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Restructured Electricity Markets: A Risk Management Approach

Hung-po Chao, Shmuel Oren and Robert Wilson[1]

Abstract

In this paper, we consider a future path of the electricity industry that builds on lessons learned from experience and the principle of risk management. A main argument is that restructuring of the electricity industry is a process, not an event, which should be evolutionary, depending on local circumstances. This evolutionary path stays midway between extremes of vertical integration and direct liberalization of wholesale and retail markets. This middle path establishes the boundaries of the firm – i.e., the extent to which a retail utility should retain some degree of vertical integration. Its merit is that it builds on the positive accomplishments of liberalization while also reserving an important role for retail utilities. This "Third Way" of industry organization emphasizes that retail utilities should continue to serve a large contingent of core customers – mostly residential and small commercial customers – who rely on inter-temporal smoothing of retail rates.

Moreover, we examine the practical aspects of implementing this role within liberalized wholesale markets. A key element is the make-or-buy decision about whether to own and manage supply resources, or to rely on wholesale markets via either spot purchases or longer-term contracts. It also requires restructuring of regulatory policies and redefinition of the regulatory compact to recognize the effects of investment, purchasing, and contracting decisions by utilities in the context of liberalized wholesale markets, and to strengthen incentives for efficient operations.

[1] The authors are affiliated with EPRI and Stanford University, University of California, Berkeley and Stanford University, respectively. The research is sponsored by Electric Power Research Institute (EPRI). Any errors and opinions are solely the responsibility of the authors.

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In this paper, we consider a future path of the electricity industry that builds on lessons learned from experience and the principle of risk management. A main argument is that restructuring of the electricity industry is a process, not an event, which should be evolutionary, depending on local circumstances. This evolutionary path stays midway between extremes of vertical integration and direct liberalization of wholesale and retail markets. This middle path establishes the boundaries of the firm – i.e., the extent to which a retail utility should retain some degree of vertical integration. Its merit is that it builds on the positive accomplishments of liberalization while also reserving an important role for retail utilities. This "Third Way" of industry organization emphasizes that retail utilities should continue to serve a large contingent of core customers – mostly residential and small commercial customers – who rely on inter-temporal smoothing of retail rates.

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Section 1 summarizes the accomplishments of restructuring and liberalization of wholesale markets, and describes the residual role of utilities and other load-serving entities (LSEs) in retail markets. It also proposes new goals for regulatory policy and describes the new regulatory compact that is required. Section 2 examines three main options for how to implement the new role for utilities. Section 3 studies in detail how performance-based regulation of utilities can operate within liberalized markets. Section 4 argues for a middle way between the extremes of regulation and liberalization of retail markets. Section 5 concludes with the research needs to support the development of the Third Way approach.

1. Lessons Learned from Restructuring and Liberalization

Restructuring demonstrated that vertically integrated utilities are not necessary. Vertical integration eased the risk exposure of those utilities that retained generation resources during periods of high wholesale prices. But system operators (including national transmission companies) have supplanted integrated operations within local utilities. The engineering procedures of system operators are largely uniform because they reflect professional expertise and methods that are well developed and largely standardized. There is great variety in the designs of their spot markets, due partly to local circumstances and history, but all achieve the primary goal of regional management. One aspect is regional scope in allocating transmission capacity and in assuring reliability and system security. Another aspect is regional scope of wholesale markets for energy and reserves. Both aspects enable better utilization of resources, and the resulting prices in spot markets reflect capacities and costs over a wide area.

The plain fact is that local operations are obsolete, since the technology and skills of grid management are now entirely capable of operations on a larger regional scale. Productive efficiency is improved overall when prices are derived from the full set of resources available within a region, and from those obtainable by imports and exports among regions – even though there are significant distributional effects from equalization of prices among local areas. The inherent deficiencies of markets in ensuring adequate provision of reserves are now corrected by assigning authority to the system operator to procure the reserves necessary to assure reliability and protect grid facilities from injury or collapse.

The advent of system operators and regional wholesale markets has several main consequences, each involving separation of ownership and control. First, retail utilities have no significant role in transmission management. They may still own and maintain most of the transmission assets in countries such as the U.S., but daily management is assigned to the system operator. Central to this new organizational design are the regulatory requirements of open access and nondiscriminatory pricing of transmission based on principles of common carriage. These requirements recognize the public good character of the transmission grid: It is the fundamental infrastructure that enables regional operations and regional wholesale markets.

Restructuring succeeded in obviating the discriminatory use of transmission capacity to favor a utility's native load and to block entry by competing firms. It also implies that ownership of transmission can be separated from retail utilities, or retained if expedient for historical reasons, but in either case it is dependent on regulators' judgments about how best to ensure efficient management of this essential infrastructure. National transmission companies are the chief means of providing efficient management worldwide, and performance-based regulation of an independent transmission company is now used (e.g., in Britain, of National Grid Company). In the U.S., Japan, and Germany, the costs of divesting utility-owned transmission can be avoided by cooperative planning of new investments that conceivably can achieve the coordination obtained by national transmission companies.

Lack of adequate resource investment has emerged as one of the most significant problems not adequately addressed by the initial steps of market restructuring. Financial distress in today's markets is already leading to deferral of investments to replace the current fleet of aging generation plants and transmission facilities. Making matters worse, a suitable replacement for traditional integrated resource planning has not been identified. As a result, transmission and generation investments are often uncoordinated.

The second consequence is that a retail utility's ownership of generation now depends on a make-or-buy decision. Like other load serving entities (LSEs), utilities have access to regional spot and contract markets for energy supplies, so they obtain little operational advantage from owning generation capacity. Contracts and spot market purchases are equally viable means of obtaining power supplies to serve their retail loads. A utility might argue that it can build and operate generation capacity at a lower long-run cost than contracts provide, but such investments are equally well undertaken by unregulated firms. Or it might cite advantages in risk management, but again (as we argue further below) there are other means, some subject to market tests, that a regulator must compare to direct investment by a utility before guaranteeing cost recovery. A regulator responsible for retail service can therefore require that inclusion of such investments in the rate base requires a market test, or as is increasingly common, cost recovery is dependent on performance.[3] But the prevailing practice now is that generation investments are made by IPPs (which are often generation affiliates of energy companies that also own utilities), and are not included in the regulatory compact.

The present situation therefore shows that backward integration of a retail utility into local transmission and generation to serve native load is obsolete. It hindered development of regional operations and markets before restructuring, and it is obviated now by successful development of regional systems managed by system operators. Regulation of transmission investments and cost recovery remains important but largely unchanged except for supervision of system operators. This situation returns utilities to their primary role of retail service. It also requires revision of the regulatory compact so that it focuses on provision of retail service rather than utility-owned generation.

