Managing Risk in the New Power Business[1]

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Managing risk is central to engineering, to business, and in fact to most human endeavors, and computer analysis is central to managing risk. This paper gives a broad exposition of risk in the competitive and privatized electric power business. Contrary to much that is being written today, we emphasize non-financial risks - hazards that are neither measured nor hedged using tools of financial markets. We present practical methods for modeling and managing risk and give real examples.

Under regulation there were fewer uncertainties and risks than we see today. System planning, engineering, and operating procedures reduced the risks of widespread or local service interruptions. Transmission, generation, distribution, and system protection engineers developed techniques and advanced software for reducing risk.

Today's new environment brings new uncertainties and risks. Different stakeholders see different risks. Much talk about risk today is focused on financial risks but it is remarkable that many important risks are not measured in dollars. In this industry, the monetary exposures for many risks are known imperfectly or are of secondary importance.

This paper describes how risk is measured (robustness, exposure, and regret) and how it can be hedged or reduced. We discuss risk management in two arenas: system planning and system operations.

How to Model and Manage Risk

<u>Risk</u> is the hazard to which we are exposed because of uncertainty. Risk also is associated with decisions. Where there are no uncertainties and no alternatives, there is no risk – e.g., there is no risk of dying, because it is inevitable and nothing we do can prevent it. But the time, place, and manner of death are uncertain.

Decisions we make can affect these uncertainties and can reduce or eliminate hazards. Some of these hazards include economic components – the premature death of a wage earner due to a travel accident, for instance. For other hazards the economic issues are secondary. For example, a living will or a health-care proxy reduces the risks of lingering in a hopeless state when recovery is impossible.

[1] *IEEE Computer Applications in Power*, Vol 13, No. 2, April 2000.
[2] Power Systems Research, Inc.
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Uncertainties

We can say things – with certainty – about uncertainties. What can be said, and what it means, depends on the uncertainty and on its affects. Most risk analysis in power and elsewhere is based on either *probabilistic* or *unknown-but-bounded* models. A third model, *completely unknown*, is logically important but will not be treated here. For example, Fig. 1 is a probabilistic model of the transmission transfer capability between two utilities. It was developed using production and network simulation programs.

