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Bulgaria

Electric Sector Business Unit Performance Management Project

INTERIM REPORT: PRICING FOR GENERATION, TRANSMISSION AND DISTRIBUTION

Prepared for
United States Agency for International Development
Ministry of Energy and Energy Resources
National Electric Company

Under contract
Regulatory Reform and Energy Sector Restructuring in Central and Eastern Europe and the Baltics
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Contents

Appendices

1. Pricing for Generation, Transmission and Distribution

1.1 Overview

This report has been prepared by Bechtel Consulting in cooperation with the Bulgarian Ministry of Energy and Energy Resources (MEER) and the National Electric Company (NEK) The United States Agency for International Development (USAID) provides funding and project guidance The project builds on reform strategies developed by the Bulgarian Restructuring Working Group representing MEER, NEK, and Bulgarian industry and academia, in cooperation with London Economics.

This Interim Report presents recommendations for transfer pricing mechanisms between electric sector business units. These transfer pricing mechanisms institute commercial business relationships between the "single buyer", which controls the market for generating resources acting on behalf of consumers, and the generating plants which pursue their own specific business objectives. Establishing the single buyer is a key step in the overall reform of the power sector.

The objectives of the proposed pricing arrangements for the Bulgarian power sector are:

- to formalize the relationship between the centralized utility services and semi-autonomous generating plants within a contractual framework that stimulates competitive performance in the generation sector;
- to establish the electric distribution branches in an autonomous commercial organization(s);
- to facilitate the initial phase of private sector investment in the electricity sector.

The pricing mechanisms recommended in this report are designed appropriate to the nature of the businesses. For generation we foresee an eventual shift from regulatory review of costs, which is appropriate while tariff revenue is less than the "cost-reflective" ideal, to a regulatory mechanism that will ensure that generation is a commercial business subject to open and fair competition for power purchase agreements. For transmission and distribution, which will remain franchise monopolies, we foresee the need for price regulation based on standard costs and service quality regulation that provides incentives for improved performance

Implementing appropriate price and quality mechanisms will improve efficiency, encourage cost-efficient use of resources, and set the groundwork for attracting investment in the electric sector. The overall pace of reform of the electric sector depends on progress in the following areas:

- Link consumer prices for electric services to the costs of providing the services, so that the industry can be self-financing. One step that has been achieved in

Bulgaria is the introduction of an automatic tariff adjustment formula for the effects of inflation, currency exchange, and fuel price swings The key step is to transition to higher, cost-reflective tariffs based on the full cost of providing services.

- Establish adequate financial performance for NEK business units, and resolve the problem of delinquent customer bills
- Adopt commercial practices at NEK business units to demonstrate the organizational capabilities required to manage private investment.
- Implement appropriate sector restructuring and associated regulation.

1.2 System of Trading Arrangements for the Electric Sector

This report focuses on the trading arrangements required to implement the single buyer structure. The single buyer structure requires the following elements which govern the flow of funds to the electric sector organizations:

- power purchase agreements between the single buyer and the generators
- price regulation of distribution/supply services
- price regulation of transmission services
- tariffs for final consumption based on the revenues required to pay generators, the distribution company and the transmission company

In practice this structure works in the following manner. The distributor collects the revenues, based on regulated uniform national tariffs. The revenues are transferred to the single buyer who allocates the funds to generators, the distributor and the transmission company based on the prices in the power purchase agreements and the regulated revenue requirements for distribution and transmission services. As a practical matter the system requires a balancing account mechanism to correct for variations between actual and forecasted revenues.

1.3 Cost-reflective Pricing: Standard Cost and Cost-of-Service

We envision price regulation of generation, distribution and transmission based on a hybrid of standard cost and cost-of-service. This approach is used to determine the cost basis for revenue targets that stimulate efficient decision-making by management of the regulated utility.

The standard cost approach is a form of benchmark regulation. The standard cost of providing utility services is determined based on engineering estimates or comparisons with other similar utilities. The result of this process is the idealized financial requirement for the utility. By basing the amount of revenues to be received by each utility on standard costs rather than on actual costs, the regulatory authority attempts to create an incentive for each utility to reduce its actual costs below its designated standard costs. In theory, different incentives can be correlated to different types of standard costs

Cost-of-service is a specific process for determining the utility's revenue target based on accounting, budget and asset information. The components of cost-of-service are operating expenses, depreciation, profit on assets, cost of debt, and taxes. Due to the effects of hyperinflation in Bulgaria, it is necessary to evaluate cost-of-service on the basis of the replacement cost of the existing assets, less physical depreciation Cost-of-service based on estimated asset replacement cost can be considered a variety of standard cost.

Cost-reflective tariffs will not be achieved overnight in Bulgaria, and electric sector business units will continue to face a difficult job prioritizing tight budgets. During the transition to cost-reflective tariffs, funds for electric utilities will be rationed in the budget allocation process. It will not be possible to make direct use of standard costs for price regulation of generation, transmission and distribution services. We envision a process for price regulation that monitors the utilities to ensure that expenditures are prioritized on the basis of:

- net present value of cash flow, which is a measure of the equivalent value today of the actual costs and benefits resulting from the expenditure; and
- payback period, the number of years of operation required for recovering the cost, which is a measure of project risk.

2. Trading Arrangements for Generators

Existing generation will graduate in a series of steps from regulated budget allocation to standard cost regulation to competitive pricing based on long term power purchase agreements. In the ultimate stage of regulation, the marketplace for power purchases will act as the regulator for the competitive generation sector, which is the reason for the emphasis of the regulatory process on assuring that competition is open to all qualified business entrants and fair to small and large players with adequate anti-monopoly safeguards.

2.1 Transition to Power Purchase Agreements

Contract-based trading arrangements between the single buyer and generators, and a regulated competitive process for the development of generation, are considered essential for competitive generation and increased private investment. We envision implementing power purchase contracts for all generators, and establishing a fair, competitive resource solicitation process.

Initially, during the transition to cost-reflective tariffs, the bulk of existing NEK generating capacity and non-NEK generating capacity, including existing CHP and industrial generation, will be contracted to the single buyer under **one year power purchase contracts** At first the one year power purchase contracts will serve as a formalization of the budget allocations to each plant. Later the contracts will provide the framework for standard cost regulation of each plant. The introduction of the one year power purchase contract will initiate market arrangements in the generation sector.

An alternative to the one year contracts is to simply regulate transfer pricing to generators, either plant-by-plant or for aggregations of plants, without the formal one year contract. The group of plants subject to regulation will shrink as some plants graduate to unregulated PPAs. Under this form of regulation, which is common in the U.S., an annual energy cost proceeding determines the allowable operating costs for the prior year. A more involved forward- or backward-looking proceeding evaluates allowable fixed costs every three or four years.

Gradually **long term power purchase agreements** (PPAs) will be awarded to strategic generators that contribute to system reliability, pass the least cost planning test, and manage the business according to the best international business practices. The long term PPA is key to stimulating the required private investment in the generation sector. The need for investment has been estimated at over two billion dollars in the next five years. Therefore it is desirable to provide PPAs for strategic generation assets as soon as economic conditions in Bulgaria allow. The transition to PPAs is limited by the speed of transition to cost-reflective tariffs and by the credit worthiness of the Bulgarian government.

