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Transmission Pricing and Incentives for Investments under Uncertainty in the Deregulated Power Industry

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Transmission Pricing and Incentives for Investments under Uncertainty in the Deregulated Power Industry

by

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Abstract

The deregulation of the power industry, introducing competition among generators, raises technical as well as economic issues related to the use and the enhancement of the transmission grid. This thesis provides an analysis of such issues.

Building on the existing literature, this thesis expands the notion of optimal investment in transmission capacity by considering the timing and rate of investment decisions and by relating it further to the notion of optimal generation mix. We generalize these two concepts of optimal investment to account for uncertainties. The recognition of risks in future power demand is shown to diminish the optimal investment in capital intensive generation technologies. This conclusion applies even more strikingly to the existing transmission technologies, calling for the introduction of more flexible transmission technologies. Transmission business remains an important part of the power industry and the design of an incentive structure for investments together with a consistent pricing scheme, are strongly advocated.

This thesis introduces two alternative pricing schemes, which acknowledge the existence of uncertainty in future use of the system and at the same time recognize the need for coordination of the generation and transmission investment policies. The first scheme is based on the existence of long-term derivative contracts for transmission capacity. The second scheme relaxes the commonly made assumption of perfect market conditions and grants a coordinating role to a transmission provider. The latter dynamically allocates on a long-term basis non-firm transmission capacity, manages in real-time the use of the grid, based on his estimation of the arrival process of requests for transmission capacity. In this dynamic allocation of non-firm transmission capacity, a transmission provider uses knowledge of existing transmission contracts to optimally invest in transmission capacity.

Finally, the existence of a non-capacity dependent cost of transmission lines is mentioned as the explanation of non-recovery of investment costs and as the main source of failure of market-based provision of transmission capacity. We explore several potential cost-recovery schemes in the last part of this thesis and emphasize the associated drawbacks. The complexity and risks associated with transmission

investment decision making calls for the introduction of incentive-based regulation.

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Introduction

The power industry represents in all industrialized countries an important part of the economy. It is often considered as a basic good by the end-users and it is an important input in most industrial processes. It embodies at the same time one of the most advanced technological systems in our modern societies.

Move toward deregulation

Like many other capital-intensive industries, this industry presents a pattern of economies of scale. For a long-time, regulation was considered the only industry structure adapted to the efficient operation and planning of the power system. Regulation took different forms in different countries. Cost-plus regulation was the form favored in the United States. Direct state control was in place in some European countries where innovative incentive-based regulation was introduced in the UK.

With the introduction of new generation technologies, new forms of industry structures based on competition appear viable. These structures already have been implemented in some countries and are being discussed in most industrialized and developing countries. The United Kingdom and Norway in Europe where the first countries to introduce competition in generation.

At the same time as the generation side of the industry is deregulated, consumers are given the choice of their power supplier. In this new pattern of competition, the transmission side of what used to be an integrated utility stands out as an industry in itself, with its own consumers, services and associated costs. The question of how to structure this industry is critical. The title of this thesis distinguishes three different aspects of this issue: pricing of transmission services, investments in transmission technologies and associated uncertainty on the level of demand for transmission[1].

Why have transmission prices?

Two different points of view on this issue can be adopted.

Seen as an industry in itself, users of the transmission grid should pay for the use of transmission services and for the provision of investment in transmission technologies. The traditional theory of marginal-cost pricing in micro-economics finds its counterpart in nodal pricing in the power industry.

Seen as a remnant of centralized utilities, the transmission industry, being the link between generators and loads, should ensure the reliability of the transmission grid by coordinating efficiently the activity of grid users by introducing prices as coordinating variables.

These two roles of transmission prices are consistent. We can add to them a third objective of transmission pricing; i.e. recovering the total cost of investment. This condition is essential to the sustainability of any for-profit company.

Investments in transmission capacity

Transmission capacity has an economic value. It enables to import inexpensive power from low-cost regions to high-cost regions. The new industry structure should then be able to invest in transmission capacity in order to provide the transmission services users paid for. More than that, the notion of optimal investment is essential. Where to invest, how much capacity and when to invest are three aspects of the same issue. They are moreover affected by the existence and recognition of risk. The transmission industry should be structured in a way that takes into account such aspects of the problem.

It is interesting to note that transmission capacity is a complement to generation capacity. As such, an important aspect of optimal investment consists in coordinating the investment policies in generation and transmission.

[1]Uncertainties in generators and transmission lines availability are ignored throughout this thesis

Transmission industry structure

Transmission capacity cost functions exhibit economies of scale. This has two consequences. First, as already seen, marginal cost pricing is unable to recover the cost of the investment, even though the investment might be profitable. Second, since it would be inefficient to incur twice this cost, only one transmission grid can exist. This creates a monopoly position for the transmission company, which in turn pervades the incentives for efficient grid operation and planning.

The industry structure has thus to be designed in a way that provides the right incentives for the regulated firm in terms of pricing and investment in transmission capacity.

Our approach

In the current debate on deregulation and transmission pricing, social welfare is often used as the measure of the efficiency of the power industry most can agree on. We will also adopt this standpoint throughout the thesis.

We state the operations and planning of a centralized utility as a social welfare optimization problem. Two type of decisions are considered:

- Investment in transmission and generation capacity
- Power injection and retrieval

Once the optimization problem has been stated, we will use it as a benchmark for measuring the efficiency of the transmission pricing and regulatory scheme presented for the deregulated industry in the last two chapters.

This methodology seems to leave little room for collective decision making. The optimal transmission pricing scheme would be leading to the maximization of social welfare and would be the result of rigorous mathematical derivations.

This is however, a too simplistic point of view. At different points throughout the thesis, we will conclude that it is impossible to recommend one particular transmission scheme over another. This should not be interpreted as a failure but as a corollary of our modeling approach, which is valid only under certain assumptions. In essence, the design of the transmission pricing scheme cannot be reduced to a single optimization problem.

We prefer, instead, to see in this formulation a basis for policy making. We intend to contribute, through this thesis, to shape the policy debate. Our hope is that the existing debates move away from often too obscure and unfounded arguments between those in favor of centralization against those in favor of free market toward a more structured and policy-oriented debate. The economics of the power industry is characterized by very special features: the inability to store power, the inability to control flows, multiple technologies and important investments coupled with high uncertainties. These features may challenge the application of traditional micro-economics. It is thus of paramount importance to us to understand these features and to pinpoint the need for further investigation whenever appropriate.

However, even before being confronted with the limitations of our modeling methodology for policy making, we should put into question the validity of total social welfare as an unconditional measure of the efficiency of a transmission pricing scheme. For instance, investment in transmission capacity and locational pricing, may have tremendous consequences on geographical development which are not captured in total social welfare. Likewise, too few investments in transmission capacity may modify the resulting mix of generators, to the detriment of nuclear power, which may not be consistent with a nation's energy policy.

Outline of the thesis

The first chapter will present the notion of optimal investment in transmission and generation. First considered in a deterministic set-up, we underline the importance of transmission investments in the efficiency of the power industry and link it with the concept of optimal generation mix. We emphasize the timing of the investment policy as an important decision along with the geographical and quantity decisions.

This notion is generalized to account for uncertainties in the first chapter. Demand is considered elastic. The demand function is parameterized. The evolution of the uncertain demand parameter will be modeled by a Brownian motion. This new approach to the generation mix leads us to the conclusion that high-cost generators should be under-represented at the optimum compared to a certainty equivalent world. We find that the same conclusion applies to investment in transmission capacity. This first chapter concludes by recognizing that it is absolutely necessary, as the power industry is being restructured, to consider the transmission side of the industry and we will advocate for the introduction of a structure of incentives for investments in transmission capacity and the introduction of new and flexible transmission technologies.

Investing in transmission capacity, as important as it is, will not be sufficient to guarantee in the long-run the efficiency of the power industry. As the transmission industry is unbundled, the coordination of generation and transmission investment decision making disappears. Having stated the economics of the power industry as a dynamic optimization problem in chapter 1, we show in this second chapter how the coordination of generators and loads can be interpreted as a dual problem. Policy makers should then be concerned with establishing the structure of interactions between transmission providers and generators which facilitates this coordination in the new industry structure. We present and introduce new frameworks for coordination in the short-run, insisting on their similarities. In the long-run, we recommend the introduction of a set of derivative contracts on short-run prices of electricity, whose prices act as coordinating variables for decisions in transmission and generation investments.

Most of the pricing schemes being discussed lead to the same dispatch under perfect conditions. The debates should then be considered in a more general set-up, where market power does exist, where markets are not always at equilibrium and where there are transaction costs. Such legitimate concerns as transparency, simplicity and firm commitment should be investigated further so that they can be traded-off along with efficiency against one another. The current policy debate, often ignoring these considerations, badly reflects the stakeholder's interests.

Recognizing the peculiarities of the power industry economics and the limits of traditional market-based models, we will introduce a new and alternative pricing structure based on the coordinated dynamic allocation of transmission capacity. This scheme relaxes the typically made strong assumption of perfect market conditions and grants a coordinating role to a transmission provider. The latter dynamically allocates on a long-term basis non-firm transmission capacity, manages in real-time the use of the grid, based on his estimation of the arrival process of requests for transmission capacity. In this dynamic allocation of non-firm transmission capacity, a transmission provider uses knowledge of existing transmission contracts to optimally invest in transmission capacity.

Finally, the third chapter will survey different types of industry structures from a regulatory point of view. We come back to the issue of economies of scale, briefly exposed in chapter 1. The importance of the non-capacity related part of the cost of transmission capacity is emphasized as the explanation of non-recovery of investment costs and as the main source of failure of market-based provision of transmission capacity. We will detail several cost recovery mechanisms and several regulatory structure. We apply some of the notions presented in this thesis and, in particular, the promising concept of market-based investments to the provision of voltage support technologies. Chapter 3 thus contains a new framework for voltage support investment and reactive power pricing.

Chapter 1

Operations and Planning in a Centralized Utility

In this chapter, we state the operations and planning of a centralized utility as a social welfare optimization problem. Two type of decisions are considered:

- Investment in transmission and generation capacity
- Power injection and retrieval

Once the optimization problem has been stated, we will use it as a benchmark for measuring the efficiency of various transmission pricing and regulatory schemes presented in the next two chapters.

1.1 Statement of the full-blown optimization problem

1.1.1 Notations

$K_l^T(t)$ is the amount of installed transmission capacity for line l.
$K_{ia}^G(t)$ is the amount of installed generation capacity for technology a at node i.
$I_l^T(t)$ is the rate of investment in transmission capacity for line l.

$I_{ia}^G(t)$ is the rate of investment in generation capacity for technology a at node i.

$C_l^T(K_l^T, I_l^T, t)$ is the cost of investment i n line l.

$C_{ia}^G(K_{ia}^G, I_{ia}^G, t)$ is the cost of investment in technology a at node i.

$P_{ia}(t)$ is the production with technology a, at node i, during period t.

$c_{ia}(t)$ is the cost of this production, excluding capacity costs.

r_i is a random variable reflecting the uncertainty of demand consumption.

$U_i(L_i(t), r_i(t))$ represents the utility function of consuming power $L_i(t)$ at node i during period t.

$F_l(P_{ia}(t) - L_i(t))$ represents the flow on line l for the given vector of net injections.

ρ is a discount rate.

1.1.2 Problem Formulation

Social welfare is defined as the difference between consumers' utility and production cost. The cost function includes both transmission costs and generation costs. The problem can be stated [1]:

$$\begin{aligned}
&\max_{I_l^T, I_{ia}^G, P_{ia}} + \textstyle\sum_i \int_{t_0}^T e^{-\rho t} \left(U_i(L_i(t), r_i(t))\right) dt \\
&- \textstyle\sum_{i,a} \int_{t_0}^T e^{-\rho t} \left(c_{ia}(t, P_{ia}(t)) + C_{ia}^G(K_{ia}^G(t), I_{ia}^G(t), t)\right) dt \\
&- \textstyle\sum_l \int_{t_0}^T e^{-\rho t} \left(C_l^T(K_l^T(t), I_l^T(t), t)\right) dt
\end{aligned} \tag{1.1}$$

subject to:

$$\begin{aligned}
\frac{dK_l^T}{dt} &= I_l^T(t) \\
\frac{dK_{ia}^G}{dt} &= I_{ia}^G(t) \\
I_l^T(t) &\geq 0 \\
I_{ia}^G &\geq 0 \\
F_l(P_{ia}(t) - L_i(t)) &\leq K_l^T \quad : \mu_l(t) \\
P_{ia}(t) &\leq K_{ia}^G \quad : \sigma_{ia}(t)
\end{aligned} \tag{1.2}$$

$$\sum_{i,a} P_{ia}(t) = \sum_{i} L_i(t) \quad : \lambda(t) \tag{1.3}$$

The optimization period is T and it corresponds to the longer of the two time intervals over which the generation or transmission investments are valued. K_{ia}^G and K_l^T are state variables. The control variables are the rate of investment in transmission capacity, the rate of investment in generation capacities and the injection of power at each node. The utility function parameters are the disturbance inputs.

The control is bounded by the set of constraints described above. A set of Lagrange multipliers is associated to each set of constraints.

1.1.3 Characteristics of the solution

This problem formulation, in spite of its apparent complexity, captures many well-known trade-offs relative to the efficiency of the power industry.

First, the discount rate reflects the time value of money. Everything being equal, it is better to spend money now than later. Thus, the investment timing balances the trade-off between the costs and benefits over time.

Second, this formulation shows that different technologies at different locations can be used to produce power. Thus, for a given load duration curve, the ratio between variable costs and capacity costs for each of these generation resources determines the optimal pattern and mix of generation.

Third, generation capacity can be substituted for transmission capacity. The trade-off between saving on generation costs and investing in transmission capacity is also encapsulated in the problem. The level of transmission capacity is not based on the maximum yearly flow. A trade-off between the costs of congestion and the costs of transmission capacity must be considered.

Finally, the problem stated above is an uncertain problem. The stochastic formulation reflects the value in flexible investment under uncertainties.

Due to the complexity of the full-blown optimization problem, we will describe these underlying economic trade-offs under some of the following simplifying assumptions:

- Deterministic set-up: we assume the random variables $r_i(t)$ are known with perfect certainty.

- Static optimization: we will assume that investments in generation and transmission can be made at $t = 0$ only.

- DC load-flow approximation: we will assume that the DC load-flow approximation applies [2].

- Lossless network: transmission losses are neglected.

- Time scale separation: we will assume we can separate the short-term dynamics of this problem from the long-term dynamics.

- No economies of scale: the cost of transmission or generation capacity investments is proportional to the capacity upgrade.

- P-Q decoupling assumption: in the formulation on the optimization problem, we implicitly assumed terminal voltages were equal to 1 per unit and we neglected reactive power.

1.2 Economic Dispatch

In this section, we focus on the short-term dynamics of the full-blown optimization problem. We thus assume:

$$\frac{dK_{ia}^G}{dt} = 0$$
$$\frac{dK_l^T}{dt} = 0$$

The full-blown problem now boils down to a static optimization problem. For practical purposes, we consider now the aggregate injection $P_i = \sum_a P_{ia}$ and the aggregate supply curve at each node $C_i(P_i)$. Assuming that the individual cost functions $c_{ia}(t)$ are convex, the resulting aggregate supply curve is also convex.

The short-term problem states:

$$\min_{P_i, L_i} \sum_{i=1}^{n} C_i(P_i) - U_i(L_i)$$

subject to the constraints:

$$\sum_{i=1}^{n} P_i = 0 \quad ; \quad \sum_{i=1}^{n} H_{li}(P_i - L_i) \leq K_l$$

Here, a simplified DC load flow approximation is used to express line flow constraints. H is the matrix of distribution factors [2] and transmission losses are neglected. Observe that the value of the H matrix is dependent on the choice of a slack bus.

The solution to this constrained optimization problem was derived in [5] and it is of the following form:

$$\begin{aligned} p_i &= \frac{dC_i}{dP_i} = \lambda - \sum_{l=1}^{L} H_{li}\mu_l \\ p_i &= \frac{dU_i}{dL_i} = \lambda - \sum_{l=1}^{L} H_{li}\mu_l \end{aligned} \tag{1.4}$$

The symbol λ represents the price of power at the chosen arbitrary (slack) node. The term $\sum H_{li}\mu_l$ reflects locational differences in optimal prices. Even though μ_l is always positive by definition, the term $\sum H_{li}\mu_l$ can be positive or negative. The value of λ and the distribution factors matrix depend on the choice of the arbitrary slack bus. However, the value of nodal prices p_i and of the μ_l are independent from this choice. The term μ_l represents the marginal value of the existing transmission capacity of line l. In other words, it represents the increment in social welfare that would result from a unit transmission capacity upgrade. This value is equal to zero, as long as the line is not congested, and becomes strictly positive when the flow on line l is equal to the capacity K_l. These formulae provide the basis for the so-called nodal or locational based marginal cost (LBMC) transmission pricing [6].

1.3 Investments in a deterministic set-up

In this section, we focus on the more complex issue of optimal investments. We assume that future demand and supply functions are known with perfect certainty. Generally speaking, the notion of investment is inherently inter-temporal. By investing a fixed amount of money today, the centralized utility reduces its costs over time. For this reason, uncertainty issues are at the heart of investment theories. We will ignore them for the time being in order to analyze the basic economic trade-offs peculiar to the power industry. In other words, we are in a certainty equivalent world where future demand and supply curves are taken equal to their expected value. The existence of risk is taken into account through the choice of the discount rate: the more uncertain future pay-offs are, the higher the discount rate is and the lower optimal investments are. This set-up leaves very little room for active risk management. This will be the topic of the next section. For the time being, we will present three different versions of peak-load pricing under the perfect certainty assumption.

1.3.1 The static peak-load pricing theory for generation

The theory of peak-load pricing was introduced in [3]. As Tirole puts it [4], "spot pricing is the ultimate peak-load pricing". It is then no surprise that the theory of peak-load pricing has regained some momentum as the power industry is being deregulated.

The whole theory hinges on the possibility to charge different prices for different periods under the underlying assumption that consumers are price-sensitive enough to modify their consumption pattern. As a by-product of this pricing scheme, the theory provides a description of the optimal generation mix.

We present here a deterministic peak-load pricing model for generation. Power is produced using different technologies a. They differ in their marginal cost c_a and their unit cost of capacity C_a^G, that we assume constant. The total installed capacity for technology a is denoted K_a^G. We assume demand curves for different periods are elastic and known with perfect certainty. Let us denote by $P^t(L^1, .., L^T)$ the demand function for period t. It is assumed to be a function of consumption quantities for all periods in order to take into account cross-temporal interdependencies. A simpler presentation would make it dependent on L^t only.

We are analyzing investments in generation capacity from a long-term perspective. Thus, contrary to the economic dispatch problem, the peak-load pricing problem take the total amount of installed capacity as an optimization variable. It is stated as the following mathematical problem [7]

$$\max_{P_a^t, L^t, K_a^G} \sum_t \int_0^{(L^1,..,L^T)} P_t(y^1,..,y^T)dy - \sum_{t,a} c_a\, P_a^t - \sum_a C_a^G K_a^G$$

Subject to:

$$\begin{aligned} P_a^t \leq K_a^G &\quad : \sigma_a^t \\ \sum_a P_a^t = L^t &\quad : \lambda_t \end{aligned}$$

The Lagrangian associated with this problem is:

$$\sum_t \int_0^{(L^1,..,L^T)} P_t(y^1,..,y^T)dy - \sum_{t,a} c_a\, P_a^t - \sum_a C_a^G K_a^G + \sum_t \left(\sum_a P_a^t - L_t \right) + \sum_{a,t} \sigma_a^t (P_a^t - K_a^G)$$

The necessary optimality conditions are obtained by stating that the first derivative of the Lagrangian with respect to P_a^t, L^t, K_a^G are equal to zero, resulting in:

$$\begin{aligned} P^t = \lambda^t & \\ \sum_t \sigma_a^t \leq C_a^G \quad &; \quad K_a^G \left(\sum_t \sigma_a^t - C_a^G \right) = 0 \\ \lambda^t - \sigma_a^t \leq c_a \quad &; \quad P_a^t\,(\lambda^t - \sigma_a^t - c_a) = 0 \\ \sigma_a^t \geq 0 \quad &; \quad \sigma_a^t\,(K_a^G - P_a^t) = 0 \end{aligned}$$

This formulation shows that, consistently with the economic dispatch methodology, inexpensive generators are dispatched first and the resulting price P^t is set equal to the short-run marginal cost.

Moreover, a combination of the second and third equations shows that the difference between the price and the cost of dispatched generators σ_a^t, when accumulated over several periods, is equal to the cost of installed generation capacity:

$$\sum_t \sigma_a^t P_a^t = C_a^G K_a^G \tag{1.5}$$

Thus, the price paid by consumers reflects the cost of capacity, and can be interpreted as a long-run marginal cost.

Thus, the peak-load pricing theory, by optimizing over installed transmission capacity, makes long-run and short-run marginal costs [1]. We should note that this result is a direct consequence of putting ourselves in a deterministic world. We will give later on a different interpretation of this result in an uncertain environment. For the time being, let us focus on some interesting results associated with the optimal mix of generators.

First, the introduction of several technologies contributes to increasing the total social welfare since we optimize over a wider range of variables. Moreover, this increase will be strictly positive due to several effects:

- Cost reduction: by spreading demand over several technologies, less of the most expensive technologies will remain idle during off-peak periods. This gain may not be completely offset by the higher fuel cost during peak-periods.

- Pricing effect: by charging a different price for different periods, this scheme provides better economic incentives. Consumers may decrease their consumption at different rates or transfer it to another period.

However, even though introducing more technologies increases total social welfare , it may be the case that the optimal installed capacity is zero for one specific technology and that, consequently, the associated increase in total welfare is null. An obvious example is the introduction of a new technology with the same cost of capacity but a higher fuel cost. This enables to introduce the efficient frontier of generators on the

[1] See [8, Chapter 5] for a formal definition of short and long-run marginal costs.

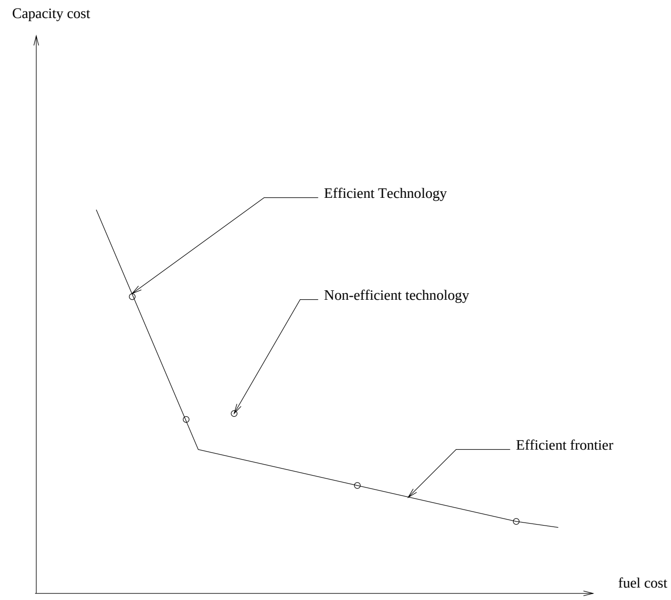

Figure 1-1: The generation peak-load pricing efficiency frontier

c_a, C_a^G plane. This efficient frontier is downward sloping since a higher fuel cost must be compensated by a lower capacity cost. This frontier is also convex, since any linear combination of two existing technologies can be implemented, a new technology must have lower cost of capacity, fuel cost being equal to the composite technology, to be efficient.

Dynamic considerations

It is possible to introduce a notion of incremental investment optimization for transmission. This may be relevant for decision making to upgrade the existing lines and provide them with more flexible technologies such as flexible AC transmission systems (FACTS) . This new formulation is described next

The previous solution gives the optimal generation capacities. However, we could define a similar problem of incremental capacity:

$$\max_{P_a^t, L^t, I_a} \sum_t \int_0^{(L^1,..,L^T)} P_t(y^1,..,y^T)dy - \sum_{t,a} c_a\, P_a^t - \sum_a C_a^G I_a$$

Subject to:

$$P_a^t \leq K_a^G + I_a \quad : \sigma_a^t$$
$$\sum_a P_a^t = L^t \quad : \lambda_t$$

Thus, the cost recovery equation (1.5) may no longer hold.

1.3.2 Peak-load pricing theory for transmission

Drawing from the work of Kleindorfer and Crew [7], a definition of an optimal grid in a static and deterministic set-up was introduce in [9, 10]. Knowing the cost functions of generators and the demand function in the future, it is possible to define the cost functions $C_i(t, P_i)$, as well as the total cost function, as time dependent functions.

At $t = 0$, investments in transmission capacity are made to minimize both the discounted costs of generation over the planning horizon and the initial cost of investments. If T is a planning horizon, ρ the appropriate discount rate, then the optimal transmission investments K_l are solution of the following optimization problem:

$$\min_{K_1,..,K_L} \int_0^T e^{-\rho t} TC(t, K_1, ..., K_L) dt + \sum_{l=1}^{L} C_l^T(K_l)$$

$$\text{subject to } K_l \geq 0 : \quad \xi_l$$

where the total cost function is defined by:

$$TC(t, K_1, ..K_L) = \min_{P_i, L_i} \sum_{i=1}^{n} C_i(P_i) - U_i(L_i)$$

The minimization is subject to the constraints:

$$\textstyle\sum_i (P_i - L_i) = 0$$
$$\textstyle\sum_i H_{li}(P_i - L_i) \leq K_l$$

The first order optimality conditions give the following necessary conditions:

$$\frac{dC_l^T}{dK_l} \quad = \quad -\int_0^T e^{-rt} . \frac{dTC}{dK_l}(t, K_1, ..., K_L) dt$$

$$= \quad -\int_0^T e^{-rt}\, \mu_l(t) dt \tag{1.6}$$

Where $\mu_l(t)$ is the value of transmission capacity on line l at time t computed in section (1.2).

This equation shows that *investments in transmission capacity should be chosen so as to equate the long-run marginal cost of capacity with the discounted sum of short-run marginal value.*

1.3.2.1 No economies of scale

If we assume further that there are no economies of scale in transmission ($C_l^T(K_l) = k_l\, I_l$), then the optimality condition 1.6 becomes sufficient and can be stated, considering only lines where it is optimal to increase the capacity ($\xi_l = 0$):

$$k_l = \int_0^T e^{-rt}\, \mu_l^t dt$$

An equation similar to equation (1.5) can be derived:

$$\sum_l K_l\, k_l = \int_0^T \sum_l e^{-rt}\, \mu_l^t\, K_l\, dt = \int_0^T \sum_l e^{-rt}\, \mu_l^t\, F_l\, dt$$

where F_l is the flow on line l. we have $\mu_l\, K_l = \mu_l\, F_l$

The left-hand side of this equation represents the total cost of transmission capacity upgrades and the right-hand side represents the discounted flow of money that would be collected by the transmission owner if he charged the Lagrange multiplier for each unit of line flow.

1.3.2.2 Economies of scale

The cost recovery feature of the proposed peak-load pricing scheme no longer holds in the presence of economies of scale. We have now:

$$\int_0^T \sum_l e^{-rt}\, \mu_l^t\, F_l\, dt = \frac{dC_l^T}{dK_l}\, K_l$$

The left-hand side of this equation represents the total amount of money collected by the transmission service provider. When the capacity cost function is concave, we have:

$$\frac{dC_l^T}{dK_l} K_l \leq C_l^T(K_l)$$

Thus, the revenue collected by the transmission service provider is unable to recover the total cost of the investment in transmission capacity. In particular, when $C_l^T(K_l) = a_l + k_l K_l$, the total transmission revenue falls short of recovering the total amount invested by the amount a_l, the non-capacity dependent part of the cost.

1.3.2.3 Incremental Investment

In this part, we assume a given amount of transmission capacity K_l is already in place and we can only add transmission capacity at $t = 0$. Transmission investments are noted $I_l > 0$.

The optimization problem now states:

$$\min_{I_1,..,I_L} \int_0^T e^{-\rho t} TC(t, K_1 + I_1, ..., K_L + I_L) dt + \sum_l C_l^T(I_l)$$

$$\text{subject to: } I_l > 0$$

The solution to this problem is:

$$\frac{dC_l^T}{dI_l} = -\int_0^T e^{-rt} \mu_l(t) dt + \xi_l$$

where ξ_l is the constraint associated with positive investments. Because of this additional constraint, the cost recovery equation may not hold, even in the absence of economies of scale.