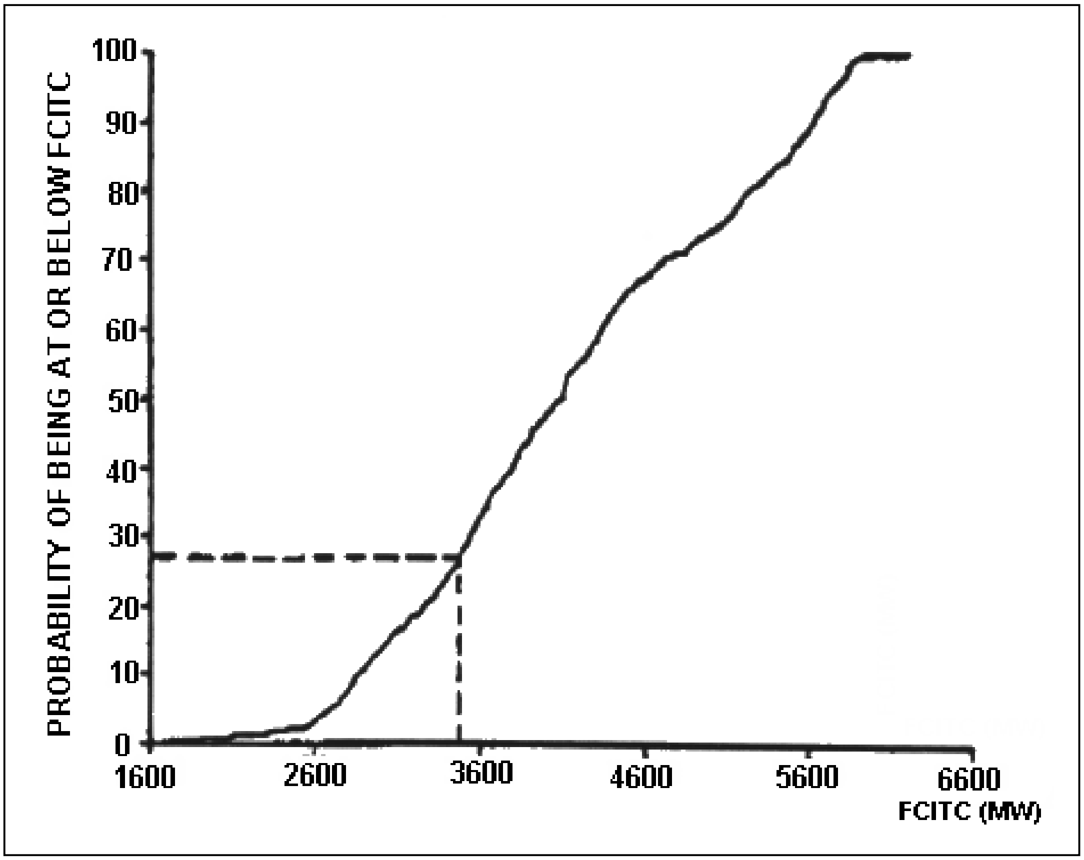


Fig. 1. First contingency incremental transfer capability between two utilities (Source: AEP)

Quantifying Risk

Robustness, the most fundamental measure of risk, is the likelihood that a particular decision will not be regrettable. Robustness can be thought of as a characteristic of choices in a two-person game. Nature, one of the players, chooses the realizations or outcomes of the uncertainties. The decision-maker chooses among his options without knowing Nature's choice.

If the decision-maker's choice turns out to be optimal[5] no matter what Nature chooses, his choice is robust. More often, his choice is optimal only for a subset of Nature's possible outcomes. Suppose that there is a probability of 0.83 that an outcome or realization from this subset materializes. Then the choice is robust with probability 0.83.

Exposure is a measure of loss if an adverse materialization of uncertainties occurs for a particular choice. Sometimes exposure can be measured in dollars, but often not. It is difficult to attach a dollar value to loss and inconvenience even for something as simple as a stray suitcase or a canceled flight.

Example 1: Transfer Capability Risk

Computer analysis of a transmission interface shows it to have from 0 to 900 MW transfer capability, with a uniform probability density function. The Transco has been asked to wheel power on a monthly basis, paying a penalty if it curtails service. The wheeling transaction has an uncertain load factor, modeled as 50% or 100% with equal probability. The point-to-point wheeling tariff is $1.80 per kW reserved per month. The penalty depends on the replacement cost to the buyer, and also is uncertain. Market simulation studies show that the average monthly penalty might be $5/MWh curtailed (Pr. = 0.9) or $20/MWh curtailed (Pr. = 0.1). How much should the Transco agree to wheel?

Table 1 shows the expected value of flow disrupted for each combination of contracted wheel (rows) and wheeling load factor (columns). Table 1 also includes the different possible penalty costs, along with the probabilities of the various combinations of load factor and per-MWh penalties.

Table 1. Expected disrupted flow (MWh per month)
and penalties ($ x 000 per month)

	Load factor = 0.5			Load factor = 1.0		
Contracted	Pr. =	0.45	0.05	Pr. =	0.45	0.05
Flow	MWh[6]	$5/MWh	$20/MWh	MWh	$5/MWh	$20/MWh
300 MW	12,000	$60	$240	36,000	$180	$720
500 MW	33,333	$167	$667	100,000	$500	$2,000
700 MW	65,333	$327	$1,307	196,000	$980	$3,920

In Table 2 penalties are subtracted from revenues (contracted flow x $1.80/kW-month) to give net income and exposure. The last column in Table 2 is the expected value of net income, computed by multiplying the net income in each cell by its column probability (Table 1) and summing each row. The Transco can maximize its expected income, E{NI}, by contracting to wheel 500 MW.

[5] Use of the term "optimal" implies that the decision-maker has a single objective. Robustness is also defined in multiple-objective situations.

[6] Thanks to Stein Wallace and Sergio Granville for pointing out and correcting an arithmetic error in these three numbers in the paper as published. Tables 1-3 are restated in this version to correct this error.

Any Transco choice may lead to a loss. We will show next that it is less risky to contract for 300 MW, even though the expected net income is a bit lower.

Table 2. Net income and exposure, $ x 000 per month

	Load factor = 0.5		Load factor = 1.0		
Penalty =	$5/MWh	$20/MWh	$5/MWh	$20/MWh	***E{NI}***
300 MW	$480	**$300**	$360	**($180)**	***$384***
500 MW	$733	$233	**$400**	($1,100)	***$467***
700 MW	**$933**	($47)	$280	($2,660)	***$411***
Max.	**$933**	**$300**	**$400**	**($180)**	

The bottom row in Table 2 is the Transco's maximum income, for each of Nature's futures, with perfect foreknowledge.

