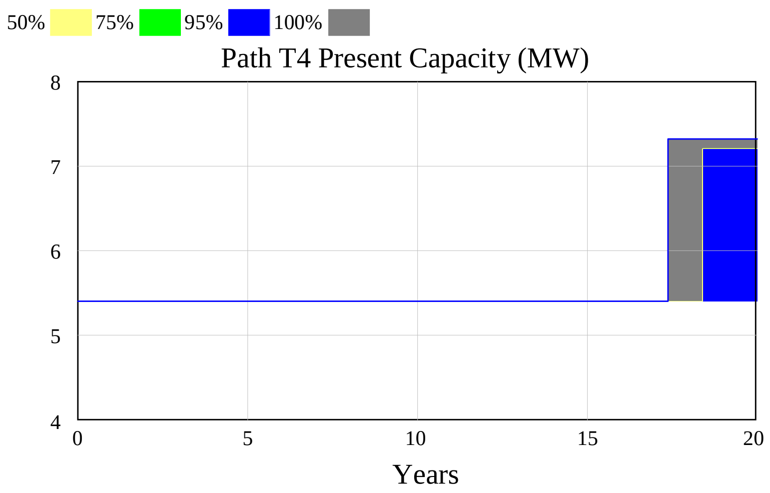

Fig. 5.38 Sensitivity of Path T4 expansion to annual loan interest rate under scenario 1

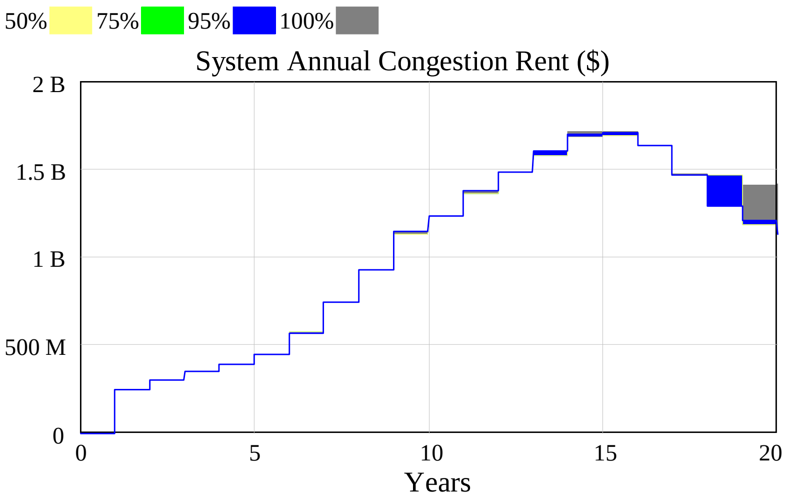

Fig. 5.39 Sensitivity of system annual congestion rent
to annual loan interest rate under scenario 1

- Sensitivity simulation results for annual profit rate

From the simulation results, we can see that path T2 ~ T4 are not sensitive to the annual profit rate. System annual congestion rent is also not sensitive to this parameter.

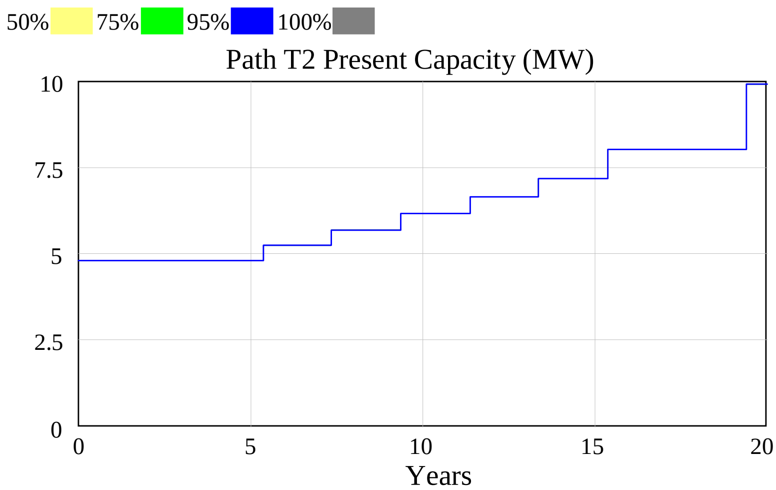

Fig. 5.40 Sensitivity of Path T2 expansion to annual
profit rate under scenario 1

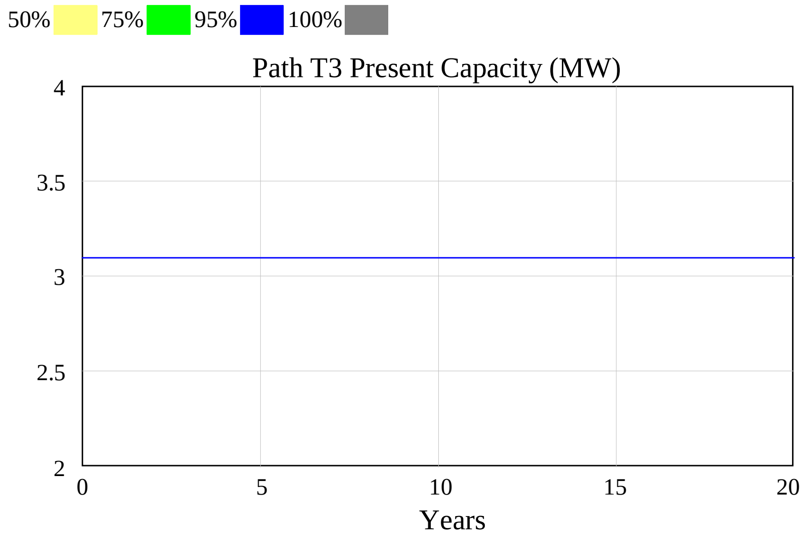

Fig. 5.41 Sensitivity of Path T3 expansion to annual profit rate under scenario 1

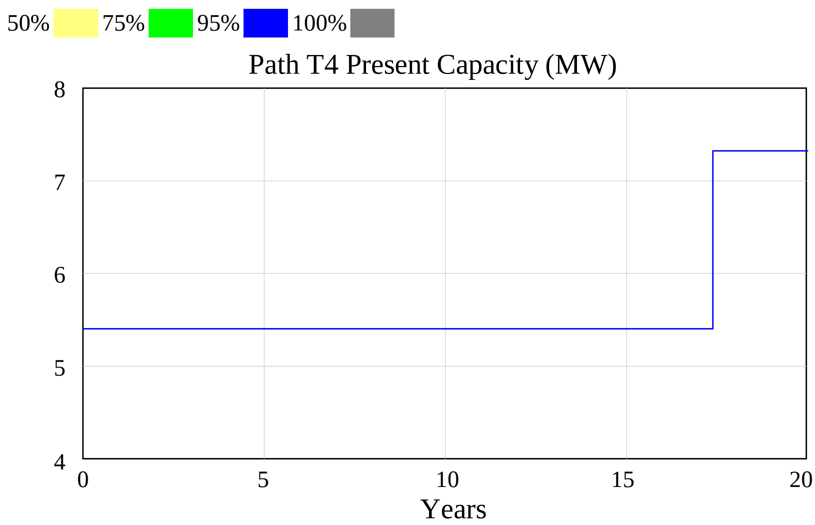

Fig. 5.42 Sensitivity of Path T4 expansion to annual profit rate under scenario 1

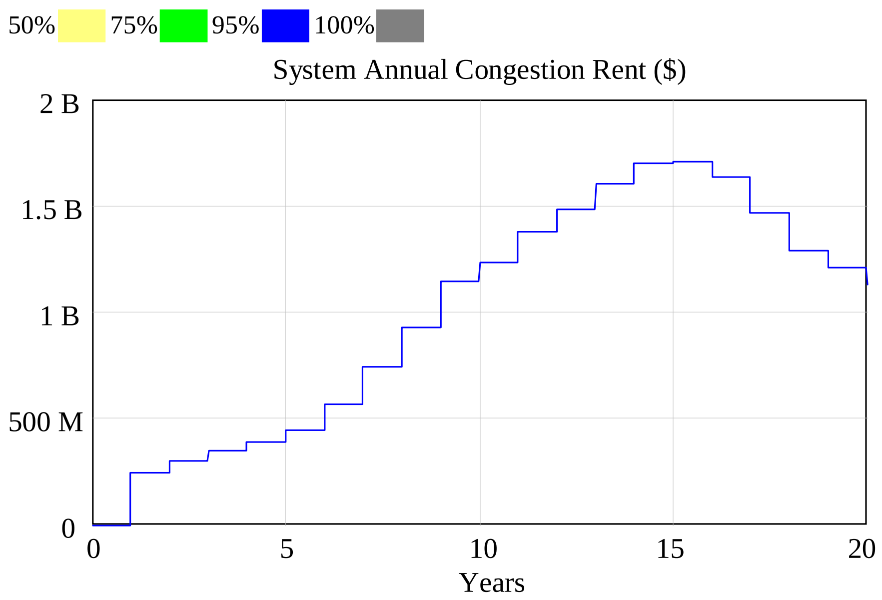

Fig. 5.43 Sensitivity of system annual congestion rent to annual profit rate under scenario 1

- **Scenario 2 simulation results**

In this scenario, merchant transmission investors employ hard margin expansion on the most congested lines in the system, and they rely on allocated PTP-FTRs options to recover their investments and make profits.

- Sensitivity simulation results for time for construction

From the simulation results, we can see that path T2 is sensitive to the time for construction; path T3 is not sensitive to this parameter, and path T4 is sensitive to this parameter after the 15^{th} year. System annual congestion rent is not very sensitive to this parameter.

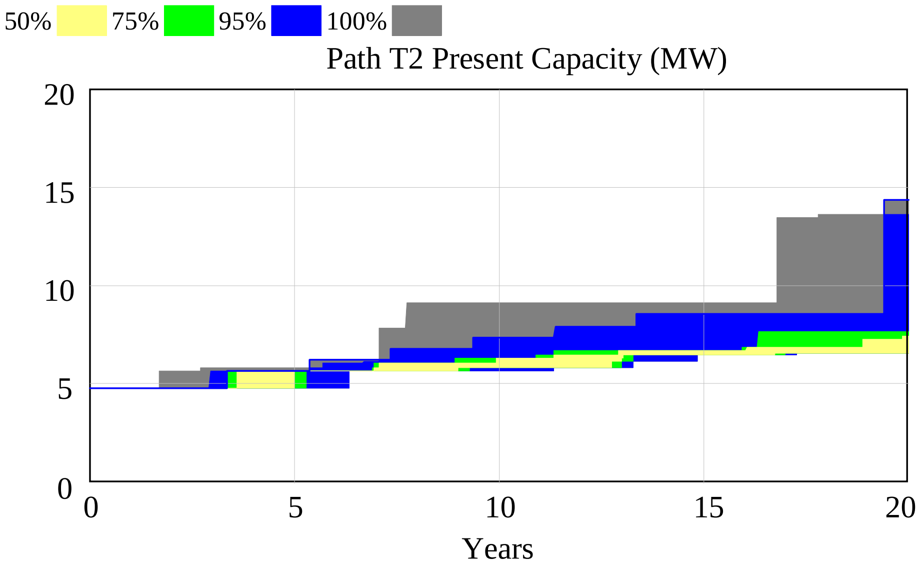

Fig. 5.44 Sensitivity of Path T2 expansion to time
for construction under scenario 2

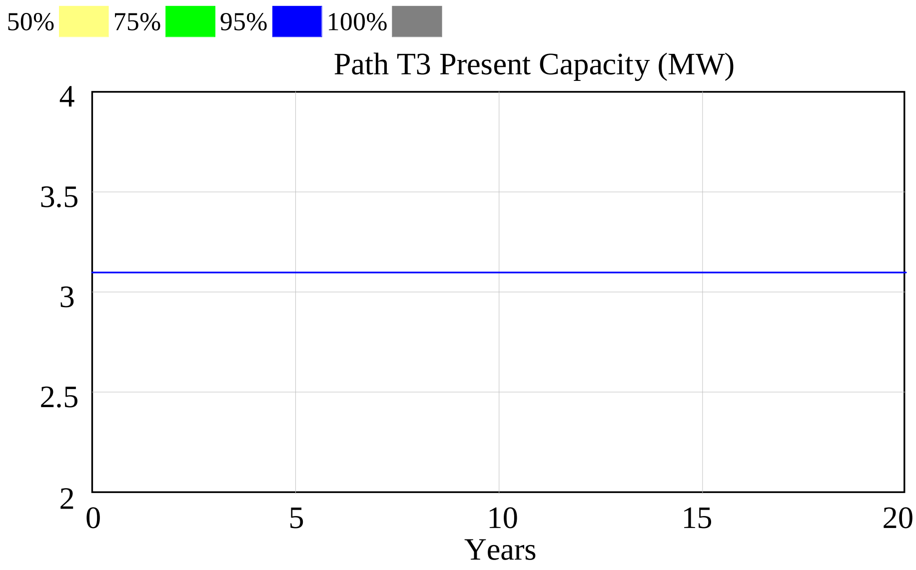

Fig. 5.45 Sensitivity of Path T3 expansion to time
for construction under scenario 2

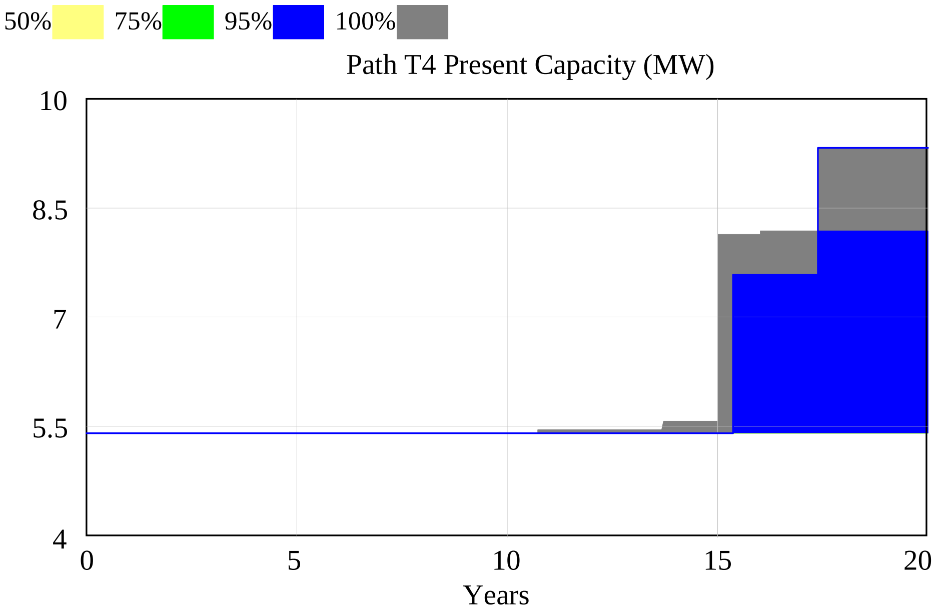

Fig. 5.46 Sensitivity of Path T4 expansion to time
for construction under scenario 2

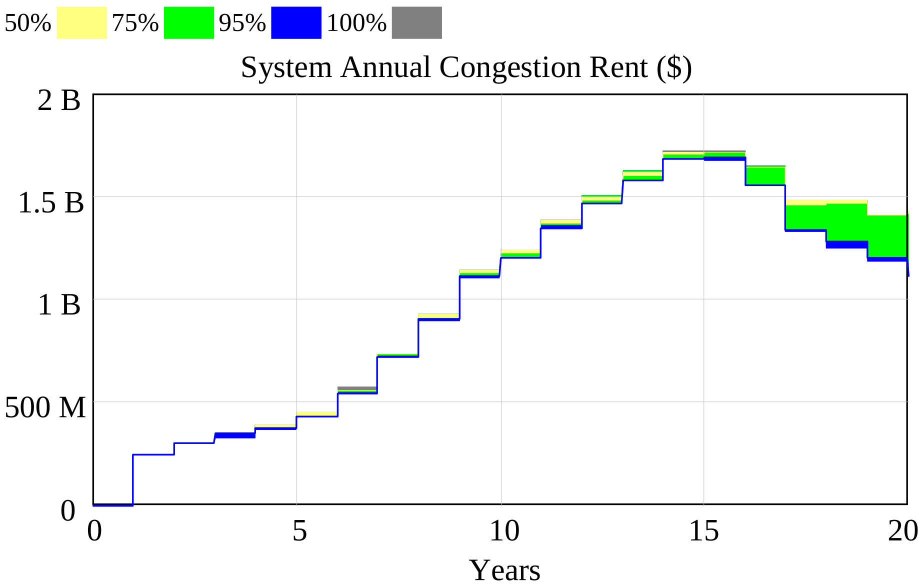

Fig. 5.47 Sensitivity of system annual congestion rent to time
for construction under scenario 2

- Sensitivity simulation results for annual loan interest rate

From the simulation results, we can see that path T2 is not very sensitive to the annual loan interest rate; path T3 is not sensitive to this parameter, and path T4 is sensitive to this parameter after around the 15th year. System annual congestion rent is not very sensitive to this parameter.

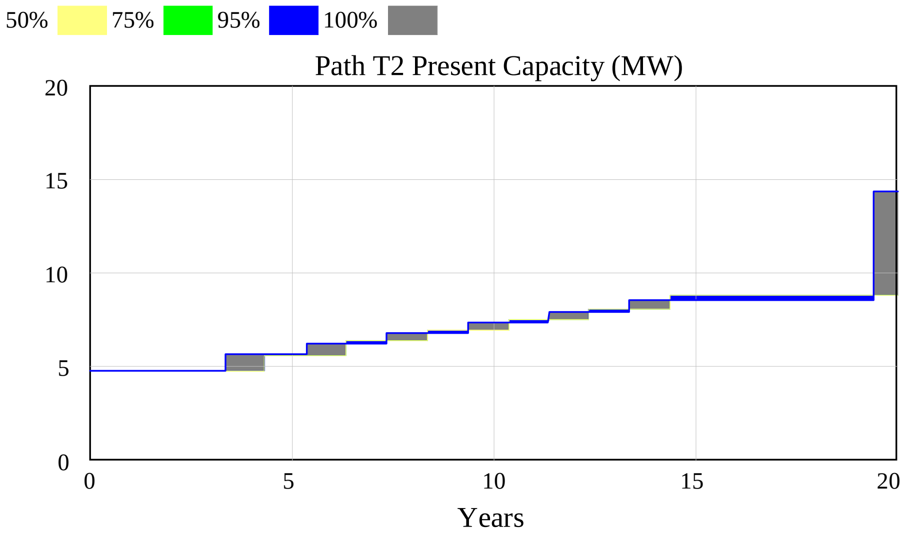

Fig. 5.48 Sensitivity of Path T2 expansion to annual loan interest rate under scenario 2

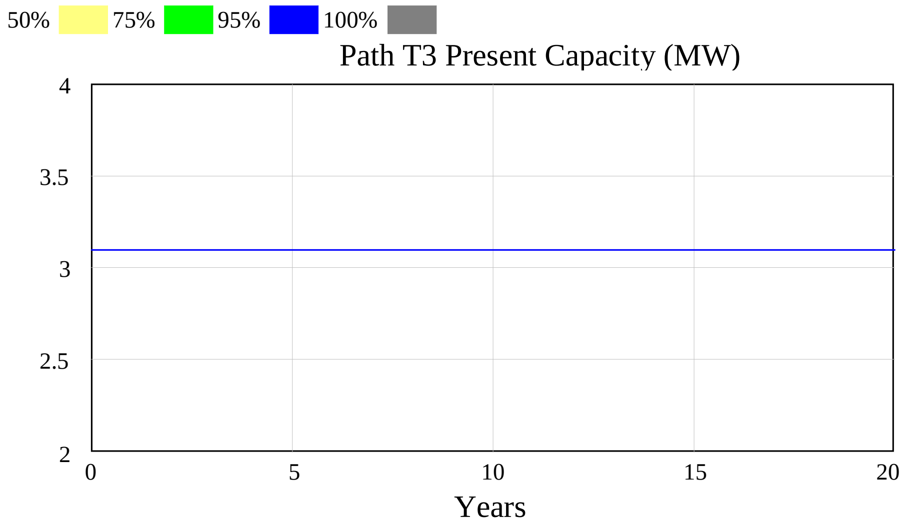

Fig. 5.49 Sensitivity of Path T3 expansion to annual loan interest rate under scenario 2

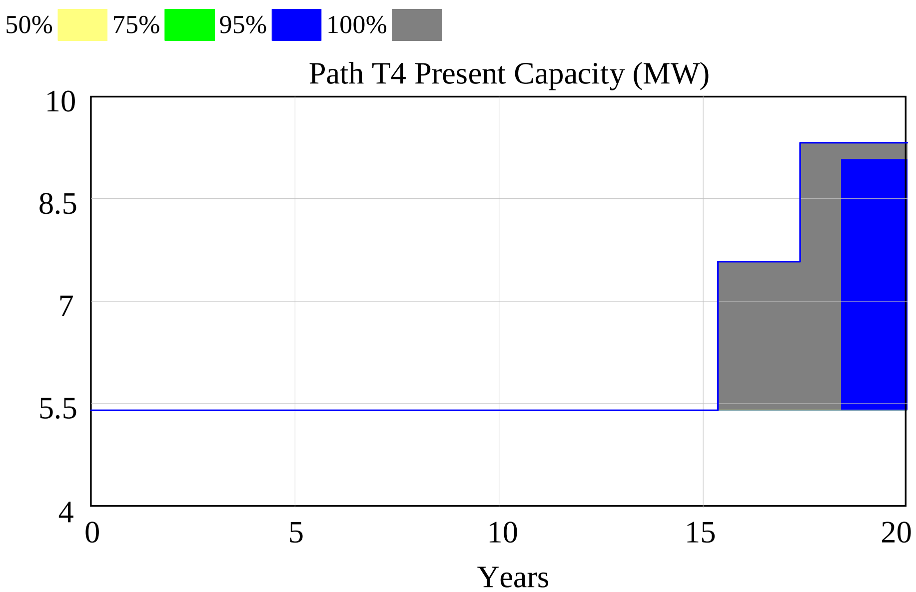

Fig. 5.50 Sensitivity of Path T4 expansion to annual loan interest rate under scenario 2

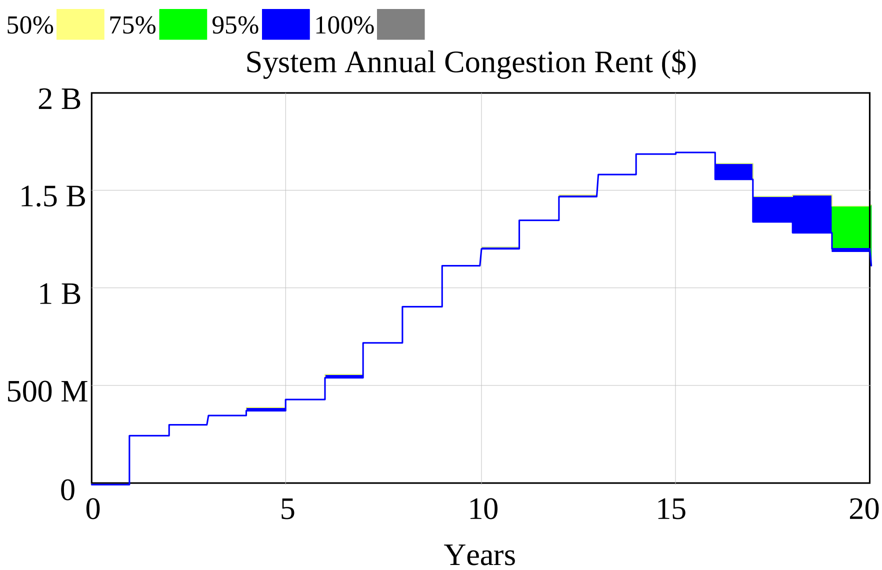

Fig. 5.51 Sensitivity of system annual congestion rent to annual loan interest rate under scenario 2

- Sensitivity simulation results for annual profit rate

From the simulation results, we can see that path T2 ~ T4 are not sensitive to the annual profit rate. System annual congestion rent is also not sensitive to this parameter.

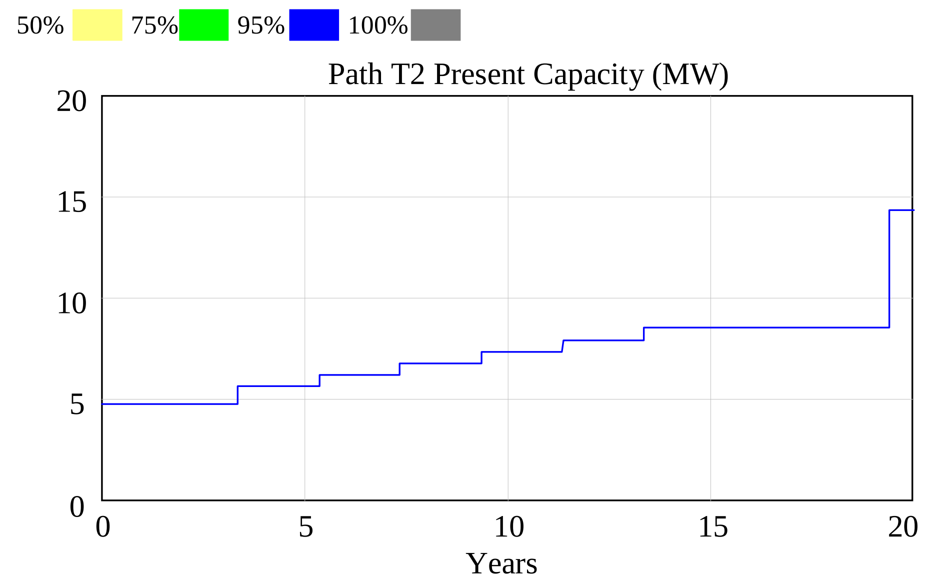

Fig. 5.52 Sensitivity of Path T2 expansion to annual
profit rate under scenario 2

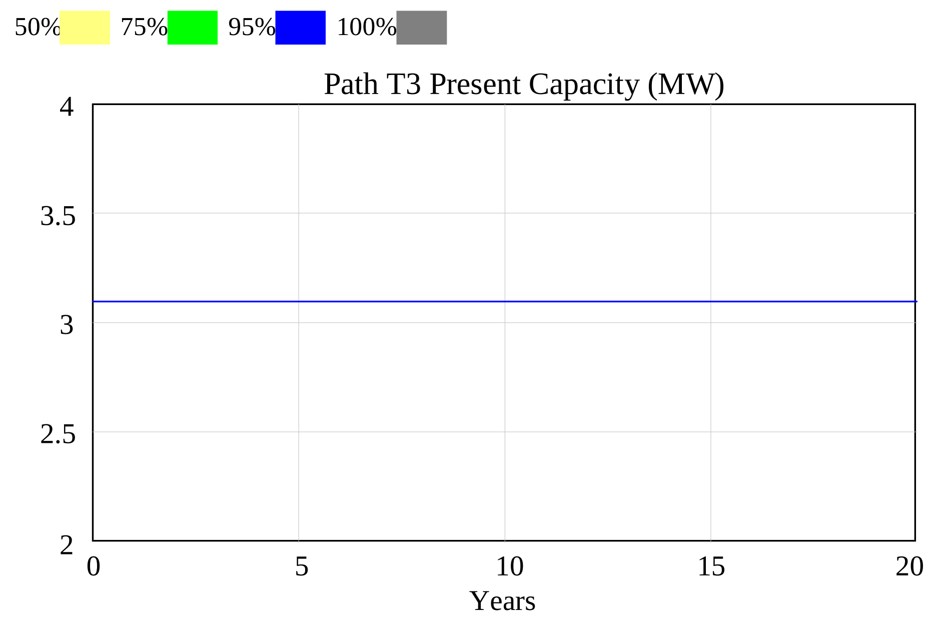

Fig. 5.53 Sensitivity of Path T3 expansion to annual
profit rate under scenario 2

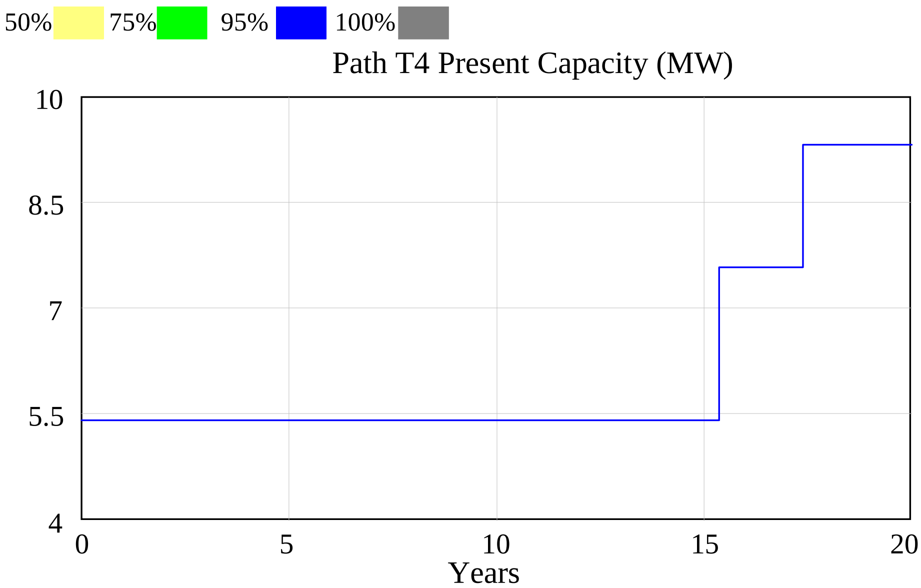

Fig. 5.54 Sensitivity of Path T4 expansion to annual profit rate under scenario 2

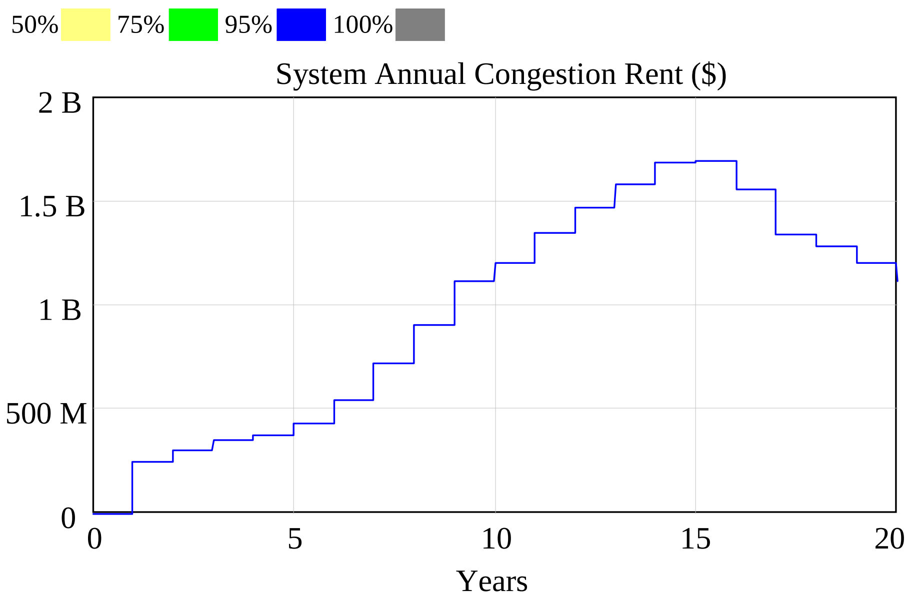

Fig. 5.55 Sensitivity of system annual congestion rent to annual profit rate under scenario 2

- **Scenario 3 simulation results**

In this scenario, merchant transmission investors employ soft limit expansion on the most congested lines in the system, and they rely on allocated PTP-FTRs options to recover their investments and make profits.