1.3.2.4 Repetitive transmission upgrades

We now assume that incremental capacity now only comes in chunks I_l. The cost of each transmission capacity upgrade for line l is W_l. In order to solve for the optimal investment policy, we introduce the 0/1 variable $u_l(t)$, which represents for each step a decision to upgrade the grid. We state the investment problem as a deterministic dynamic programming problem and introduce the cost-to-go function $F(K_1, .., K_L)$, dependent on the vector of transmission capacity. At each stage, $F(K_1, .., K_L)$ is equal to the cost function plus the discounted value of the cost-to-go function at the next stage, assuming the optimal decisions u_l are made:

$$\rho\, F(K_1, ..., K_L) = \min_{u_l = 0,1} TC(K_1 + u_1\, I_1, ..., K_L + u_L\, I_L) + \sum_l u_l\, W_l \\ + (F(K_1 + u_1\, I_1, ..., K_L + u_L\, I_L) - F(K_1, ..., K_L))$$

Thus, the investment in transmission capacity is made any time the total cost of this investment is equal to the decrease in the cost-to-go function generated by this investment. The decrease in the cost-to-go function is computed along the optimal investment path.

There is no cost-recovery feature associated with this scheme.

1.3.2.5 Continuous investment

The previous versions of peak-load pricing focused on either the quantity of transmission capacity or the timing of investments. In this last version, these two aspects of investment decision making are taken into account by the introduction of the rate of investment in line l, I_l.

It is presented in details [10] and [7]. This version assumes that during each period, capacity in transmission can be added. The increment in transmission capacity is equal to the rate of investment $I_l(t)$ multiplied by the length of the period. $K(t)$ is the vector of capacities at time t. $P_i(t)$ is the vector of net injections at time t, $t \in [0, T]$. The effective transmission capacity decays at a constant rate throughout time. δ_l is the positive depreciation rate of capacity for line l and $\triangle = diag(\delta_l)$.

$$\dot{K}_l(t) = -\triangle K_l(t) + I(t)$$

The dynamic expansion problem states:

$$\min_{P(t),K_l(t)} \int_0^T e^{-rt}(\sum_i C_i(P_i(t)) - \sum_l k_l I_l(t))dt$$

subject to

$$\dot{K}_l(t) = -\triangle K_l(t) + U_l(t)$$

$$\sum_i H_{li} P_i(t) \leq K_l(t)$$

$$\sum_i P_i(t) = 0$$

$$I_l(t) \geq 0$$

$$K(0) = K^0$$

The optimality conditions are characterized by the existence of L adjoint variables ζ_l solutions of the following differential equation:

$$\dot{\zeta}_l = (r + \delta_l)\zeta_l - \mu_l$$

The solution to this set of differential equations is given by

$$\zeta_l(t) = Ae^{r+\delta_l} - e^{(r+\delta_l)t} \int_T^t e^{-(r+\delta_l)t} \mu_l(K_l(t), t)dt$$

When t=T, there should be no incentive to invest and $\zeta_l(T) = 0$. This gives A=0 and the optimality condition can be written:

$$k_l = \xi_l + e^{(r+\delta_l)t} \int_t^T e^{-(r+\delta_l)t} \mu_l(K_l(t), t)dt$$

$$\xi_l(t) \geq 0 \quad \xi_l(t)I_l(t) = 0$$

This relationship is very similar to the static optimization scheme. At time t, a long-run marginal cost of generation is equal to the discounted sum of marginal values. However, those marginal values are computed at t=0. They have to be multiplied by the term $e^{(r+\delta_l)t}$ to obtain their value at time t. Contrary to the static case where the transmission capacities are fixed for $t > 0$,in this formulation they vary throughout time. The transmission values are computed along the optimal trajectories.

1.3.2.6 Relationship between capacity upgrades and distribution factors

Although the transmission capacity of each line is considered as a control variable in our model, we use the DC load flow equation with a constant matrix H. By doing so we assume as a first approximation that the line capacity and line reactance are not directly related. Further research needs to be carried out in order to assess the influence of line enhancements on the distribution factors matrix, depending on the enhancement method. More generally, any technical modification affecting the H matrix is likely to influence the economic efficiency of the transmission grid. In particular, the optimal dispatch of reactive power and the use of FACTS devices deserve further attention. They are however very likely to lead to second order improvements in total welfare compared to transmission capacity upgrades.

1.3.3 Combined peak-load pricing theory: optimal generation / transmission mix

In this section, we assume all cost functions are linear. Demand is assumed to be inelastic and equal at each node to $L_i(t)$. The combined optimization problem can be stated as:

$$\min_{P_{i,a}(t),K^G_{i,a},K^T_l} \sum_{i,t,a} c_{i,a}P_{i,a}(t) + \sum_l k_l\, K^T_l + \sum_{i,a} C^G_{ia}\, K^G_{ia}$$

Subject to:

$$\sum_{i,a} H_{li}(P_{i,a}(t) - L_{i,t}) \leq K^T_l \quad : \mu_{l,t}$$
$$P_{ia}(t) \leq K^G_{ia} \quad : \sigma^a_{i,t}$$
$$\sum_{i,a} P_{ia}(t) = \sum_i L_i(t) \quad : \lambda_t$$

This problem is linear. The Lagrangian of this problem is

$$L(P_{ia}(t), K^T_l, K^G_{ia}) = \sum_{i,t,a} c_{i,a}P_{ia}(t)) + \sum_l k_l K^T_l$$

$$+ \sum_{i,a} C^G_{ia}\, K^G_{ia} - \sum_{l,t} \mu_{l,t}(K^T_l - \sum_{i,a} H_{li}(P_{ia}(t) - L_i(t))$$
$$- \sum_{i,a,t} \sigma^a_{i,t}(K^G_{ia} - P_{ia}(t)) - \sum_t \lambda_t(\sum_i L_{i,t} - \sum_{i,a} P^a_{i,t})$$

The first order condition to this problem can be written:

$$c_{ia}(t) = \lambda_t - \sigma^a_{i,t} - \sum_l H_{li}\mu_{l,t} \quad if \quad P^a_{i,t} = G^a_{i,t} or P^a_{i,t} = 0$$
$$k_l = \sum_{l,t} \mu_{l,t} \tag{1.7}$$
$$C^G_{ia} = \sum_t \sigma^a_{i,t} \tag{1.8}$$

$\mu_{l,t}$ represents the marginal value of transmission capacity and $\sigma^a_{i,t}$ represents the marginal value of generation capacity. Low variable cost generators collect a higher rent than high cost generators but have to face higher cost of generation capacity. This result is no different from the peak-load pricing theory of Crew and Kleindorfer

[7]. It takes into account the costs of transmission capacity and thus reflects the locational aspects of the optimal mix.

1.3.3.1 Value of transmission capacity

The optimal amount of transmission capacity thus depends essentially on the cost differential among nodes and on the consumption pattern.

We note that, at the optimum, it would appear that there is no reason why generators should be sited close to the loads. *Transmission has a value in itself and does not only represent a cost.* It enables the import of power from low cost regions into high cost areas. It is thus an essential part of the design of the transmission industry to allow for such investments.

1.3.3.2 Potential policy issues

We should also note that, as a result of this optimization process the locational mix of generators and the total output available to consumers will be affected by transmission investments. This may cause serious policy issues. For instance, if a a marginal cost pricing scheme is coupled with this optimal pricing scheme, locational prices disparities will soon appear. Regions where cheap fuel is easily available will face much lower prices than other regions. Likewise, due to the non-capacity dependent cost associated with transmission investments, some entire regions will have to provide their own electricity, at a higher price, if demand is not high enough to justify investments in transmission capacity. This may have tremendous consequence on the economic and industrial development of often already declining regions. Moreover, temporal prices fluctuations is against the traditional conception of power as a basic good and may sparkle waves of discontentment. Finally, the total generation mix is also affected by transmission investments. In general, low investments in transmission capacity favor high-cost fuels, which may have some implications on the energetic national policy.

1.4 Investments under uncertainties

Sources of uncertainty

Demand for electricity is highly uncertain. Even though it is possible in the short-run to forecast accurately demand for electricity, long-term forecasts are usually wrong. There are many examples of ill-planned power systems.

Such uncertainties are usually related to economic growth, technology changes, population development over long time spans. It is all the more difficult to make good forecasts for transmission investment purposes since we are interested, in addition to the total level of demand, in its locational spread. This makes the task of the transmission planner difficult.

However difficult it may be, there is a value in recognizing the existence of uncertainty. In this chapter we show and illustrate how such a recognition modifies the technology and locational mix of generators as well as transmission investment decisions. It is critical, before moving to a fully unbundled industry to understand these critical issues.

To this end, we will introduce and model uncertainties in demand function in the long-run through parameterization of demand functions at each nodes.

It should be clear by now that the Lagrange multiplier $\lambda(t), \mu_l(t)$, presented in the previous sections, can be interpreted as prices in a competitive market. An extensive coverage of investments under price uncertainty exists in the literature. We chose, however, not to take this path but instead to model more fundamental variables. Indeed, prices do not reflect the primary source of uncertainty and are partly the results of investment decisions. We thus cannot assume prices as given exogenously.

1.4.1 Value of generation capacity

In this section, we propose a new notion of marginal value of generation capacity for a given stochastic evolution of a random variable r, representing fluctuations in demand. We first ignore transmission constraints. Thus, we can assume that there exists a single price for energy and a single demand function. This function is assumed

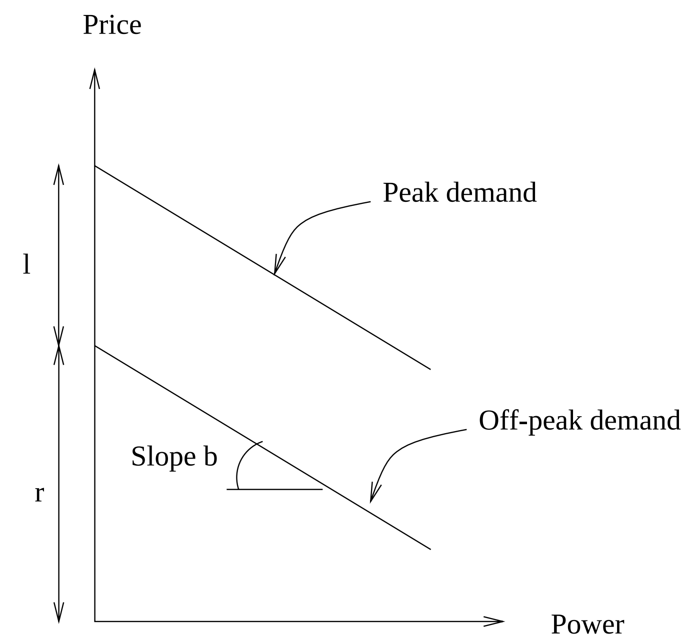

Figure 1-2: Peak and off-peak demand function

to be:

$$U_L(P_L) = r\,P_L - 1/2\,bP_L{}^2$$

where r is an uncertain parameter.

We assume for r a stochastic diffusion Wiener process of the form:

$$\frac{dr}{r} = \alpha dt + \sigma dz$$

α represents the instantaneous expected rate of growth and σ the instantaneous standard deviation of the rate of growth. We assume that a demand function for peak-period can be derived from an off-peak period demand function as follows:

$$U_L(P_L) = (r + l)\,P_L - 1/2\,bP_L{}^2$$

where l is a fixed parameter of the model.

These demand functions are pictured in Figure 1-2.

In other words, since we are interested in investment, we ignore short-term fluctuation in demand and assume they are all encapsulated in the fixed parameter l. Thus, the above diffusion process reflects the long-term uncertainties in power consumption.

1.4.1.1 The model

We ignore issues related to transmission pricing. Energy is supplied by two generators:

- A low cost generator, marginal cost c
- A high cost generator, marginal cost C

We assume the amount of total installed low-cost capacity is equal to K.

We compute in this paragraph the value of low cost capacity. In order to do that, we consider the discounted sum of social welfare over several periods for different values of K. This sum, it can be decomposed in the value for off-peak periods and peak-periods.

We compute the first one. Let us note $V(r)$ this value. The difference between the value at $t+dt$ discounted at the discount rate ρ and the value at t is equal to the increment in social welfare accrued between t and $t+dt$:

$$\begin{aligned} V(r) &= \frac{E(V(r+dr))}{1+\rho\, dt} + SW(r)dt \\ E(dV) - V\rho\, dt + SW(r)dt + SW(r)\rho\, dt^2 &= 0 \end{aligned} \tag{1.9}$$

The value of social welfare is equal to the consumer surplus minus the cost of fuel. However, depending on the value of the parameter r, we have to distinguish several cases:

- Case 1: if $r \leq c$, no power is dispatched and $SW(r) = 0$
- Case 2: if $r - bK \leq c$, only the low cost generator is dispatched. In this case, $SW(r) = \frac{1}{2}(r-c)^2$.

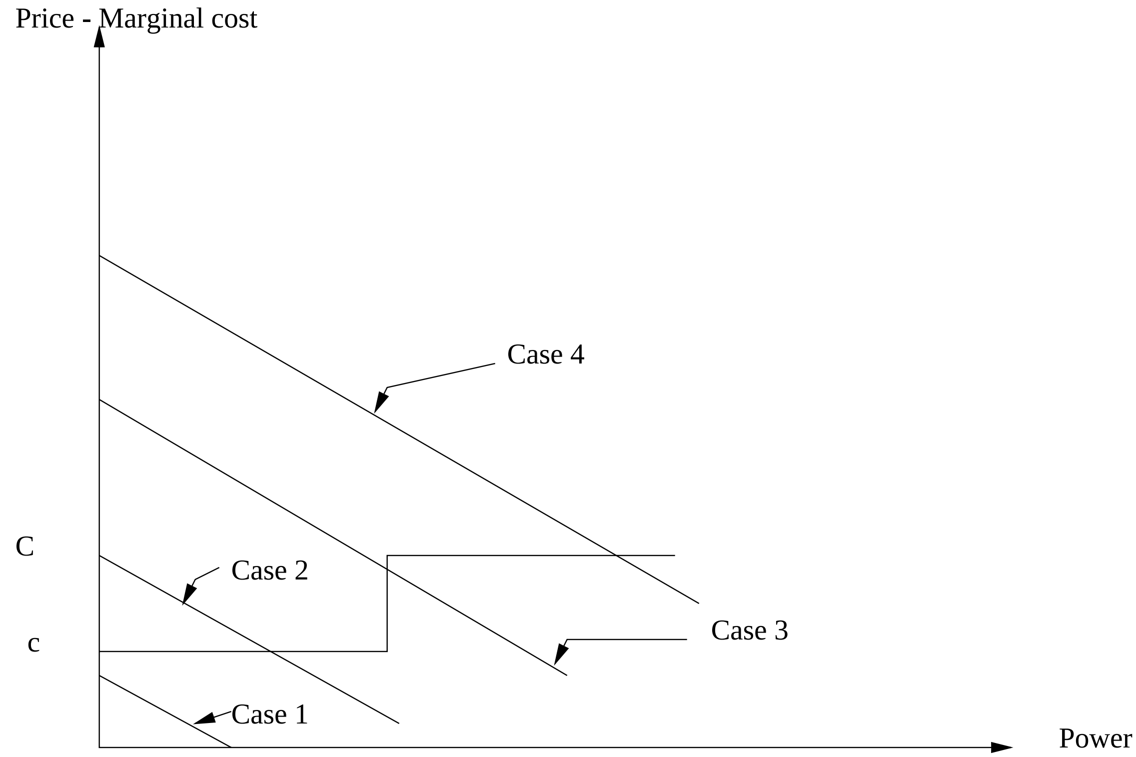

Figure 1-3: Demand and supply functions for different uncertain parameter values

- Case 3: if $c \leq r - bK \leq C$, the low-cost generator is fully dispatched. $SW(r) = (r-c)K - \frac{bK^2}{2}$.
- Case 4: if $r - bK \geq C$, the high-cost generator is partially dispatched. $SW(r) = \frac{1}{2}(r-C)^2 + K(C-c)$.

These different configurations of demand - supply functions are illustrated in Figure 1-3.

1.4.1.2 Deterministic case

$$cE(dV) = \left(\frac{d}{dr}V(r)\right)E(dr)$$
$$E(dV) = \alpha\, r \frac{d}{dr}V(r)$$

V is thus a solution of the following differential equation:

$$\alpha r \frac{d}{dr} V(r) - \rho V(r) + SW(r) = 0$$

since $SW(r)$ is defined as a piecewise linear function, we find a solution of the above equation for each of the interval on which SW is defined. We assume $\rho \geq 2\alpha$.

$$V1(r) = r^{\frac{\rho}{\alpha}} A1$$

$$V2(r) = 1/2\,(c^2\rho^2 - 3\,c^2\rho\,\alpha + 2\,c^2\alpha^2 - 2\,rc\rho^2$$

$$+4\,rc\rho\,\alpha + r^2\rho^2 - r^2\rho\,\alpha + r^{\frac{\rho}{\alpha}} A2\,\rho^{-1} b^{--1}\,(-\rho + 2\,\alpha)^{-1}\,(-\rho + \alpha)^{-1}$$

$$V3(r) = -1/2\,(-bK^2\rho + \alpha\,K^2 b - 2\,Kc\rho + 2\,c\alpha\,K + 2\,Kr\rho + 2\,r^{\frac{\rho}{\alpha}} A3)\rho^{-1}(-\rho + \alpha)^{-1}$$

$$V4(r) = 1/2\,(-3\,C^2\alpha\,\rho + 2\,C^2\alpha^2 + C^2\rho^2 - 6\,KbC\alpha\,\rho + 4\,KbC\alpha^2 + 2\,KbC\rho^2 + 4\,rC\rho\,\alpha$$

$$+6\,Kbc\alpha\,\rho - 4\,Kbc\alpha^2 - 2\,Kbc\rho^2 - 2\,rC\rho^2 + r^2\rho^2 - r^2\rho\,\alpha)\rho^{-1} b^{-1}(2\,\alpha - \rho)^{-1}\,(\alpha - \rho)^{-1}$$

$$+r^{\frac{\rho}{\alpha}} A4$$

where $A1, A2, A3, A4$ are constants of integrations.

It is possible to solve for three constants by writing a continuity condition at $c1, c1 + bK, c2 + bK$. One variable is still missing. In order to solve for this fourth variable, we will compute the value $V(r)$ directly, for large r. In this case, we can assume that $SW(r) = \frac{1}{2}(r - c2)^2 + K(c2 - c1)$. Moreover, we know that $r(t) = re^{\alpha t}$. Then:

$$V(r) = \int_0^\infty ((re^{\alpha\,t} - C)^2 + K(C - c))e^{-\rho\,t}dt$$

$$V(r) = (-3\,C^2\alpha\,\rho + 2\,C^2\alpha^2 + C^2\ rho^2 - 6\,KbC\alpha\,\rho + 4\,KbC\alpha^2 + 2\,KbC\rho^2$$

$$+6\,Kbc\alpha\,\rho - 4\,Kbc\alpha^2 - 2\,Kbc\rho^2 - 2\,rC\rho^2 + 4\,rC\rho\,\alpha - r^2\rho\,\alpha + r^2\rho^2)\frac{1}{2\rho b(2\,\alpha - \rho)\,(\alpha - \rho)}$$

By comparing with the value $V4(r)$ previously obtained, we find that $A4 = 0$. It is thus possible to solve for all undefined variables. The value we have just computed represents the value for off-peak period. Similar computations could be conducted for peak-periods by replacing the costs c and C by $(c-l)$ and $(C-l)$. For a given value of r, the optimal installed capacity K is obtained when the sum of the marginal value for peak and off-peak periods is equal to the unit cost of generation capacity. We should thus emphasize the importance of the notion of marginal value for a given value of r:

$$MV(K) = \frac{dV}{dK}(K)$$

Note that the marginal value function is solution to the following differential equation:

$$\alpha\, r \frac{d}{dr} MV(r) - \rho\, MV(r) + \frac{dSW}{dK}(r) = 0 \tag{1.10}$$

Since $\frac{dSW}{dK}$ is either zero or equal to the price of energy λ minus the marginal cost of generation, we thus have:

$$\alpha\, r \frac{d}{dr} MV(r) - \rho\, MV(r) + max(\lambda - c, 0) = 0 \tag{1.11}$$

For the sake of the illustration, here is represented the value as a function of total installed capacity, with the following numerical values:

$r = 1500$, $b = 10$, $c = 200$, $C = 500$, $\alpha = 0.02$, $\rho = 0.15 =$, $l = 1000$.

As we can see on Figure 1-4, the marginal value of capacity is diminishing as the total installed capacity increases. The optimal capacity is obtained when this marginal value gets equal to the marginal cost of capacity.

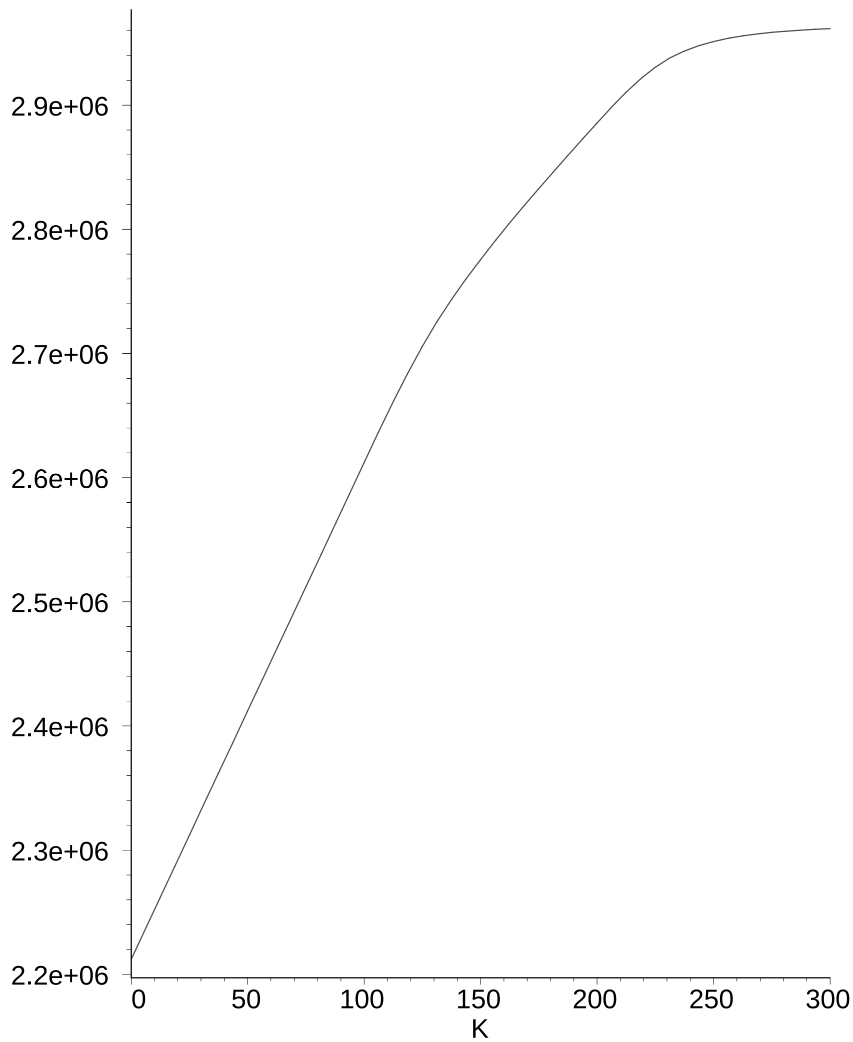

Figure 1-4: Deterministic case: Total social welfare function as a function of capacity

1.4.1.3 Uncertain case

According to Ito's lemna [11], equation (1.9) becomes:

$$dV = \left(\frac{d}{dr}V(r)\right) dr + 1/2\,\left(\frac{d^2}{dr^2}V(r)\right) dr^2$$

Thus, the value of the total installed generation capacity is a solution of the following second order differential equation in r:

$$1/2\,\sigma^2 r^2 \frac{d^2}{dr^2}V(r) + \alpha\, r \frac{d}{dr}V(r) - \rho\, V(r) + SW(r) = 0$$

We thus have to solve a second order non-homogeneous differential equation. In order to do this, we consider a solution for each interval. We assume $\rho \geq 2\alpha$. The four solutions to these equations are:

$$V1(r) = A1\, V^{\beta_1} + B1\, V^{\beta_2}$$

$$V2(r) = A2\, V^{\beta_1} + B2\, V^{\beta_2} + f2(r)$$

$$V3(r) = A3\, V^{\beta_1} + B3\, V^{\beta_2} + f3(r)$$

$$V4(r) = A4\, V^{\beta_1} + B4\, V^{\beta_2} + f4(r)$$

Where β_1 and β_2 are solutions of the following associated characteristic equation:

$$\frac{1}{2}\sigma^2 x(x-1) + \alpha x - \rho = 0$$

$$\beta_1 = -1/2\, \frac{-2\,\sigma^2 + 2\,\alpha - \sqrt{4\,\alpha^2 - 4\,\alpha\,\sigma^2 + \sigma^4 + 8\,\rho\,\sigma^2}}{\sigma^2}$$

$$\beta_2 = -1/2\, \frac{-2\,\sigma^2 + 2\,\alpha + \sqrt{4\,\alpha^2 - 4\,\alpha\,\sigma^2 + \sigma^4 + 8\,\rho\,\sigma^2}}{\sigma^2}$$

Given our assumptions, we have $\beta_1 > 1$ and $\beta_2 <= 0$.

$A1, A2, A3, A4, B1, B2, B3, B4$ are constants and $f2, f3, f4$ are particular solutions of the corresponding differential equation.

When $r = 0$, there is no prospect of r increasing, thus the corresponding value of capacity is equal to zero. Consequently, $B2 = 0$.

The constants reflect $A1, A2, A3, A4$ the possibility of r moving from one interval to the immediately above interval. By taking r large enough, the probability of r changing interval gets close to zero. Thus $A4 = 0$. The resulting solution is of the form:

$$
\begin{aligned}
V4(r) = \frac{-1}{2\, b\rho\, (\alpha - \rho)\,(2\,\alpha + \sigma^2 - \rho)} & - 2\,bKC\rho^2 - 2\,rC\rho\,\sigma^2 + 2\,bKc\rho^2 - 4\,bKC\alpha^2 \\
& +4\,bKc\alpha^2 - 2\,bKC\alpha\,\sigma^2 - 2\,bKc\rho\,\sigma^2 + 2\,bKc\alpha\,\sigma^2 \\
+2\,bKC\rho\,\sigma^2 + C^2\rho\,\sigma^2 - C^2\alpha\,\sigma^2 & - C^2\rho^2 - 2\,C^2\alpha^2 + 6\,C\rho\,\alpha\,bK - 6\,c\rho\,\alpha\,bK \\
& -4\,rC\rho\,\alpha - r^2\rho^2 + 3\,C^2\alpha\,\rho + 2\,rC\rho^2 + r^2\rho\,\alpha + B4\; r^{\beta_2}
\end{aligned}
$$

When $\sigma \to 0$, this solution converges toward the deterministic solution. However, one should note that for a given value of σ, this solution do not converge toward the deterministic solution when $r \to \infty$. This is due to the non-linearities of the social welfare function.

Once again, it is possible to write continuity and differentiability conditions at each interval and compute the integration constants.