Regret is the difference in exposure between *some choice* and *the best choice* for a particular realization of the uncertainties. Table 3 is the difference between the Transco's maximum income and its actual income for each choice. For each choice (each row) the **worst** of Nature's realizations is in bold-face type. If the Transco wishes to minimize its maximum regret, then it will contract to wheel 300 MW, with a maximum regret of $453 k per month. At 500 MW, in an adverse future its regret could be $920 k per month.

Table 3. Regret ($ x 000 per month)

	Load factor = 0.5		Load factor = 1.0		Maximum
Penalty =	$5/MWh	$20/MWh	$5/MWh	$20/MWh	Regret
300 MW	**$453**	$0	$40	$0	**$453**
500 MW	$200	$67	$0	**$920**	$920
700 MW	$0	$347	$120	**$2,480**	$2,480

A hedge is an option that reduces risk. In example 1, the Transco can hedge by contracting to wheel 300 MW instead of the income-maximizing 500 MW. Hedging generally reduces risk, but at a cost – in this case, the expected return is lower.

There may be other hedges. One approach: change the market rules to eliminate the penalty, and let customers bid for increasingly less-firm blocks of transmission. Potentially the full 900 MW of transfer capability could be sold – or even more than 900 MW, because of diversity effects. Some of this would be on a very interruptible basis, but it would increase the value of the network to society - and the Transco might even make more money!

Example 2: Hedging with Flexible Options

Suppose that in a generation planning problem we have two investment options, as shown in Table 4. Suppose also that we have two load scenarios, 1000 MW and 2000 MW, each with a 50% probability. What is the best expansion plan?

In this case the hydro plant is the best option for each load scenario, *if we know what the load will be*.

We might wrongly conclude that constructing hydro is also a robust strategy *if we don't know what the load will be*. Suppose the rationing cost is so high that we will build 2000 MW to cover the high load scenario. This is risky because if load is low, we will have costly excess capacity.

Table 4 Generation Options

Option	Investment cost ($/MWh)	Operating cost ($/MWh)
Hydro	30	0
Thermal	15	25

Table 5 shows that a 50-50 split (1000 MW of hydro and 1000 MW of thermal) is less risky than pure hydro. This option is less risky because it has lower maximum regret ($5/MWh) than either pure hydro ($15/MWh) or pure thermal ($10/MWh).

Table 5 Cost ($/MWh)

2000 MW	Low Load	High Load
Hydro	60	30
Thermal	55	40
50/50	45	35

Limitations of Expected Value Criteria

Although minimizing expected value is useful for some applications, it does not capture the variability or volatility of results across different scenarios.

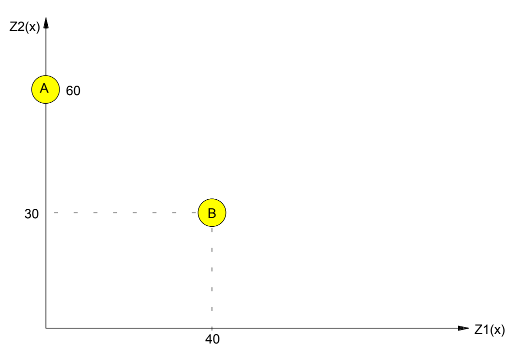


Figure 2. Expansion alternatives and costs

For example, Figure 2 shows two expansion options, A and B, which have to be evaluated under two possible scenarios. The costs of option A for scenarios 1 and 2 are respectively 0 and 60. The costs of B for the same scenarios are 40 and 30.

If the scenarios had the same probability, the average costs of the alternatives would be 30 and 35, respectively. Therefore under the least-average cost criterion, option A would be selected.

However, we observe in Fig. 2 that A presents extreme results: very good in scenario 1, but very vulnerable, or exposed, in scenario 2. In contrast, option B seems more balanced, as costs are reasonable in both scenarios. As a consequence, most people intuitively prefer option B to A, in spite of its being more expensive on the average.

This risk aversion is what motivates, for example, the purchase of car insurance. If we decide not to have insurance, we pay zero in the no-accident/no-theft scenario and a lot in the other scenarios. Conversely, when we buy insurance we have a modest constant cost (the insurance premium) over all scenarios.

Our risk aversion depends on the exposure relative to our financial capability and on the frequency of unfavorable scenarios.