While tariffs to final consumers continue to be subject to government approval, and until the principal of cost-reflective tariffs is established under Bulgarian law, pricing under the long term PPAs will have to be guaranteed by the Bulgarian government. In general, such obligations are viewed similar to debt by financial institutions. The ability of the state to incur additional obligations will be a limiting factor in the amount of generating capacity that can be awarded PPAs. From a practical standpoint, some existing power plants that are needed for system reliability and require significant investments will have to continue to defer their investment programs until financial circumstances in Bulgaria allow the awarding of PPAs.

We envision a plant-by-plant approach to awarding PPAs over a transition period. Under the current circumstances in Bulgaria each PPA should be accompanied by a tariff increase sufficient to support the incremental cost of the guaranteed revenues under the PPA, otherwise the remaining generators on one year contracts will be disadvantaged.

The one year and longer term contracts will be structured to preserve a scheduling and dispatch protocol based on cost merit order, adjusted according to the particular operating constraints of Bulgarian generation and transmission. This will ensure maximum overall efficiency of the integrated operation of production and transmission activities. The power purchase contracts will not stimulate dispatch competition among generators. Dispatch competition may be impractical for the particular mix of Bulgarian generators, especially at this time while a majority of the generators are unable to obtain adequate funds for investments and profits.

2.2 Alternative Transition Approaches: Hungary and Poland

The example of Hungary illustrates a "big bang" transition approach. Over the last few years the government of Hungary has tendered PPAs for many of the generating plants in a massive privatization. It should be noted that the plants are based on oil and gas technologies which in general are more attractive to investors than coal and nuclear. The contracts are in effect until the expected end of the life of the plant, with pricing designed to support cost plus profit for the life of the plant. In some cases the PPAs have been structured based on negotiations with investors.

The example of Poland illustrates a slower managed approach. The Polish generating sector is primarily government-owned and coal-based. Beginning in 1994, several of the least cost generators requiring significant investment in the near term were awarded long term PPAs intended to encourage private investment. The other existing generators were granted medium term four year contracts. Initially the medium term contracts covered 100% of each plant's capacity, decreasing to between 25% and 80% by the end of the four years. The capacity freed from the medium term contracts is eligible to compete in the Polish spot market. This generation restructuring process is being used to implement two parallel functioning market segments: a spot (pool) market and a contract market.

2.3 Price Structure for Power Purchase Agreements

We envision capacity and energy payment components in the power purchase agreements. The **energy price** will be based on the operating costs of the power plant, and will be consistent with the pricing used for system dispatch. Fuel costs will be directly passed through to the single buyer, as long as fuel purchasing is outside of the control of the generator. The **capacity price** will reflect the capital budget allocation, the fixed cost-of-service or the price negotiated in the competitive solicitation process, depending on the overall progress of the restructuring of generation.

Eventually the energy and capacity payments will be subject to incentive mechanisms. The approach for transitioning to performance-based pricing for the one year and long term power purchase agreements is described further in the sections below.

2.4 Contractual Provisions for Ancillary Services

One alternative for contracting for ancillary services (voltage regulation, reserves, load following, black start, emergency services) is to provide separate payments to the generator for each service. In practice it is difficult to "unbundle" the costs of the various ancillary services provided by the generator. Separate payments for ancillary services also require special metering, and can involve complex billing determinations.

In the initial stage of power purchase contracting, we envision adopting a simpler approach based on minimum performance criteria with associated penalties for noncompliance. With the criteria approach, payments for ancillary services are rolled in with the capacity payment. Penalties for noncompliance can be based on the costs to the single buyer in the event that the single buyer must procure ancillary services from another source.

2.5 System Planning and Dispatch

The single buyer will have overall responsibility for system planning and dispatch The distribution company will provide demand forecasts to both the single buyer and the regulator. The single buyer, working in close coordination with the transmission business unit, national dispatch, and potential new generators, will seek approval from the regulator to initiate the competitive bidding process for generation, if required.

National dispatch will direct the operation of the generation and transmission systems. Dispatch will be in accord with the contracts between the single buyer and the generators. The contracts will have provisions for economic dispatch, as modified by the constraints of the generation and transmission systems. It is important to emphasize that the contracts will also provide for emergency support when system reliability is threatened. The contracts will incorporate the following principles:

- Regardless of short-term economics, a generator will follow the direction of national dispatch if it is physically capable of doing so within its technical parameters.
- Any generator which suffers economic loss while following directions to support system reliability will be made whole for such loss.
- A grid code will provide technical guidance for all generators.

2.6 One year Power Purchase Contracts

The one year power purchase contracts will set up a contractual relationship between generators and the single buyer as an important step in commercialization of the generation sector An example of a one year power purchase contract is presented in **Attachment 1**.

Initial pricing for existing generating capacity under the one year contracts will be determined based on budget allocation of available revenues in the next budget cycle of NEK. Pricing will be updated each year with the budget cycle, under a regulated proceeding. This is basically the same process as the current budget allocation at NEK.

The contract will be structured to stimulate cost efficiency of the electric sector through use of a fixed annual budget and direct quality incentives. In the near term, significant cash bonus incentives may be impractical because of the shortage of cash for funding the electric sector. The initial stage of restructuring will keep the current salary bonus system at NEK which rewards employees of the generating plants for achieved results in electricity production, availability of capacity, and frequency regulation. The level of funding for the reward program will be determined during the annual price proceeding. The regulator will attempt to target rewards to organizations that have made optimal use of limited funding.

Once the principle of cost-reflective tariffs is established in Bulgaria, the form of price regulation of the one year power purchase contracts will change. Annual payments to generators will be based on standard costs. A performance pricing mechanism will adjust revenues to generators based on achieved results. Eventually there will be energy payment incentives for fuel consumption efficiency, startup cost, and variable costs of operations and maintenance, and there will be capacity payment incentives for availability of capacity.

2.7 Long Term Power Purchase Agreements

Competitive generation eventually will be stimulated using a process to award long term power purchase agreements for up to 20 years duration not to exceed the life of the plant Eventually the generating sector will include a mix of one year and long term contracts.

Pricing under the PPA will provide adequate revenues and quality incentives to operate Bulgarian generating companies on a commercial basis and attract private investment. PPAs will support the financing of new capacity or investments in existing capacity based on the security of future contractual receivables. Pricing for the different categories of generation will be established according to the following:

- Pricing for **existing NEK thermal generation** will be on the basis of cost plus profit. We envision that eventually all of the NEK thermal power and CHP plants will have contracts. Pricing for CHP plants will recognize a fair split of costs between district heating and electricity.

- The **Chaira Pumped Storage Power Plant** and the existing **NEK hydroelectric power plants** initially will remain part of the central utility functions Capital and operating expenditures for these plants will be regulated along with the other costs of the single buyer. Eventually these plants may receive long term PPAs, possibly longer than 20 years because of long plant lives. Any hydroelectric plant requiring significant refurbishment or capacity expansion will be a candidate for a long-term PPA with pricing based on cost plus profit. Pricing and dispatch provisions of PPAs for hydro plants can be complicated due to special dispatch considerations, low operating costs, and low accounting value relative to market value.

- Contracts or tariffs for **non-NEK CHP and industrial generation** will contain negotiated prices not to exceed system marginal energy cost plus a capacity price based on the expected contribution of the generating capacity to system requirements Pricing will reflect the plant's capacity and operating contributions to system requirements. The capacity payment will be subject to capacity testing and demonstrated capacity availability.