- Sensitivity simulation results for time for construction

From the simulation results, we can see that path T2 is sensitive to the time for construction; paths T3 and T4 are not sensitive to this parameter. System annual congestion rent is a little bit sensitive to this parameter after year 15.

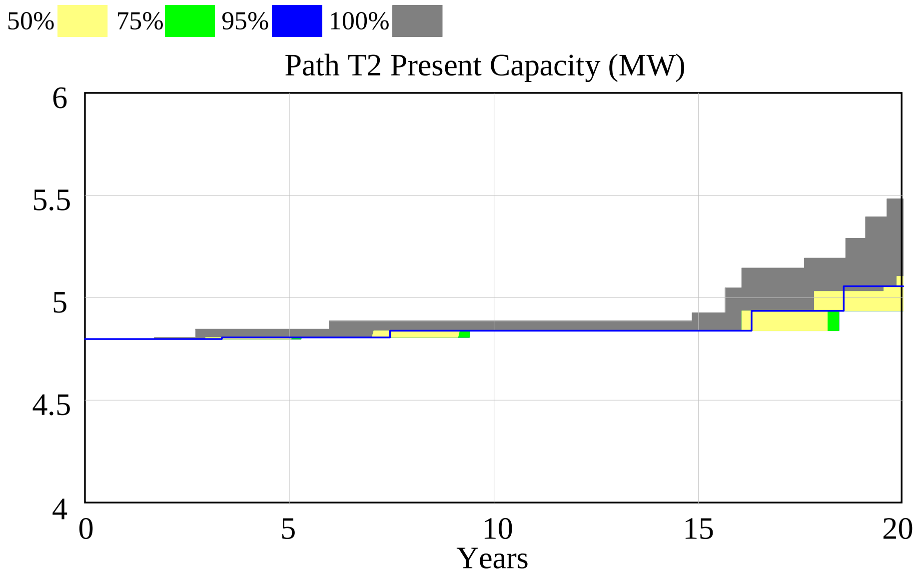

Fig. 5.56 Sensitivity of Path T2 expansion to time
for construction under scenario 3

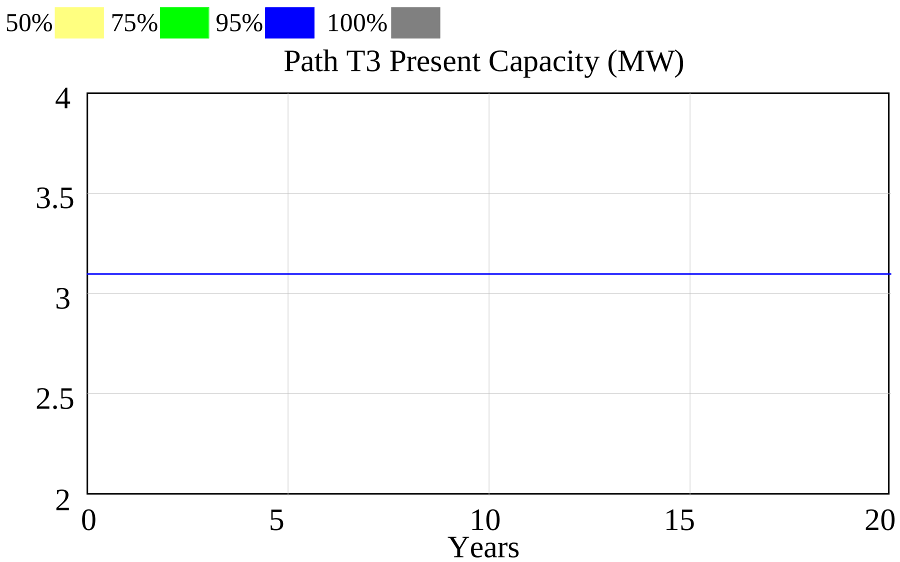

Fig. 5.57 Sensitivity of Path T3 expansion to time
for construction under scenario 3

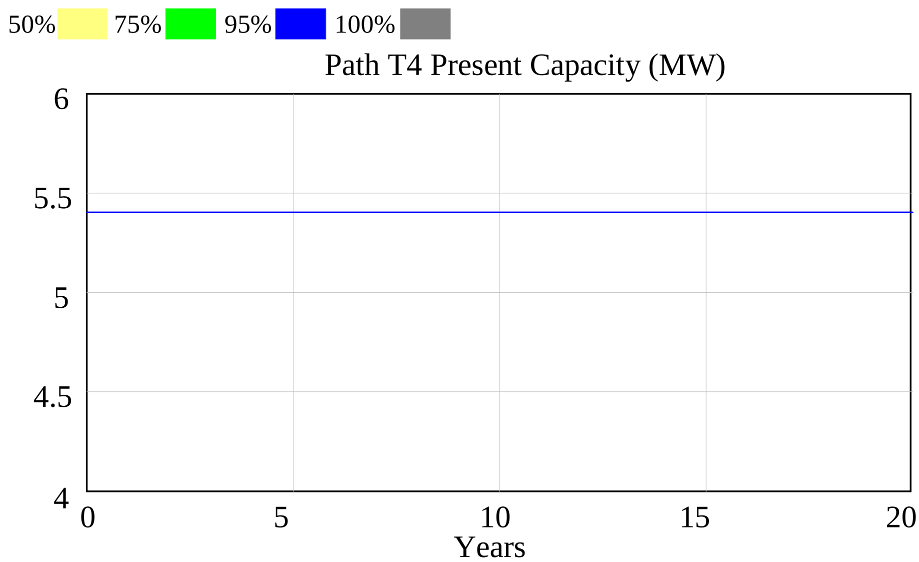

Fig. 5.58 Sensitivity of Path T4 expansion to time
for construction under scenario 3

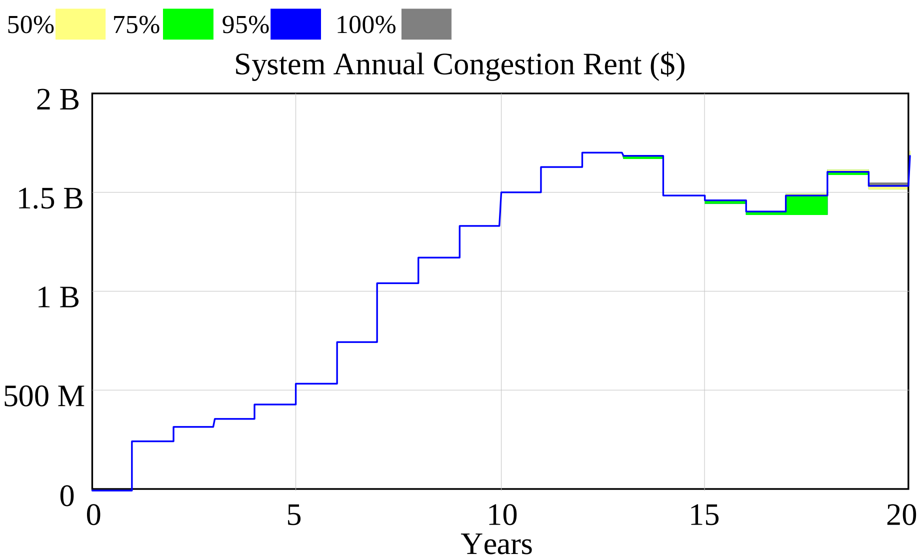

Fig. 5.59 Sensitivity of system annual congestion rent to time
for construction under scenario 3

- Sensitivity simulation results for annual loan interest rate

From the simulation results, we can see that path T2 is sensitive to the annual loan interest rate; paths T3 and T4 are not sensitive to this parameter. System annual congestion rent is a little bit sensitive to this parameter.

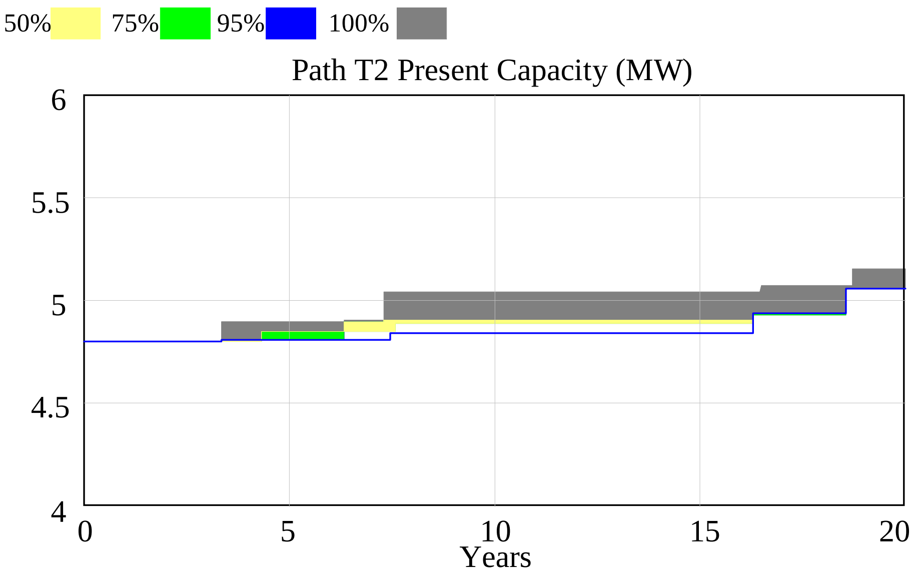

Fig. 5.60 Sensitivity of Path T2 expansion to annual loan interest rate under scenario 3

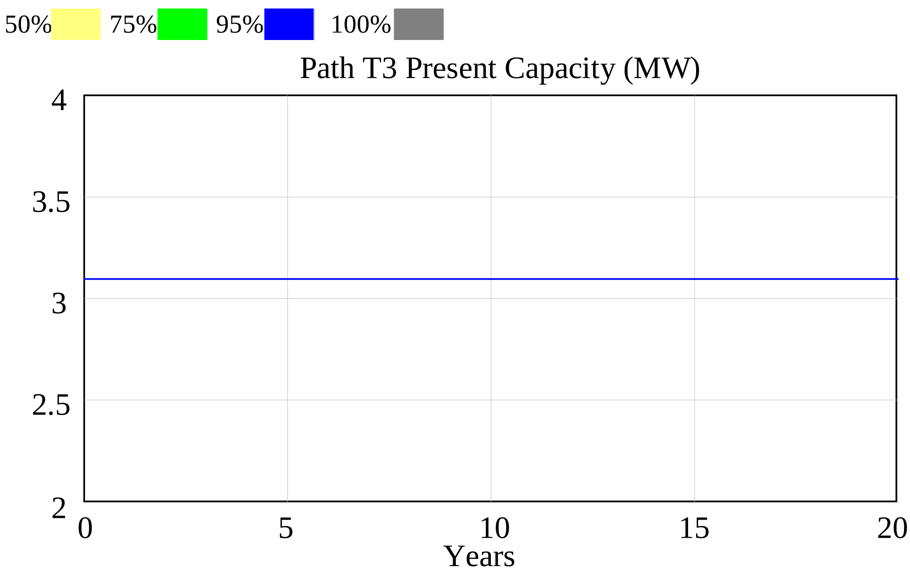

Fig. 5.61 Sensitivity of Path T3 expansion to annual loan interest rate under scenario 3

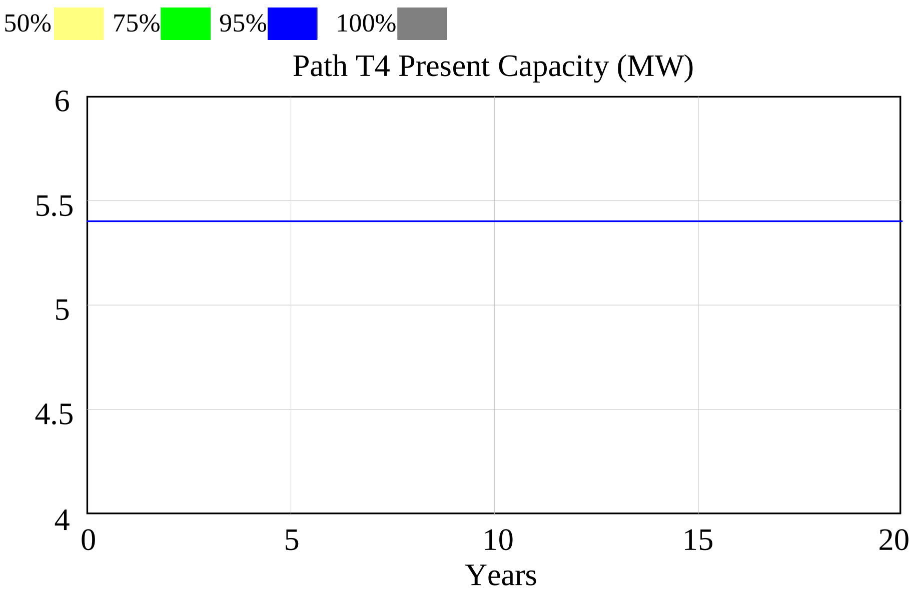

Fig. 5.62 Sensitivity of Path T4 expansion to annual loan interest rate under scenario 3

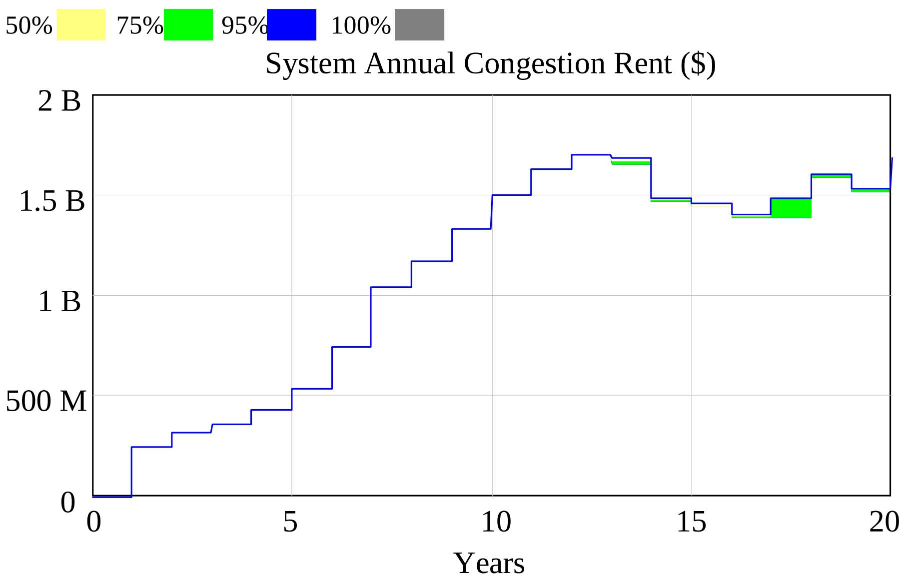

Fig. 5.63 Sensitivity of system annual congestion rent to annual loan interest rate under scenario 3

- Sensitivity simulation results for annual profit rate

From the simulation results, we can see that paths T2 ~ T4 are not sensitive to the annual profit rate. System annual congestion rent is also not sensitive to this parameter.

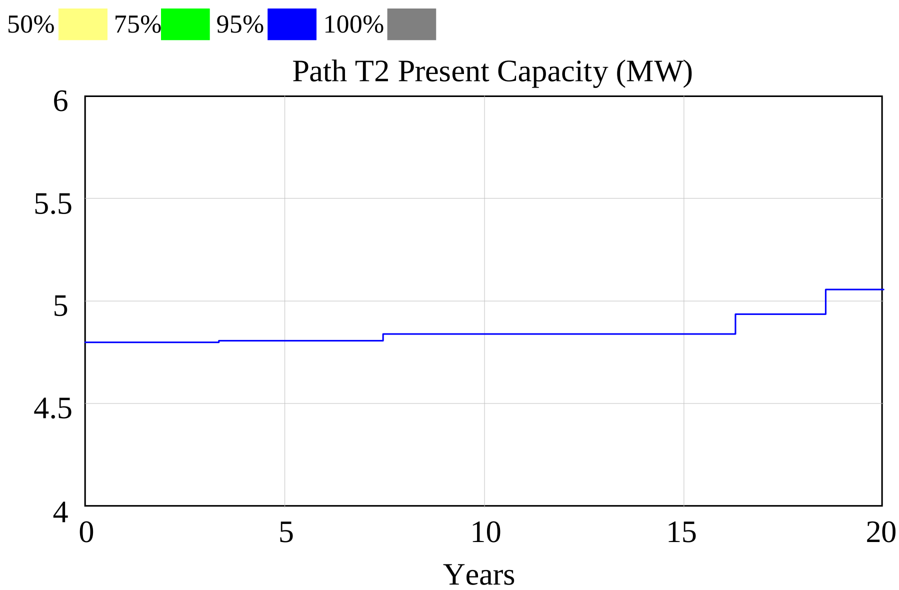

Fig. 5.64 Sensitivity of Path T2 expansion to annual profit rate under scenario 3

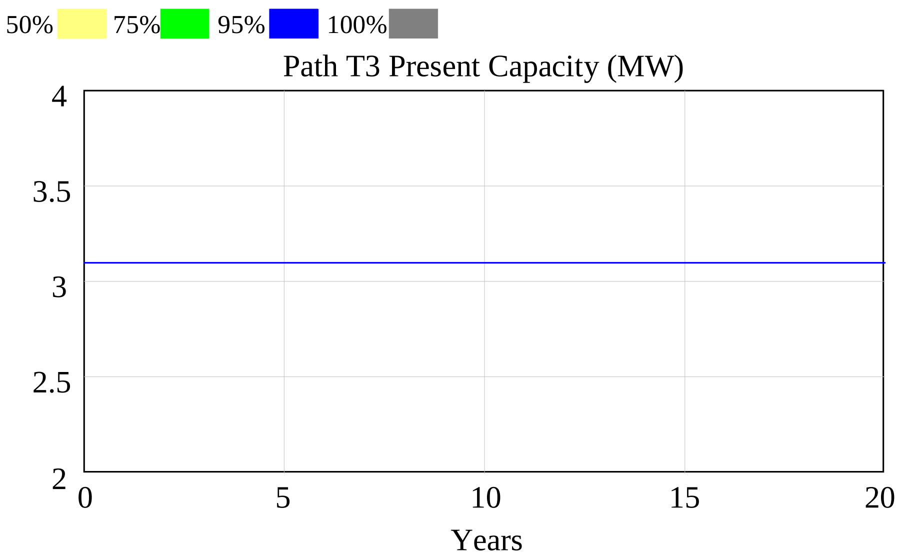

Fig. 5.65 Sensitivity of Path T3 expansion to annual profit rate under scenario 3

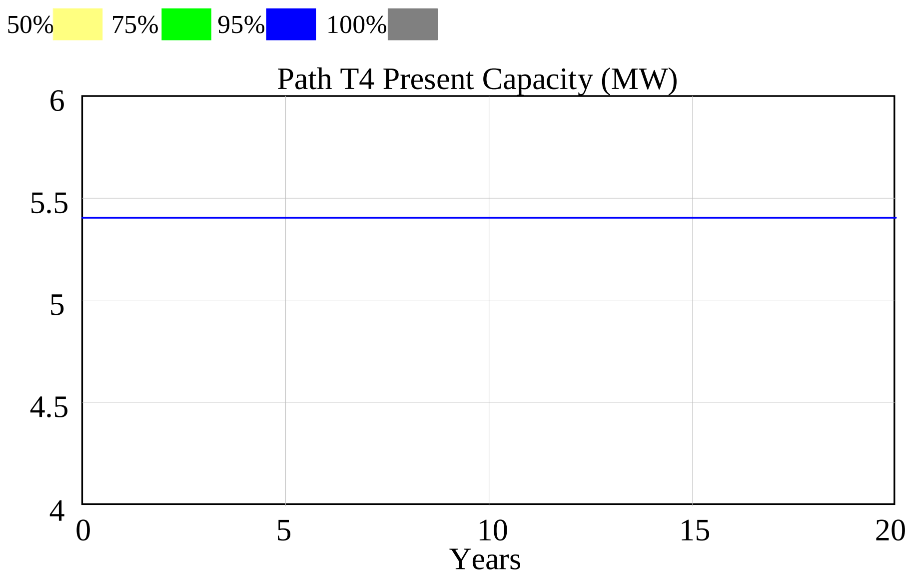

Fig. 5.66 Sensitivity of Path T4 expansion to annual profit rate under scenario 3

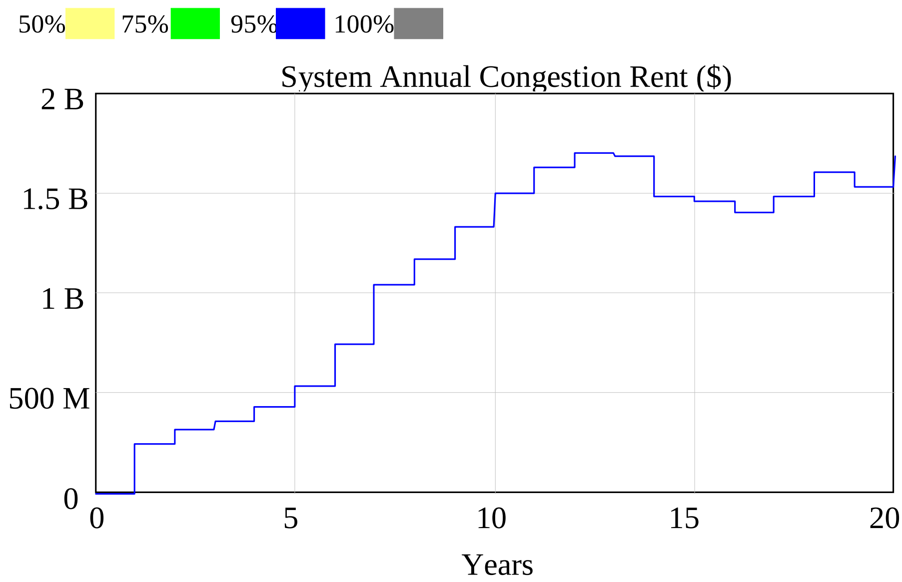

Fig. 5.67 Sensitivity of system annual congestion rent to annual profit rate under scenario 3

- **Scenario 4 simulation results**

In this scenario, regulated transmission investors deploy hard limt expansion on the most congested lines in the system, and they rely on ROE granted by regulators to recover their investments and make profits.

- Sensitivity simulation results for time for construction

From the simulation results, we can see that paths T2 and T3 are very sensitive to the time for construction; path T4 is also sensitive to this parameter. System annual congestion rent is very sensitive to this parameter.

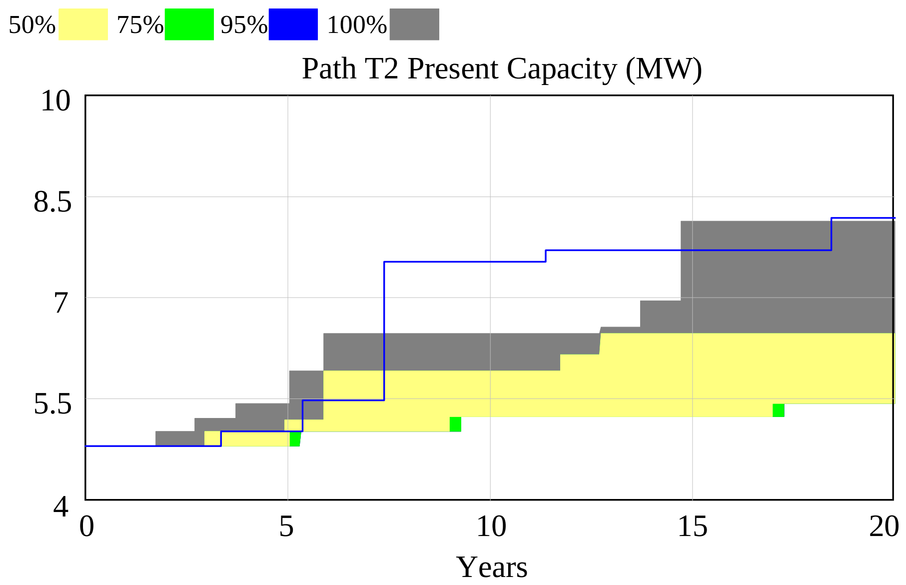

Fig. 5.68 Sensitivity of Path T2 expansion to time
for construction under scenario 4

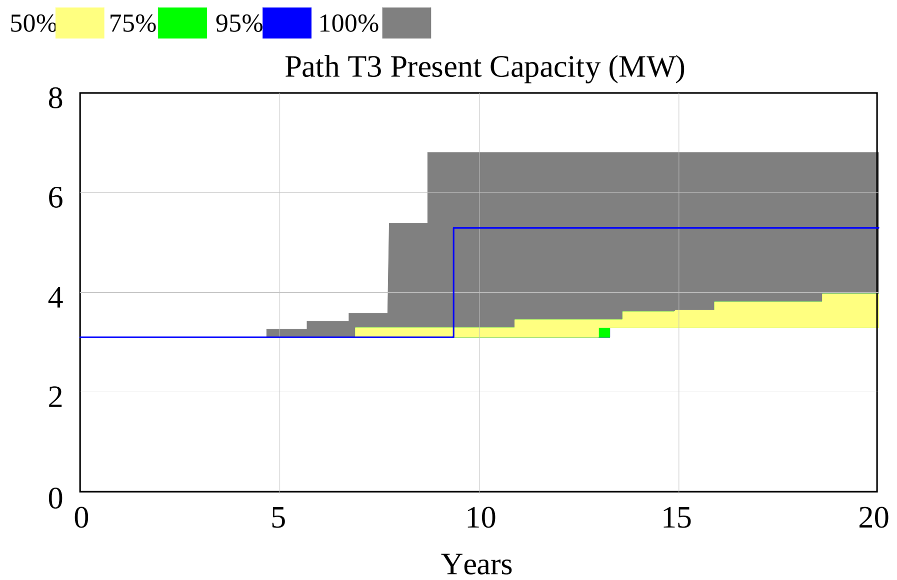

Fig. 5.69 Sensitivity of Path T3 expansion to time
for construction under scenario 4

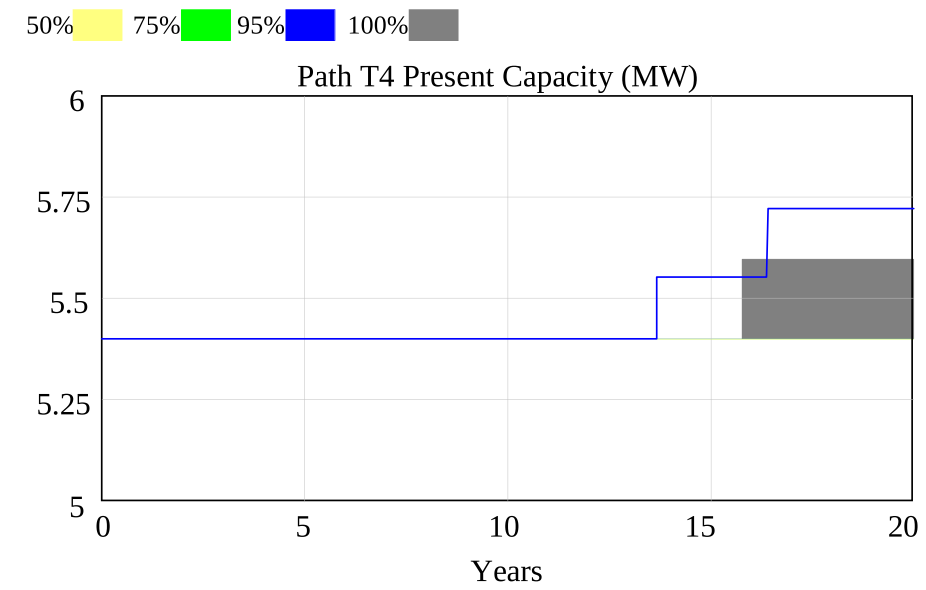

Fig. 5.70 Sensitivity of Path T4 expansion to time for construction under scenario 4

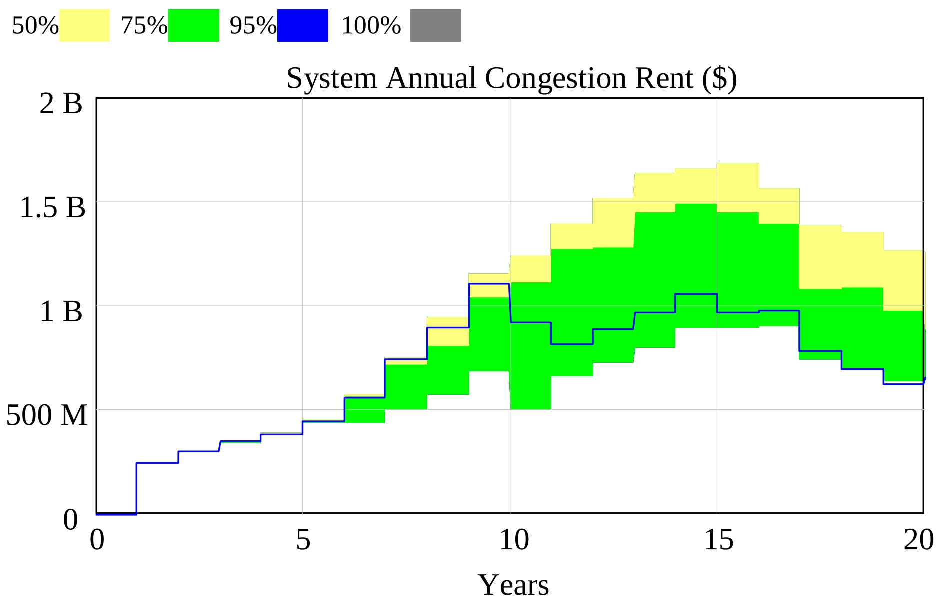

Fig. 5.71 Sensitivity of system annual congestion rent to time for construction under scenario 4

- Sensitivity simulation results for annual loan interest rate

From the simulation results, we can see that paths T2 ~ T4 are sensitive to the annual loan interest rate. System annual congestion rent also is sensitive to this parameter.