1.4.1.4 Value of generation capacity as a function of volatility

Figure 1-5 represents the total expected social welfare function as a function of r for different values of volatility. For a given level of demand, the expected social welfare increases with volatility. More interesting is the next plot, Figure 1-6, representing the marginal value of the low-cost generator as a function of capacity for different levels of volatility:

This plot shows that the marginal value is a decreasing function of total capacity, as expected. Moreover, as volatility increases, this value is also increasing. We should

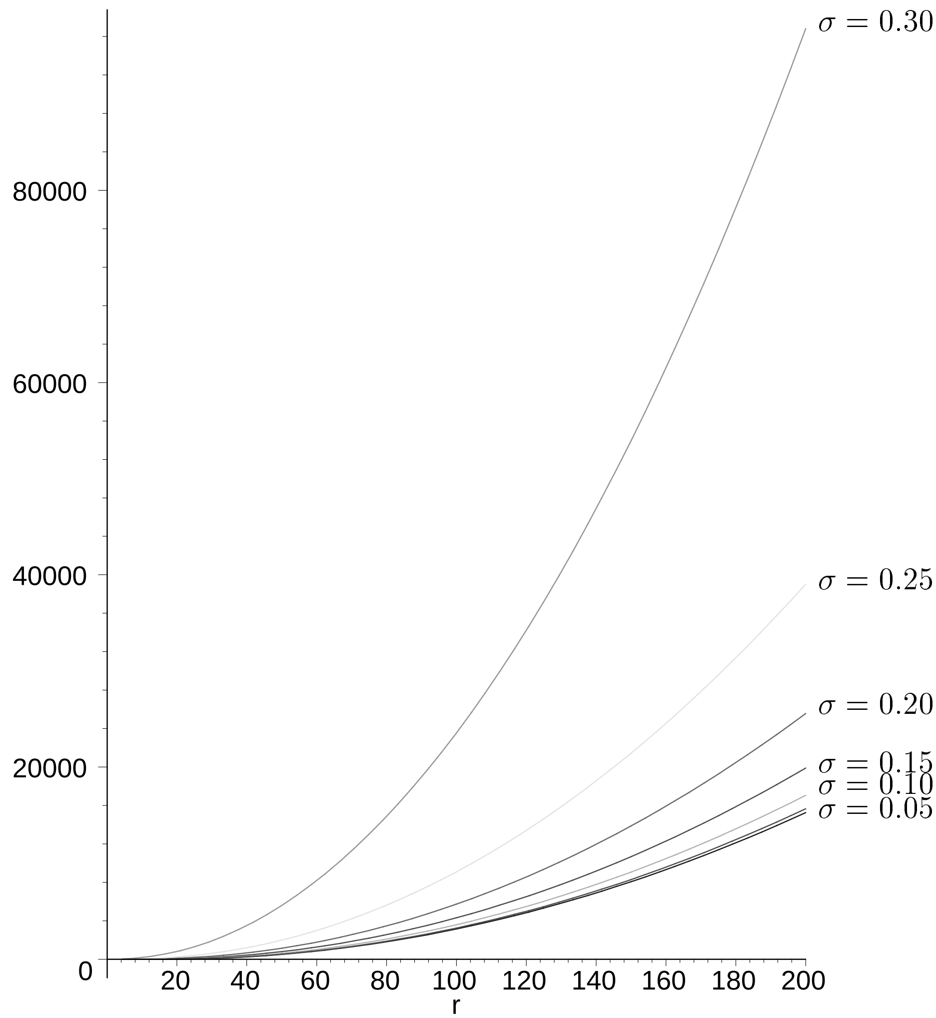

Figure 1-5: Total social welfare function for different values of volatility

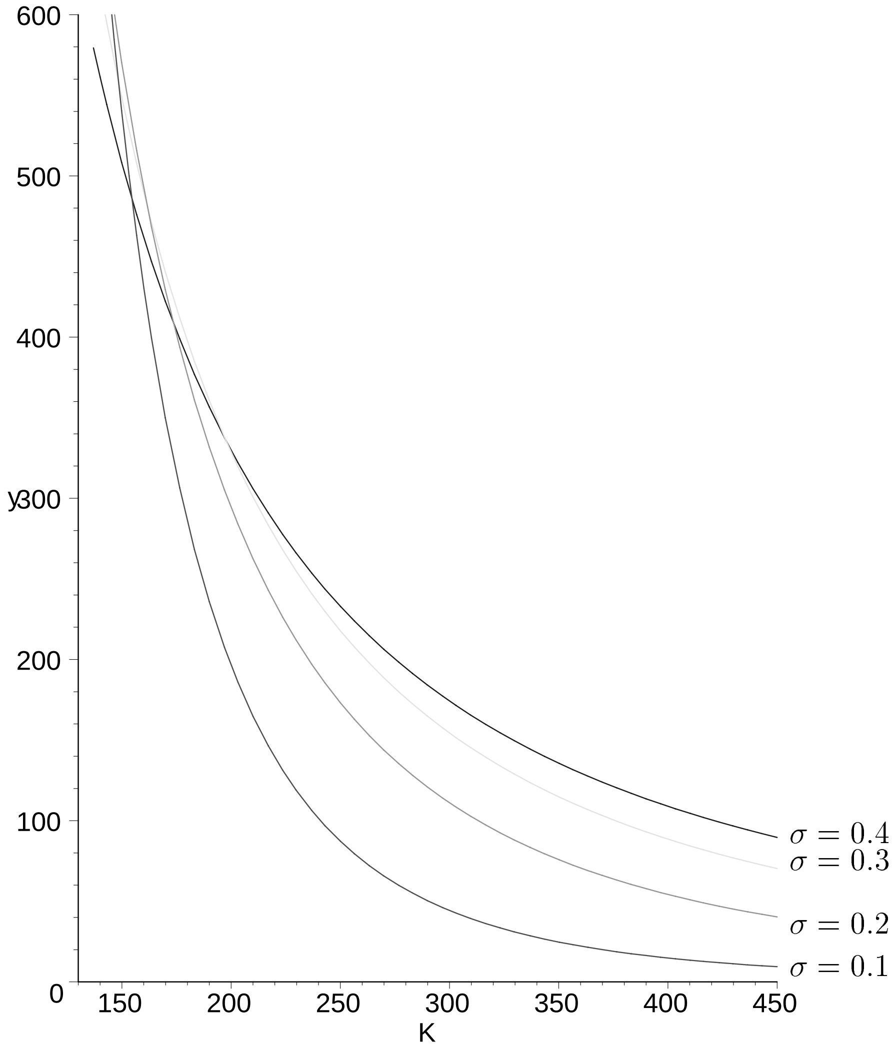

Figure 1-6: Marginal value of a low-cost generator for different levels of volatility

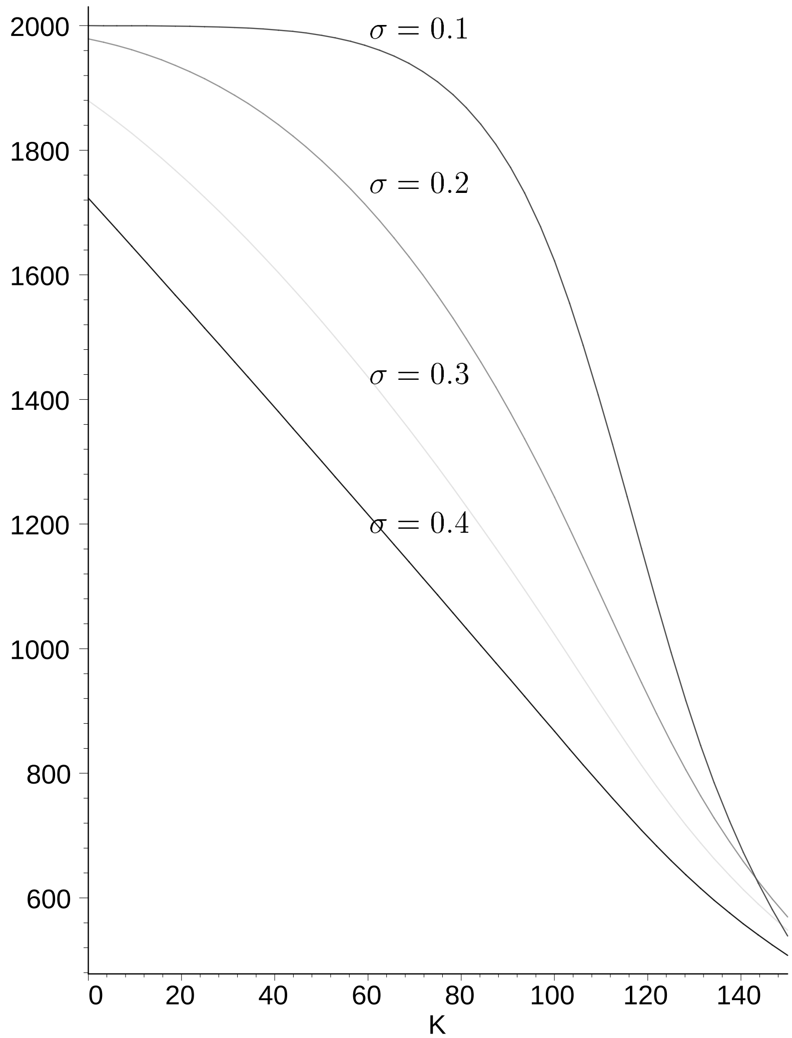

Figure 1-7: Marginal value of a low-cost generator for different levels of volatility, for $K \leq 140$

note however, that this is not true for low values of K as illustrated in Figure 1-7.

For low values of generation capacity, the low-cost generator is never optimal and upward movements of the demand curve will not increase the marginal value of capacity since there are no higher cost generator than C. As a consequence, marginal value is decreasing with volatility. This is in contradiction with the theory. However, it is only due to the oversimplified model adopted here and appears as a border effect.

1.4.1.5 Value of generation capacity as a function of fuel cost

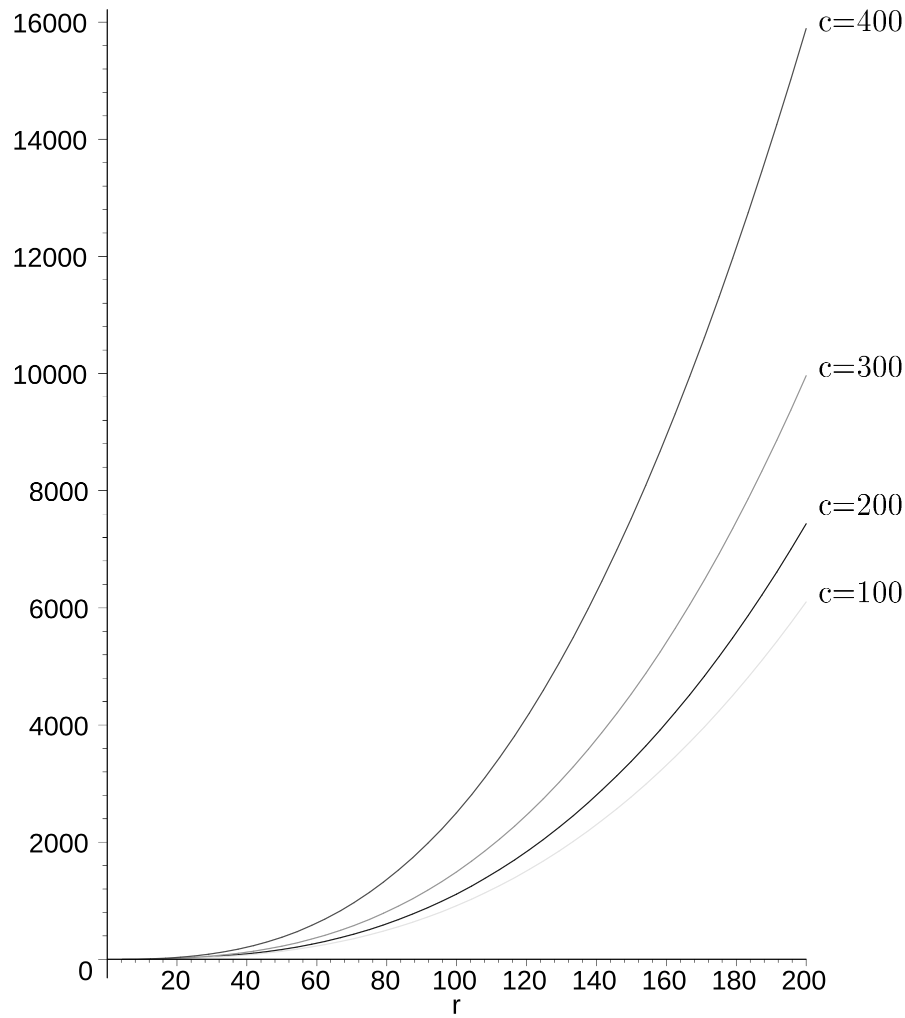

Figure 1-8: Total social welfare function for different values of c

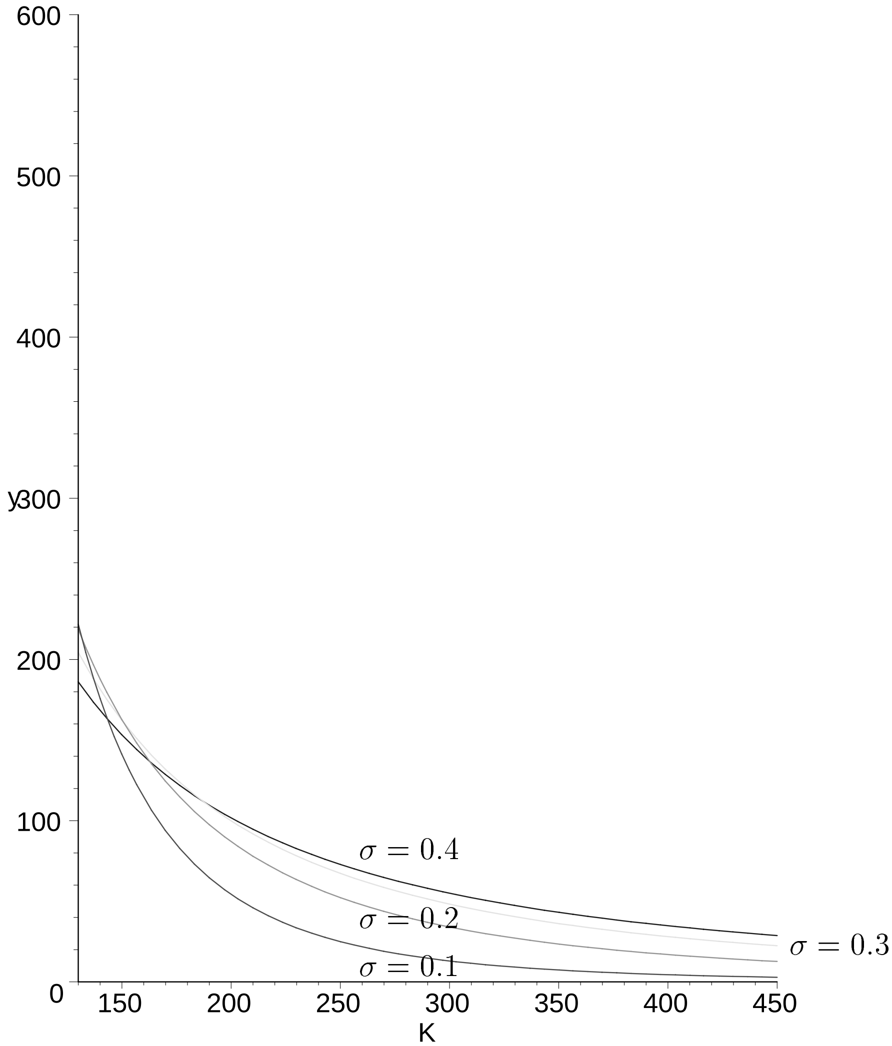

Figure 1-9: Marginal value of capacity for c=400

Total welfare decreases as the low cost c increases. We represented the marginal value of generation capacity for different values of capacity as in Figure 1-6. However, instead of taking the low cost generator equal to 200, we take it equal to 400. The result is shown in Figure 1-9. The overall value of marginal capacity decreases as expected (higher cost generator is less valuable). If, for instance, the cost of capacity is equal to 50 for a generator whose marginal cost is $c = 400$, then the optimal capacity is 200 when $\sigma = 0.1$. Likewise, if the cost of capacity is equal to 180 for the generator which marginal cost is equal to $c = 200$, then the optimal capacity is 200 when $\sigma = 0.1$. We thus have similar optimal capacity when $\sigma = 0.1$. If we now assume that $\sigma = 0.3$, the optimal capacity is 300 when $c = 200$ and 340 when $c = 400$. We can see that the increase in marginal value due to higher volatility is much greater for high-cost generators than for low-cost generators.

1.4.1.6 An intuitive interpretation

In Figure 1-10, the supply function is represented along with several demand function. For each unit of generation capacity K_a^G there is an associated marginal cost c_a. As seen before, the marginal value of this unit of capacity is the sum over several periods of the terms $\sigma_a(t)$. At the optimum, the marginal cost of this unit of capacity is equal to this marginal value:

$$k_a = \sum_t \sigma_a(t)$$

We should also remember that:

$$\sigma_a(t) = \max(\lambda(t) - c_a, 0)$$

where $\lambda(t)$ is the uniform price of power during period t.

Thus, the expected marginal value is equal to:

$$\sum_t E\left(\sigma_a(t)\right)$$

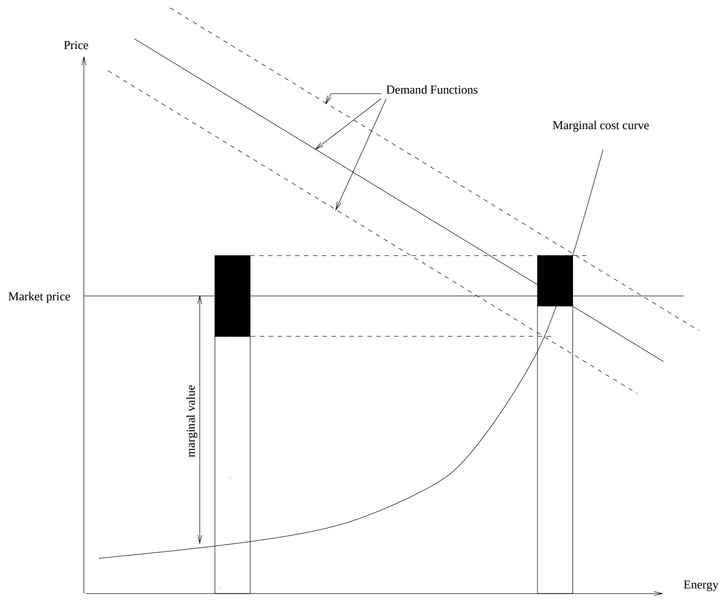

Figure 1-10: Marginal value of generation capacity under uncertainty

Because of the non-linear function max, this expected value is different from

$$\sum_t \max(E(\lambda_a(t)) - c_a, 0)$$

Indeed, we have:

$$\sum_t E(\max(\lambda(t), c_a, 0)) \geq \sum_t \max(E(\lambda_a(t)) - c_a, 0)$$

as illustrated in Figure 1-10.

Indeed, when the price of electricity λ is uncertain, the marginal value of capacity for a given period is also uncertain. However, this value is downward limited by the marginal cost of capacity. In other words, when demand decreases, it is always possible not to turn on some generators. High fuel cost generators benefit more than low-fuel costs generators since they are most of the time idle or marginal units. On the contrary, low cost generators will run most of the time, even during unexpectedly low demand outcomes.

When computing the optimal capacities values under perfect certainty, we use the value $\max(E\left(\lambda_a(t)\right) - c_a, 0)$ and thus under evaluate high fuel cost generators. The marginal cost of capacity being the same, the entire optimal mix of generation is shifted toward less capital intensive generators.

1.4.1.7 Real option interpretation

As the random parameters r_i vary, the opportunity cost of power λ follows its own stochastic path. According to Ito's lemma, we have:

$$d\,\lambda = \left(\alpha\, r\, \frac{d\,\lambda}{d\,r} + \frac{1}{2}\,\sigma^2\, r^2\, \frac{d^2\,\lambda}{d\,r^2}\right) + \sigma\, r\, \frac{d\,\lambda}{d\,r}\, d\,z$$

where $d\,z$ is a Wiener process.

For each period in the future, generation capacity can then be considered as a put option on this price. The producer has an option to sell power at a given price (his marginal cost) on the market. It would thus be possible to assume a power price process and compute the value of generation capacity using the Black-Scholes formula. However, this method is hardly acceptable since the price process for power cannot be considered as exogenous. As the total amount of installed generation capacity changes, the price of power changes but also the parameters of the stochastic evolution of power price.

For this reason, we preferred to model the evolution of the primary sources of uncertainties. This stochastic evolution is independent of the installed capacity. Only the value of generation capacity changes with total capacity.

1.4.1.8 Multiple technologies

The examples shown above illustrate the influence of uncertainty on the value of generation capacity for two given technologies. When more than two technologies are considered, the resulting differential equation is no different. However, more than four cases have to be considered.

In this context, it is interesting to use a real option interpretation in order to describe the optimal mix of generation.

First, assuming the price process is exogenous to the choice of generation capacity, we can note that high cost generators are more represented under uncertainty than under certainty. Intuitively, most of the total cost of high fuel costs generators can be avoided when demand is less than forecasted. In contrast, most of the cost of capital intensive technologies is incurred before uncertainty is resolved. Therefore, it is hardly possible to reduce total costs when demand is less than expected. This asymmetry in pay-offs weights in favor of high cost generators.

Second, the choice of the optimal mix will influence the parameters of the power price process. Increasing the total installed capacity of inexpensive generators will move to the right the total supply function and thus will decrease the price of power for all periods.

If for instance, we assume that the total existing supply function is MC(P) and that we are operating close to the position $P = P_o$, then the marginal cost function can be approximated by :

$$MC(P) = MC(P_0) + (P - P_0)\, MC'(P_0)$$

If the demand function is:

$$\lambda = r - b\,P$$

then, we can express the price of power λ as a function of the uncertain parameter r at the market equilibrium $\lambda = MC(P)$.

$$\lambda = r\,(1 - \frac{b}{b + MC'(P_0)}) + const$$

As we increase inexpensive generation capacity, the expected price of power $MC(P_0)$ decreases and so does the coefficient $(1 - \frac{b}{b+MC'(P_0)})$. As a consequence, the variance of λ diminishes. In other words, the presence of inexpensive generators tends to diminish the variance of the price process and thus diminishes the marginal value of expensive generators.

The same reasoning can be applied to transmission capacity. Increasing transmission capacity makes nodal prices more stable. Intuitively, any locational demand spike can be met by a wider pool of resources. Thus, the value of expensive generators is diminished. We would thus expect transmission capacity to be under-represented at the optimum under uncertainty. The next section goes into the details of these issues, and adopts a dual point of view, whereby transmission capacity is seen as a real option on the opportunity cost of transmission capacity with a strike price equal to zero.

1.4.2 Value of transmission capacity

As seen before, generation capacity has a real option feature. In contrast, transmission capacity has no such feature. As we saw before, a Lagrange multiplier associated with the capacity constraint for line l can be interpreted as a price. However, as long as this price is strictly positive, the entire transmission capacity will be used. Thus, transmission capacity investments involve no future decision on whether to use it or not since there are no significant costs associated with using it, once the investment cost is sunk. Thus, as compared with generation technologies, transmission capacity is less flexible. Therefore, the greater uncertainty is, the lower the optimal transmission capacity should be at the optimum.

In order to illustrate this, we use the following two-node model. The uncertain load is located in A, along with an unlimited capacity of expensive generation capacity (fuel

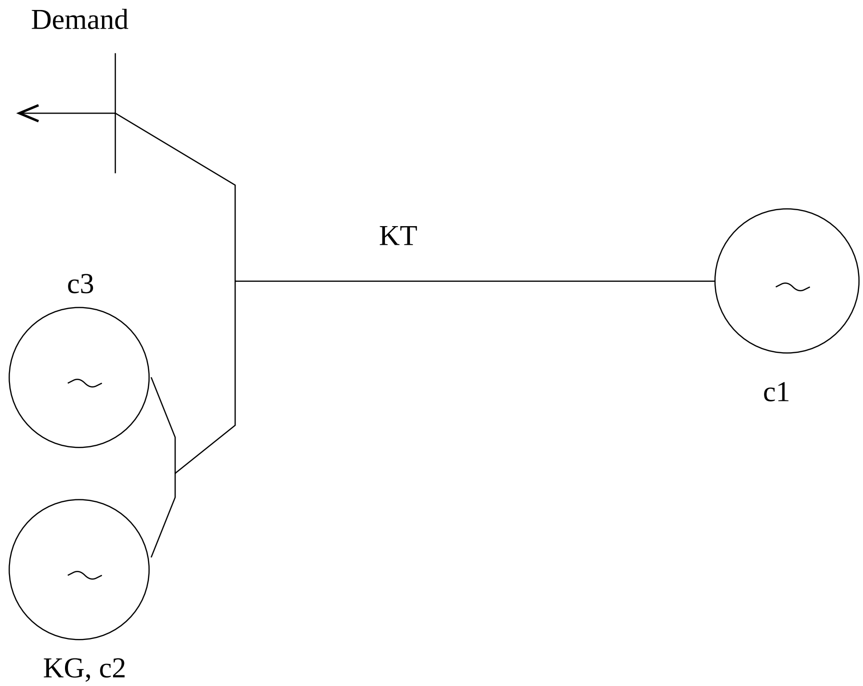

Figure 1-11: Two node example

cost is equal to c_3). Unlimited inexpensive generation capacity (fuel cost is equal to c_1) is located in B. The maximum transmission capacity between A and B is equal to K_T. An amount of K_G generation capacity is installed in A. The corresponding fuel cost is equal to c_2. The rate of growth of demand is $\alpha = 0.02$. The discount rate is $\rho = 0.15$. $c_1 = 100, c_2 = 200, c_3 = 500$. The cost of generation capacity is $k_G = 184$. The cost of transmission capacity is $k_T = 1154$. In the base case, the volatility of the growth rate $\sigma = 0.2$. For this level of volatility we found using the techniques presented above that the optimal generation and transmission capacity equal to 100 for both generation and transmission capacity. When the volatility decreases to a level of 0.1, the optimal transmission capacity is now 123 and the optimal generation capacity becomes 53. Conversely, when uncertainty increases to a level of 0.35, the optimal transmission capacity comes down to 60 whereas the optimal generation capacity becomes 158. Uncertainties undoubtedly favor less capital intensive technologies.

In conclusion, the deterministic peak-load pricing theory presented in section 1.3.3 has to be modified in order to reflect the influence of uncertainty on the value of transmission capacity. Since we adopt a global approach to the issue, price cannot

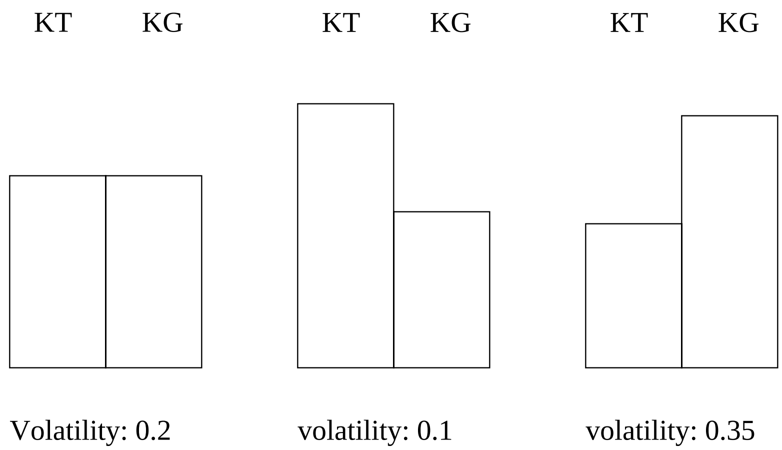

Figure 1-12: Optimal Transmission Capacity Vs. Generation Capacity under uncertainty

be considered as an uncertain variable and we have to use the primary drives of uncertainty as our explicit variables. The interaction between the total amount of installed capacity now becomes very intricate since the amount of installed transmission or generation capacity not only influences the absolute level of prices but also the volatility of the price process. We will come back to this issue in Chapter 2.

However, this represents only part of the questions associated with investments, that is the question of "how much capacity to invest". Another important question is related to the timing of investments. In order to answer this question, it is necessary to consider dynamic aspects of the problem.

1.4.3 Dynamic considerations

We saw in the previous section how uncertainty affects the optimal mix of generation, the location of generation capacity and investments in transmission capacity. However, these results were valid for the total amount of generation and transmission capacity. Actually, they should be modified in order to reflect some initial conditions on generation and transmission capacity. Thus, the previous problem formulation should not have total capacities as optimization variables but instead incremental capacity.

Moreover, we have also to recognize that investments do not have to take place at t=0 but can instead be delayed. We presented such a framework of analysis previously in a deterministic set-up. In this case, the possibility to delay investment costs added value to the project because of the time value of money. In an uncertain context, other factors come into picture as well. In particular, when some parameters are uncertain, there is value in waiting and collecting more information about the future evolution of the stochastic variable. As explained in [12], this option to invest has to be included in the valuation framework in order to fully integrate the dynamic feature of the full-blown optimization problem presented in the first part of this chapter.

1.4.3.1 Incremental investment

We value here the investment rule for a one-time incremental investment in transmission in an uncertain context. The volume of the capacity upgrade is thus set. We will later on propose a similar valuation framework that accounts for the possibility of repetitive investments and how the investment efforts should be spread over time.

Using the valuation techniques presented above, it is possible to value the expected difference in social welfare resulting from a capacity upgrade (either in generation or transmission). This corresponds to the value of the investment $V(r)$. This value fluctuates with the random variable r. We assume there exists a threshold value $r^\star$ above which it is optimal to invest. Under perfect certainty condition, this value is such that:

$$V(r^\star) = I$$

where I is the cost of the investment. Under uncertainty, however, this rule no longer holds since there the value of the investment $V(r)$ is not an uncertain variable, whose value fluctuates according to Ito's lemma as:

$$dV = \left(\alpha \frac{dV}{dr} + \frac{1}{2} \sigma^2 \frac{d^2 V}{dr^2} \right) dt + \sigma \frac{dV}{dr} dz$$

where dz is a Wiener process.