- Pricing for **new generation** will be established through a competitive tender or negotiation mechanism. In general, an appropriate mechanism achieves a price equal to the cost plus profit of the most economic alternative. Rehabilitation of existing generating capacity will compete in the tender process under the same rules for new generating capacity. An example of the competitive tender process used in the U.S. is provided in Attachment 2.

2.8 Life-of-Plant PPAs for Power Plants that will be Retired

Once the principle of cost-reflective tariffs is established in the Bulgarian electric sector, there is the possibility to offer special contracts for the remaining life-of-plant for power plants that will be retired without significant additional investment. Pricing will reflect cost-of-service. In this type of contract it is important to balance any front loading of payments with the possibility of performance penalties if the plant fails to deliver the agreed services throughout the term of the contract.

2.9 Existing Bulgarian Power Purchase Arrangements

Power purchase arrangements currently implemented or under development at NEK include:

- Generation buyback tariff. The generation buyback tariff covers NEK's purchases of power from non-NEK industrial generators and CHP. Prices are subject to approval by the government of Bulgaria.

- Three year contracts for non-NEK hydroelectric power plants (currently under development at NEK).

- Periodic transactions with neighboring utility systems.

2.10 Prerequisites for Long Term PPAs

Existing generators will qualify for eligibility for a PPA by establishing a commercial structure and a financial plan for the company. PPAs will be awarded to existing generators in priority order as established by the single buyer in coordination with the regulatory authority. The process of awarding PPAs will allow competition between existing NEK generation, new IPPs and existing non-NEK generation. Competition in the awarding of PPAs will ensure that the generation sector develops in the most cost efficient manner.

PPAs should be awarded as required to ensure the continuing reliability of the supply of generation at least cost. This suggests the important role of electric system planning to determine the optimum economic investment targets (modernization of existing capacity, construction of new capacity, development of CHP systems, conservation), the fuel structure for power generation, as well as an economically feasible program for environmental protection.

Electric system planning provides the means to create a list of investment priorities in the power sector. Supply- and demand-side alternatives and NEK and non-NEK alternatives are allowed to compete on an equal footing to gain a place on the priority list. This list becomes the basis for signing the first long-term contracts between the single buyer and the power generators offering the most beneficial projects. Eventually, when demand catches up with supply, the resource acquisition process will be managed by the regulator so that each year an equal MW block of generating capacity or demand-side measure is signed under PPAs.

New resources will be acquired through competitive tenders open to new resources, existing resources with significant investment requirements, and existing plants with terminated PPAs. A plant near its end of life will have an incentive to improve performance and reduce costs in preparation for the competition. If the plant, refurbished or not, is the least-cost bidder, it can continue to operate under a new contract. If not, it will be replaced with lower cost resources.

In summary, long term contracts will be granted gradually on a case-by-case basis in time to ensure security of supply of generation Only a generator meeting the following requirements will be eligible for a long term PPA:

- The generator is necessary for electric system reliability.
- The generator is the least cost alternative as determined by least cost planning, subject to competition with non-NEK generators.

- The generator is established as a commercial company with the necessary groundwork for acquiring needed investment.

3. Price and Quality Regulation of Electricity Distribution

3.1 Current System

Funding for the Bulgarian distribution branches is determined in the annual budget allocation which is approved by the NEK Board of Directors. Each distribution branch is allocated its "planned expenditures" which determine an overall cost target for the branch. Due to the Bulgarian economic downturn there is insufficient funding available to meet the full revenue requirement for the distribution sector. The current system is a process for dividing the available funds fairly among the distribution branches.

The process of allocating available funds to the distribution branches is appropriate in the current economic environment. The trend in the industry is toward price cap mechanisms, however a multi-year price cap mechanism is impractical in Bulgaria while funding for the distribution sector is inadequate because under these circumstances there is no possibility for "profits" even if the distribution branch achieves excellent cost efficiency.

Performance is stimulated at the distribution branches through a salary incentive mechanism. The incentive system provides employee salary bonuses based on achieved results in two areas: cost-efficient use of annual budgeted funds and reduction of distribution energy losses. The salary incentive encourages the distribution branches to make the most of the available funding. International experience indicates that salary incentives are an effective stimulus for achieved results. The current system, if faithfully implemented, will encourage cost-efficiency in the distribution branches.

A limitation of the current salary incentive mechanism is its narrow focus. There is no stimulus in the salary incentive for distribution service to meet or exceed minimum quality standards for customer outages, voltage fluctuations, customer satisfaction and safety. There is no stimulus for attaining conservation achievements that have the potential to reduce the cost to customers and society of electric services. The lack of stimuli for service quality is understandable in the current climate of limited funding. It is perhaps unwarranted to provide incentives for measures that would require investments and additional maintenance expenditures. In this regard the current incentive for loss reduction is questionable because reducing losses typically requires additional funds.

3.2 Commercialization of Distribution Services

Obtaining private investment in the distribution sector requires establishing a commercial financial structure for the NEK distribution business unit. The commercial structure will allow investors to obtain regulated profits in exchange for the use of their capital.

Conceptually, commercialization of the distribution sector is possible even in the current economic climate in Bulgaria, however it would require price guarantees from the Bulgarian government. This would impose an additional debt burden that would have to be weighed relative to competing objectives for federal fiscal policy. Ideally, establishing a commercial distribution sector will coincide with implementing cost-reflective tariffs in the electric sector.

We envision that initially the electric distribution branches will be established as a single commercial company subject to price and quality regulation. A later stage of restructuring may bring further disaggregation into multiple companies. Several key issues will have to be addressed prior to splitting distribution into multiple commercial companies. This will require:

- developing standards for service quality and universal service
- evaluating organizational economies of scale
- determining ideal sizes for privatization
- establishing transmission interconnection points and appropriate metering
- establishing a process for price and quality regulation

3.3 Price Regulation of Distribution Services

The key to price regulation of distribution services is evaluating the revenues required to own and operate the distribution business. A revenue target is set on the basis of the costs approved by the regulator, as determined through account-by-account review of historic business costs, budget forecasting, or estimates of standard costs. The revenue target is established in a periodic regulated proceeding between the company, the regulator and the public.

When the NEK distribution business unit is established as a commercial business unit, the following regulatory process can be used for price regulation:

- Estimate the revenue required for the distribution business unit:

  a) determine allowable variable costs on the basis of standard cost estimates established through benchmarking or time and materials estimation, determine fixed costs on the basis of the replacement cost of the existing assets, less physical depreciation, plus a "reasonable" profit on this "real" asset value; or

b) determine both variable and fixed costs on the basis of standard costs

- Allocate revenue requirements to the following components: cost per customer differentiated by customer class; cost per kW demand differentiated by time and season, and cost per kWh energy consumption differentiated by time and season.
- Use the revenue targets for cost per customer, cost per unit of demand and cost per unit of energy consumption as the basis of the regulated price of distribution service for a period of 4 years
- During the 4 year period there will be annual automatic adjustments to the total allowed distribution revenue for the following factors:
  - growth in number of customers
  - growth in demand
  - growth in energy consumption
  - change in the prior year retail price index
  - currency exchange effects
  - expected improvements in productivity
- Special adjustments to base revenues will be allowed on a case-by-case basis for "extraordinary" expenses such as storm damage.
- At the end of the 4 year period the cost targets will be reevaluated.
- Any cost efficiencies achieved by the distribution business during the 4 year period will be shared 50/50 with electric service customers. That is, if the price target in a year is P_t, and to achieve the minimum guaranteed return it will be possible to charge a lower price P', then the price to consumers will be set to $(P_t + P')/2$.
- Customer-specific charges that are collected direct from the customer, for example connection charges, constitute a separate regulated revenue item outside of the base revenue mechanism.
- Quality service is encouraged by providing a separate incentive payment, or alternatively enforcing minimum standards of quality service A quality incentive payment will have to be carefully designed to work together with the price cap incentive that motivates the business to reduce costs. The quality incentive mechanism will address:
  - customer outage frequency and duration
  - voltage fluctuation
  - customer satisfaction
  - employee and public safety