Gain versus Risk Tradeoffs

There is no universally-accepted way to resolve the gain-versus-risk tradeoff. Three popular approaches are:

- minimax regret
- value at risk (VaR)
- utility functions

The first, minimizing the maximum regret, was illustrated in examples 1 and 2.

Value at Risk (VaR)

Suppose you have two electric power investment options: the first has an expected rate of return of 15%, but results could vary in the range [6%; 20%] (note that the probability distribution is not symmetrical, as the expected value is not the mid-point). The second option has a lower expected rate of return, say 11%, but with a much smaller variability (e.g. [10%; 13%]).

As with car insurance, the choice depends on your risk aversion profile. For example, if you have to borrow money at high interest rates in case the investment return is less than 10%, the second option may be “safer”. On the other hand, if you have a high financing capability, it may be worth “taking the risk” of having an unfavorable outcome in exchange for the possibility of obtaining a high rate of return.

In the VaR approach, we quantify this risk by looking at the worst outcome for a given probability level. For the example above, suppose that with a 95% probability the rate of return for the first investment option exceeds 10%. In this case, even the “risk averse” investor would take that option, because the probability of problems would be acceptably small.

In expansion planning models, the VaR approach corresponds to allowing 5% of the scenarios to be ignored, and applying a minimax rule to the remaining scenarios.

Utility Functions

An important limitation in both minimax and VaR criteria is not considering the true costs/benefits of either good or bad outcomes. For example, one of the 5% discarded scenarios may have catastrophic consequences, as the well-publicized crisis with the LTCM hedge fund has shown. Conversely, measuring the benefit of the remaining 95% scenarios by their worst result may be too conservative.

Utility functions translate revenues or other attributes into risk neutral "utility units". The objective is then to maximize the expected utility. For example, a risk-indifferent investor would have a linear UF such as in Figure 3a. This means that a revenue increase has the same impact as a reduction; as a consequence, the expected utility is equal to the expected income. A risk-averse investor would have a concave UF, as shown in Figure 3b. For him the loss from a bad outcome is not compensated by the gain from a favorable outcome. Finally, a risk-taker would have a convex utility function, as shown in Figure 3c.

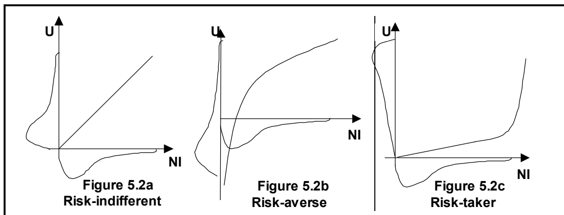


Figure 3. Types of Utility Function

Example 3: Investment Portfolio

The expected value criterion is linear, in the sense that the expected total revenue of a portfolio is the sum of the expected revenues of each individual project in that portfolio. As a consequence, the economic evaluation of a given project can be carried out without reference to other investments. In contrast, all risk/gain measures discussed above are directly or indirectly related to the variance of total revenues, which is given by the sum of individual variances plus covariance terms. In other words, the riskiness of a given project depends on the other projects in the portfolio.

This also means that total risk can be decreased by selecting investments with negative correlations, i.e. one can hedge against an undesirable outcome by betting on the opposite direction.

Consider hydro and thermal plants in a hydro-dominated country. In wet periods, hydro production is high, which decreases spot prices. Hydro plants meet their contracts with low operating costs. In dry periods, hydro production is low and spot prices are high. Now hydro plants have both price and quantity risks, i.e. not producing enough to meet their contracts (blackouts) and having to buy what they can at high prices in the spot market.

Thermal plants have the opposite revenue pattern: they make little money in wet periods, where they lose to hydro, and have high revenues in dry periods. As a consequence, the variance of a mixed hydro-thermal portfolio is smaller than that of all-hydro or all-thermal portfolios. If the consumer ultimately pays all the costs, then his risk is minimized with a mixed portfolio.

This risk can be analyzed and minimized in a single seller structure, or with centralized planning. Without centralized planning, each independent producer will plan to minimize his own risk – which will not necessarily minimize the risk to the consumer. Mechanisms will be needed to encourage construction that will minimize consumer risk.

Planning Case Studies

Example 4: LNG Supply to Brazil's Northeast Region

The NE region's sole hydro resource, the São Francisco River, is essentially exhausted. One option is LNG-fired thermal capacity.