Thus, there exists an option value in waiting to invest. Let us denote this value as $O(r)$. The difference between the value at $(t+dt)$ discounted at the discount rate ρ and the value at t is equal to the increment in social welfare resulting from the investment accrued between t and $t+dt$:

$$\begin{aligned} O(r) &= \frac{E(O(r+dr))}{1+\rho\, dt} + \Delta SW(r)\, dt \\ E(dV) - O\rho\, dt + \Delta SW(r)\, dt + \Delta SW(r)\rho\, dt^2 &= 0 \end{aligned}$$

The increment in social welfare due to the investment between t and $t+dt$ is equal to 0 if no investment decision was made $(r \leq r^\star)$. Thus, the value of the option for $r \leq r^\star$ is equal to:

$$O(r) = C_1\, r^{\beta_1} + C_2\, r^{\beta_2}$$

As before, when $r \to 0$, the option value should be equal to 0. Thus, $C_2 = 0$. Thus, $O(r) = C_1\, r^{\beta_1}$.

Moreover, for $r \geq r^\star$, we have $O(r) = V(r) - I$ since the option has been exercised. At the limit, for $r = r^\star$, we should have:

$$\begin{aligned} O(r^\star) &= V(r^\star) - I \\ \frac{dO}{dr}(O(r^\star)) &= \frac{dV}{dr}(r^\star) \end{aligned}$$

This system of equations gives:

$$V(r^\star) = \frac{r}{\beta_1}\frac{dV}{dr}(r) + I$$

This equation shows that the investment will not be made until its expected value is above the investment cost by at least $\frac{r}{\beta_1}\frac{dV}{dr}(r)$.

This simple model is very general and illustrates how uncertainty, when combined with irreversible decisions, increases the threshold value $r^{\star}$ and leads to a less frequent investment.

1.4.3.2 Continuous investment in transmission capacity

Up until now, the investment model we have considered was deterministic. All information about the future demand and the future costs of generation was assumed to be known by all market participants. Thus, the cost function $C_i(t, P_i)$ was completely deterministic.

Let us now consider a situation where the cost function of the net injection at each node depends on a random variable $\tilde{r}_i(t)$: $C_i(t, P_i, \tilde{r}_i(t))$. This random variable reflects, at the same time, the fluctuation in demand and the cost of generation.

The investment problem is now a stochastic control problem. The evolution of the random variables is modeled through a stochastic process and the investment decisions are made based on the expected costs. Contrary to the stochastic model referred to in the static optimal grid model, the investment planning problem is now characterized by inter-temporal considerations. In particular, the trade off between reduction of costs and flexibility of investment is at the center of the following model. This model draws on the ideas in [12].

1.4.3.3 Simplifying assumptions

First, in order to focus on the investment issues, we neglect the inter temporal issues related to unit commitment [13] . Next, we adopt the assumption of perfect markets already stated in the first section. As a result, during each period, the total cost of generation is minimized. This total cost, as well as the associated values of capacity, now become random variables.

The evolution of the random variables r_i is modeled as a Brownian motion;

$$dr_i = \alpha_i r_i dt + \sigma_i r_i dz$$

where dz is a Wiener process. The relationship between $\Delta = z$ and Δt is: $\Delta z = \epsilon_t \sqrt{\Delta t}$, where ϵ_t is a normally distributed random variable with a mean of zero and a standard deviation of 1.

As explained earlier, this stochastic process does not model the short-term variations of the capacity price. Likewise, we suppose that the total cost function does not depend explicitly on time. Note that we adopt in this part a more general notation than previously. The total cost function TC already introduced is now functionally dependent on the random variables r_i. Contrary to section 1.4, this relationship is not made explicit throughout the derivations.

In order to simplify computations and obtain an analytic solution to the investment planning problem, we will restrict the problem to one random variable. The associated parameters are $\sigma$and α. The discount rate is ρ.

1.4.3.4 The cost to go function

The total cost function, as well as the short term transmission prices, are now random functions. We can define recursively the cost to go function as the total future discounted costs of generation and transmission, assuming that, during each period, the amount of investment is optimal.

During each period Δt, the amount of investment on each line $I_l \Delta t$ is chosen to minimize the cost of generation and transmission investment as well as the discounted value of the expected cost to go function of the next period. The investment control variable has to remain positive. Let us denote ξ_l, as the associated Lagrange multiplier.

$$
\begin{aligned}
F(t, K_1, ...K_l^T, r) \quad &= \min_{I_l} TC(K_1, ...K_l^T, r)\Delta t + \sum_{l=1}^{L} k_l I_l \Delta t \\
&+ \frac{1}{1+\rho\Delta t} E[F + \Delta F]
\end{aligned}
$$

When the planning horizon is infinite, the problem at $(t + dt)$ is similar to the problem at t, except for the different value of the state variables $K_1, ...K_L, r$. Thus, the function F does not depend explicitly on time. This problem can be formulated as:

$$\begin{aligned}\rho \Delta t F(K_1, ...K_L, r) &= \min_{I_l}(TC(K_1, ...K_L, r)\Delta t \\ &+ \sum_l k_l I_l \Delta t)(1 + \rho \Delta t) + E[\Delta F]\end{aligned}$$

dividing by Δt and letting $\Delta t \to 0$ results in

$$\rho F(K_1, ...K_L, r) = \min_{I_l}(TC(K_1, ...K_L, r) + \sum_l = k_l I_l) + \frac{1}{dt}E[dF]$$

Using Ito's lemma:

$$E[dF] = \sum_l \frac{dF}{dK_l} I_L dt + \frac{dF}{dr} r\alpha dt + \frac{1}{2}\sigma^2 \frac{d^2F}{dr^2} r^2 dt$$

1.4.3.5 Solution

Assume $r > 0$ and, for the sake of illustration, r represents a positive shift on a given demand function. The optimality conditions for the choice of I_l can be written as:

$$\begin{aligned}k_l &= -\frac{dF}{dK_l} + \xi_l \\ \xi_l &\geq 0 \\ I_l \xi_l &= 0\end{aligned}$$

At the optimum, we have the differential equation:

$$\rho F(K_1, ...K_L, r) = TC(K_1, ...K_L, r) + \frac{dF}{dr}\alpha r + \frac{1}{2}\sigma^2 r^2 \frac{dF}{dr}$$

This is a second order non-homogeneous differential equation with its associated characteristic equation:

$$\frac{1}{2}\sigma^2 x(x-1) + \alpha x - \rho = 0$$

Let β_1 and β_2 be the real-valued solutions to this equation. β_1 is the positive root $\beta_1 \geq 0$. Assuming the discount rate ρ is higher than the growth rate of r and α, we have $\beta_1 > 1$. The class of solutions to this equation is given by:

$$A_1 r^{\beta_1} + A_2 r^{\beta_2} + \frac{2}{\sigma^2(\beta_2 - \beta_1)}(r^{\beta_1} \int_{\infty}^{r} x^{-\beta_1 - 1} TC(K_l, x) dx \\ - r^{\beta_2} \int_0^r x^{-\beta_2 - 1} TC(K_l, x) dx)$$

We note that when r comes close to 0, dr will be small and r will remain close to zero. Under these conditions, the total cost function remains bounded and the cost to go function has no reason to become infinite. Thus, $A_2 = 0$.

We can modify the solution to the differential equation by changing the variable in the integrations. The new integration variable is t, linked to the variable x by the relation:

$$x = r e^{t \frac{\rho}{\beta_1}}$$

$$dx = r \frac{\rho}{\beta_1} e^{t \frac{\rho}{\beta_1}} dt$$

The first integral becomes:

$$r^{\beta_1} \int_{\infty}^{r} x^{-\beta_1 - 1} TC(K_l, x) dx = \frac{\rho}{\beta_1} \int_{\infty}^{0} e^{-\rho t} TC(K_l, r e^{t \frac{\rho}{\beta_1}}) dt$$

Likewise,

$$r^{\beta_2} \int_0^r x^{-\beta_2 - 1} TC(K_l, x) dx) = \frac{\rho}{\beta_2} \int_{\infty}^{0} e^{-\rho t} TC(K_l, r e^{t \frac{\rho}{\beta_2}}) dt$$

Thus, the optimal decisions for investment can be stated. By noting that $\frac{dTC(K_l, r)}{dK_l} =$

$-\mu_l$, the value of transmission, we have:

$$\begin{aligned}
k_l &= -\frac{dF}{dK_l} + \xi_l \\
&= \frac{2\rho}{\sigma^2(\beta_1 - \beta_2)}(\int_0^\infty e^{-\rho t}(\frac{1}{\beta_1}\mu_l(K_l, re^{\frac{\rho}{\beta_1}t}) \\
&\quad -\frac{1}{\beta_2}\mu_l(K_l, re^{\frac{\rho}{\beta_2}t}))dt) + \xi_l - \frac{dA_1}{dK_l}r^{\beta_1} \qquad (1.12) \\
\xi_l &\geq 0 \\
I_l\xi_l &= 0
\end{aligned}$$

To determine the value of the constant A_1, we make the smooth-pasting assumption [12]. At the optimum $\frac{dF}{dK_l dr} = 0$. This gives:

$$\begin{aligned}
0 &= \frac{2\rho}{\sigma^2(\beta_1 - \beta_2)}(\int_0^\infty e^{-\rho t}(\frac{1}{\beta_1}e^{\frac{\rho}{\beta_1}t}\frac{d\mu_l}{dr}(K_l, re^{\frac{\rho}{\beta_1}t})dt \\
&\quad -\frac{1}{\beta_2}e^{\frac{\rho}{\beta_2}t}\frac{d\mu_l}{dr}(K_l, re^{\frac{\rho}{\beta_2}t}))dt + \beta_1\frac{dA_1}{dK_l}r^{\beta_1 - 1}
\end{aligned}$$

To justify the existence of the first integral, we have to note that $\beta_1 > 1$, based on the assumption that $\rho > \alpha$. Through integration by parts, we obtain:

$$\begin{aligned}
&\rho(\textstyle\int_0^\infty e^{-\rho t}(\frac{1}{\beta_1}re^{\frac{\rho}{\beta_1}t}\frac{d\mu_l}{dr}(K_l, re^{\frac{\rho}{\beta_1}t})dt \\
&= -\tfrac{\mu_l(K_l,r)}{r} + \tfrac{\rho}{r}\textstyle\int_0^\infty e^{-\rho t}(\mu_l(K_l, re^{\frac{\rho}{\beta_1}t})dt
\end{aligned}$$

Or;

$$\begin{aligned}
&\frac{2\rho}{\sigma^2(\beta_1 - \beta_2)}(\int_0^\infty e^{-\rho t}(\frac{1}{\beta_1}re^{\frac{\rho}{\beta_1}t}\frac{d\mu_l}{dr}(K_l, re^{\frac{\rho}{\beta_1}t})dt \\
&= -\frac{2}{\sigma^2(\beta_1 - \beta_2)}\frac{\mu_l(K_l, r)}{r} + \frac{2\rho}{r\sigma^2(\beta_1 - \beta_2)}\int_0^\infty e^{-\rho t}(\mu_l(K_l, re^{\frac{\rho}{\beta_1}t})dt \qquad (1.13)
\end{aligned}$$

By combining equations (1.12) and (1.13), we obtain:

$$k_l = \xi_l + \frac{-2\rho}{\sigma^2\beta_1\beta_2}\int_0^\infty e^{-\rho t}\mu_l(K_l, re^{\frac{\rho}{\beta_2}t})dt$$

Noting that $\beta_1\beta_2 = -\frac{\sigma^2}{2\rho}$, we obtain;

$$k_l = \xi_l + \int_0^\infty e^{-\rho t}\mu_l(K_l, re^{\frac{\rho}{\beta_2}t})dt$$

1.4.3.6 Interpretation

This condition can still be interpreted as the discounted sum of transmission values. However, since β_2 is negative, these values are computed assuming r will follow a decreasing path.

By comparison, a deterministic optimal gird condition would have been:

$$k_l = \xi_l + \int_0^\infty e^{-\rho t}\mu_l(K_l, re^{\frac{\rho}{\alpha}t})dt$$

since $re^{\frac{\rho}{\alpha}t}$ is the expected value of r at time t.

Thus, a computation of the discounted transmission value is much more conservative under uncertainty and subsequently, the rate of transmission capacity investment will be slower than in the deterministic case. The deterministic set up only reflects the trade off between cost of generation and cost of transmission, taking into account the time value of money. The stochastic models, in addition, reflect the value of flexibility. *By delaying the investment in capacity, it is possible to gather more information about the evolution of the random variable in order to make wiser decisions. Consequently, the value of transmission capacity will be higher compared to a perfect certainty situation.*

The same situation could happen in a competitive set-up [12, chapter 8]. Even though the discounted sum of profits may fall under the long run cost of transmission capacity, private investors may be reluctant to invest knowing that the value of their investment will remain low due to subsequent investments. In other words, if the value of transmission turns out to be higher than expected, they will make the most out of this favorable outcome, as other investors will be attracted by this new opportunity. On the other hand, transmission owners will incur full losses resulting from optimistic expectations. As a result, the competitive equilibrium will not be a zero profit equilibrium and private investors may make supra normal profits.

Economies of scale in transmission

The previous model is valid assuming the cost of investment is proportional to the rate of investment. In reality, transmission investments are lumpy and present some economies of scale as already explained. This fact should make investments in transmission even less desirable.

We will come back in Chapter 3 to the issues of economies of scale.

1.5 Conclusions - Remainder of the thesis

Optimal decision making in a decentralized set-up

In this chapter, we have introduced the problem of optimal investments decisions for a centralized utility under several assumptions. In particular, we have emphasized two aspects of optimal investments:

- A coordinated investment policy in generation and transmission can lead to social welfare improvements. In particular, transmission should not be considered as a mere technical input but can also bring value to market players.
- The existence of risks and pro active risk management solutions in both generation and transmission.

As the power industry undergoes restructuring , new players appear, with their own objectives, power and private information. Policy makers should be concerned with making sure that the resulting interactions are consistent with the optimal investment assessment described above. First, the balance between investments in generation and in transmission should be guaranteed by an appropriate valuation of transmission investment and locational impact of generation investments, based not only on expected demand scenarios but also on the existence of risk. Second, financing schemes should be designed for the allocation of the non-capacity part of the cost in order to ensure that valuable transmission investments are carried out in spite of free-riding issues. Finally, the transmission industry should be structured in order to make the appropriate investment and pricing decisions in the context of limited information. In particular, the risk associated with investment decisions should be efficiently managed by the transmission company.

New transmission technologies

This part of the thesis emphasized the value of transmission capacity in an uncertain context. We assumed all along that investments consisted of transmission capacity upgrades and showed how this value was affected by the existence of risks. We have however ignored some aspects of the transmission industry. It is possible, thanks to new technologies, so-called FACTS technologies, to modify the distribution factors matrix. Thus, instead of building new transmission lines or replacing existing transmission lines, it is possible to use more efficiently the existing ones. In particular, these technologies are flexible in the sense that the distribution factors matrix can be modified within a certain range in order to adapt to load and generation changing patterns. Further research is needed in order to assess the potential of these technologies, in particular in an uncertain context. They are however very promising.

Likewise, a wise dispatch of of reactive power can achieve, through different channels, the same results and flexibility than FACTS devices [2]. By lifting the P-Q decoupling assumption, one should then be able to assess the benefits of coupling the dispatch of active and reactive power.

These solutions have hardly been explored by centralized utilities. As the whole efficiency of the power industry is put into question, it is high time that these theoret-

[2]See section 3.3

ically promising solutions were envisioned. In order to do that, the new transmission industry structure should not only achieve in the operation and planning efficiency, but should also be able to incorporate in the long-run promising transmission technical solutions. This is certainly where lies the whole motivation for deregulation.

Social, Energy and Environmental considerations

We have however to relativize the two previous recommendations and recognize that in practice, most investments in transmission capacity are not the result of a sound economic analysis. As explained above, many of the social consequences of transmission investments are not captured by the above model. Transmission investments are the vector of geographical development, energy and social policies. They also have tremendous environmental impacts. Since they are today important parts of the transmission investments decisions, they should also be incorporated in the new industry structure. We leave aside for the rest of the thesis these considerations in order to focus on the first recommendations.

Chapter 2

Coordination of the Power Industry

2.1 A competitive market for generation

2.1.1 Unbundling the Power Industry

The basis for creating a power market is that market participants(generators, loads), by maximizing their individual expected profit or utility, will optimize total welfare in the same way as integrated utilities did when running an OPF. The main question to address in this section is whether the same concept can be developed when transmission capacity constraints are accounted for.

Let us consider the certain equivalent problem to the integrated utility problem defined in section 1.3. Uncertain parameters are replaced by their expected values first. The solution to this problem can be formulated by introducing the following Lagrangian:

$$\begin{aligned} &\textstyle\sum_{i,a} \int_{t_0}^{T} e^{-rt}[c_{ia}(t)P_{ia}(t) + C_{ia}^G(K_{ia}^G(t), I_{ia}^G(t), t)]dt \\ &+ \textstyle\sum_l \int_{t_0}^{T} e^{-rt}[C_l^T(K_l^T(t), I_l^T(t), t)]dt \\ &+ \textstyle\int_{t_0}^{T} \sum_{ia} \sigma_{ia}(t)(K_{ia}^G - P_{ia}(t)) \end{aligned}$$

$$+\sum_i \int_{t_0}^T e^{-rt}[U_i(L_i(t), u_i(t))]dt$$
$$+\lambda(t)(\sum_i L_i(t) - \sum_{i,a} P_{ia}(t))$$
$$+\sum_l \mu_l(t)(K_l^T - \sum_{i,a} H_{li}(P_{ia}(t) - L_i(t))dt$$

The terms in this Lagrangian can be rearranged in order to decompose this single optimization problem into several simpler optimization sub-problems. If the values of $\mu_l(t)$ and $\lambda(t)$ (transmission and electricity prices) are given, the simpler optimization problem at node i for technology a are:

$$\max_{I_{ia}^G, P_{ia}} \lambda(t)P_{ia}(t) + \sum_l \mu_l(t)H_{li}P_{ia}(t))dt$$
$$-\int_{t_0}^T c_{ia}(t)P_{ia}(t) + C_{ia}^G(K_{ia}^G(t), I_{ia}^G(t), t)dt$$

subject to :

$$\frac{dK_{ia}^G}{dt} = I_{ia}^G(t)$$
$$T_{ia}^G \geq 0$$
$$P_{ia}(t) \leq K_{ia}^G \quad : \sigma_{ia}(t)$$

The task of a coordinator is to set the trajectories of the investment rate and of the dual variables $\mu_l(t)$ and $\lambda(t)$ and to make sure that those value are consistent with the thermal line constraint (1.2 and the balance equation constraint (1.3).

This minimization subproblem can be interpreted very simply. If $\lambda(t)$ is the price of energy and $\mu_l(t)$ is the price of transmission service line by line, then the objective function in this optimization subproblem is the difference between revenue and costs: profits. Thus, by imposing the proper prices for energy and transmission services and ensuring that the investment policy in transmission will be able to accommodate the pattern of flows, the grid operator can control the entire problem and induce the profit maximizing entities to choose the optimal amount of net injection.

The variables $\lambda(t)$ and $\mu_l(t)$ act as coordinating variables for the dispatch of power.

At this stage, we are one step away from a true competitive market for generation since the price of energy $\lambda(t)$ in the above framework is still imposed by the coordinator. We will assume that this price will result naturally from information exchanges between generators and consumers and that it will obey the law of supply and demand. The entire optimal control problem (1.1) then reduces to the choice of transmission prices $\mu_l(t)$ and capacities $K_l^T(t)$. It is important at this stage to consider these two decisions as dual. Thus a transmission pricing scheme cannot ignore the investment policy and the investment policy should be dependent on the amount of congestion on the grid.

The main issue in this formulation of transmission pricing as a coordinating activity resides in the information structure of the problem. Not only is the transmission provider unable to predict with perfect certainty the future values of demand, but he does not know the cost structure of generators. The transmission industry should thus be structured in a way that enables the incorporation of this information in the appropriate time frame.

In the short-run, the prices of transmission services must be set in accordance with existing transmission capacities whereas in the long-run, capacities are adjusted in order to accommodate the long-trend dynamics of the system at a minimum cost.

2.1.2 Transmission constraints Vs. Generation constraints: need for a coordinated allocation of resources

The above decomposition of objectives assumes generation capacities issues are handled in a decentralized way by profit-maximizing generators. However, transmission constraints cannot be handled in a decentralized way. They require the introduction of additional variables reflecting the multidimensionality of the network and the associated externalities.

2.1.2.1 A review of Kuhn-Tucker Optimality Conditions

Necessary conditions Let $f : \mathcal{R}^n \to \mathcal{R}$ and $g_i : \mathcal{R}^n \to \mathcal{R}$ for $i = 1, .., k$ and consider the optimization problem:

$$\max_x f(x) \tag{2.1}$$

subject to:

$g_i(x) \leq 0$ for 1=1,...,k

If $x^\star$ solves the above optimization problem , the there exists a set of Lagrange multipliers $\lambda_i \geq 0$, for $i = 1, ..., k$ such that:

$$\frac{df}{dx}(x^\star) - \sum_{l=1}^{k} \lambda_i \frac{dg_i}{dx}(x^\star) = 0$$

Furthermore, we have the following complementary slackness conditions:

$$\lambda_i \geq 0 \qquad for\ all\ i$$
$$\lambda_i = 0 \quad if\ g_i(x^\star) < 0$$

Sufficient conditions If we further assume that f is a concave function and g_i are convex functions, we have the following sufficiency conditions:
Let $x^\star$ be a feasible point and suppose that we can find nonnegative numbers λ_i consistent with the complementary conditions such that:

$$\frac{df}{dx}(x^\star) - \sum_{l=1}^{k} \lambda_i \frac{dg_i}{dx}(x^\star) = 0$$

Then $s^\star$ solves the maximization problem stated in 2.1.

Lagrangian saddle point Under the same assumptions of concavity/convexity, then $x^\star$ solves the global optimization problem stated in 2.1 if and only if there exist $\lambda_i^0 \geq 0$ for i=1,...k such that $(x^\star, \lambda_i^0)$ is a saddle point of the Lagrangian. The Lagrangian is defined as:

$$\mathcal{L}(x, \lambda_i) = f(x) - \sum_{i=1}^{k} \lambda_i \, g_i(x)$$

That is to say $\mathcal{L}(\, x, \lambda_i^0) \leq \mathcal{L}(\, x^\star, \lambda_i^0) \leq \mathcal{L}(\S^\star, \lambda_\rangle)$ for all (x, λ_i)

2.1.2.2 The mathematical intuition behind decentralization

An integrated utility is used to maximizing social welfare subject to capacity constraints and the power balance constraint. The optimization problem can be stated:

$$\min_{P_i} \sum_i C_i(P_i) \tag{2.2}$$

$$\begin{aligned} \sum_i P_i &= 0 \\ P_i &\leq K_i \\ \sum_l H_{li} P_i &\leq K_l \end{aligned} \tag{2.3}$$

Ignoring transmission capacity constraints, this optimization problem can be stated as a min-max problem:

$$\max_{\lambda, \sigma_i} \min_{P_i} \sum_i C_i(P_i) - \lambda . \sum_i P_i - \sum_i \sigma_i (K_i - P_i)$$

The proof for the equivalence between a centralized approach and the market approach is based on the fact that:

$$\max_{x_1, \ldots, x_n} \sum_i f_i(x_i) = \sum_i \max_{x_i} f_i(x_i)$$

When the objective function is separable, the global optimization problem can be decomposed into a series of one variable optimization sub problems:

$$\max_{P_i} \lambda\, P_i - C_i(P_i)$$

$$\text{subject to } P_i \leq K_i$$

The min-max problem equivalent to the constrained can be stated:

$$\max_{\lambda} \max_{\sigma_i} \min_{P_i} \sum_i [C_i(P_i) - \lambda P_i - \sigma_i(K_i - P_i)]$$

We now have n optimization problems. Each one of them can be interpreted as a constrained profit optimization with respect to a single decision variable. Thus, given the right price for power, individual players can choose their output appropriately. The fact that there are capacity constraints in generation does not change the separation property of the problem and explains why we obtain the same result when running an OPF or setting a price for power. More intuitively, this shows that the opportunity cost for capacity can be expressed as a function of the price for power only.

2.1.2.3 Transmission capacity constraints

By contrast, the externalities created by transmission capacity constraints, cannot be handled at the individual level since they appear in the objective function along with the matrix H (equation (2.3)). The optimization function is no longer separable. This explains why these constraints have to be handled through a coordinating mechanism similar to the power price mechanism.

2.2 Short-term coordination

In the new competitive market for power, each market participant tries to maximize its profit. The existence of a single price for power, seen as a coordinating variable, ensures that during each period, the forecasted generation output balances the expected load. This market mechanism performs in a decentralized way the minimization of generation costs. However, the optimal power flow program performed daily by integrated utilities not only includes the power balance constraint but also accounts for the transmission capacity constraints. As shown above, those additional constraints cannot be handled individually by each market participants and create the need for new forms of network coordination: congestion management.

If market participants are ultimately to be responsible for the choice of their generation output or consumption, short-run prices of transmission services are the only control variables left to make sure that the system remains together at the minimum cost. Ideally, transmission services should be priced in the short-run at their marginal value in order to achieve this objective. This pricing can be made explicit by charging exogenously for each transaction on a locational and temporal basis, or it can result from the interaction of demand and supply for transmission capacity in a competitive way by auctioning transmission rights, or it can be interpreted as an opportunity value when firm transmission rights are pre-allocated to market participants.

We will explore in greater details these different possibilities. Their similarity stems from the fact that as soon as congestion appears on the grid, power does not have the same value at each node but is traded on the primary market as if it did. The congestion management scheme, whichever it is, has thus to incorporate these differences. The transmission rent, presented in the first part of this thesis, will appear, under one form or another, in all congestion schemes as an economic reality. It will serve later in the thesis as a basis for developing a uniform approach to long term incentives. We will then ignore the practical implementation of congestion management so that we can focus on its associated economic incentives.

The definition of the value of transmission capacity is not straightforward. In the short-run, demand and cost functions can be considered deterministic. However, a transmission provider has no exact knowledge of their value. The main issue in setting the value of the coordinating variables μ_l therefore consists of information asymmetries. Many diverse mechanisms have been proposed to price transmission based on its market-value. Most of them are based on information exchanges between the coordinating entity and market participants. Not surprisingly, strategic behavior issues and convergence issues are the most often quoted issues associated with these pricing schemes.

Not surprisingly also , all congestion management schemes lead in theory to the same dispatch of generation resources. We cannot differentiate between them at the equilibrium or under the assumptions of perfect market conditions. The most suitable structure for value-based transmission pricing should, on the contrary, be judged on its ability to mitigate market power, to handle uncertainty in demand, and to converge toward equilibrium prices.

2.2.1 The Pool-co model

The Pool-co pricing scheme was introduced by Hogan [6]. The existing mandatory power pool implemented in England and Wales is directly based on this concept.

Market participants bid their supply curves and the market maker at the same time dispatches power and allocates transmission capacity using the same economic dispatch program used in a vertically integrated structure. The one exception is that the costs functions are replaced by market bid functions. In this way, power and transmission capacity remain bundled. Competition among generators give them the incentive to bid their marginal cost curve. Likewise, under the assumption of inelastic demand, loads bid their marginal value curve.

