

Draft

**Best Practices Guide:
Implementing Power Sector Reform**

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Acronyms

CALPX	California Power Exchange
CC	Combined Cycle
CO2	Carbon Dioxide
CPI	Consumer Price Index
CT	Combustion Turbine
DOE	Department of Energy
DSM	Demand Side Management
EPACT	Energy Policy Act of 1992
EWG	Exempt Wholesale Generator
FAC	Fuel Adjustment Clause
FERC	Federal Energy Regulatory Commission
GENCO	Generating Company
IOU	Investor Owned Utility
IPP	Independent Power Producer
IRP	Integrated Resource Planning
ISO	Independent System Operator
kW	Kilowatt
kWh	Kilowatt-hour
MC	Marginal Cost
MR	Marginal Revenue
Mwh	Megawatt-hour
NERC	North American Electric Reliability Council
NOx	Nitrous Oxide
PBR	Performance Based Regulation
PJM	The Pennsylvania-New Jersey-Maryland Power Pool
POOLCO	Power Pool Company
PPA	Power Purchase Agreement
PUHCA	Public Utility Holding Company Act
PURPA	Public Utilities Regulatory Policies Act of 1978
RFP	Request for Proposals
ROE	Return on Equity
RR	Revenue Requirement
SO2	Sulfur Dioxide
TD	Transmission and Distribution
TRANSCO	Transmission Company
TRC	Total Resource Cost
UK	United Kingdom

Introduction And Summary

This manual contains a distillation of material developed by the Regulatory Assistance Project for use in teaching a the full range of issues needed for a restructured electric utility industry. The evolving nature of electric utility industry restructuring and regulation mean that much of the manual will be in constant need of refinement and updating. There are many lessons being learned around the world. Learning and applying the lessons creatively to the situation in any given country will assure that reforms serve the widely held goals of an efficient, fair, and environmentally sustainable electricity sector.

China's ongoing utility sector reform efforts can benefit greatly from the many lessons learned in the United States and other countries. The list of lessons have been learned from mistakes as well as from successes. The lessons relate to policy, process and the course of implementation.

The most important lessons and those with the most relevance to China are in the following areas:

Single Government Agency with Professional Staff, Comprehensive Jurisdiction, and Limited Right of Review Creates the Foundation for a Reformed Industry.

Professional regulatory oversight serves three functions: 1) It protects consumers by preventing discrimination and the exercise of monopoly or market power, 2) It creates a predictable and financially sound industry that can attract the capital needed to reliably meet energy needs, 3) It assures that the long-term expansion and operation of the industry is consistent with public interest goal, and 4) It can insulate the electric system, its financing and operations, from political influence and pressure.

Incentive Regulation Can Align Private and Public Interests. Every system of regulation and tariff setting produces financial incentives promoting certain behavior and discouraging other behavior. The best approaches encourage utilities to invest in increased end use energy efficiency whenever the cost of energy efficiency is less than the cost of power supply.

Integrated Resource Planning (IRP) Can Lower Direct and Indirect Costs. IRP considers the costs of all alternatives to meeting the public's demand for energy services. Alternatives include conventional power plants, renewable sources of supply, end use energy efficiency, and load management. All costs and benefits are considered including risk and the externalized cost of pollution associated with each option. The best practices use IRP to find the least costly mix of options needed to meet energy service needs.

Competitive Acquisition of Power Supply Can Lower Cost, Lower Risk, Increase Flexibility. Electric utility industry reforms include opening the industry to private power producers. Private power options are one of the many options considered in an IRP process. The best approaches to competitive solicitations and contracting combine bidding and IRP to produce substantial cost and environmental savings at reduced risk to consumers.

Properly Designed Market Structure and Market Rules Can Yield Significant Cost and Environmental Savings. The design of market structures and market rules including separation of generation from transmission and distribution, reducing concentration of

ownership, efficient pricing and access rules for use of transmission facilities, and bidding rules in competitive spot markets will all influence the performance and efficiency of a reformed industry. The best approaches include market-based approaches such as demand-side bidding, Renewable Portfolio Standards and System Benefit Charges as ways to assure that renewables and energy efficiency are delivered efficiently.

Coordinated Environmental and Economic Reforms Can Further Economic And Environmental Goals. The electric utility industry accounts for a very large fraction of air pollution. Some approaches to environmental regulation are more compatible with competitive generation markets than others. Cap and trade approaches which limit the total levels of industry emissions and Emission Performance Standards which limit emissions per kWh are two of the best market based approaches.

Chapter 1: The Economic Justification for Utility Regulation

The history of utility regulation, in the United States and around the world, is storied. Each country's history is, of course, unique in its particulars, but the fundamental justifications for governmental oversight of the utility sector — in this case, the electric industry — are the same everywhere. The first is the widely-held belief that the sector's outputs are essential to the well-being of the society — its households and businesses — and the second is that its technological and economic features are such that a single firm can serve the overall demand for its output at a lower total cost than can any combination of more than one firm. This is called “natural monopoly,” and it bestows upon its possessor the power to restrict output and set prices at levels higher than are economically justified.

Economic Regulation: The explicit public or governmental intervention into a market to achieve a public policy or social objective that the market fails to accomplish on its own.

Theory of Price in Competitive Markets

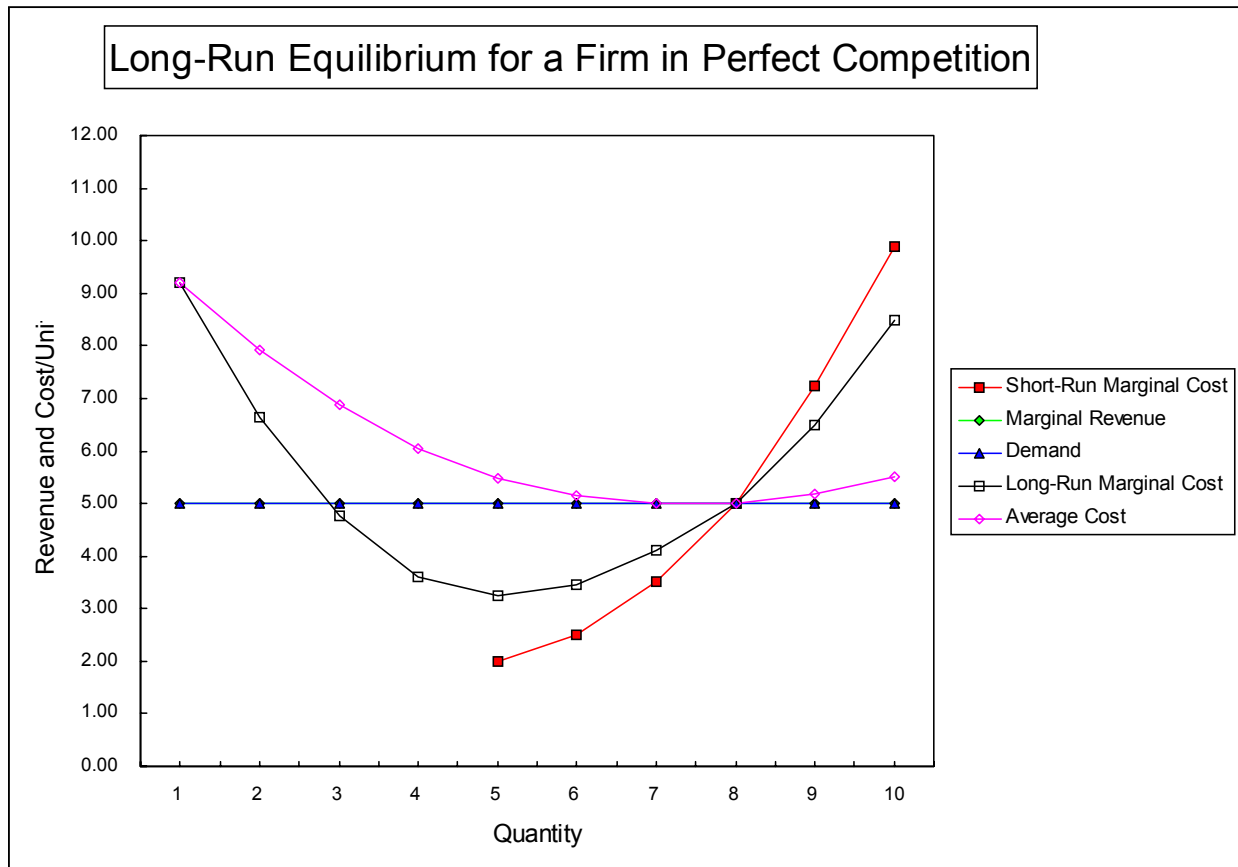
Modern economists are interested in discovering the elements and conditions of economic activity that will yield the greatest level of societal welfare, given an *a priori* distribution of income. Societal welfare is increased by maximizing economic efficiency: namely, that scarce resources are put to their most highly valued uses and are used most efficiently in production. There are two components of economic efficiency: allocative and productive.

The objective of allocative efficiency is met when as great a quantity of a good as possible is produced and sold at a price that satisfies the demand for that good at that price. Productive efficiency is maximized when a given quantity of output is produced at the lowest possible total cost. Generally speaking, allocative efficiency increases as productive efficiency increases.

Economists have developed a complex set of tools to describe and predict the behavior of economic actors under a variety of conditions. In general, their observations are expressed in terms of a market's proximity to perfect competition, which has been shown by mathematical proof to assure the most economically efficient outcomes. In its simplest form, the proof works as follows:

Firms act to maximize their own profit and consumers act to maximize their own welfare. In perfect competition, price is set by the market and in equilibrium it occurs when producers are willing to supply that amount, and only that amount, at a price that will meet total demand for the good at that price. As price increases, producers are willing to supply more units of the good, but consumers are willing to purchase fewer units. Thus, there is only one price that satisfies the preferences of both suppliers and consumers simultaneously, and it is often referred to as the market *clearing* price (all goods produced at that price will be demanded).

Because no firm or consumer has market power (which is to say that the production or consumption decisions of any one firm or consumer will have no effect on overall supply or demand and, therefore, no effect on price), firms and consumers in competition are *price-takers*. Put another way, the relationship between price and demand that describes the behavior of consumers in the overall market for the good (namely that as demand increases, the price consumers are willing to pay decreases) does not describe the consumer behavior that any one firm confronts: specifically, the unwillingness of any consumer to pay higher than the market price for any of its output. (They would, of course, be perfectly happy to purchase all its output at less than the market price, but under such circumstances it would be unable to meet the increased demand and simultaneously cover its



costs.)

Because firms in competition cannot change the market price, they will instead optimize their factors of production (capital, labor, other inputs) in order to produce that quantity of goods and services which will, at the market price, maximize their profits (*i.e.*, minimize their costs). Mathematically, they will continue to produce goods until the cost of producing the next unit of output (the *marginal* unit) equals the additional (or marginal) revenue that they will receive for that unit, which of course

is the market price. At that point they will stop producing, since to produce more will be to incur marginal costs that exceed marginal revenues, and total profits will fall.

The marginal cost of production is the cost incurred to serve an additional unit of consumption at a particular time, and it represents the cost to society to satisfy that incremental demand. Since it represents the true cost of putting resources to a particular use, a price equal to marginal cost correctly informs consumers as to the minimum value of that use; thus informed, they can choose to purchase or not to purchase, depending on how highly they value that consumption (and alternatives to it) themselves. Mathematically, marginal cost equals the difference between a firm's total costs if it supplies the incremental unit and its total costs if it does not.

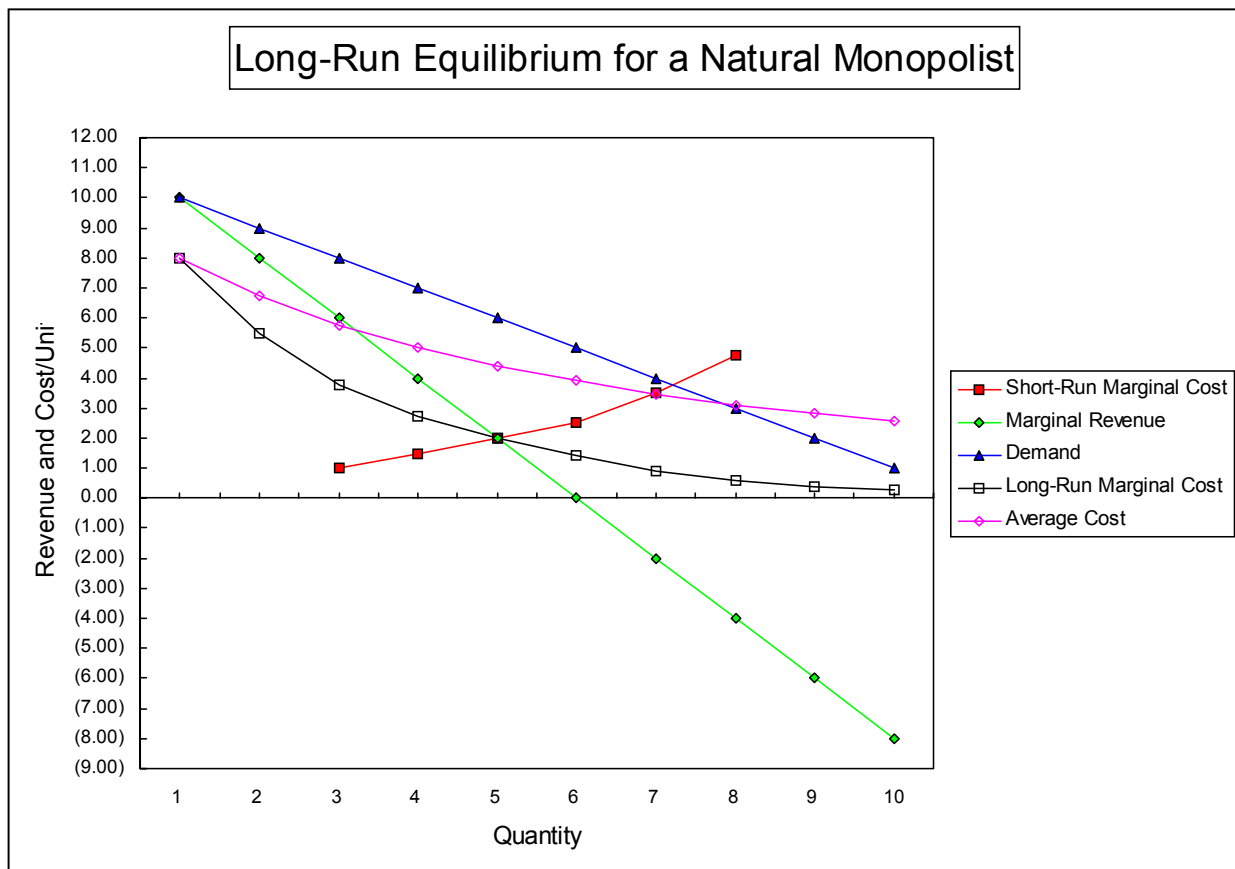
The interaction between supply and demand in an environment where the costs of production increase as output increases has the effect of creating economically efficient outcomes. The increasing-cost nature of the particular industry invites new producers to enter the market in the hope of producing at a lower cost, thus winning consumers and profits. However, the overall increase in supply caused by the new producers can only be sold (or *cleared*) at a lower market price. This, as a consequence, improves overall societal welfare, since more consumers will then derive value from use of the good. In this way, competitive markets drive down the price of a good to the lowest possible point for a given level of demand.

Of critical importance in this analysis is the fact that the marginal cost of production should equal the price that consumers pay ($P = MC$). When $P = MC$, consumers are correctly informed as to the value of society's resources that are allocated to produce the incremental unit of output that they are demanding (or considering demanding). If society's resources are to be put to their most highly valued uses, prices should reflect the true costs of production. In this way, consumers, who make purchasing decisions based on the relative values that they assign to alternative uses of their own resources (income and wealth), will necessarily make consumption decisions that most efficiently allocate society's resources (*i.e.*, put them to uses that maximize their net value). If a good is priced below its marginal cost (under-priced), then some quantity of the good will have been produced at a cost that exceeds its value to society, and the resources that were given to its production could have been allocated to better (more highly valued) uses elsewhere. The converse is true of over-priced goods.