- Allow conservation investments to earn a profit to induce the distributor to develop appropriate conservation programs. The conservation incentive mechanism must be closely regulated to ensure that conservation incentives meet the criteria of reducing the social costs of energy consumption. The conservation cost recovery mechanism must be carefully designed to work together with any revenue mechanism that links revenues to sales. An incentive mechanism that has been used in California allows the distributor to keep as profit thirty percent of the net present value of efficiency savings, subject to a four year verification program following implementation of the conservation program. There is also provision for penalizing the utility for programs found to be useless.

3.4 Attracting Investment in the Distribution Sector

Rational price-setting and transparent and non-discriminatory processes to govern prices and quality standards set the stage for attracting investment, thus reducing the need for investment by the government of Bulgaria. Firms that strive to meet investor and consumer expectations pursue cost reduction and performance improvement as a matter of corporate strategy. A regulated firm will attract investors if it meets the following criteria:

- The firm operates on a commercial basis and is organized along logical corporate lines.
- Revenues are sufficient to provide a reasonable profit.
- The firm is worthy of credit and has control over its business decisions.
- The general economic conditions within the country are stable.
- A sound legal and regulatory framework for private investment exists, including institutions and practices that provide for fair and nondiscriminatory treatment of all investors.

4. Price and Quality Regulation of Electricity Transmission

Price and quality regulation of electricity transmission is conceptually similar to distribution. We envision an indexed revenue target developed according to a cost-of-service or standard cost approach, with a complementary mechanism for quality based on direct incentives or minimum criteria for achieved results. Transmission service will be provided under a standard tariff for use of the transmission system with a tariff component or separate contract for interconnection services.

International experience indicates that the transmission company should have cost responsibility not only for the costs associated with owning and operating transmission facilities, but also for dispatch "uplift" associated with the incremental costs of transmission bottlenecks and voltage regulation Combining all transmission-related costs in a single regulated revenue stream allows a revenue mechanism that stimulates cost-efficient transmission investment decision-making.

In the case of a combined transmission and distribution company there is the possibility of a simplified single mechanism for price and quality regulation of combined transmission and distribution services. Under current conditions in Bulgaria where there is no provision for open access and the distribution branches are not separated into multiple companies, there is some organizational rationale for combining the transmission and distribution functions.

The future possibility of open access and customer choice of supplier will require separating the transmission service function in an independent organization and establishing transmission tariffs. A system that allows multiple buyers and sellers may require transmission congestion contracts to ensure equal access to limited transmission.

The future possibility of multiple suppliers and regionally differentiated cost of service will require consideration of location in the application of transmission use-of-system charges Eventually the use-of-system charges will have the following structure:

- a charge per kWh to cover the costs of **grid system services** (voltage regulation, reserve services, black start)
- a charge per kWh to cover the cost of **transmission losses**, differing according to location
- a charge per MW of maximum demand at time of system peak load flows to cover the **transmission fixed costs,** differing according to location

5. Next Steps

- Establish the process for price regulation of generation, transmission and distribution.
- Develop detailed cost-of-service studies for generation, transmission and distribution. Evaluate standard costs based on engineering estimates and international comparisons with other utilities. This is an essential step for commercializing electric sector companies.
- Develop a set of rules to provide an opportunity for NEK and non-NEK generators and conservation to compete on a fair and reasonable basis to fulfill Bulgaria's power requirements.
- Develop, negotiate and sign one year power purchase agreements between the single buyer and existing generators. Alternatively, establish the regulatory cost proceeding for generators without PPAs.

- Identify which if any existing generators are eligible for a long term PPA in support of potential privatization or to provide guaranteed revenues to pay for significant investments in the plant.
  - Establish a commercial structure for ownership and management of the plant.
  - Develop the terms and conditions for the PPA
  - Establish pricing in the PPA based on evaluation of standard cost
  - Implement changes in tariffs to end consumers to support pricing under the PPA.
- Establish transmission and distribution as a single or multiple autonomous business units.
  - Establish commercial structure.
  - Implement a process to determine cost-of-service or standard cost for transmission and distribution services.
- Establish the single buyer as an autonomous business unit.

Appendix A

EXAMPLE CONTRACT

CAPACITY AND ENERGY
ONE-YEAR POWER PURCHASE AGREEMENT
BETWEEN
____________ POWER PLANT ("SELLER")
AND
BULGARIAN CENTRAL BUYER ("BUYER")

Article 1 Purchase of Power

The SELLER shall make available to the BUYER and the BUYER shall purchase from the SELLER, the Net Dependable Capacity, Net Electrical Output (Energy) and the Related Services from and after the effective date of the contract.

Article 2 Purchase Price

The BUYER shall pay the SELLER at fixed prices authorized from time to time by the REGULATOR. The purchase price shall be derived from the reasonable costs of the SELLER to produce the power sold to the BUYER, as determined by the REGULATOR.

The energy payment shall be authorized by the REGULATOR in an annual proceeding to approve the actual expenses for the preceding year for fuel, operations and maintenance, and other variable costs of operations.

The capacity payment shall be authorized by the REGULATOR in a periodic proceeding at intervals of three or four years. The REGULATOR shall, at its sole discretion, authorize capacity payment the the SELLER on the basis of one of the following alternatives:

a) Budgeted fixed costs of the SELLER. The SELLER shall provide appropriate economic analysis to justify its budget request.

b) Estimated standard fixed cost of the plant, as estimated by the REGULATOR or an unbiased qualified third party.

Article 3 Addresses for Notifications

Article 4 Designated Switching Center

16

Article 5 General Provisions

This Agreement includes the following appendices which are attached and incorporated by reference.

- Attachment 1 - General Provisions
- Attachment 2 - Interconnection (not available)

Article 6 Term of Agreement

This Agreement shall become effective on the date of execution by the Parties and shall remain in effect until terminated by either Party with authorization of the REGULATOR.

Article 7 Signatures

17

Attachment 1

GENERAL PROVISIONS

1.1 DEFINITIONS

1.2 OPERATION

1.2.1 Inspection

1.2.2 Facility Operation and Maintenance

The SELLER undertakes to operate in technically proper manner his own FACILITY, to comply to operating discipline, to perform in due time the operating switchings and regime restrictions as ordered, and to implement all instructions of the BUYER given within his functional competence.

1.2.3 Voltage Regulation

The SELLER shall provide such reactive power support as may be reasonably required by the BUYER to maintain system voltage level and power factor. SELLER shall operate the FACILITY at the power factors or voltage levels prescribed by the BUYER. If SELLER fails to provide reactive power support, BUYER may do so at SELLER's expense.