Restructuring and liberalization of retail markets succeeded in enabling large industrial and commercial customers to contract directly with IPPs and to purchase directly from wholesale markets. Its major failure was incomplete development of competitive retail markets for smaller customers. LSEs have made slight inroads, but utilities remain the dominant providers for core customers – those dependent on level rates for standard

[3] Even before restructuring, California approved cost recovery from PG&E's nuclear plant at Diablo Canyon only contingent on performance.

service plans. Liberalized retail markets were initially envisioned as bringing richly differentiated service plans offered by many competing LSEs as well as the incumbent utility. This vision failed to materialize because it ignored the central problem of risk management in the retail sector. The volatility of wholesale prices (compounded by systemic risks inherent in this industry) jeopardizes the financial viability of LSEs and utilities if retail rates are fixed rigidly. At the other extreme, where wholesale prices are passed through directly into retail rates, core customers consider the inherited volatility intolerable.

The initial plan of retail liberalization failed because it ignored the importance of preserving the inter-temporal smoothing of retail rates that prevailed before liberalization. In most jurisdictions, as a safety precaution, regulators continued cost-of-service regulation for retail utilities serving customers choosing to remain in the core, but this backstop turned out to be nearly the whole story of retail liberalization. Most small customers preferred to continue in the core of their local utilities because comparable financial hedges were not available, and non-utility LSEs lacked the financial resources to offer comparable assurance of level rates. Utilities were uniquely able to sustain level rates, or required by regulators to offer level rates, because they obtained guaranteed recovery of their costs by amortization over extended periods. An LSE could offer rates differentiated by customers' load profiles or other attributes, but at best, subject to year-to-year revision. The first year that a utility's level rate was below the LSE's revised rate, the customer returned to core service from the utility, and the LSEs' small market shares shrank further. In the extreme case of the California crisis, those LSEs still alive in 2001 summarily discontinued business and sent their customers back to the utilities. The following subsection examines other failings that followed from reliance on LSEs to provide competitive retail markets.

1.1 Problems with LSEs

LSEs withdrew unceremoniously from the California market simply by sending form letters to customers informing them that their services were canceled and they were "reassigned" to their local utilities. Unlike the utilities, which were precluded by legislation from long-term contracting, the LSEs had unrestricted opportunities to contract long-term to ensure service, but they did little and most were exposed to losses from rising wholesale prices. Their customers were also exposed since the LSEs could not offer financial hedges at reasonable cost, nor had they sufficient capital to provide intertemporal smoothing. Indeed, for an LSE, rather than maintaining costly reserves of financial capital, withdrawal (or bankruptcy) and reassignment of its customers to the utility turned out to be the cheapest form of insurance against high procurement costs.

Relying on LSEs poses deeper problems even if no extreme events occur that are of the magnitude of the California crisis. A customer's relationship with his retail provider is a continuing one, and implicitly, loyalty is an important ingredient. The LSE is more than a financial intermediary, since it is also provides a financial buffer between the customer and wholesale markets. This buffer protects the customer from the volatility of wholesale spot prices. If the LSE cannot or will not sustain this buffer through the ups and downs of the spot markets then the customer might as well pay real-time prices. The value of sustained financial buffering is one aspect of the general fact that retail service is very complex. A customer may choose continuing service from an LSE because it offers a particularly attractive plan or rate, but in fact the full list of relevant service attributes is lengthy: For example, is the LSE merely a reseller of energy purchased in wholesale spot markets? What assurance is there that next year's rates will be similar to this year's rates? Has the LSE adequate capital and how has it hedged against price volatility? What are the terms and durations of its long-term supply contracts? What assurance is there that its contracts can be renewed on favorable terms and what happens to me if it cannot meet its service commitments? Finally, is the provider of last resort (POLR) obligation of the utility my only recourse if my LSE withdraws or collapses? Because most customers are ill-informed about this longer list of relevant attributes of an LSE, they have little appreciation of the true nature of their service relationships with LSEs. In particular, their naïve expectations that service from an LSE is much like the ones they previously had with their local utilities is inaccurate.

The California crisis was so complex that it is difficult to derive crystal clear conclusions about the failings of LSEs; in particular, regulatory restrictions stifled opportunities to capture larger market shares. Even so, the end result was that in many cases the outcome was a game of "bait and switch". Customers who signed up with LSEs found that in fact there was no continuing relationship, and just three years after retail liberalization they were reassigned back to their local utilities.

In the next sections we address the task of retail liberalization with acute awareness that risk management is at the heart of the problem. It has the two aspects that inter-temporal smoothing is important for both utilities and for core customers. Both depend on the state's guarantee of deferred cost recovery to minimize the short-term financial risks they bear.

2. Options for Retail Liberalization

In this section we outline three options for liberalization of retail markets. Each recognizes that regulated retail utilities have important roles in assuring universal service and insuring core customers against volatile wholesale prices. We begin with our view of the new emphasis on retail service that should be the focus of the regulatory compact. This is the foundation on which each option relies because it is the state's guaranteed amortization of costs and rates that enables utilities and their core customers to be insured against the short-term volatility of wholesale prices. Thus, utilities and their core customers share a common interest in sustaining the regulatory compact's provisions for cost recovery and rate adjustment.

In contrast, industrial and large commercial customers bear price volatility more readily, and they use contracts with IPPs to manage commercial risks. Therefore, the many practical complications implied by the regulatory compact are unnecessary burdens. Since retail liberalization also excludes cross-subsidization among customer classes, there is no residual motive for including industrial and large commercial customers.[4] Thus we

[4] More precisely, liberalization excludes implicit subsidies. All systems provide explicit subsidies for disadvantaged customers. Increasingly, the subsidies for serving the most costly customers are explicit; e.g., distribution to remote rural customers, and enhanced reliability and backup services for essential public facilities like hospitals and public transport.

assume throughout that a new regulatory compact applies only to core customers; i.e., those who continue to rely on the utility's basic services.

2.1 The New Regulatory Compact

The objective of regulatory policy remains essentially the same. The chief responsibility is to assure universal service with its attendant attributes of quality and price.[5] The chief instrument is designation of a franchisee – the utility – with service obligations, and reciprocally, entitlement to cost recovery. However, retail liberalization allows other load serving entities to compete with the utility, and in addition, independent power producers (IPPs) can contract directly with large customers.

In the retail sector, the scope of regulatory intervention extends to three components:

- **Resource Adequacy**. Regulators can impose measures to assure that sufficient capacity is available. This authority was rarely needed previously because it was subsumed in the service obligation of vertically integrated utilities. It is more relevant now, and applies to both utilities and LSEs, because service depends on supplies obtained from large regions, and fundamentally, liberalized markets does not necessarily provide sufficient investments in the long run, nor operating reserves in the short-run, to assure reliability and other public-good attributes of service quality. Federal and state regulators and system operators must take explicit measures to assure that generation and transmission capacity meets minimum requirements.