Theory of Price under Monopoly Conditions

A monopolist, like a competitive firm, will maximize profits at that level of output where its marginal cost equals its marginal revenue ($MC = MR$). However, for the monopolist, marginal revenue per unit does not equal what would otherwise be the market price for the good. Because a monopolist supplies the entire market for a good, it is not a price-taker. It has the power to set price at that level which maximizes its profits, rather than merely the ability to optimize its factors of production. A monopolist's profit-maximizing strategy is generally to restrict output and raise prices.

Its price-setting power is not absolute, however. The fundamental — inverse — relationship between price and demand still operates. The value that consumers see in a good is a function of its price, and this will determine how much of a good will be purchased at a particular price. Even if the good in question is essential, consumers may nevertheless be willing (or forced) to forego consumption if the price is too high. Ideally, a monopolist would like to charge each individual consumer the highest possible price that he or she is be willing to pay for the good (this is *price discrimination* in the economic, not legal, sense of the term). However, it is prevented from doing this by the threat of emerging secondary markets, wherein consumers would resell the good at prices higher than they themselves paid. This is arbitrage, and the independent attempts by many resellers to do so would quickly lower the market price to that originally charged by the monopolist. Thus, all consumers pay



the same price for the good, though some of them would have been willing to pay a higher price. This is, of course, also a feature of competitive markets.

The effect of this market reality on monopolists is that, as output increases, price fall, but so too does marginal revenue. Consider, by way of example, the monopolist who can sell 100 units of its product at \$2.00 per unit, 200 units at 1.50 per unit, and 300 units at 1.00 per unit. In the first instance, the firm's total revenue is \$200, and its marginal revenue is also \$200. If it increases its output to 200

units, its total revenue becomes \$300, but its marginal revenue falls to \$100. If it again increases its output, this time to 300 units, its total revenue is \$300, but its marginal revenue is zero. Unless its cost to make those additional 100 units is also zero (or less!), it is quite unlikely that the monopolist will produce them.

By itself, this exercise does not tell us what the profit-maximizing price and quantity of output are — before we can determine them, we need to know how the firm's costs change as output increases: we need to know its marginal cost curve — but it does reveal an important constraint that the price-setting firm faces. For the competitive firm, marginal revenue equals the market price, which does not change as the firm's output changes. But for the monopolist, marginal revenue is always less than price. Since the monopolist will continue to produce until marginal revenue equals marginal cost, it means that the monopolist will cease production when price is double marginal cost. This is hardly the most efficient level of output — output can be expanded until marginal cost equals price, and society will be better off. Again, whether the monopolist will still be profitable when price equals marginal cost (will it cover its total costs?) depends on the relationship of its average cost curve to its marginal cost curve at that point. But the essential point is that a monopolist's profit incentives do not cause it to act in a way that maximizes societal welfare. Monopoly power, then, is the power to set price above marginal cost (and, of course, above average cost).

Natural Monopoly

Monopolies can arise for any of a number of reasons, for example, through possession of legally granted patent or franchise rights or through control over some essential aspect of the production and marketing process. Some industries, however, are characterized by an unusual feature, called increasing economies of scale, which is to say that their costs of production actually decrease as output increases. When this remains true for a broad range of output, it is generally more efficient (less costly) for one firm, rather than two or more, to supply the entire market. This is referred to as *natural monopoly*.

Natural monopoly: A market in which a single firm can produce a desired level of output at a lower cost than any output combination of more than one firm.

Typically, it is an industry's technological characteristics that lead to natural monopoly, and we often see that a common feature of natural monopolies is a high ratio of fixed costs to total costs. Consequently, as output increases, average cost decreases. The technological elements of the electric industry that create natural monopoly conditions are, first and foremost, the transmission and distribution systems. They have very high fixed costs and low operating costs: it doesn't pay to have two or more sets of wires running down the street. T&D exhibits tremendous economies of scale. As for generation, it appears now that we have exhausted (or overcome) most economies of scale — cost no longer declines as the size of power stations increases. The current debate on restructuring in the U.S. has been precipitated by this question.

Objectives of Economic Regulation

In light of these economic features of the utilities, certain objectives for price regulation emerge. The two overarching objectives are *economic efficiency* and *fairness* (or equity). These can be further broken down as follows:

Efficiency, both allocative and productive. Since electric utilities generally do not operate in competitive markets that would impose cost discipline upon them, regulation must fulfill that function. This objective is promoted by setting rates that reflect, to the greatest extent possible, the marginal costs of production.

Fair prices. Fair to both consumers and investors. By this we mean price regulation is intended to guard against the reaping of economic profits while still enabling the utility to generate revenues adequate to cover prudent expenses and investment and to provide a reasonable return on that investment. In the provision of essential goods and services, it is deemed inappropriate for private economic actors to reap "windfall" profits.

Non-discriminatory access to service for all consumers.

Adequate quality and reliability. Because electricity is an essential service, reliability is critically important.

Other stated public policy objectives (e.g., environmental protection, universal service, low-income support, energy efficiency, etc.).¹

Public Goals of the Electric System

As an essential element of state and national infrastructure, as a system with natural monopoly characteristics, and as a system with a very large environmental "footprint", the electric system affects the public good in many ways. It is reasonable, and often necessary, to support public purpose programs through the electric system and its regulation. Well-established traditions, programs, and practices to support public purposes include:

- Universal service policies, including service to low-income customers and rural areas;
- Investments and other program support for energy efficiency in generation, delivery, and end-use services;
- Investments in, and development of, renewable, sustainable, and less-polluting generating resources;

¹ Not discussed here, but of critical importance, are the effects of unpriced environmental impacts: *externalities*. Often, there are costs to production and consumption that are not reflected in the actual price of a good. There are many reasons why such costs might go unaccounted for, but economists agree that all such costs should be internalized (reflected in price) if price is to meet the efficiency objective.

- Support for research and development on electricity generation, delivery, use and impacts;
- Consumer protection and consumer education programs.

What Public Benefits Should the Electric System Support?

Because the electric system offers a means of revenue collection connected to an essential service, advocates and governments may look to the utility or the regulatory authority for support for a variety of legitimate, perhaps even compelling, public purposes. However, keeping the goals of economic efficiency in mind, it is important not to distort electric prices unduly by transforming electric rates into all-purpose general taxes. Striking the balance here requires consideration of the following questions:

- Is this public purpose program or expenditure directly related to the electric system, or would the revenues collected be more in the nature of a general tax? (General taxes, such as sales taxes, property and income taxes, etc., may all be collected from electricity producers and consumers, as with any commercial activity, but these should be treated in the manner of other taxes.) Expenditures directly related to the administration of the electric system — such as renewable energy procurement, efficiency programs, and universal service — may properly be administered by the utility and regulatory authority within the cost of service.
- Does the proposed program or expenditure promote the long-term public good?
- Can this program or expenditure be administered with minimal price and market distortion?
- Is this program or expenditure undertaken to correct a market failure, or overcome a barrier to an efficient market?

Renewable energy and energy efficiency programs may be justified on economic grounds as a means of correcting the market's failure to incorporate environmental costs in the price of electric generation, and overcoming consumer barriers to deployment of cost-effective efficiency technology. Thus, even though these programs may raise the short-term price of electricity, they do not distort electricity markets. Correcting market failures is not a market distortion.

Electric System Public Purpose Mechanisms

Across the globe, and over many years, electric utilities, governments, and utility regulators have explored numerous mechanisms to deliver public interest programs in connection with electric service. Many successful examples exist. Some, such as the practice of Integrated Resource Planning, were developed in the context of vertically-integrated electric systems, and have greatest applicability in any type of single buyer industry structure (See Chapter 7). Others have been developed in connection with emerging retail competitive models.

Public Purpose Mechanisms — Leading Examples

A comprehensive review of public purpose mechanisms across the electric industry would need to cover a very large number of topics and examples. In addition to the traditional mechanisms used under various franchise systems, a number of new techniques are now emerging for application in a competitively-neutral fashion in competitive electricity markets. Leading examples include:

Energy Efficiency Programs

- Comprehensive energy efficiency and load management programs have been developed and widely implemented as part of utilities' Integrated Resource Plans;
- Jurisdiction-wide programs have been funded through wires or system "uplift" charges, and administered through public efficiency agencies (e.g., the UK's Energy Savings Trust, and California's Energy Commission, or the new Energy Efficiency Utility franchise set up in Vermont);
- Efficiency measures have been promoted through voluntary programs (e.g., the EPA's "Green Lights" and "Energy Star" programs) and mandatory building and appliance efficiency programs;
- Some jurisdictions have simple mandatory spending guidelines (e.g., Texas under restructuring, and Brazil's 1% spending mandate);
- In some regions the focus is on Market Transformation activities (e.g., the U.S. Pacific Northwest and New England).

Renewable Electricity Generation

- Mandatory purchase requirement at avoided cost (e.g., PURPA in the U.S. and feed laws in Germany and elsewhere);
- Support for renewable energy research and development through research consortia (e.g., the Electric Power Research Institute and several state-level programs);
- Creation of a renewable energy fund to support new renewable energy production in response to a public bid offering;
- Establishment of a Renewable energy Portfolio Standard applicable to all generators or retail electric sellers in a competitive electric market.

Research and Development

- Pooled funding, either voluntarily (e.g., Electric Power Research Institute) or through a mandate (e.g., a wires charge), to support public-purpose research and development;
- Tax credits for qualified R &D;
- Public expenditures through government agencies, universities, and grants to utilities and equipment manufacturers.

Universal Service Mechanisms

- Traditional franchise: obligation to serve all customers within the franchise territory;
- Rural build-out requirements as part of franchise awards in urban areas;
- Geographically-averaged distribution rates provide support for service at average rates in high-cost portions of the service territory;
- Affordability subsidies for low-income households (lifeline rates, low-income discounts, bill arrearage forgiveness programs, disconnection moratoria);
- Rural electrification subsidies (both grid and off-grid options);
- Rural electric cooperatives;
- Efficiency programs targeted to low-income households.

As a general matter, successful programs satisfactorily address the questions set out above in the discussion of *What Public Benefits Should the Electric System Support?*. Program designers should also consider:

- Whether the program can be accomplished within the authority of the regulatory agency, or whether it requires general governmental enabling legislation;
- Whether the proposed program is compatible with the existing and anticipated industry structure — including a competitive market if that transition is intended. In particular, to the degree that either wholesale or retail competition is expected, public purpose support or performance mechanisms must be “competitively neutral” and “non-bypassable”; and
- Whether continued regulatory oversight can be maintained, to monitor program effectiveness and make necessary adjustments and improvements over time.

1. : Institutional Framework and Process

Background

In most countries, the electric utility has been typically operated by a government agency which is often organized under a ministry of energy or other ministerial level unit. In this framework, the utility fulfills a government responsibility of providing utility service, acting as an agency of the government. Pricing decisions are often premised on social welfare or political criteria. Underlying cost structures are not closely related to prices. In fact, prices are often set using an “ability to pay” theory. Almost universally, there is an assumption that industrial and large commercial are the consumers that are able to pay, while household and agricultural customers are not able to pay. As a result, electric pricing tends to be a highly political process, unsupported by rational economic policy. As a result the operations of the electric utility may experience low levels of reliability, inability to serve total consumer demand and little or no access to local, regional or global capital markets. These conditions have led to a widespread effort to reform the electric sector in many developing countries.

Electric sector reform usually involves two major reorganizations of the industry. First, the utility operations are transformed from a government agency into an enterprise format. This may or may not involve transferring the assets of the utility to private ownership. Even where the utility remains under government ownership, its entire operations are separated from the government structure and budget process and placed on a standalone *enterprise* basis. See Chapter 7.

Functions and Responsibilities of a Regulatory Commission

The other major reorganization involves the creation of a utility regulatory commission to regulate and control the reformed utility. A regulatory commission must impose a variety of economic regulations on the utility and must be mindful of a variety of collateral issues. The functions and responsibilities of a commission include:

- Rate setting (often called tariff setting);
- General regulatory rulemaking;
- Utility system resource planning;
- Environmental impacts of resource utilization;
- Conservation and efficient use of utility and societal resources;
- Consumer Protection;
- Maintenance of the utility’s financial integrity;
- Assuring high system reliability; and,
- Utilization of appropriate tools to assure that utility management is given the proper set of incentives.

These functions and responsibilities are often at odds with another. As a result, the commission is often faced with the task of balancing these competing objectives to develop a workable framework of regulation.

Key Characteristics of a Regulatory Commission

The structure, scope and powers of a regulatory commission are key to a successful restructuring of the industry. The key characteristics of a good regulatory commission include:

- Independence from the political process;
- Independence from the regulated enterprise;
- A broad mandate to protect the public interest;
- Technical expertise in the functions and business of the regulated enterprise; and,
- Continuing monitoring and enforcement of rules and orders.

The single most important characteristic of a successful regulatory commission is its independence. A commission should be independent of political and industry influence. Capital markets are typically very concerned with the political and regulatory environment faced by any company. This is especially the case in the electric industry which is a highly capital-intensive industry. Also, because the electricity sector cuts across virtually all strata of the public, it has the potential of becoming the focus of political interest. Because of this, the capital markets have a heightened concern over regulatory and political risk. Capital markets have higher confidence in the utilities being finance, where the commission has greater independence from the political process, both as a matter of explicit policy and through the demonstrated track record of the commission. Independence is viewed as fundamental to assuring the continued financial viability of the utility.

Higher risk translates directly into higher financing costs and higher retail prices.

Because the new commission will often be faced with tough pricing decisions that may not be well received by the public, the commission must achieve a high level of institutional acceptance by the public. Members of the public are often highly skeptical of their government. As a result, the new commission may be viewed as just window dressing to obscure an underlying political or governmental activity. The ability to demonstrated independence from politics is a necessary component of achieving public acceptance. The most importance tools for securing public acceptance are:

- Public Education;
- Administration of an open and transparent process;
- Validation of consumer participation in the process; and
- Demonstrated rationale for decisions of the commission.

Independence of the Commissioners

An additional point, deserving special attention, is the issue of independence of the commissioners themselves. The public must have confidence in the individuals who serve as commissioners. A commissioner must maintain a degree of judicial stature in the eyes of the public. This means maintaining a special degree of integrity through both rhetoric and action. The commissioners should be bound by a strong ethical code. The key components of such a code include:

- Prohibition against any ownership, gratuity or other material economic interest in the regulated utility;
- Prohibition against any ownership, gratuity or other material economic interest in any consumer or consumer group affected by any commission decision;
- Prohibition against *ex parte* communications with parties in a pending matter; and,
- Prohibition against political influence or interference.

Because no regulatory commission exists prior to restructuring, the commissioners and its staff may be initially be drawn from within the electric sector. While this may be necessary and, indeed, desirable, it is equally desirable for the new commission to establish its independence from the industry it regulates. Creation and activation of the new commission should be viewed as one of the *first* steps in restructuring. By activating the commission very early in the process, the commission is able to gain important and timely first-hand experience with the industry it will be regulating. In addition, this allows the commission to establish, develop, and implement its independence from the utility. This is especially important because of the commission's broad public interest mandate.

The commission plays a unique role in synthesizing the competing interests of the utility, the financial community, the customers and government.

Commission Staff

It is imperative that the commission have sufficient staff to carry out its duties and mandates. Staffing requirements, and their associated functions, of a commission include:

- Administrative Staff:
 - Budget;
 - Personnel; and,
 - Records and archives.
- Advocacy Staff, including, attorneys, economists, accountants, engineers
 - Rate and tariff analysis;
 - Development of public policy issues and positions; and,
 - Representation of consumer and other public interests, especially those not otherwise represented in any given proceeding.
 - Hearing officers or administrative law judges:

- Conducting hearings; and,
 - Recommending decisions to the commission.
- Commission Advisory Staff, including attorneys, economists, accountants and engineers:
 - Direct expert advice to commissioners;
 - Policy analysis; and,
 - Rate and Tariff Analysis.

A regulatory commission has attributes very different from most governmental agencies. Because of the highly technical nature of the subject matter, a commission is typically staffed with a large number professionals (attorneys, engineers, etc) and very few of the typical governmental bureaucrats. The nature of the staffing requirements and the need for real independence from the industry, customers and politics call for adequate compensation schedules. The type and level of compensation for the commissioners and staff should be significantly higher than that typical of other government agencies. In addition, the best practice is to prohibit the commissioners and the staff from having any form of compensation or other benefits directly or indirectly related to the electric industry or any other party affected by the commission's decisions.