1.2.4 Point of Delivery

1.2.5 Operating Communications

(a) The SELLER shall provide forecasts of available capacities for each generating unit. Such forecasts shall include, but not be limited to:

- Annual forecast of capacity availability
- Monthly forecast of capacity availability
- Notice of unforeseen changes to forecast availability
- Day ahead availability forecast

(b) The SELLER shall maintain operating communications with the designated switching center of the BUYER. The operating communications shall include, but not be limited to, system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, levels of operating voltage or power factors, and daily capacity and generation reports.

(c) The SELLER shall keep a daily operations log for each generating unit. Operating information and local operation instructions shall include economic dispatching, synchronization and separation, scheduled and unscheduled outages and complete data on proper functioning of the FACILITY.

(d) SELLER shall measure and register on a graphic recording device power in kW and voltage in kV at a location within the FACILITY.

(e) SELLER shall report daily to the designated switching center the hourly readings in kW of capacity delivered and the energy delivered in kWh.

(f) SELLER shall provide monthly reports to BUYER identifying all periods during the month when the FACILITY was available at less that the Dependable Capacity. BUYER may audit these reports within 6 months after the date of the report. SELLER shall permit the BUYER to visit the FACILITY, if requested, to verity forced outages.

(g) Provision for telemetering.

1.3 DISPATCH

1.3.1 Economic Dispatch Criteria

BUYER is obligated to dispatch the FACILITY on an economic basis in accordance with the Dispatch Protocol. The prices for services provided under this contract will be used for economic dispatch purposes.

1.3.2 Dispatch Protocol

(a) The BUYER shall provide dispatch instructions. Such instructions will include but not be limited to:

- Non-binding monthly schedule of hourly generation
- Voltage schedule as required
- Day ahead schedule of hourly generation
- Real-time schedule changes as required.

(b) SELLER shall make reasonable efforts to fulfill dispatch instructions within the physical capability of the FACILITY.

(c) Changes to operating schedules may be made as follows:

- When the facility is on-line, changes in scheduled output may be made with the Facility's nominal ramp rate. The facility may be scheduled off-line with Off-line Prior Notice.

19

- When the Facility is off-line, a scheduled start-up may be delayed or canceled with two-hours prior notice. A start up may be scheduled with Start-up Prior Notice.

1.3.3 Facility Dispatch Limits

1.3.4 Annual Review of Facility Dispatch Limits

1.3.5 Emergency Operations

SELLER, at BUYER's request, shall during a System Emergency or during a System Pre-Emergency operate the Facility within its operating limits in a manner to mitigate the System Emergency or System Pre-Emergency.

1.3.6 Voltage Regulation

1.3.7 Provision for Energizing and Deenergizing Facility

1.3.8 Automatic Generation Control Operation

1.4 FUEL

1.4.1 Supply of Fuel to Facility

BUYER (will/will not) provide all fuel requirements for the facility...

1.4.2 Coordination of Fuel Supply

1.5 MEASURING AND ACCOUNTING FOR ELECTRIC POWER

1.6 BILLING AND PAYMENT FOR ELECTRIC POWER

1.7 PURCHASE OBLIGATION ADJUSTMENT

1.8 CONTRACT AMENDMENT

1.9 LIABILITIES

1.10 DISPUTE RESOLUTION

10

<u>**Appendix B**</u>

SINGLE BUYER TENDER PROCESS FOR

PURCHASES OF ELECTRICITY FROM POWER PRODUCERS

AND

PURCHASES OF ELECTRICAL SAVINGS FROM CONSERVATION SUPPLIERS

21

Purpose and Scope

The purpose of this chapter is to establish rules for determining prices, terms, and conditions governing the tender process used by the single buyer for purchases of power and conservation savings. These rules are intended to provide an opportunity for conservation and generating resources to compete on a fair and reasonable basis to fulfill the single buyer's new resource needs. Bids under these rules shall include the costs of compliance by the project with environmental laws, rules, and regulations in effect at the time of the bid and those reasonably anticipated to be in effect during the term of the project.

These rules do not preclude electric utilities affiliated with the single buyer from constructing electric resources, operating conservation programs, purchasing power through negotiated purchase contracts, or otherwise taking action to satisfy their public service obligations. Information about the price and availability of electric power obtained through the bidding procedures described in these rules may be used, in conjunction with other evidence, in cost recovery proceedings pertaining to resources not acquired through these bidding procedures.

Definitions

(1) "Avoided costs" means the incremental costs to the single buyer of electric energy or capacity or both which, but for purchases to be made pursuant to these rules, the utility would generate itself or purchase from another source.

(2) "Back-up power" means electric energy or capacity supplied by the single buyer to replace energy ordinarily generated by a generating facility's own generation equipment during an unscheduled outage of the facility.

(3) "Regulatory authority" means the commission or agency responsible for energy regulation.

(4) "Conservation measures" means electric energy efficiency improvements to buildings or energy using equipment and processes.

(5) "Economic dispatch" means, within contractually specified limits, modifying the timing of power purchases from a generating facility so as to minimize the costs of delivering electricity.

(6) "Electric utility" means any public service company engaged in the generation, distribution, sale, or furnishing of electricity and which is subject to the jurisdiction of the regulatory authority.

(7) "Eligible conservation suppliers" means electric utility customers, or third party conservation contractors installing energy efficiency measures as described in these rules

22

(8) "Generating facilities" means plant and other equipment employed for the purposes of generating electricity purchased through contracts entered into under these rules.

(9) "Independent power producers" means generating facilities that are not subject to cost recovery in the retail tariffs of any electric utility

(10) "Interruptible power" means electric energy or capacity supplied by the single buyer to a generating facility subject to interruption by the single buyer under certain specified conditions.

(11) "Least cost plan" means the filing made every two years by the single buyer in accordance with applicable law or regulation.

(12) "Maintenance power" means electric energy or capacity supplied by the single buyer during scheduled outages of a generating facility.

(13) 'Project developer' means an individual, association, corporation, or other legal entity potentially entering into a power or conservation savings contract with the utility.

(14) "Project proposal" means a project developer's document containing a description of the project and other information responsive to the requirements set forth in the tender.

(15) "Prototype contract" means standardized terms and conditions that govern specific electric power or electrical savings purchases by electric utilities. Prototype contracts may be structured to accommodate terms and conditions specific to individual projects.

(16) "Supplementary power" means electric energy or capacity supplied by an electric utility, regularly used by a generating facility in addition to that which the facility generates itself.

(17) "Tender" means the document describing the single buyer's solicitation of bids for the delivery of power or electrical savings.

(18) "Utility subsidiary" means a legal entity, other than a qualifying facility, which is owned, in whole or in part, by an electric utility, and which may enter a power or conservation savings contract with that electric utility.

Filing Requirements for Prototype Contracts

The single buyer shall file its initial prototype contracts with the regulatory authority. Long term prototype contracts for demand- and supply-side resources shall be attached to the tender. Prototype contracts may be structured to allow for project-specific contract language where appropriate.

23

Long Term Prototype Contracts

The single buyer shall file with the regulatory authority three contracts which will be used pursuant to the requirements set forth in this chapter.

(a) The first contract shall be used in contracting with generating facilities from winning bidders as determined through the solicitation and bidding process described in this chapter.

(b) The second contract shall be used in contracting with facilities of design capacity of one megawatt or less. The purchase price for power from these projects shall be based on avoided energy and capacity costs

(c) The third contract shall be used in contracting with conservation suppliers as determined through the solicitation and bidding process.