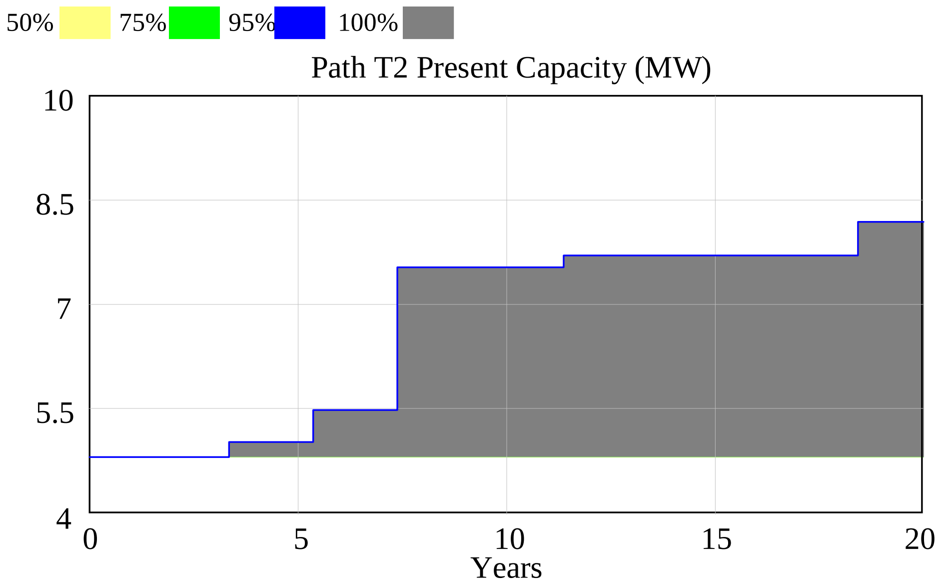

Fig. 5.72 Sensitivity of Path T2 expansion to annual loan interest rate under scenario 4

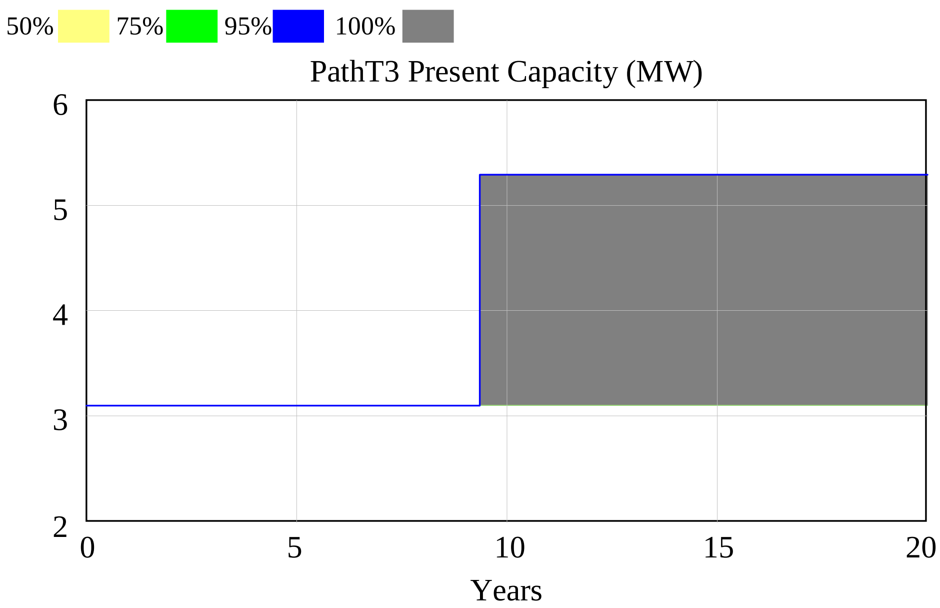

Fig. 5.73 Sensitivity of Path T3 expansion to annual loan interest rate under scenario 4

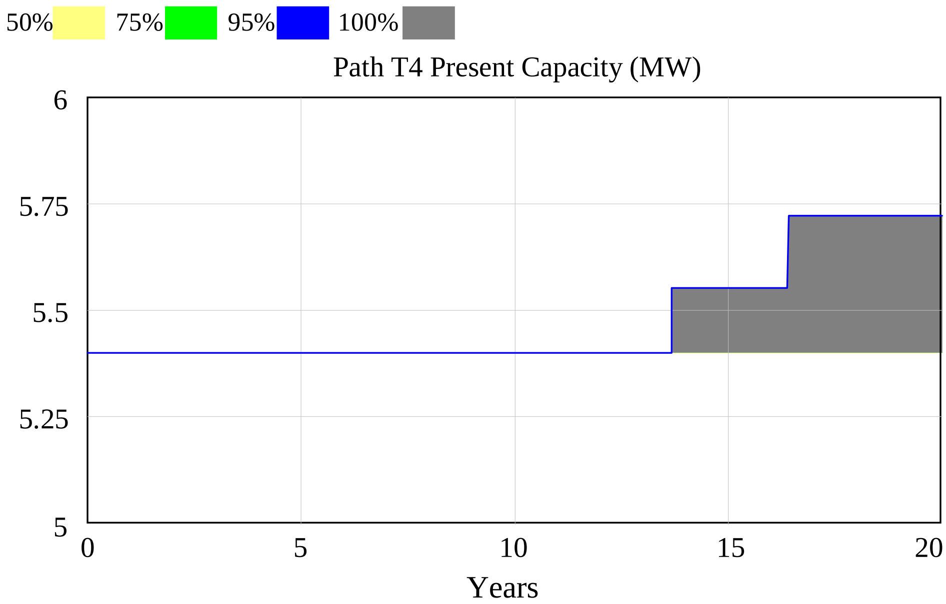

Fig. 5.74 Sensitivity of Path T4 expansion to annual loan interest rate under scenario 4

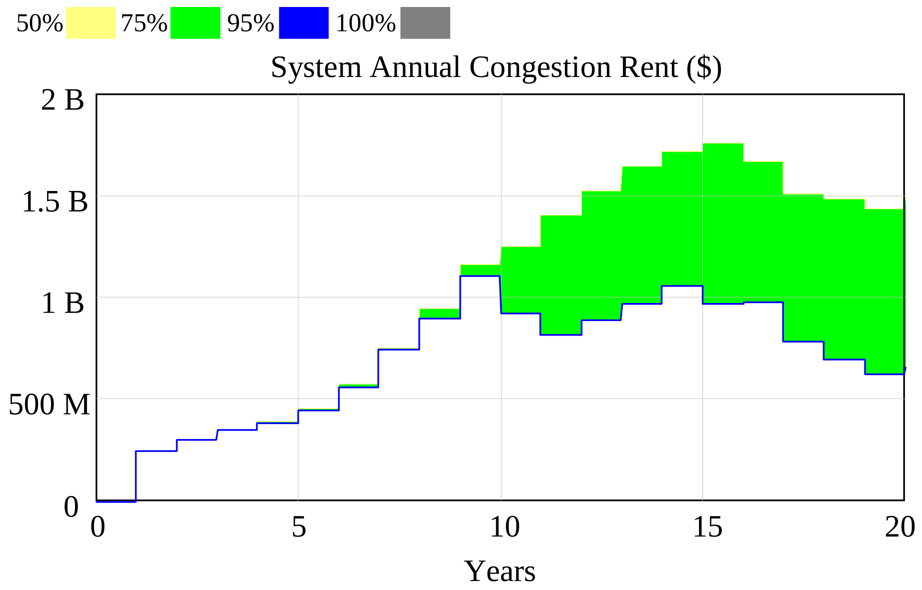

Fig. 5.75 Sensitivity of system annual congestion rent to annual loan interest rate under scenario 4

- Sensitivity simulation results for annual profit rate

From the simulation results, we can see that paths T2 ~ T4 are not very sensitive to the annual profit rate. System annual congestion rent is also not very sensitive to this parameter.

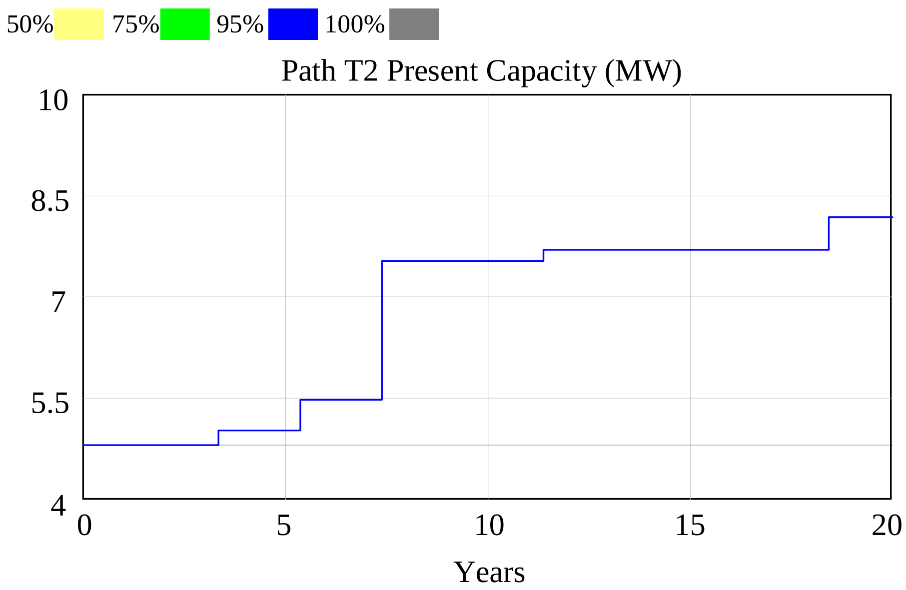

Fig. 5.76 Sensitivity of Path T2 expansion to annual profit rate under scenario 4

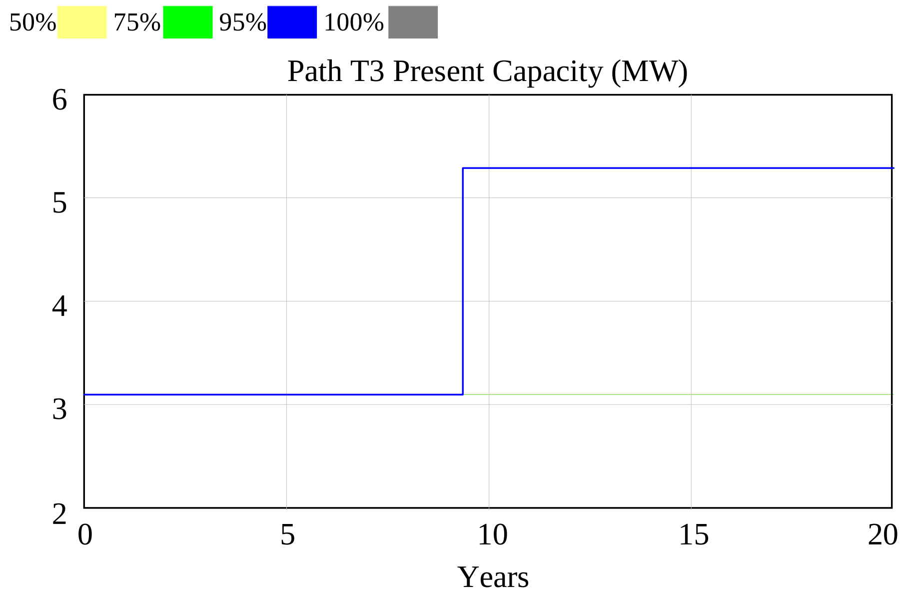

Fig. 5.77 Sensitivity of Path T3 expansion to annual profit rate under scenario 4

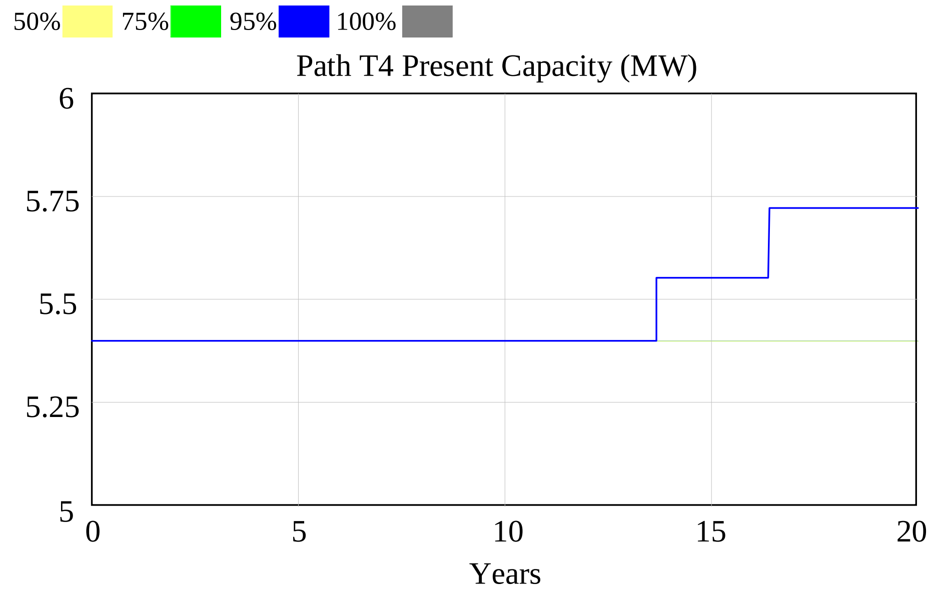

Fig. 5.78 Sensitivity of Path T4 expansion to annual profit rate under scenario 4

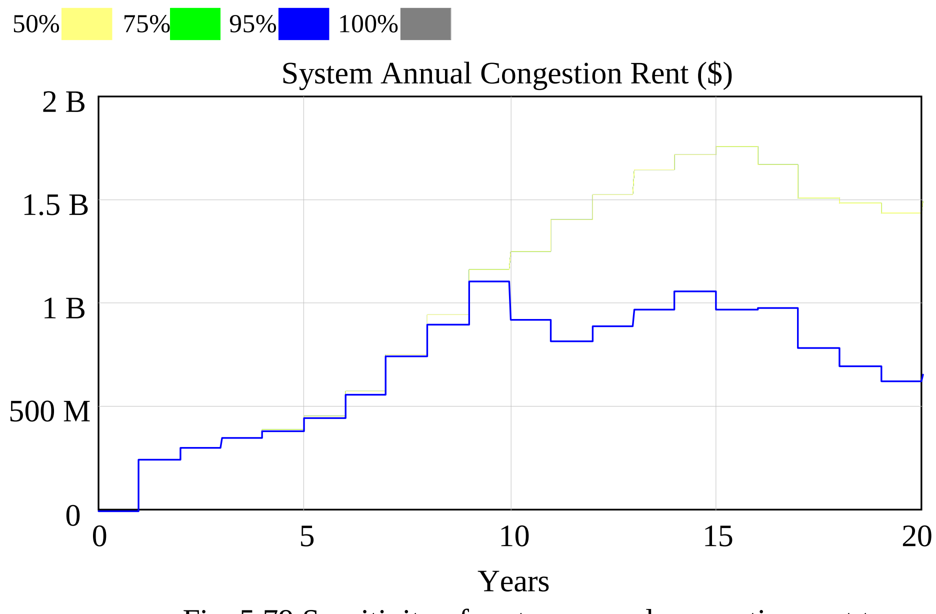

Fig. 5.79 Sensitivity of system annual congestion rent to annual profit rate under scenario 4

- **Scenario 5 simulation results**

In this scenario, regulated transmission investors use hard margin expansion on the most congested lines in the system, and they rely on ROE granted by regulators to recover their investments and make profits.

- Sensitivity simulation results for time for construction

From the simulation results, we can see that paths T2 and T3 are very sensitive to the time for construction; path T4 is also sensitive to this parameter. System annual congestion rent is very sensitive to this parameter.

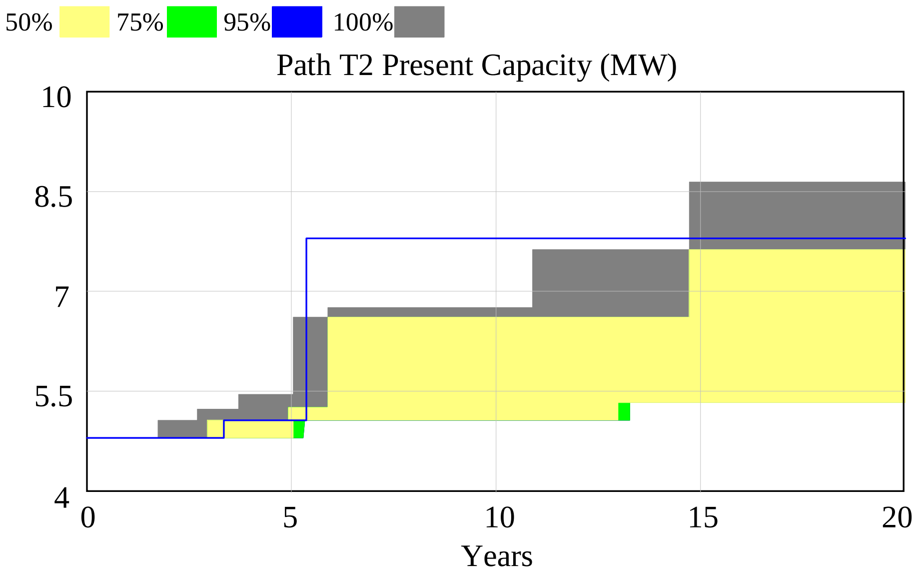

Fig. 5.80 Sensitivity of Path T2 expansion to time for construction under scenario 5

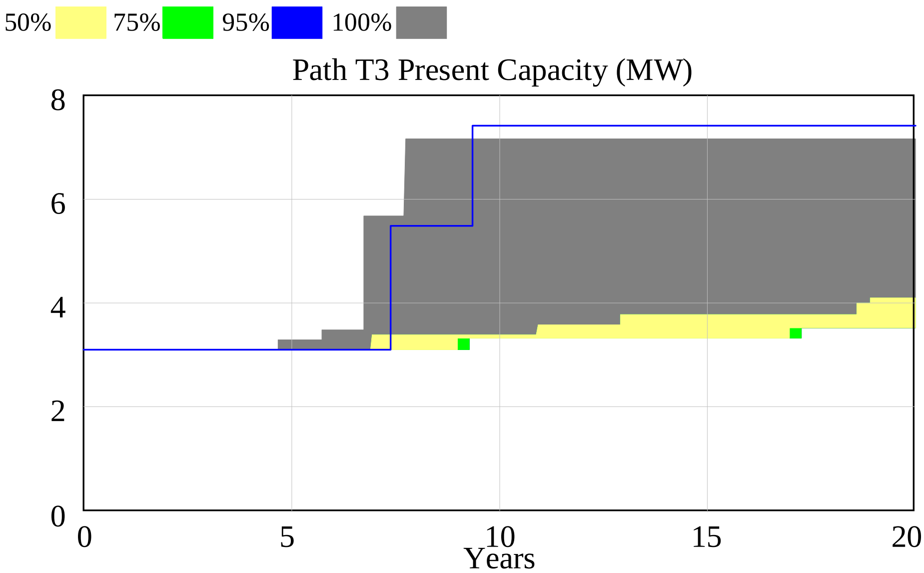

Fig. 5.81 Sensitivity of Path T3 expansion to time for construction under scenario 5

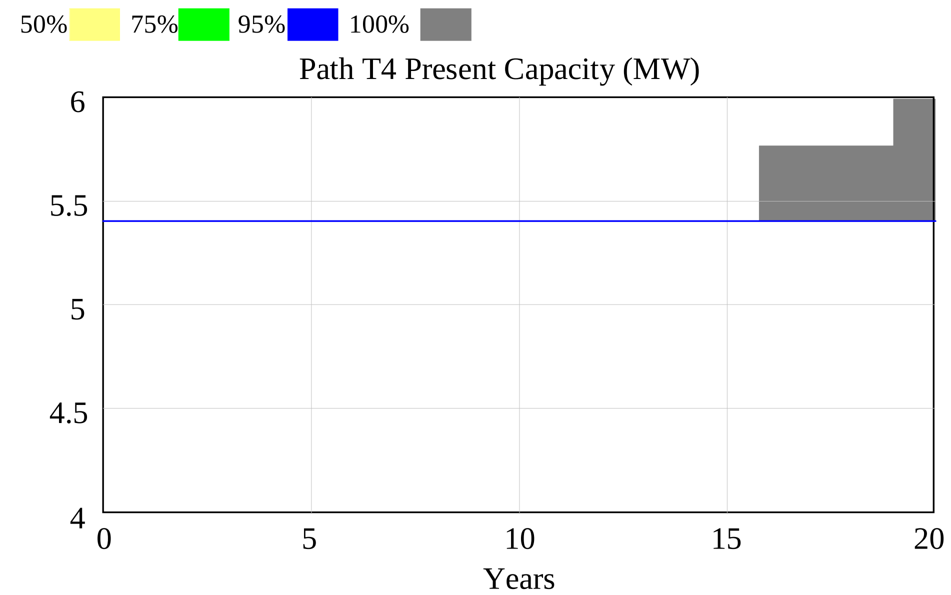

Fig. 5.82 Sensitivity of Path T4 expansion to time
for construction under scenario 5

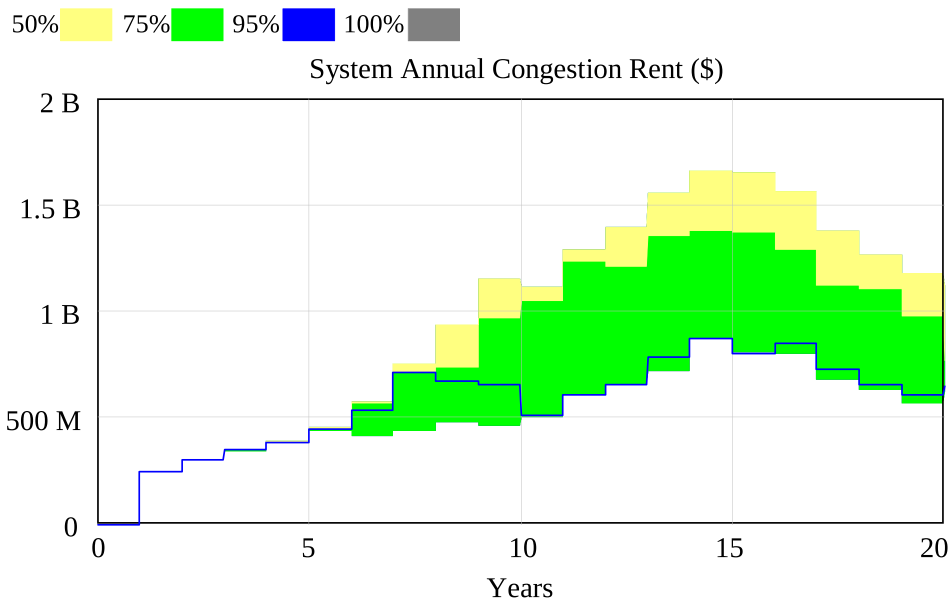

Fig. 5.83 Sensitivity of system annual congestion rent to time
for construction under scenario 5

- Sensitivity simulation results for annual loan interest rate

From the simulation results, we can see that paths T2 and T3 are very sensitive to the annual loan interest rate; path T4 is not sensitive to this parameter. System annual congestion rent is very sensitive to this parameter.

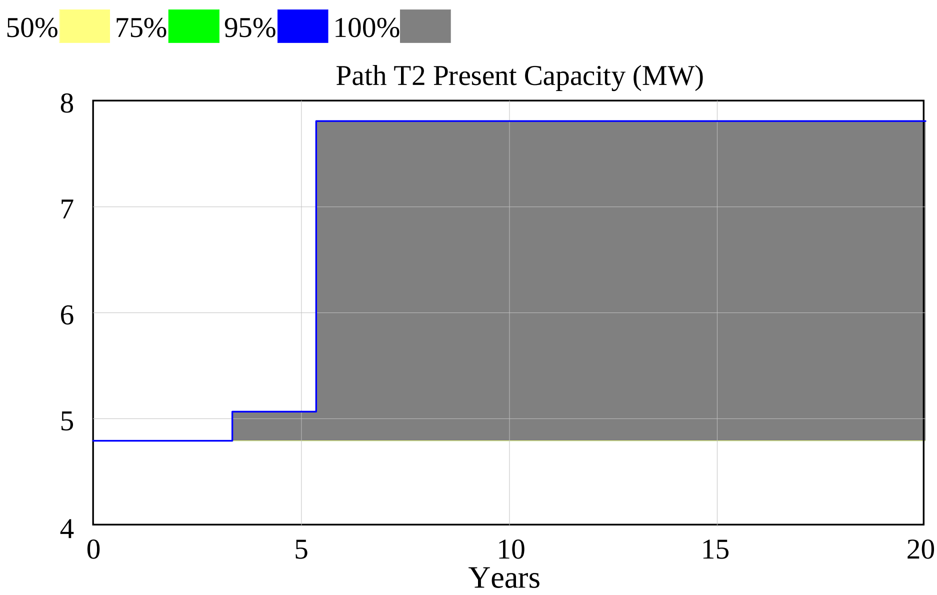

Fig. 5.84 Sensitivity of Path T2 expansion to annual loan interest rate under scenario 5

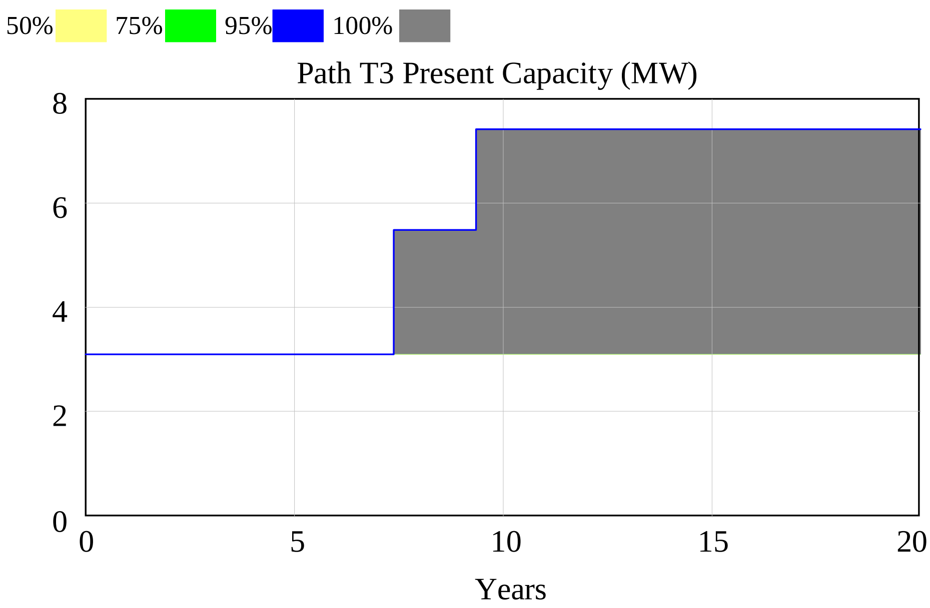

Fig. 5.85 Sensitivity of Path T3 expansion to annual loan interest rate under scenario 5

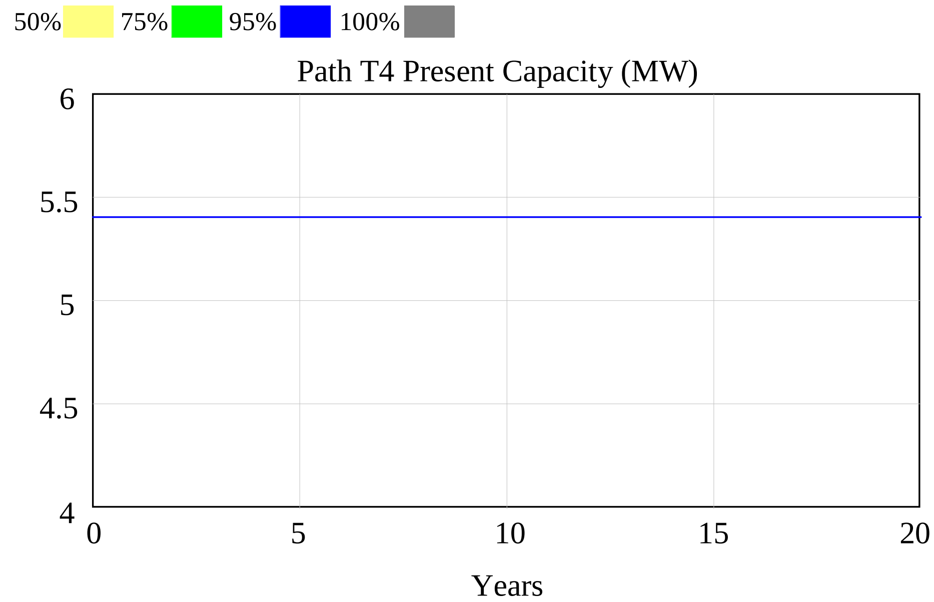

Fig. 5.86 Sensitivity of Path T4 expansion to annual loan interest rate under scenario 5

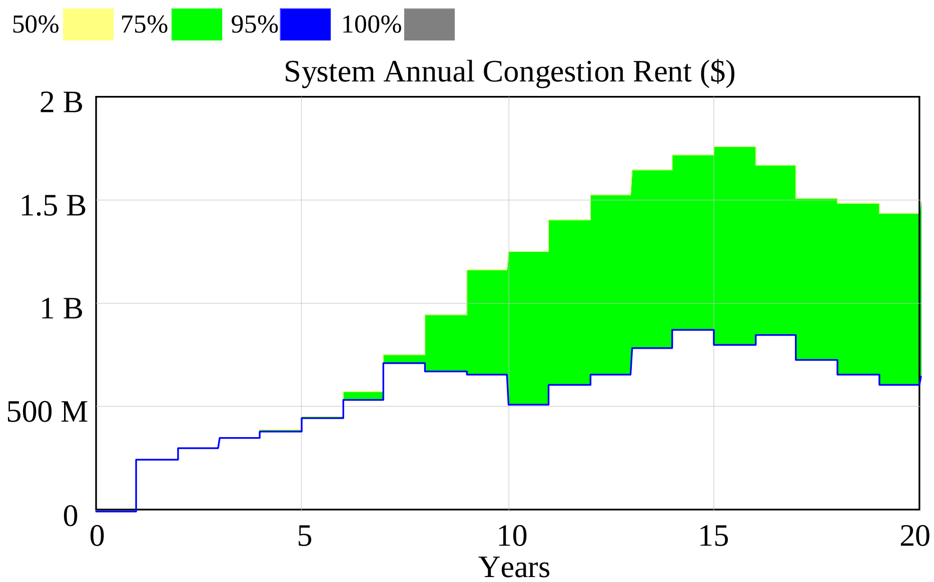

Fig. 5.87 Sensitivity of system annual congestion rent to annual loan interest rate under scenario 5

- Sensitivity simulation results for annual profit rate

From the simulation results, we can see that paths T2 and T3 are not very sensitive to the annual profit rate; path T4 is not sensitive to this parameter.

System annual congestion rent is not very sensitive to this parameter.