- **Distribution**. Because it is a natural monopoly, a local distribution system is a monopoly franchise and strictly regulated. Regulators establish service standards and control rates charged to recover investments and costs of maintenance. Liberalization allows other LSEs to sell retail services in

[5] Development of a new regulatory compact in response to the restructuring changes just described requires appropriate balance between competition and regulation, raising a variety of questions which can be addressed by cost-benefit-risk analysis.

competition with the utility. Therefore the LDC must deliver energy to customers of all retailers. As with transmission, regulators require open access and nondiscriminatory pricing of distribution. The chief economy obtained previously from combining the local distribution company (LDC) with the utility – the franchisee for retail service – occurred in local control, metering, and billing. The utility and LSEs are now the main beneficiaries of improved metering capabilities so they or their customers bear the costs of enhanced meters. But regulators can establish metering requirements to facilitate expansion of differentiated services.

- **Basic Service**. To ensure universal service, regulators can require the designated utility to offer service plans of prescribed quality with standard terms and conditions, and fix rates to recover the utility's costs over time. These requirements can be extended to LSEs if necessary, but usually it is only the utility that has default service obligations; that is, the utility is the provider of last resort (POLR) for basic services. A key ingredient of retail liberalization is that each customer can choose whether to purchase a basic service plan from a regulated utility. Each customer can choose an enhanced service plan from the utility, or from an LSE, and large customers can bypass utilities and LSEs by contracting directly with IPPs or purchase from the system operator's spot markets.

In this section we concentrate on the third component, basic service. We emphasize that regulatory interventions need not extend beyond designating a POLR, specifying its basic service plans, and providing for recovery of their costs from the rates charged. An LSE or the utility might offer other service plans but enhancements beyond the basic service plans are not regulated and the regulator need not provide for cost recovery.

In this view the scope of regulatory intervention has two aspects. One pertains to provision of basic service, obtained by designating one or more franchisees with POLR obligations that consist mainly of offering standard service plans on terms specified by the regulator. The second is the regulator's reciprocal financial obligation – the regulatory compact – to provide cost recovery from the rates charged for basic service.

The central problem of regulatory policy stems from the fact that these two aspects are linked inextricably by the deep aversion to price volatility among many retail customers who rely on basic service. Rather than pass through wholesale costs directly and immediately into retail rates for basic service, procurement costs are amortized based on costs of capital, which enables retail rates to be leveled over time.[6] Only the regulator can guarantee cost recovery from retail rates, and equally, only the regulator can level customers' payments over time.

The key role of the regulatory compact in providing inter-temporal smoothing of cost recovery from retail rates stems from two considerations. Regulatory guarantees of eventual cost recovery enable utilities (or in some cases, LSEs with POLR obligations) to obtain interim financing from capital markets at relatively low cost. In contrast, customers of basic service plans cannot obtain adequate financial hedges against price volatility from private insurers at reasonable costs. This need not be so, but experience has shown that private markets for financial instruments are slow to develop, and the few examples smooth rates over short durations – at most a year or two. Retail liberalization was often undertaken with optimistic predictions that auxiliary financial markets would diminish the need for regulatory measures to smooth rates over time, but these have not materialized. In [6], we describe the fundamental reasons that systemic risks impede development of financial markets.

Implementation of regulatory responsibilities in liberalized retail markets presents difficult problems. A main explanation for the slight inroads of LSEs is that they are not eligible for the guarantees of cost recovery granted to the utility. In other words, the utility is immune to financial risks that LSEs must bear and therefore that they must pay for via higher costs of capital. On the other hand, as LSEs attract away the most profitable customers, those customers that remain with the utility are vulnerable to rising rates. Long swings of wholesale prices exacerbate this problem, since more customers leave the core when wholesale prices are low, and then they return when wholesale prices

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[6] Remarkably, wholesale prices for gas and oil for heating are often passed through with less resistance from customers. The difference may lie in the specialized application to heating in winter, and the availability of substitutes and mitigating measures, whereas lighting and appliances require electricity throughout the year.

are high. The ultimate risk faced by regulators is that in extreme events the utility can incur procurement costs so large that they jeopardize its financial viability. Afterward, retail rates must remain high for a long time to repay the utility's costs, which encourages further defections from the core if wholesale prices have returned to normal levels. In such cases the regulator may need to charge fees for exit from and/or entry into the core, or as in the California crisis, revoke retail liberalization.[7]

Retail liberalization entails two presumptions about the financial responsibilities of a utility and its core customers. We state these baldly at first and then comment on problems of implementation.

- For the utility, any procurement of energy required to serve its core load is prudent if it pays the spot price in the system operator's wholesale market. The utility might purchase some supplies by contracting with IPPs, and obtain some by investing in generation capacity, and surely these alternatives are subject to regulatory scrutiny and to comparisons with spot prices. But given the existence of spot prices in regulated regional markets conducted by an independent system operator, the regulatory compact surely now requires that these spot prices are prudent *de facto*. Further, its cost of capital to finance deferred cost recovery is prudent if it pays the rate of return in competitive financial markets for loans, bonds, and shares.

- For a customer, firm service is obtained only by paying spot prices for energy. Because non-core customers are subject to this standard, either directly or via service contracts purchased from LSEs and IPPs, equal treatment requires that the same standard apply to core customers. Core customers differ in that they pay rates that are leveled over time to the extent possible, but the basic principle remains that it is the spot prices for energy that are amortized. Thus, the utility's revenue from retail rates for energy to serve core customers, accumulated over

[7] Complying with a legislative directive, the California PUC's order of September 20, 2001, stated that "… suspension of the ability to acquire direct access service will provide [the state] with a stable customer base from which to recover the cost of the power it has purchased and continues to purchase."

time at the utility's cost of capital relevant for basic service, must approximate the corresponding accumulation of its procurement costs.

Regulators and utilities are very familiar with regulatory reviews of the prudency of contracting and investments. One new problem is that rates that recover spot prices might impair universal service, but we assume here that explicit subsidies suffice to ensure basic service to disadvantaged customers (and distribution to remote rural customers). Another new problem is accounting for the costs to serve core customers when the utility also offers enhanced services to others. In this case our assumption (elaborated later) is that the utility provides basic service to all customers, and which makes it easier to account separately for enhancements offered on a strictly commercial basis by the utility.