The regulatory authority shall review all prototype contracts filed by the single buyer pursuant to this section. Any modification to such prototype contracts proposed by the single buyer in between tender submittals shall be filed with the regulatory authority.

Eligibility for Long Term Contracts

(1) Any developer of a potential generating facility may participate in the bidding process.

(2) The single buyer may broaden the scope of the solicitation and bidding process to include other electric utilities, subject to the approval of the regulatory authority. Such a decision must be explained in the utility's tender submittal.

(3) In the event the single buyer is affiliated with an electric utility, the electric utility may participate in the bidding process as a power supplier, on conditions set forth in applicable law or regulation. Such a decision must be explained in the utility's tender submittal.

(4) A project developer must provide evidence that a generation site has or will be obtained (e.g., letter of intent) before signing a contract with the single buyer.

(5) The project developer shall specify, as part of the price bid, the costs of complying with environmental laws, rules, and regulations in effect at the time of the bid and those reasonably anticipated to be in effect during the term of the project.

(6) Any bid which involves the acquisition of energy from a hydroelectric project must provide proof that the project developer has obtained the necessary approvals from all entities legally responsible for the protection or management of fish or wildlife resources affected by the project The bid shall specify the estimated costs of such compliance.

24

Eligibility for Long Term Conservation Purchase Agreement

(1) Any eligible conservation supplier may participate in the bidding process. In the event the single buyer is affiliated with an electric utility, the electric utility may participate as a conservation supplier, on conditions set forth in applicable law or regulation. Such a decision must be explained in the utility's tender submittal.

(2) A participating conservation supplier shall provide evidence that the proposed conservation measures can be installed and will produce anticipated savings over the term of the contract.

(3) All conservation measures included in a project proposal must:

(a) Produce electrical savings over a time period greater than five years, or a longer period if specified in the single buyer's tender. A measure with an expected life which is shorter than the contract term must include replacements through the contract term.

(b) Be consistent with the utility's least-cost plan at the time of the bid.

(c) Produce savings that can be reliably measured or estimated with accepted engineering methods.

Size of Resource Block

(1) The single buyer shall, as part of its tender submittal, identify a resource block consisting of the overall amount of power to be solicited from project developers through the bidding process. The regulatory authority shall review the proposed resource block in its evaluation of the single buyer's tender submittal.

(2) The single buyer shall, as part of its tender documentation, demonstrate that the size of the resource block is consistent with the range of estimated new resource needs identified in the utility's least-cost plan.

Avoided Cost Schedules

The single buyer shall determine the avoided costs for the energy and capacity associated with the resource block calculated on an annual basis for the greater of twenty years or the longest period over which power purchase contracts entered under these rules will be effective. This price stream will be referred to as the utility's avoided cost schedule. The avoided cost schedule and its supporting documentation shall be filed with the tender and shall be reviewed by the regulatory authority. The assumptions used in calculating the avoided cost schedule shall be consistent with the utility's least-cost plan.

25

The single buyer shall use this stream of avoided costs to provide general information to potential bidders about the cost of new power supplies absent non-utility resources. For projects rated at one megawatt capacity or less, the most recently approved long-term avoided costs will be the basis for prices.

The Solicitation Process

The single buyer shall begin the solicitation process by issuing a request for proposals (tender). The information which a bidder files in accordance with the single buyer's tender will be referred to as the project proposal. Project proposals will be subject to a competitive ranking procedure to determine the group of bidders with which the single buyer will finalize long term purchase contracts.

Requirements for issuing a request for proposals:

(a) The single buyer shall solicit bids for electric power and electrical savings in conjunction with its least cost planning schedule. The single buyer is required to file its draft request for proposal with the regulatory authority within ninety days of the single buyer's filing of its final least cost plan. More frequent solicitations shall be allowed at the discretion of the single buyer. The solicitation must take the form of a tender approved by the regulatory authority.

(b) The single buyer shall submit a proposed tender and accompanying documentation to the regulatory authority at least ninety days before its proposed issuance date. Persons interested in receiving regulatory authority notice of the tender filing can request the regulatory authority to place their name on a mailing list for notification of future tender filings. Interested persons shall have sixty days from the tender's filing date with the regulatory authority to submit written comments to the regulatory authority on the proposed tender. The regulatory authority shall take action on the proposed tender within thirty days after the close of the comment period. The regulatory authority may suspend the tender filing to determine whether its issuance is in the public interest.

(c) The tender shall specify the resource block and the long-term avoided cost schedule.

(d) The tender shall explain the evaluation and ranking procedure to be used by the single buyer. The tender must also specify minimum criteria that bidders must satisfy to be eligible for consideration in the ranking procedure.

26

Project Ranking Procedure

(1) The single buyer shall adopt ranking procedures to evaluate project proposals on the basis of least-cost planning goals. The project ranking procedure must use explicitly stated criteria.

(2) The criteria used to rank project proposals are subject to regulatory authority approval and must be explained in the tender. These factors must at a minimum address price, dispatchability, risks imposed on end consumers, and environmental effects including those associated with resources that emit carbon dioxide.

(3) The single buyer's ranking procedures shall recognize differences in relative amounts of risk inherent among different technologies, fuel sources, financing arrangements, and contract provisions.

(4) Information submitted by the bidder pursuant to an approved tender shall remain sealed until expiration of the solicitation period specified in the tender. The utility shall make project proposal summaries and a final ranking available at its place of business for public inspection after the project proposals have been opened for the purpose of ranking. The regulatory authority shall retain the right to examine project proposals as originally submitted by potential developers.

Pricing and Contracting Procedures

(1) On the basis of the ranked project proposals, the single buyer shall identify the bidders that best meet the selection criteria and that are expected to produce the energy, capacity, and electrical savings as defined by the resource block.

(2) The price bid, the requested pricing configuration, and terms of the proposed bid services are subject to negotiation. If a generating facility agrees to be operated under economic dispatch, then the price bid shall be adjusted by operating performance adjustments such as the project's equivalent availability factor. The methodology for such performance adjustments must be explained in the utility's tender submittal.

Security Considerations

(1) The purpose of security requirements shall be to protect consumers' interests. The requirements and the rationale for them shall be explained in the single buyer's tender submittal.

(2) Security is required on all project contracts whose expected payment to the project developer at any point in time will exceed the payment which would have been made under the utility's avoided cost schedule. No minimum security is required if payments to the project developer are expected to be

21

Special Conditions for Purchase of Electrical Power or Savings from a Utility Affiliated with the Single Buyer

(1) With the approval of the regulatory authority, a utility affiliated with the single buyer may participate in the bidding process. Under such circumstances, the solicitation and bidding process will be subject to additional scrutiny by the regulatory authority to ensure that no unfair advantage is given to the affiliate.

(2) The electric utility must indicate in its tender submittal how it will ensure that its subsidiary or subsidiaries will not gain, through its association with the electric utility, any unfair advantage over potential nonaffiliated competitors. Disclosure by the central buyer to its affiliated utility of the contents of a tender or competing project proposals prior to the public availability of such information, shall be construed to constitute an unfair advantage

(3) Upon a showing to the regulatory authority that any unfair advantage was given to an affiliate of the central buyer, recovery of costs associated with the affiliate's project(s) may be denied in full or in part.

Filings-Investigations-Exceptions

(1) The single buyer shall file with the regulatory authority and maintain on file for inspection at its place of business the current rates, prices, and charges established pursuant to these rules.