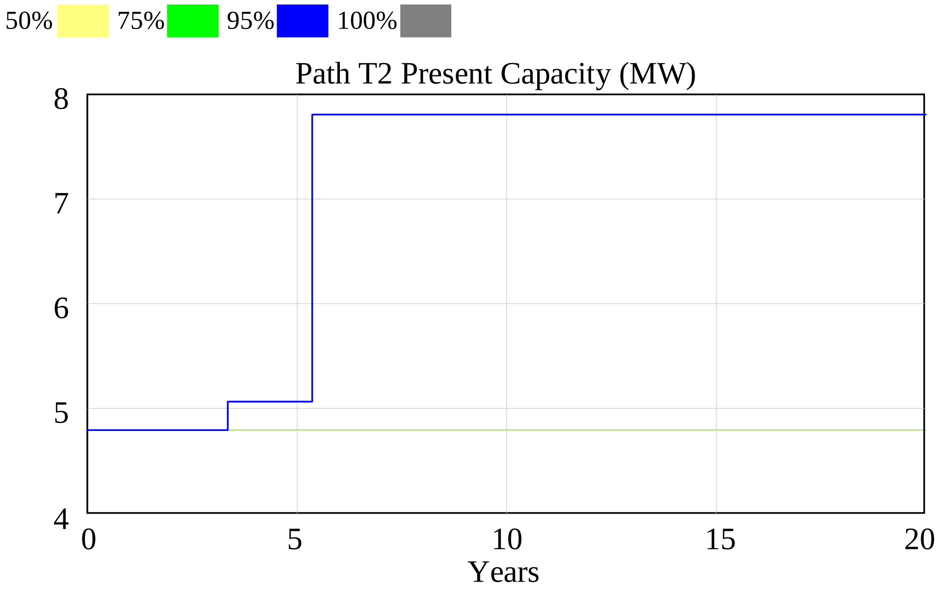

Fig. 5.88 Sensitivity of Path T2 expansion to annual profit rate under scenario 5

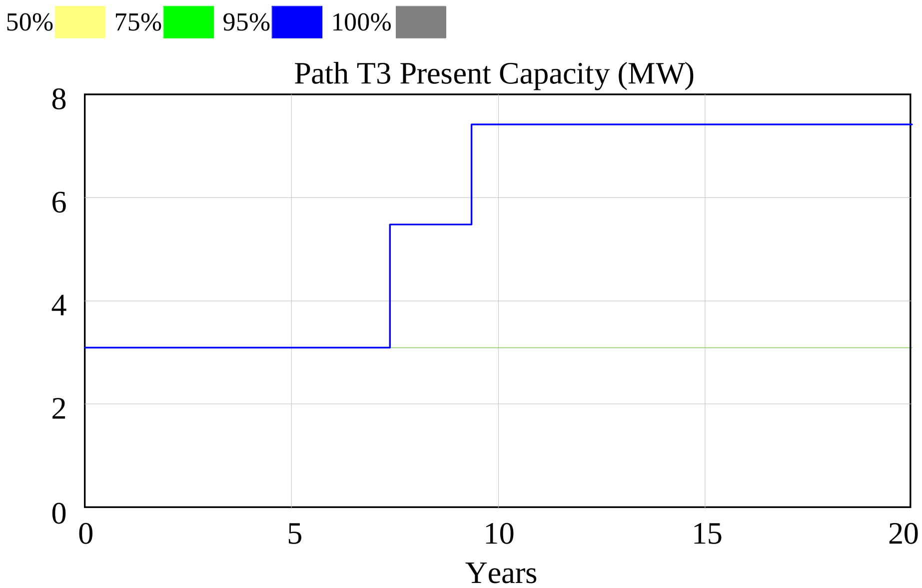

Fig. 5.89 Sensitivity of Path T3 expansion to annual profit rate under scenario 5

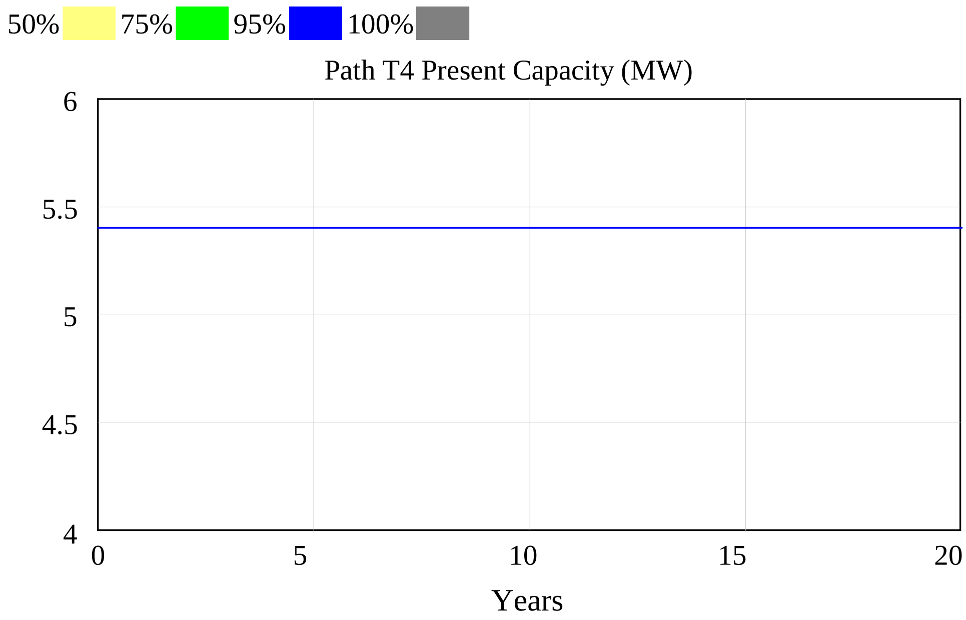

Fig. 5.90 Sensitivity of Path T4 expansion to annual profit rate under scenario 5

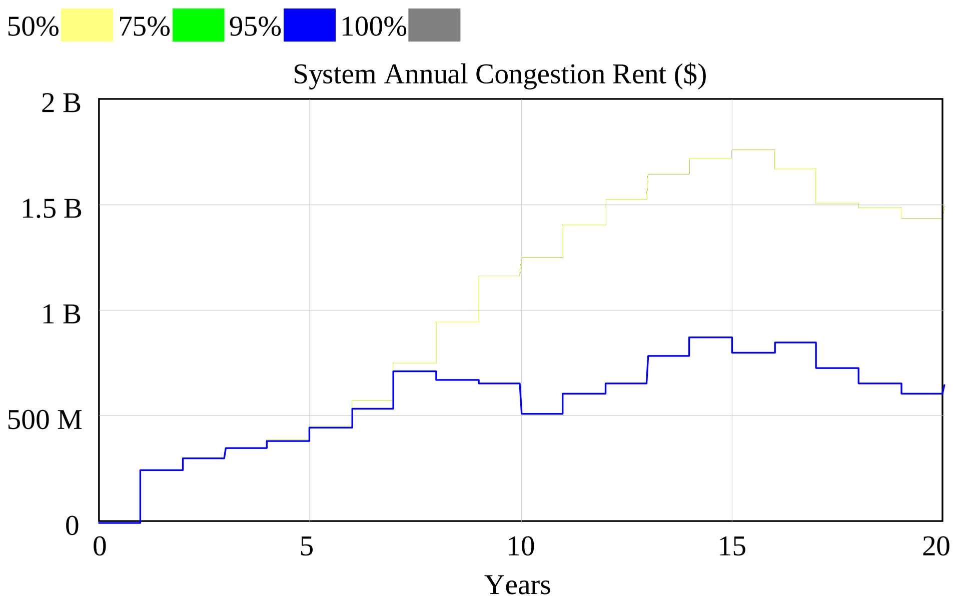

Fig. 5.91 Sensitivity of system annual congestion rent to annual profit rate under scenario 5

- **Scenario 6 simulation results**

In this scenario, regulated transmission investors employ soft limit expansion on the most congested lines in the system, and they rely on ROE granted by regulators to recover their investments and make profits.

- Sensitivity simulation results for time for construction

From the simulation results, we can see that paths T2 and T3 are very sensitive to the time for construction; path T4 is not sensitive to this parameter. System annual congestion rent is very sensitive to this parameter.

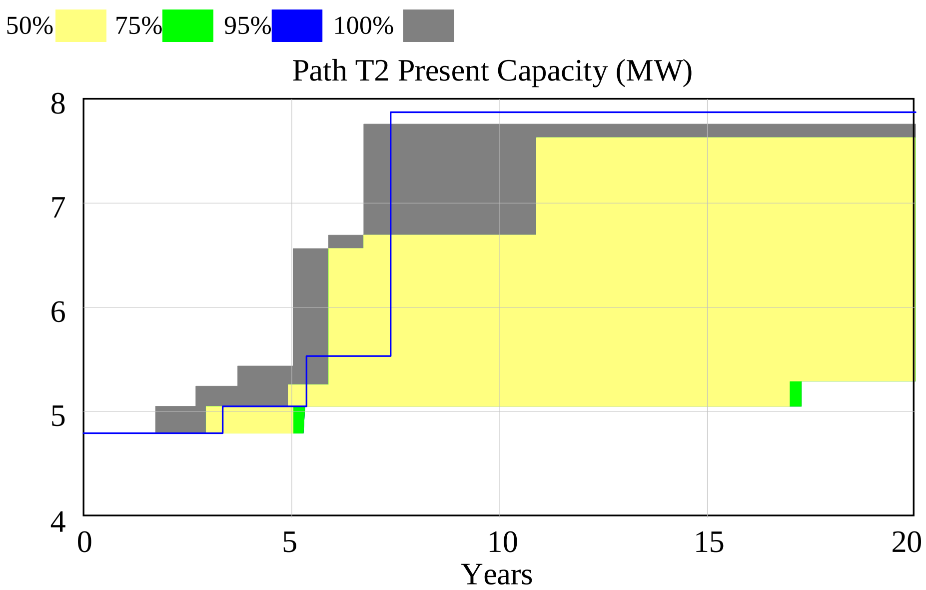

Fig. 5.92 Sensitivity of Path T2 expansion to time for construction under scenario 6

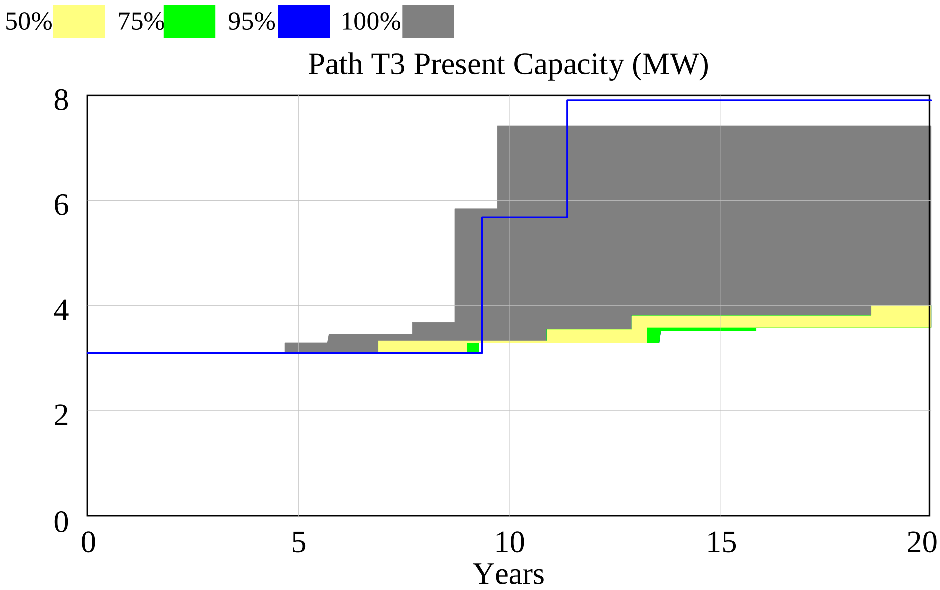

Fig. 5.93 Sensitivity of Path T3 expansion to time
for construction under scenario 6

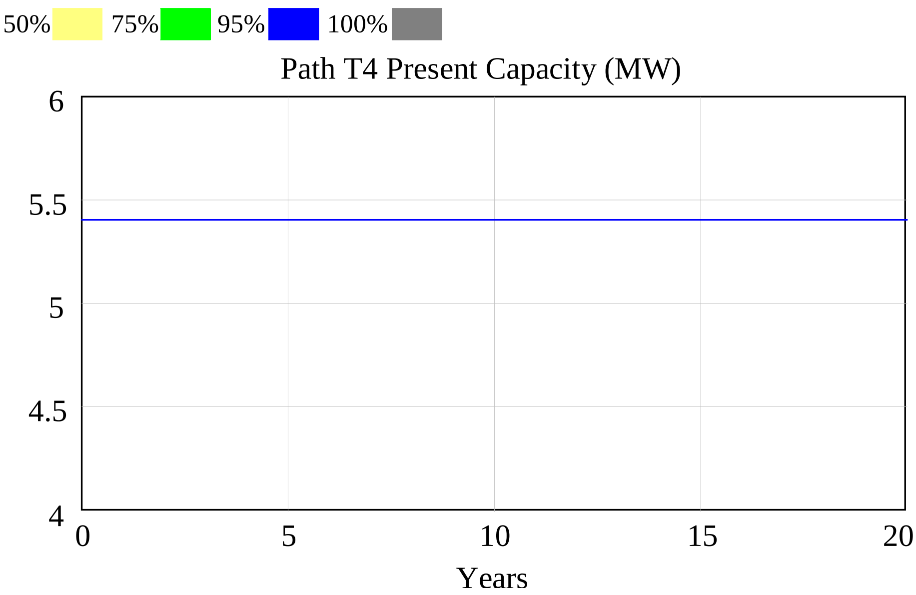

Fig. 5.94 Sensitivity of Path T4 expansion to time
for construction under scenario 6

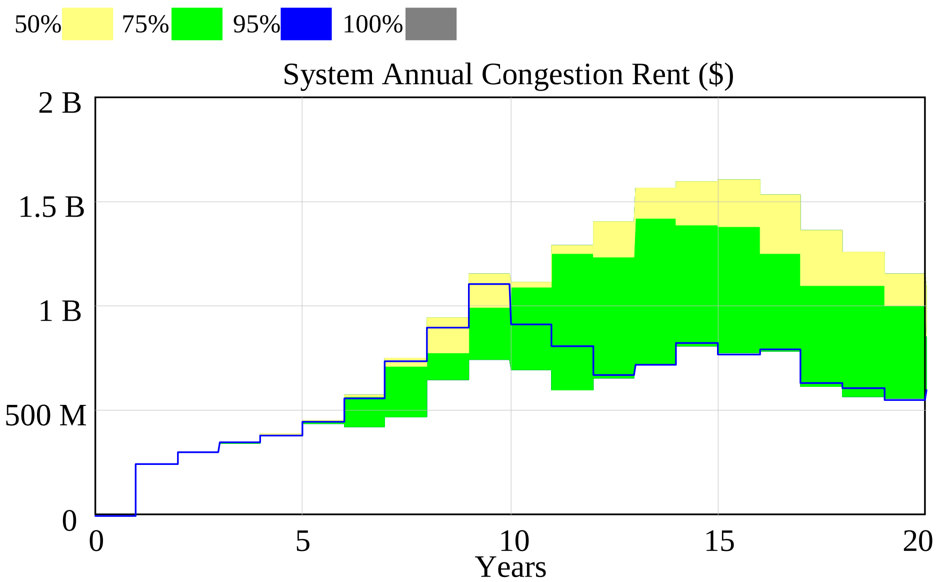

Fig. 5.95 Sensitivity of system annual congestion rent to time for construction under scenario 6

- Sensitivity simulation results for annual loan interest rate

From the simulation results, we can see that paths T2 and T3 are very sensitive to the annual loan interest rate; path T4 is not sensitive to this parameter. System annual congestion rent is very sensitive to this parameter.

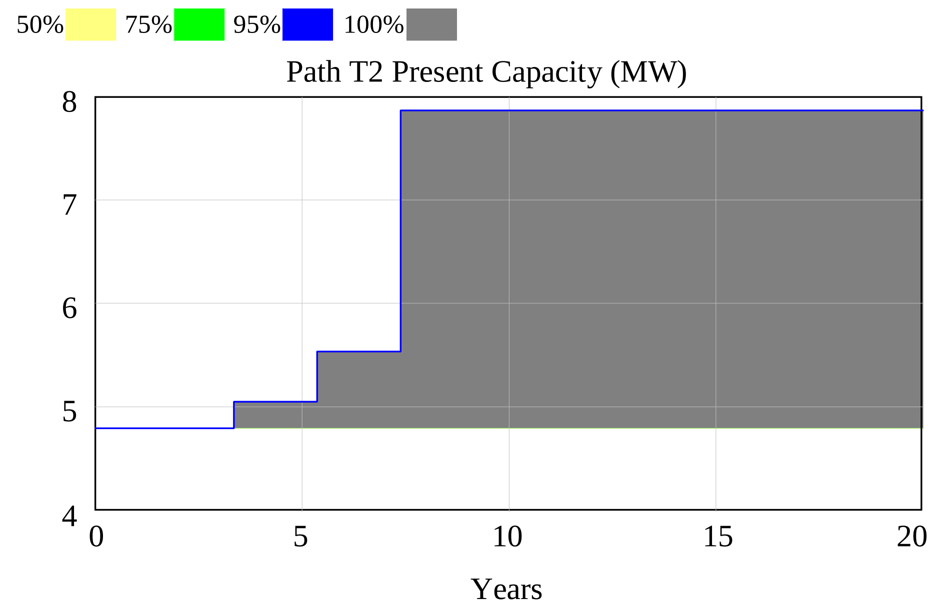

Fig. 5.96 Sensitivity of Path T2 expansion to annual loan interest rate under scenario 6

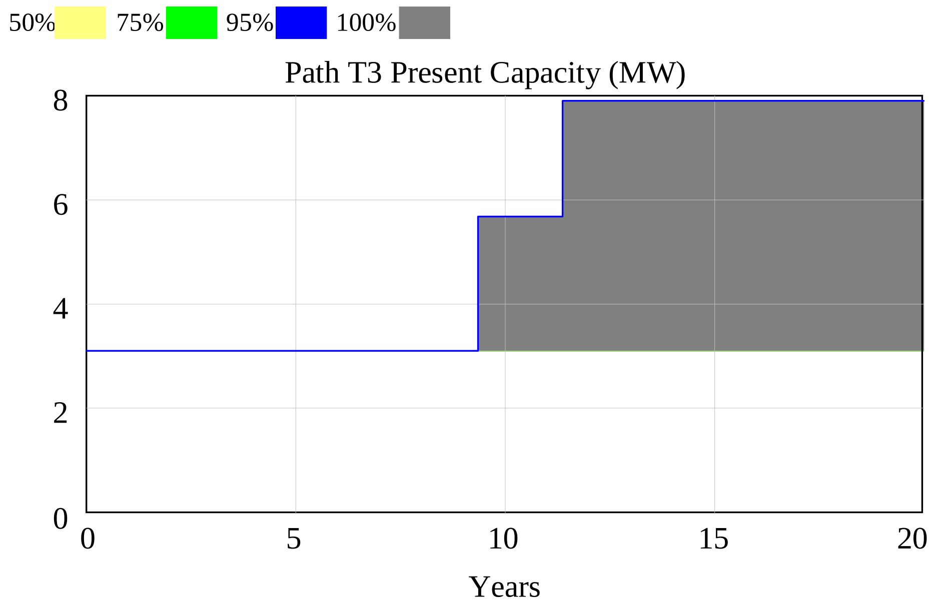

Fig. 5.97 Sensitivity of Path T3 expansion to annual loan interest rate under scenario 6

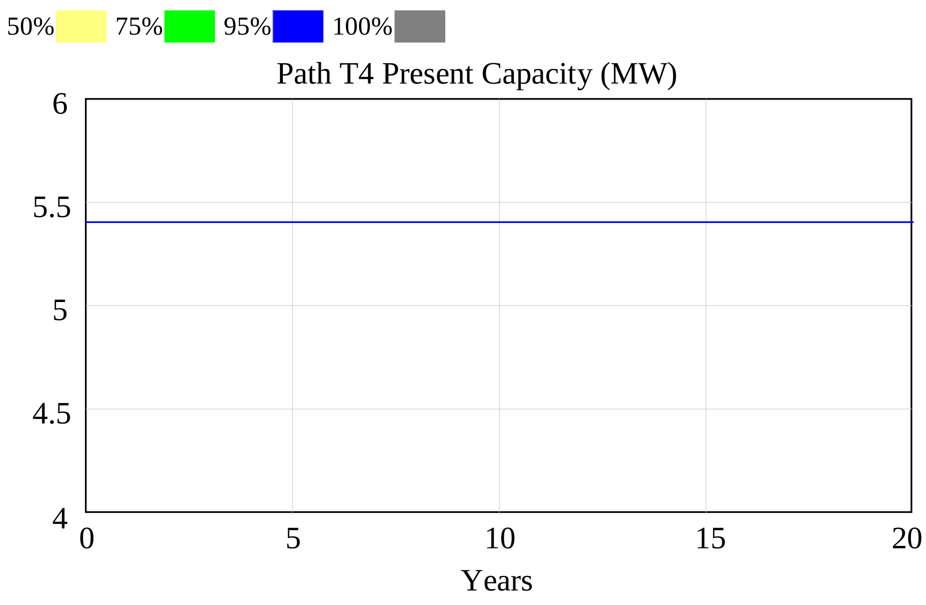

Fig. 5.98 Sensitivity of Path T4 expansion to annual loan interest rate under scenario 6

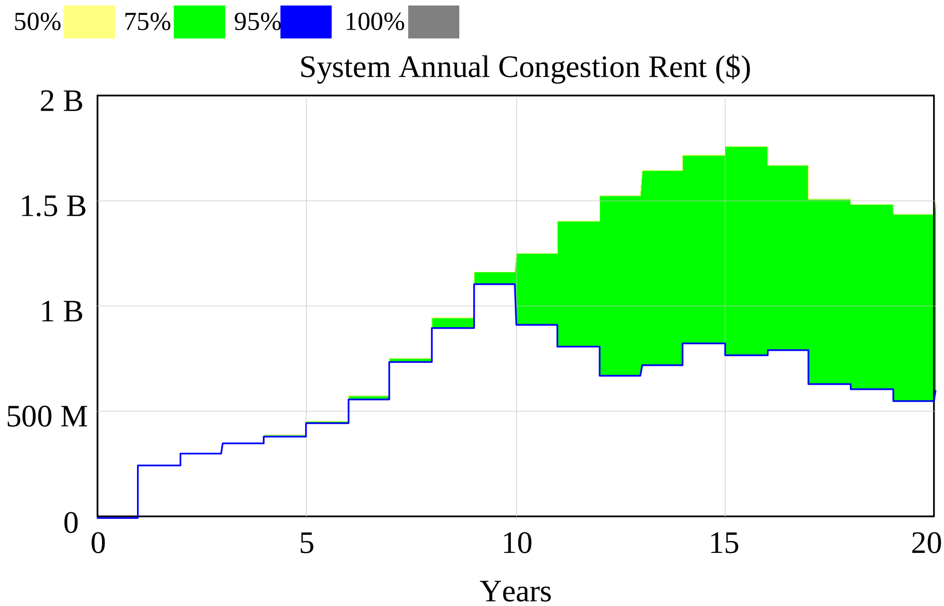

Fig. 5.99 Sensitivity of system annual congestion rent to annual loan interest rate under scenario 6

- Sensitivity simulation results for annual profit rate

From the simulation results, we can see that paths T2 and T3 are not very sensitive to the annual profit rate; path T4 is not sensitive to this parameter. System annual congestion rent is not very sensitive to this parameter.

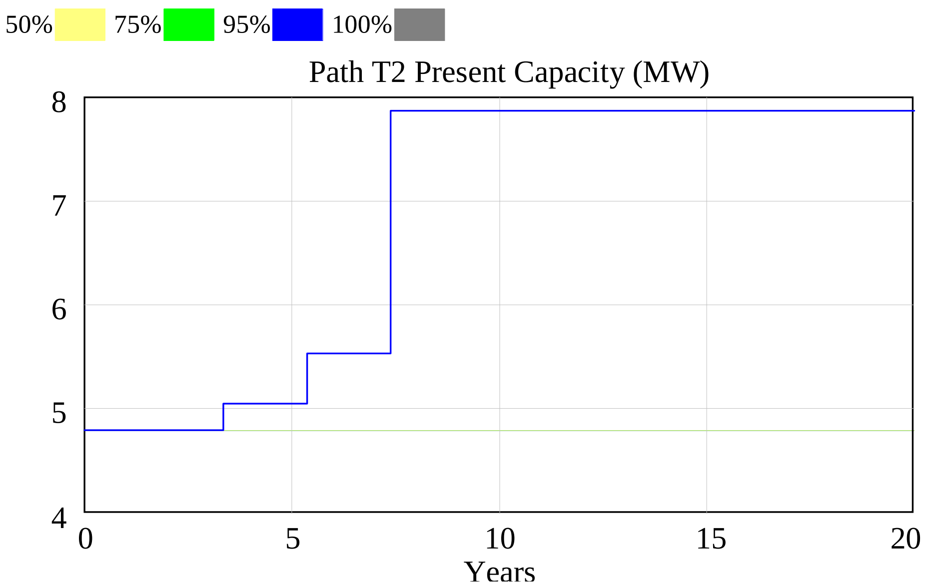

Fig. 5.100 Sensitivity of Path T2 expansion to annual profit rate under scenario 6

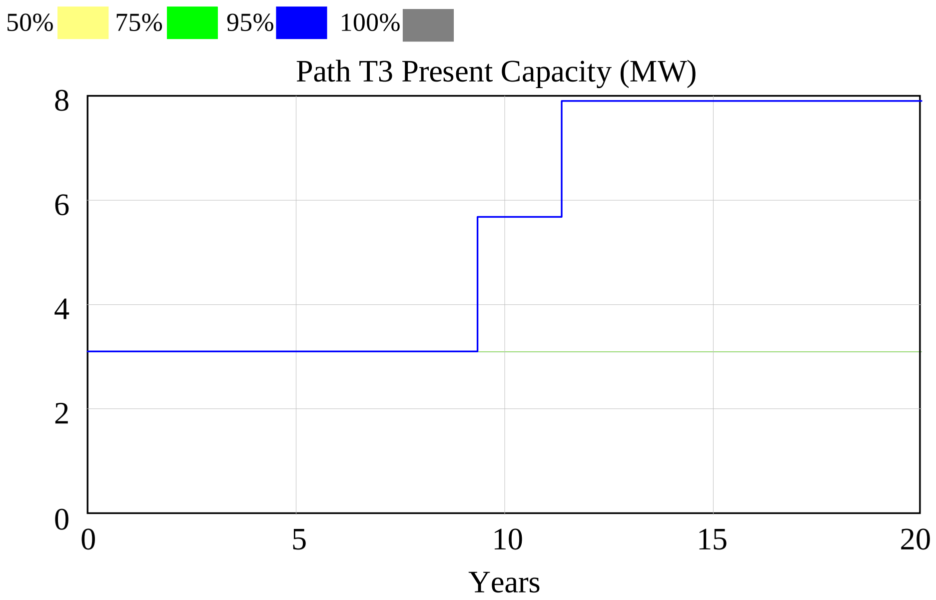

Fig. 5.101 Sensitivity of Path T3 expansion to annual profit rate under scenario 6

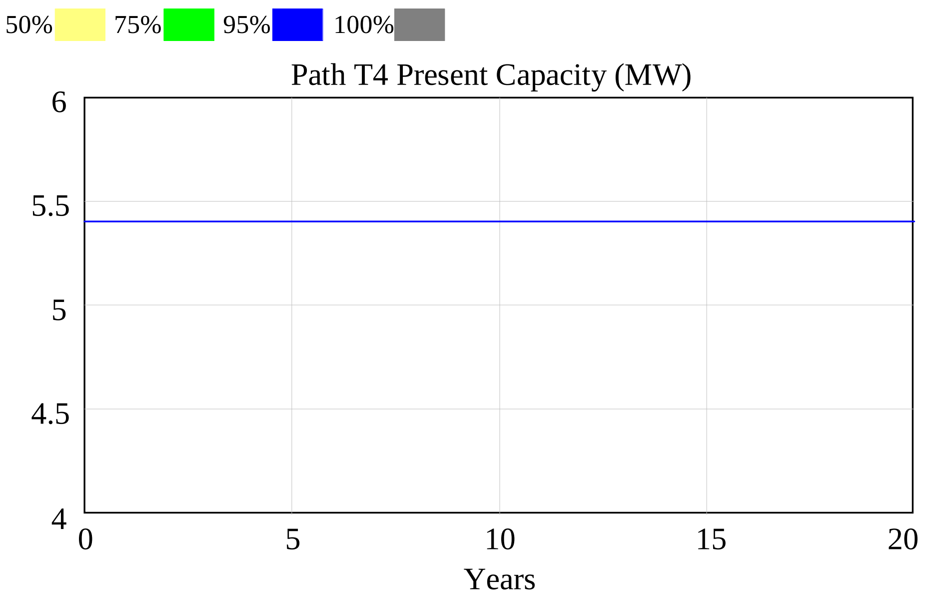

Fig. 5.102 Sensitivity of Path T4 expansion to annual profit rate under scenario 6

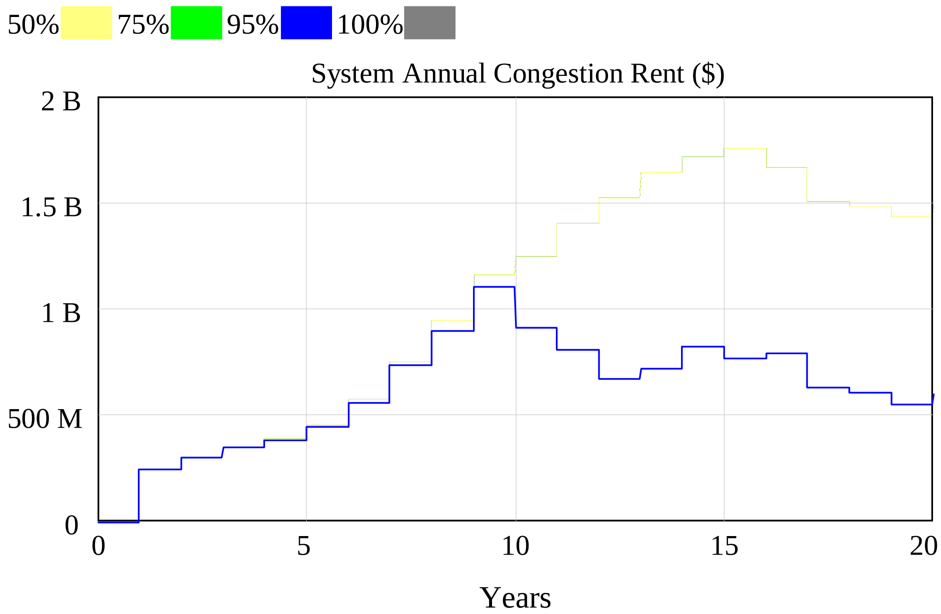

Fig. 5.103 Sensitivity of system annual congestion rent to annual profit rate under scenario 6

- **Scenario 7 simulation results**

In this scenario, regulated transmission investors use hard limit expansion on most congested lines in the system, and they rely on ROE plus ROE adders granted by regulators to recover their investments and make profits.

- Sensitivity simulation results for time for construction

From the simulation results, we can see that paths T2 and T3 are very sensitive to the time for construction; path T4 is also sensitive to this parameter. System annual congestion rent is very sensitive to this parameter.