The most basic problem in regulating a utility pertains to its cost of capital. The utility's capital structure supports both regulated basic service and unregulated enhancements. Moreover, it comprises both debt and equity, and also implicit debt in the form of long-term contracts. These have different roles in supporting regulated basic service and unregulated commercial activities. For basic service, the utility needs both debt and equity capital because of its POLR obligation to serve and its obligation to defer cost recovery as needed to sustain level rates. In addition, debt and equity capital are needed for unregulated commerce. There is, however, a key difference: The regulatory guarantee that the costs of basic service will be recovered from retail rates over time enables greater reliance on debt. Further, this debt can be obtained at low cost as in the regulated era when investor-owned utilities relied heavily on bonds, which were issued with interest rates close to those of government securities.

We assume that it is a matter of judgment in particular cases whether the regulator makes an *ad hoc* determination of the cost of capital attributable to basic service, or requires a particular capital structure to support basic service, or most extreme, requires that basic service is financed by a separately incorporated entity such as an affiliate or subsidiary of the utility. *Ad hoc* determinations are least satisfactory because it is too easy for the regulator to ignore the utility's exposure to risks inherit in its obligations for POLR and deferred cost recovery, as well as in long-term contracts. As a result, a regulator may incorrectly suppose that capital can be obtained mainly from loans and bonds at interest rates below the cost of equity capital. Therefore, we suppose that an appropriate capital structure is established to support basic service.

For utility customers, the problems of implementation pertain mainly to rate design. One basic problem stems from adverse selection. The basic service plans are usually fixed over longer durations than customers' choices. It may be necessary therefore to charge fees for exit and/or entry from the core that account for the surplus or deficit in the difference between accumulated revenues and recovered costs. Similarly, it may also be necessary to impose charges that account for adverse selection as core customers switch among service plans.

The second main problem of rate design is to provide incentives for customers to use power efficiently. This includes incentives for demand-side management programs (e.g., investments in efficient appliances and control technologies, such as cycled air conditioners), and incentives for moderating usage when the aggregate load is high. The latter range from rates differentiated by standard peak and off-peak periods, or by annual load-duration profiles, or by service priorities, to the extreme of real-time pricing. Generally, however, stronger incentives are obtained only by reducing the insurance provided against price volatility. Fortunately, the practical solution to this problem is one endorsed by theoretical analysis. The preferred solution is to offer a rich menu of basic service plans that provides each customer with an array of possible choices. That is, the traditional "bundled" service – a single uniform basic service plan that is the same for all customers – is unbundled into a spectrum of differentiated service plans.

The options in a full menu of service plans enable each customer to choose more or less insurance, while recognizing that reduced insurance entails more exposure to price variation and therefore stronger incentives to adapt usage to the price that prevails. A customer with greater tolerance for risk bearing, or greater ease in adapting usage to price variations, can therefore benefit from selecting among those options with less insurance and stronger incentives -- and at less total cost, if the customer responds to the incentives. Insurance need not be confined to level rates, since it might also include financial compensation for service curtailments and interruptions when wholesale prices are high. The efficiency improvement from a menu of basic service plans comes fundamentally from the heterogeneity among customers, because it enables different customers to be matched with different service plans adapted to their individual preferences and opportunities for risk bearing and cost-effective management of usage.

In the next subsection we describe three main options for regulation of basic service. In each of these, a key component is performance-based regulation of the utility, including incentives for the utility to promote efficiency of customers' usage patterns. In Section 3 we address in detail the design of regulation dependent on utility performance.

2.2 Three Options for Regulation of Basic Service

We distinguish options that differ in the extent to which they insure jointly the utility and its customers, and correspondingly, the extent to which their incentives are diminished. The options can therefore be placed along a spectrum between the other sectors of the industry. At the one extreme are the transmission and distribution sectors that are natural monopolies, tightly regulated, and guaranteed full cost recovery. At the other extreme are the unregulated generation and retail sectors (IPPs and LSEs) that are competitive, largely unregulated, and dependent on the commercial success of their efforts. There are natural alliances between regional transmission and local distribution companies, due to their physical connections and their mutual dependence on engineering operations and coordination – and in some countries they are combined. There are also natural alliances between IPPs and LSEs, due to their trading relationships and their mutual dependence on bilateral contracts to hedge against volatility of prices in wholesale markets. Indeed, in some countries, such as Britain, restructuring has been followed in later years by mergers between suppliers and retailers.

We envision the utility as operating within this mixture of regulated and unregulated firms, but with a special role as the designated POLR that provides basic service under regulatory supervision. Necessarily, incentives are weakened to some degree with each expansion of insurance coverage; that is, with guarantees of cost recovery for the utility, and unvarying rates for customers. The design task is to identify the right mixture of elements that promote efficiency, including both the efficiency of the utility's operations and the efficiency of customers' usage. We list the main options and then comment on each in more detail.

> **<u>Option 1</u>**. This option continues cost-of-service regulation, much as in the regulated era except that it is restricted to basic services.

In Option 1 the utility is guaranteed amortized cost recovery for basic services. Therefore, all risk bearing is allocated either to IPPs via long-term supply contracts, or to core customers via retail rates that are mostly level but adjusted periodically so that the utility's accumulated revenues from basic services eventually recover its accumulated costs. In the interim until costs are recovered, the utility draws down reserves of capital obtained from financial markets, or repays outstanding debt when there is a surplus.

Even though Option 1 simply continues past practice, we view it now as *fundamentally unstable*. On the supply side, the utility's incentives for cost-effective procurement are weak. As in the regulated era, the regulator must ultimately judge whether the utility's supply contracts and financing were prudent, and as usual this judgment is conducted in a forum with adversaries from the utility and consumer groups arguing contentiously. But the basic deficiency is that the utility has no incentive to contract optimally with IPPs; indeed, it can rely on spot purchases and still receive recovery of its procurement costs. This deficiency is severe, since it is the utility's contracting decisions that determine the allocation of risk bearing between IPPs and core customers. Customers have a significant stake in how the utility contracts for energy supplies, but regulatory intervention is their only means of influencing the decisions made by the utility.

There are also problems on the demand side. The main challenge is to stimulate (or require) the utility to offer a menu of basic service plans that promote efficient usage by customers. Now this must be done amid competitive offers from LSEs and the utility's motive to profit from unregulated differentiation of enhancements to basic service plans. Typically, each plan in the efficient menu provides the customer with a rate reduction (justified by expected cost savings) in exchange for bearing some risks of price variation and/or rewards for modifying usage. But a portion of the efficiency gains from service differentiation can be captured by the utility as profit if basic service is undifferentiated (fully "bundled") and if it is only the utility's unregulated enhancements that provide differentiation. Before restructuring, regulators had to either require or reward utilities for offering multiple service plans and promoting demand-side management programs, and the stimulus required now must be even stronger.