LNG Supply Economics The steps and costs of the LNG production chain are:

1. natural gas extraction cost abroad – low,
2. LNG production plant abroad - $2 billion,
3. LNG shipping costs to Brazil using special-purpose ships - $250 million per ship, and
4. gasification plant in the Northeast region - $200 million.

Because all costs in the chain are essentially fixed, the LNG thermal project developer would have to sign a take-or-pay fuel contract (i.e. pay a fixed cost regardless of actual usage) and declare itself as an inflexible plant in the region's Wholesale Energy Market dispatch. The developer would then sign a power purchase agreement (which would cover plant investment costs plus fuel supply contract) with a local distribution company or independent customer. This in fact has been the practice in most countries.

However, because Brazil is 95% hydro, the system has been designed to be able to supply load under very severe droughts. As a consequence, there is excess production capability in wet, medium, or even slightly dry years. This means that spot prices are zero around 70% of the time. The rest of the time, they range from medium to very high (in 5% of the cases), when they reflect a higher risk of rationing.

Due to its inflexible dispatch, the thermal plant investor is missing an opportunity of meeting its power contract with cheap purchases in the spot market. For example, suppose that the plant operating cost (mainly fuel supply contract) is US$20/MWh. If the plant were flexible, it would only have to operate 30% of the time (when spot price is high), and purchase the power it contracted for from the spot market the remaining 70% of the time (when prices are very low). The average plant operating cost would be 0.3×20 = US$6/MWh. In summary, there is a strong incentive to make the plant flexible.

Creating a Flexible Dispatch With high fixed costs, how can flexibility be created? One way is by diverting LNG shipments whenever they are not necessary in Brazil to a gas spot market, for example to Spain or Turkey. Of course, the shipped LNG gas is more expensive than the gas usually sold in these markets (for example, US$3/MMBTU for LNG versus US$1.8/MMBTU in the spot). The US$1.2/MMBTU difference is therefore the insurance premium, or option price, the plant owner pays in order to obtain dispatch flexibility. If this option price is smaller than the additional gains from dispatch flexibility, the owner will exercise this option. Otherwise, he will stick with the fixed dispatch scheme.

Example 5: The Fruit-Gas Portfolio

In Brazil's Northeast region water is a scarce resource and there is strong competition to use it for power production and for irrigation (fruit production for export). This has been handled on an ad hoc basis: legislators assign the rights to irrigation or to power production, depending on social and political pressures.

The problem is that the opportunity cost of water for power production is extremely variable: 70% of the time it is close to zero, and the remainder of the time it is quite high. The rational solution would be to use the water for irrigation when its opportunity cost is low, and reduce the irrigation area when it is high, i.e. when the system is dry. But this lays a financial risk on the fruit growers, because their revenues are reduced in dry periods.

They need insurance, or a hedge, against this risk. The ideal insurance in this case is to buy equity in thermal plants. Their revenue profile is opposite that of fruit growers: very high spot revenues when the system is dry and low revenues when it is wet. In other words, the variance of the fruit-gas portfolio is very close to zero.

The Operational Risk Management Problem

Operational risk is the failure of the mechanism to deliver electric power. A subset of operational risks, the low frequency and high impact events, do not lend themselves to pure market solutions.

Operational risk has been studied for decades. There is bountiful data and methodology available for analyzing operational risk. However, the restructuring of the industry and new inventive ways of hedging supply risks will require revisiting the old data and developing new data on topics from counter parties to weather.

We also argue that hedging of revenue uncertainty is changing the reliability of customer service by masking the operational risk. The conclusion is that the customer, either consciously or unconsciously, will see an increase in the supply risk during the restructuring of the electric power industry. A likely outcome is that the customer will become a primary supplier of operational risk hedges.

The three central issues are:
1. How to encourage covering this type of risk?
2. Who can or should cover it?
3. What is the proper level of incentive?

Identifying Operational Risk

We will provide context by giving examples of low frequency and high impact events that might be classified as operational risk. We will try to order them from the more likely to the really unlikely. This idea of ordering the risk from high to low (although always relatively high) can be seen in most regional transmission reliability criteria. And of course with a discussion of a particular risk we need a discussion of how to model the consequences and likelihood as well as the means to control risk.

Individual unit forced outages are not the issue. Even significant multiple forced outages are not the issue. We restrict ourselves to those periods where the ISO or other system operator has to declare a state of emergency. Emergency conditions should be low frequency events.