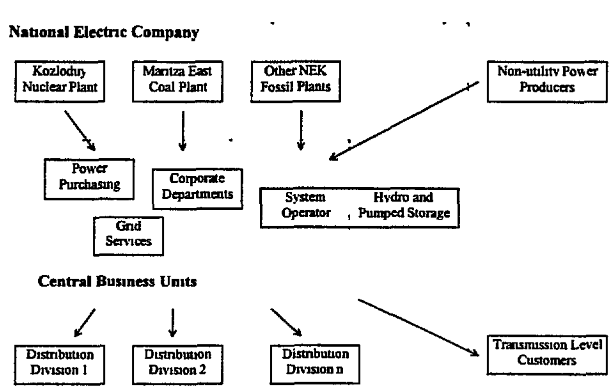
(2) If, at any time, a project developer is aggrieved by an action of the single buyer pursuant to these rules, the aggrieved party may petition the regulatory authority to investigate such action. The regulatory authority may, at its discretion, open an investigation and, if it deems necessary, hold public hearings regarding any such petition.

(3) The regulatory authority may grant such exceptions to these rules as may be appropriate in individual cases.

Alternative Contract Mechanisms between Electric Sector Business Units for Implementing the Single Buyer in Bulgaria

Sofia, Bulgaria
September 1996
Bechtel Consulting

Framework of Internal and External Contracts



29

Overview: Agreement between Buyer and Power Producer ("Generator")

Alternative Forms of Agreement Between the Buyer and the Generator

- **Operations and Maintenance Agreement**
- **Power Purchase Agreement**
  - Alternative 1 "Pass through" transfer from the Generator to the Buyer of the Generator's actual expenses plus profit, costs approved by Regulatory Body
  - Alternative 2 Agreement on payment of predetermined budgeted costs plus profit, adjusted by incentives for achieved results

Operations and Maintenance Agreement

- **Structure**
  - The Buyer owns the plant and manages the capital program
  - The Plant Operator provides operating and maintenance services
  - The Buyer or a third party provides engineering, procurement and construction services
  - The Buyer pays the Plant Operator's budgeted costs to operate and maintain the plant The payment to the Plant Operator may include performance incentives
- **Benefits**
  - Potential to increase cost-efficiency of operations and maintenance

Operations and Maintenance Agreement

- **Duties of Regulatory Body**
  - Regulatory Body approves all budgets
  - Requires surveillance and approval of actual expenditures
- **Risks**
  - If actual costs are automatically transferred, the Plant Operator may not have adequate inventive to exercise careful cost control
  - Maintenance and construction under separate management may increase conflict over scheduling and duration of plant outages
  - The Plant Operator does not directly control the capital program, and may feel less responsible for the plant's future

31

Power Purchase Agreement

- **Structure**
  - Establish autonomous Generator that owns plant and is responsible for all plant activities
  - Generator finances all capital requirements
  - Buyer pays to the Generator
    - Budgeted fixed costs (depreciation, interest on debt, allowable return on equity, taxes, fixed O&M)
    - Actual or budgeted variable costs
    - Differences between budgeted fixed costs and "allowable" actual costs collect in an account that accrues interest and is payable to the Generator
- **Benefits**
  - If Buyers' discount rate is higher than the Generator's, the Buyer may prefer that the Generator own the asset and finance capital requirements

Power Purchase Agreement (continued)

- **Incentives**
  - Automatic transfer of fixed cost from the Generator to the Buyer provides a positive motivation for the Generator to make capital investments, and may encourage profligate spending
  - Automatic transfer of variable costs provides weak incentive for Generator to control costs
  - Incentive mechanisms can be included
    - Establish predetermined cost ceilings for capital expenditures and operating expenses
    - Recovery of capital expenditures depends on achieved results measured by availability of capacity and delivery of energy
    - Recovery of operating expenses subject to performance measured by energy delivery, fuel consumption per kWh, fuel procurement, O&M, emissions, etc

32

Power Purchase Agreement (continued)

- **Revenue Impact**
  - May require greater revenue due to tax effects
  - Requires greater revenue if the Generator's cost of capital is higher than the Buyer's discount rate
  - Has a smoothing effect on revenue requirements since it spreads the cost of an investment over several years
- **Duties of Regulatory Body**
  - Regulatory Body approves all budgets or cost ceilings
  - Requires surveillance and approval of actual expenditures
  - Cost ceiling mechanism reduces the regulatory burden, and also reduces accounting burden on the Generator to provide the information requirements of the Regulatory Body

Generation Transfer Pricing

Goals of Transfer Pricing

- **Provide proper economic signals to generators**
- **Decentralize decision-making**
- **Increase accountability and cost transparency**
- **Provide incentives to improve performance**

34

Transfer Pricing Key Issues

- Financial viability of Business Units
- Coordination of business unit and corporate decision making
- Process of investment planning and control of funds for repair and expansion of generating capacity
- Potential competition with independent power projects

Approaches to Transfer Pricing

- Actual cost plus fixed profit
- Budgeted cost plus profit adjusted for performance incentives/penalties (fixed cost plus premium)
- System marginal cost pricing (pseudo-market)
- Pool pricing, as in the U.K. (market)

35

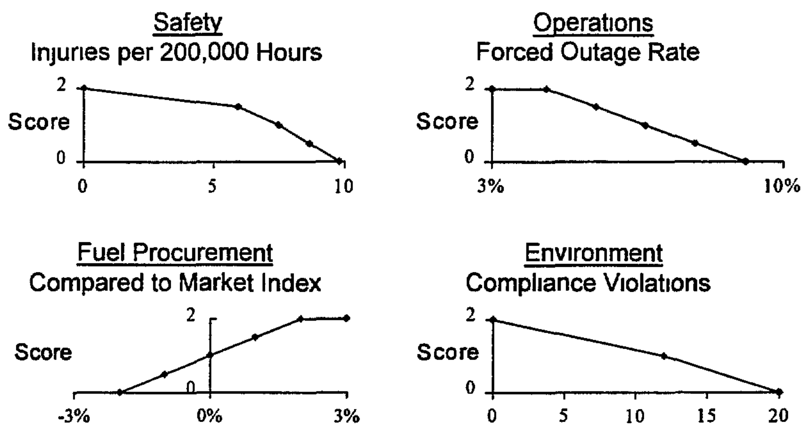
Application of Approaches

Approach	Example
Market	UK, Argentina, Chile
Psuedo-market	Introduction of independent power in US, Germany, France
Actual cost plus fixed profit	Traditional US approach, Denmark
Fixed cost plus premium	Spain, Portugal, US, Hungary

Actual Cost Plus Fixed Profit

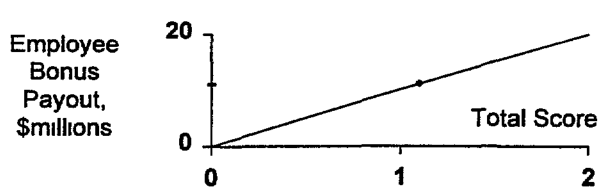
- **Actual costs of the Generator transferred to the Buyer**
- **Regulatory Body reviews costs and operations**
- **Regulatory Body encourages Generator to minimize costs**
  - Regulatory Body at an information disadvantage for regulating costs
- **Standards and criteria for reliability, safety, customer satisfaction, etc.**
- **Employee bonus plans**