We expect that in liberalized retail markets the easiest way out of this dilemma is the one most likely: Namely, basic service plans will provide minimal differentiation, and regulators will rely on the unregulated initiatives of the utility and competing LSEs to provide a menu of options. Whether this will be sufficient depends on local circumstances, chiefly the vigor of competition from LSEs. LSEs might thrive in ordinary years with moderate price volatility, but the California crisis shows that when wholesale prices rise unexpectedly offers from LSEs disappear and all their customers revert to basic service. This is precisely the occasion when differentiation of basic service is most important because it is then that the greatest gains are obtained from customers' efforts to economize on usage.

We view Option 1 as marginally viable only if it is supplemented by active regulatory interventions to ensure efficient contracting and service differentiation. It is especially inefficient in times of volatile prices if basic service plans do not include substantial differentiation that rewards customers' efforts to alter their usage patterns in cost-effective ways.

> **Option 2.** This option allocates some risk-bearing to the utility, complemented by incentives for efficient contracting and service differentiation. It is implemented by performance-based regulation of the utility provision of basic services.

Option 2 recognizes that incentives for efficient provision of basic service by the utility require that it bears some risk. Full insurance in the form of guaranteed cost recovery, as in Option 1, inevitably dilutes the utility's incentives for efficient contracting and service differentiation. The magnitude of the long-term risks borne by core customers is partly determined by how effectively the utility contracts long-term with IPPs for energy supplies, and partly by how well service differentiation succeeds in stimulating demand-side responses to wholesale prices. Collectively, core customers benefit from curtailing aggregate loads when wholesale prices are high; but individually, when retail rates for basic service are fixed in the short term, each customer prefers that other customers curtail their loads. Differentiation of plans for basic services escapes this free-rider problem by providing preferential rates or compensation to each customer who selects a plan that encourages the customer to moderate its own load in response to wholesale prices.

Option 2 depends on performance-based regulation (PBR) of the utility. PBR can take the simple form that superior performance on important dimensions is rewarded, using performance measures imposed by the regulator. Theory suggests that this form suffices if the regulator is fully knowledgeable about risks (e.g., knows the probabilities of events) and is concerned only to motivate the utility to apply sufficient effort to attain good performance in mitigating the financial consequences of these risks. The prevalent situation, however, is that the utility has superior information about risks and also the opportunities available to mitigate them. This is the usual case as regards market conditions and contracting opportunities, and equally, the utility knows better how basic service plans can be designed to improve demand-side responses. In this case, theory suggests that PBR should be implemented by offering to the utility a menu of incentive schemes: The utility then chooses among the options in the menu based on its information about which scheme offers the best prospects of profits from its basic service operations.[8] This is the analog of the menu of service plans offered to retail customers; in both cases, the menu enables a choice based on the superior information of the customer or the utility about which plan offers the greatest net benefit. In Section 3 we discuss in more detail the practical aspects of implementing PBR.

[8] In Britain, NGC was allowed to choose among several incentive schemes for its performance-based regulation by OFGEM. It chose one in which it is rewarded by a share of the reductions in its grid management charge ("uplift") that it accomplishes. R. Green describes it thus in a personal communication: "The Uplift Management Incentive Scheme (1994-5) and its successors (transmission services scheme, system operator incentive scheme, ...) were cost-sharing on the cost of dealing with constraints, losses, demand forecast errors, etc. Most were annual deals, renegotiated each year. In some cases, NGC was offered a menu of contracts with a choice between a tough target and a generous share of any savings, or an easier target with a lower share of savings if they beat it."

From a regulatory perspective, PBR brings both costs and benefits. The more risks the utility bears the higher is its cost of capital to finance basic services; in particular, it may need more equity capital. On the other hand, PBR offers profits from superior performance that can lower the cost of capital. From a customer's perspective, the relevant financial measures of performance include both the long-run average of procurement costs and the variability of these costs. Therefore, customers can benefit from rewarding efforts of the utility that reduce some weighted average of these two components.

Customers are also affected by differentiated service plans both directly and indirectly. A customer obtains a direct benefit from the plan selected; e.g., a customer who can easily reduce usage benefits from a plan that offers preferential rates for service that is curtailable when wholesale prices are high. Indirectly, customers benefit collectively when aggregate demand is responsive to wholesale prices and demand-side management programs improve the overall efficiency of power usage. Regulators have long required utilities to offer incentives of this kind, but PBR has the advantage that it motivates the utility to exploit fully its opportunities improve the efficiency of usage overall, and to stimulate price-responsive behavior. Some aspects might require subsidies. An example is installation of more sophisticated meters, but subsidies in this case can be justified by the gains obtained from the service differentiation that it makes possible.

Option 2 is not necessarily stable. Differentiation of basic services inevitably competes with unregulated service enhancements offered by the utility, and with all services offered by LSEs. It could be, therefore, that the core becomes merely the base on top of which enhanced services come to have the dominant role. Or it could be that the core shrinks as unregulated products offered by LSEs and utilities supplant basic service plans. Either could occur only if it benefits customers; therefore, each is a welcomed development from a regulatory perspective. However, retail liberalization has sometimes been undertaken with mistaken confidence that competitive retail markets will surely evolve quickly. This brings us to the third option.

> **Option 3.** This option relies on markets to allocate risk bearing among all participants – suppliers, LSEs, and customers. Each of the regulatory interventions is phased out, including the utility's responsibility as POLR to offer basic services, and regulatory guarantees that the utility will recover its costs.

Option 3 supposes that the wholesale and retail energy sectors of the electricity industry can be organized like other basic commodity industries, leaving only system operations, transmission, and distribution as the regulated sectors. Provision is made for a transition in which the utility continues to offer basic services and is assured cost recovery during this phase. But the utility and core customers are informed that the era of regulation of basic services will end. For example, California allowed the four years 1998-2002 for the transition, and this was also the period in which a utility had its last chance to recover from regulated retail rates the "stranded" costs of assets in its rate base. If necessary to assure universal service, some regulators (e.g., Massachusetts) have conducted procurement auctions to select a provider of last resort who bears financial responsibility for subsidies to disadvantaged customers, or for the extra costs of basic services to core customers during the transition.

The transition can be difficult. For instance, California's provisions for recovering stranded costs prohibited most long-term contracting by utilities and excluded effective competition for core customers by forcing LSEs to offer essentially the same retail prices as the utilities. A lesson from this experience is that taxing retail sales to repay past investments should not distort retail competition. A sharp transition to unfettered retail markets seems better.

Even after the transition, the predicted benefits from vigorous retail competition must be compared with the costs. On the supply side, a utility's cost of capital typically rises when it loses guaranteed recovery of the costs of basic services. More equity capital is usually needed, and the financial distress of several utilities in the U.S. has raised interest rates on utility bonds. This is a genuine social loss, since it results from leaving unused the state's proven ability to reduce capital costs by guaranteeing cost recovery. On the demand side, most core customers experience loss too, since they cannot obtain financial hedges from commercial firms at rates comparable to those previously paid for the long-term inter-temporal smoothing of the regulated era.