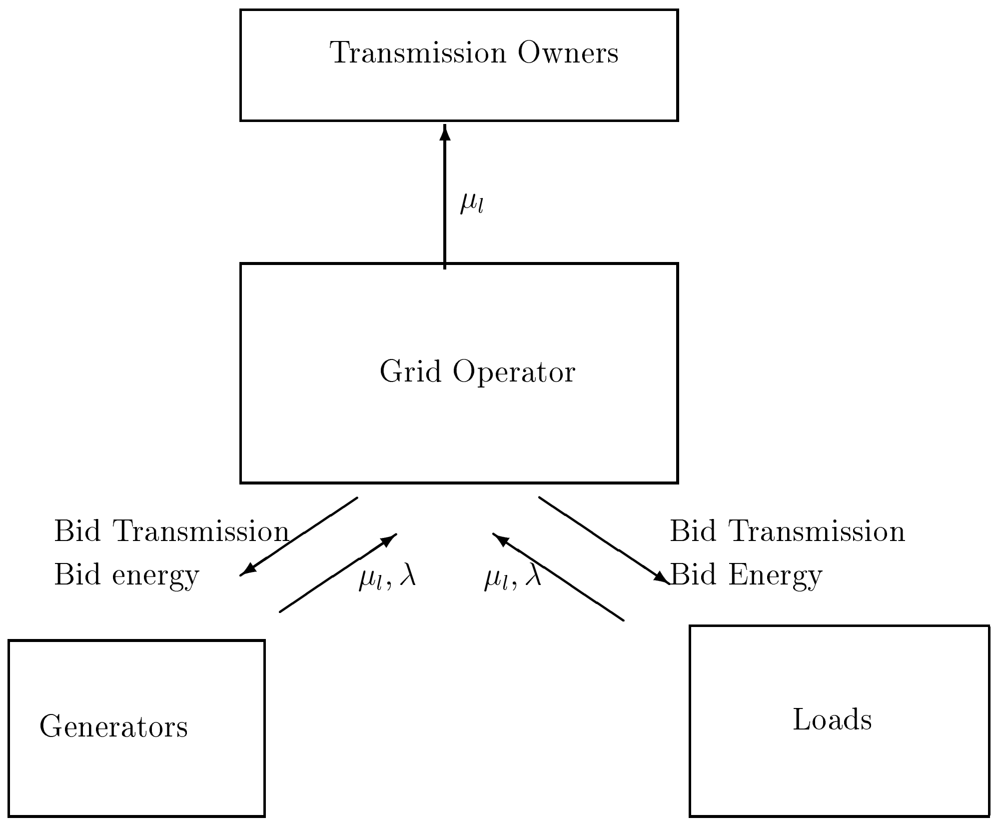

Figure 2.2.1: The Pool-co model

2.2.2 Tradable transmission rights

The concept of tradable transmission rights was introduced by Chao and Peck [14] in 1996. According to this scheme, the ownership of a line is split into transmission rights. Those rights can be traded freely by their owners. The link between the market for transmission rights and the market for power at one chosen arbitrary node is established by forcing market participants to buy the quantity of transmission rights corresponding to the amount of flow each of their transactions is causing. These trading rules for congestion management enable the incorporation of the externalities associated with the use of congested transmission lines. Counterflows create new transmission rights, eligible for trade.

The price of power and the prices of transmission rights evolve in accordance with the law of supply and demand: the price increases whenever the residual demand is positive and decreases otherwise. By making the right assumptions about the shape of the cost functions [15], the pricing process can be shown to converge toward a unique equilibrium.

In this scheme, the role of the grid operator is limited to making sure that all transactions comply with the trading rules. He does not play any role in the trading process.

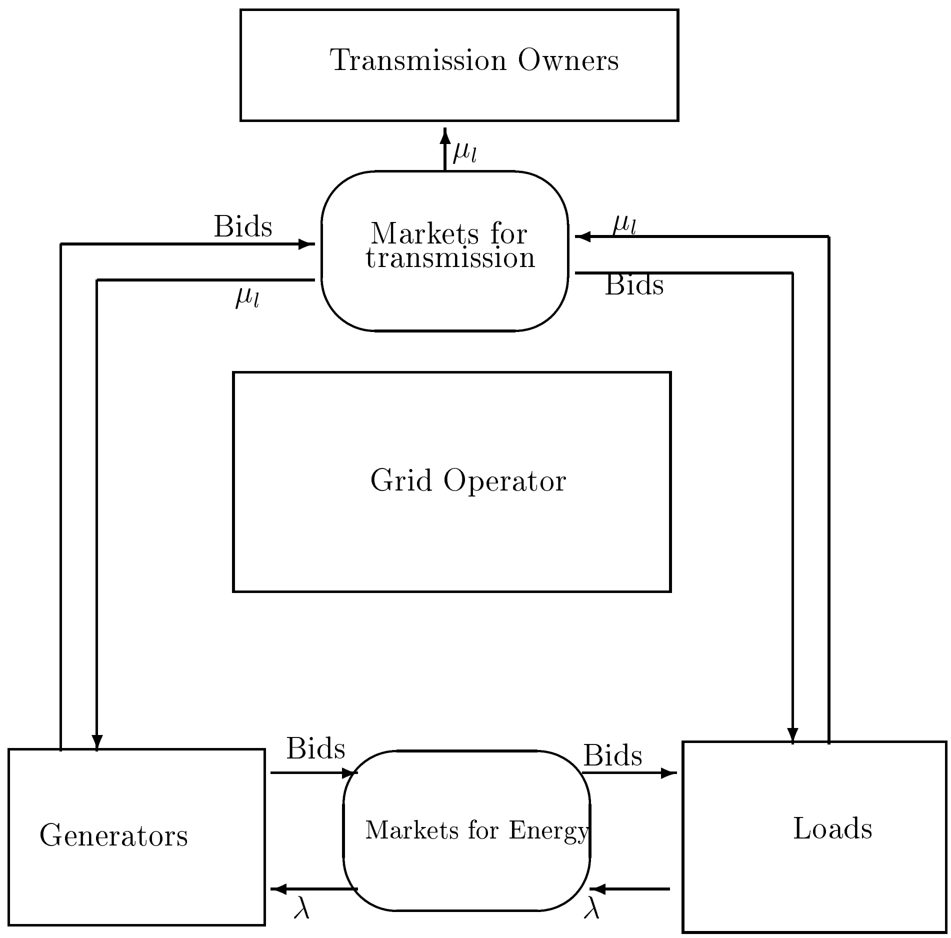

Figure 2.2.2: Tradable transmission rights

As argued in [16], the active role of the transmission owner could bring the price of the transmission rights closer to its value and thus mitigate the incentive for market participants to appropriate the rent.

In order to go deeper into the analysis of this pricing scheme, we interpret tradable transmission rights and power as the the only components of a multi-product economy. We can then state some general equilibrium dynamics conditions.

2.2.2.1 Notations

In this section, the following notation is used:

P_i represents the net injection at node i. P_i can be seen as a function of time. $P_i > 0$ corresponds to a net injection and $P_i < 0$ corresponds to a net withdrawal.

L is the number of transmission lines.

λ is the price of power delivered at an arbitrary node i_0 before the equilibrium is reached. This price at the equilibrium is $\lambda^\star$. We assume in this model that market participants trade power at an arbitrary point of delivery and transmission rights in order to transport it to (from) the node of consumption (production). This economy thus have $L + 1$ products.

The matrix of distribution factors is denoted H. The slack bus is assumed to be at node i_0 so that H_{li} represents the flow on line l produced by an unitary trade from i to i_0.

μ_l are the prices of transmission rights before reaching the equilibrium. At the equilibrium, they are equal to $\mu_l^\star$.

K_l are the transmission constraints.

C_i represents the cost of generations when P_i is positive and the negative of the utility function when the net injection is negative.

2.2.2.2 Residual demand for transmission rights

For a given set of prices (λ, μ_l), the demand for transmission rights for line l is equal to the flow that would be created on line l if all trades which value is more than the cost of transportation were implemented. For instance, at node i, the apparent price of power would be the cost of power at node i_0 plus the cost of transportation:

$$\rho_i = \lambda - \sum_k H_{ki} \mu_k$$

This would create a total transaction between i and i_0 equal to:

$$P_i(\lambda - \sum_k H_{ki}\mu_k)$$

where $P_i(\rho_i$ is the total injection at node i for a price equal to ρ_i.

Thus, the total demand for line l is:

$$F_l(\lambda, \mu_l) = \sum_{i \neq i_0} H_{li} P_i(\lambda - \sum_{k=1}^{L} H_{ki}\mu_k)$$

We can then define the residual demand as

$$f_l(\lambda, \mu_l) = F_l - K_l$$

2.2.2.3 Residual demand for power

Likewise, the demand for power at node i_0 is equal to the local net demand plus the exports to other nodes.

$$d(\lambda, \mu_l) = -P_{i_0}(\lambda) - \sum_{i \neq i_0} P_i(\lambda - \sum_k H_{ki}\mu_l)$$

2.2.2.4 The tatonnement process

We then assume that prices and residual functions are continuous and derivable functions of time and obey to the tatonnement assumption: the derivative of a price is proportional to the residual demand.

Following Arrow and Hahn [17], we include two additional conditions in order to have positive prices and strictly negative residual demand at the equilibrium:

$$\frac{\partial \lambda}{\partial t} = 0 \ \ if \ \ \lambda \leq 0 \ \ and \ \ d \leq 0 \tag{2.4}$$

$$\frac{\partial \lambda}{\partial t} = k_0 \, d \ \ otherwise \tag{2.5}$$

$$\frac{\partial \mu_l}{\partial t} = 0 \ \ if \ \ \mu_l \leq 0 \ \ and \ \ f_l \leq 0 \tag{2.6}$$

$$\frac{\partial \mu_l}{\partial t} = k_l \, f_l \;\; otherwise \qquad (2.7)$$

k_0 and k_l are positive constants.

This tatonnment process encapsulates the common intuition of the supply and demand law. Whenever supply is more than demand, the price will decrease and conversely. If demand happens to be more than supply, the price will increase.

The two additional conditions model the fact that if no scarcity is associated with a good, its price should be equal to zero.

It is possible to show that the price will always remain positive. Moreover, given the appropriate assumptions concerning the convexity and concavity of the supply and demand functions at each node, we know that the equilibrium is unique. Thus, if the process above described converges, it will reach this equilibrium.

2.2.2.5 Linearization around the equilibrium

It is possible to linearize the residual demand functions around the equilibrium. Let us denote $MD_i = \frac{\partial P_i}{\partial \rho_i}$, where ρ_i is the total price of power (power+transportation) at node i.

$$\frac{\partial d}{\partial p} = -\sum_i \frac{\partial P_i}{\partial p} = \sum_i MD_i$$

$$\frac{\partial d}{\partial t_l} = MD_{i_0} - \sum_{i \neq i_0} H_{li} MD_i$$

$$\frac{\partial f_l}{\partial t_k} = \sum_{i \neq i_0} H_{li} H_{ki} MD_i$$

$$\frac{\partial f_l}{\partial p} = \sum_{i \neq i_0} -H_{li} MD_i$$

This system of equations illustrates cross-demand effects. In particular, the terms $H_{li}H_{ki}$ may be either positive or negative. The term MD_i is always positive since a price increase leads to a reduction in demand and an increase in supply. Increasing the price on one line will always lead to a decrease in flow on this line since the terms

$H_{li}H_{li} = H_{li}^2$ are always positive. Notably, increasing the price on one line may not be enough to decrease the flow on this line since the modification of prices on other lines should also be accounted for.

However, this approach is not very efficient to study the stability of the trading process since this process is not linear. Instead, Chao and Peck [14] define a Lyapunov function associated with the trading process.

2.2.2.6 A Lyapunov Function

Let us consider next a surplus function at each node plus the transmission rent as a function:

$$V(\lambda, \mu_l) = P_{i_0}\,\lambda + \sum_{i \neq i_0} P_i(\rho_i)\,(\rho_i) - \sum_i C_i(P_i) + \sum_l \mu_l K_l$$

Let's define the nodal price $\rho_i = \lambda - \sum_i H_{li}\mu_l$.

We can show that the time derivative of this function is negative. In order to show this, let us derive the gradient of this function. First, let's note that the first three terms represent the total social welfare, which is the sum of social welfare at each node SW_i. It is assumed that at each node, the output is chosen so as to maximize profit and consumer surplus. Thus, the derivative of social welfare at each node relative to the nodal price is equal to the net injection P_i (envelope theorem).
Thus:

$$\frac{\partial V}{\partial \lambda} = \sum_i \frac{\partial SW_i}{\partial \rho_i}\,\frac{\partial \rho_i}{\partial \lambda} = \sum_i P_i$$

$$\frac{\partial V}{\partial \mu_l} = \sum_i \frac{\partial SW_i}{\partial \rho_i}.\frac{\partial \rho_i}{\partial \mu_l} + K_l = -\sum_i P_i H_{li} + K_l = K_l - F_l$$

The derivative of V relative to time is given by:

$$\frac{\partial V}{\partial t} = \frac{\partial V}{\partial \lambda}.\frac{\partial \lambda}{\partial t} + \sum_l \frac{\partial V}{\partial \mu_l}.\frac{\partial \mu_l}{\partial t}$$
$$= \sum_i P_i \frac{\partial \lambda}{\partial t} + \sum_l (F_l - K_l).\frac{\partial \mu_l}{\partial t}$$

Given the chosen trading rule, this quantity is null or negative.

Besides, we know that the equilibrium being unique, is the same as the result of the centralized constrained optimization formulated in problem (2.2). We can identify the chosen Lyapunov function with the negative of the Lagrangian of the constrained optimization problem so that the equilibrium prices correspond to a saddle point of the Lagrangian.

The process is thus stable and reaches its equilibrium.

2.2.2.7 Moving equilibrium

The trading process described by equations (2.4),(2.5), (2.6), (2.7) is supposed to take place before equilibrium and for given demand functions. In reality, demand is moving at the same time as trading is taking place so that this process should rather be described as a moving equilibrium.

2.2.3 Iterative pricing

In spite of its advantages, the mechanism of transmission rights may not be implementable. The trading process may not always converge or depending on the time constants, it may take a long time to reach the equilibrium process. This would make the stationary assumption irrelevant and very likely, the transactions would not be implemented at the optimum.

This is due, in particular, to the cross-dependencies of demand for transmission rights: even though the price increases on one line, the demand may still increase due to a drop in price on a substitute line or an increase in price in a complementary line.

As an alternative solution, we propose to introduce an auctioneer in the trading process. In contrast to the pool-co model, this entity would not set the price for a bundled product but only for transmission capacity. The auctioneer would first set prices for transmission. Market participants would then submit their schedule. The auctioneer would then modify the set of prices consistently with the overflows observed in the schedule. After several iterations, this process could lead to the optimal set of prices.

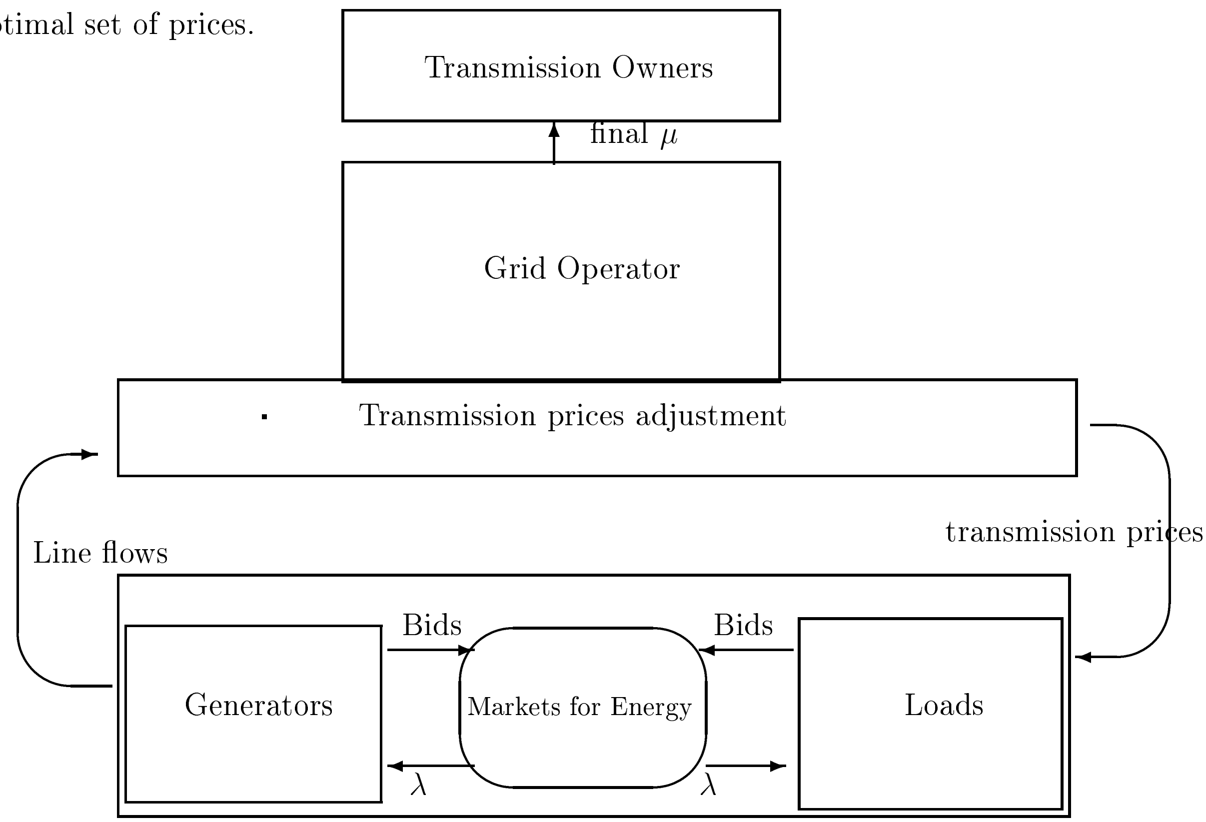

Figure 2.2.3: Iterative Pricing

2.2.3.1 Transmission rights

In this model, we will assume that the equilibrium is reached immediately on the power market, or that between two iterations of the iterative pricing process, the trading process for power has reached its equilibrium. Given a set of prices t_l^n, the market participants can optimize immediately the cost of generation and transportation.

At each iteration, the transmission provider modifies the prices of transmission rights based on the demand for transmission rights.

The rule for modifying the prices vector t based on proposed transactions is very similar to the dynamic market model.

$$\mu^{n+1} = 0 \text{ if } \mu^{n+1} \leq 0 \text{ and } F(\mu^n) \leq T$$
$$\mu^{n+1} = \mu^n + K\left(F(\mu^n) - T\right) \text{ otherwise}$$

However, in contrast with the earlier model(equations (2.4),(2.5), (2.6), (2.7), the matrix K needs not be only diagonal and constant throughout time. More precisely, the knowledge of physical parameters of the system and estimations of price sensitivity at different nodes can be used to accelerate the convergence of the process.

2.2.3.2 Iterative equation solving

Another way to see this problem is to consider that the equilibrium is reached when $t_l^n(F_l - T_l)$ is equal to zero. The problem is then similar to solving a set of L equations and the proposed method is an iterative method. Its convergence is guaranteed as long as:

$$||I - KJ|| \leq 1$$

Where J is the Jacobian matrix of F and I is the identity matrix.

T is the vector of transmission constraints. F is the vector of observed flows. In contrast with the market model (2.4),(2.5), (2.6), (2.7), the matrix K is not diagonal and can be chosen so as to take into account the cross-effects previously described.

In particular, with some estimates of terms MD_i, it can be possible to ensure fast convergence of the iterative pricing mechanism by incorporating knowledge about technical parameters H_{li}.

2.2.3.3 A multilevel optimization and the gradient projection method

The proposed pricing scheme can be seen as a static two level optimization [18].

The problem of the entire system is to maximize total welfare given transmission constraints. It can be stated as:

$$\min_{P_i} \sum_i C_i(P_i)$$

$$\text{subject to } \sum_i P_i = 0$$

$$\text{subject to } \sum_i H_{li} P_i \leq T_l$$

The Lagrangian associated with this problem is:

$$\mathcal{L}(P_i, \lambda, \mu_l) = \sum_i C_i(P_i) - \lambda \sum_i P_i - \sum_l \mu_l (T_l - \sum_i H_{li} P_i)$$

At the first level, market participants minimize the cost of generation and transportation given a set of prices for using the line.

$$L(\mu_l) = \min_{P_i} \sum_i C_i(P_i) + \sum_l \mu_l F_l$$

This minimization is subject to $\sum_i P_i = 0$.

At the secondary level, the coordination entity sets the coordinating variable μ_l and thus modifies the goal of market participants in order to make the most of transmission capacity. Those Lagrange multipliers are set iteratively in order to settle at the saddle point of the total Lagrangian.

Thus, the objective function of the coordination is to maximize the value of $L(\mu_l) - \sum \mu_l t_l$. The transmission capacity constraints are now replaced by the constraint of choosing positive prices. However, the coordinator does not have access to this function since it lacks economic information. However, as shown in the previous section, the derivative of this function relative to μ_l is exactly the difference between the demand for transmission capacity and the total capacity.

Thus, different gradient based optimization methods can be applied. In the case where the matrix K is diagonal and constant, the coordinator modifies by a fixed quantity the prices in the direction of a gradient. Whenever the constraint of the positiveness of prices is hit, he projects the gradient on the orthogonal space of the constraint. The coordinator does not need to compute the gradient at each step since it is equal to the excess scheduled flow.

This process, inspired from the functioning of a market, can be shown to converge toward a unique equilibrium. However, the convergence of the method is generally slow and several techniques of decentralized optimization can be applied to increase the rate of convergence of this process. Such “decomposition techniques” for economic dispatch are currently used by integrated utilities to reduce the size of the optimization problem. In [19], the author explains how individual production centers at Electricité de France are considered independent economic agent in the decentralized economic dispatch. After the coordinating entity sets a price of power, the production centers send back to the coordinator the power they can economically dispatch at this price. The coordinator then changes the prices in order to balance the system and to comply with transmission capacity constraints.

A coordinator could certainly not achieve the same rate of convergence. However, based on its technical expertise of the grid, a coordinator has some knowledge about the shape of the demand function for transmission rights. This information can be used to modify the prices and accelerate the convergence of the iterative process.

2.2.4 Physical curtailment

In the solution to the congestion management issue proposed in [20], a grid operator curtails some physical transactions whenever the schedule proposed by market participants results in congestion on a line. The trading process can then resume in order to supply the curtailed loads. However, the trading process is now subject to certain trading rules enacted by the grid operator in order to ensure that the new proposed schedule will not exceed the capacity limits.

The resulting dispatch of generation resources can be shown to be optimal. However, in contrast with the previous pricing schemes, no money is collected by a transmission operator here and the transmission rent is appropriated by market participants. As a result, even though the pattern of generation is socially optimal, the profits made by individual market participants depend on the curtailment rule applied by the grid operator [21]. For this reason, the physical curtailment methodology cannot be strictly considered as a pricing scheme.

2.2.5 Priority service

In this pricing scheme, the uncertainty on the level of demand for transmission is used by the transmission provider to ration transmission capacity. Transactions contract for non-firm transmission services from point i to point j.

From this point of view, each transaction willing to use the grid has to provide its own out-of-merit generation on a non-firm basis. The level of reliability chosen by the buyer of the contract can be used by the grid operator as a self-selection tool to derive the value of the contract. Knowing this information, the grid operator manages congestion in the most efficient way by trading-off between the contract value and the congestion costs created by the contract.

If the grid operator accurately forecasts demand, he will be able to to provide the long-run level of reliability he was contracted to provide. This commitment ensures that, in return, the buyer of the contract has the incentive to reveal the value of its contract.

A similar approach for generation was proposed in [22]. Here we propose a new formulation foe the similar problem as applied to transmission provision¿

To start with, a non-firm transmission contract is defined by:

- The point of injection and the point of retrieval i and j
- The capacity of the contract D_{ij}
- The time profile of the contract χ_T and its total length T
- Its probability of implementation r_{ij}
- Its price p_{ij} per unit of power

This is the simplest characterization of a non-firm transmission contract. It can be used between a generator and a load willing to be curtailed or between two generators as a means to provide out-of-merit generation.

Each contract can be associated with a cut-off parameter μ_0. If the spot value of the transmission path between i and j is greater than μ_0, the contract is not implemented. If, on the contrary, the spot value is less than the cut-off value, the contract is implemented. The probability of implementation can be derived from the cut-off value.

The value μ_l^t of each transmission line, at time t, can be considered by the transmission provider as a random variable. Let us define $f(t, \mu_1, ..., \mu_L)$, the joint probability distribution of the L random variables. It is also possible to define, given the distribution factors B_{ij}^l[1] of the path ij, the convex set $\Omega_{ij}(\mu_0)$:

$$\Omega_{ij}(\mu_{ij}^0) = \{\sum_l B_{ij}^l \mu_l \leq \mu_{ij}^0 : \mu_l \geq 0\} = \{\mu_{ij} \leq \mu_{ij}^0\}$$

where μ_{ij} is the difference in nodal price between i and j.

Then :

$$r_{ij}(\mu_0) = \int \int_{\Omega_{ij}(\mu_0)} f(t, \mu_1, ..., \mu_L) d\mu_1 ... d\mu_L dt = \int_{-\infty}^{\mu_0} f_{ij}(\mu_{ij}) d\mu_{ij}$$

The pricing of this type of contract depends on the value of the cut-off parameter and on the points of injection and retrieval.

2.2.5.1 Self-selection

Consider a contract whose value is v per unit of energy to its buyer. If the buyer is not risk averse, he will maximize the following expression by choosing (explicitly or implicitly) the cut-off parameter:

$$\left(r_{ij}(\mu_{ij}^0) v - p_{ij}(\mu_{ij}^0)\right)$$

$r_{ij}(\mu_{ij}^0)$ represents the cumulative distribution function of μ_{ij}^0. The first condition

[1] $B_{ij}^l = H_{li} - H_{lj}$, H being the distribution factor matrix

gives:

$$v = \frac{dp_{ij}(\mu^0_{ij})}{d\mu^0_{ij}} / \frac{dr_{ij}(\mu^0_{ij})}{d\mu^0_{ij}}$$

where $\frac{dr_{ij}(\mu^0_{ij})}{d\mu^0_{ij}}$ is the density of probability distribution of the value of the transmission path between i and j.

The most socially efficient use of the transmission grid is obtained when the cut-off parameter is equal to the value of the transaction. Thus, if we want the self selection process to be efficient, the price of the contract must be related to the probability of implementation by the following relationship:

$$\frac{dp_{ij}(\mu^0_{ij})}{d\mu^0_{ij}} = \mu^0_{ij}.\frac{dr_{ij}(\mu^0_{ij})}{d\mu^0_{ij}}$$

Given that the price of a zero reliability contract is zero, this equation can give by integration:

$$p_{ij}(\mu^0_{ij}) = \int_{-\infty}^{\mu^0_{ij}} \mu_{ij} \frac{dr_{ij}(\mu_{ij})}{d\mu_{ij}} d\mu_{ij}$$

For instance, the price of a firm contract will be equal to the expected spot value of the transmission grid. A non-firm contract on the same path will pay a lower fee.

2.2.5.2 Real time operation of the grid

This kind of contract can be written by any financial intermediary. However, the non-firm capacity contract can also serve as a basis for congestion management.

The grid operator, based on the estimated law of joint probabilities, can offer a menu of price-reliability for different paths. The user chooses a level of reliability corresponding to the value of its transaction. In virtue of the self-selecting property, a high value transaction will choose to secure a high level of reliability. In this way, the notion of reliability is path-dependent. A transmission provision of 80 % reliability can be very expensive on a highly congested path and almost free on another path.

However, the fraction $\frac{dp_{ij}(\mu^0_{ij})}{d\mu^0_{ij}} / \frac{dr_{ij}(\mu^0_{ij})}{d\mu^0_{ij}}$ is not path-dependent and it reflects the absolute value of the contract. It can thus serve as the basis for congestion management at the grid-level by maximizing the total value of the implemented contracts subject to the capacity constraints.

This can also be interpreted as choosing the values of the cut-off parameters on each line in order to maximize the total value of the transactions subject to the capacity limits.

This new rule for curtailment is based on a dual interpretation of the primal optimal power flow problem. If all transactions are decomposed into single unitary transactions, the convex supply functions can be interpreted as stair functions. Therefore, the OPF problem simplify into a linear program. The dual problem is now to maximize the value of implemented transactions under the transmission capacity constraints. Note that this curtailment rule takes into account loop-flows. Transactions are not curtailed based on the reliability level only.

2.2.5.3 Example

We consider in this example a three node grid. Demand is located at bus two and three respectively. For the sake of simplicity, we consider demand inelastic ($L_2 = 126$ and $L_3 = 90$). However, this strong assumption could be easily removed. We assume the marginal costs of each plant, located at node 1 and 2, constant. The supply curve at node one is given in Figure 2-1. The supply curve at node one is given in Figure 2-2. Generators at node 2 are more expensive.

We analyze two situations. In the first one, there is no capacity constraint. The price of power is equal to 1. The production at node 1 is 120 MW and 96 MW at node 2.

In the second case, the transmission capacity of line 1-2 is reduced to 30 MW. Consequently, some output has to be shifted from generator 1 to generator 2 if the pattern of injection is to remain optimal under these new physical characteristics. More precisely, at the optimum, 90 MW are generated at node 1 and 126 MW are generated at node 2. The corresponding nodal prices are 2 and 12.

A set of transactions

We have to consider a set of transactions resulting in an optimal injection pattern.