Commission Process

It is imperative that the commission establish rules that are open and encourage public participation. Not only does public participation increase public confidence in the commission as an institution, experience has shown that public participation improves the overall end result of regulation. Rules that encourage participation by all interest parties will help to ensure that the commission fully understands the issues of importance to those parties, as well as the impact of the commission's decisions.

To support and implement a viable public process, the commission's rules should address the following key subjects.

- Rules of procedure;
- Minimum data and format requirements for filing a tariff/rate case;
- Rules for disposition of consumer complaints;
- Service quality rules for the utility;
- Annual and other periodic disclosure and reporting for utilities;
- Rules for enforcement of the commission's decisions;
- Rules for system planning issues (See *Integrated Resource Planning*); and,
- Rules for competitive bidding for resource acquisition (See *Independent Power Production and Competitive Bidding*).

Chapter 3: Cost-Based Ratemaking

Objective of Rate Setting

Rates should be set so as to enable a utility a reasonable opportunity to recover prudently incurred expenses (including investment) and a fair return on the remaining cost (the un-depreciated portion) of investment.

Mechanics of Traditional Rate Setting

The general mathematical formula for determining rate levels begins with a computation of total revenues (revenue requirement) necessary to meet demand for service, as follows:

$$RR = E + d + T + [r * (V - D)]$$

where:

RR = Revenue requirement, or total revenues

d = Annual depreciation expense

T = Taxes

V = Original book value of plant in service

D = Accumulated depreciation

Note: (V - D) = "Net rate base"

r = Weighted average cost of capital

Test Year. The period of time under examination. In many places, rates are set using a *historic test year*, adjusted for "known and measurable" changes. The exercise yields an *adjusted test year* cost of service that is meant to be a predictor of a company's revenue needs during the period rates will be in effect.

The simplest way to set rates would be to divide the revenue requirement by sales volume (kWh), as follows:

$$\text{Rates} = \text{RR} / \text{Volume of sales}$$

Although actual rate-setting is somewhat more complicated than this (for example, customers are grouped according to their usage patterns, and the revenue requirement is allocated among those classes, according to principles of cost causation), but the essential mathematical relationship holds: the product of rates and sales is the revenue requirement.

Critical point: this exercise assumes that there is a direct relationship between a utility's revenue requirement and the rates it should be allowed to charge. This is, of course, true, but bear in mind that regulators have traditionally set *rates*, not revenues (See Chapter 6 for more recent trends toward revenue based regulation). The revenue calculation is merely a tool for doing so. But,

because rates are set to cover costs, regulators devote a good deal of attention to the constituent elements of a company's cost of service.

Elements of Rate Setting

The three major components of an exercise in rate-setting are rate base, return on rate base (sometimes referred to as return on investment), and operating expenses. These combine to create a *cost of service*, *i.e.*, the calculation of total costs that total revenue is intended to cover.

Rate Base. Rate base, broadly speaking, consists of those long-lived investments made by the utility to provide service. They include, among others, utility-owned generating facilities, other buildings, poles, wires, meters, vehicles, computers, and so on.

Depreciation. Rate base is intended to approximate the current value of capital goods that are "consumed" over periods of more than one year. The consumption of these goods over time requires that they be paid for over time. These payments are called depreciation.

There are a variety of depreciation methods. A simple and common one is "straight-line." If an asset costs \$100,000 and has a 20-year life, we will depreciate it at a rate of \$5,000 per year ($100,000/20$). After the first year, the asset will be worth (or its remaining value will be) \$95,000, after two it will be 90,000, and so on.

Expenses. Sometimes referred to as annual or operating expenses or cost of service. These are the company's current annual (test year) costs of operation.

Operating expenses include power or production costs (including delivery costs), wages and salaries, benefits, insurance, miscellaneous administration and general expenses, billing costs, legal and regulatory expenses, and taxes.

Power costs can represent anywhere from 50-90% of a company's total cost of service. They consist of the operating costs (including fuel costs) of the generating facilities that the company operates, the total annual costs of purchased power, operations and maintenance costs, and the costs of delivering that power ("wheeling" charges and any other variable costs caused by transport). The capital costs of production and delivery facilities are, as mentioned above, included in rate base.

Depreciation is an expense also, though a *non-cash* expense. It represents the return *of* (not on) investment in rate base.

Return on rate base is added to operating expenses and depreciation to calculate a total cost of service.

Not included in this set of expenses is interest on debt or dividends on equity. These costs are covered by return on rate base.

Return on Rate Base. This represents the monies to be returned to investors for the use of their investment to purchase assets to meet demand for electric service. There are two major components to its calculation: one, the costs of (demanded rates of return on) investment funds and, two, the relative shares of debt and equity. Return on rate base is the weighted average cost of capital that the company faces.

Costs of borrowing

Debt. Long- and short-term.

Equity. Common and preferred.

Capital Structure

The relative shares of a company's total capitalization.

Chapter 4: Rate Design: Pricing for Regulated Services

What should unit prices look like? How can the general objectives of economic efficiency and fairness be met?

Rate Design: To a regulator, rate design is the *structure* of prices, that is, the form and periodicity of prices for the various services offered by a regulated company. The two broad categories of pricing are usage charges and fixed, recurring charges.

Objectives of Rate Design

The general objectives of economic regulation inform the rate design process. More specifically, we want to set economically-efficient prices (*i.e.*, prices which reflect, to the greatest extent possible, the long-run marginal costs of service), while simultaneously enabling the regulated firm a reasonable opportunity to recover its legitimate costs of providing service (including return on investment).

The particular problem faced by regulators in this exercise is that the legitimate historic (accounting or “embedded”) costs that a utility incurs are to be recovered in rates, but these costs may only bear a passing resemblance to the forward-looking long-run marginal costs that form the basis of economically efficient prices. The reconciliation of the need to cover historic costs with the desire to set economically efficient prices, and then to meet other objectives of regulation (such as fairness and low-income protection), requires much judgment. The several and sometimes competing rate design goals can be categorized as follows:

Revenue-Related Objectives:

- Rates should yield the total revenue requirement;
- Rates should provide predictable and stable revenues; and,
- Rates themselves should be stable and predictable.

Cost-Related Objectives:

- Rates should be set so as to promote economically-efficient consumption (static efficiency);
- Rates should reflect the present and future private and social costs and benefits of providing service;
- Rates should be apportioned fairly among customers and customer classes;
- Undue discrimination should be avoided; and,
- Rates should promote innovation in supply and demand (dynamic efficiency).

Practical Considerations

A rate design should be, to the extent possible, simple, understandable, acceptable to the public, and easily administered.

Embedded Costs

As stated at the beginning of this chapter, rates are intended to recover the prudently incurred, embedded costs of service — the costs that the utility actually pays. These costs are allocated among customer classes, consumer groupings typically formed according to their patterns of usage. Similar usage causes similar costs, thus enabling class-specific assignment of those costs. Among the costs to be identified and “functionalized” are energy and capacity, transmission, distribution, customer service, and others. The methods for cost assignment can be complex, but in the end the objective is to have those customers who cause the costs pay the costs.

Of course, not all costs can be easily categorized (for example, the joint and common costs that are necessary to the overall operations of the firm but are not directly necessary to the provision of any particular service), and so apportioning them among customer classes becomes an exercise in judgment. Regulators may decide in certain instances to allocate a cost according to a class’s share of total energy usage, and in others according to class coincident demand for capacity. Regulators are guided by notions of reasonableness and fairness when making these decisions.

Once the cost of service is allocated among customer classes, rates can be set according to the mathematics already described. Each customer class has its own revenue requirement and expected volume of sales. Typically, however, not all of the costs of service are collected in energy charges, some (usually small) portion of them may be recovered through fixed, recurring fees called customer charges. These are billed whether the customer uses any electricity or not; the charges are intended to cover the costs of utility activities that are unrelated to usage, for example, metering, billing, and collection. In the main, however, the majority of costs are recovered through charges that vary with a customer’s usage. There are two categories of these: energy and demand.

Energy charges collect revenues on a per-kWh basis. Demand charges collect revenues on a per kW basis. It is common for low-usage customer classes to pay energy-only charges, and included in those fees are the costs of capacity needed to serve that customer group. High-usage customers often are billed on both an energy and demand basis; their capacity costs are separated from their energy costs. While the costs of metering for this kind of service are higher than energy-only metering, the savings (for both the customer and utility) that flow from the customer’s ability to respond to the clearer price signals invariably exceeds those costs.

Marginal Cost Pricing

As discussed in the first chapter, the marginal cost of service is the cost incurred to serve an

additional unit of consumption at a particular time, and it represents the cost to society to satisfy that incremental demand. By the very nature of monopoly, however, it is unlikely that at any particular time marginal cost will equal embedded cost (which is, in large measure, an average historic cost), and thus setting prices strictly equal to marginal costs will fail to generate the appropriate level of revenues for the company. Whether they are too high or too low will depend on the relationship of the utility's historic costs to the current costs of fuel and new technology.

The task of identifying and functionalizing the utility's costs for the purpose of determining its marginal cost of production at specified times is, in many ways, quite similar to the work done for embedded costs. Unlike an embedded cost study, which in effect calculates the average cost per unit of demand for each class and period under examination, a marginal cost study measures the cost of producing a defined increment of demand for each class and period specified. Total cost is only relevant insofar as marginal cost is a measure of the change in total cost as demand changes. In certain cases, particularly at times of peak demand when additional capacity may be called for, marginal cost will often exceed average cost; at other times, marginal cost may be significantly less than average cost, since typically the only costs incurred to serve incremental demand off peak are variable fuel and maintenance costs.²

Once calculated, marginal costs are then treated as prices and are multiplied by expected units of demand in the various periods under study. This yields the expected total revenue that the company would collect under a marginal-cost pricing regime, which can then be compared to the embedded cost revenue requirement. How prices should then be adjusted depends on whether the marginal cost revenues are greater or less than the embedded.

There are a variety of ways to reconcile marginal cost prices with an embedded revenue requirement. Rates differentiated on the basis of time of day, week, or year of use are quite common, and often are designed to reflect marginal costs at times of peak demand (when costs are high) and

²One complexity, which we can only briefly discuss here, is the relationship between generation capacity and energy. It affects both the allocation of embedded costs and the calculation of marginal costs. Since a utility is under a legal obligation to serve, it follows that it must install sufficient capacity to serve all customers *on demand*. This means, therefore, that capacity needs (and costs) are driven by peak demand. If a utility's only obligation were to meet peak demand, then it would install only the least-cost capacity. However, a utility also must serve energy needs at other times, and it is an unhappy fact of electric generation technology that as capacity costs decrease variable operating costs increase. The total costs and average (per unit output) costs of the different generation technologies vary as output varies; in certain cases, average costs increase as output increases, and in others they decrease. There is, therefore, a trade-off between capacity and energy costs that system planners must consider when building (or purchasing) new capacity, if they hope to minimize total costs. Which technology (or contract) to use depends on how much energy it will be expected to deliver; as load factor of demand to be served (the ratio of energy demanded in a period to the maximum possible energy demand in that period) increases, so usually do the capacity costs of the units that can most efficiently serve that load. In these instances, the unit serves both capacity and energy needs, and the cost of that capacity which exceeds that cost of the lowest-cost form of capacity has in fact been incurred to serve energy needs. This is sometimes referred to as the capitalization of energy costs, and it has important impacts on rate design. It is appropriate to recognize those incremental capacity costs as energy costs for the purpose of designing rates; as a general matter, they should be included in kWh — not kW — charges.

average costs at other times. In this way, the utility's risk of revenue shortfall is lessened, and consumers see the important cost signals at times of capacity constraints. Inclining or declining tail-block rate structures are another option. With these, price changes (increases or decreases) as volume demanded during a period (say, a month) increases. These may not send as accurate a price signal as will time-of-use rates, but they are generally seen as an improvement over flat, average rates.

In the end, regulators must apply their expertise and judgment when designing rates. Considerations that can inform their discretion include fairness, differences in demand elasticities (willingness to pay), and other public policies (such as low-income support and the pricing of environmental externalities). Distortions that hinder economically efficient outcomes will inevitably creep into prices; this disjunction between marginal and average costs is an unavoidable aspect of natural monopoly. What distortions, and in what magnitudes, then are acceptable? This is one of the central dilemmas of regulation, and there are no easy answers.

Chapter 5: Licensing the Utility

Licenses

A fundamental choice confronting all newly established regulatory commissions is whether to rely on the license³ or on generic rules as the primary instrument of regulatory control. A license-based system establishes most of the conditions of operation in the individual license documents. A rule-based system promulgates most conditions in rules of general applicability, supplemented by decisions in specific "cases".

In theory, a license-based system has attributes of a contract between the government and the utility, with the terms set forth clearly at the outset, while a rule-based system, offering the advantage of greater flexibility to meet changing conditions, depends for stability on societal concepts of due process of law. In fact, both flexibility and stability are essential attributes of all effective utility regulation, so each system must find mechanisms to assure the apparent advantages of the other. In so doing, they tend to converge - with each having to take on some of the disadvantages of the other in order to secure the advantages. Dispute resolution and the possibility of periodic competitive bidding for the license itself are two important sources of flexibility that can be built into a license-based system.

The issuing of licenses offers both an opportunity for innovative regulation and a serious dilemma. The opportunity stems from the fact that commissions faced by a multitude of duties and expectations may be able to use the license agreements as a substitute for generic rulemakings that they do not have the time and resources to undertake. However, the dilemma inherent in this opportunity is that license agreements, unless carefully structured, can become straitjackets as regulatory concepts and national priorities change over time. This concern will be exacerbated if regulators focus too heavily on suspension and revocation of licenses (rather than fines or ratemaking techniques) as the principal means of imposing penalties. Revocation means little unless other qualified operators are available to step in, and it is not suitable as a remedy for any but the most severe shortcomings.

In short, license agreements cannot be both a guarantor of full financial stability for the incumbent and an effective instrument for the introduction of a measure of competition and of customer protection. Financial stability and effective competition only go hand in hand for the firms that are performing well. License agreements should aim instead to reconcile an assurance of fair treatment and professional dispute resolution with the flexibility to adapt to circumstances and needs that are certain to evolve quite rapidly.

³ Sometimes called "franchises" or "concessions."

At least three types of bidding frameworks are possible:

- **Once-for-all license contracts:** Under this approach, the license would be awarded competitively only once, at the outset. The bidding would be in the context of a contract that would state as specifically as possible all of the terms and conditions of service. Because such a contract for the distribution of electricity could not possibly anticipate all future contingencies, it would necessarily be incomplete - with mechanisms for adaptation to unforeseen circumstances. Such mechanisms would be likely to involve the regulatory agency in some manner.
- **Incomplete long-term license contracts:** Under this approach, the license would be awarded for ten years or longer but would be subject to competitive bidding when it came up for renewal. This would require development of both a formula for the transfer of undepreciated investment to a successful bidder and an agreed upon mechanism for settling disputes both during the life of the license and at the time of renewal.
- **Recurrent short term license contracts:** Under this approach the license would be subject to competition at much shorter intervals - perhaps as little as three or four years. This would avoid many of the difficulties inherent in the drawing up contracts that must either foresee contingencies unfolding far into the future or count on regulators to resolve the disputes. It would maximize the license holder's sense that poor performance could lead to rapid displacement. It would increase the need to have an effective asset transfer process in place, since such transfers might take place far more frequently. Such short intervals require strong and reliable assurance that the undepreciated prudent investment would be fully recovered if the license were transferred. Otherwise necessary investment in long-lived assets would be discouraged.

The license cannot merely go to the highest bidder. Such an approach does no more than capitalize expected monopoly profits, to the immediate benefit of the license grantor and the eventual benefit of the license holder. Either the license must itself contain the formulae by which prices will be limited or bids should be judged on the basis of some criterion such as the lowest per unit price or revenue requirement within specified service quality parameters.

Argentina seems to have the most advanced license bidding system at this time. It requires that distribution licenses be awarded competitively at the outset and that a controlling share be rebid at ten-year intervals thereafter, or at anytime that a license is terminated for nonperformance. If performance has been satisfactory, the current license holder may be among the bidders and may retain the license by outbidding all others. In that event, no money changes hands. While an incumbent could retain control with an artificially high bid, such a bid would deny it any opportunity to sell on favorable terms.