In Section 4 we argue that Option 2 provides a middle way between the extremes of retail regulation and liberalization represented by Options 1 and 3. But this argument depends ultimately on the practical implementation of performance-based regulation, which we address next in Section 3.

3. Implementation of Performance-Based Regulation

The advantage of PBR is that it strengthens incentives while retaining regulation of basic services. The regulator retains authority to specify retail prices and quality attributes of basic services for core customers. In this respect it is like Option 1 rather than Option 3, which relies on competition forces in retail markets. Option 2 relies on competitive wholesale and retail markets in a different way – as standards against which the performance of the utility can be measured.

PBR has two main features. One is an objective measure of performance, and the other is a scheme for rewarding superior performance and penalizing deficient performance. The following subsections address these separately.

3.1 Performance Measurement

In the regulated era, a judgment about whether a utility's decision was sufficiently prudent for the cost to be included in the rate base was ultimately subjective. The regulator relied on data offered by the utility and considered arguments pro and con from the utility and from ratepayer advocates. When a judgment was reached *ex post facto*, as in many cases, it was inherently biased because the some of the uncertainty that influenced the utility's decision had been resolved by events. A utility faced the "regulatory risk" that costs that seemed justified *ex ante facto* could later be judged imprudent by the regulator. PBR corrects this distortion by establishing objective measures of performance, and explicit rewards and penalties for performance.

Essentially, PBR implements the regulatory compact as an explicit contract. It may allow the utility some discretion in choosing among a menu of PBR schemes, and it may be revised or renegotiated periodically to cope with changing circumstances, but in any case it establishes *ex ante facto* performance measures and rewards to guide decision-making by the utility. PBR is vastly simpler after restructuring because objective measures of performance can be based on data from wholesale and retail markets.

On the supply side, wholesale prices in the system operator's spot markets provide an objective standard for comparison. The relevant measure of performance for a long-term contract for energy supply is the difference between spot market prices and the contract price over the duration of the contract. If this measure is low or negative then the utility has proved *ex post facto* that its contracting decisions were justified. The utility is rewarded for superior performance by receiving a share of the savings obtained from the contract as compared with spot purchases, and penalized for contract costs that exceed spot prices. In effect, the utility obtains an equity share in the difference between actual spot prices and contract costs for procuring energy that serves core customers.[9]

The actual form of the contract need not concern the regulator. For example, the utility might hedge against quantity risks by using option or tolling contracts, or against financial risks by trading futures contracts, but the net result is the same since the standard remains the cost were supplies purchased entirely from spot markets. The standard remains unchanged if the utility invests in generation, but the long life of a plant requires an explicit plan that establishes transfer prices for supplies allocated to basic service. Besides amortizing construction costs, transfer prices might include adjustments for fuel prices and other factors outside the control of the utility. Like self-generation, any contract (e.g., with an affiliate of the utility) that entails self-dealing requires prior approval of terms. In general, however, regulators exclude self-dealing entirely except for direct investments in generation by the utility, since there is no assurance that the price in a contract with an affiliate is the lowest available from competing suppliers.

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[9] For practical implementation of PBR, the rewards and penalties can be accumulated in a fund to smooth the immediate financial impacts due to the volatility in spot price.

Like any fixed payment rule, PBR can be vulnerable to "gaming" strategies. In this case, the prime target for gaming might be the wholesale spot prices used as the objective standard for comparison with contract prices. As a large buyer, the utility's monopsony influence might be used either to raise spot prices or to reduce contract prices, either of which can increase its profit under the simplest PBR schemes that consider only the difference between the two prices. However, customers prefer that the utility minimize total procurement costs, comprising the sum of spot and contract purchases, plus of course the incentive payment from the PBR scheme. If the utility has little influence on spot prices in regional wholesale markets, then it prefers to minimize contract prices and (assuming it obtains contract prices lower than average spot prices) maximize contract quantities and thus minimize spot procurements. This is usually the case because procurements are obtained mainly from contracts, and the utility's influence on prices in spot markets is diminished the more it relies on contracts. Nevertheless it may be necessary for the regulator to insist as part of PBR that energy supplies are obtained mostly from contracts rather than spot purchases.

The importance of this restriction is greater if the utility and/or its affiliates are net sellers who benefit directly from higher prices. The restriction might not be needed since the utility's influence on spot market prices is usually limited to arbitrage between the day-ahead and real-time markets, because its load not met by contracts must be purchased in one spot market or the other. Still, to avoid gaming that exploits differences between day-ahead and real-time prices, the standard of comparison should be the weighted average of these two spot prices based on the proportions the utility actually buys or sells in the two markets – that is, the average price of transactions in the two spot markets.

On the demand side, PBR incentives can reward improvements in efficiency. One category includes demand-side management (DSM) programs. Familiar examples include investments in distributed generation and backup resources, energy-efficient appliances, user-controlled devices for cycling air conditioners, sensors that turn off lights in unoccupied rooms and idle unused appliances, and induction motors that produce reactive power. Another example is shifting production processes and work times to lessen the steepness of the ramp-up in the morning and ramp-down in the late afternoon. Another category is aggregation of demand-side resources for sale in wholesale markets.

Because the system operator cannot dispatch core customers, however, they cannot serve individually as reserves. Rather, they can serve collectively as reserves when the utility organizes responses. Aggregation is simplest for cycling of air conditioners and regulation of thermostats controlled by broadcasts of radio signals or power-line FM signals. Larger scale programs for curtailments in extreme conditions or interruptions in emergencies require greater investments in meters, communication, and control. The incentive offered to the utility can be a share of the difference between the prices of such reserves in the system operator's market and the cost of the preferential rates offered to participating customers. Although DSM and aggregation programs can also be conducted by competing LSEs, the utility has unique advantages of scale due to its large base of core customers, and from integration with distribution and metering operations.

The main challenge on the demand side is to stimulate differentiation of basic service plans. Aggregation is one mode of differentiation, but there are many others. Because customers are heterogeneous, a menu of service options improves benefits for customers and can produce a financial surplus (net of greater metering costs) that allows a share for the utility as profit.

- A familiar example is different retail rates for energy in peak and off-peak periods. Another approach uses a separate meter for the circuit connected to energy-intensive appliances (heaters, washers, dryers, air conditioners) and charges more for on-peak power for these appliances. More elaborate tariffs increasingly approximate real-time pricing, although for core customers it is necessary that they be cast as forward contracts so that customers can rely on the terms and avoid continuous monitoring of spot prices. A typical scheme offers annual discounts that are greater if the customer selects a lower fuse level, but entail higher energy charges whenever usage exceeds the fuse level. Such schemes encourage customers to avoid peak loads above the selected fuse level. Less refined are the two-part tariffs used in the regulated era for industrial customers but that can also be offered to core customers: A customer pays a demand charge for his annual peak load and pays separately a rate charged for energy.