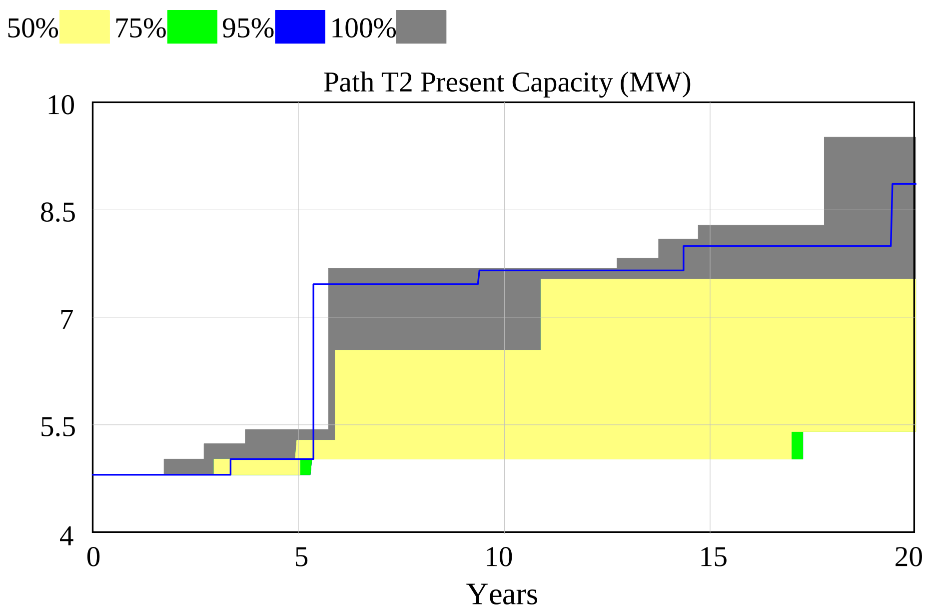

Fig. 5.104 Sensitivity of Path T2 expansion to time for construction under scenario 7

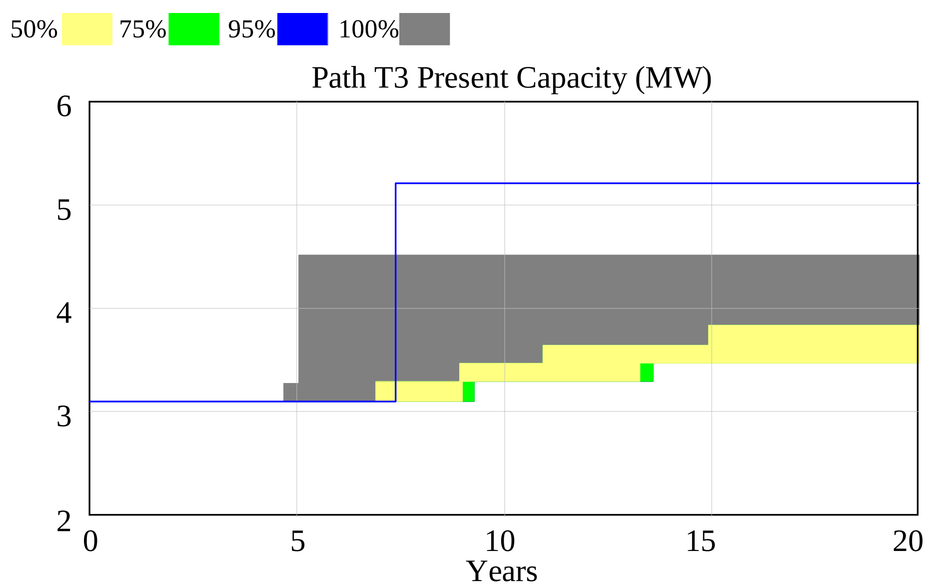

Fig. 5.105 Sensitivity of Path T3 expansion to time for construction under scenario 7

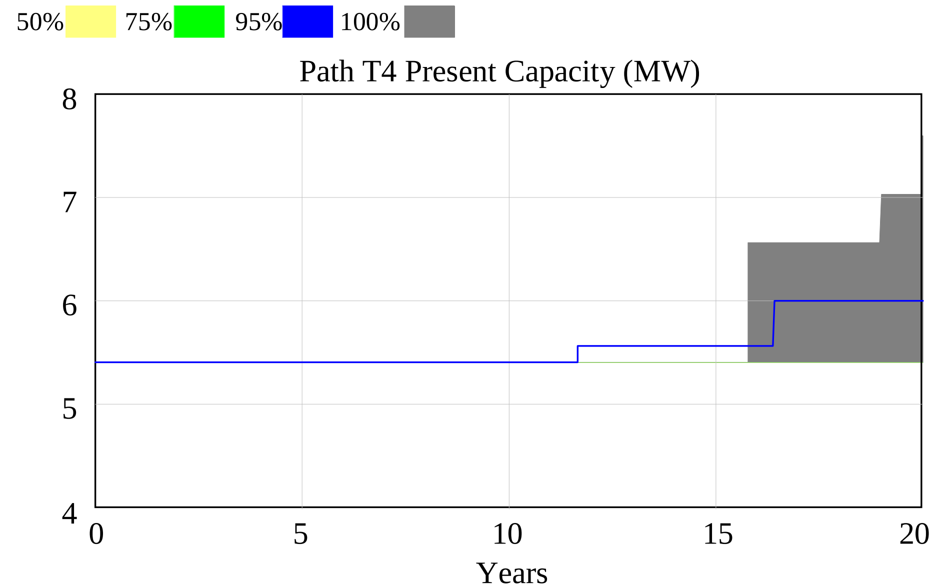

Fig. 5.106 Sensitivity of Path T4 expansion to time
for construction under scenario 7

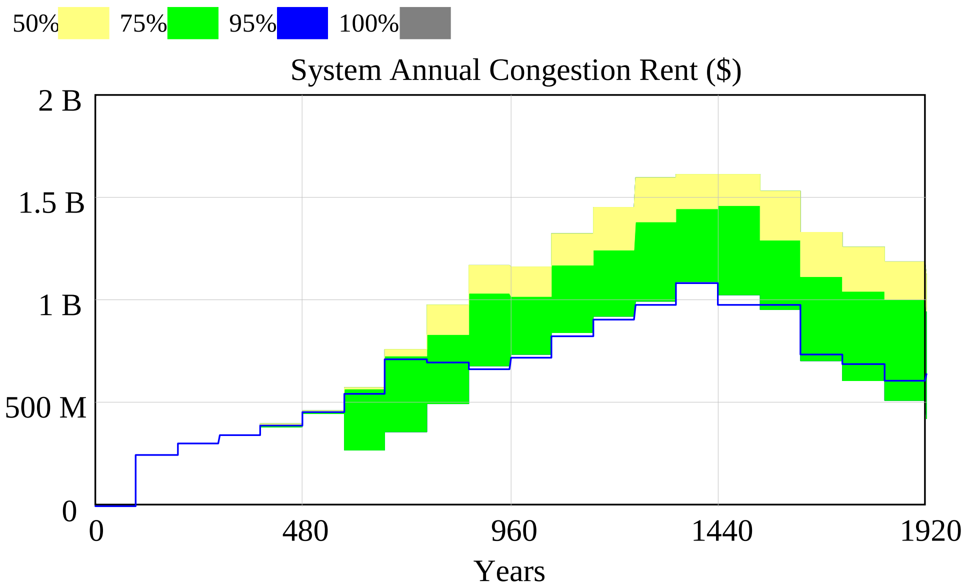

Fig. 5.107 Sensitivity of system annual congestion rent to time
for construction under scenario 7

- Sensitivity simulation results for annual loan interest rate

From the simulation results, we can see that paths T2 and T3 are very sensitive to the annual loan interest rate; path T4 is also sensitive to this parameter. System annual congestion rent is very sensitive to this parameter.

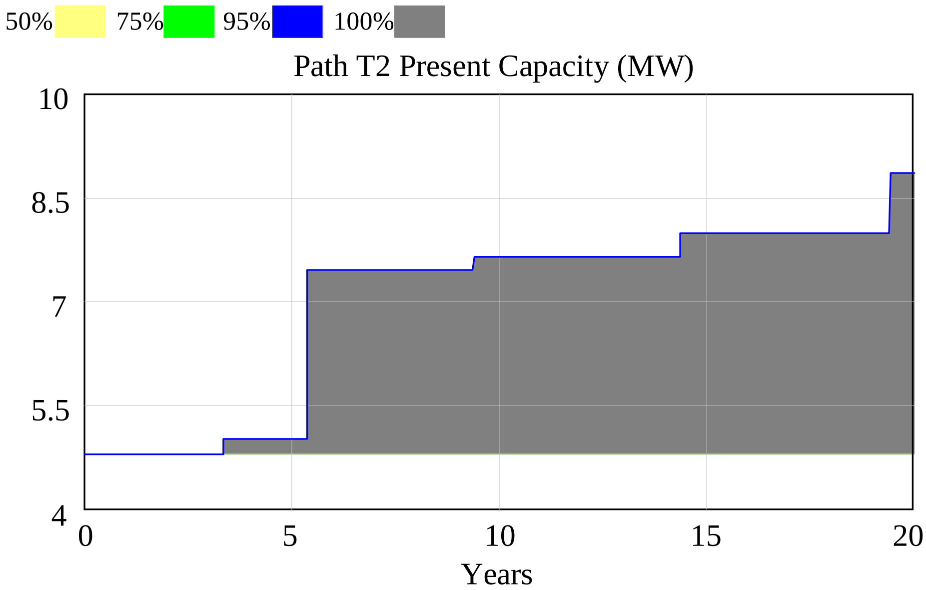

Fig. 5.108 Sensitivity of Path T2 expansion to annual loan interest rate under scenario 7

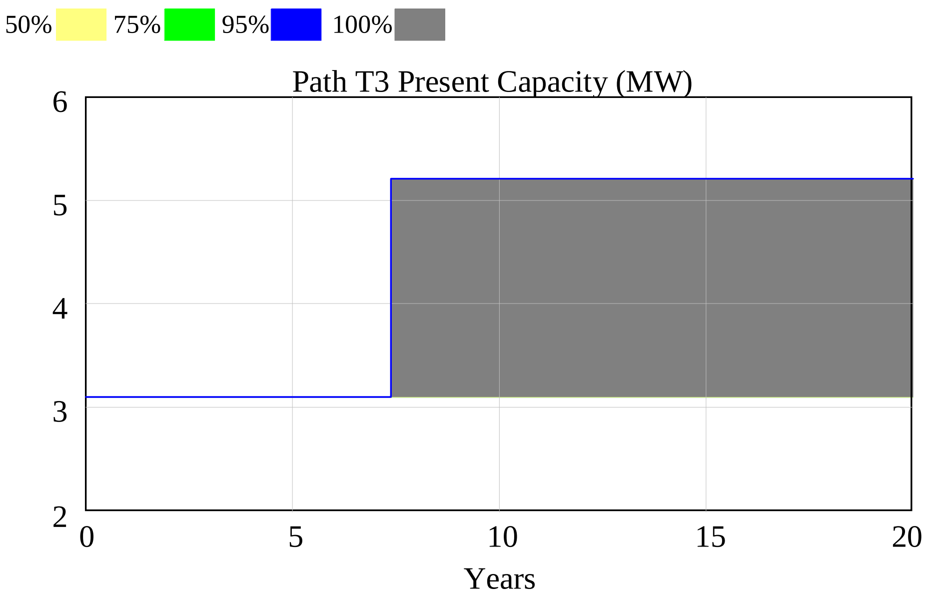

Fig. 5.109 Sensitivity of Path T3 expansion to annual loan interest rate under scenario 7

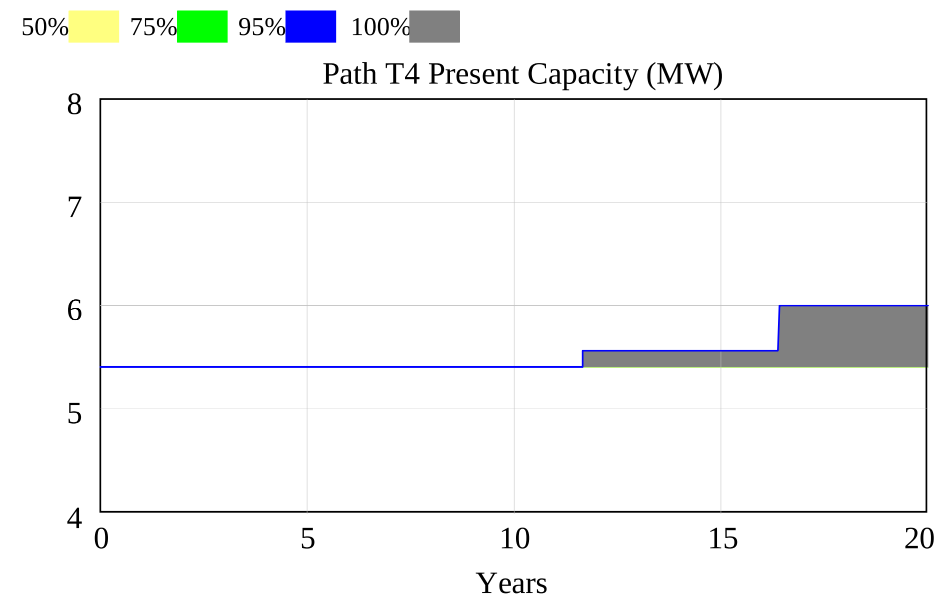

Fig. 5.110 Sensitivity of Path T4 expansion to annual loan interest rate under scenario 7

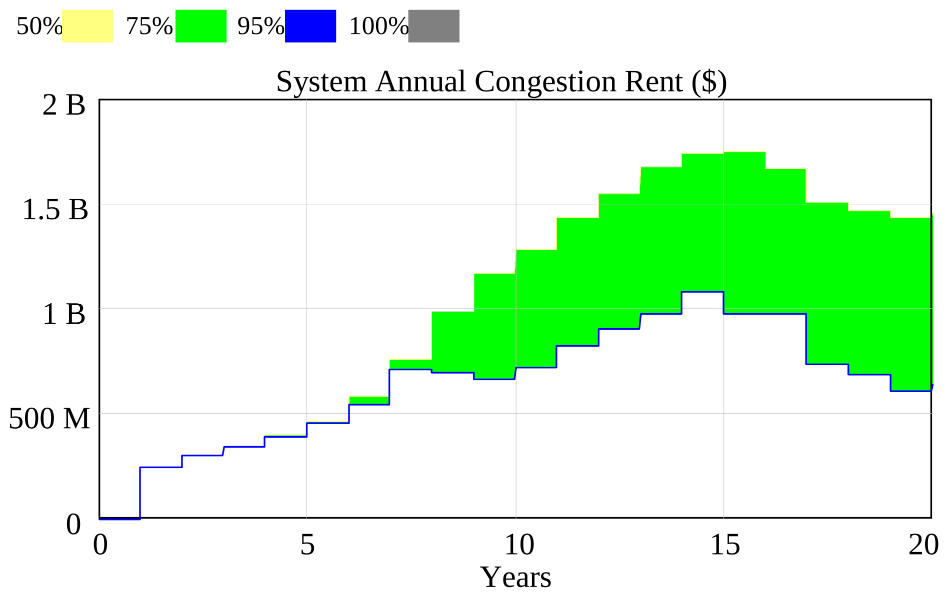

Fig. 5.111 Sensitivity of system annual congestion rent to annual loan interest rate under scenario 7

- Sensitivity simulation results for annual profit rate

From the simulation results, we can see that paths T2 ~ T4 are not very sensitive to the annual profit rate. System annual congestion rent is also not very sensitive to this parameter.

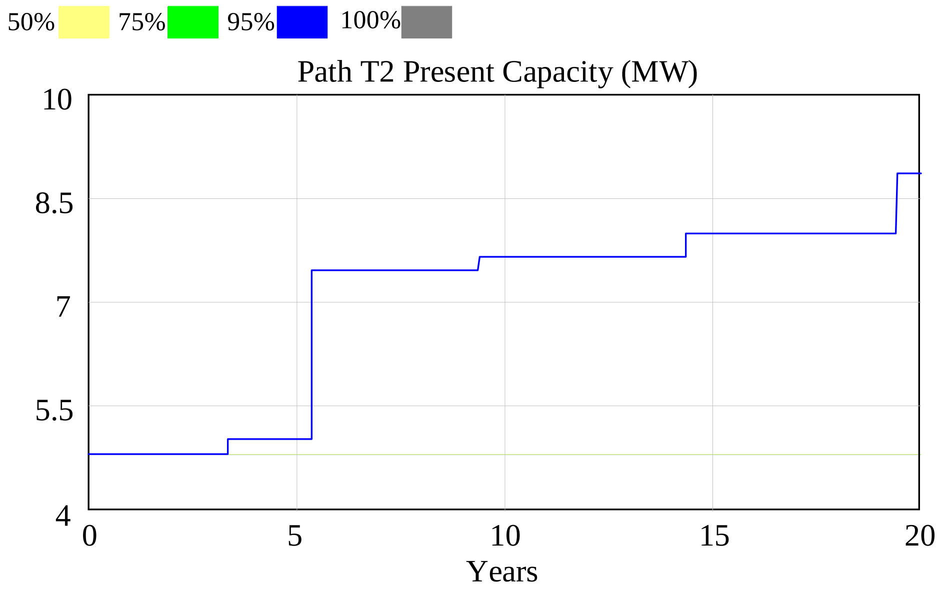

Fig. 5.112 Sensitivity of Path T2 expansion to annual profit rate under scenario 7

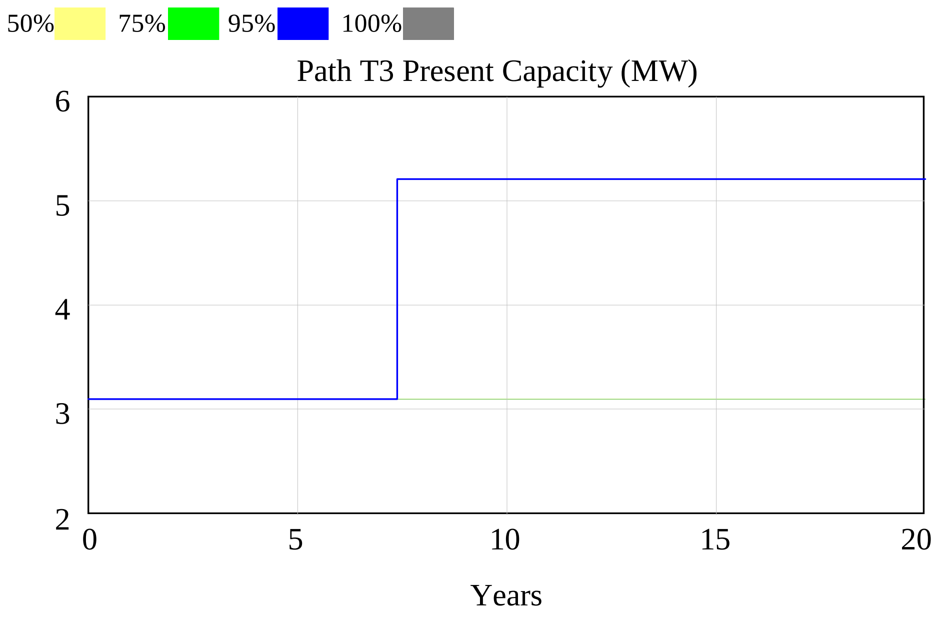

Fig. 5.113 Sensitivity of Path T3 expansion to annual profit rate under scenario 7

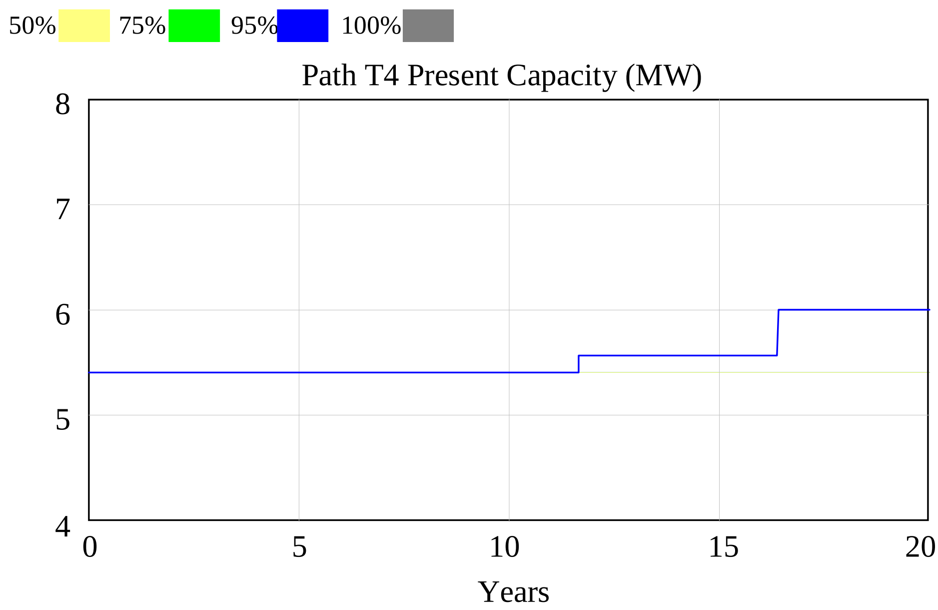

Fig. 5.114 Sensitivity of Path T4 expansion to annual profit rate under scenario 7

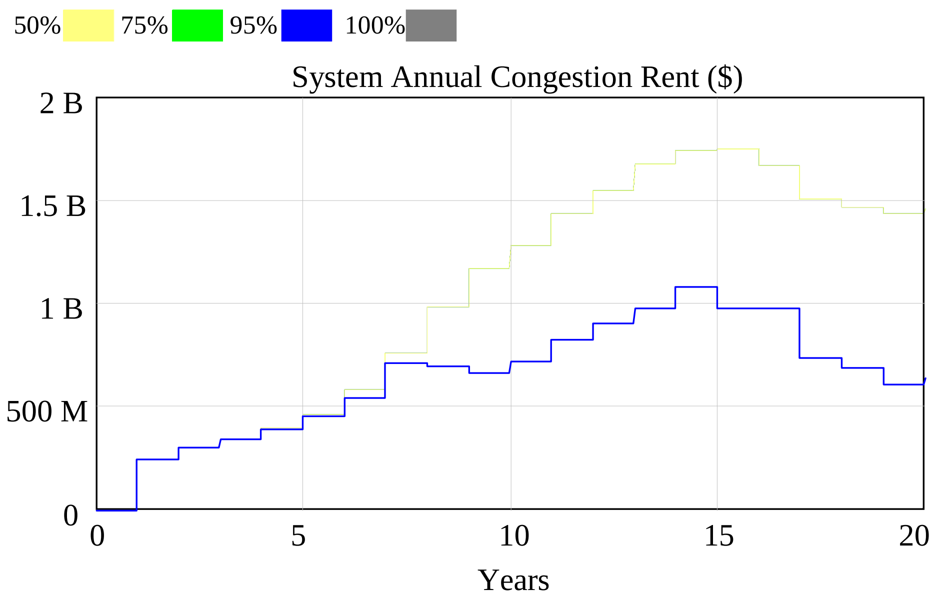

Fig. 5.115 Sensitivity of system annual congestion rent to annual profit rate under scenario 7

- **Scenario 8 simulation results**

In this scenario, regulated transmission investors use hard margin expansion on the most congested lines in the system, and they rely on ROE plus ROE adders granted by regulators to recover their investments and make profits.

- Sensitivity simulation results for time for construction

From the simulation results, we can see that paths T2 ~ T4 are very sensitive to the time for construction. System annual congestion rent is also very sensitive to this parameter.

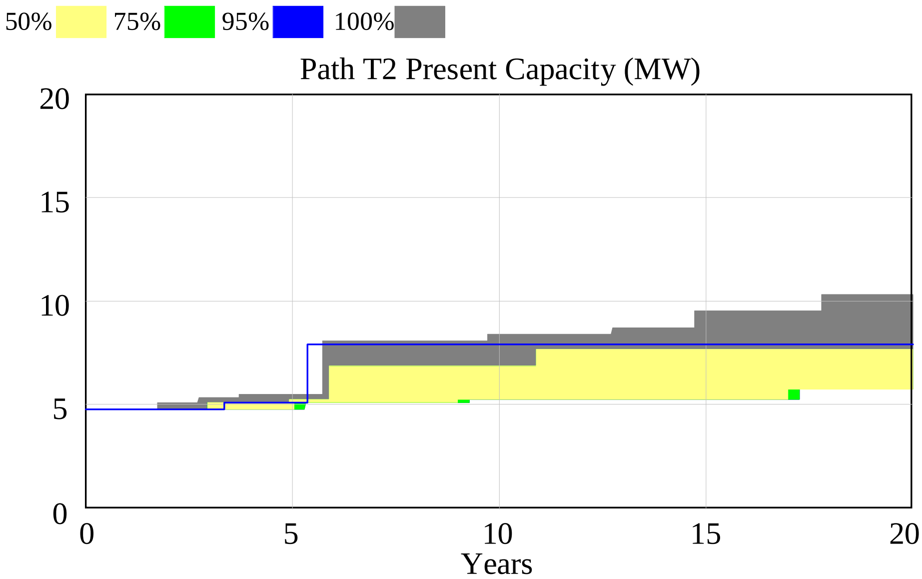

Fig. 5.116 Sensitivity of Path T2 expansion to time for construction under scenario 8

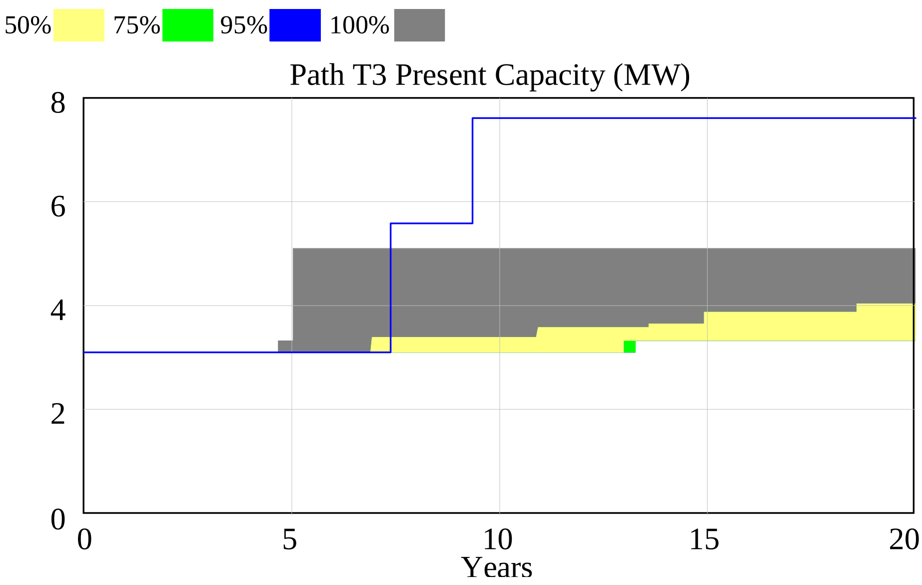

Fig. 5.117 Sensitivity of Path T3 expansion to time
for construction under scenario 8

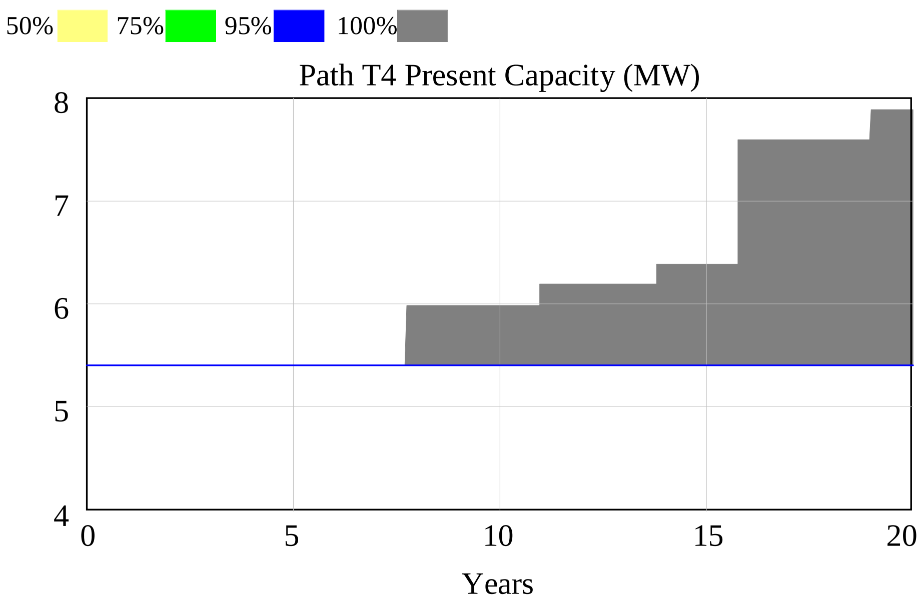

Fig. 5.118 Sensitivity of Path T4 expansion to time
for construction under scenario 8

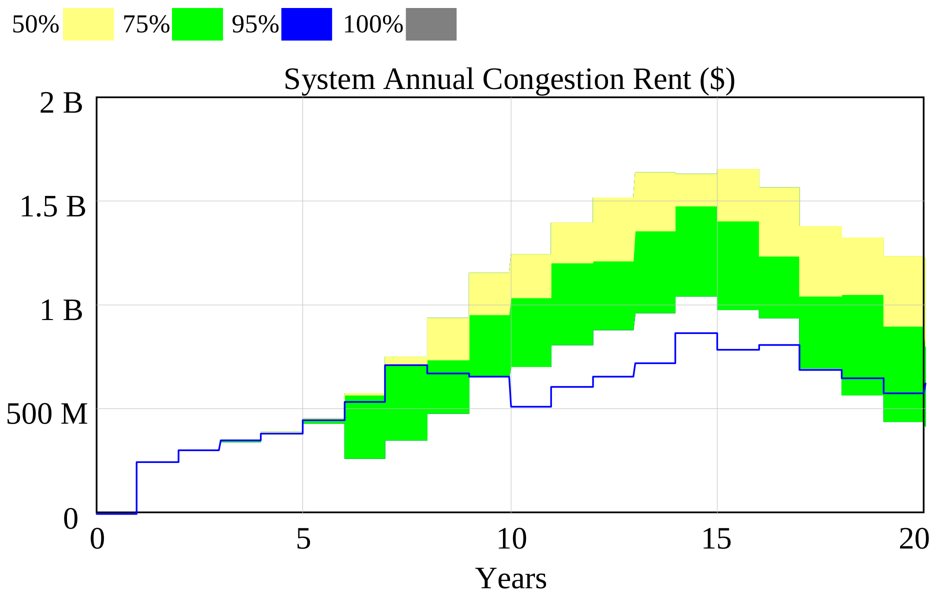

Fig. 5.119 Sensitivity of system annual congestion rent to time
for construction under scenario 8

- Sensitivity simulation results for annual loan interest rate

From the simulation results, we can see that paths T2 and T3 are very sensitive to the annual loan interest rate. Path T4 is not sensitive to this parameter. System annual congestion rent is also very sensitive to this parameter.