The Argentine system appears to offer substantial incentives to operate the system well within the ratesetting framework established by regulators. Since rates are regulated (on a price cap basis) and licenses can be terminated for poor performance, customers also have protection if regulation is well administered. The mechanism by which prices are reviewed and reset just prior to the ten-year offering will be critical in determining the extent to which benefits are shared between customers and investors. Since Argentine licenses have not yet reached their tenth year, no actual experience with a full cycle is yet available.

As the Argentine example shows, license competition clearly is not a complete substitute for regulation. Because of the impossibility of developing license agreements that anticipate all contingencies and because of the likelihood of disputes during the periodic license rebidding, ongoing need for regulatory supervision is unavoidable. Such supervision by a professional regulatory body may reduce the politicization that has occurred in the cable television industry in the U.S., where this process has more often than not been overseen by city councils.

Finally, it is important to acknowledge that we have had little meaningful experience with electric utility license competition. This is a considerable argument in favor of short-term contracts, at least initially, as long as the necessary assurances of full recovery of prudent investment at the time of transfer can be provided. Indeed, short-term license contracting could be the first step in a transition toward consolidation of distribution entities, since the more successful distributors would be among the most obvious candidates to bid for the less successful. Short-term contracting could also smooth a transition to rule-based regulation as regulatory agencies mature, although such a strategy would have little appeal if license competition under the supervision of a capable regulatory agency were working well.

Licenses as a Supplement to Regulation

For licenses to be effective instruments of regulatory control, the following conditions should apply:

- The license duration should be limited, especially in uncertain conditions, to a few years. Even under conditions of relative stability it should not exceed twenty years;
- The regulator should be able to terminate the license for noncompliance with license conditions following appropriate notice, an opportunity for correction and a public hearing. However, this power should be supplemented by a system of lesser penalties, perhaps through the tariff-setting process;
- Transfer of the license without regulatory approval should be prohibited;
- The licensee should have to supply a complete, audited financial statement annually and the regulator should have complete access to the licensee's books and records at any time, as well as the power to compel the prompt furnishing of all necessary information;
- The property of the licensee should be subject to inspection by the regulator at any time;

- The regulator should have the power to resolve any disputes arising between the licensee and its customers, and perhaps also between the licensee and its suppliers of fuel and electricity;
- The license conditions could include targets and time requirements for extension of service in countries where many people lack electricity;
- License conditions could also include goals as to energy efficiency, metering, loss reduction and collections;
- The license could specify a surety bond as a further guarantee of good performance;
- The license should specify that service should be according to the highest and best standards of the industry, or some other acceptable standard, and more specific standards as to service quality and customer rights could also be included;
- The license should include a requirement, in the event of termination of the license, that the holder sell to the successor, probably at prudent original cost depreciated, as determined by the regulator;⁴
- The license should be subject to a power to compel license consolidations - upon payment of appropriate compensation - when economic efficiency or service reliability would thereby be enhanced;
- The license-awarding authority should be national or regional in scope and should have no significant economic stake in the success of the license.

A final, critical issue is whether to provide a pricing formula (i.e., cost of service, price cap, or revenue cap - together with automatic adjustment clauses, if any) in the license agreement. Such provisions substantially increase investor certainty and may be quite workable if the contract is not for a long period of time, allowing for modification according to the lessons of recent experience. The processes of bidding and negotiation that would accompany the awarding of such a license would be likely to be more informative than the rate cases that would otherwise be likely to occur. However, the viability of any approach that depends for its success on the presence of several entities desiring to provide electric service is uncertain in countries requiring substantial new investment to attain minimally satisfactory standards.

Still, license competition is most likely to be successful when the technology is well developed, demand is well defined, the need for unique skills is slight and displacement of an incumbent license holder - if necessary - can be achieved without serious asset valuation problems. As to electric distribution systems generally, these conditions can be substantially met, even though the unsatisfactory state of record-keeping in many electric systems will mean that the original cost of past investments will be an elusive standard.

⁴ A sale at market value is also possible under a system of performance-based regulation that shares efficiency gains with customers and caps the prices to be charged under the new ownership. Under rate-of-return regulation, where investors receive their capital back through depreciation and their return is figured into the price, a market price above book values produces a windfall for investors.

The potential for licenses to assist regulation and stimulate efficiency and competition has not yet been explored in much depth. Very careful attention should be paid to the drawing of the early licenses to be sure that valuable options are not inadvertently foreclosed.

Addendum

A variation on the concept of license regulation and competition is the application of the bidding concept to a subpart of the distribution utility mission. For example, the provision of service to low-income communities in the U.S. for a fixed sum or a fixed sum per customer has been considered by some regulatory commissions. So too have the functions of serving customers who do not choose a specific supplier or of providing certain types of energy efficiency services. In countries with substantial unserved populations or substantial groups not being metered, the task of serving these groups within a price ceiling could be done through competitive bidding even if the license itself were not awarded on such a basis. It is possible that innovative solutions to the special problems associated with serving customers in this category would emerge through such a process.

Chapter 6: Market Prices, Subsidies, and Public Policy Goals

Introduction

The Importance of Cost-Based Rates

As emphasized above (Chapter 3) governments, regulators, and utilities have found that rates must be set to reflect the costs of providing service to particular customer classes, in order to meet several important objectives:

- To collect adequate revenues to operate the electric system reliably and to attract necessary capital for system maintenance and expansion;
- To send efficient price and consumption signals to electric consumers; and,
- To allocate the costs of the system fairly among customers.

These considerations underlie well-established policies of cost-based ratemaking, with “cost” initially set at the long-run marginal cost of providing particular services (modified as necessary to produce sufficient revenues to cover the utility’s embedded cost of service). Importantly, such rates are also intended to approximate the price that a well-functioning, competitive market would send to consumers and producers.

Markets Are Not Perfect

Cost-based, and market-like rates are an essential starting point for utility rate-setting, but public policy also has a proper role to play in setting utility rates and services, for at least two reasons. First, market failures significantly affect the production, delivery and consumption of electricity. For example:

- Power plants are among most nations’ most polluting industrial facilities, and the cost of that pollution is rarely included in the costs of production;
- The uneven distribution of income in many locations distorts the demand curve for electricity, since many potential customers simply cannot afford to purchase it;
- The transmission and distribution network is a natural monopoly service, much like a public highway system; individual customers cannot build it alone;
- Customers lack much necessary information for making informed choices about electricity services, especially demand-side and efficiency options, and the transactions costs associated with conveying this information are very high; and,
- Individual customers appear to have very high discount rates for certain kinds of investments, including efficiency investments — much higher than the “social” discount rate used by governments, utilities, and regulators to evaluate utility investments proposed on behalf of those same customers.

Electricity Policies and the Public Interest

In addition to dealing with or surmounting these market barriers and failures, governments rightly view the electric system as a proper means of advancing other public policy objectives. As a key element in a nation's infrastructure, electric systems have long been recognized in both legal and political decisions as industries "affected with a public interest." Electricity policies are important elements in governmental programs for economic development, agricultural production, and rural and social development. Electric generation resources and fuels have important national energy policy consequences, and often impose very large environmental costs across large regions. For all of these reasons, governments and regulators recognize that electricity is "not just another commodity."

The challenge to decision-makers is in *balancing* the conflicting goals set out above: on the one hand, adhering to the discipline of cost-based rates that reflect market realities; while on the other hand, setting policies to overcome market failures and promote important public goals.

The Problem of Subsidies

Utilities, governments, and utility regulators are often called upon to deliver low-cost electric services to particular classes of customers (for example, low-income households, and irrigation users), or to individual customers, such as important industries, politically powerful individuals, or government agencies. The breadth and depth of such decisions can raise serious problems for the entire electric system.

Improper subsidies:

- Encourage inefficient consumption by the subsidized consumer — why invest in efficient technology, co-generation, or efficient fuel substitution if electric service is very cheap?
- Discourage consumption by other users, whose rates are raised to pay the subsidy;
- Can slow economic growth by using limited electricity supplies in low-value end-uses rather than higher-value applications;
- Promote uneconomic bypass decisions (e.g., on-site generation) by customers whose rates are raised to pay for subsidies to others; and,
- Can impair the credit-worthiness of the utility or the governmental agency that is supporting the subsidy, and their ability to attract financing for new electric system investments.

Subsidies Can Be Defined in a Variety of Ways

Customers and policymakers often consider a rate a "subsidy" if the price charged to one customer is lower than rates charged to others on the assumption that this shifts costs unfairly to other

customers. This may or may not be true, depending upon whether the rate differential is justified by a differential in the costs of serving the customers in question.

Economists generally agree that a rate does not confer a “subsidy” unless the price charged is below the long run marginal cost (LRMC) of providing the service in question. In many electric applications, average rates are above LRMC, so rate discounts can be justified on this basis. But there are two other considerations: (a) The utility’s LRMC may be lower than the LRMC on a total societal basis when unpriced environmental pollution or other externalities are considered; and (b) discounts to some customers will raise rates to other customers if the discounted consumption is consumption that would have occurred in any event at the normal rate.

Utility managers and regulators face persistent pressure to approve or tacitly ignore subsidies in many forms. Many should be resisted, including:

- Utility political and charitable contributions;
- Discriminatory rates within a customer class;
- Class cross-subsidies — extreme discounts to public facilities, private industries, residential or agricultural users, or other favored customer classes.

Discounts and Economic Development Rates

In distinguishing between justified discounts and unjustified subsidies, “economic development rates” provide a useful borderline example. These rates are often sought by industries and governments in order to promote new private sector investment and employment. Policymakers should support these rates only when their investment and employment objectives can be obtained without unfairly imposing additional costs on other customers. To avoid cost-shifting, economic development discounts will be justified only where:

- The discounted rate exceeds the utility’s LRMC (too often regulators wrongly use SRMC as the price floor);
- The new sales are incremental (i.e., they aren’t reducing income from pre-existing sales volumes); and,
- The incremental consumption would not occur with out the discount (the “but-for” test);

Moreover, in order to minimize the total costs imposed on the utility system over the long term, and to minimize the need for continuing discounts, the new load should use efficient end-use technology. Efficient building and equipment standards are an important condition of economic development discounts, and should be required as part of the discount offer or regulatory approval.

Discounted (Economic Development) Rate Example

- Industry proposing to build or expand operations in the service territory with employment and investment benefits;
- Industry may locate elsewhere (or not build) without lower electric rates;
- Assume:
 - Existing tariff rate of \$.07/kWh;
 - Proposed discount rate of \$.05/kWh.
- If marginal cost is \$.04/kWh, the discount may be justified;
- The discount rate still exceeds marginal cost by 25%; and,
- The industry's sales will contribute to the utility's fixed costs, reducing costs borne by other customers.

Other important considerations: Can we tell whether the additional consumption really meets the “but-for” test? Often, it's impossible to tell. For this reason, a healthy margin above LRMC is necessary to avoid a practice of pure games-playing by favored users. Key to economic fairness is being able to ensure that the rate charged will exceed marginal costs. Additional moderating features are also desirable, including:

- A pre-scheduled phase-down of the discount, so that its expiration does not cause “rate shock” to the discounted customer, and raise political problems in the future;
- A limited term to the discount, so that over time all users are brought to common tariffed rates without discrimination;
- Efficiency standards, so that only efficient load growth is supported by these explicit discount policies; and,
- Independent regulatory review of proposed discounts to minimize political pressure and insider dealing at the utility, and to ensure other customers that they are being treated fairly.

Other Potentially Justified Discounts

As in the case of Economic Development Rates, discounts may be justified in other instances where lower-cost electric service advances well-established public policy goals. Examples may include: rural electrification; service to low-income households that would otherwise not be able to afford electricity; and support for end-uses that are key to national development, such as agriculture and education. Any such discount proposals should be analyzed against the same criteria set out above:

- Are these sales that would not have occurred at full tariffed rates in the absence of the discount?
- Will revenues exceed marginal costs?
- Is the consumption efficient?
- Do the public policy goals supported through this program justify an exception to the general rules regarding posted, universally-applicable tariffs?

Chapter 7: Performance-Based Regulation

All regulation is incentive regulation; an important skill for regulators to develop is to understand what incentives are created by any particular regulatory scheme. Thus, to understand performance based regulation (PBR) one needs a good understanding of the incentive characteristics of traditional cost of service regulation.

Performance-based regulations generally come about due to dissatisfactions experienced with cost-of-service or rate-of-return regulation. Some believe that cost-of-service regulation stifles utility innovation by providing a risk with no outside reward and causes utility managers to be more responsive to regulators than to customers or financial incentives. PBR has also been pursued by some in order to create a more rational risk allocation.

Components of a PBR

Constructing a PBR consists of three basic steps.

- Define goals. This requires a realistic assessment of what types of behavior one wishes to encourage or discourage. It also means addressing the questions of how risks should be allocated between consumers and investors as well as any type of protective measures put in place to guard against unforeseen circumstances.
- Develop the structure of the PBR. The structure is the most important aspect of PBR that dictates whether the original goals will be met.
- Get the numbers right. One could create a properly structured PBR that puts incentives into proper direction, but if the numbers are wrong, the utility or shareholders will be enriched or injured.

Setting the Goals

The goals of a PBR should be clearly identified and articulated because it is the goals that determine the outcome on many individual PBR issues and options. Among the likely goals are the following:

- To create strong incentives for cost containment;
- To improve incentives for innovation;
- To encourage increased energy efficiency in supply and in end use;
- To encourage increased use of clean and renewable energy supplies;
- To increase customer service and service quality.

PBR Structure

The single most important structural issue is whether the PBR focuses on prices (price caps) or revenues (revenue caps). The following formula can be used to describe either structure.

$$\text{Cap}_2 = \text{Cap}_1(I-x) +/- z$$

The cap (capped prices or revenue) equals last year's cap times some index (such as consumer inflation) which broadly gauges growth in costs, less a productivity factor ("x"), plus or minus items that are not covered by the PBR ("z factors").

Under either the price or revenue approach the caps are typically set for a fixed period of time. The cost cutting incentives for price and revenue caps are identical. The main difference is that price caps may also encourage increased sales and hence discourage end-use energy efficiency. With revenue cap approaches, the incentives to invest in energy efficient range from neutral to significant.

Revenue caps make the most sense if one of the goals of the PBR is to encourage end-use energy efficiency and if cost do not vary with volume. Price caps make the most sense if end use energy efficiency is not a goal and if costs vary with volume. With respect to distribution utilities the data are fairly clear that costs do not vary with kWh volume, making revenue caps the most sensible approach. (Costs may relate to growth in the number of customers served but not to the growth in electricity use per customer.) The primary difference between price caps and revenue caps is the incentive created for demand-side management or end-use energy efficiency. With the price caps the utilities have an incentive to increase sales and have a very powerful disincentive to encourage or directly invest in end-use energy efficiency.

"Z" Factors

Most PBRs contain so called "Z factors". Z factors are events or cost items that fall outside the scope of the normal operation of a PBR. These may include items such as adjustments for changes in costs due to new laws or cost adjustments for items outside a utility management's control. Many PBRs include a long list of potential Z factors. Regulators tend to limit Z factors to items that are outside of a utility's management control and items of fairly substantial economic consequence. Whether a particular risk is outside a utility's control is not the most important consideration. The most important factors to consider in approving Z factors is a clear understanding of what risks you want the utility to bear. These may or may not be items that are outside of their control. For example, weather is clearly outside the control of utility management, but if utilities bear the weather related risk it will influence their decisions on what types of power plants to construct and perhaps even how to construct a transmission and distribution system. Similarly, if the cost of future environmental control is made a Z factor, utilities will not bear the risk of future changes in environmental laws. Although certain risks may be beyond management control, they nevertheless fall right within the range of risks that businesses in competitive markets must bear. Management should, therefore, be charged with managing the exposure to such risks through investment decisions and cost controls.

PBRs should include specific provisions for service quality. (For details on establishing PBR service quality criteria see *Chapter 10: Consumer Protection Issues*.) The easiest way for utilities to increase profits under any form of regulation is to cut service quality while maintain high prices.

Regulators may wish to add incentive or penalty provisions for service quality items such as outage hours, the proper response to customer complaints, and safety. Of special note is the approach taken in the United Kingdom where a long list of service quality requirements is imposed. Violation of service quality standards in the UK often results in payments directly to the affected customers. This penalty provides strong incentives for better service quality it also properly compensates the injured party for any degradation in service quality.