- We described in [6] the retail pricing scheme in France that, in effect, charges a customer for his actual load-duration profile over the year in a way that emphasizes both the cost of energy and the long-run cost of generation capacity. As with more familiar industrial and commercial tariffs, a customer pays a demand charge that depends (nonlinearly) on its annual or seasonal peak load and then, for each kW within that peak load, a separate energy charge that depends on the number of hours that particular kW is used during the year. Because each increment of the peak load is costly, and each hour of usage of the peak kW costs more than usage of a lesser kW, a customer realizes that he pays more for peak loads of short duration than for steady base loads. France also uses tariffs that impose higher rates in extreme or emergency conditions, announced by radio broadcasts. Competitive retailers in other countries have more frequently relied on forward contracts whose prices are based on customers' load-duration profiles in previous years.

- Genuine real-time pricing of energy may be feasible for some core customers if the utility provides auxiliary financial instruments that level payments over some period. Of course this leveling of payments must be coordinated with the regulator's overall program of leveling rates over a long time frame.

- Prices for reserves in wholesale markets enable a utility to offer curtailable and interruptible service plans that compensate customers for providing demand-side reserves. A more elaborate version insures a customer against its own cost of disruption. In this case, a customer receives a compensatory payment whenever it is curtailed or interrupted. The customer selects the amount of the compensation.

Although the utility can offer this insurance, commercial casualty insurers might also offer it.[10]

Depending on metering costs, the financial surplus comes from the fact that reductions in peak loads enable the utility to rely less on spot purchases of energy at peak prices and more on cheaper long-term contracts adapted to base loads. In the U.S., undifferentiated pricing is largely responsible for deterioration of the aggregate load-duration profile, reflected in the steady growth of the ratio of peak to base load, and increasing total costs of energy supplies due to greater reliance on peakers with high heat rates.

PBR provides to the utility a significant incentive to expand these efforts. It does so indirectly by rewarding long-term contracting at prices below average spot prices. In addition, however, it is desirable that the regulator reward directly those improvements in the aggregate load-duration profile attributable to the utility's initiatives – or in liberalized markets the more relevant measure of progress is the profile of wholesale spot prices versus durations of the utility's core load.

Basic service can be the base on which the utility offers enhanced service options. The utility necessarily competes with other retail service providers offering service enhancements.

3.2 Performance Incentives

Our discussion of performance measurement above has already mentioned the basic elements of performance incentives. Here we consider several more complicated issues.

Strength of Incentives. The strength of the utility's incentives depends crucially on the utility's share of the net benefit from performance improvement. There are economic theories about how to set the share optimally, but they depend on elaborate calculations using the marginal cost of the utility's efforts, and also on the relative risk aversion of

[10] Retail service of this kind are described by H. Chao and R. Wilson, "Priority Service: Pricing, Investment, and Market Organization," *American Economic Review* 77: 899-916, December 1987; and R. Wilson, "Implementation of Priority Insurance in Power Exchange Markets," *Energy Journal* 18: 111-123, January 1997.

core customers and the utility.[11] These theories are too complicated to be practical but they point to the main considerations. Essentially, for any degree of risk bearing by the utility, expected rewards must be great enough to justify the utility's efforts. In addition, it is inefficient for the utility to bear risks (and incur pay more for equity capital) that customers can bear by sharing among them (via the rates they pay) and further minimize by inter-temporal smoothing of rates. Our view is that, in practice, this decision should be made by the regulator based on local circumstances. Even so, there is a potential gain from offering the utility a menu of options so that it can take advantage of its superior knowledge about its costs and its opportunities for performance improvements. For example, the simplest menu offers two schemes:

1. This scheme only rewards or penalizes performance outside a band around a nominal target, and within this band provides ordinary cost recovery.

2. This scheme rewards or penalizes performance over the entire range of possible outcomes.

Scheme 1 is safer for the utility if it perceives few opportunities for performance improvements, or actions to improve performance are very risky or require expensive capital reserves, or improvements are costly to implement. Scheme 2 is more attractive for the utility when it anticipates inexpensive low-risk opportunities to improve performance. More elaborate menus can appeal to other special circumstances that might affect the utility's motives for pursuing performance improvements.

Cost of Capital. PBR strengthens the utility's incentives for efficiency improvements, but it also exposes the utility to more risk because circumstances beyond its control can reduce measured performance even if the utility responded vigorously to the incentives. More equity capital is therefore required to provide financial reserves for basic services. The cost of capital allowed by the regulator should recognize the larger equity

[11] For practical purposes the risk aversion of the utility is measured by the cost of equity capital. For core customers it is derived from analyses of the net effects of diversifying risk bearing among them and intertemporal smoothing of rates. See R. Wilson, "Risk Measurement of Public Projects," in *Discounting for Time and Risk in Energy Policy*, R. C. Lind (ed.), Washington DC: Resources for the Future and John Hopkins University Press, 1982.

requirements. The appropriate amount depends heavily on local circumstances, so here we cannot offer general guidelines.

Comparative Evaluation. One way to reduce the utility's exposure to exogenous risks is to base rewards for performance on a comparison with other utilities – and with LSEs to the extent data can be obtained. In the U.S., comparative evaluation is facilitated by the fact that each state regulates several retail utilities, all relying on the same system operator and all procuring supplies from the same regional market. Thus it is possible to include rewards for relative performance, which is less susceptible to exogenous events affecting all utilities in the region.

Asymmetric Rewards and Penalties. Most PBR implementations reward superior performance more than they penalize inferior performance. Asymmetries might impair efficiency, but they address the realistic aspect that performance goals and measures are set by the regulator with less detailed information about the market environment than the utility has. Offering a menu of PBR schemes diminishes this information deficiency, since it allows the utility to take advantage of its superior information when it selects its preferred PBR scheme from the menu. However, there remains a residual risk that the regulator's menu or any particular PBR scheme is based on a mistaken understanding of the realistic conditions that the utility will confront. The chief role of less severe penalties, as compared to the rewards for superior performance, is to assign a share of the responsibility for deficient performance to possible inadequacies of regulation and the design of PBR schemes.

Exit and Re-Entry Fees. Switching fees are important for customers who continue in the core because the costs of basic service depend on the composition of the core, and over time their rates depend on the accumulated costs that must be recovered. Those who remain in the core suffer if some leave when wholesale prices are low and return when wholesale prices are high. The cure for this adverse selection is to charge exit and re-entry fees that account for the costs that switching customers impose on those who remain. The utility also has a significant stake in ensuring that fees accurately account for the costs of switching customers. Perhaps most important is that the utility's ability to contract cost-effectively for long-term for energy supplies depends heavily on reimbursement for the adverse effects of switching.