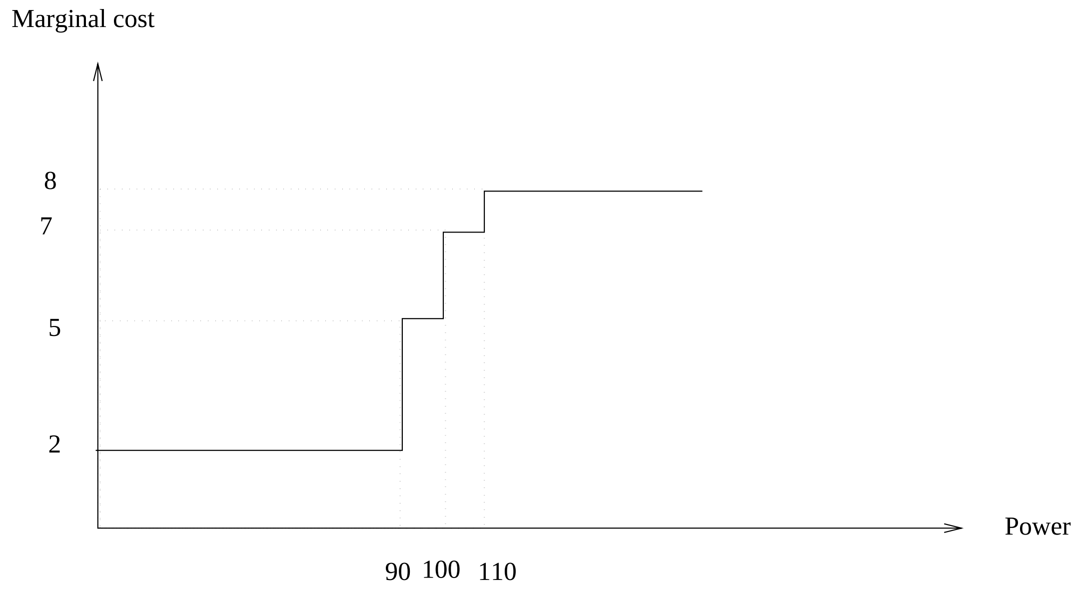

Figure 2-1: Supply curve at node 1

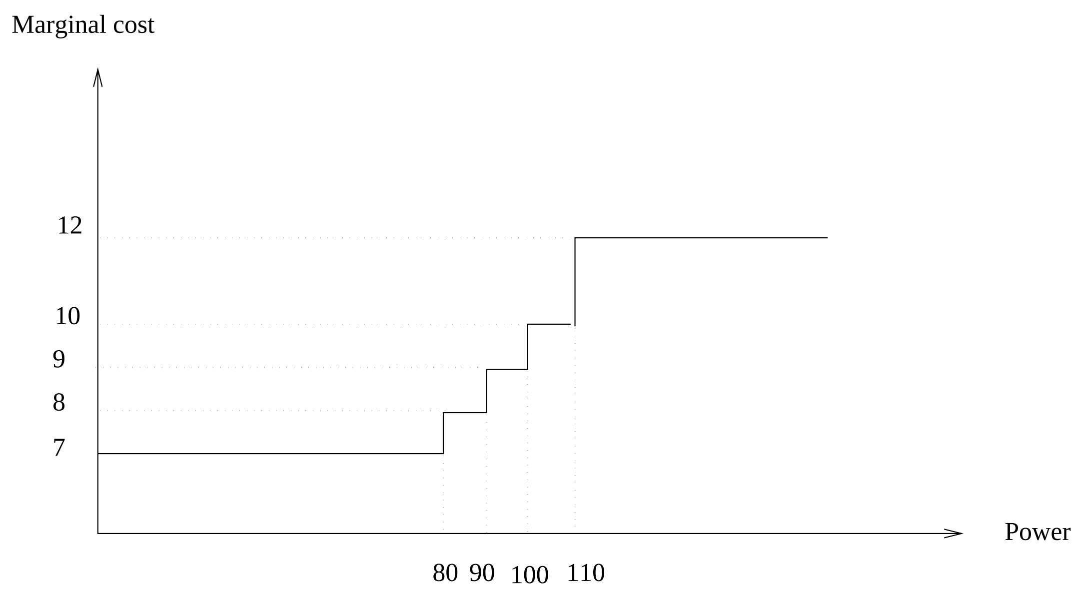

Figure 2-2: Supply curve at node 2

Among the many possibilities, we choose the following one:

Number	*From*	*To*	*Quantity*	*Value*
(1)	$G_2(12)$	L_2	16	∞
(2)	$G_2(10)$	L_2	10	∞
(3)	$G_2(9)$	L_2	10	∞
(4)	$G_2(8)$	L_2	10	∞
(5)	$G_2(7)$	L_2	70	∞
(6)	$G_1(2)$	L_1	90	∞
(7)	$G_1(5)$	$G_2(12)$	10	7
(8)	$G_1(7)$	$G_2(10)$	10	3
(9)	$G_1(8)$	$G_2(12)$	6	4
(10)	$G_1(8)$	$G_2(9)$	4	1
(11)	$G_2(7)$	$G_1(8)$	10	1
(12)	$G_1(8)$	L_2	10	∞

$G_2(12)$ represents the generator at node 2 with a marginal cost equal to 12.

How were chosen the figures in this example? There are two situations. Constrained and unconstrained, situation 1 and situation 2, respectively. Transaction (2) considered together with transaction (8) is equivalent to having $G_1(7)$ supply L_2. Thus, when they are both implemented, G1 produces, which is optimal. When the second one is curtailed, then G2 produces, which is also optimal under the new physical constraint. Thus, the set of transactions have to be considered pair by pair. There exists a mapping between curtailing one of those two transactions and the decisions a centralized grid operator would make.

All these transactions have requested access to the grid. The value of a transaction between a generator and a load is infinite because of the assumption of non-elasticity. However, the value of a transaction between two generators is equal to the difference in marginal costs between these two generators. This reflects the fact that the best strategy in case of a contingency is first to re-dispatch generation before curtailing end-users. When there is no transmission capacity constraint, one can easily check that they can be all implemented and that the resulting pattern of injection is optimal.

If, for instance, a line goes out of service and the transmission capacity on line 1-2 is reduced down to 30 MW, some transactions will have to be curtailed. It is possible to check that by curtailing transactions (7), (8), (9), (10), the resulting pattern is optimal given the new physical constraint. We can note that these four transactions are not the lowest value transaction. At the optimum, transaction (11) is still implemented even though it has the lowest value of all transactions.

This fact can be explained easily in the light of loop flow issues. Assuming a DC load flow approximation, transaction (11) creates a counter-flow on the congested line. Thus, even though its economic value is modest, it does not use transmission capacity but, on the contrary, creates more transmission capacity.

2.2.5.4 Characteristics of the price-reliability menu and interpretations

These results show that the notion of offered reliability of service is locationally dependent. Even a highly valuable transaction will have to be curtailed very often if it causes a flow on a frequently congested line. Thus, the menu of price/reliability has also to be dependent on the path of injection and the path of retrieval. For each couple (i, j), we denote by $r_{ij}(\mu_{ij}^0)$ the offered level of reliability. μ_{ij}^0 is the index of the contract. We take this probability equal for each μ to the estimated probability that the nodal price between i and j is less than μ_{ij}^0. The problem of the grid operator is to choose, for a given couple of nodes i,j, the price of contract μ_{ij}^0. We denote such price $P_{ij}(\mu_{ij}^0)$. The objective of the grid operator is to induce the users of the grid whose economic value of the transaction is v to choose the contract indexed by μ_{ij}^0 so that $\mu_{ij}^0 = v$. The condition for this self-selection process to be successful is

$$\frac{dP_{ij}}{d\mu_{ij}^0}(\mu_{ij}^0) = \mu_{ij}^0 \, \frac{dr_{ij}}{d\mu_{ij}^0}$$

This relationship can be integrated in order to obtain the price menu. The constant of integration is taken equal to zero in order not to restrict the use of the grid above the efficient level.

The resulting path-dependent menus are not all independent. In particular, the probabilities r_{ij}, which constitute the most important input in the pricing scheme, can be derived through distribution factors, from the knowledge of the joint probability distribution of transmission spot values, line by line.

First, the total price for a menu can always be negative if the density of probability is non-zero for $\mu_{ij} \leq 0$. For instance, if a seller chooses a level of reliability $\mu_{ij}^0 \leq 0$, the transaction will always be implemented when the difference in nodal prices between the two nodes of interest is negative. This contract will always increase the transfer reliability of the grid by creating counterflows on some congested line. Thus, the fact that this transaction is rewarded is understandable.

Another way to interpret this is to say that the buyer of the contract offers the grid operator the option of curtailing its transaction.

Second, the relationship between the price reliability menu from i to j and from j to i has to be defined.

We note that:

$$\frac{dr_{ji}}{d\mu_{ij}^0}(\mu_{ij}^0) = \frac{dr_{ij}}{d\mu_{ij}^0}(-\mu_{ij}^0)$$

Therefore, we can obtain the simple relationship between P_{ij} and P_{ji}.

$$P_{ij}(\mu_{ij}^0) = E(\rho_j - \rho_i) + P_{ji}(\mu_{ij}^0)$$

In terms of option theory, this result is the equivalent of the put-call parity setting the relationship between the value of the option to sell and the value of the option to buy.

Finally, considering point-to-point reliability menus, one might wonder whether those menus are independent. More particularly, let us consider three nodes i, k, j and let us compare the menus P_{ik}, P_{kj} and P_{ij}.

If the difference in nodal prices between i and k is perfectly correlated to the difference in nodal prices between k and j, then the following result holds:

$$P_{ij} = P_{ik} + P_{kj} \tag{2.8}$$

Proof: we denote μ_{ij}, μ_{ik}, μ_{kj} the difference in nodal prices between i and j, i and k, k and j respectively. If μ_{kj} is perfectly correlated to μ_{ik}, there must exist a monotonic function f so that $f(\mu_{ik}) = \mu_{kj}$. Let us denote the function $g = (1+f)^{-1}$. We assume that the value of μ_{ik} follows a law of probability given by its density function f_{ik}. Since, $\mu_{ij} = \mu_{ik} + \mu_{kj}$, all other probabilities densities can be derived from f_{ik}.

For instance,

$$f_{kj}(\mu_{kj}) = \frac{df^{-1}}{d\mu_{kj}} f_{ik}(f^{-1}(\mu_{kj}))$$

Likewise,

$$f_{ij}(\mu_{ij}) = \frac{dg}{d\mu_{ij}} f_{ik}(g(\mu_{ij}))$$

To a given contract choice μ_{ij}^0 on the main path ij, we associate two contracts on the path ik and kj respectively through the relationships:

$$\mu_{ik}^0 = g(\mu_{ij}^0)$$

$$\mu_{kj}^0 = f(\mu_{ik}^0) = f(g(\mu_{ij}^0))$$

By definition of the function g, we have:

$$\mu_{ik}^0 + \mu_{kj}^0 = \mu_{ij}^0$$

It is also possible to prove that all three contracts have the same level of reliability.

$$r_{ij}(\mu_{ij}^0) = \int_{\mu_{ik}+f(\mu_{kj}) \leq \mu_{ij}^0} f_{ik}\, d\mu_{ik} = \int_{-\infty}^{g(\mu_{ij}^0)} f_{ik} d\mu_{ik} = r_{ik}(\mu_{ik})$$

Likewise, it is possible to show that $r_{ik}(g(\mu_{ij}^0) = r_{kj}(f(g(\mu_{ij}^0))$.

Then, the price $P_{ij}(\mu_{ij}^0)$ can be computed as follows:

$$P_{ij}(\mu_{ij}^0) = -\int_{-\infty}^{\mu_{ij}^0} \mu_{ij} f_{ij}(\mu_{ij}) d\mu_{ij}$$

By changing the variable of integration, this expression can be shown to be equal to :

$$P_{ij}(\mu_{ij}^0) = -\int_{-\infty}^{g(\mu_{ij}^0)} (\mu_{ik} + f(\mu_{ik})) f_{ik} d\mu_{ik}$$

Likewise,the price menu P_{kj} can be computed:

$$P_{kj}(\mu_{kj}^0) = -\int_{-\infty}^{f^{-1}(\mu_{kj}^0)} f(\mu_{ik}) f_{ik} d\mu_{ik}$$

By subtracting these two values, we obtain:

$$P_{ij}(\mu_{ij}^0) - P_{jk}(\mu_{jk}^0) = P_{ik}(\mu_{ik}^0)$$

However, the assumption of perfect correlation between all point-to-point transmission prices is too strong. When there is no perfect correlation between the node-to-node values of transmission capacity, relation (2.8) no longer holds. This reflects the fact that there is a value having two transactions implemented at the same time.

2.2.5.5 Other applications of priority service

The concept of priority service may be applied in many different ways. We propose in this section to present an alternative to price reliability menus, whereby the transmission provider does not commit to a specific level of reliability but only to reimburse a given amount of money if transmission is not granted in real time. Thus, the posted menu is now P_{ij}, μ_{ij} instead of P_{ij}, r_{ij}. μ_{ij} now represents a reimbursement fee paid by the transmission provider to the customer whenever the transaction is not implemented.

The term r_{ij} now corresponds to the probability of the μ_{ij} contract being implemented. Even though it can be used by the transmission provider in order to inform customers, there is no commitment on the part of the transmission provider to provide a given level of reliability. As before, the matrix $P_{ij}(\mu_{ij})$ can be designed in order to ensure the optimum self-selection properties. In particular, a transaction worth v will receive with the probability r_{ij} the amount $(v - P_{ij})$ when the transaction is implemented and $(\mu_{ij} - P_{ij})$ with the probability $(1 - r_{ij})$ when the transaction is not implemented. μ_{ij} will be chosen by the transaction in order to maximize the expected gain. The first-order condition states:

$$(v - \mu_{ij}) \frac{dr_{ij}}{d\mu_{ij}} + (1 - r_{ij}) - \frac{dP_{ij}}{d\mu_{ij}} = 0$$

If the transmission provider chooses its price menu so that $(1 - r_{ij}) = \frac{dP_{ij}}{d\mu_{ij}}$, then the transaction will choose a level of insurance μ_{ij} equal to the value of its transaction v. If we integrate the previous condition, we find:

$$P_{ij}(\mu_{ij}) = \mu_{ij}\,(1 - r_{ij}) + \int_{-\infty}^{\mu_{ij}} \mu \frac{dr_{ij}}{d\mu}\, d\mu$$

This price includes two parts. The term $\int_{-\infty}^{\mu_{ij}} \mu \frac{dr_{ij}}{d\mu}\, d\mu$ corresponds to the priority charge already described in the first part of this section. The first term $\mu_{ij}\,(1 - r_{ij})$ is the price of an insurance premium. Thus, this implementation scheme is nothing more than the traditional priority service implementation coupled with the provision of insurance contracts.

The real-time implementation of transactions is made by minimizing the total payment to transactions.

2.2.5.6 Long-term priority service contracts

As presented in the previous sections, priority service is proposed for each period and it generally leads to efficient rationing thanks to the existence of uncertainty in the level of demand. We can extend the application of priority service to multi-period contracts, where the transmission provider proposes a price/reliability menu over several periods.

The value of a transmission link is very volatile and amplifies power demand volatility. On the other hand, the marginal costs of generation are quite stable over time and most of the demand can be forecasted on a long-term basis. This explains why some generators enter in long-term bilateral deals. However, these bilateral transactions may still want to remain responsive to the price of transmission and choose their production pattern according to the value of transmission without entering the costly and time-consuming process of spot market trading. This flexibility can be achieved with non-firm bilateral contracts. Thus, most of the market participants can avoid incurring the transaction costs associated with spot pricing.

Not only do such multi-periods contract enable one to cap the costs of transportation for its buyers and avoid spot trading, but it also can serve as a basis for congestion management.

2.2.6 Adjustment curves

The separation between the power trading process and the centralized allocation of scarce transmission resources is at the heart of the adjustment curves proposal presented in [23]. Power is traded through different types of transactions: bilateral transactions, multi-lateral transactions, power exchange, marketers, etc. Each transaction bids at each node an adjustment curve reflecting their willingness to be curtailed at this node. This is truly meaningful for multi-lateral trades where expensive generation can be substituted for by inexpensive generation in order to avoid high transmission rates. Each transaction values transmission capacity differently, depending on the amounts of generation and load resources available. Each market (or multi-lateral transaction) lets the grid operator know how much it values transmission through the adjustment bidding curves. The grid operator then constructs for each line a demand function and derives from it a price for transmission capacity.

As already stated, an entirely bilateral transaction cannot, in general, bid for adjustment. Since it involves only one generator, the room for adjustment is limited to the own price elasticity of the load. With transactions involving several generators, some output from an inexpensive generator may be substituted for the output from a high cost generator. For instance, a single company owning several generators can produce a meaningful set of adjustment curves. Likewise, a power exchange is a perfect candidate for the adjustment curve bidding process since the adjustment curves can be derived directly from the bidding curves of the exchange participants.

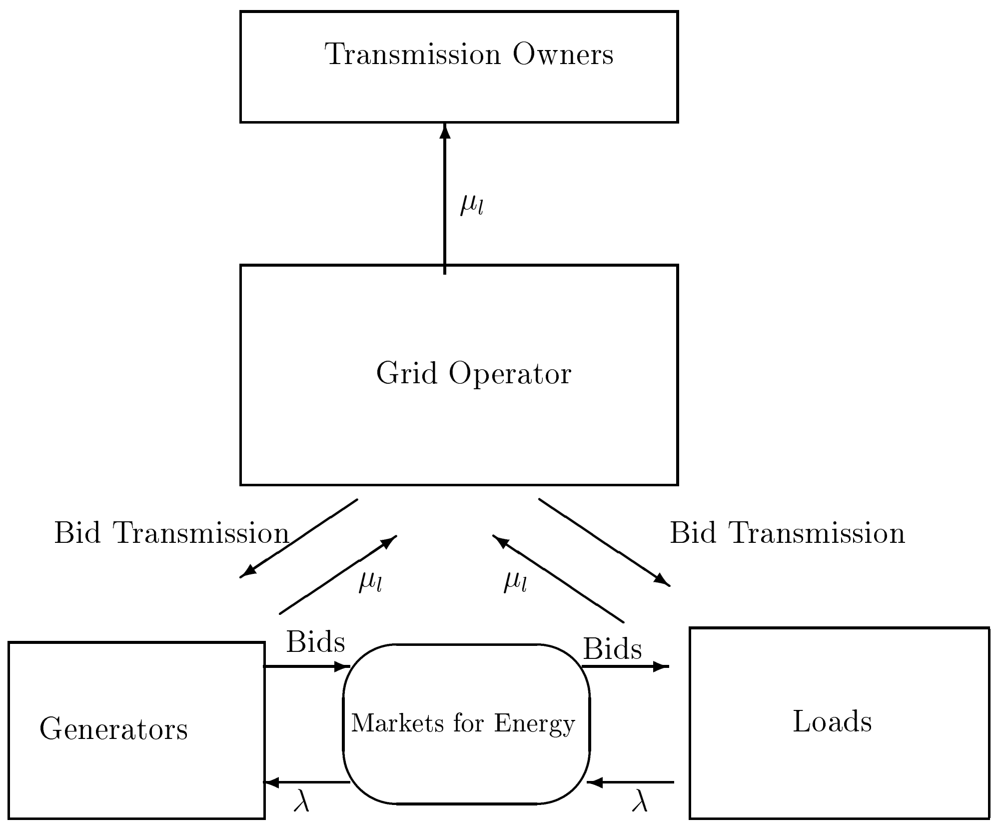

Figure 2.2.6: Adjustment curves

Whether or not these prices reflect the value of transmission depends on whether or not the aggregate value placed on capacity by the different markets reflects its true value. The answer to this question depends, in very general terms, on the individual efficiency of the underlying energy markets, their ability to produce adjustment curves that reflect the value of transmission and the way those markets are related.

In a recent proposal for transmission pricing, the Midwest ISO proposes a pricing scheme very similar to adjustments curves. Bidding is not mandatory and the price of transmission is essentially determined by the power exchange. Likewise, adjustment bidding curves are the main element of the congestion management scheme in California.

A simpler way to handle the coexistence of bilateral trades and a power exchange consists in setting the price of transmission through the power exchange and applying these charges to the bilateral trades. Bilateral trades will, in general, always be implemented but at a price the traders have no control over. In concept, this is the simplest form of the adjustment bidding curve with two markets: the power exchange and the bilateral market. However, because of this simplicity, this pricing scheme may discourage some generators from entering the bilateral market, because they have no control over the price they will pay. This situation may be acceptable for low cost generators, knowing that the transmission price, as long as it remains close to its expected value, will not change the profitability of the transaction. However, generators at the margin will certainly prefer to bid into the power exchange.

The iterative pricing scheme and the tradable transmission rights scheme can easily accommodate the existence of several markets for power. Since a price for transmission exists in these two schemes, systems users (either bilateral or multilateral trades) will incorporate this price in their decision making. In particular, the power exchange, instead of minimizing total generation costs only, will also include transmission costs.

2.2.7 What distinguishes the above pricing mechanisms

2.2.7.1 Unbundling power / transmission services

Traditionally, seen as two different and opposite types of industry structure, the bilateral and the Pool-co models can also be taken as two extreme instances of the same structure. On the one hand, the need for long term commitment in the PoolCo model creates the need for financial hedging instruments. On the other hand, the need to cope with uncertainties in the bilateral model calls for spot transactions.

Under open access, power is likely to be traded on different markets and through different types of transactions. We can envision several power exchanges and power marketers co-existing with a set of long term bilateral transactions [24].

The transmission pricing scheme, whatever it is, will have to cope with this variety of transaction types.

As we saw earlier, the value of transmission services cannot be completely unbundled from the energy trading process. However, the role played by the grid operator in the energy trading varies from one model to the other. Whereas the grid operator plays an active role in the Pool-co model, its role is limited to handling adjustment bidding curves and is almost nonexistent in the trading process for transmission rights and in the iterative pricing scheme, respectively.

2.2.7.2 Exchange and centralization of information

The different models of industry structure also differ by the degree of information centralization. Whereas in the iterative pricing scheme and in the Pool-co model, generators have to give away some information about their cost curves, this information can be kept secret with the tradable permits and the adjustment curves.

These considerations may become central in a context of imperfect competition.

2.2.7.3 The trading process

In the Pool-co and the iterative pricing model, prices are set once and for all. These prices are the equilibrium prices and no trade can take place away from this equilibrium. The necessary management of risk exposure is made through derivative contracts.

In a more decentralized set-up, trading power can take on many different forms and the price for delivery of power at a given date varies in time with the expectations of the market participants.

2.2.8 Some assumptions

2.2.8.1 All pricing mechanisms lead to the same result

All of the pricing mechanisms discussed so far lead to the same dispatch. In theory, the generation plants are operated as if they were owned by a single, integrated utility.

In the Pool-co model, competition between market participants forces their bid down to the level of their marginal cost function. The transmission provider subsequently performs the traditional Optimal Power Flow.

In a tradable permit model, the cost reduction behavior of generators and the rent seeking behavior of marketers and transmission rights owners drives the prices to the saddle point of the constrained optimization problem.

The iterative pricing model can also be considered as a two-level optimization tool and is currently used in some integrated utilities.

The fact that all schemes lead to the same physical dispatch, however, is the result of very strong assumptions. The different pricing schemes should not be compared one to the other under such perfect assumptions but, on the contrary, should be judged on their ability to alleviate the consequences of imperfect market conditions. We have listed several assumptions we consider essential to a thorough analysis of short-run pricing issues.

2.2.8.2 Different exposure to market power issues

Up until now, we have assumed that market participants are price takers. However, the primary market may be dominated by some players, able to influence the price of power. This situation may be worsened by transmission constraints and the associated local market power. Much has been written about imperfect market conditions [25], [27].

2.2.8.3 Markets do not reach instantaneously equilibrium

As already seen, the equilibrium of the trading process is equivalent to the optimal operation of the generation and transmission resources. However, when the demand is constantly changing, it is difficult to assume that the markets are always in equilibrium and it is even impossible to define an equilibrium. The concept of static equilibrium has to be replaced by the concept of a moving equilibrium. Thus, at each time, the prices may be different from the static equilibrium prices.

2.2.8.4 Initial conditions matter

As the power industry is moving into the competitive world, some transmission contracts may still be carried over. Those contracts, not subject to short run transmission pricing rules, may compromise the efficiency of the pricing mechanism.

2.2.8.5 Transaction costs

The above described pricing schemes involve different types of market structures and consequently different types of transaction costs. This fact may influence the efficiency of the short-run dispatch of resources. For instance, a holder of a long term bilateral contract may not be willing to incur the transaction costs related to the trading on the secondary market of transmission rights even though the price of those rights may be higher than the value of the transaction. In contrast, such discrepancy could not happen in a mandatory Pool-co model.

Likewise, we should recognize that the computational efforts involved in the above pricing schemes vary from one solution to another.

2.2.9 Which pricing scheme? - Need for new models

Under the assumption of perfect market conditions and assuming the markets are always at the equilibrium, all transmission pricing schemes described in this thesis lead to the same dispatch of generation resources. This strong result contributes to shed a new light on the on-going debate between proponents of a particular scheme versus another. In light of this result, such discussions appears pointless if they are taking place under the assumptions of perfect market conditions.

However, one of these pricing schemes has to be implemented. Thus, it is not under the assumptions above mentioned that this choice can be made. The policy maker has to go beyond these traditional assumptions and resort to new tools. More complex modeling of transmission pricing can still be used. Several examples of market power analysis generated by transmission constraints have been put forward [25]. We will propose in the next section some dynamic allocation schemes acknowledging the existence of dynamics in the reaction of price changes. Finally, new approaches to transmission pricing, based on data analysis can be envisioned.

2.3 Dynamic pricing schemes

As outlined in the previous section, it is not under the assumption of perfect markets that policy makers can decide which short-term pricing scheme should be implemented. In order to help shape this policy issues, we introduce in this section some new models for transmission pricing, recognizing that perfect market conditions not always prevail.

2.3.1 Real-time pricing

This congestion management scheme rests on the interpretation of transmission prices μ_l as control variables and recognizes the existence of dynamics in the market reaction to price changes. Market participants not always react immediately to price changes. There exist some information delays.

Through the setting of transmission prices, the transmission provider controls line flows and make sure that they remain below the maximum values. Thus prices are changed in real time in order to influence the energy trading process. However, as emphasized in the previous sections, demand functions parameters are not known to the transmission provider, making the optimal control even more difficult.

The objective function

The objective function of the transmission provider is to minimize the value of unused transmission capacity, while leaving transmission flows below the maximum transmis-

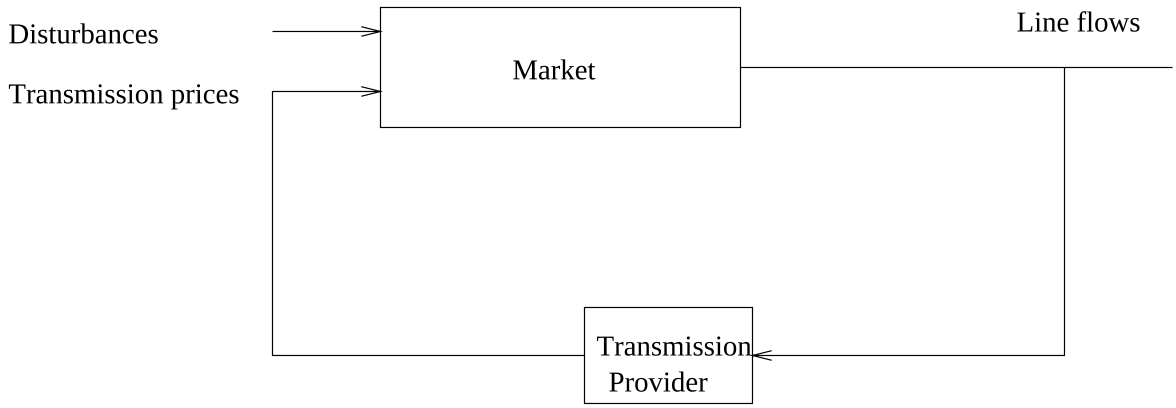

Figure 2-3: Real-time pricing

sion capacity value:

$$\min_{\mu_l} \mu_l \ (K_l - F_l)$$

Proof: This term is always positive and it can be made equal to zero by either setting a price equal to zero or adjusting it so that $F_l = K_l$. These conditions correspond to the optimal pricing conditions.

The price setting problem can then be stated as a stochastic optimal control problem. Some parameters of the problem, in particular the market dynamic parameters are unknown but can be learned by the transmission provider.

Because of the dynamics in market participants reactions, the optimal prices will not result in transmission flows equal to transmission capacity when prices are strictly positive. Instead, transmission flows will remain below maximum transmission capacity.

2.3.2 Dynamic allocation of non-firm transmission capacity

We introduce here a new scheme for the dynamic allocation of transmission capacity. Market participants have expressed the need for the possibility to secure early in time transmission rights. Such concern is taken into account in the concept of tradable transmission rights [14] and was presented earlier in the thesis. We also expressed doubts over the tractability of this scheme. In contrast with tradable transmission rights, a transmission provider plays a central role in the scheme we introduce here. He has the responsibility of allocating and pricing ex-ante transmission rights for each period in the future. These transmission rights are not tradable on a secondary market.