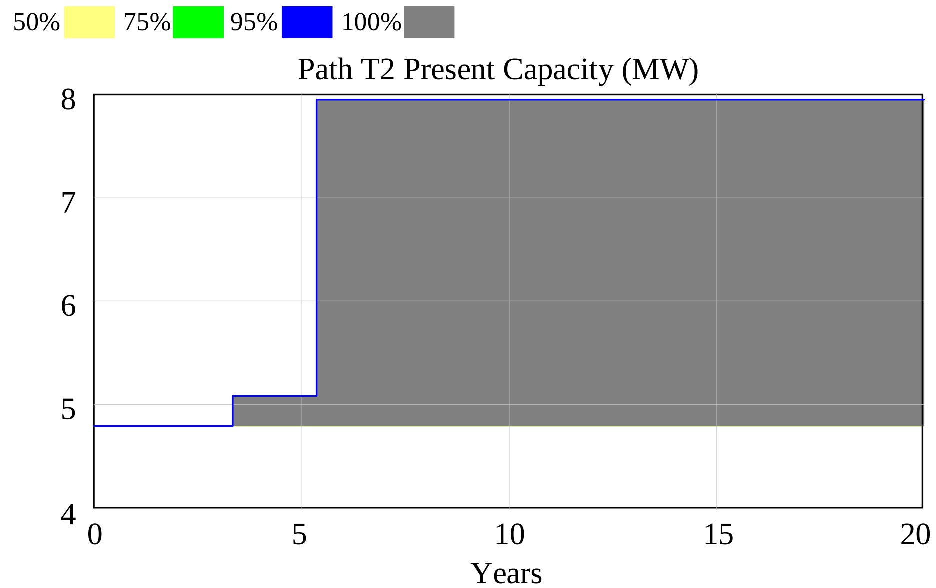

Fig. 5.120 Sensitivity of Path T2 expansion to annual loan
interest rate under scenario 8

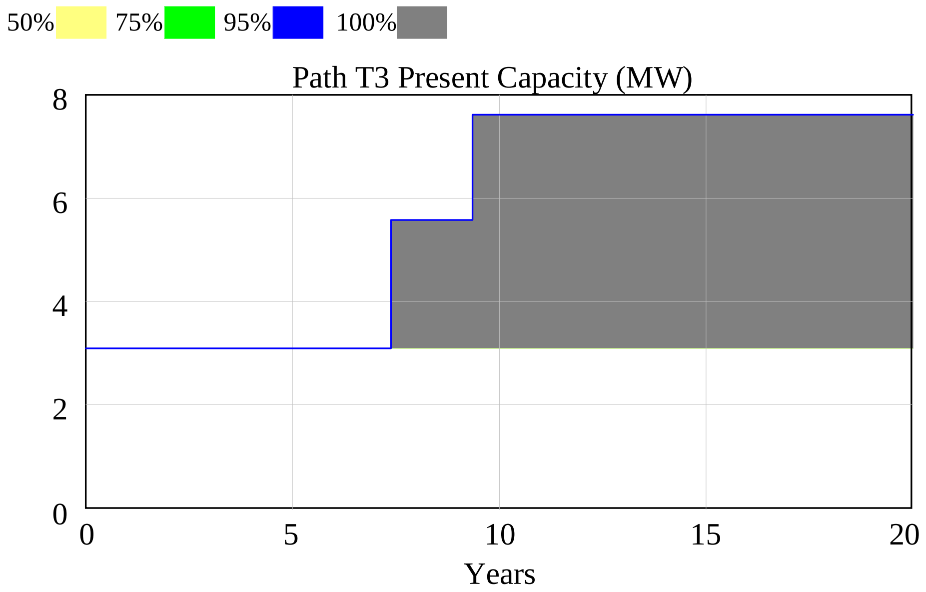

Fig. 5.121 Sensitivity of Path T3 expansion to annual loan interest rate under scenario 8

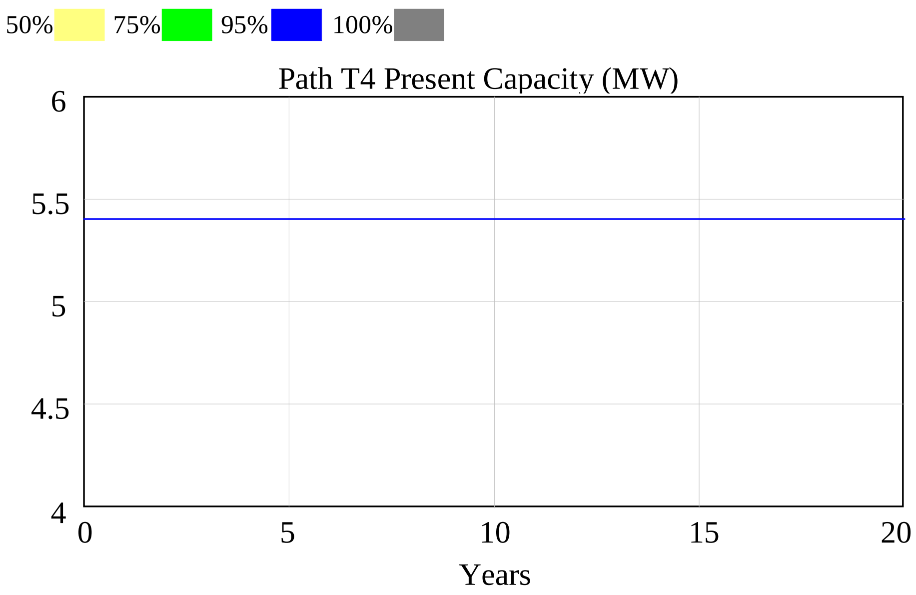

Fig. 5.122 Sensitivity of Path T4 expansion to annual loan interest rate under scenario 8

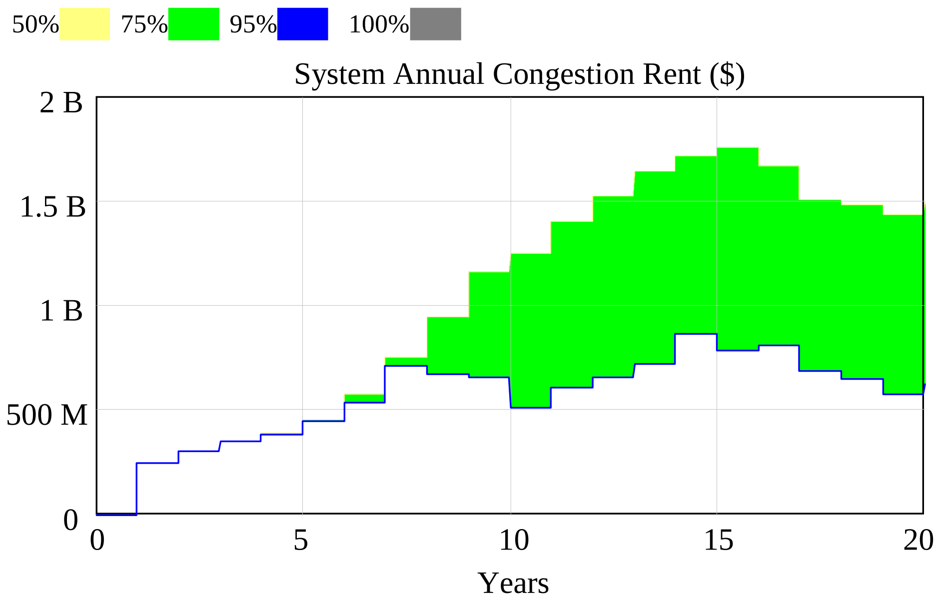

Fig. 5.123 Sensitivity of system annual congestion rent to annual loan interest rate under scenario 8

- Sensitivity simulation results for annual profit rate

From the simulation results, we can see that paths T2 and T3 are not very sensitive to the annual loan interest rate. Path T4 is not sensitive to this parameter. System annual congestion rent is also not very sensitive to this parameter.

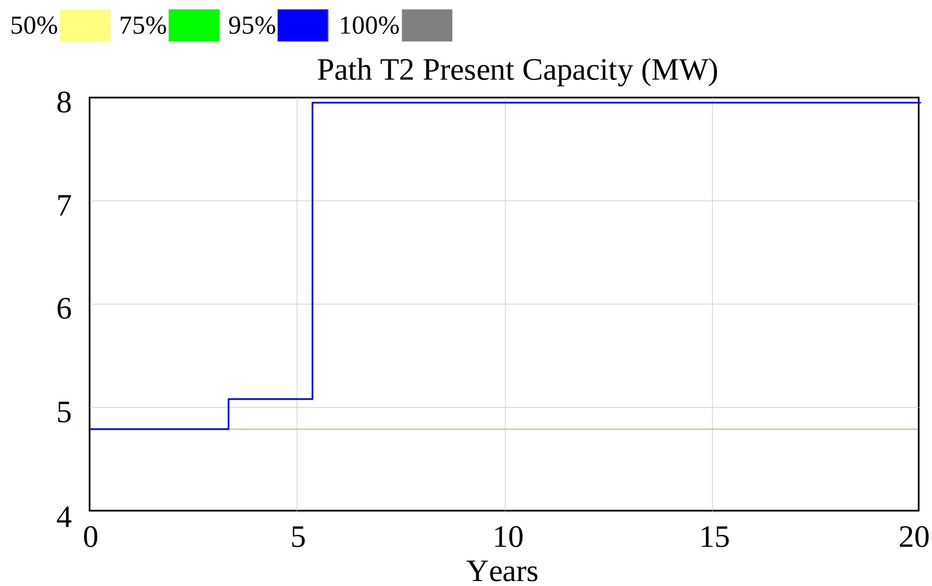

Fig. 5.124 Sensitivity of Path T2 expansion to annual profit rate under scenario 8

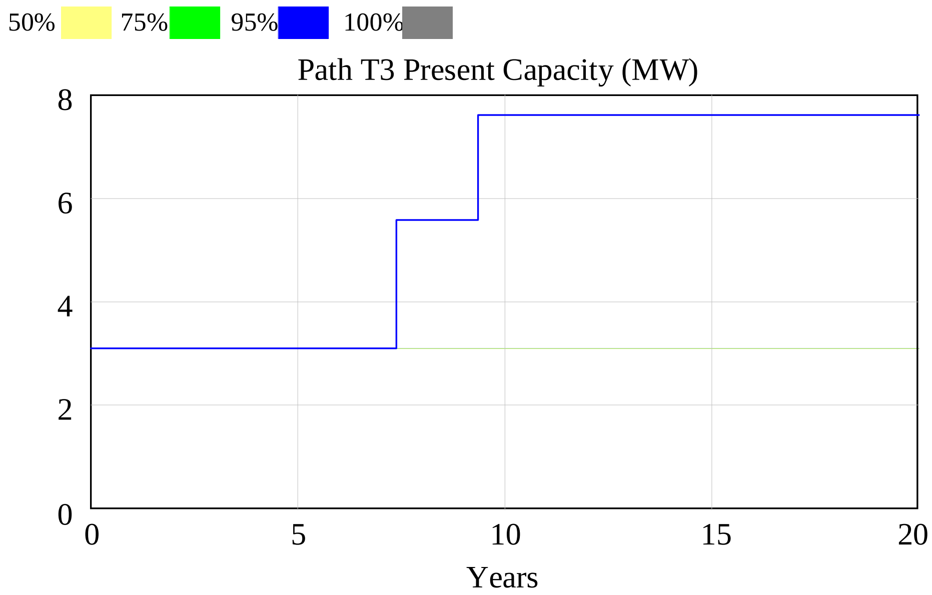

Fig. 5.125 Sensitivity of Path T3 expansion to annual profit rate under scenario 8

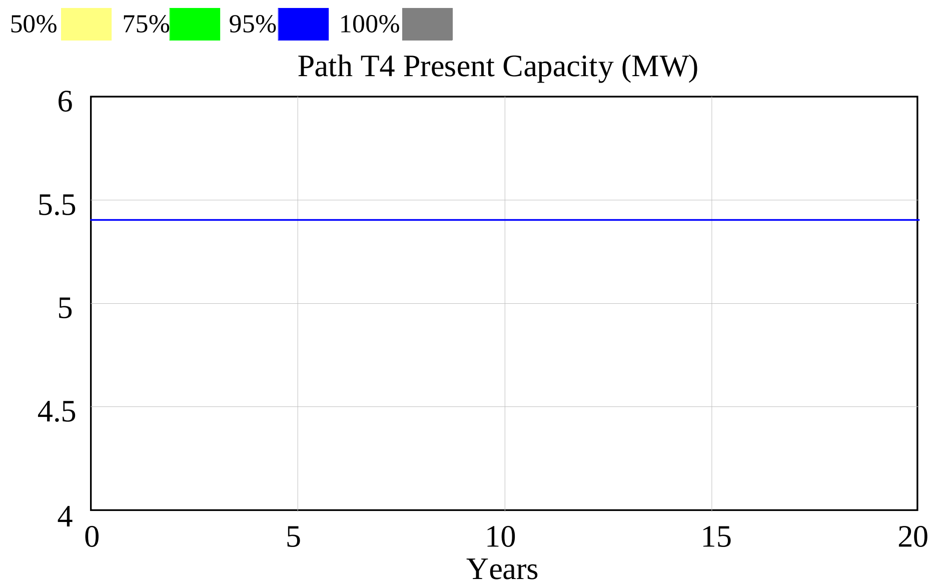

Fig. 5.126 Sensitivity of Path T4 expansion to annual profit rate under scenario 8

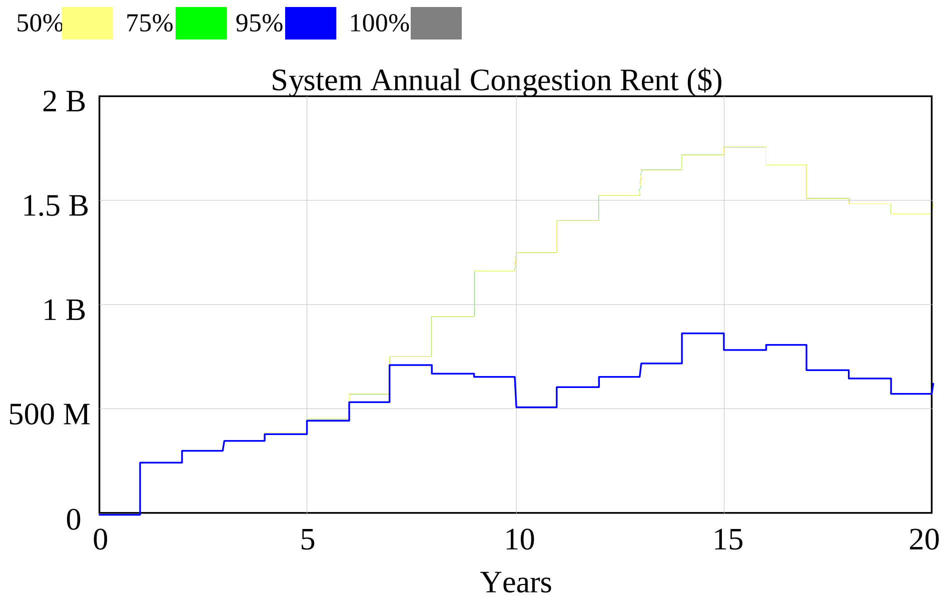

Fig. 5.127 Sensitivity of system annual congestion rent to annual profit rate under scenario 8

- **Scenario 9 simulation results**

In this scenario, regulated transmission investors use soft limit expansion on the most congested lines in the system, and they rely on ROE plus ROE adders granted by regulators to recover their investments and make profits.

- Sensitivity simulation results for time for construction

From the simulation results, we can see that paths T2 and T3 are very sensitive to the time for construction. Path T4 is not sensitive to this parameter. System annual congestion rent is also very sensitive to this parameter.

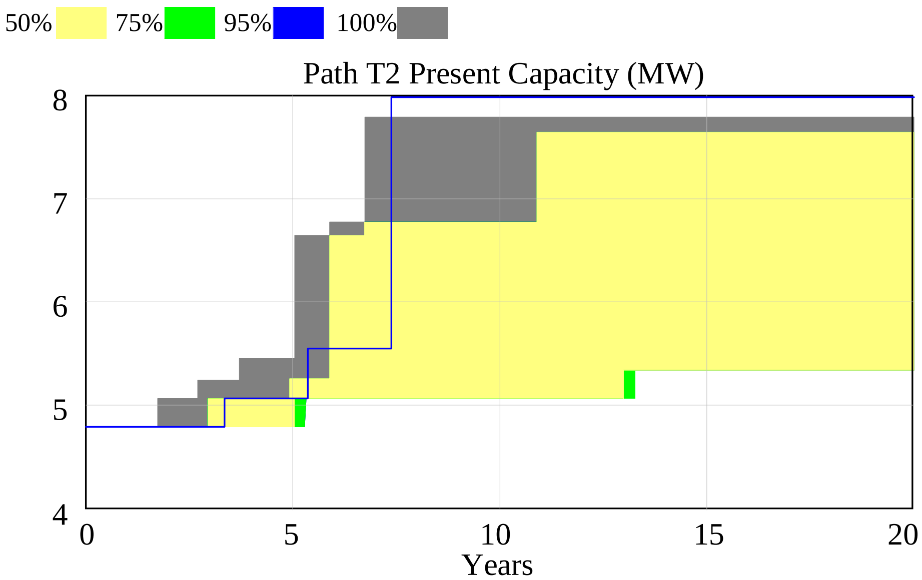

Fig. 5.128 Sensitivity of Path T2 expansion to time
for construction under scenario 9

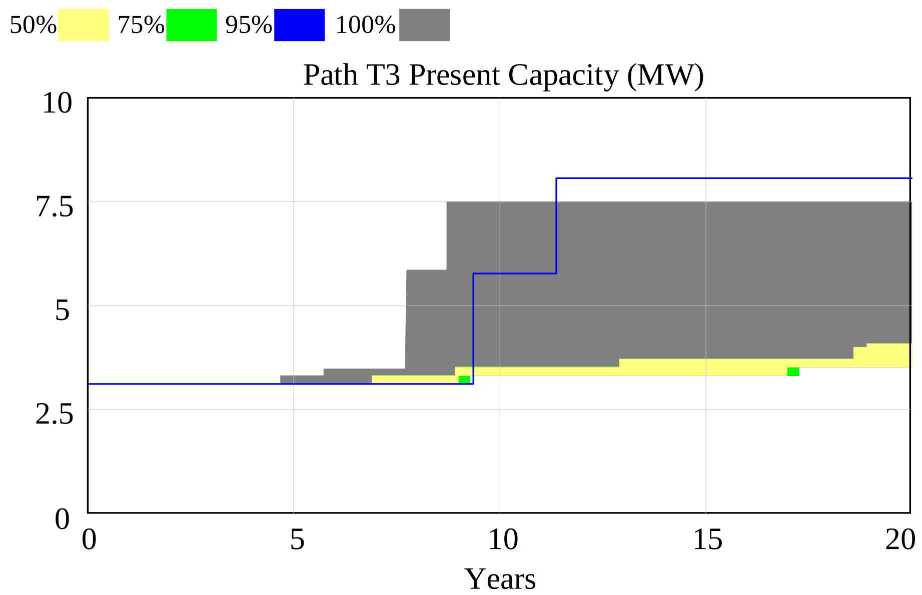

Fig. 5.129 Sensitivity of Path T3 expansion to time
for construction under scenario 9

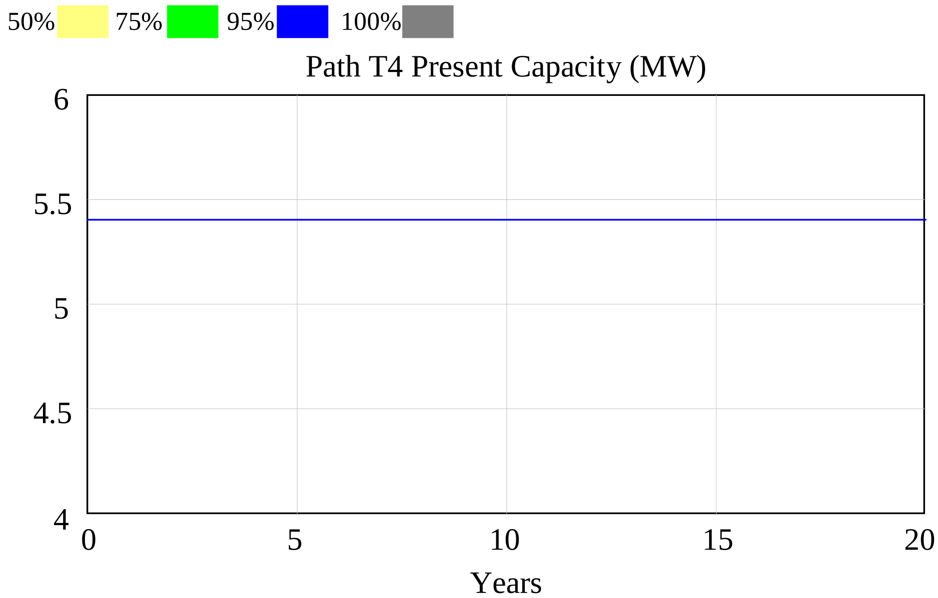

Fig. 5.130 Sensitivity of Path T4 expansion to time
for construction under scenario 9

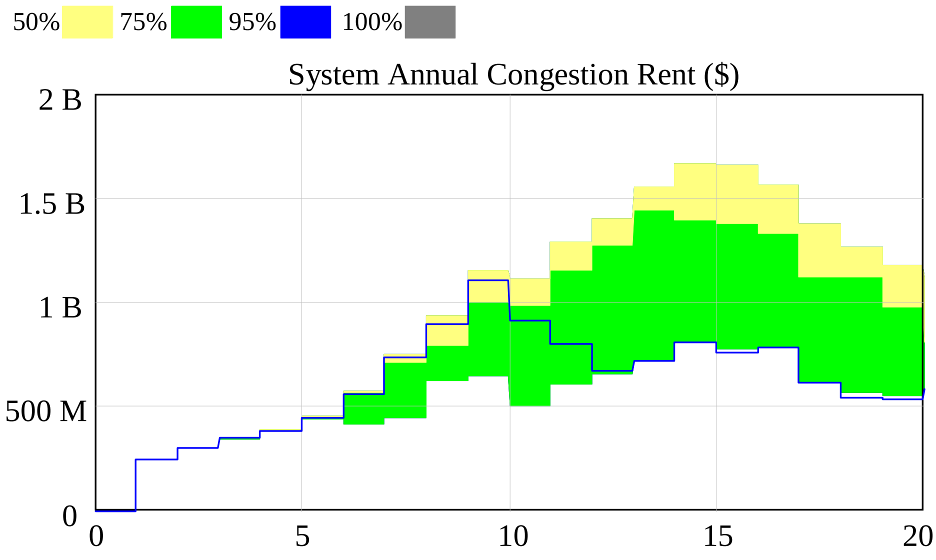

Fig. 5.131 Sensitivity of system annual congestion rent to time
for construction under scenario 9

- Sensitivity simulation results for annual loan interest rate

From the simulation results, we can see that paths T2 and T3 are very sensitive to the annual loan interest rate. Path T4 is not sensitive to this parameter. System annual congestion rent is also very sensitive to this parameter

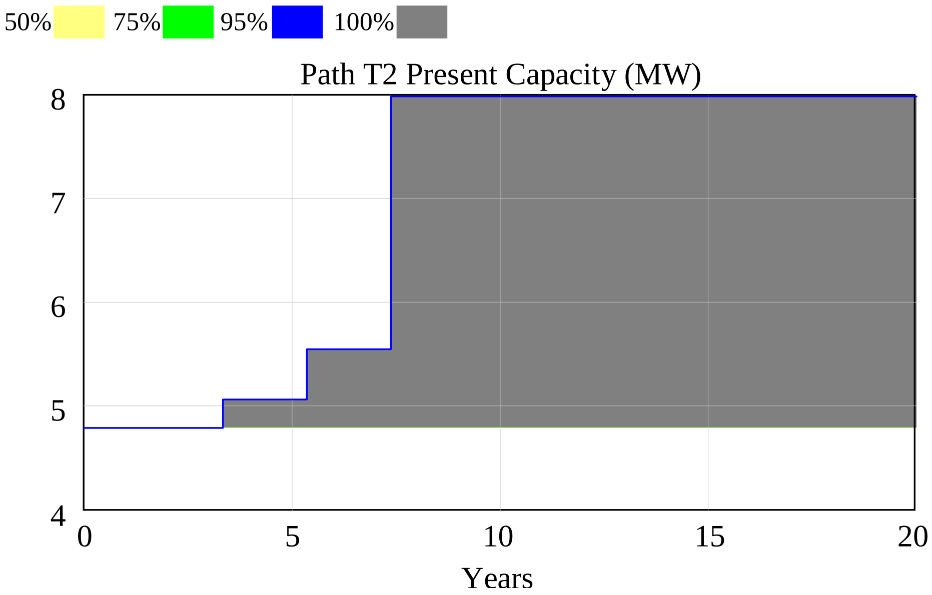

Fig. 5.132 Sensitivity of Path T2 expansion to annual loan interest rate under scenario 9

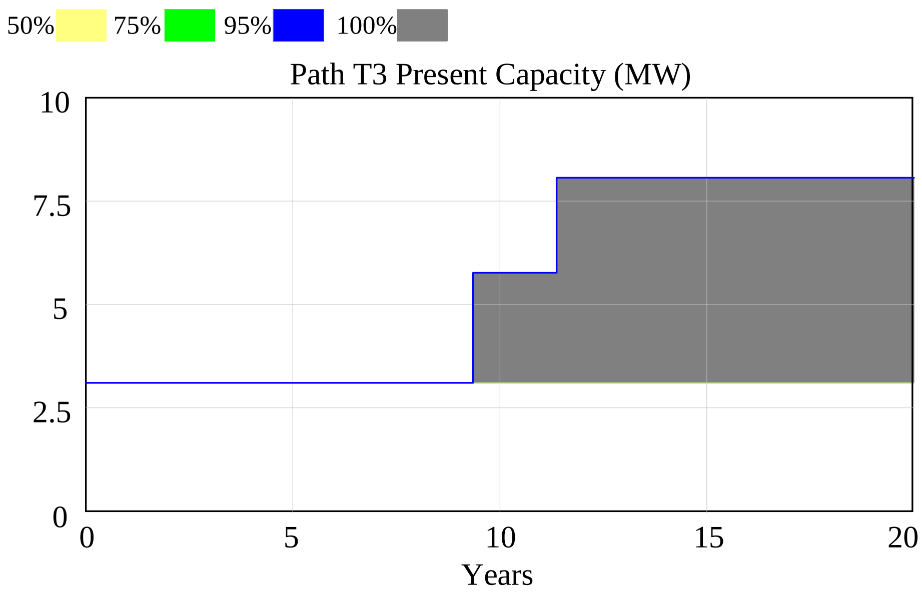

Fig. 5.133 Sensitivity of Path T3 expansion to annual loan interest rate under scenario 9

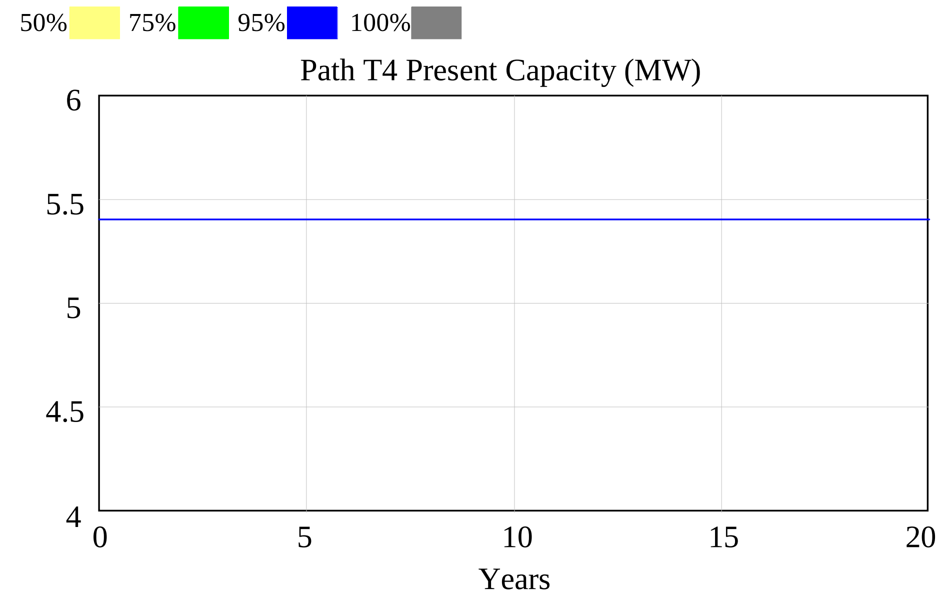

Fig. 5.134 Sensitivity of Path T4 expansion to annual loan interest rate under scenario 9

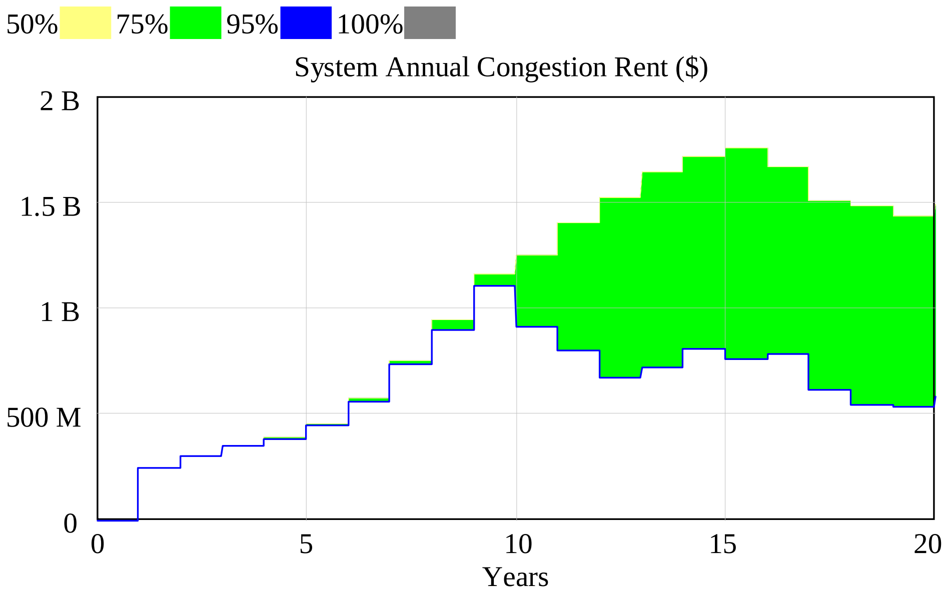

Fig. 5.135 Sensitivity of system annual congestion rent to annual loan interest rate under scenario 9

- Sensitivity simulation results for annual profit rate

From the simulation results, we can see that paths T2 and T3 are not very sensitive to the annual profit rate. Path T4 is not sensitive to this parameter.

System annual congestion rent is also not very sensitive to this parameter.