Auxiliary Obligations. Among the mandates imposed by regulators are those requiring increased reliance on renewable sources of energy (wind, solar, biomass, etc.), assured services for low-income households, access for disabled persons, responsible stewardship of lands, ethnic diversity of employees, and opportunities for minority contractors. If comparable mandates do not apply to competing LSEs in liberalized markets, then the costs of these mandates should be recognized in measuring performance. Reliance on renewable energy sources is especially important because their quality attributes differ significantly – chiefly because generation is intermittent, they are less adapted to dispatch by the system operator, and they are less available and less reliable as reserves – yet in each hour their actual energy output is paid the same price in the real-time market as energy from any other source. Therefore, a performance measure that uses spot prices as the standard of comparison is inevitably biased against a utility required to contract for significant quantities of energy from renewable sources. Our view, therefore, is that performance measures must be adjusted to account for this discrepancy.

Renegotiation. Specifications of PBR provisions must be revised every few years to account for experience and changing circumstances. From the utility's perspective, the chief hazard of renegotiation is the risk that the regulator will not take account of the utility's long-term commitments (e.g., procurement contracts, and the composition of debt and equity in its capital structure), or worse, exploit the utility's inability to alter previous commitments. Our view is that the regulatory compact must be extended to PBR, and therefore, changes in PBR should include provisions for recovery of stranded costs of the utility.

4. A Middle Path "Third Way" Between Regulation and Liberalization

Restructuring of the electricity industry was a means to an end. The goal was improved efficiency in investments and operations, and improved customer satisfaction from lower rates and expanded service options. The means included regional wholesale markets managed by regulated transmission system operators and competitive markets for retail service, including open access to transmission for independent power producers and their industrial customers. Incentives were strengthened by requiring non-utility generators to bear investment and operating risks, and by requiring retailers and/or their customers to bear price risks. These risks were to be moderated by long-term procurement contracts and financial hedges.

Actual performance falls short of the original goals. The two main deficiencies stem from market imperfections. Markets have fundamental limitations in stimulating sufficient investment in reserve capacity to meet rare extreme contingencies. For this reason, physical risks are managed by requiring adequate investments in generation capacity sufficient to meet peak loads plus a reserve margin. These mandates are established by regulators and system operators.

The failure of markets for contracts to moderate financial risks is not fundamental; indeed, in some countries these markets are vigorous and largely successful. But in the U.S. the situation is quite different. The exposure of investor-owned generators and utilities to greater financial risks in regional wholesale markets has raised the cost of capital amid financial distress of all major power traders, many generators, and some utilities. The plight of the utilities is the central fact of this situation because they remain the dominant suppliers of core customers, unlike other countries that have restructured. As mentioned, at one extreme the former utilities in Scandinavia are mostly government owned and now serve mainly as local distributors of energy that customers purchase from competing retailers along with financial hedges against volatile spot prices. At other extreme the government owned utilities in New South Wales are hedged against spot price volatility by a fund established by the government (and financed by generators). In the U.S. those states that restructured adopted a hybrid in which investor-owned utilities are not hedged (nor endowed with vesting contracts) but they have been allowed to continue as the dominant retailers to core customers.

The increased risk exposure of generators stems ultimately from the situation of the utilities; for, if the utilities relied more on long-term contracts for their energy supplies then these contracts would provide generators with financial hedges and security for loans used for investments in new plants. But a utility is understandably reluctant to commit heavily to long-term contracts since, as a default service provider, its customer base can contract or expand depending on whether spot and IPP contract prices are lower or higher than regulated retail rates. Equally, its core customers are reluctant to contract short-term with retailers when few longer-term hedges are available – they have the better option of level rates from the utility. It could have been that the utilities were relegated to the role of local distribution companies, as some proponents of restructuring argued originally on the premise that this would spur vigorous development of retail competition (as in Scandinavia). But the plain fact is that the investor-owned utilities had, and will continue to have, substantial incumbency advantages that minimize inroads by competing retailers, and they have the further advantage of assured cost recovery from level rates.

The basic dilemma is that cost-of-service regulated investor-owned utilities continue to serve a large contingent of core customers – and with good reason, since their level rates offer substantial advantages for small customers in the absence of other financial hedges. But these utilities are vulnerable to quantity risks as the core shrinks or grows (and price risks in the interim until cost recovery is complete), so their participation in markets for long-term contracts has been too weak to sustain the financial vitality of the generator sector, which remains heavily exposed to volatile spot prices. Amid these difficulties, the service differentiation that was expected to come from liberalized markets has not materialized. A utility regulated on a cost-of-service basis has little incentive to offer service enhancements unless the regulator insists.

In this situation, it is useful to re-examine the restructuring scenario that was envisioned a decade ago. The vision of a fully competitive retail sector must be put aside in favor of a realistic view that incumbent investor-owned utilities will continue to serve the core of small customers who depend on level rates as their sole hedge against volatile spot prices.[12] This suggests the advantages of establishing a middle "Third Way," based on a revised regulatory compact.

This revised compact involves liberalized wholesale and retail markets in which a utility retains the obligation of provider of last resort of basic service at regulated rates that recover allowed costs over time. The costs that are allowed provide an implementation of performance-based regulation that rewards or penalizes the utility's equity owners, depending on whether procurement costs are less or more than wholesale spot prices. In addition, to protect against adverse composition of core customers, exit and entry fees are charged that reflect the embedded cost of the utility's long-term contracts.

This form of the regulatory compact has beneficial impacts. On the supply side it encourages the utility to contract long-term for supplies at contract prices better than expected spot prices. On the demand side it encourages service differentiation that provides incentives for customers to reduce peak loads and provide demand-side substitutes for reserves.

[12] Many of the problems that have occurred during market restructuring experiments so far resulted from over-reliance on a single solution: full unbundling of vertically integrated utilities.

5. Conclusion

Restructuring poses new challenges for risk management, as electricity markets are inherently incomplete due to technological limitations of non-storability and the absence of demand response. Efficient allocation of financial risks among generators, utilities and other retailers, and customers is essential for recovering low costs of capital, sustaining investments to meet continued growth in demand, and eliciting efficient demand-side usage. To support a Third Way approach to the restructuring of the electricity industry will require the support of new research agenda that integrates the perspectives of market design and risk management. In particular, restructuring has greatly altered the financial risks faced by all market participants. The comprehensive insurance provided by vertical integration and the regulatory compact is now replaced by exposure to wholesale market prices. To the extent that a utility cannot pass wholesale prices through to retail customers, its financial viability is jeopardized. A corporate strategy for managing these risks can minimize the utility's cost of capital.

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