We assume that a transmission provider at each period posts prices for the use of the transmission grid in the future. However, in order to achieve ex-post optimality and to cope with short-term uncertainties, these transmission rights are not firm. Several classes of transmission rights co-exist and have to be priced consistently.

Through prices, a transmission provider controls the rate of arrival of transaction on the system. In real time, the transmission provider controls the use of the system and effects which transactions have to be turned-off.

In essence, this transmission scheme proposal builds on both the real-time pricing and priority service. The spot price for transmission lines is thus set in real-time by a transmission provider as a function of:

- real-time requests for the use of the system
- curtailment of non-firm transactions

This arrival process is represented in figure 2-4. At time t several transactions request the use of the system in the immediate or remote future at different levels of priority firmness.

At time t, a transmission provider posts the price for point-to-point service for the different dates T in the future. This price also depends on the level of priority firmness. This level is represented by the amount of money a transmission provider will reimburse the transaction in case of non-implementation. The higher this amount, the higher is the probability of implementation. Let us denote by $P_{ij}(t, T, \mu_{ij})$ this price. The price for multi-period contracts such as these represented in figure 2-4 is the sum $\int_t^{T_1} P_{ij}(t, T, \mu_{ij})\, dT$. For each period (t, T) and each class of priority μ_{ij},

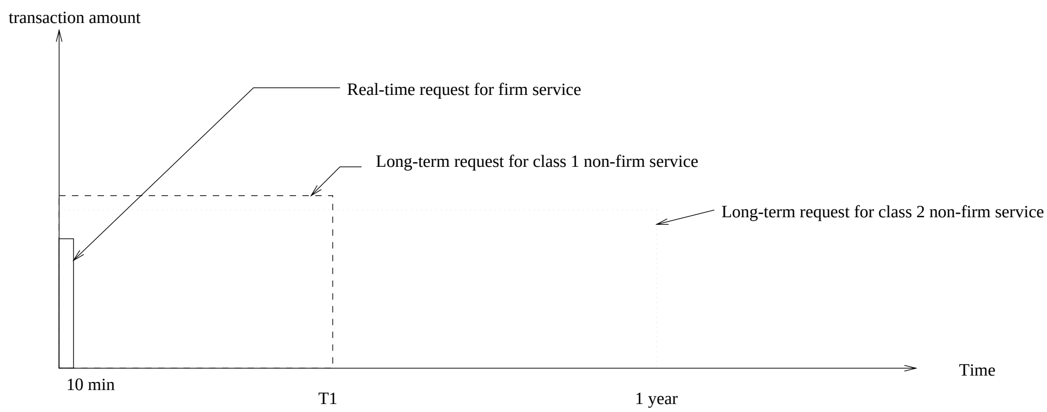

Figure 2-4: dynamic Peak-load pricing

there is an associated probability r_{ij} of implementation. Even though a transmission provider does not commit to this probability, it can be advertised so that transactions can make their choice.

2.3.2.1 Self-selection

Similarly to priority service, a transaction of value v will expect to make a profit equal to:

$$v\, r_{ij} + \mu_{ij}\,(1 - r_{ij}) - P_{ij}$$

The optimal choice of the transaction is thus characterized by:

$$v = \frac{1}{\frac{d\, r_{ij}}{d\, \mu_{ij}}} \left(\frac{d\, P_{ij}}{d\, \mu_{ij}} + \mu_{ij} \frac{d\, r_{ij}}{d\, \mu_{ij}} + r_{ij} - 1 \right) \tag{2.9}$$

thus, from the choice of μ_{ij}, a transmission provider can derive the value of the transaction v and use it in real-time implementation in order to maximize the values of transaction on the grid.

2.3.2.2 The arrival process

The previous self-selection property is valid under any price-reliability menu. However, this menu has to be designed in order to maximize the value of the transmission grid in real-time. This result was achieved in static priority service by imposing the condition $v = \mu_{ij}$ resulting from a static optimization. In this scheme, we do not impose such a condition but rather consider a dynamic optimization. Prices are considered control variable and influence the arrival rate of transaction on the system. Let us denote by $S_{ij}(t, T, \mu_{ij})$ the total amount of allocated transmission capacity between i and j at time t for period T with priority μ_{ij}. We assume that between t and $t + dt$, this quantity increases by an uncertain amount:

$$dS_{ij}(t, T, \mu_{ij}) = f_{ij}\left(P_{ij}(t, T, \mu_{ij}), S_{ij}(t, T, \mu_{ij})\right)\, dt + \sigma\, dz \tag{2.10}$$

This increment is dependent on the price but also on the amount of allocated transmission capacity. This formula reflects the fact that for a given price, only a part of the total demand will be allocated during this period. Thus, through prices, a transmission provider can influence the rate of arrival of transactions of the system, and as a consequence, can modify his expectations about the total demand for period T.

2.3.2.3 Real-time operations

In real time, a transmission provider sets the spot prices of transmission lines $\mu_l(T)$. This price represents:

- the price at which short-term bilateral transactions can get on the system. Since there is no uncertainty left in real time, short-term transactions from i to j have to pay the following price:

$$\sum_l (H_{li} - H_{lj})\, \mu_l(T)$$

- this prices also represents cut-off values for the curtailment of non-firm contracts. Whenever the value of a transaction v from i to j is less than the term $\sum_l (H_{li} - H_{lj})\,\mu_l(T)$, the transaction is curtailed and the amount of money μ_{ij} is paid back to the transaction.

Note that this curtailment rule, along with the condition (2.9) sets the structure of price-reliability menus since in real time valuable transactions will be curtailed as a last resort, they will pay a higher price. However, there are no explicit formulaes for the expression of prices. They are the result of a stochastic optimal control problem, instead.

2.3.2.4 The objective function

Like in the real time problem, the objective of a transmission provider is to minimize in real-time the value of unused transmission capacity

$$\min_{\mu_l(T)} \sum_l \mu_l(T)\,(K_l - F_l)$$

while accepting all real-time requests and remaining below the maximum available transmission capacity.

2.3.2.5 Similarities with other pricing schemes

Compared to the long-term version of priority service presented in 2.2.5.6, the learning process by a transmission provider is explicitly taken into account. As transaction request arrive to a transmission provider, they provide him with a valuable information on future demand. Moreover, this process can be influenced by the transmission provider through his pricing policy: this is an active learning process.

2.3.2.6 Coupling the pricing-investment decisions

As a transmission provider allocates transmission capacity for future use, he also has to make investment decisions. These two problems can be coupled into a single problem in which pricing decisions depend on the possibility of investment and inversely, investment decisions depend on the information collected through long-term commitments. For instance, even though a transmission capacity still not exists, it can be allocated on a non-firm basis. The mere possibility of investment has to be incorporated in the pricing decisions. Conversely, securing long-term transmission contracts will help reduce the information asymmetries between users of the transmission grid and a transmission provider. Thus, the additional uncertainties created for the transmission provider by the asymmetries of transmission and generation are greatly reduced through long-term commitments.

Effectively, this pricing scheme achieves a centralized form of the long-term coordination task described in section 2.4.

2.4 Long-term coordination

In the same way that short-run coordination has to ensure that transmission capacity constraints are not violated, some form of coordination has to be established in the long-run in order to balance the long-run cost of generation with the costs of transmission capacity.

A set of financial contracts based on short-run prices of transmission capacity can play this role. For instance, futures contracts on transmission capacity, whether they are line-by-line or point-to-point contracts, can give an indication, for a given period of time, of the expected price of transmission capacity. If they are traded freely on the market, the prices of these contracts can incorporate private information about costs and can change over time as market players commit to particular investment projects. Such contracts can thus serve as a basis for long-run coordination. Likewise, priority service contracts, introduced in [22], give a more detailed vision of future transmission prices since they are based not only on the expected price of transmission, but also on the distribution of the probability of these prices. They can be used by market participants as a basis for valuing complex investment decisions.

However, the interaction between the monopolistic transmission provider and these market may be intractable. For this reason, a centralized dynamic transmission capacity allocation system may be envisioned. We present in the last part of this section such a scheme.

2.4.1 Future contracts

Even before considering uncertainties in the future level of demand, the unbunling of the power industry creates structural informational asymmetries issues in the long-run. In particular, the transmission owner does not know future generation siting decisions.

Even though demand could be accurately forecasted, generation investment decisions could not be forecasted since the associated locational costs of production are unknown to the transmission owner. This critical and scattered information thus need to be incorporated in the price setting process.

2.4.1.1 Supply and demand functions in the long-run

Using the same notations as in section 1.3.3, we interpret the investment optimality equations in terms of supply and demand functions:

Given an installed amount of generation capacities K_{ia}^G and transmission capacities K_l^T, the terms:

$$\sum_t \sigma_{i,t}^a$$

$$\sum_t \mu_l^t$$

represent the long-run marginal value of transmission capacity. They can be interpreted as the price market participants are expected to be willing to pay today for the use of this capacity in the future. We should note that they depend on the current amount transmission and generation capacity K_{ia}^G, K_l^T.

Likewise, from the capacity cost function C_{ia}^G and C_l^T, it is possible to derive the marginal costs functions, which in turn can be interpreted as supply function. The optimal equations (1.7) and (1.8) are then equilibrium conditions between supply and demand functions.

If we recall that $\sigma_{ia}^t = max(\lambda^t - \sum_l H_{li}\, \mu_l^t, 0)$, we can then see how the expected future price of transmission services enter into the long-run generation investment optimal decisions.

Thus, in the same way as the variables μ_l can ensure in the short-run the coordination of the power industry, some coordination needs to be established for investments. In particular, market participants need to get an idea of the evolution of transmission prices in the future. These prices in particular depend on the amount of transmission capacity invested but also on the pattern of generation capacity investments.

2.4.1.2 Future contracts

In order to achieve this coordination task, one possibility is to use the price discovery properties of futures market. If contracts on the future value of μ_l could be created, they would incorporate all the necessary information and would reflect the future price of transmission services.

A future on the price of transmission service is a contract between two market participants whereby one of the party agrees to pay the short-term price $\mu_l^{t_0}$ of a transmission service for a given period in the future against a fixed price, the price of the future.

These future prices could be used by generators in order to value their locational decisions and by the transmission provider in order to make investment decisions, which in turn would affect the future price. The discounted sum over several periods of all future prices could then be traded-off in a decentralized way against the locational cost differential in production by generators or against the cost of transmission by the transmission owner as shown in the first chapter.

Thus, if the resulting future prices were above the optimal future value, some investments in generation or in transmission would be come profitable and would be carried-on. As a consequence, the futures price would be driven down. This stable feedback process would at the same time enable to incorporate private information about production costs.

The set of existing future contracts does not necessarily need to include all future dates but only some of them. However efficient these future market may be, they would however be unable to reflect the distribution spread of the transmission price around its expected value. It would then be unable to coordinate some of the properties of the optimal mix between transmission and generation presented in the first part of this thesis.

2.4.2 Non-firm contracts

Example: Let us consider a two-node system where the uncertain demand in located in A. An investor hesitates between locating his new power plant in A, for a cost I_A or in B, for a costI_B. The fuel cost however are different and $c_A > c_B$. The price of transmission from B to A is equal to μ. The risk profile in the two investment configurations is very different. On the one hand, if capacity is invested in A, the only risk involved is the total demand risk. On the other hand, if the new plant is built in B, the risk profiles now includes the transmission price risk. Thus, the investor has to trade-off a fixed gain on fuel costs against the volatile transmission price.

In order to balance this trade-off, the expected price of transmission services is not enough and the investors need to be provided information about risk probability distributions. The existence of option contracts may complete the existence of future contracts in providing an adequate picture of locational risks involved in generation investments.

2.4.3 Interaction between the transmission provider and market participants

The existence of a future market can be used by the transmission provider in order to value its investments and make investment decisions according to the rule presented in the first section:

$$k_l = \int_0^\infty e^{-\rho t} \mu_l(t)\, dt$$

However, the transmission provider should be aware of the fact that these prices reflect not only market expectations about future demand and generation supply, but also incorporates market expectations about its own future decisions on transmission investments. The transmission provider is thus involved in a strategic where information about future project is as important as the investment decisions themselves in coordinating transmission investments.

This power will obviously raise some policy issues in the third part of the thesis, which is concerned with the regulation of the transmission provider.

2.5 Remainder of the thesis

We presented in the first part of this thesis the notion of optimal dispatch and investments. The unbundling of the power industry raises new challenges since decision making power is split between market participants. The existence of coordinating variables, in the short-run and in the long-run ensures that generators and load make the appropriate decisions at the right time. However, even though we formulated for the transmission provider the conditions for optimal investments, the structure of the transmission industry and the associated incentive schemes still remain to be presented. This is the theme of the last part of this thesis.

Chapter 3

Industry Structure and Regulation

The coexistence of a single transmission grid with multiple market players represents one of the most important challenges of transmission pricing. A single transmission provider would benefit a monopoly position on transmission services. We will analyze in the first part of this chapter the extent of this monopoly power and will present some possible solution to curb it. Contrary to the gas industry, where the coexistence of several transportation providers is likely to curb market power, multi-ownership of transmission assets will not affect the dominant position of transmission providers. However, monopoly power is limited in the long-run by the ability of generators to locate close to the load. More than that, the inability of the monopolist transmission provider to commit to reasonable prices in the long-run may have disastrous effects on the the locational pattern of generation investments.

We will conclude this first part on the need to design new industry structure. Among them, we will distinguish a competitive market, cost-plus regulation and incentive regulation. We will introduce a framework for a competitive supply of voltage support technologies.

Part of this chapter is based on [26].

3.1 Monopoly structure

This first section illustrates the behavior of the transmission owner if pricing is not regulated. First, we assume that a single company owns all lines. We then relax this hypothesis in order to assess the potential benefits of a multi-owners scheme.

3.1.1 Short-run monopoly pricing

3.1.1.1 A monopoly pricing model

According to this first pricing model, the transmission owner is free to set the rates on each line. Each transaction will have to pay for all lines a specified rate t_l multiplied by the flow caused on this line by the transaction. This means that the transmission owner may have to pay some participants, including bilateral transactions. If those bilateral transactions were not given credit, they could be incorporated in another transactions (a pool for instance) and would reduce the fee of other transactions. Thus, they could sell their participation and would receive exactly the same amount. We propose here a second pricing mechanism aiming at charging counterflows while avoiding this kind of arbitrage opportunity.

The pricing rules are somewhat arbitrary since the payment to the transmission owner depends on the choice of orientation of line flows. We have to acknowledge this fact and let the transmission owner be able to choose a negative price. However, for simplicity, we can always assume that the orientation has been chosen so that the resulting price is always positive. This then reduces to assuming that the orientation is chosen positive for the total flow and negative for counterflows. In the end, the owner receives a positive rate multiplied by the flow on its line, but the mix of bilateral transaction and a pool requires one to establish such a complex mechanism.

If, in addition to bilateral transactions, a power exchange is also active, it will have to pay this fee for all the pool participants. The power exchange will then maximize the social welfare of the participants minus the cost of transportation. The resulting consumer surplus will enable the pool to pay the collective fee.

As a consequence of this process, the resulting economic equilibrium will be the solution of the following optimization problem 1:

$$\min_{P_i} \sum_i C_i(P_i) + \sum_i \sum_k H_{ki} P_i t_k$$

$$\text{st: } \sum_i P_i = 0$$

The solution of this problem is given by the following set of equations:

$$\frac{\delta C_i(P_i)}{\delta P_i} = \lambda - \sum_l H_{li} t_l = \rho_i$$

To each set of prices t_l corresponds a set of $P_i(t_1, ..., t_L)$.

The solution of this problem is very similar to nodal pricing, except that the multiplier of the constraints on the transmission capacity are replaced by the rate t_k. The prices are no longer reflecting scarcity but are exogenously set by the monopolist:

We can consider the flow on each line as the demand for this line. Given a set of prices, the demand for capacity on line l is equal to $\sum_l \sum_i H_{li} P_i(t_1, ..., t_L)$. We can easily show that this demand for transmission is downward slopping:

$$\frac{dD_l(t_1, ..., t_L)}{dt_l} = \sum_i H_{li} \frac{dP_i(t_1, ..., t_L)}{dt_l} = -\sum_i H_{li}^2 \frac{dP_i}{d\rho_i}$$

The term $\frac{dP_i}{d\rho_i}$ being positive, the demand is downward slopping.

We can then consider the monopolist as a multi-product monopolist, trying to maximize her profit, subject to the constraint that she can fulfill all the demand for capacity:

$$\max_{t_l} \sum_i \sum_k H_{ki} P_i(t_1, ..., t_L)$$

$$\text{st: } \sum_i H_{li} P_i \leq K_l$$

where $P_i(t_1, ..., t_L)$ is the result of the optimization problem 1:

The first order conditions give the following L equations:

$$\sum_i H_{li} P_i P_i = \sum_i H_{li} \frac{dP_i}{d\rho_i} \sum_k H_{ki}(t_k - \mu_k)$$

Thus, the price on the line are very likely to be way above the marginal cost.

Example

Let us consider the following two node example. An expensive generator (cost c_2) is located close to the demand (demand function is linear: $a - b\,Q = P$. Several inexpensive generators with the same marginal cost (cost c_1) are located a the other node (Total capacity K). The transmission monopolist can charge any price between 0 and $(c_2 - c1)$. We assume that generators in 1 will compete in order to supply power. In this case, even though there is no transmission capacity constraint, it is in the interest of the monopolist to charge the following price:

$$\mu = c_2 - c_1 \quad if a - b\,K \geq c_2$$
$$\mu = \frac{a - c_1}{2} \quad if a - b\,K \leq c_2$$

There exists however a situation where the transmission owner would be forced to lower their prices down to the marginal value of capacity: if there existed different lines on the same path, transmission owner would be forced through a Bertrand competition to lower their price. However, due to economies of scale, the optimum size of a line is much higher than the demand. There is only room for one line and one transmission owner.

3.1.1.2 Long-run Vs short-run monopolistic pricing

There is a limit however to the short-run monopolistic behaviors described above. Indeed, generators may decide in anticipation of short-run monopoly pricing to locate close to the loads. For instance, knowing that the transmission provider would appropriate all the generation rent, the generators at node 1 would never have invested at node 1. As a result, a monopolist would not make any profit. In order to avoid this, a transmission provider may want to set future prices higher than short-run monopolistic prices in order to create some incentives for investment in generation.

However, such long-run monopoly pricing may be difficult to create. in particular, if a monopolist is not able to commit to these future prices, market participants may still not want to invest by fear of being charged once they have invested a higher price.

3.1.2 Influence of multi-ownership

We now assume that different transmission lines are owned by different entities. Let us assume that all prices are positive and let us analyze the influence on different transmission rents of one transmission owner increasing its price.

$$\frac{dD_k(t_1, ..., t_L)}{dt_k} = -\sum_i H_{li} H_{ki} \frac{dP_i}{d\rho_i}$$

The sign of this depends on the product $H_{li}H_{ki}$ since $\frac{dP_i}{d\rho_i}$ is positive. When the product is positive, the two lines are complements. Increasing the price on one line decreases the demand for the other line. When the product is negative, the two lines are substitutes. Increasing the price on one line will generate a positive externality for the owner of the other line.

When the ownership of the grid is broken into multi-ownership, the transmission owners do not take into account these positive and negative externalities. Thus, when a transmission owner increases her price, a transmission owner generates as many externalities as there are other lines. The global effect can be a positive externality. Since this externality will be ignored by the transmission owner, she will set the price at a lower value than the single monopolist would have done. Conversely, if the global effect is a negative externality, a transmission owner will set the price at a higher value. its

The global effect of multi-ownership is hard to determine and depends on the signs of the cross products $H_{li}H_{ki}$, on the price elasticities at each node and on the ownership structure. However, since the lines are not always substitutes, multi-owner ship cannot be considered as a substitute for competition or perfect regulation.

3.1.3 Monopolistic supply of transmission capacity

In [29], the author assumes short-run prices are optimally set equal to the marginal value of transmission capacity and analyze the long-run consequence of having a single profit-maximizing entity investing in transmission capacity. This monopolists collects for each period the rent $\sum_l K_l\,\mu_l$. The discounted value of cash-flows $\int_0^T e^{-rt}\,\mu_l^t\,dt$ is a decreasing function of I_l and represents the price market participants are willing to pay for an additional unit of transmission capacity. Considered as a function of I_l, the author interprets it as a demand function for transmission capacity.

From this point of view, providing transmission capacity becomes a business in itself and the optimal grid condition (equation (1.6)) is nothing less than a marginal cost pricing rule for multiple products.

Let us consider the situation where a single unregulated monopolist has to design an investment policy and is rewarded based on the market value of transmission capacity. The profit of a transmission grid owner of the grid is equal to:

$$\max_{I_l} \sum_{l=1}^{L} (K_l^0 + I_l). \int_0^T e^{-rt} \mu_l^t.dt - k_l.I_l$$

$$\text{subject to } I_l \geq 0$$

The solution of this problem is given by:

$$k_l = \int_0^T e^{-rt}.\mu_l^t dt + (K_l^0 + I_l). \int_0^T \frac{d\mu_l^t}{dI_l} dt + \xi_l$$

The second term in this equation is negative and reflects the negative effect on the transmission owners profit from increasing the capacity. As pointed out in [29], transmission owners have no incentive to increase the capacity of their lines. This is consistent with the demand analogy. Monopolistic suppliers of capacity will tend to restrict their output in order to maintain a high price on infra-marginal units.

Granting the transmission rent to the owner of the transmission assets has been recognized for a long time as a bad incentive for investment [30]. However, the previous model shows that the ability of the transmission rent to reflect the need for investment is not the problem. Bad incentives stem from a monopolistic behavior whenever a single entity has the exclusive right to invest in transmission enhancements.

Building on this intuition, the following part of the thesis provides a framework for a competitive supply of transmission assets building on this intuition.

As we can see, even though a transmission allocation process may be regulated in the short-run, the existence of a single entity in charge of investments in transmission capacity may create incentives for under-investments and higher prices.

In order to get around this problem, we analyze in the next section a scheme where any investor is free to build a new line and collect the associated rent. We find that, under the assumption that there are no economies of scale, this scheme is efficient. However, this industry structure is not adapted to the current transmission technologies, which exhibit strong economies of scale. This analysis, nevertheless, is interesting from two different points of view:

- First, it uses the transmission rent as a common measure of the value of investment in transmission capacity and paves the way for incentive regulation based on the transmission rent.

- Second, the same pricing scheme may be implementable in other part of the transmission industry not pervaded by economies of scale. We expand in particular a framework for the pricing of voltage support and show how the same concepts developed for transmission capacity may lead to optimal capacitor banks investment.

3.2 Competitive supply of transmission capacity

3.2.1 Supply of transmission capacity without economies of scale

In this section, we assume that the cost of investment is proportional to the rate of investment $C_l(I_l) = k_l I_l$. Under this assumption, we show that a market-based pricing scheme gives the proper incentives for investment in transmission capacity and leads to the optimal investment policy.

If several investors are allowed to invest in transmission capacity, competition among them will ensure that an adequate level of capacity is supplied[24, chapter 8]. If a transmission capacity investment level is lower than its optimal value, some investors can make more profit by increasing capacity. Under free entry conditions, the economic profit made by transmission owners will be equal to zero at the equilibrium. The existence of markets for financial contracts enables the potential investors to value and hedge their investment.

This scheme is consistent with the optimality conditions for the investment trajectory thanks to the following model:

At time t, an increment ΔK_l of transmission capacity costs $k_l \Delta_l$ and is worth $\Delta_l \int_0^T e^{-rt} \mu_l(K_l(t), t) dt$. This value does not take into account the fact that the increment of capacity will decrease the value of the existing capacity, either because the investors do not already own transmission capacity or because they consider the enhancement unavoidable.

Assuming all profit opportunities are exhausted, these two values are equal and as a result:

$$k_l = \xi_l + \int_0^T e^{-rt} \mu_l(K_l(t), t) dt$$

$$\xi_l(t) \geq 0 \quad \xi_l(t) I_l(t) = 0$$

This relationship is very similar to the optimal condition already obtained. At time t, the long-run marginal cost of generation is equal to the discounted sum of marginal values. The transmission values are computed along the optimal trajectories. Thus, the coordination of the investment policy can be ensured by a free-entry mechanism. This result hinges on perfect market assumptions and the following discussion indicates how this mechanism may fail to provide the proper amount of transmission capacity.

The previous model assumed perfect certainty of the future states of the world. Indeed, when congestion turns out to be lower than expected, transmission capacity investors receive a rate of return lower than the normal rate associated with this level of risk. This makes up part of the risks of investing and is incorporated in the implicit expected rate of return.

However, when congestion turns out to be higher than expected, investors do not reap the full benefits from their investment. New capacity may be built by other investors to take advantage of the increased demand for transmission capacity. This potential outcome may modify the incentives for investments and could result in capacities lower than the optimal capacity under certainty.

Some people may argue that investors should be given a preemptive right or should have the exclusive right to invest for a given period of time in order to protect the value of their investment. It is argued that with such insurance, investors would invest the optimal amount of capacity.

We argue, on the contrary, that the rule of investment should not be modified and that only the definition of optimal capacity needs to be re-examined. With a new definition of optimal capacities, based on a dynamic programming approach, the incentives for investment generated by free entry are optimal.

The optimal control model presented in the first part of this thesis assumes perfect certainty and does not recognize the value of flexibility in an uncertain context. This concept is based on the theory of real options [12, chapter 8]. There is a value in delaying an investment since this decision enables one to collect more information on the expected states of the world. Thus, any time money is invested, this option disappears. Its value should be incorporated in the cost of investment. As a result, an optimal dynamic policy under uncertainty leads to a lower rate of investment in general, as is the case in the competitive scheme.

3.2.2 Supply of transmission capacity with economies of scale

The proposal for a competitive supply of transmission capacity ignores economies of scale in investments in transmission capacity. A more realistic cost of investment model is $C_l(I_l) = A_l + k_l.I_l$.

Thus, a zero profit equilibrium would lead to an under-supply of transmission capacity since in addition to the capacity-related costs, they would have to incur the non-capacity-related part of the cost A_l.

For this reason, a competitive supply of transmission capacity may not be suitable and the transmission industry should be structured as a regulated industry. A price cap regulation, if well designed, may conciliate incentives for optimal investment and pricing with full recovery of the non-capacity dependent part of the cost, as described below.

3.3 Competitive supply of voltage support

This section introduces a market-based pricing scheme for the provision of voltage support. Reactive power is usually considered to be an inexpensive resource, so that short-run efficiencies introduced in the dispatch of reactive power by such a scheme are likely to be negligible. However, such a statement is based on the assumption that there exists efficient capacitor banks to be switched in order to support terminal voltages. The critical goal of market based pricing scheme is then to provide in the long-run the right incentives to invest in voltage support technologies.

We will analyze in the first place the cost of providing voltage support. The short-run costs mainly consist of an opportunity cost related to an apparent power constraint for generators. For this reason, the price of voltage support is by essence related to the nodal price of power.

We will then assess the impact of market participants decisions on voltage support at each node. By using a linearized model, we will then assume that these effects can be superposed. This will constitute the basis for our pricing scheme proposal.

Having laid the basis of this short-run pricing scheme, we will turn to long-run incentives for investment in voltage support technologies. Contrary to transmission enhancement investments, the cost function for capacitors does not present economies of scale, making possible a fully decentralized and private incentive scheme for investment.

Finally, we will go over a critical appraisal of this pricing proposal and raise some critical issues worth investigating further.

3.3.1 Cost of reactive power

3.3.1.1 Introduction

We assume that there exist a uniform minimum and maximum acceptable voltage level. The choice of this technical standard is controversial and will have tremendous consequences on the price of reactive power. The tighter the constraints, the higher the price of reactive power will be. In the last part of this paper, we will go over potential schemes to overcome this uniform assumption. In practice, consumers are more or less sensitive to voltage levels.

For the time being, we take for given these voltage constraints at each node. In the decoupled real/reactive power, we focus on the net injection of reactive power at each node. The cost of voltage support is the cost of producing reactive power so that voltage at each node remains within the specified limits. They are two ways to produce reactive power:

- use of shunt capacitance
- generation based production of reactive power

We will analyze in turn the costs associated with each of these two possibilities.

3.3.1.2 Generation based production of reactive power

Reactive power (Q) is usually considered to be a by-product of real power (P) production. However, by modifying the exciter field reference level, it is possible to control the injection of reactive power. However, for technical reasons, the total apparent power $S^2 = P^2 + Q^2$ is limited $S \leq S_{max}$. consequently, the more reactive power is produced, the less real power can be injected into the grid. This constraint can be very expensive for low marginal cost units.