The Strength of the Incentives

For either traditional cost-of-service or more recent performance-based regulatory approaches the power, or strength of the incentives is determined by two factors. The first is the marginal impact of performance on profits. For example, if a cost savings of \$1.00 results in an increase in profits of \$1.00 the incentive to cut costs is as strong as possible. If \$1.00 of savings produces a \$.50 increase in profits the profit incentive, or cost cutting incentive, is obviously dulled. Similarly, if \$1.00 of increased revenue increases profits by \$1.00 the incentive to increase revenues is much more potent than if the increase in profits is only \$0.25. This factor is discussed further in the next section on Sharing Mechanisms

The second factor is the time lag between regulatory or rate reviews. For cost-of-service regulation the time limit can be either stated or undetermined. In most jurisdictions there is no set time limit in between rate cases. Performance-based regulation generally includes a fixed number of years that a particular scheme will stay in place, typically three to five years. The longer the time period between rate reviews, the stronger the incentives. Thus, if \$1.00 of annual savings can produce \$1.00 increase in annual profits, the cost-cutting incentive is much more powerful if the profits are realized for five years than a system in which the \$1.00 in profits lasts just a single year. (It goes with out saying that at the time of the review of the PBR the savings would be reflected in new prices and would hence no longer flow to the utility or shareholders.)

Assuming that a goal of regulation or regulatory reform is to increase the incentives to cut costs and improve service the question could be asked which approach, cost of service or PBR, is better? The answer is not clear. It depends on the details of the particular regulatory system. Performance-based regulation, at least as generally practiced thus far, is not necessarily more powerful than traditional cost-of-service regulation. Most performance-based regulatory schemes have sharing mechanisms where the benefits of any costs savings after some limited period are shared between consumers and shareholders. This tends to dull the incentive characteristics.

Sharing Mechanisms

An important feature that influences the strength of the incentives created by a PBR is the presence and design of any sharing mechanism. A typical U.S. PBR allows utilities to keep 100% of any savings it can achieve, provided that the rate of return is within a predetermined range. Outside of this range PBR sharing mechanisms share the costs or benefits of the PBR between customers and shareholder. For example, there may be no sharing if the ROE is within 100 basis points of a

specified level, say 10%. Between 100 basis points, and say 200 basis points, customers and shareholders may share the benefits (or costs) in some pre-specified way. Beyond 200 basis points the may be even more sharing.

There are many variations of sharing mechanisms. Some, like the one described above, are symmetrical, others are more one-sided. The specific design is often a tradeoff between different interests and theories. In general, the range within which there is no sharing is quite narrow, meaning that the necessity to share benefits kicks in quite easily. The less sharing the stronger the incentives for the utility to cut costs, thus if the utility saves \$1.00 it must share 50% of the savings with consumers.

Fuel Adjustment Clauses

Fuel adjustment clauses (FAC) are common in many regulatory schemes. Although the details differ from jurisdiction to jurisdiction the basic operation is to hold utilities harmless from the financial effect of fuel costs. The terms frequently used are that with a FAC fuel costs “flow through” or “pass through” to consumers.

There are many justifications given for FACs, but the fact remains that FACs move in the opposite direction of rewarding incentives to improve performance and cut costs. Fuel adjustment clauses generally remove the incentive for any genuine efficiency, they remove the incentive for reduction of line losses and then to skew the trade-off between capital and operating costs and reduce any incentive for owners to invest in portfolios that diversify fuel mixes.

Getting the Numbers Right

The task of creating a good PBR, which we define as a PBR with powerful incentives consistent with broadly accepted goals, is not complete until the specific numerical components of the PBR are reasonably set. This entails several important tasks.

- The starting point must be reasonable. The general format of a PBR is to set prices or revenues and then for a specified period of time prices or revenues are automatically adjusted according to prespecified rules. At the outset of the PBR initial prices or revenues must be set at a reasonable level. The most common approach is to start with prices or revenue set after a full cost of service review.
- During the PBR period, prices or revenues may be reset using a formula set in the PBR but costs are not reviewed until the end of the PBR period. Thus the first step in getting the numbers right is to be sure that the initial prices or revenues are reasonable.
- The PBR formula must use the right inflator and coefficients. The most common formula for a PBR adjusts prices or revenues by $CPI-X$. CPI is a measure of inflation

and in theory the inflation measure used should be a reasonable measure of the costs that are subject to a PBR. Thus if a PBR is to apply to a wires-only company, an inflation index that is heavily weighted toward fuel cost would be a poor choice.

- The “X” factor is a productivity factor that measures the extent to which the costs for the utility in question rise faster or slower than the inflation. Thus, if a review of historical information showed that the utility has consistently kept its growth in costs 1% below the CPI, a reasonable PBR formula might be $CPI - 1\%$.

Conclusion

PBR may or may not be an attractive and efficient way to regulate a utility. The key steps to creating a desirable PBR is to clearly articulate goals, adopt a PBR structure that is consistent with the goals, and work hard to get the numbers right so neither the utility nor consumers are unjustly enriched.

Chapter 8: Industry Restructuring

Electric utility restructuring means different thing to different people and different countries. No one model fits all countries and regardless what model one chooses initially, restructuring is an ongoing and evolving activity. This chapter will describe the most important considerations.

Goals and Constraints

The most important step in any electric utility restructuring is to clearly understand and articulate the country's goals and constraints. Typical goals may include:

- Reducing electric costs;
- Attracting private capital;
- Maximize public revenues from the sale of existing government owned assets;
- Creating an environmentally sustainable electricity sector; and,
- A more efficient sector.

Constraints are equally important to know.

- Existing prices may be subsidized for customers and overcharged for others;
- Changing prices rapidly, as one rapidly implements electric utility restructuring and competitive markets, may be politically and practically impossible;
- National security or economic condition may force the use of local resources; and,
- Current industry employment levels may be well above the level that a competitive industry would support. Rapid reductions in the workforce may not be possible.

A full and complete understanding of a country's goal and constraints will control the shape and pace of industry restructuring.

Range of Restructuring Models

There is a very wide range of possible electric utility restructuring models. We will describe three. Model 1 sits at one extreme. In this model one simply supplements the existing industry with the competitive acquisition of all new generating plants. Model 2 is an intermediate restructuring option that creates a fully competitive wholesale generation sector. In this approach all generation would be subject to competition regardless of vintage. Model 3 is a fully competitive retail and wholesale model. . All generation services would be competitive from the generation to the retail consumption level. In this model only the transmission and distribution system would continue to have any form of regulation.

All three models are discussed further below but these are just three of many possible options. All of these options share a few common attributes. First, they all have, to varying degrees, competitive generation markets. As a result the structures and institutions necessary to support and facilitate a competitive generation market such as an efficient spot market must be designed and put in place. Second, they all have aspects of a continuing monopoly transmission and distribution system. Third, all options are based on arm's length transactions between any regulated and unregulated business.

Prerequisites for Effective Competition

There are several prerequisites for competitive markets to operate efficiently. First there must be no market power. This means that no buyer or seller acting alone or in collusion with others can influence prices in any significant or long lasting way. Market power may present itself in as horizontal market power, i.e. any one player has too much control over a given market; or as vertical nature, in which case control of a monopoly service say transmission, is used to influence the price of competitive generation. Second, given the nature of electricity markets and the physics of the transmission system, all participants in a competitive market must have equal access to transmission and non-discriminatory and efficient prices. Finally, buyers and sellers should have access to all relevant information and all costs must be internalized.

Model 1 — New Generation Competitively Acquired

In Model 1 existing generation and all transmission and distribution continue to be owned and operated by the existing utility. All new generation is added by IPPs and sold to existing utilities who then sell the electricity in the retail market. (This model and the next are called a single buyer model.) Generation is subject to competitive bidding and is sold to the single buyer under a long term contract. (See discussion of Competitive Bidding important contractual considerations.)

In this model customers remain captive and hence there is a significant role for an independent regulatory commission. The role of the regulator is to create competitive conditions for the acquisition of new generation. Also, in this model Integrated Resource Planning (IRP) considerations continue to be used to plan the system and to evaluate the competitive bids. Questions such a risk allocation and risk reduction are among the many issues that continue to be considered by regulators in the context of their IRP responsibilities.

Other important conditions for this model include clear and enforceable contracts with credit worthy buyers. Competitive generation in this model continues to rest on the financability of the underlying power sales contracts. If contract enforceability or the creditworthiness of the buyer are in doubt, other forms of credit guarantees will be needed.

This model may be particularly appropriate for countries that are just beginning to consider industry restructuring and have a need to attract additional capital to meet growing electricity needs. It allows for competition to be introduced incrementally into an existing system. It provides new sources of private capital and a wider range of options for the purchasing utility than may otherwise have been

the case. Risk can be distributed fairly between utilities and developers under the terms of the contracts. The greatest weakness of this model is that it fails to achieve generating efficiencies in the stock of existing generating plants.

Model 2 — Full Wholesale Competition

Model 2 is the fully competitive wholesale model. All generation, new and existing, is competitive and generation receives market prices. The utility becomes a transmission and distribution (T&D) company. There should be no affiliation between the utility and generators. The utility in this model continues to be the sole buyer of power and the sole retail seller. The utility is a monopoly and is regulated by an independent regulatory commission.

Because the utility is a single buyer and customers remain captive. The regulatory role includes regulation of T&D prices and services as well as IRP oversight of the utility's purchasing decisions. A significant regulatory role in this model is to create the institutions and rules needed for an efficient generation market. This model is particularly valuable because of the very powerful incentives it can create for the efficient operation and expansion of the generating sector. It can be very effective in reallocating risks in an efficient and fair fashion. It can also be very effective at raising capital and allowing in country capital to be used for other purposes including the upgrading and expansion of the transmission and distribution systems.

Some of the issues to be addressed, if this model is pursued, including price volatility, market design to give reasonable incentives to add capacity when needed. Also, the transition for existing plants may provide country's with an opportunity to sell existing plants for prices that exceed their existing book value. The increased revenue can be used for a wide variety of purposes.

Model 3 — Full Retail Competition

Model 3 extends the competitive model to all retail customers. In this model, the utility is no longer the single buyer. The utility is the transmission and distribution system. It has an obligation to connect, but not an obligation to serve. Customers will buy generation services from the supplier of their choice.

The role of regulation in this model is the least of all possible models. The regulators' focus will be on establishing market structures, market institutions which can assure the greatest level of competition and the greatest level of choice for customers, prices and service quality for the distribution utility, and consumer protection. There is no economic regulation of the generation sector. Regulatory roles are to ensure open access, reasonable and competitive conditions and to generally protect against a monopoly power of buyers and sellers.

U.S. History of Industry Restructuring

Three historical subjects relating to restructuring in the U.S. deserve discussion: First, why did the U.S. initiate industry restructuring? Second, why is the nation finding it so difficult to complete the restructuring? Third, what are the critically important issues in the debate? The third topic is the one most likely to be of direct importance to other nations, so it is the one emphasized here.

First, the nation unknowingly initiated industry restructuring in 1978 with the passage of PURPA. One section of that law which seemed to most to be of little consequence, required electric utilities to purchase power from non utility suppliers that produced power from renewable energy or using efficient cogeneration plants. This began the U.S. experience with IPPs and led to subsequent restructuring initiatives.

The next major step toward a competitive generation market occurred in 1992 with the passage of the Energy Policy Act of 1992 (EPACT). Two efficiencies, in particular, were expected from a competitively-disciplined generating sector. One, the risks of building and operating generation would be placed firmly on those who voluntarily assumed such risks by choosing to enter the generating business. In contrast, the regulatory practice required ratepayers to be the principal risk bearers for the industry. And, two, it was expected that competitive markets would reveal the costs of producing energy at different hours of the day and of the seasons better than could regulators.

The consensus to restructure, however, did not extend to the essential characteristics of the new industry. The nation still has not reached enough agreement on the proper market structure to satisfy federal legislators. And state legislators, with a few exceptions, notably California, are not manifesting much concern with the need for an efficient marketplace. Their restructuring efforts are almost always concentrated on finding equitable compromises of the conflicting claims before them.

The compromise among the conflicting interests in 1992 was made possible because the large investor owned utilities (IOUs) wanted freedom to employ their expertise and financial strengths abroad, and they were willing to accept supplier access to their North American transmission services in order to get free of some of the constraints of PUHCA (The Public Utility Holding Company Act) and PURPA (The Public Utilities Regulatory Policies Act).⁵

A key compromise was to limit the electricity market to one in which anyone could become a generator, and all generators would have access to transmission services but the only buyers would be franchised utilities. The states and state-empowered regulators, but not the Federal Energy Regulatory Commission (FERC) or the U.S. Department of Energy (DOE), would determine when, how and if users would be permitted to buy electricity from an unregulated power merchant or generating company (GENCO).

⁵PUHCA placed significant constraints on the abilities of holding companies to own multiple generating companies in different nations (and in different U.S. states). PURPA denied holding companies a right to own a majority of the stock in a Qualified Facility, as defined in the PURPA, and required IOUs to purchase energy and/or capacity from Qualified Facilities located in their service territories at prices determined by state regulators.

Hindsight supports the conclusion that leaving the design of electricity markets to the states granted enormous powers to the large utilities. They have been dominant players in states' legislative processes. In effect, the foxes have been granted a major voice in the design of the henhouse.

Two compromises were critical in the EPAct: (1) electric utility holding companies gained the right to own PURPA machines and "exempt wholesale generators," (EWGs) in the U.S. and abroad and gained the right to use oil and natural gas as the principal fuel for such plants,⁶ and (2) the FERC was given explicit authority to order "transmitting utilities" to provide transmission service to GENCOs and Federal Power Marketing Agencies for wholesale transactions, as wholesale is defined in the Federal Power Act.⁷

The EPAct was understood to be only a first step in restructuring the industry: more legislation would soon be needed. Forty eight states, ten Canadian Provinces and the government of Mexico, acting independently, are not likely to create an efficient North American electricity market. Furthermore, international cooperation is needed to replace the NERC (North American Electric Reliability Council) with an international organization which can define operating standards needed for reliability and impose financial penalties on parties who violate those operating standards.

Second, the obstacles to a compromise that would allow the further development of a competitively disciplined industry are many. The principal market design issues are discussed in the next section. Here it is important to note the great diversity of the U.S. industry. In this political debate, as in all such debates, the parties (utilities, states, regulators, and users) are seeking to preserve all existing benefits of the current system while gaining additional benefits in the new structure.

The diversity of the U.S. industry makes agreement difficult. The current electric industry can be seen as consisting of (1) the legal entities that own and operate, lease, and operate or contract for the services of physical assets and legal rights that permit the generation, transmission, and distribution of electricity to end-users; (2) economic regulators, both state and federal, who control some of the terms under which assets are constructed, utility services are provided and inter-firm cooperation occurs; and (3) users of electricity.

The approximately 250 IOUs generate about 75 percent of the nation's power and serve about 75 percent of all retail customers, but the other 3,000 municipal, cooperative, and federal government-owned utilities are also politically potent. The interests of these utilities conflict with one another and with those of the IOUs. The electric industry also has many regulators. Its principal economic regulators at the federal level are the FERC, the DOE, the Securities Exchange Commission, and the Rural Utility Service. At the state level, they are public utility commissions, state energy

⁶The Power Plant and Industrial Fuel Use Act of 1978 insisted that every power plant be capable of using coal and denied to utilities the right to build generating plants that depended on oil and/or natural gas. Section 301 of EPAct repealed the Power Plant and Industrial Fuel Use Act.

⁷Section 726 of the EPAct defines "transmitting utility" as "any electric utility, qualifying facility, small power production facility, or Federal power marketing agency which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale.

planning agencies, and environmental siting agencies. The growth of state energy planning agencies in the last two decades is evidence of the increasing role some states intended, and may still intend, to play in future asset additions in the electric industry. These regulatory agencies have conflicting agendas, and many of them are vigorous proponents of their positions. The users of electricity are also a diverse group, and some user sectors are better organized than others, but all are insisting on a major voice in the structure of the new industry.