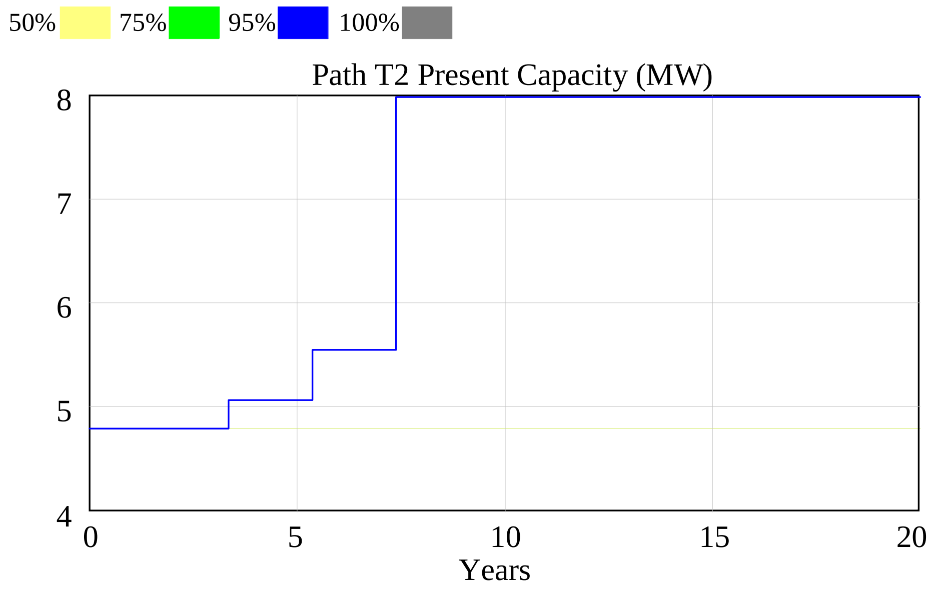

Fig. 5.136 Sensitivity of Path T2 expansion to annual profit rate under scenario 9

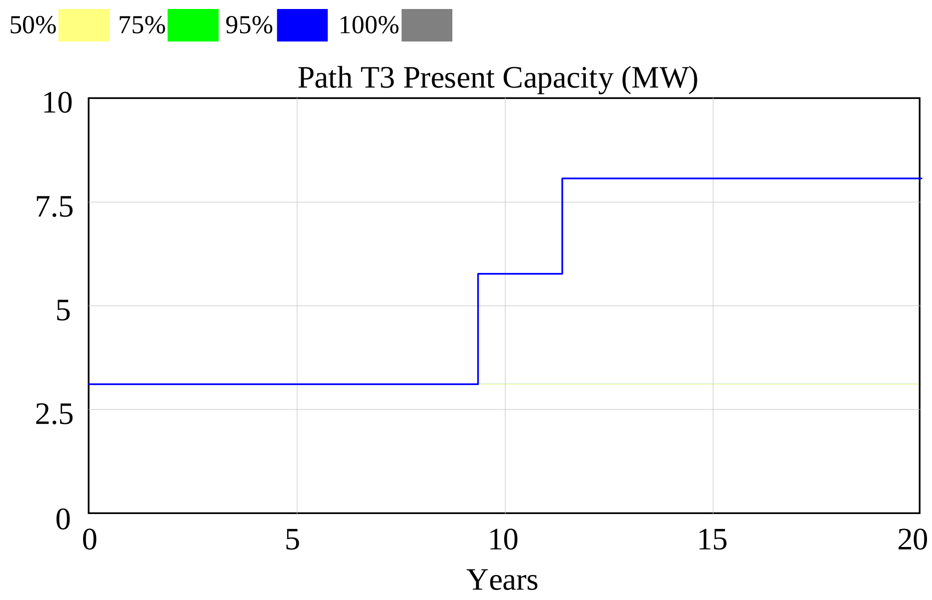

Fig. 5.137 Sensitivity of Path T3 expansion to annual profit rate under scenario 9

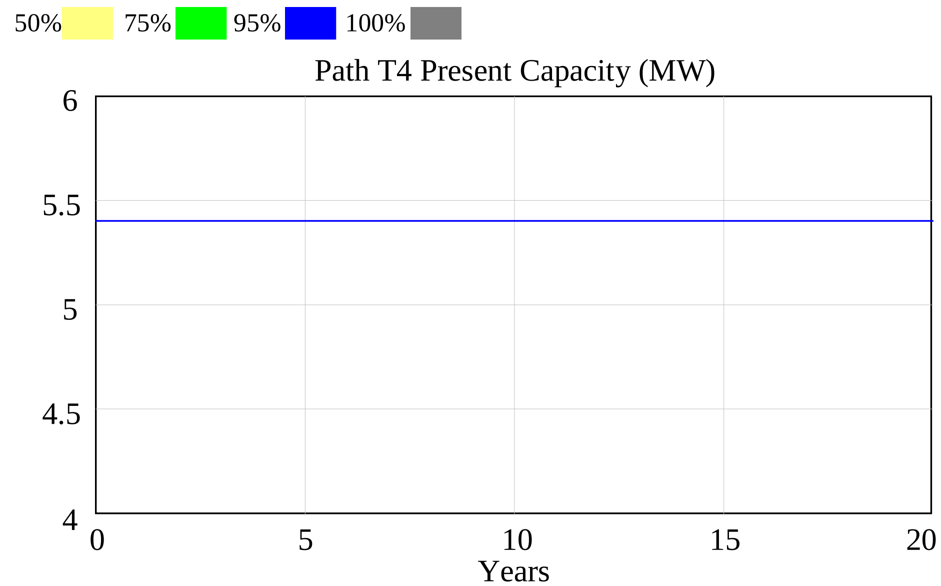

Fig. 5.138 Sensitivity of Path T4 expansion to annual profit rate under scenario 9

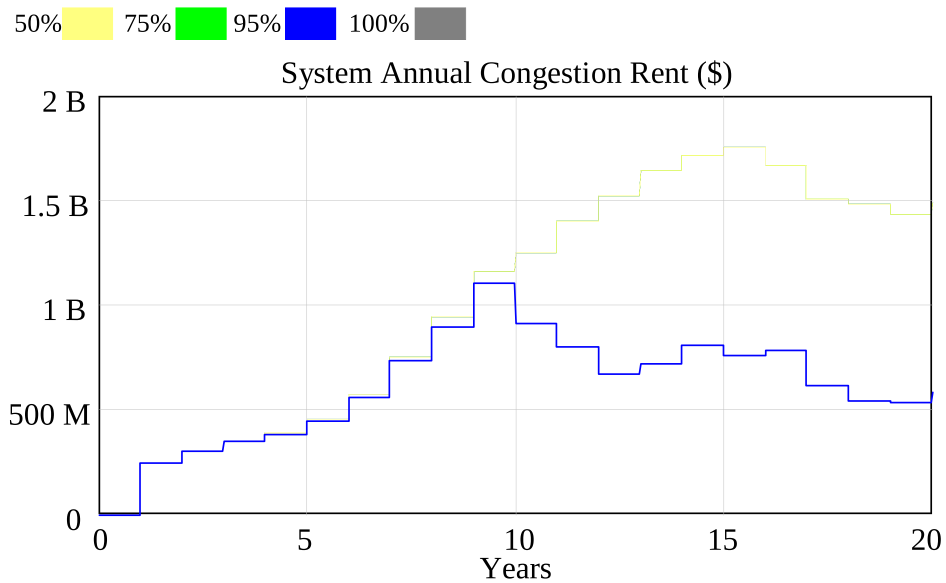

Fig. 5.139 Sensitivity of system annual congestion rent to annual profit rate under scenario 9

5.6.1 Sensitivity simulation results analysis

From the above figures for different parameters under different scenarios, we observe that

- System transmission investments and annual congestion rent are sensitive to the time for construction (time delay) and annual loan interest rate but not so sensitive to the annual profit rate.
- Under transmission expansion strategy 1, transmission capacity expansion and system congestion rent change are more sensitive under regulated investment (scenarios 4 and 7) than under merchant investment (scenario 1) for all three tested parameters: time for construction, annual loan interest rate, and annual profit rate.
- Under transmission expansion strategy 2, transmission capacity expansion and system congestion rent change are more sensitive under regulated investment (scenarios 5 and 8) than under merchant investment (scenario 2) for all three tested parameters: time for construction, annual loan interest rate, and annual profit rate.
- Under transmission expansion strategy 3, transmission capacity expansion and system congestion rent change are more sensitive under regulated investment (scenarios 6 and 9) than under merchant investment (scenario 3) for all three tested parameters: time for construction, annual loan interest rate, and annual profit rate.
- For different parameter sensitivity simulations under different scenarios, transmission investments remain in path T2 ~ T4, and the path expansion has

a similar pattern for different combinations between parameters and scenarios. We also observe the same pattern for annual congestion rent changes. These show that the SD models for transmission investment are robust with regard to the tested parameters.

5.7 Conclusions

According to these simulation results of the nine scenarios for economic analysis and sensitivity analysis and our analysis of these results, we can draw the following conclusions:

- Single stage or multi stage planning is not sufficient to investigate the impacts of transmission investment on system congestion rent change. Closed-loop feedback control SD models better manage the greater uncertainties and risks introduced by electric power industry restructuring. One is also able to look at total effectiveness over a planning horizon.
- For merchant transmission investment, if one wants to alleviate the most system congestion rent, hard margin expansion is the most effective; however, soft limit expansion has greater economic efficiency.
- For regulated transmission investment (with or without adders), if one wants to alleviate system congestion rents, hard margin expansion is again the most effective; however, hard expansion has better economic efficiency.
- For regulated transmission investment, ROE plus adders is more effective than simple ROE based incentives in alleviating system congestion rent. From the perspective of transmission investment economy efficiency, adders also

perform better using a hard expansion strategy. Simple ROE is more efficient for hard margin and soft limit expansion strategies.

- Whether merchant transmission investment or regulated transmission investment, investors are more sensitive to the time for construction (time delay) and annual loan interest rate and less sensitive to annual profit rate.
- For three different transmission expansion strategies, transmission capacity expansion and system congestion rent change are more sensitive under regulated investment than under merchant investment for all three tested parameters: time for construction, annual loan interest rate, and annual profit rate.
- The SD models for transmission investment are robust to variations in lifecycle of transmission expansion, interest rate and profit rate for both merchant transmission investment and regulated transmission investment.

We summarize the optimal transmission expansion strategies for different objectives under different investment incentives in Table 5.7.

Table 5.7 Optimal transmission expansion strategies for transmission investment

Objective	**Merchant Investment**	**Regulated Investment**
Mitigate system congestion rent	Hard margin expansion (Strategy 2)	Hard margin expansion (Strategy 2)
Improve investment economic efficiency	Soft limit expansion (Strategy 3)	Hard limit expansion (Strategy 1)

CHAPTER SIX

CONCLUSIONS

6.1 Contributions

The electric power industry restructuring has introduced a more complex environment for long-term transmission planning. With industry restructuring, the originally vertically-integrated and centralized structure has evolved to a non-integrated and more decentralized structure. The numerous market participants and the complexity of their inter-relationships render the traditional transmission planning process, single-staged or multi-staged, inadequate. This thesis introduces SD modeling to solve the transmission planning problem and tests different transmission investment incentives under restructured system conditions. Specifically, this work introduced the following:

- research on the long-term transmission expansion problem through an information feedback system for the first time;
- tests of the effects of different incentives on long-term transmission expansion under the restructured industry conditions;
- a new framework for transmission planning by considering information feedback;
- a detailed SD model for the WECC.

6.2 Limitations

The SD model more effectively captures the characteristics of transmission planning after the restructuring of the electric power industry. It provides a method to model and understand the complex power system and the relationship between its components through simulations. Still, there are a number of limitations in this method, including:

1. **SD modeling cannot substitute for detailed transmission planning**: Because the SD model is not a detailed model for point prediction, the results obtained cannot be directly used for generating a specific transmission plan. Only when it is combined with the detailed modeling, which here is called a *two-step transmission planning process*, can the model contribute to a transmission plan. Complications in the transmission planning under the restructured electric power industry lies in at least three aspects as we depicted in a three dimensional space in Fig. 6.1:

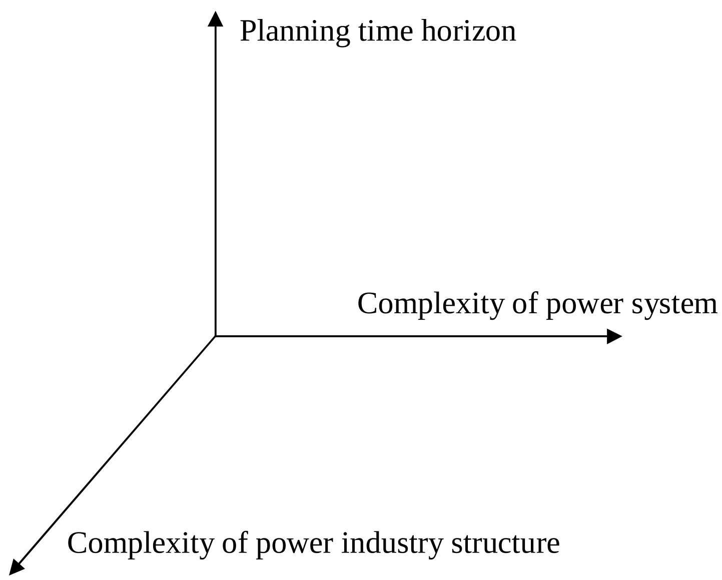

Fig. 6.1 Modeling considerations for long-term transmission planning after power industry restructuring

- **Complexity of power industry structures**: As depicted in Fig. 1.3, the restructured power industry has becomes more complicated in that:

    1) The vertically integrated industry structure is now horizontally decentralized. The GenCos, TransCos/GridCos and DistrCos no longer reside in the same utilities in the post-restructured power industry.
    2) There are many more entities in the post-restructured industry.
    3) The interrelationships between any two entities are accordingly more complicated due to market uncertainties and different incentives.
    4) Market participants are more numerous and active than before.
    5) It has become much harder to monitor and oversee the industry.

    With these changes, coordinating planning between generation and transmission investments has become extremely difficult. Unlike the integrated-resource planning (IRP) before restructuring, where IRP could potentially co-optimize generation and transmission expansions in a single company, today generation and transmission planning are performed by numerous different companies. Sauma and Oren [67] have shown that the social welfare gains earned from post-restructured transmission planning are lower than those earned from IRP, whether or not there is coordination between generation and transmission planning. Also, the increase in industry entities and the complexity among these components make the responsibilities for reliable performance more diffuse.

- **Complexity of power system:** The modern electric power system is a highly complicated, high-dimensional, and nonlinear synchronized system. There are often tens of thousands nodes connected by transmission lines and associated advance control devices in such systems. The dimension of a detailed power system model for transmission planning analysis is extremely large. Moreover any part's expansion in such a system will have complex indirect impacts on the other parts of the system.
- **Planning time horizon:** In long-term transmission planning, the greater the time length considered, the more operation circumstances that could be considered to ensure desired transmission performance. In the dynamic transmission planning process we depicted in Fig. 1.1, any transmission expansion will inevitably influence the transmission investment decisions in the future. Moreover with closed-loop information feedback, any information from previous and current markets is utilized as inputs for current and future transmission planning computations. This should result in better preparation for unforeseen events and a reduction in future uncertainties. Traditional single-stage or multi-stage transmission planning only consider one or a few staged time horizons and lack the closed-loop information feedback process between different stages that could help reduce these uncertainties.

Because of the complexity in the post-restructured transmission planning problem, current mathematic tools and hardware computation capabilities cannot solve the full problem as a single system model. We propose to simplify this complication by selectively reducing one of the three dimensions depicted in Fig.

6.1 at each step in the planning process. Through the two-step method we proposed, the system complication is decomposed by:

Step 1 - Simplified power system model: The details of power industry structure and the planning time horizon are kept, and the complication of power systems is simplified. An SD model built at this step includes the industry participants and their relationships while the power system physical model is greatly simplified by aggregating the system into several areas connected by equivalent tie-lines.

Step 2 - Simplified power industry structure and planning time horizon: The complexity of power industry structure and planning time horizon are reduced and the full detailed of power system models are employed. A detailed transmission planning model is considered at this step that is best multi-staged. The market participants and their relationships are simplified in this detailed model, since they have been considered in Step 1. The outputs from studies in step 1 provide guidance to the multi-state process at each step.

Compared to traditional transmission planning method, this two-step methodology can potentially help planners improve planning efficiency and overall strategies for meeting reliability requirements. For example there may be several sets of candidates for long-term transmission planning to mitigate system congestions in the long run. Step 1 can help planners screen these candidates and remove some unqualified ones so to improve planning efficiency and provide more reasonable scenarios for investigation. In this step, we can use the two proposed economic metrics to measure these candidates and help us screen unqualified ones, i.e., alleviated congestion rent defined by (5.4) and *ICAE* defined by (5.5). Fig. 6.2 depicts a simple flowchart for this example. In this figure, as long as the initial SD model has been built, the update of this model by adding the transmission expansion candidate sets is straightforward.

2. **Large number of assumptions limits confidence in results**. The intent of SD is not to build a detailed system model. Still, the researched system requires a large number of system specific parameters and assumptions on participant behavior. These assumptions directly influence the validity of the SD model and hence the conclusions drawn from the model. These modeling reductions are not straightforward since the simplification inevitably causes the loss of precision that may violate physical laws and cannot anticipate unusual market behavior. This perhaps is not so much a limitation of the approach as an admission that the decentralized decision-making is inherently uncertain and limits the confidence with which one can make planning decisions.

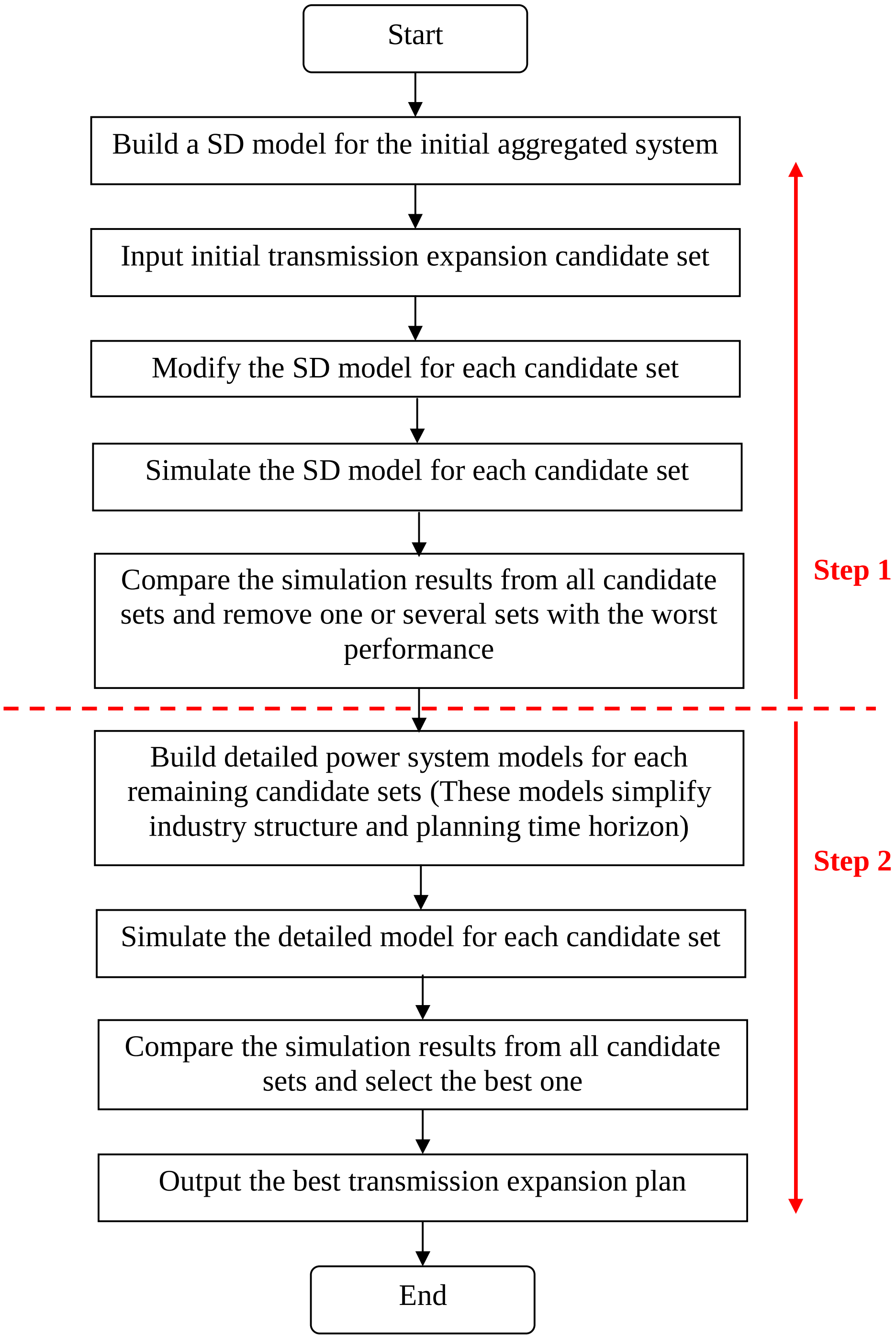

Fig. 6.2 Flowchart for a two-step transmission planning process

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APPENDIX A

TRANSMISSION NETWORK MODELING

A.1 WECC System

Our research interests lie in the impacts of different transmission investment incentives on transmission investments and system congestion rents mitigation. In the WECC system, California-Mexico Power Area is the load pocket with expensive electricity prices. Summer is the peak season for this area. WA/OR area has inexpensive hydro generation capacity and is a winter peak area. So in the wet summer season, there is significant power flowing from WA/OR area to California-Mexico Power Area. In the winter season, lots of power flows from SW area through California to WA/OR area. The large amounts of power transactions between these areas often cause transmission congestion on the tielines connecting them. We are interested in researching the dynamic impacts of transmission incentives on mitigating the congestions between these areas. In order to investigate the dynamic impacts, we need to build SD models for the long-term transmission planning process under different transmission investment incentives.

A.2 Simplified WECC Transmission System

The SD models require system power flow data between areas, which we can calculate based on detailed power flow models for the base case scenarios. We are primarily interested in the transmission congestion on the tielines connecting different areas under different transmission incentives, especially between Washington/Oregon and California-Mexico area. Our research does not focus on the transmission congestions within a WECC area. The software and methods used to build SD models are not suitable for large numerical computations as required for a full load flow model. It is not possible to build a System Dynamics model incorporating a system of say 10,000 buses both due to the required computations and the lack of meaningful data. Based on the goal of our research though, there is no need to build such detailed SD models for long-term transmission planning. Lumped system models should be adequate as long as they can capture the broad system characteristics.

In general, WECC divides itself into four areas: Pacific Northwest, Rocky Mountain, Desert Southwest and California/Mexico. Based on this division and our research objectives, we further divide Pacific Northwest into Canada, WA/OR and the remaining part of NWPP, and California/Mexico into NCA and SCA, since we are interested in the power transfers between WA/OR and SCA, NCA, where the congestion often occurs. With this division, we aggregate WECC into a seven-area and ten-tieline system.

We begin from detailed WECC power flow data for the 1996 Winter Peak hour and 2002 Summer Peak hour, to provide the original data for the lumped system. Based on these two detailed systems, we formulate another six detailed power flow data of winter off-peak, spring peak, spring off-peak, summer off-peak, fall peak and fall off-peak. In each area, the detailed data is summed to obtain for each area generation, load and tie-line flows. A shift factor (SF) matrix will be defined in the following to allow for the relationship between area net power injection and tie-line power flows.

A.3 HVDC lines (PDCI & IPP) in SF matrix update and transmission expansion

The power flow on the HVDC line is actively controlled through power electronic devices based on scheduled values. In the Vensim SD models, we can not rely on the SF matrix to calculate the power flows along these HVDC lines. Thus, the HVDC lines have to be handled independently. We propose a process to treat these HVDC lines as follows:

- The power flow on HVDC is set to the scheduled values in different seasons that are published in WECC's reports.
- From the solution of DC-OPF, we find the power flow values for the lumped AC tie-lines. For the HVDC line, if there is mismatch between the scheduled values and the calculated solutions, we will adjust the scheduled values to be equal to the calculated values so that the KCL is satisfied on each node in the equivalent system.
- The LMP calculation for a system with HVDC lines is the same as a system without HVDC lines. It is still the sum of the dual variables for power balance equation and line flow constraints in the DC-OPF problem.
- In the SF matrix update, we do not update the rows corresponding to HVDC lines.
- The transmission investment incentives for HVDC lines remain the same as AC lines.
- The scheduled line flow on HVDC lines increase proportionally with their capacity increase.

A.4 Line construction and maintenance data

The data concerning transmission investments, construction, and maintenance are as follows:

- Per MW.mile Cost for transmission expansion is assumed to be $1075 per MW.mile [68].
- The lifecycle of a major transmission line project includes choosing transmission routes, public information meetings, open houses and public outreach, regulatory review, environmental review, real estate issues, construction, and commission. The length of this lifecycle changes from project to project and is highly variable. In our research, we assume this lifecycle is two years: starting from project application, ending with the commission of an expanded transmission line.
- For transmission investment, the fixed costs are much greater than the variable cost. The variable costs mainly include an operations and maintenance fee. In our research, we assume that the annual variable cost for transmission lines is $524 per mile.

A.5 Equivalent tie-line

Because the entire WECC system is lumped to a seven-area and ten-tieline small system, the parameters concerning ten tie-lines connecting these seven areas are derived based on the following assumptions:

- **Line Capacity**: we do not know the exact capacity for each line included in the equivalent tie-lines. We use OTC (Operating Transfer Capability) under different seasons to approximate its capacity. The actual WECC system OTC data are given in [69-70].
- **Line Reactance**: we assume all lines are parallel for each equivalent tie-line. Based on this assumption, we can calculate the line reactance for each equivalent tie-line as in (A. 1).

$$\frac{1}{X_{eq}}=\sum_{i=1}^{n}\frac{1}{X_i} \tag{A. 1}$$

- **Line Length**: for the two HVDC lines (PDCI & IPP) we can find their exact lengths. For the HVAC lines, we cannot find their equivalent lengths. So we approximately calculate lengths based on some typical per mile reactance values at different voltage levels [71]. Based on these typical values and the equivalent lines' reactance calculated by (A.1), we calculate an equivalent line length by (A. 2) below. The calculated value is assumed to be the length of the equivalent tie-line. Where X_p is per mile line reactance value.

$$Length=\frac{X_{eq}}{X_p} \tag{A. 2}$$

A.6 SF matrix

In the lumped WECC system, we do not know the exact line reactance so it's not possible to calculate the SF matrix directly by the approximated line reactance derived in

(A. 1). Still, we have detailed power flow data from the WECC system. We assume that there is a linear relationship between area power flow injections and tie-line power flows (this assumption is reasonable for our lumped seven-area and ten-tieline system). We define a matrix to describe this linear relationship as the SF matrix. Its initial value can be calculated by the data coming from detailed power flow. After some transmission upgrade or expansion, the SF matrix can be updated by approximate methods discussed in detail below.

1) Calculate SF initial value

From the detailed WECC power flow solutions, we can calculate the initial SF matrix SF^I by least square estimation. Assume that there number of nodes is m and number of lines is p in our researched system, and then we have the following equation with node one as the reference

$$\begin{bmatrix} P_{\ell,1} \\ P_{\ell,2} \\ \ldots \\ P_{\ell,p} \end{bmatrix} = \begin{bmatrix} S_{11},\ S_{12},\ \ldots,\ S_{1,m\text{-}1} \\ S_{21},\ S_{22},\ \ldots,\ S_{2,m\text{-}1} \\ \ldots \\ S_{p1},\ S_{p2},\ \ldots,\ S_{p,m-1} \end{bmatrix} \begin{bmatrix} P_{in,2} \\ P_{in,3} \\ \ldots \\ P_{in,m} \end{bmatrix} \qquad \text{(A. 3)}$$

Let $\underline{P}_\ell = \begin{bmatrix} P_{\ell,1} \\ P_{\ell,2} \\ \ldots \\ P_{\ell,p} \end{bmatrix}$, $SF^I = \begin{bmatrix} S_{11},\ S_{12},\ \ldots,\ S_{1,m\text{-}1} \\ S_{21},\ S_{22},\ \ldots,\ S_{2,m\text{-}1} \\ \ldots \\ S_{p1},\ S_{p2},\ \ldots,\ S_{p,m-1} \end{bmatrix}$ and $\underline{P}_{in} = \begin{bmatrix} P_{in,2} \\ P_{in,3} \\ \ldots \\ P_{in,m} \end{bmatrix}$.

To express the linear relationship between transmission line flows and power injections for the initial WECC system, we have

$$\underline{P}_{\ell} = SF^{I}\,\underline{P}_{in} \tag{A. 4}$$

and for the i^{th} line we have the following equation to calculate the power flow on this line

$$P_{\ell,i} = \underline{S}_i\,\underline{P}_{in} \tag{A. 5}$$

where $\underline{S}_i$ is the i^{th} row of the SF^{I} matrix.

If we have n detailed power flow cases and $n > m-1$ (*m* is the number of nodes), i.e., the problem is overdetermined, then for the i^{th} line we calculate power flows on this line for each case as

$$\begin{aligned} P_{\ell,i}{}^{1} &= \underline{S}_i\,\underline{P}_{in}{}^{1} + \varepsilon^{1} \\ P_{\ell,i}{}^{2} &= \underline{S}_i\,\underline{P}_{in}{}^{2} + \varepsilon^{2} \\ &\dots \\ P_{\ell,i}{}^{n} &= \underline{S}_i\,\underline{P}_{in}{}^{n} + \varepsilon^{n} \end{aligned} \tag{A. 6}$$

where $\varepsilon^{1}, \varepsilon^{2}, ..., \varepsilon^{n}$ are errors introduced by simplifying the detailed power flow cases. Reformulating (A. 6) in vector and matrix form yields

$$\begin{bmatrix} P_{\ell,i}{}^{1} \\ P_{\ell,i}{}^{2} \\ \dots \\ P_{\ell,i}{}^{n} \end{bmatrix} = \begin{bmatrix} P_{in,2}{}^{1},\ P_{in,3}{}^{1},\ \dots,\ P_{in,m}{}^{1} \\ P_{in,2}{}^{2},\ P_{in,3}{}^{2},\ \dots,\ P_{in,m}{}^{2} \\ \dots \\ P_{in,2}{}^{n},\ P_{in,3}{}^{n},\ \dots,\ P_{in,m}{}^{n} \end{bmatrix} \underline{S}_i{}^{T} + \begin{bmatrix} \varepsilon^{1} \\ \varepsilon^{2} \\ \dots \\ \varepsilon^{n} \end{bmatrix} \tag{A.7}$$

Now let $\underline{Y} = \begin{bmatrix} P_{\ell,i}{}^{1} \\ P_{\ell,i}{}^{2} \\ \dots \\ P_{\ell,i}{}^{n} \end{bmatrix}$, $X = \begin{bmatrix} P_{in,2}{}^{1},\ P_{in,3}{}^{1},\ \dots,\ P_{in,m}{}^{1} \\ P_{in,2}{}^{2},\ P_{in,3}{}^{2},\ \dots,\ P_{in,m}{}^{2} \\ \dots \\ P_{in,2}{}^{n},\ P_{in,3}{}^{n},\ \dots,\ P_{in,m}{}^{n} \end{bmatrix}$, $\underline{\theta} = \underline{S}_i{}^{T}$ and $\underline{\varepsilon} = \begin{bmatrix} \varepsilon^{1} \\ \varepsilon^{2} \\ \dots \\ \varepsilon^{n} \end{bmatrix}$, Then we have

$$\underline{Y} = X\,\underline{\theta} + \underline{\varepsilon} \tag{A.8}$$

Problem (A. 8) can be solved by Least Square Estimation (LSE). The condition that the rank of X is $m-1$ is always satisfied in our problem, since the power system model is nonlinear and the power flow solutions under different load levels will be independent of each other. Next we derive the normal equation for the LSE problem. First define a residual vector $\underline{r} = \underline{Y} - X\,\underline{\theta}$. Based on this definition, the least-squares solution is obviously the one with the smallest misfit to the measurements as given by

$$min\ \underline{r}^T\,\underline{r} = \sum_{i=1}^{n} r_i^2 \tag{A. 9}$$

By first order conditions, we want $\underline{\theta} = \hat{\underline{\theta}}$ such that $\nabla_{\underline{\theta}}\left[\underline{r}(\underline{\theta}) \cdot \underline{r}(\underline{\theta})\right] = \underline{0}$.