Transmission failures are a source of operational risk. Individual outages may cause bottlenecks, they may raise the cost of load service, and they may reduce the security margin, but current design criteria mean they should not be an immediate threat to load service. It is when a tornado touches down on two parallel rights of way, or an ice storm or avalanche takes out a corridor through the mountains, that the system is at risk.

There are operational risks associated with fuel. Here we do not mean it gets very expensive; we mean it is not available at any price. Reservoir water cannot be purchased, nor can gas in a 1 in 60-year low temperature event, without a firm contract – or maybe even with a firm contract.

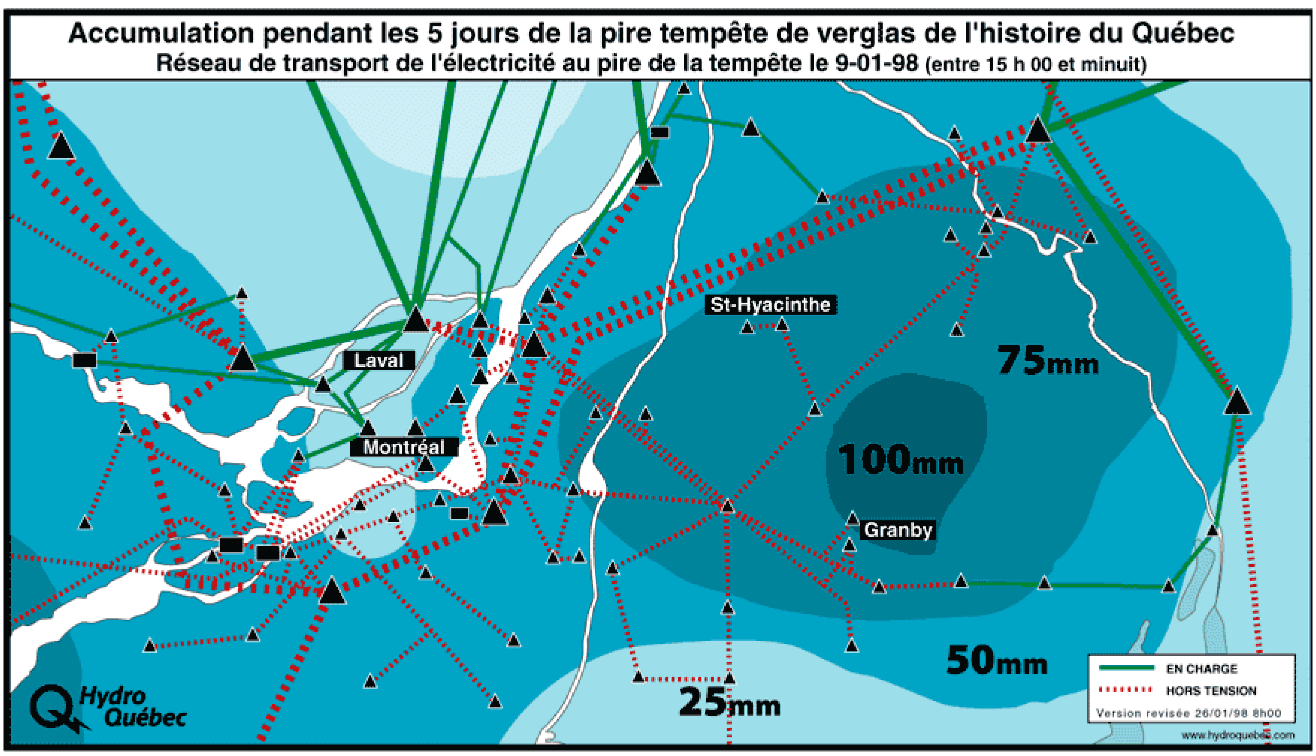
Finally there are those events which create some of the most glaring failures of current risk management methods. They remind us of the Asian currency crisis. A few people yell “wolf” about them until the wolf in some form arrives. This industry has experienced several such events in the last couple of decades – e.g., problems for the owners of nuclear power plants, their shareholders, and their customers. Is the EMF/cancer issue just where the cigarette industry was 20 or 30 years ago? Scientists find little evidence linking EMF to cancer, but risk managers and insurance companies must cover the legal risk posed by zealous trial attorneys. There is legal risk even though – or perhaps because – the medical risks have not been proven.