Congress has not yet been able to craft a compromise that will gain a majority in both houses, and it has been trying for more than five years. Furthermore, the FERC, for many reasons, has failed to provide needed leadership.⁸

The FERC's reluctance to mandate a particular market structure has been partly the result of its limited powers but also a reflection of the fact that the issues explored in early debates revealed intense disagreements among industry participants. Moreover, although the continuing research and extended debates in subsequent years have made the arguments more precise and therefore more complex, the issues that divided the parties in the mid 1990s remain the issues that divide them today. The gridlock in Congress is caused in significant part by the conflicting views over the proper market design.

Power Pools or Bilateral Trading

Two critical issues that remain to be resolved in the U.S. for the creation of an electric industry in which the generating sector is competitive and efficiently integrated with the monopoly elements of transmission, distribution, and system coordination are market design and deterring the exercise of monopoly power. In the market-design debates in the early 1990s, two classes of models were proposed. One class of models built on the English experience and the other drew lessons from the U.S. natural gas deregulation experience. The first set of models were labeled POOLCO models and the second set were called Bilateral trading models. The critical difference between the two models is the importance assigned to the integration of the spot market and the dispatch process. One proponent of POOLCO models, Larry Ruff, described his position as follows:

[A]n integrated spot market/dispatch process is the only practical way to ... internalize the real-time network externalities that otherwise make competitive electricity markets unacceptably inefficient and unreliable. The financial contracting that becomes possible only when there is an open spot market then largely displaces more complex physical contracting, allowing producers and

⁸In March 1995 the FERC provided some direction to the intense national debate with its NOPR, RM95-8. This NOPR was followed by FERC Order Nos. 888 and 889 on April 24, 1996. These orders, as important as they were, fell far short of accomplishing the objectives sought by the FERC. In particular these orders did not settle much in the debate over proper market design.

consumers to meet their commercial needs with relatively low transaction costs and risks.⁹

Ruff further notes that,

Most of the problems that have arisen in electricity markets — other than those due to structural problems such as inadequate competition — are attributable to specific flaws in the integrated spot market/dispatch process or to failure to take full advantage of the spot prices arising from this process.¹⁰

The proponents of Bilateral Trading models disagree emphatically with this conclusion. They emphasize the danger of having a monopoly utility that controls dispatch and whose first priority is system reliability implementing markets. They stress the beneficial results that will flow from permitting unregulated parties to organize all markets. In their view, the role of system operators is to implement the orders received from market participants and to preserve system reliability.

People who venture into this debate should be warned: For many parties, it is not an intellectual exercise; it is a political battle, and their arguments are designed to move the political system to their advantage. Despite irreconcilable differences between the two groups, there is agreement on some issues. Proponents of both models (1) support the continuation of the NERC, or a similar organization, to create and enforce reliability standards for operating the North American bulk power system, and (2) recognize the need for independent system operators who coordinates grid operations in each control area and preserve reliability.

The U.S. has seen POOLCO models adopted in the former tight power pools of New England, PJM (Pennsylvania, New Jersey, Maryland) and New York. California currently has a version of a POOLCO model with the market maker, the California Power Exchange (CALPX), and the ISO in separate organizations. No other area of the nation has yet implemented an ISO-managed spot market. In most of the Southeast, Southwest, Midwest, non-regulated markets are evolving based on bilateral transactions.

ISO VS. TRANSCO

The U.S. developed the concept of an independent system operator (ISO) in response to characteristics of the industry that are not widely shared by other countries. The U.S. has many utilities, each owning a portion of the transmission system. Creating a large regional or national transmission entity that owns, plans, builds, maintains, and operates the grid in a way that facilitates a regional competitive market was politically and legally very difficult. The U.S. alternative was to create the ISO, an entity that could operate the transmission system without changing the existing

⁹Larry E. Ruff, “Competitive Electricity Markets: Why They Are Working and How to Improve Them.” 12 May 1999. Mr. Ruff is an economic consultant with n/e/r/a/.

¹⁰*Ibid.*

ownership pattern. The fact the ISOs manage assets owned by others, generally has no power to build new transmission, and is governed by various types of stakeholder boards make it a very unnatural entity.

Most countries pursuing industry restructuring start from a very different position and as a result the notion of an ISO may not make sense in many circumstances. The role and functions that are filled by ISOs in the U.S. can more easily be fulfilled by a national grid or transmission company that have no direct or indirect affiliation with buyers or sellers of electricity.

The most important role for regulators of a transmission or grid company is to create incentives to balance congestion and construction and to price transmission services efficiently. Pricing of transmission services should give power plant operators and developers clear price signals that reflect marginal transmission costs. This will allow power plant dispatchers to efficiently operate plants and power plant developers to site new power plants to reflect transmission costs.

But efficient pricing of transmission may not be enough. Transmission companies should be regulated in a fashion that encourages it to search out and implement least cost solutions. For example, as discussed in chapter 6 the right PBR structure is essential. Consider a revenue cap PBR that operates with two parts. First, the revenue cap is equal to the normal transmission revenue requirement, plus the expected cost of transmission congestion. (see Chapter 6 for a full description of revenue versus price caps). Next, any actual congestion cost incurred is paid for by the transmission entity. Thus if transmission revenue needs are \$1 million and congestion costs are \$100,000 the revenue cap is \$1.1 million. In effect the transmission firm has \$100,000 to pay the expected congestion cost. This produces the right economic balance because the transmission firm benefits if it can find a ways to reduce congestion costs for less than \$100,000.

Market Power

The monopoly abuse problem is an ever present one. Economists generally favor the creation of a structure that makes it very difficult for firms to collude, but that solution has not been implemented by state or federal authorities. In almost every market, the number of GENCOs is relatively small, five to ten. The ability of firms in interconnected markets to sell into non-native markets provides some reassurance that the exercise of monopoly power will not be a serious problem. On the other hand, the very high prices at times have created serious concerns for many.

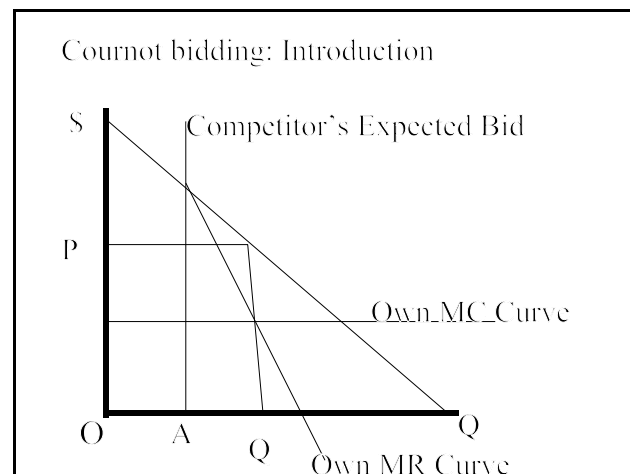
The principal problem arises during periods of peak demands. During such periods, there may be only a small number of GENCOs with discretionary capacity. The opportunity for various forms of “price boosting” then develops. Clearly, the desire to maximize profits encourages GENCOs to constrain their competitive inclinations. If the firms can “collude” and behave as a monopolist would behave, they can increase the price and their collective profits. The antitrust laws make explicit collusion very risky, however. One theory of quasi-collusive behavior is the Cournot theory. The essence of the Cournot theory is that a firm bidding into a market in which there are only a few sellers, (e.g., during a peak demand period) will assume that the quantity bid by the other GENCOs

will be the same as it was in the last similar period and, as a consequence, the firm can assume that the remainder of the market demand curve is its to exploit. The firm, therefore, will bid like a monopolist for that segment of the demand curve. If all the firms behave in a similar way, there will be an equilibrium price higher than the competitive price.

The attached figure illustrates a part of this theory.

If the competitor is assumed to bid a quantity of A in the next period, then the “Own” firm can assume that the demand curve to the right of A belongs to him. His profit-maximizing position, given the marginal cost and marginal revenues curves drawn, is a quantity bid of Q which will cause a price of P .

It can be shown that if the competitor responds by taking the Own firm’s bid quantity as a signal of what it will bid in the next period and behaves as the Own firm behaved, the two firms will converge to an equilibrium price that is higher than the competitive price and lower than the monopoly price. Similarly, the market quantity will be lower than the competitive quantity and higher than the monopoly quantity. At this convergent price, the two parties will satisfy one another’s expectations.



Conclusion

There are many alternative approaches to industry restructuring. No one model will fit the needs of all countries. The most important step is to begin with a very clear and articulated set of goals and constraints. All restructuring models share certain common elements. These include independent regulatory oversight of monopoly activities, market structures that are free from market power problems, and clear and enforceable property rights.

Chapter 9: Environmental Issues

Background

Outputs from electric power plants affect the air, lakes and streams, land, animal habitat, and human health. Unfortunately, these environmental impacts of electricity production can be quite large and they are experienced not only locally and nationally, but their impacts, such as in the case of global warming gases, can be international as well. For most countries, the environmental harm caused by producing electricity is rivaled only by that of rapidly growing transportation sector.¹¹ Electricity production is almost always the single largest stationary source of air pollution.

Because of the close link between electricity production and environmental harm, government policy makers are well advised to carefully coordinate economic and environmental policies to achieve the overall least cost, most efficient production of electricity for society with the least necessary environmental impacts. While most governments wish to create abundant low-cost electricity for their citizens and economy, to do so by ignoring the environmental consequences only creates other large costs for society such as human ill health. Thus, it is better to take environmental impacts into account at the time an electricity system is planned or expanded, rather than after the fact when the environmental harm has occurred.

What are the Environmental Impacts of Electricity Production?

The environmental pollutants from the electric industry include: nitrous oxide (NO_x), a key cause of ground level smog, ozone and acid rain; sulfur dioxide (SO₂) another key cause of acid rain; air toxics such as mercury, arsenic and other metals which contaminate waters and soil, sometimes for many, many years; fine particulates; greenhouse gases, notably carbon dioxide (CO₂); as well as radioactive materials, noise, land and water impacts. These environmental outputs from electricity production cause human illness and death; damage to crops, timber and livestock; degradation to visibility, harm to precious cultural monuments; possible catastrophic accident; and, in recent years, the threat of large, disruptive climate change. Environmental harms are experienced as real costs by individuals and by the societies which bear them, yet rarely are they included in the price of electricity.

¹¹ In most countries, the electricity producing sector of the economy is quite small compared to the sector's share of harmful environmental outputs. For example, in the United States, which has a fully developed electric industry, the electricity production sector is about 2% of the overall economy, yet it causes more than one third of all air pollution.

AIR POLLUTION FROM FOSSIL ELECTRIC GENERATORS	
POLLUTANTS	HEALTH & ENVIRONMENTAL HARM
Sulfur Dioxide (SO ₂)	Acid Rain Fine Particles - Death & Illnesses Regional Haze & Pollution in Parks
Nitrous Oxide (N ₂ O)	Acid Rain Fine Particles - Death & Illness Regional Haze & Pollution in Parks Smog - Asthma & Respiratory Disease Nitrogen Poisoning of Estuaries
Carbon Dioxide (CO ₂)	Climate Change
MERCURY	Fish Contamination Consumption Warnings Poisoning of Wildlife

The most common environmental impact of electricity production world wide is undoubtedly air pollution caused by the burning of fossil fuels: coal, petroleum and natural gas. On average, coal has the largest output of the pollutants discussed above, petroleum about two thirds the output of coal and natural gas about half the output of coal. However the relative contribution of each fuel to air pollution varies depending upon the technology (efficiency, heat rate) of the power plant burning the fuel and the quality of the fuel itself.

Comparative CO ₂ Emission Rates		
Technology	Heat Rate	Carbon output lbs/kWh
Gas CC	8230	.26
Gas CT	15,040	.49
Coal (conventional with sulfur control equipment)	15,040	.59
Coal CC	8980	.51
Oil (steam)	9680	.45
Oil CT	14,020	.64

What Steps Can Regulators Take to Reduce Environmental Harm?

The principles of economics teaches us that resources of all kinds are allocated most efficiently when their full cost are included in prices and distributed in a competitive market. This is as true for electricity as it is for other products and services. To avoid unnecessary damage to the environment, to people's health and to the productivity of other segments of a nation's economy, the actual cost of environmental harms of each potential electricity resource should be factored as completely as possible into the resource selection process. Where competitive markets are used, the best option is to reflect environmental damages in the competitive price. Where government regulators have the responsibility of selecting electricity resources, they should take environmental costs directly and fully into account when comparing the cost of one resource with another. If the cost of environmental harm is not internalized to electricity production, a competitive advantage is created which favors those resources, however dirty, that are most successful in transferring environmental costs to the rest of society.

Investments in renewable energy sources (wind and solar) and in energy efficiency (lighting, building shells, heat systems) will go a long way towards reducing both the cost of electricity and environmental harm.

A full cost comparison of all supply-side electricity production projects alongside all demand-side energy efficiency projects will effectively yield the least cost, least environmental harmful portfolio of electricity resources. (See, Chapter 9: Integrated Resource Planning.)

Methods of Internalizing Environmental Costs

There are three general ways of taking external environmental costs into account when planning or expanding an electricity system: full cost pricing; the use of "adders"; and environmental dispatch of resources. The first, full cost pricing, includes (internalizes) all environmental costs in the price and lets the market (customers or government regulators on behalf of customers) decide based upon value and price, which resource should be developed. This method is the simplest to describe but can be the hardest to do as including the full cost of environmental damage in prices can significantly raise the price of electricity.

The second approach is to take external environmental costs into account when optimizing a resource portfolio by implying or "adding" the environmental cost to the bid price when selecting which resource should be developed next. The adders are not included in the costs passed on to customers, but rather are used only in the selection process. This approach has the effect of passing less than full environmental cost into the price to customers.

Environmental dispatch is the third approach. With this method, the electric system operator dispatches power plants based upon their relative environmental harm, dispatching the cleanest plants first, thereby reducing the total air emission output in each hour of operation. This too tends to passes less than full environmental cost to customers.

Cap and Trade Approaches

Often, environmental regulators will create a standard for controlling pollutants. Environmental standards are much more effective when set on an output basis (e.g., tons of emission per MWh) rather than on a fuel or heat input basis. As pointed out above, the efficiency of the electric power plant has a great effect on the amount of pollution produced. Cap and trade approaches to minimizing pollution can be very effective. A typical cap and trade approach sets an overall cap on the level of permitted pollution (set on a local, national or even international geographical basis) and then encourages affected parties to trade among themselves to most efficiently achieve the required cap. The trades are accomplished through the creation of pollution credits, one credit for each permitted ton of pollution (e.g., SO₂), with auctions or other allocation methods used to distribute the credits initially. Those business which can lower their pollution outputs less expensively than purchasing a needed credit at auction will do so. In fact, some businesses will find that it is most economical to reduce pollution output below required levels and sell their unused pollution credits at auction to the highest bidder.

Environmental regulation which reduces the level of allowed pollution does internalize the cost of regulated environmental harm, but unless the regulation requires complete elimination of all harm, the residual harm remains unpriced.

Economic Decisions that have Environmental Impacts

It is important to be aware that the selection of power production resources is not the only economic decision made by government regulators which have environmental impacts. In truth there are many decisions made routinely by regulators that have direct environmental consequences.

State regulatory decisions with environmental implications include the following:	
Default Service Pricing	Low default prices mean few shoppers and few green shoppers, few green retailers
Stranded Cost Recovery	Including future costs subsidizes inefficient plants
Distribution Pricing	Average pricing discourages energy efficiency
Rate Design	High fixed charges, low variable charges discourage energy efficiency
PBR	Rate caps, as opposed to revenue caps, discourage energy efficiency
Line Extensions	Subsidized prices discourage off grid options

State regulatory decisions with environmental implications include the following:	
Consumer Protection, Disclosure, and Education	Labeling, disclosure and consumer education make for informed consumers and larger green markets
Net Metering	Absence increases transaction costs and discourages use of very small renewable energy
Distribution Planning	Needed to assure consideration of cost-effective distributed resources
Interconnections	Lack of standard requirements discourages distributed resources
Siting	Siting requirements affect fuel and technology choice
Green Pricing	Provides captive monopoly customers access to green options
Merger and/or Asset Sales	Can create market power and keep older plants from facing serious competition
Public Funding	Vital to delivery of energy efficiency and renewable energy. How the money is spent matters
IRP	Needed more than ever instates without retail competition
Transmission Pricing, Access, and Priority	May ignore the special characteristics of renewable energy and small facilities
Pool Rules	Bidding rules may ignore the special characteristics of renewable energy, small facilities and energy efficiency

There are also federal restructuring decisions that have significant state input that belong on this list: Transmission Pricing, Transmission Access and Priority and Power Pool Rules.