Equivalently,

$$\nabla_{\underline{\theta}}\left[\left(\underline{Y} - X\,\underline{\theta}\right)^T\left(\underline{Y} - X\,\underline{\theta}\right)\right] = \underline{0} \tag{A. 10}$$

Expand (A. 10), we obtain

$$\nabla_{\underline{\theta}}\left[\underline{Y}^T\underline{Y} - \underline{Y}^T X\,\underline{\theta} - \underline{\theta}^T X^T\underline{Y} + \underline{\theta}^T X^T X\,\underline{\theta}\right] = \underline{0} \tag{A. 11}$$

We know that

$$\underline{Y}^T X\,\underline{\theta} = \underline{\theta}^T X^T\underline{Y} = \left(X^T\underline{Y}\right)^T\underline{\theta} \tag{A. 12}$$

Substitute this relationship (A. 12) into (A. 11), and then the gradient becomes

$$\nabla_{\underline{\theta}}\left[\underline{Y}^T\underline{Y}-2\left(X^T\underline{Y}\right)^T\underline{\theta}+\underline{\theta}^T X^T X\underline{\theta}\right]=\underline{0} \qquad \text{(A. 13)}$$

Calculating this gradient, we find

$$-2X^T\underline{Y}+2X^T X\underline{\theta}=0 \qquad \text{(A. 14)}$$

From (A. 14) we derive the normal equation (A. 15) to estimate $\underline{\theta}$ by LSE, provided $X^T X$ is nonsingular.

$$\hat{\underline{\theta}}=\left(X^T X\right)^{-1}X^T\underline{Y} \qquad \text{(A. 15)}$$

Although we can calculate $\hat{\underline{\theta}}$ directly from the normal equation, it is possible that the matrix $\left(X^T X\right)^{-1}$ is very poorly conditioned and forming $\left(X^T X\right)^{-1}$ can also produce undesirable round-off error. In order to improve the numerical stability of the LSE problem, the QR algorithm is used to decompose matrix X as (A. 16) with $Q^T Q=I$ and R upper triangular.

$$X_{n\times(m-1)}=Q_{n\times(m-1)}R_{(m-1)\times(m-1)} \qquad \text{(A. 16)}$$

If we substitute $X=QR$ into the normal equation, it is straightforward to show that the LSE can be expressed as (A. 17)

$$\hat{\underline{\theta}}=\left(R^T Q^T QR\right)^{-1}R^T Q^T\underline{Y}=R^{-1}Q^T\underline{Y} \qquad \text{(A. 17)}$$

or equivalently as (A. 18)

$$R\underline{\hat{\theta}} = Q^T \underline{Y} \qquad \text{(A. 18)}$$

Because R is upper triangular, a very stable estimate of $\underline{\hat{\theta}}$ can be obtained by back substitution. The Matlab function *mldivide* uses QR algorithm to solve LSE problem, so it is used to solve the problem in our research.

2) Update SF matrix with transmission expansion

Because it is impossible to calculate the exact reactance for the equivalent tie-lines, we have to approximate the update of the SF matrix with an equivalent tie-line capacity increase. For the long-term transmission expansion problem in a large lumped system like WECC, this approximation need not be too precise as long as it generally captures the impact of transmission expansion on a line.

- First we define a linear relationship between line capacity and its reactance as in (A. 19)

$$C_f = P^c X \qquad \text{(A. 19)}$$

We assume that line capacity and line flow are equal for heavy load conditions. Although there is some difference between these two values, this assumption is still within our desired accuracy, since this difference should not be very large compared to the heavy load conditions and most transmission congestion happens in heavy (or peak) load conditions. Fig.

A. 1 depicts a transmission line under heavy load conditions. Based on our assumptions, the power flow along this line could be calculated by (A.20).

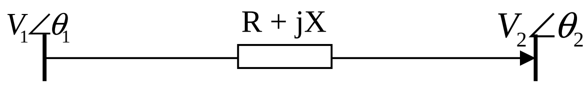

Fig. A.1 A heavy loaded transmission line

$$\begin{aligned}
P^c + jQ &\approx P + jQ = \vec{V}_1 \vec{I}_1^{\,*} \\
&= \vec{V}_1 \frac{\vec{V}_1^{\,*} - \vec{V}_2^{\,*}}{R - jX} \\
&= \frac{\left|\vec{V}_1\right|^2 - \vec{V}_1 \vec{V}_2}{R - jX} \\
&= \frac{V_1^2 - V_1 V_2 \angle(\theta_1 - \theta_2)}{R - jX} \\
&= \frac{V_1^2 - V_1 V_2 \cos(\theta_1 - \theta_2) - jV_1 V_2 \sin(\theta_1 - \theta_2)}{R - jX}
\end{aligned} \tag{A. 20}$$

Let $\delta = \theta_1 - \theta_2$, we find an approximate line capacity value P^c by

$$P^c \approx \frac{\left[V_1^2 - V_1 V_2 \cos\delta\right] R + V_1 V_2 X \sin\delta}{R^2 + X^2} \tag{A. 21}$$

Substituting P^c into the linear relationship described by (A.19). We can calculate the coefficient C_f between line capacity and line reactance as

$$C_f = P^c X \approx \frac{\left[V_1^2 - V_1 V_2 \cos\delta\right] \frac{R}{X} + V_1 V_2 \sin\delta}{\left(\frac{R}{X}\right)^2 + 1} \tag{A. 22}$$

We choose some typical values for $\frac{R}{X}$ and P^c for different voltage levels, and then assume there is 10% voltage drop along the line under heavy load conditions, i.e. $V_1 = 1.05V_{base}$, $V_2 = 0.95V_{base}$. The angle difference along a heavy loaded transmission line can be calculated from the bus voltage angles in the detailed power flow solutions. In our research for each equivalent area tieline, we choose the maximum angle difference value from all angle difference values for the lines combined together to formulate this equivalent tieline.

Based on all the above assumptions, we have enough data to calculate the coefficient value C_f in (A. 22).

- Based on the coefficient C_f, we then calculate line reactance approximately as

$$X = \frac{C_f}{P^c} \tag{A. 23}$$

Based on the line capacity before transmission expansion, we then calculate line reactance X and hence the matrix SF^o before transmission expansion. With transmission expansion, both line capacity and line reactance will change accordingly. Let ΔX be increased line reactance and ΔP^c be increased line capacity. The previous linear relationship assumption still holds for the line reactance and capacity after transmission expansion. So we have

$$X + \Delta X = \frac{C_f}{P^c + \Delta P^c} \tag{A. 24}$$

We have known line reactance X before transmission expansion from (A. 23). Substituting this into (A. 24), and the line reactance increase ΔX after transmission capacity increase can be calculated as

$$\Delta X = -\frac{C_f \Delta P^c}{\left(P^c\right)^2 + \Delta P^c P^c} \tag{A. 25}$$

After finding the increased line reactance ΔX from (A. 25), we calculate the line reactance value $\overline{X}$ after transmission capacity increase using

$$\overline{X} = X + \Delta X \tag{A. 26}$$

With this line reactance $\overline{X}$ after transmission expansion, we calculate the new SF matrix $\overline{SF}$ based on system reactance values. Finally, we calculate the percentage change for each term in the SF matrix shown in (A. 27) based on the SF matrix values SF^o and $\overline{SF}$ before and after transmission expansion.

$$\Delta SF\% = \frac{\overline{SF} - SF^o}{SF^o} \times 100\% \tag{A. 27}$$

With this SF matrix percentage change, we update the SF matrix using

$$SF = \left(I + \Delta SF\%\right) SF^{I} \qquad \text{(A. 28)}$$

APPENDIX B

DETAILED MODEL IMPLEMENTATION AND VALIDATION

B.1 Data sources

In this appendix, we derive a 24-hour daily load level for each area in each typical season for our lumped seven-area and ten-tieline WECC system.

- Hourly data

We have two original detailed WECC power flow data files and six other derived scenarios. Power generation and load levels are adjusted in small step sizes. After each adjustment, the detailed power flow analysis is performed. This process is repeated until the power flow diverges. Fig. B. 1 depicts the flowchart of the above mentioned repeated power flow analysis process. Based on this analysis, we obtain the following data to represent the other six typical seasons at On/Off Peak hours as follows:

Winter Off-Peak Hour **–** *85.74%* Winter Peak Hour in load and generation levels

Spring Peak Hour **–** *90.25%* Winter Peak Hour in load and generation levels

Spring Off-Peak Hour **–** *81.45%* Winter Peak Hour in load and generation levels

Summer Off-Peak Hour **–** *86.21%* Summer Peak Hour in load and generation levels

Fall Peak Hour **–** *93.04%* Summer Peak Hour in load and generation levels

Fall Off-Peak Hour **–** *81.98%* Summer Peak Hour in load and generation levels

After the above power flow analysis process, we have eight sets of WECC power flow solutions. We use them to represent the peak and off-peak hours for each area in each typical season in a year: area generation capacity, area load level, and equivalent tie-line power flow.

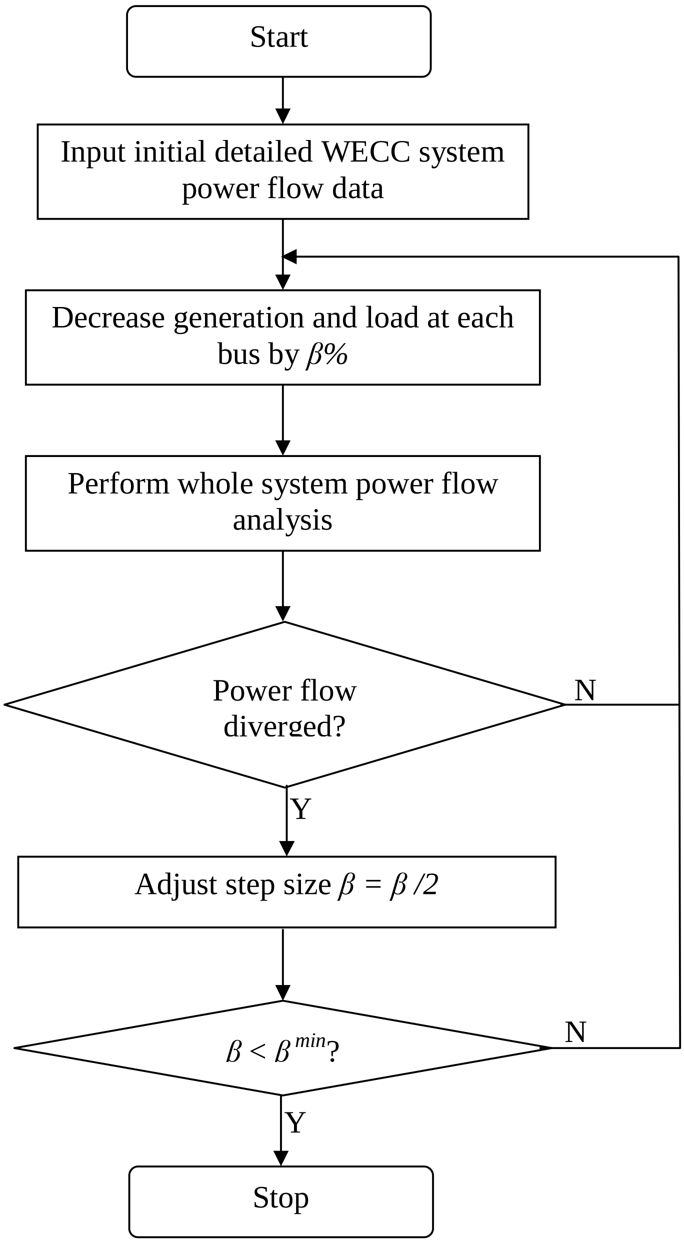

Fig. B. 1 Flowchart for repeated power flow analysis process

- Daily load pattern

We use the 24-hour load curves to produce the 24-point daily load pattern for the above eight typical days in each area. Currently there is only one ISO, California ISO, in the WECC system, where we have the daily load curve from its OASIS. We do not have 24-hour daily load curve for the remaining areas in WECC system. But there are some other ISOs/RTOs with OASIS. From them, we find some typical 24-hour daily load curves. Considering the similarity in area climate patterns, we use the data from some other ISOs/RTOs outside of WECC system to represent the areas in WECC system. This approximation is the best we can do considering current data availability. We believe this approximation should be accurate enough to serve our modeling purpose. We know that the biggest factor to affect the load pattern in the WECC system is climate in each area. As long as the load curves from ISOs/RTOs outside WECC have similar patterns, they can be used for our modeling. Another reason is that our SD models are based on a lumped seven-area and ten-tieline WECC system. For such a lumped system, we use one load curve to represent the whole area load pattern. Even if precise system data by area, the aggregation only approximates the load and flow patterns. The correspondence between WECC area and ISOs/RTOs is given in Table B.1.

Table B.1 Correspondence for WECC area load curve pattern representation

WECC area	**Data source for area daily load curve pattern**
WA/OR	NYISO
RM	MISO
SW	ERCOT
SCA	CAISO
NCA	CAISO
Remainder of NWPP	PJM
Canada	ISO-NE

- Daily load level

Now we have some on-peak and off-peak hour data from detailed power flow analysis for each area in each typical season and also daily load pattern for each area in each typical season from ISOs/RTOs OASIS. Combining them together as in (B.1), yields the daily 24-hour load level for each area

$$P_{L,i}(t,k) = \mu(t)P_{L,i}(k) \tag{B.1}$$

In (B.1), t=1, 2, ..., 24; i=1, 2, ..., 7; k=1, 2, 3, 4; $\mu(t)$ is the load pattern at time point t. $P_{L,i}(k)$ is the load level for area i at season k. $P_{L,i}(t,k)$ is the load level at time point t for area i at season k.

B.2 Area generation bidding

Based on results from previous work [72], we can derive quadratic bidding functions for CAISO. Four regimes are given as the functions of MCP (Market Clearing Price) vs.

load in [72], and they are expressed by cubic functions. Quadratic functions are used as bidding functions in our research. We use LSE (Least Square Estimation) to derive the quadratic bidding functions required by our research. Given n independent variable x_i and n cubic function value z_i. The quadratic function is defined as:

$$y_i = ax_i^2 + bx_i + c \tag{B.2}$$

The residual is defined as the difference between quadratic function value and cubic function value

$$r_i = z_i - y_i \tag{B.3}$$

Then the quadratic residual is calculated by

$$S = \sum_{i=1}^{n} r_i^2 = \sum_{i=1}^{n} (z_i - y_i)^2 \tag{B.4}$$

Based on the first order conditions, we take the derivative of quadratic residual S to variable β_j and let it be zero as in

$$\frac{\partial S}{\partial \beta_j} = 2\sum_{i=1}^{n} r_i \frac{\partial r_i}{\partial \beta_j} = 0 \tag{B.5}$$

Let β_j in (B.5) be the quadratic function coefficients *a*, *b*, and *c* respectively. We obtain

$$\begin{aligned} &\beta_j = a: \ \ 2\sum_{i=1}^{n} r_i(\text{-}x_i^2) = 0 \Rightarrow \sum_{i=1}^{n}\left(r_i x_i^2\right) = 0 \Rightarrow \sum_{i=1}^{n}\left[\left(y_i - ax_i^2 - bx_i - c\right)x_i^2\right] = 0 \\ &\Rightarrow \ \sum_{i=1}^{n}\left(x_i^2 y_i\right) - a\sum_{i=1}^{n}\left(x_i^4\right) - b\sum_{i=1}^{n}\left(x_i^3\right) - c\sum_{i=1}^{n}\left(x_i^2\right) = 0 \\ &\Rightarrow \ a\sum_{i=1}^{n}\left(x_i^4\right) + b\sum_{i=1}^{n}\left(x_i^3\right) + c\sum_{i=1}^{n}\left(x_i^2\right) = \sum_{i=1}^{n}\left(x_i^2 y_i\right) \end{aligned} \tag{B.6}$$

$$\beta_j = b: \;\; 2\sum_{i=1}^{n} r_i(\text{-}x_i) = 0 \Rightarrow \sum_{i=1}^{n}\left(r_i x_i\right) = 0 \Rightarrow \sum_{i=1}^{n}\left[\left(y_i - a x_i^2 - b x_i - c\right) x_i\right] = 0$$

$$\Rightarrow \;\; \sum_{i=1}^{n}\left(x_i y_i\right) - a\sum_{i=1}^{n}\left(x_i^3\right) - b\sum_{i=1}^{n}\left(x_i^2\right) - c\sum_{i=1}^{n}\left(x_i\right) = 0 \qquad \text{(B.7)}$$

$$\Rightarrow \;\; a\sum_{i=1}^{n}\left(x_i^3\right) + b\sum_{i=1}^{n}\left(x_i^2\right) + c\sum_{i=1}^{n}\left(x_i\right) = \sum_{i=1}^{n}\left(x_i y_i\right)$$

$$\beta_j = c: \;\; 2\sum_{i=1}^{n} r_i(\text{-}1) = 0 \Rightarrow \sum_{i=1}^{n}\left(r_i\right) = 0 \Rightarrow \sum_{i=1}^{n}\left(y_i - a x_i^2 - b x_i - c\right) = 0$$

$$\Rightarrow \;\; \sum_{i=1}^{n}\left(y_i\right) - a\sum_{i=1}^{n}\left(x_i^2\right) - b\sum_{i=1}^{n}\left(x_i\right) - nc = 0 \qquad \text{(B.8)}$$

$$\Rightarrow \;\; a\sum_{i=1}^{n}\left(x_i^2\right) + b\sum_{i=1}^{n}\left(x_i\right) + nc = \sum_{i=1}^{n}\left(y_i\right)$$

Combining (B.6)-(B.8) together in matrix and vector forms yields

$$\begin{bmatrix} \sum_{i=1}^{n}\left(x_i^2\right) & \sum_{i=1}^{n}\left(x_i\right) & n \\ \sum_{i=1}^{n}\left(x_i^3\right) & \sum_{i=1}^{n}\left(x_i^2\right) & \sum_{i=1}^{n}\left(x_i\right) \\ \sum_{i=1}^{n}\left(x_i^4\right) & \sum_{i=1}^{n}\left(x_i^3\right) & \sum_{i=1}^{n}\left(x_i^2\right) \end{bmatrix} \begin{bmatrix} a \\ b \\ c \end{bmatrix} = \begin{bmatrix} \sum_{i=1}^{n}\left(y_i\right) \\ \sum_{i=1}^{n}\left(x_i y_i\right) \\ \sum_{i=1}^{n}\left(x_i^2 y_i\right) \end{bmatrix} \qquad \text{(B.9)}$$

Now let $A_{eq} = \begin{bmatrix} \sum_{i=1}^{n}\left(x_i^2\right) & \sum_{i=1}^{n}\left(x_i\right) & n \\ \sum_{i=1}^{n}\left(x_i^3\right) & \sum_{i=1}^{n}\left(x_i^2\right) & \sum_{i=1}^{n}\left(x_i\right) \\ \sum_{i=1}^{n}\left(x_i^4\right) & \sum_{i=1}^{n}\left(x_i^3\right) & \sum_{i=1}^{n}\left(x_i^2\right) \end{bmatrix}$, $b_{eq} = \begin{bmatrix} \sum_{i=1}^{n}\left(y_i\right) \\ \sum_{i=1}^{n}\left(x_i y_i\right) \\ \sum_{i=1}^{n}\left(x_i^2 y_i\right) \end{bmatrix}$, then to find quadratic function coefficients *a*, *b*, and *c* in matrix form

$$\begin{bmatrix} a \\ b \\ c \end{bmatrix} = A_{eq}^{-1} \cdot b_{eq} \qquad \text{(B.10)}$$

According to our analysis, Regime 3 in [72] is closest to a quadratic function. So it is used as the cubic function to derive the quadratic area generation bidding function for LSE. This quadratic function is derived from CAISO data, so it only matches California. For the other areas, we derive quadratic bidding functions from the wholesale electricity markets. The derived quadratic functions by LSE cannot be directly used as quadratic bidding functions for the seven areas in the lumped WECC system. In order to find these functions, we modify data from electricity energy trading hubs in the WECC area. The historic electric power price in each hub is available [73]. Figure B.2 shows the electric energy trading hubs in the US. For each area in our WECC SD model, we can find a corresponding trading hub. Table B.2 lists this correspondence. Assuming the marginal price is $2ax+b$ at trading hubs, the above two data sources can be combined to find an area generation bidding function for each area in the lumped WECC system.

Table B.2 The correspondence between trading hubs and WECC areas

Trading Hub	Mid-Columbia	Four Corners*	Palo Verde	NP15	SP15	COB	Alberta Pool
Area	WA/OR	RM	SW	NCA	SCA	Remaining Part of NWPP	Canada

*Note: there are no trading hubs in RM area, so Four Corners, which is most close to RM area, is assumed to be the trading hub in RM area.

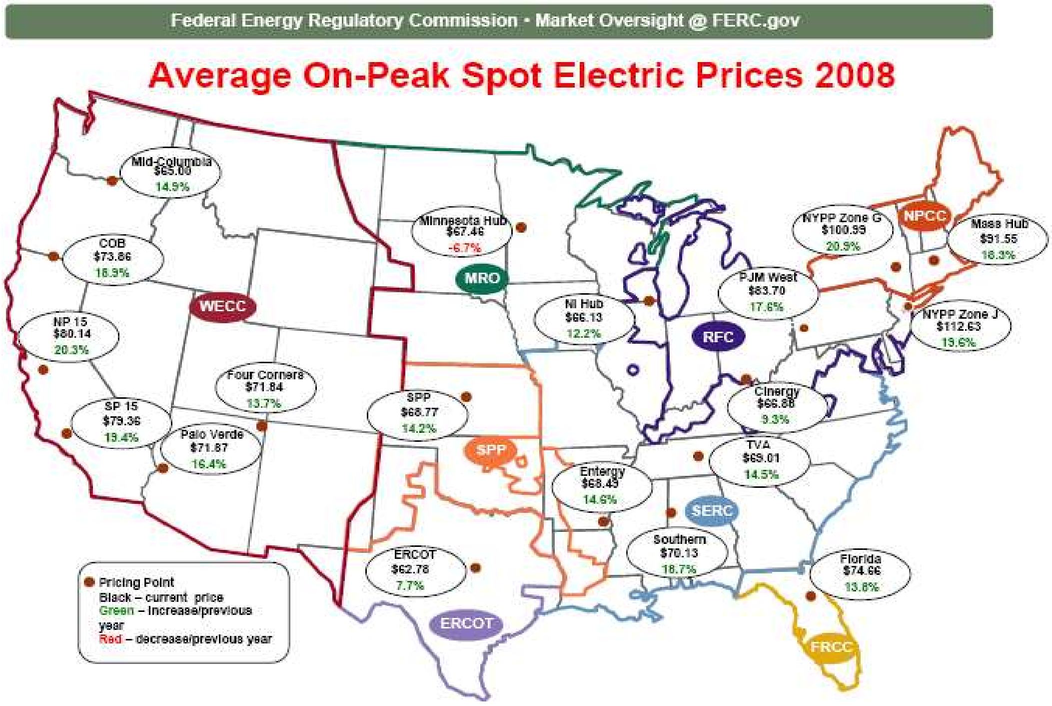

Fig. B.2 US average on-peak spot electric prices 2008 at electric energy trading hubs

B.3 Software tools - Vensim

In this section, we introduce how to build SD models in Vensim and how to call external functions defined in other software, such as Matlab, in Vensim.

- Vensim calls of Matlab functions

Vensim provides some simple built-in functions to realize basic calculations in SD models. Some complex and purpose-specific calculations required by SD models have to be realized by user defined functions. In our research, the LMP calculation for wholesale electric markets sub-model, SF matrix update for SF matrix update sub-model, optimal capacity expansion and system reliability index calculation for transmission investment sub-model require complex optimization calculations. Vensim provided functions cannot solve these problems. In this work, Matlab is used to formulate these external functions for the following reasons: (1) it provides many functions that realize some basic algorithms that can be directly called in our own Matlab functions; (2) Matlab is designed to perform vector and matrix operations efficiently. These characteristics meet the calculation requirements in our research well. In order to use these user defined functions in Vensim, we observe the following steps:

Step 1: According to SD models' requirements, define functions and write codes in Matlab.

Step 2: Invoke Matlab compiler through mcc command to prepare M-files for deployment outside of the Matlab environment. It generates Matlab function dynamic link library (.dll) files, runtime library (.lib) files, and header (.h) files for C/C++.

Step 3: Copy the runtime library files and header files formulated at Step 2 to the directory where the main file, a C/C++ file, for Vensim external function definition exists. Add codes in this main file to realize the functions defined in Matlab.

Step 4: Build a project in C/C++ to produce the dynamic link library (.dll) file that includes the external file definition. Copy this dynamic link library file and the dynamic link library files getting at Step 2 to the directory where the Vensim model exists.

Step 5: Open Vensim and open the menu "Tools->Options". Set the External function library to be the dynamic link library function formulate at Step 4 as the "Startup" option. Then close Vensim. Next time when Vensim model is started, it will load the user defined external functions, and they can be called in Vensim directly, just as built-in functions.

Fig. B.3 clearly depicts the above external function definition process [39].

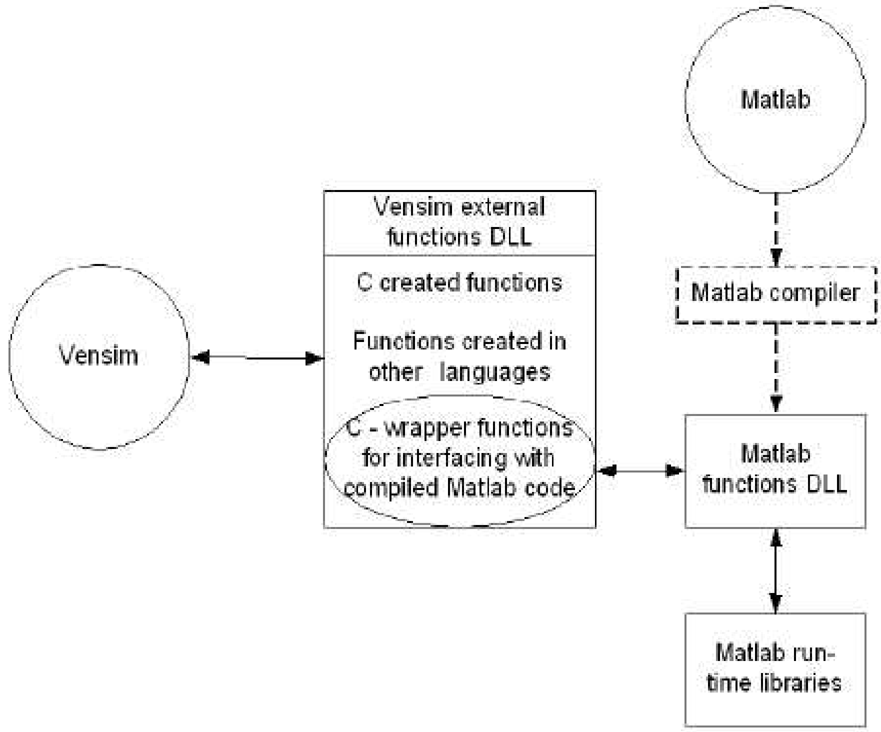

Fig. B.3 the process to formulate Vensim external functions defined by Matlab

B.4 Model validation and analysis

The effectiveness of a SD model depends on the validity of this model. If a SD model is invalid, all conclusions drawn from this model will be misleading. If the impacts of a decision based on such a model are not harmful, they are at least nonbeneficial. So SD model validation is the most important step before any policy or structure is tested on this model. Historical data about the researched system are the benchmark to measure a model's validity. Among these historical data, the dynamics of important data, i.e., their change over time, is more important than the value itself. SD model should predict and reproduce the behavior character of a system, but not specific events or particular, unique sections of actual system time history [47]. In particular, an SD model often approximates a large system with numerous simplifications, which means it is not a model for point prediction but behavior character prediction. Though capturing behavior character is more important than point prediction, the predicted point should also be within reasonable error ranges.

In our research, the WECC system is our research object and it is simplified to be a seven-area and ten-tieline lumped system. Considering the original dimensions of the detailed WECC system, this reduction is a huge simplification. The validation of this model observes the following steps:

Step 1: Validate the power flow values calculated by the SD model. This validation is realized by comparing the values from SD model to the results found from actual detailed power flow analysis for the original eight detailed cases. In the SD model, the power flow values are calculated in the wholesale electric market sub-model. This sub-model is based on a DC-OPF model. The errors between them are in the range of 2%~200%. For the important lines with higher power flows, such as line T1~T5 and T7, the errors are relatively small. For the less important lines with lower power flows, such as T6 and T8~T10, the errors are relatively large. These error ranges should be reasonable to serve our research purposes, since for such a large system the difference of the power flow values on different lines are quite tremendous: the highest value can be 500 times of the lowest value. Although the relative errors for such unimportant lines are large, the actual values are really small. These error ranges are accurate enough for our research.

Step 2: Validate the power flow dynamics calculated by the SD models in different seasons. This validation is realized by comparing the power flow direction change with seasons between the SD model case and the realistic case for the original eight detailed power flow cases. Because there are many hydro generators in WA/OR, the generation output in this area is high in wet seasons (late spring, summer, and early fall), and low in dry seasons (late fall, winter, and early spring). So the power flow pattern to this area is power flows out from WA/OR to NCA and SCA in wet seasons, and flows into WA/OR from NCA and SCA. Canada sells electricity to US all year around, so power always flows from Canada to WA/OR. SCA is a load pocket with expensive generation units, and SW with cheaper generation units. So SW area sells electricity to SCA area all year around, and the power always flows from SW to SCA.

Once the Vensim model passed the above two-step validation process, then the model is believed to be valid. After the validity test, different transmission investment incentives are added to the valid SD models in Transmission line investment sub-model. So we can test their impacts on long-term transmission investments and system congestion rents through analyzing the simulation results.