In the long-run, it is possible to relieve this constraints by implementing the right technical design modifications.

3.3.1.3 Shunt capacitance

It is possible to install variable shunt capacitances at each node in order to support voltage by switching capacitors up to a maximum number of capacitors. Neglecting the maintenance costs associated with this operation, the short-run cost of this operation are null.

In the long-run however, there is a one-shot investment cost associated with this possibility.

3.3.2 Minimum cost dispatch of reactive power

Because of the intricate link between the cost of reactive power and the cost of real power, the minimum cost dispatch of reactive power must take into account the cost of real power. The optimization problem can be stated as follows:

$$\min_{P_i,Q_i,b_i} \sum_{i=1}^{n} C_i(P_i) \tag{3.1}$$

subject to:

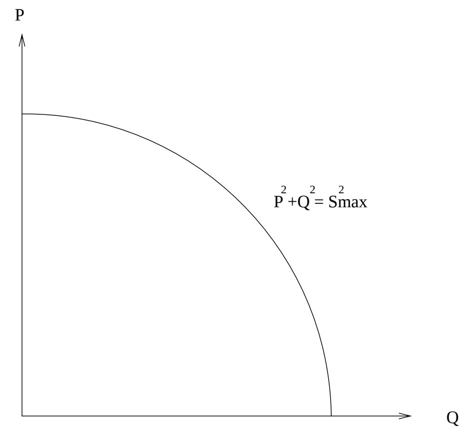

Figure 3-1: Apparent power constraint

$$
\begin{aligned}
V_i \le V_{max} &\quad \alpha_i \\
V_i \ge V_{min} &\quad \beta_i \\
P_i^2 + Q_i^2 \le S_{max}^2 &\quad \sigma_i \\
b_i \le b_{i,max} &\quad \chi_i \\
F_l \le K_l &\quad \mu_i \\
\sum_{i=1}^{n} P_i = 0 &\quad \lambda
\end{aligned}
$$

the optimization variables are real power, reactive power and the shunt capacitance.

The first two constraints represent the terminal voltage constraints. The third constraint is the apparent power constraint for generators and is represented in figure 3-1. The fourth constraint represent the maximum shunt capacitance at node i. The last constraint is a thermal transmission constraint.

Two indirect effects relative to voltage constraints have to be noted. First, as already said, the choice of reactive power sets a limit on the maximum real power output and has an indirect cost. Second, the resulting voltage profile determines the real power flow pattern. This may also generate indirect transmission costs by modifying the distribution factor matrix.

This optimization problem was partially performed by Hogan in [31]. However, in this paper, the author ignores the existence of variable shunt capacitance. As a result, the author concluded that voltage support constraint were quiet expensive and found substantial prices for reactive power.

In [32], the authors performs the full optimization problem and concluded that the price of reactive power was negligible. This result confirmed the intuition according to which reactive power is an almost unlimited resource. However, it rested mainly on the assumption that there is enough shunt capacitors to support voltages. This paper contributed to shifting the focus from short-run dispatch of reactive power to long-run incentives for investments in shunt capacitors bank.

3.3.3 Impact on voltage support

We can identify four different types of market participants:

- Loads are consuming reactive power in proportion to their real power consumption. The ratio is given by their load factor

- Generators, by modifying the exciter field, can change their reactive power injection

- The owners of capacitor banks can decide how many capacitors to switch

- The transmission operator is concerned by level voltages since this affects the efficiency of its transmission operation. However, for the time being, we will neglect him, considering only the three first players

The Kirchoff's laws for reactive power can be written at each node i as follows:

$$V_i^2((\sum_{k\neq i} B_{ik}) - b_i) - V_i \sum_k V_k B_{ik} sin(\delta_{ik} - \xi_{ik}) = Q_i$$

These equations can be differentiated:

$$(2V_i((\sum_{k\neq i} B_{ik}) - b_i) - \sum_k V_k B_{ik} sin(\delta_{ik} - \xi_{ik}))dV_i - V_i^2 db_i = dQ_i$$

by linearizing around some nominal conditions (E_i^0, b_i^0), these equations can be written as

$$E = E^0 + H_q Q + H_b b \tag{3.2}$$

This equation summarizes the impact of each market participant on voltage level. It is essentially local, in that the injection of a given reactive power quantity at one node affects the voltage level at all other nodes. We can note a difference with real power where a mismatch between consumption and generation has a global effect on frequency. However, due to high level of reactive power losses, the impact of reactive power injection is likely to be limited to a few terminal voltages. Thus, the clustering of nodes into zones will very likely be even more justifiable than for real power [33]. In other words, most of the coefficients of the H_q and H_b matrix in 3.2 are small.

The values and signs of H_q coefficients encapsulate the impacts of market participants on voltage levels. If for instance $H_{q,ij}$ is positive, a withdrawal of reactive power at i will induce a decrease of the voltage level at j. Depending on the value of these coefficients, a given market participant (generator, load or capacitor owner) can be considered as a consumer or a producer of 'voltage units'. He will then have to pay or receive a payment equal to the quantity produced/consumed multiplied by the price of this voltage unit. There will then be as many prices as they are voltage constraints.

3.3.4 Economics of voltage units

Once the notion of voltage units has been introduced, it is possible to compute net demand function and supply function for these units.

3.3.4.1 Supply function

There are two voltage constraints at each node. the number of voltage units available is equal to the difference between voltage E^0 and the voltage constraint. This function does not depend on price

3.3.4.2 Net demand function for generators

Generators decide at the same time their real power and reactive power injection level in order to maximize their profits. Given a price of reactive power λ and a set of voltage unit prices $(\nu_1, .., \nu_n)$, the optimization problem for generator i can be stated as follows:

$$\max_{P_i, Q_i} \sum_{k=1}^{n} H_{q,ik} Q_i + \lambda P_i - C_i(P_i)$$

subject to:

$$Q_i^2 + P_i^2 \leq S_{max}^2$$
$$P_i \geq 0$$
$$Q_i \geq 0$$

from this optimization, it is possible to derive a demand function, which for each level of prices, associates a level of real and reactive output.

3.3.4.3 Net demand function for loads

The problem is essentially the same for loads. However, instead of considering costs in the optimization function, we consider real power utility function. Likewise, the first constraint has to be replaced by he following one:

$$\frac{P_i}{cos(\phi)} = \frac{Q_i}{sin(\phi)}$$

3.3.4.4 Net demand function for capacitor owner

Since no short-run costs are involved in the capacitor owner decision making, every time the additional revenue generated by switching one more capacitor is positive, the transmission owner will do it.

3.3.4.5 Resulting equilibrium prices

At the equilibrium, prices are such that:

- ν_i is equal to zero if net demand at this node is less than the total available voltage units.
- supply equals demand at node i if $\nu_i > 0$

The existence of a set of positive prices and its unicity would requires further investigation.

As interesting are the possible market structure potentially able to lead to such a set of prices. As in the transmission pricing issues, several market structures can be envisioned.

3.3.4.6 market structures

Since the supply function for capacitor owners is very simple, they do not need to take part in the price setting process. The first solution would be to have loads and generators trading voltage units according to the trading rules resulting from equation 3.2. During the trading process, prices are evolving according to the law of supply and demand.

The same process can be coordinated by a market-maker, essentially providing information on prices and adjusting prices as a function of the mismatch between supply and demand.

Because of the nature of reactive power losses, simplified trading rule would be used and would make the whole process more tractable.

3.3.5 Long-run incentives for investment in voltage support technologies

As said earlier on, the real purpose of market based voltage support pricing is not to achieve an efficient dispatch of reactive power but rather to ensure that the optimal amount of capacitors are installed at the right time and at the right place. By efficiently taking into account costs associated to voltage support provision, it is possible to derive the long-run value of voltage support technologies.

Let us assume that the cost a capacitor is proportional to its maximum capacity:

$$C(b_{max}) = kb_{max}$$

It is then possible to optimize not only on short-run variables like P_i, Q_i, b_i as it was the case in problem (3.1), but also on the total installed maximum shunt capacitance b_{max}. We then how to consider several periods.

$$\min_{P_i^t, Q_i^t, b_i^t, b_{i,max}} \sum_{t=1}^{T} \sum_{i=1}^{n} C_i(P_i^t) + \sum_{i=1}^{n} kb_{i,max} \tag{3.3}$$

subject to:

$$\begin{aligned} V_i^t \leq V_{max} &\quad \alpha_i^t \\ V_i^t \geq V_{min} &\quad \beta_i^t \\ (P_i^t)^2 + (Q_i^t)^2 \leq S_{max}^2 &\quad \sigma_i^t \\ b_i^t \leq b_{i,max} &\quad \chi_i^t \\ \sum_{i=1}^{n} P_i = 0 &\quad \lambda^t \end{aligned}$$

It is possible to form the Lagrangian for this optimization problem and to derive the first order necessary conditions. Among other equations, we have:

$$\alpha_i^t \frac{dV_i}{db_i} = \chi_i^t \tag{3.4}$$

$$\sum_{t=1}^{T} \chi_i^T = k \tag{3.5}$$

The left-hand side of equation 3.4 represents the net payment received by the owner of the capacitor bank at node i. Equation (3.5) tells us that the sum of payment over several periods has to be equal to the cost of one unit of capacitors. Thus, when the installed capacitors' capacity is optimal, the transmission owner can recover the cost of his investment.

These equations are consistent with an investment incentive scheme where investors are free to install capacitors in order to collect the rent associated with it. Whenever the expected payment is more than the cost of investment, there is an incentive to invest in capacitors bank.

This scheme is very similar to the peak-load pricing scheme proposed in [10] and illustrated in [34]. However, the assumption of linear cost, which constitutes the basis of the cost recovery feature, seems to be more adapted to the provision of capacitor banks.

3.3.6 Other market players

The basic pricing scheme presented above could complexified further in order to account for two issues:

- The influence of terminal voltage levels on transmission costs
- The possibility of having non-uniform technical standards for voltage support

The first issues is not taken into account in the proposed pricing scheme. It is theoretically possible to allow the transmission operator to participate in the voltage unit market. Contrary to other players who are obliged to buy voltage units in proportion to their impact on voltage levels, the transmission owner would be free to buy or not these units. By buying and not using these voltage units, the transmission provider would be able to drive voltage up or down to its convenience.

The same principle can be applied to the issue of technical standards. A minimum voltage level of 0.95 may not be acceptable for a specific consumer. This consumer should then have the ability, by paying more than the minimum required, to drive the voltage level up by buying more units than required.

There are some serious issues of free-riding here since several consumers at the same node have to share the same voltage level and may not be able to agree on a financing scheme for the purchase of extra voltage units.

3.3.7 Critical appraisal and conclusions

The pricing scheme proposed in this section is very similar to the ones developed for transmission pricing purposes. It is based on a linear approximation of reactive power Kirchoff laws. This approximation may be valid enough for accounting purposes but certainly not for the real time dispatch of reactive power. Moreover, the choice of the linearization point may have some influence on the buying rules and the prices of voltage units and may be controversial.

Likewise, the choice of the voltage level constraints is hard to justify. As suggested in the previous paragraph, we could imagine a scheme under which no such restriction exist. Market players would buy some units of voltage beyond what is required in order to drive prices up to their convenience. However, free riding issues would soon make this scheme intractable. The purpose of voltage constraint is then to ensure that a minimum voltage level is ensured and represents a convenient way to allocate the cost of this support.

Finally, we have ignored in this section the issues related to non-existence of load-flow solution. For some values of b_i, the matrix H_q may no longer be definite positive, thus endangering the stability of the grid. It is however possible to compute maximum bounds on capacitance so that the load flow solution exists [35].

As explained above, full competition for the provision of transmission capacity may not be implemented in the near future given that the existing technologies are subject to strong economies of scale. For the time being, the structure of the transmission industry will have to be based on regulation. In the context of this thesis, a central question is: whose responsibility is it to invest in transmission capacity. Under the typical cost-plus regulatory schemes, the regulator makes such a decision and the problem boils down to an allocation problem. In the next section, we will shortly review several allocation schemes. However, in some regulatory schemes, so-called incentive based regulatory schemes, this decision is left out to the regulated company. This scheme leaves much room for cost reduction efforts. However, since the regulated firm has a monopoly on investment, it has a natural tendency to under-invest. We will explore several incentive schemes which modify these natural tendency.

3.4 Regulation

3.4.1 Cost plus regulation

Cost-plus regulation represents the traditional form of regulation. It has been used in the United States for a long time and has proven to be fair and workable. As the generation side of the power industry is becoming competitive, it may be wise to proceed one step at a time and adopt a cautious regulatory structure for the transmission business.

The regulated firm under cost-plus regulation has no incentive to reduce costs since it is authorized to recover its costs plus a fair return on its capital. For this reason, we can hardly imagine putting the responsibility of operating the grid into the hands of a for profit-grid operator under cost-plus regulation. Thus, cost-plus regulation applies to the owners of the transmission grid only and has three objectives:

- to supply the optimal amount of transmission capacity.
- to reward the transmission owners for the cost of capital invested into the line.
- to allocate this costs among the users of the grid.

A regulator is responsible for investment decisions and must try to balance the trade-off between congestion and transmission capacity costs. Even though a regulator has little information about the needs for investment, he can use transmission rent from any of the congestion management scheme as a guiding tool.

This being said, the issues associated with cost-plus regulation amount to the following questions:

- How to allocate the costs?
- What to do with the transmission rent?

Since the transmission capacities are supposed to be close to their optimal values, congestion prices reflect long-run marginal costs of transmission and thus provide proper incentives for generation siting decision in long-run. The rent can come in deduction of the total revenue requirement.

The answer to the first question is more difficult. The allocation of the revenue requirement, possibly net of the transmission rent, can take many different forms. In the first four of the eight listed below, generators participate directly or indirectly in the recovery of transmission costs beyond the long-run marginal costs.

3.4.1.1 Flow-based tax

A first solution to the allocation of the revenue requirement could be the imposition of a usage-based tax. As a first approach, a different tax e_l could be associated with each line and a given transaction D_{ij} from bus i to bus j would have to pay:

$$\sum_{l=1}^{L}(H_{li} - H_{lj})e_l D_{ij}$$

The value of e_l can be chosen to recover the fixed costs associated with each line l.

The equivalent of the nodal prices are now:

$$\frac{dC_i}{dP_i} = \lambda + \sum_{l=1}^{L} H_{li}\mu_l + \sum_{l=1}^{L} H_{li}e_l$$

This flow-based tax modifies the apparent marginal cost of generators and thus distorts the economic dispatch equilibrium. For instance, in the absence of congestion, some low-value trades will not take place.

As an indirect effect, the tax modifies the demand for transmission capacity so that the μ_l in the above formula are not equal to the value of capacity. Thus, the taxing scheme reduces the congestion rent. As we can see, the recovery of non-capacity related costs through a flow-based tax and the allocation of transmission capacity are two related problems.

3.4.1.2 Ramsey pricing

The flow-based tax can be computed in order to recover the fixed cost line by line. Another approach would be to pool all the revenue requirement and to choose a single set of prices. This would be a Ramsey-pricing like approach.

This approach enables one to take into account cross-elasticities between the demand for capacity on the different lines and will thus lead to more efficient prices. An illustration of this pricing scheme is given in [29].

3.4.1.3 Capacity tax on generators

According to this scheme, each generator chooses and pays for a maximum transfer capacity for a given period of time. We can think of taxes for each line or for the entire grid. Inevitably, the generator will restrict its maximum output in order to avoid part of the tax. As a result, this system also distorts the competitive output. Contrary to the flow-based tax, which restricts competition mainly during off-peak hours, the capacity tax restricts it during peak-hours [36].

3.4.1.4 MW-Mile

These schemes are very similar to flow-based taxes except that the charge applies to the absolute value of the flow. The application of this methodology may be difficult whenever some bilateral transactions exist. For instance, two trades causing flows in opposite direction on one line could agree to merge into one transaction. Instead of paying twice the tax on the absolute value of their flow, they pay it once on the aggregate flow.

3.4.1.5 Postage stamp

The postage stamp can be applied either to a generator or to a load. If it is the same in the entire grid, marginal incentives are not modified with the exception of a restriction in consumption. If the postage stamp charge is applied to the load, it does not need to be the same in all regions. This enables one to take into account a sense of fairness in the recovery of fixed costs. With open access, all transmission resources are used on a common basis by the loads. However, some of them have paid in the past more than others in order to provide those common resources. It should be fair that they pay less now.

3.4.1.6 Capacity tax on loads

The tax on loads can be made proportional to their maximum consumption. Once loads have paid this tax, loads have no incentive to restrict their consumption except for the maximum limit allowed. Thus, this type of tax only restrict consumption during the load peak hours.

3.4.1.7 Non-linear pricing

The traditional theory of optimal multi-part tariffs [39] can also be applied to the recovery of fixed costs. The regulated firm can offer to users a menu of usage fee and access fee. Based on its expected level of consumption or generation, the grid users chooses a level of access fee and its associated usage fee. Typically, big consumers will choose a high access fee in exchange for a low usage fee. Implicitly, through this choice, a user reveals its expected usage pattern. This information can be used by the regulator in order to minimize the marginal distortions introduced by the cost recovery constraint.

Thus, users would pay a fixed fee each year and a charge proportional to their consumption.

3.4.1.8 Axiomatic allocation

The notion of fairness is at the heart of the axiomatic allocation approach. In order to allocate the costs, a regulator replicates what could be the outcome of a cooperative allocation between the users of the grid. This game does not take place but is simulated by the regulator.

The allocation depends on the set-up of the game and the solution concept chosen by the regulator. However, it always satisfies the two constraints presented previously:

- the payment of users is always less than their stand alone cost (individual rationality constraint)
- it is always above the incremental cost (this condition can be derived from the group rationality constraint).

These two main conditions alone cannot determine the allocation of the costs and the regulator has to choose a solution concept. However, as argued in [41], they provide upper and lower limits for the payment of users.

3.4.1.9 The policy process

The allocation of the non-capacity related fixed cost is potentially one of the most contentious of all issues in transmission pricing. Any allocation key could be used in order to split this cost. There is no right answer to this question since any recovery mechanism introduces in the short-run or in the long-run distortions in the optimal allocation of resources. This distortion may affect the absolute level of consumption or production, their locational pattern, investments in generation, consumption during peak-hour.

This distortions affect differently the various players of the power industry. Depending on their asset portfolio, some generators may argue in favor of one scheme,e versus another. For instance, generators owning mainly base-load generators may prefer the introduction of capacity based taxes.

3.4.2 A price-cap regulated Grid-CO

3.4.2.1 Price-cap regulation and profit-sharing

Cost-plus regulation is entirely cost-based. Although consumers would benefit from cost reduction due, for instance, to technology improvements, and risks are limited for the regulated transmission company, there is no real incentive in the long-run for the utility to minimize costs.

Price cap regulation was designed in order to mitigate this drawback of cost-plus regulation. Under this scheme, the maximum price a regulated firm is able to charge is set exogenously for a given period of time by a regulator. It usually takes the form of an initial price and a rate of decrease/increase over-time, reflecting expected efficiency gains, the rate of inflation, etc. Any cost reduction resulting from a higher than expected gain in efficiency of the regulated firm will increase its profit: the firm has the incentive to implement the efficient level of effort in order to maximize its profits. However, under this scheme, prices soon become disconnected from costs, contradicting first-best pricing or second best pricing [38]. Likewise, the firm may be able to make more profit than the rate of return associated with the level of risk.

More generally, the design of a regulatory scheme reduces to a trade-off between productive efficiency, allocative efficiency and distributive efficiency. On the one hand, cost-plus regulation can be considered as fair (full distributive efficiency) and enables one to implement some form of optimal pricing (for allocative efficiency). On the other and, price-cap regulation maximizes the incentive to reduce costs (productive efficiency) [40].

In order to take into consideration allocative efficiency, a profit-sharing mechanism can be implemented in parallel with price-caps. The modification of the price-level is not purely set exogenously but also incorporates a part of the profit made by the regulated firm so that if the firm makes supra-normal profits, part of it is distributed to the loads the next period in the form of price decrease. The part of profits passed back to consumer by the firm is a central parameter. When equal to zero, there is no profit sharing and the firm is price cap regulated. When it is equal to 1, the firm is cost plus regulated. The choice of this parameter gives a regulator one additional degree of liberty to balance the three objectives of efficient regulation. As we can see, the cost-plus and price-cap regulation can be viewed as two polar instances of the same continuum of regulations.

Likewise, a regulatory lag between two review periods is a central parameter. Under the ideal cost-plus regulation, there is no lag between reviews. On the contrary, under the ideal price-cap regulation, prices are set once and for all. In the actual implementation of cost-plus regulation, there is a lag so that prices are set for a given period of time and the firm can retain any profit resulting from improved efficiency. On the other hand, price-cap are also reviewed from time to time and the accounting profits made by the firm can be used by the regulator to track costs more closely. This mitigates the incentive to reduce costs in the long-run. Thus, the distinction between cost-plus and price-cap regulation is more one of degree rather than one of nature.

3.4.2.2 Price cap regulation of the transmission industry

One of the main objectives of price cap regulation is to give the regulated transmission firm the incentives to achieve the trade-offs presented in the first chapter. In particular, once the transmission capacities are chosen at their optimal value, generators pay the long-run marginal cost of transmission, as defined by the capacity-dependent part of the costs. Consequently, one of the major tasks of regulation is to pass on the trade-off between congestion costs and costs of capacity to the regulated firm, which have a better knowledge of costs. As suggested by Kleindorfer in [42], such a regulation should be performance-based and customer-focused.

This regulatory scheme also uses two-part tariffs as the way to enable the firm to recover its costs. Even though the firm no longer has full guarantees of cost recovery, the transmission business has to remain viable in order to attract investors. Using the same notation as in [43], p^t and F^t are the usage fee and the access fee for period t respectively. The usage charge can be spatial and temporal, reflecting an optimal short-run pricing scheme. Likewise, the access fee can vary from customers to customers.

In order to balance the trade-off, the firm has to be responsible for the costs of congestion. This is effectively the case in the England and Wales pool, where the National Grid company is partly responsible for reimbursing constrained-off generators and paying constrained-on generators.

However, this is not the only solution. Several proposals are based on this same idea of making congestion costly to the grid company([29], [43]). In [43], the grid company is subjected to a price-cap constraint on an average index of prices including short-run usage fees and connection fees.

The price index is equal to

$$PI = \sum_i w_i^t p_t + \sum_j w_j^t F^t$$

Thus, whenever the firm increases its short-run prices, it has to decrease the connection fees in order to comply with the constraint. The structure of incentive heavily depends on the choice of weights between the different prices. For instance, if generally speaking, the weights of usage fees are high, the firm will try to decrease the price of congestion by investing in capacity. If, on the other hand, those weights are low, the firm will rely more on congestion fees and will save on the costs of transmission capacity.

Thus, a regulated firm, with an obligation to serve, has the incentive to keep usage fees low and, at the same time, has to fulfill all requests for transmission services. This will lead to prices close to the value of transmission in the short-run.

In the long run, the regulated firm is responsible for the cost of congestion. It has the incentive to invest in transmission capacity whenever its penalty for congestion becomes higher than the cost of transmission capacity. Thus, the trade-off between transmission capacity can be passed on to the firm through the choice of the weights in the price index.

However, this solution only shifts the problem from choosing the optimal capacity under a cost-plus regulation to choosing the optimal weights in a price-cap scheme

[4].

3.4.2.3 Dynamic problem

In [37], the author proposes to define the weights for one period equal to the quantities offered in the previous period by the regulated firm. This scheme can be shown to converge toward the optimal prices for the short-run use of the network and to minimize the costs of transmission in the long-run. This model also includes some profit sharing by modifying the maximum price index each period based on the profits made by the firm.

3.4.2.4 Regulation of the transmission company with a non-profit ISO

A similar scheme was proposed in [29, chapter 6]. An independent non-profit ISO is in charge of operating the grid and managing congestion. Regulation only concerns the supply of an adequate amount of transmission capacity. In order to do this, the payment of the regulated firm is made dependent on the congestion rent and on the change in capacity between two periods according to the following formula

$$\begin{aligned} R^N(K^{i-1}, K^i) &= \sum_t \sum_l \mu_l^t(K^i)(K_l^{i-1} - K_l^i) \\ &-\alpha . \sum_l k_l(K_l^i - K_l^{i-1}) \end{aligned}$$

K^{i-1} represents the vector of capacities for the previous period. If the regulator knows the firm's discount rate, the parameter α can be chosen so as to lead to an optimal dynamic expansion of the grid by the regulated firm .

Thus, the revenue of the firm depends on the difference between what the rent would have been if the firm had not invested and the actual rent.

The author makes the distinction between non-capacity dependent costs and capacity costs. The recovery of the latter are not fully guaranteed and are made dependent on actual congestion while the recovery of the former are entirely passed on to the consumers.

Conclusions

Throughout this thesis, we made clear how important it is, as the power industry is being deregulated, to provide an appropriate framework for the allocation of scarce transmission resources and the long-term financing of new investments.

The chapter 1, in particular, showed how transmission investment decisions are not solely technical decisions resulting from the generation investment policy but are strategic decisions that bring value to the end-users. Several aspects of transmission have been considered: the total amount of installed transmission capacity, the location of new investment and the timing of investments. These three levies of transmission investment condition the efficiency of the whole industry. At the same time as the spatial and temporal patterns of demand are changing, the transmission grid needs to be enhanced and adapted. We underline the need to take uncertainties into account in long-term planning of transmission investments and show how risk affects negatively the optimal amount of transmission capacity compared to a certainty equivalent set-up. This fact supports the introduction of new and flexible transmission technologies such as FACTS devices and sheds a new light on the economic importance of reactive power dispatch. The models used to back this theory are very simplistic but advocate for the introduction of incentives for wise investment decision making in the deregulated industry.

In the short-run, rationing scarce transmission resources is critical. Transmission lines are too expensive to accommodate all requests for transmission services. The efficiency of the rationing scheme is thus critical. First-come first serve schemes or other arbitrary relief procedures do not pass this efficiency threshold. It may seem at first glance unusual to worry about short-run efficiency since markets and competition among market players have proven to be efficient. However, the use of the transmission grid is fraught with positive and negative externalities. Unless these externalities are internalized through an efficient congestion management scheme, deregulation of power industry will not meet the expectations of the policy makers.

We introduced in the second chapter of this thesis two potential scheme for the coordination of the power industry. The first scheme relies on the decomposition between short-term and long-term coordination. In the short-term, we presented and introduced new coordination schemes for the most efficient use of transmission capacity. We recommended the introduction of long-term derivative contracts in these short-term prices in order to coordinate generators investment policy with the transmission provider grid enhancement policy.

There exists, among policy makers and stake-holders, a strong incentive to neglect these issues. Generation, after all, represents the most important costs involved in providing electricity. For this reason, and also perhaps because the technical considerations underpinning most of the transmission pricing issues are sometimes ignored, transmission issues are often considered secondary. FERC Order 888, by requiring that transmission owners provide equal open access to all competitors, paves the way for an efficient primary market. However, this is not enough to guarantee an optimal allocation of existing transmission resources and the provision of transmission investments.

The current debate on the structuring of the transmission industry revolves around congestion management, which, as said before, is a relevant issue. However, most of the pricing scheme being discussed lead to the same dispatch under perfect conditions. The debates should then be considered in a more general set-up, where market power does exist, where markets are not always at equilibrium and where there are transaction costs. Such legitimate concerns as transparency, simplicity and firm commitment should be investigated further so that they can be traded-off along with efficiency against one another. The current policy debate, often ignoring these considerations, badly reflects the stakeholder's interests.

We thus introduced later on an innovative dynamic transmission capacity allocation scheme where the transmission provider at the same time allocates transmission capacity on a non-firm basis over an extended period of time and performs the dynamic investment policy presented in the first part of the thesis. The difference between short-term and long-term coordination disappears as the transmission provider is able to coordinate short-term and long-term decisions and effectively achieves the optimization tasks described in the first chapter of this thesis. The regulation of such a transmission provider remains an open issue.

Contrary to congestion management, the incentives for investments in transmission capacity have somehow been neglected in the policy debates. As explained above, it is certainly as important. Assuming there were no economies of scale, the transmission rent would entirely reflect the value of transmission capacity and the cost of transmission could be easily be allocated among users. However, the transmission rent only reflects the marginal value of transmission capacity and ignores the benefits associated with the existence of the transmission lines. Part of the cost of building a transmission line has a cost which is not related to the total capacity of the line. In essence, this cost represents a public good. Left alone, no one will assume the responsibility to provide this infrastructure. It is thus critical that the transmission industry is able to invest in transmission capacity and to share the corresponding costs.

Since a direct allocation of this cost, based on cooperation between users of the transmission grid is bound to fail because of free-riding issues, this responsibility has to be assumed by a single, regulated entity.

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