Conclusion

Regulators need to understand the environmental implications of their electric industry resource selection and other decisions. As a first principle, regulators should strive to do no additional harm to the environment. Where policy options exist that will protect or improve the environment while achieving a desired economic objective, regulators should act affirmatively to protect the environment. Finally, in those countries where continued operation of older fossil plants are at issue,

electric utility regulators should establish a close, consultive relationship with environmental regulators to better understand and achieve their environmental objectives.

Chapter 10: Consumer Protection Issues

The Need for Consumer Protection

Historically, monopoly utilities had little need to develop a strong and responsive consumer protection function. This is especially true of government-owned utilities who lacked a shareholder constituency and who saw no need for developing a positive public image. Certainly, in the case of both government-owned and investor-owned utilities, the monopoly condition diminishes the incentives and needs for the company to assure that the customers are both well-served and satisfied with their service.

In the context of power sector reform underway or contemplated in numerous countries around the world, some form of a regulatory agency, a “public utility commission,” has been or will be formed to regulate newly reorganized utilities. One of the roles of the commission will be to substitute regulation for the functions of a competitive market. While the principal market function performed by the commission is the setting of prices, every commission must also provide for consumer protection. Regardless of whether consumer protection is explicitly provided for in a commission’s enabling legislation, the pragmatic reality is that the commission will become the focal point for the consumer’s need for both regulatory protection and a forum in which to be heard. It is, therefore, incumbent upon the commission to articulate consumer protection standards and to provide for resolution of consumer complaints.

One of the first issues a commission should address is the policy framework for addressing consumer protection. In other words, what public needs should be served through the commission’s consumer protection policies? At a minimum, consumer protection policies should foster the following goals:

- Public access to the commission and its processes;
- Public education;
- Public perception of fairness;
- Fairness in fact;
- Balancing the powers of the parties;
- Efficient utilization of commission resources; and,
- Timely resolution of complaints.

Choices for Providing Consumer Protection

In some countries, there may be consumer protection agencies or other groups who have historically provided consumer representation. In other countries, no consumer protection agencies or group existed prior to the creation of the electric regulatory commission. In these cases, the commission or legislature will have the option of delegating the consumer protection functions to those agencies or groups. In countries that are severely constrained by a lack of resources, consumer protection may

be completely delegated to the utility itself. Finally, the new commission may fulfill the principal consumer protection functions.

Where consumer protection agencies are available, they may provide play a role in electric consumer protection. However, because of the variety of engineering, finance, accounting, and legal skill that may be required to resolve consumer protection complaints, non-specialized consumer protection agencies may not be up to the task of providing adequate services. Even so, the commission should develop a strong working relationship with such agencies to maximize its effectiveness.

A seemingly expeditious approach is to delegate principal consumer protection functions to the utilities themselves. While this may minimize the budget requirements for consumer protection, it is unlikely to provide adequate protection to the public for obvious reasons. Nonetheless, the utilities do represent the “first line of defense” for consumer protection. As such, many affirmative consumer protection functions should be placed on the utility.

The best practice for the provision of consumer protection is to blend together all available consumer protection resources. However, the principal source for consumer protection will, as a practical matter, remain with the commission. As discussed below, the overall goals and objectives of consumer protection can only be adequately met through a strong commission role. The commission should be the centerpiece of consumer protection. Because of its technical and regulatory expertise as well as its on-going historical perspective of the industry, the commission is well suited for this role. Nonetheless, it is essential that a formal consumer protection advocacy office be established. This office may either be within the commission itself or may be an independent government office.

Public Access to the Commission and its Processes

Those consumers most in need of protection are the small commercial, agricultural, and household/residential customers. Because of their general level of sophistication and their relative economic circumstances, these customers need a consumer-friendly forum for addressing their questions and complaints. For example, if available, the commission should utilize a toll-free telephone number to receive calls from the public. In addition, the rules and forms for resolution of consumer complaints should be easily understood and used by the public. If at all possible, little or no cost should be borne by consumers in the process, especially when informal processes are in use.

Public Education

Perhaps the most effective means of consumer protection is that of public education. In most situations, the customer understands very little about how public utilities operate, how prices are determined or what the role of the public utility commission plays in the regulation of the utility. Educational efforts should, at a minimum, should be oriented toward the following goals:

- Information about the customer’s relationship with the utility;
- Information about the commission and what role it plays in consumer protection;
- Information about energy usage, conservation and demand-side management;

- Disclosure of pricing, resource mix and environmental impacts of energy use;
- Information about low-income assistance programs; and,
- Information about public safety.

Consumer education should be the responsibility of both the utility and commission. In most situations, the commission should have the authority to require the utility to engage in certain types of educational activities. For example, as part of a rate setting process, the commission should require the utility to notify its customers of any proposed change in prices. This notice should be published in local newspapers and be included with customer bills. Other commission-required utility-performed educational topics may include low-income assistance programs, service disconnection and connection information, system safety and availability of the utility's own customer service representatives.

Because the customer may or may not trust the utility, especially when the customer is involved in a complaint against the utility, certain educational items may be better provided by the commission. Commissions should consider publishing pamphlets providing information about the commission and what it does as a regulatory body, the commission's complaint process and how a customer can use that process, customer service connection and disconnection rules and standards, and any other matter that repeatedly presents itself to the commission during consumer contacts.

Public Perception of Fairness and Fairness in Fact

The commission should manage consumer complaints and the overall issue of consumer protection in a manner that assures a public perception of fairness. The complaint procedure should be easy to use for customers and should provide a forum that fosters a sense of confidence in both the process and in the commission. Efforts should be made to make sure that customers are not "out-manuevered" by the utilities lawyers through the use of rules of procedure that are not likely to be well understood by the customer.

In addition to the public's perception of fairness, the process should produce results that are truly fair. A few "bad" cases can do more to damage the institution's overall credibility with the public than all the "good" cases combined. This requires consistency in results and clearly stated reasons for the disposition of complaints. Where possible, the end result should be easily reconciled with the reasonable expectations of an informed consumer.

Balancing the Powers of the Parties

One of the keys to successful consumer protection is the assurance that the consumer has "equal" standing before the commission. This can be accomplished through both procedural rules (e.g., easy access to the complaint process) and substantive rules (e.g., fair calculation of line extension costs). Because the utility is typically in command of the data necessary to resolve most consumer complaints, the utility should be required to make full disclosure to the consumer of all information

relevant to that consumer's complaint. This is especially true with regard to billing and metering information for that consumer.

Effective and Efficient Utilization of Commission Resources

Like any organization, the commission's resources will always be scarce and often, seemingly, inadequate. As a result, the commission must be judicious in the use of its resources and find ways to achieve the greatest results possible. There are two principal methods for resource conservation. First, the resources may be used selectively for different types of problems. Second, the commission may off-load certain responsibilities to other parties, most particularly the utility.

A variety of processes for complaint resolutions should be used. These range from summary disposition of items over which there is little or no fact dispute to formal hearings for matters worthy of such consideration. The commission should consider a tiered approach in this regard. Matters such as complaints over the price charged can be summarily resolved, so long as the price in question is the filed and approved tariff rate. Complaints over the billed energy consumption (meter reading disputes) may require some informal process designed to determine or impute energy usage, depending on the circumstances. On the other hand, a large industrial customer's complaint over transformer loss adjustments on its bill may require a formal hearing complete with expert engineering witnesses and the review of sophisticated billing data.

Perhaps the most effective tool for conserving the commission's resources is the use of rules that require the utility to maintain a sufficient consumer service staff of its own. The utility should be given a clear understanding of the consumer protection performance expected by the commission. In addition, there should be a reporting process that allows the commission to monitor the utilities consumer protection performance. Performance criteria can include such activities as turnaround times for new service connections, wait times for phone calls, response times for repairs and safety threats, reliability performance, and other aspects of the interface between the utility and its customers. All of these criteria should be reasonable within the context of the individual utility and should be achievable by the utility. Penalties and rewards may be considered by the commission, especially with regard to on-going problem areas.

Timely Resolution of Complaints

The commission should assure that consumer complaints are dealt with in a timely fashion. In the case of matters that involve little fact dispute, this can mean disposition in a matter of days or even on the same day, depending on the nature of the problem. More complex cases may require hearings and more time. In addition, the commission should be mindful of the relationship between the type of complaint and need for timely resolution. Issues involving connection of service or disconnection of service may present more time pressure, especially where the absence of residential space heating or cooling may present serious health threats.

The Obligation to Provide Reasonable and Adequate Service

A key factor in implementing a consumer protection policy is a clear understanding of the utility's obligation to provide service. While it is often said that a utility has an obligation to service, that obligation is not absolute. The utility's obligation can generally be grouped into three categories:

- Situations where there is no obligation to serve;
- Situations where there is a conditional obligation to serve; and,
- Situations where there is an unconditional obligation to serve.

A utility has no obligation to serve a customer who would procure service through fraud or misrepresentation. Customers previously disconnected for failure to pay may seek to be reconnected under a false name or through the name of a child or other relative. Often customers may seek service at a new address when they have a previously unpaid bill at a different address. In situations such as these, the commission should have a clearly stated policy that allows the utility to avoid the adverse consequences of serving these customers. Care should be taken to narrowly construct these exceptions to the obligation to provide service.

In some situations, the obligation to serve may be conditional. Customers seeking new service may be required to pay a portion of line extension costs, especially where those costs are very high. The customer who resides several kilometers from the nearest distribution line must pay some or all of the costs of that line extension. Customers with previous credit problems or unpaid utility bills may be required to place a deposit with the utility or to make arrangements to pay previously unpaid balances.

Most customers, absent poor credit or high cost conditions, are entitled to service. The customer located in a fully developed urban center, where the distribution system is in place, should be able to initiate service in a timely fashion. Wait times for new service connections in these situations should be kept to a minimum. The utility here has a clear obligation to serve. In addition, payment of an unpaid bill left over from a previous tenant who has no relationship to the new tenant should not be made a condition of new service. Finally, the commission should assure that the utility does not discriminate against customers on the basis of neighborhood, income level or other inappropriate basis.

Other duties of the utility should also be clearly defined by the commission. These include:

- The provision of accurate meters and meter reading;
- Requirements for individual metering for multi-unit dwellings and commercial buildings;
- Timely and fair resolution of metering disputes;
- Provision of accurate bills;
- Standardized billing procedures and formats;
- Fair and equal access to bill payment arrangements for customers in arrears;
- Disconnection of customers for non-payment, theft or other reasons;

- Internal company consumer protection rules;
- Notices to customers of their rights to seek relief at the commission;
- Notices to customers of the availability of government or NGO assistance;
- Special duties for persons with medical conditions;
- Energy efficiency programs; and,
- Low-income assistance programs.

Each of these duties should be clearly addressed in the commission's rules. As part of its enforcement role, the commission should monitor the utilities' performance in each of these areas.

Service Quality and Performance Standards

A critical tool in the provision of consumer protection is the establishment of service quality and performance standards. The commission should clearly define what constitutes adequate service quality. These standards should cover standards for such activities as delays in establishing new service, power quality and reliability standards (outage events per customer, response to weather related events, plant and facility maintenance programs, etc.), business office performance (customer call centers, calls answered promptly, etc.), customer satisfaction survey results, repair response times, and safety response times.

Enforcement of Consumer Protection

The commission should assure consumer protection through continuing enforcement of the service quality and performance standards. Enforcement can take the form of transaction-based proceedings to deal with individual consumer complaints, the use of fines or damage awards in special hearings, and the use of penalties and rewards in the setting of rates.

Obviously, consumer protection must be achieved through a variety of tools ranging from the commission's rule-making authority to the use of specific enforcement orders in individual cases. Consumer protection rules and proceedings provide a continuing feedback mechanism for the commission and can provide critical information in assessing and developing policy initiatives for the commission. In a very real sense, the success of consumer protection is measure of the success of the commission.

Chapter 11: Integrated Resource Planning

What is IRP?

Modern utility Integrated Resource Planning, or IRP, has evolved from the simple expansion of supply-side resources (power plants) to a more complete economic analysis that integrates all available resources and technologies, available on the supply-side or the demand-side. IRP is the combined development of electricity supplies and energy-efficiency improvements, including managing the growth of demand (DSM options), to provide energy services at minimum total cost, including environmental and social costs. This integration seeks the broadest reasonable range of options to meet demand for electric service, including technologies for energy efficiency and load control on the demand-side, as well as decentralized and non-utility generating sources, into the mix of potential resources. By selecting technologies and programs to minimize the total cost of electric service, and by including environmental and social costs in the cost criteria, IRP makes it possible to design a plan for electric supply and demand-side options to meet electricity demands without wasting economic or natural resources.

The expected result of the market and non-market changes brought about by IRP is to create a more favorable economic environment for the development and application of efficient end-use technologies and cleaner and less centralized supply technologies, including renewable sources. IRP means that these options will be considered, and the inclusion of environmental costs means that they will appear relatively attractive compared to traditional supply options. The difficulty with implementing such changes in a market economy is that the environmental quality is not traded in the market, since it is a common social good, and that the benefits of energy efficiency technologies are not fully captured by the market, because of various market distortions and institutional barriers that have been extensively documented. Thus, planning and regulation have been used to correct these problems and to provide incentives to move the market toward cleaner and more efficient energy technology. Higher electricity prices are often needed to implement the plans and resource allocations resulting from IRP, but price measures are not a sufficient solution in a market with imperfect competition and incomplete information.

IRP developed out of more traditional electricity planning as practiced prior to the 1980s. Before that time, electric utilities relied almost solely upon the expansion of supply side resources to meet anticipated demand growth – an approach which had been steadily aided by improving economies of scale in electric generation. The declining costs of large scale steam boilers for the production of electricity in the first half of the twentieth century led to a nearly-universal strategy of rapid capacity expansion and promotion of demand growth, with little consideration of the necessity or efficiency of energy use. However, in the latter decades of the century, declining economics of scale for large central station power units couples with the emergence of smaller, less capital intensive technologies such as combustion turbines (jet engines) and increasing concern for the negative environmental impacts of electricity production caused a major shift in electric system to a broader, multi-faceted IRP approach.

Today, as the era of utility nationalization gives way to privatization, and as utility regulation changes to capture the benefits of competition by creating wholesale and retail electricity markets, the interests of society of minimizing overall costs, particularly the environmental costs of electricity production, continues to be served through IRP. The introduction of wholesale competition produces new supply-side choices which government regulators can integrate with demand side resources to meet customer needs at the overall lowest total cost to society. If competition is extended to the retail level, IRP can be used to improve the efficiency of the remaining transmission and distribution monopolies.

The successful development and implementation of an integrated resource plan requires utility regulators to articulate clearly and right from the start the goals to be achieved. By addressing in advance the following policy areas, utility regulators will be positioned to better understand and communicate to the utility and other stakeholders what the IRP process should accomplish.

What Is the Objective You Seek to Achieve with Integrated Resource Planning?

The overarching goal and objective of IRP should be straightforward. IRP is an economic efficiency model that provides a framework for conducting analysis and comparison of a wide variety of resources, in the context of a wide range of possible futures in order to find the most efficient, reliable and least cost combination of energy resources.

The critical issue for utility regulators in defining the objective they seek to achieve through IRP is the need to define efficiency. What is "most efficient?" What will "most economic outcome" mean in each country? Historically, the test for efficiency was simply to minimize the utility's revenue requirements for a given level of demand for electricity. This analysis consisted of a resource portfolio that depended 100 percent on supply-side resources. The level of demand was considered a given.

IRP takes a different perspective by distinguishing between electricity, kilowatts, kilowatt-hours, and energy services such as heat, light, motor drives, etc. This energy service perspective recognizes that the costs customers face are the combination of the price of kWhs that drive a motor or refrigerator and the number of kWhs needed to produce the desired motor drive or cooling. This means that how efficiently the motor or refrigerator converts kWh to motor drive or cooling is important. IRP, therefore, requires consideration of demand-side management (DSM) options in the resource mix.

Most utility regulators strive to minimize the total costs of energy services, including the costs borne by the utility, the customer and, in some cases, society at large. For example, there are frequently costs to customers associated with their participation in demand-side programs. It is important to consider these costs in order to achieve a complete and fair comparison of all costs associated with one resource to that of another.