The previous discussion gives broad examples of areas of operational risk. The following questions give some insight into the complexity of specific questions.

- The stock market can severely penalize companies that do not maintain their earnings. With revenues dependent on loads and unit performance while loads are dependent on temperatures, how can revenues be made more secure? These financial ramifications of operating under uncertainty are getting lots of attention, to the detriment of operational risk coverage.

- Transmission transfer capability is a random variable, not a single number, as is the actual loading by transmission customers. How does an ISO or a Transmission Company decide how much transfer capability it can sell? Maximizing the expected value of return generally competes directly with minimizing risk. See example 1 above.
- Several Canadian and US utilities experienced severe damage due to ice buildup on transmission lines during a storm in January 1998. See Fig. 4. Ice melting through resistive heating has been proposed. It takes much less heat to prevent ice building up than it does to melt it once it has accumulated. There may be cost or reliability penalties or both associated with ice-prevention heating, perhaps with no *a priori* assurance that icing would have occurred. How should Transmission Companies go about developing an appropriate operating policy for limiting the risk of future failures due to heavy icing?

Fig. 4. All lines feeding downtown Montreal and all lines to the south and east were out of service (many on the ground) during the January 1998 ice storm.
[Source: Hydro-Quebec]



- Failure or misoperation of control or protective devices contributed to many loss-of-load incidents. Since it may be more difficult to site transmission lines in the future, power delivery may require increased use of special protection schemes. How can we measure and mitigate the risk of loss-of-load outages due to failure or misoperation of these control or protective devices?

Encouraging the Taking of Operational Risk

Traditionally, Public Service Commissions allowed utilities to collect a return from actions taken to mitigate certain risks. While the market may automatically replace this function, we do not believe that the mechanisms are in place to do so. For example, FERC policy provides an opportunity for a transmission provider to collect rent when a request for service triggers a need for more transmission capacity. It is not clear whether a generator that increases transfer capability can collect such a rent.

What is probably needed is a combination of market and regulatory mechanisms.

For instance, there is a need to encourage cooperation and sharing of data. A system operated with shared data can be more efficient and less risky than one operated by independent parties none of whom has complete information. Yes, the ISO is supposed to have access to all necessary information, but it is not the only decision-maker.

Quantifying Uncertainty and Operational Risks

There is an enormous literature on quantifying operating risks for electric power systems. There is a tremendous amount of data available, along with highly developed analytic techniques. This needs to be adapted to the new environment.

In particular, trade-offs will need to be made of new risks and costs of mitigating them. The trade-offs inherent in traditional operating standards and methods will need to be revisited.

Hedging Operational Risks

Financial hedges are being mixed up with operational risk hedges. For instance, weather-indexed hedges are available to allow companies to protect their revenues if abnormal temperatures cause sales to drop.

Such revenue hedges give the impression of dealing with operational risk. They do not. They count on a market to provide power in periods of shortage. But the markets may not have enough “physical” players. Suppose a hydro generator bought an insurance policy to provide a payoff in dry years. This would provide a revenue stream to help maintain earnings. But it would not provide electricity to the consumers.

Revenue hedging seems to be making great strides, but probably at the expense of operational risk. Policy makers are recognizing the trouble in letting the market take care of low-frequency, high-impact events. Rules will likely be made to cover these until market mechanisms are developed to hedge them. As in the past, the customer will cover some of them.

For Further Reading

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Biographies

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From 1975 to 1986, he worked at Cepel, where he coordinated the development of methodology and software in power system planning and operations (PSPO). From 1983 to 1985, Dr. Pereira was a project manager at EPRI's PSPO program. In 1987, he co-founded Power Systems Research Inc. (PSRI), where he has developed computational tools and methodologies for planning and operations for several utilities in Latin America, USA, Europe, New Zealand and China, plus multilateral institutions such as the World Bank and IDB.

Dr. Pereira has also been an advisor on privatization and power sector restructuring issues in Brazil, Colombia, Venezuela and South of China. He has been a professor at the Catholic University in Rio and has authored and co-authored about 150 papers and three books on power system planning, operation and economics.

Michael F. McCoy received his B. S. in Engineering Physics from the University of Portland in 1961 and his Ph.D. in Applied Mathematics from Oregon State University in 1966. He was formerly the chairman of the Mathematics Department at the University of Portland, Head of the Power System Planning Branch of the Bonneville Power Administration, and a Project Manager in System Reliability for the Electric Power Research Institute.

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