There are two ways of measuring efficiency that look beyond a utility's cost alone. Minimizing the Total Resource Cost (TRC) has been the most commonly adopted method. This measure considers both the utility's direct expenditures and the cost borne by consumers who participate in a utility DSM program. Several states have expanded upon the TRC objective by requiring utilities to optimize resource choices based upon total societal costs. This approach demands consideration not only of the direct costs incurred by the utility and its customers but also the indirect, social costs and benefits placed on society. Most often these indirect, or external, costs are those associated with environmental damage, but sometimes they include other external impacts as well such as economic growth and job development.

In general, IRP focuses on *minimizing customers' bills rather than their rates*. An overall reduction in total resource cost achieved through the efficient use of energy will lower average bills. At the same time, as sunk costs shift to a smaller pool of kWh sales, higher rates may result. Utility regulators need to keep an eye on both bills and rates. Bill savings greatly outstrip any rate increases. All customers benefit from lower system costs achieved through IRP, but customers who actually receive DSM programs get an additional benefit through the lower use. As utilities implement their DSM programs, what happens to the customers who do not or cannot participate in any program? Their use does not decrease, but their prices may increase as fixed costs are spread over fewer kWhs. Utility regulators must pay attention to this effect, both by reviewing bill impacts and by making sure that the utility offers programs that will turn non-DSM participants into participants.

When Does a Utility Need New Resources?

For years, the answer to this question was simple. A utility needed a new resource whenever customer demand exceeded reliable supply.

By the 1980s, as the economic approaches which ultimately led to IRP developed, the answer shifted to: A utility needs a new resource *whenever acquiring a new resource reduces total costs*. Stated another way, a utility "needs" any resource that costs less than the avoided cost. Need, then, becomes an economic question in addition to a reliability question. This shift in thinking means that sometimes new resources will be acquired to keep the lights on, and sometimes they will be acquired to lower overall costs. Even utilities with "excess capacity" can lower their costs by using resources that are cheaper than their current operating costs.

An understanding of avoided cost has been very important for analysis. For instance, some conservation programs can be implemented for less than 2¢ per kWh. This cost falls below the price most utilities pay for fuel at a typical power plant. By opting for a DSM program, a utility runs existing units less. The cost of DSM is less than the fuel cost savings, thus reducing the overall cost of providing energy services.

At the heart of IRP is the question: "*As compared to what?*" What existing and planned utility resource would a new resource displace? What time of day or year would the new resource provide energy services? Would the overall costs be lowered or raised if the new resource were added? To

develop an accurate assessment and comparison of costs, all relevant costs for alternative and existing options must be included in an analysis.

In implementing IRP, some utilities have used the cost of the next planned unit as the avoided cost for acquiring any new supply- or demand-side resource. This approach, however, misstates the value of many resources. To fully exploit the IRP process, the full value of the resources displaced by the alternative resource option should be calculated and compared to the full cost of the alternative resource.

Transmission and distribution savings should also be looked at when determining what resource choice makes most sense. Acquisition of demand-side alternatives or dispersed small-scale supply alternatives can mean that costly line upgrades could be postponed or avoided altogether. Similarly, renewable resources, such as photovoltaics or wind turbines, offer the possibility of avoiding more costly line extensions into remote settings.

Finally, there are the external costs. Renewable resources and DSM programs generally cause less environmental damage than most traditional supply-side resources. Attributing costs to environmental damage generally improves the economic attractiveness of non-traditional resources.

How Can Market Forces Be Captured in the IRP Process?

Incorporating competitive market forces can improve IRP outcomes and lower energy costs. How can the utility capture the economies offered in the competitive wholesale generation market? The utility must develop some systematic way to quiz the market to find out what resource options are available.

One effective method is for the utility to devise and circulate its optimal plan describing the most efficient resource mix it can produce. Then, through a competitive bidding and/or negotiation process, the utility can create the opportunity for competitive wholesale providers to step forward and show whether they can provide more attractive resources at a lower cost. Often the negotiation process, following up on the market response is key to acquiring resources at the lowest possible cost.

Requiring the utility to optimize first and others to bid second allows accurate measurement of the value of the resource offered. This approach is sensitive to the highly competitive, fast moving market environment in which Independent Power Producers operate. (The term used to refer to all types of competitive wholesale providers.) When an Independent Power Producer (IPP) can respond to a specific plan, the value of its offered resources will be clearer, the bid review and/or negotiation process moves more quickly as does issuing and financing of purchase contracts. In recognition of the need to work within the realities of the competitive market place, regulators must carefully balance the need for oversight with the need for flexibility and speed.

The IRP Process

The implementation of the IRP process generally requires:

- Collection of reliable data on electricity end-use demand patterns and technical alternatives for improving their energy-efficiency or load profiles (treating demand in terms of energy services, rather than strictly kWh);
- Definition and projection of future energy-service (end-use) demand scenarios;
- Calculation of the costs and electric-load impacts of the demand-side alternatives;
- Comparison of their costs with the economic costs and environmental impacts of conventional and alternative electricity supply options;
- Design of an integrated supply and demand-side plan that satisfies the least-cost criteria in terms of economic costs and environmental impacts and;
- Implementation of the least-cost strategy.

The IRP planning horizon generally spans 10 to 15 years, with a specific action (investment) plan developed for the immediate upcoming two to three years. Total electricity demand is disaggregated by sector, end-use, and technology, with as much resolution as possible given available data. Based on these end-use demand break-downs and existing electric demand forecasts, disaggregated projections of future levels of energy-service growth are made.

Technologies for improving energy end-use efficiency or influencing load shapes are identified. The technical and economic performance of these alternatives are estimated, compared, and ranked according to cost-effectiveness. Based on these results, DSM programs and other energy-efficiency strategies are analyzed in terms of their total costs and rates of market penetration over time.

Production-cost analysis of the performance of existing and new electric supply alternatives is used to rank these alternatives according to marginal cost values. The results are compared to the marginal costs of demand-side options, including environmental costs to the extent possible. The two sets of options (supply-side and demand-side) are then compared and combined to produce the “integrated” least-cost electricity plan. The integrated electricity plan is subjected to further financial evaluation and sensitivity analysis before the final plan is completed. The incorporation of these issues may re-order the ranking of the integrated plan somewhat, or exclude certain resources from the plan. This step “fine-tunes” the IRP results to account for specific issues and options inherent in the local or national setting.

Who Should Know IRP?

IRP provides an overarching framework guiding all utility planning and regulation. The IRP process is the backbone from which many other regulatory decisions flow — decisions ranging from rate design cases to prudence review cases to resource acquisition cases. For this reason, basic IRP principles need to be understood by all utility regulatory staff who work on electric utility matters, not just the staff members responsible for reviewing the utilities’ long-term resource plans. Utility

management decisions as well as regulatory decisions should consistently apply IRP principles to avoid higher system costs and higher risks for shareholders and ratepayers. This suggests that nearly everyone involved in the electric utility or its regulation would benefit from a working knowledge of IRP. At the very least, those who are involved in the following issues or functions should be well-versed in its principles:

Load Forecasting

Load forecasts are used for ratemaking, for calculating fuel cost adjustments and in the IRP process. End-use forecasts which calculates the energy use of each customer class based upon each type of use (refrigeration, motor power, lighting, etc.) are most accurate and best support the development of energy efficiency programs..

Avoided Costs

Avoided cost calculations determine the value of each particular offered resource (build or buy) to the overall utility system. Any resource which costs less than it is worth to the system should be acquired as it will lower overall system costs.

Rate Cases

Utilities must develop these cases in a manner consistent with good planning. Any commission staff reviewing rate cases must understand the original planning process and objectives undertaken by the utility to decide how good a job the utility is doing in its pursuit of its stated objectives. This is particularly true in prudence review and fuel cost reviews.

Need or Certificate Cases

Cases involving a determination of need for new capacity or the issuance of a license to build a new power plant should use the load forecasts done under an IRP framework.

Fuel Cost Adjustments

Fuel costs should be consistent with the implementation of a utility's IRP, with variations explained. Connecting fuel and capacity expenditures with the plan is essential to the success of the plan.

Energy Efficiency

A broad array of energy efficiency programs should be considered in the IRP process and cost-effective programs, those programs which lower total costs for all ratepayers and for society should be available. An array of programs should be available to each customer class.

Utility Rate Design

As discussed in Chapters 1 and 3, rates that accurately reflect long-run costs promote the most efficient use of the utility system. When prices reflect long-run costs, customers can be expected to make wise purchasing decisions. If rates are inconsistent with long-term costs, customers are more likely to make inefficient electric and energy choices. Depending on what price signals customers receive, they are as likely to use too much as they are to use too little energy. But when the price signals send the wrong message, use will not match the demand predicted in the IRP process. Similarly, special rates, such as cogeneration deferral rates rely upon deciding which actions are economic and which are uneconomic. IRP informs utility regulators whether these rates make sense.

Utility Power Purchases

Wholesale purchase plans, including purchases from Qualifying Facilities, Cogenerators, Independent Power Producers, Exempt Wholesale Generators, and other utilities should be compared to determine whether a utility's wholesale purchase decisions result in lower costs and are consistent with the utility's own planning projections.

Transmission And Distribution Planning

Often utilities spend as much for transmission and distribution upgrades and improvements as spent upon power plant additions. These expenditures should be consistent with a planning process that examines alternatives to transmission and distribution investments (including demand- and supply-side options) with the objective of minimizing system cost.

Conclusion

Exploration of IRP and its implementation requires new skills and new thinking. However, customers should not be denied the benefits of DSM benefits or even minimal investment in DSM while the details of IRP are being worked out. Utilities can, and should, be encouraged to start adding low-cost DSM to their resource mix without fearing that they are putting themselves or their customers at risk.

Chapter 12: Independent Power Production and Competitive Bidding

Chapter 7 described a wide range of possible restructuring options. Each option has some role for Independent Power Producers (IPPs). Depending on the restructuring model selected the role of IPPs can range from representing a fraction of new generating resources to the ownership and operation of all generation.

The Goals for an IPP Program

As with most aspects of electric utility industry restructuring the nature of a country's IPP program will be shaped by the country's goals. There are at many possible goals that could shape a country's IPP program but the three that arise most often are:

- Attract outside capital, to meet rapidly growing electricity needs without imposing large strains on the nations internal financial capabilities;
- Reduce electricity costs through competitive pressures; and,
- Assign risks in a more efficient or desirable manner.

Which of these goals are adopted will influence the final design of an IPP program .

Relationship to Electric Utility Industry Restructuring

In addition to the goals of an IPP program, the IPP program must fit logically with the nature of a country's overall electric restructuring plans. In some countries restructuring calls for all new power generation to be constructed by IPPs, in other countries, only some portion of new power plants will be constructed by IPPs. Still other countries prefer to have IPP participation through joint ownership arrangements some with IPPs holding a minority stake and others with IPPs holding a majority interest. Other countries have chosen to make all generation competitive and have sold (or have plans to sell) all existing generation to IPPs.

Any of these models is achievable; however, care must be taken to avoid conflicts between the goals of an IPP program and the scope and limitations of a restructuring plan.

Risks and Rewards

Electricity prices offered by IPPs will generally reflect the costs and risks borne by the IPP. Several general principles explain variations in IPP prices.

- The greater the risks the higher the prices.;
- The more competitive the market the lower the prices; and,
- The more stable and predictable the market the lower the prices.

To an IPP, risk can come from a number of different sources. Some of the more important risks include the following:

<u>RISK TYPE</u>	<u>DESCRIPTION</u>
Currency risk	IPP payments may be in local currency yet many IPP costs such as fuel costs, equipment and repair costs, and cost of capital may be in U.S. dollars.
Payment risk	The purchaser of power from an IPP may be financially weak creating the risk of non-payment.
Political	The existing or future government may change the rules
Management Risk	IPP participation through minority equity ownership increases risk of loss of IPP management oversight.
Technology and Performance	The technology selected may not perform as originally expected

To some degree these risks, if borne by the IPP, will be reflected in electricity prices. The higher the risk, the higher electricity prices. At some point the level of risk becomes so high that project financing and development is impossible and the IPP option disappears. To keep electricity prices within reason, it is desirable to assign risks to the entity that can most efficiently deal with the risk or to reduce IPP risks through some form of a guarantee from stable government or international financial institutions.

In a general matter, IPPs finance and construct plants based on the financial strength of an underlying power sales contract. In some cases where the markets are more stable and predictable, IPPs have constructed merchant plants with either little or no plant capacity subject to a power sales contract.

Power Purchase Agreements (PPA)

Most PPAs or power sales contracts are long-term, fifteen years or more, full output contracts. PPAs have become increasingly complex documents that have grown over the past ten years from twenty pages in length to over two hundred pages. The full content of PPAs is well beyond the scope of this report.

Pricing terms are the most important. Electricity prices are either on a rolled-in energy basis (“x” ¢/kWh) or two-part (“y” \$/kW plus “z” ¢/kWh) in nature. In either case, there may be performance standards (unit availability) tied to rewards or penalties. In general, the best practice is to have a two-part contract where the price components reflect the underlying cost of the technology being purchased. Thus a hydro plant and a gas-fired plant that are each expected to deliver power at

4¢/kWh would have different two-part contracts. The hydro plant would have a very high fixed component and a low variable component relative to the gas-fired plant.

There are a growing number of examples where merchant power plants, IPP merchant power plants, are being constructed without long-term contracts. In this case IPPs who have sufficient confidence in the economic, financial, and accounting operation of spot electricity markets or in the strength of retail competition will finance plants based on expected cash flow from direct sales to retail customers or sales to a spot market or power pool. This development is relatively recent and will probably be limited for substantial time to countries that have particularly clear, well-established, and stable electricity markets and underlying institutional and legal foundations that permit the financing of this type. In the mean time, most IPPs will continue to be constructed primarily based on long-term contracts. These long-term contracts will themselves rest on the financial strength of the underlying purchasers, generally the local transmission and distribution companies.

Competitive Bidding Issues

Competitive bidding begins with issuance of a very clear and complete Request for Proposals (RFP). Clear and complete proposals will solicit the greatest number of bids designed to meet the specific country needs. The greater the number of bids, the more efficient the competition and the greater confidence one can have in the selection of the winning bidder. The RFP should clearly describe the important attributes of the project and how proposals will be evaluated.

The bidding evaluation criteria can be very prescriptive with specific weights stated for every aspect of the proposal. In this case bidders could self-score their own proposals. At the other extreme, the RFP may simply generally describe the purchasers needs and desires and leave the bidders free to meet the RFP in potentially innovative ways. Each approach has its benefits and deterrents. In developing countries with little or no track record or experience in this area, the best practice probably means using a detailed and highly prescriptive RFP.

Power Purchase Agreements (PPAs) have become very complex, lengthy documents. Including all standard provisions of a PPA as a part of the RFP is beneficial and would simplify negotiations, reduce uncertainty, improve the financing costs of the contract, be fair among all participating vendors and speed the contracting process.

Dealing with Contingencies

Power contracts can allow independent generation to be used as efficiently and flexibly to deal with risks and contingencies as utility-owned units. In the preconstruction phase, PPAs have included specific provisions that allow the purchaser to delay the In Service Date of an IPP. In many cases the financial costs of this delay may be lower than similar delay costs exercised by utilities in their own projects. Contracts may also provide for buy-out provisions, or provisions that allow the purchaser to terminate the contract provided that the termination is exercised by a specific date, generally prior to construction.

Post-construction flexibility is generally more expensive to obtain, but experience shows that flexibility in the post-construction phase is also achievable. Provisions for early termination and buy-outs can be most successfully arranged if done prior to the execution of the PPA.

Renegotiations

Many jurisdictions have or are facing the problem of IPP contract prices which may have seemed reasonable when the contracts were executed but today seem too high. Renegotiating these contracts is possible but should be approached from the perspective of meeting the needs of both the purchaser and the seller. The key to renegotiation of these contracts is for both parties to have a clear understanding of each other's goals and constraints. With the goals and constraints clearly expressed, creative solutions can generally be found. Options may include contract extensions to bring near-term prices down, refinancing or modified fuel contracts to bring IPP costs down, or contract buy-outs or buy-downs.

Conclusion

IPPs are an important part of all restructuring options. Careful planning and procurement practices can assure that IPPs meet a country's needs in the most flexible and cost-effective manner possible.