Example Performance Measures for Employee Bonus Plans



Example: Generating Company Performance Objectives

- **Performance Weighting**
  - Safety Performance 15% 1 5
  - Operations 35% 1 2
  - Fuel Procurement 25% 0 8
  - Management 10% 1 0
  - Environment 15% 1.0
  - Total 100% 1 1



37

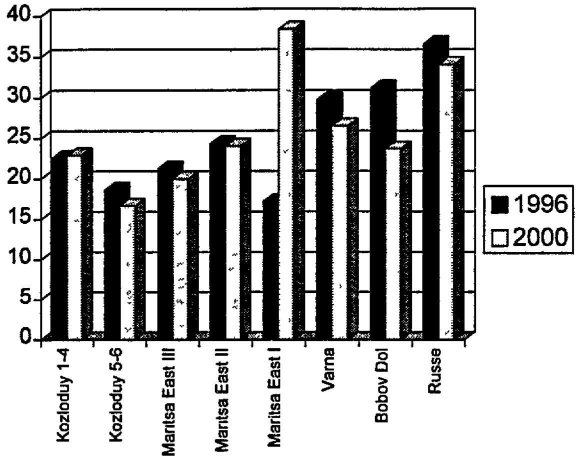
Actual Cost Plus Fixed Profit
Elements of Pricing

- **Fuel cost**
- **Material cost**
- **Labor cost**
- **Depreciation**
- **Taxes**
- **Operating income profit**

Actual Cost Plus Fixed Profit
Calculation of Fixed Profit

- **Asset base = fixed asset value - accumulated amortization + working capital = net asset value + working capital**
- **Depreciation = asset base/ remaining life**
- **Profit = allowed profit on assets in % multiplied by net asset base**
- **Need to revalue and index net asset value**

Actual Cost Plus Fixed Profit Pricing to Bulgarian Generating Plants



Allocation of Revalued Assets

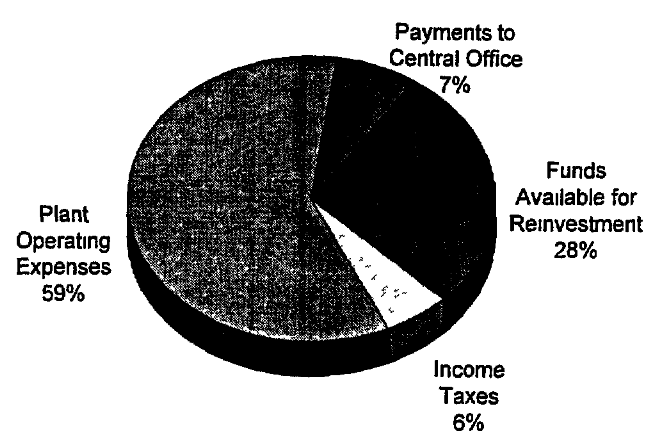
	Fixed Asset Value	Acuumulated Depreciation	Annual Depreciation	Capacity (MW)	Remaining Life (yrs)	MW-yrs	Allocation
Nuclear							
Kozloduy 1-4	329,897	80,000	24,990	1600	10	16000	41%
Kozloduy 5-6	470,103	120,000	29,175	1900	12	22800	59%
Total Nuclear	800,000	200,000	54,165			38800	
Existing Fossil							
Maritsa East III	176,604	14,717	8,520	780	19	14820	29%
Maritsa East II	315,313	26,276	13,764	1260	21	26460	53%
Maritsa East I	10,725	894	1,966	180	5	900	2%
Varna	41,827	3,486	12,781	1170	3	3510	7%
Bobov Dol	27,170	2,264	6,226	570	4	2280	5%
Russe	22,642	1,887	2,075	190	10	1900	4%
Maritsa West	5,720	477	874	80	6	480	1%
Total Existing Fossil	600,000	50,000	46,207			50350	
Total Existing Thermal	1,400,000	250,000	100,372			89150	100%

39

Varna- Example Pro Forma (thousands 1996 $)

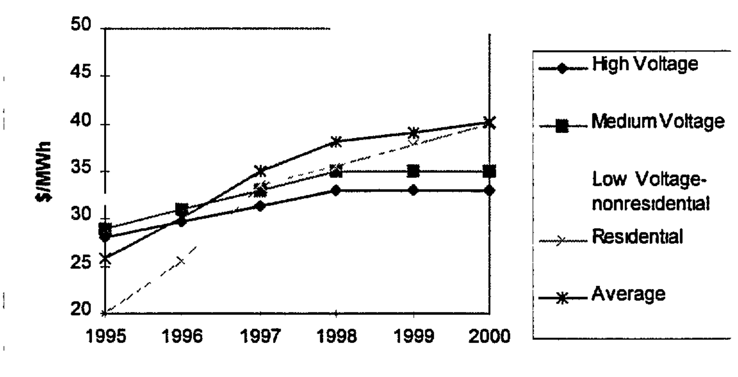
	1995	1996	1997	1998	1999	2000
Revenues						
Capacity	16,518	15,943	14,531	8,937	8,135	7,112
Energy	70,474	51,101	53,161	59,770	83,925	61,588
Total	86,992	67,045	67,692	68,707	92,060	68,699
Expenses						
Fuel	65,193	47,350	49,316	55,491	77,914	57,268
Purchased Energy	-	-	-	-	-	-
Operations & Maintenance	3,627	3,053	2,467	2,491	2,516	1,906
Depreciation	9,585	9,585	9,585	4,793	4,793	4,793
Central Services	5,282	3,752	3,845	4,280	6,011	4,320
Total Expenses	83,687	63,739	65,213	67,054	91,234	68,286
Pre-tax profit	3,305	3,305	2,479	1,653	826	413
Tax on profit	1,388	1,388	1,041	694	347	174
Net profit	1,917	1,917	1,438	959	479	240
Profit on Investment, %	*5 0%*	*5 0%*	*5 0%*	*5 0%*	*5 0%*	*5 0%*
Cost of Electricity in ($/MWh)	*27 5*	*29 8*	*29 3*	*26 8*	*25 5*	*26 5*

Generation Expenses



40

Retail Transition Pricing



Transition Pricing for Hydro and Non-NEK Generation ($/MWh)

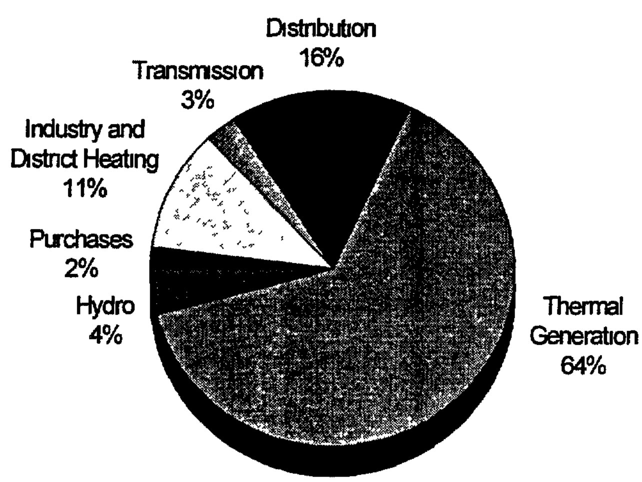
	1995	1996	1997	1998	1999	2000
Hydro	26 8	26 8	26 8	26 8	26 8	26 8
Industrial and District Heating	16 0	19 7	23.3	27 0	30 6	34 3

41

Assumed T&D Charges ($/MWh)

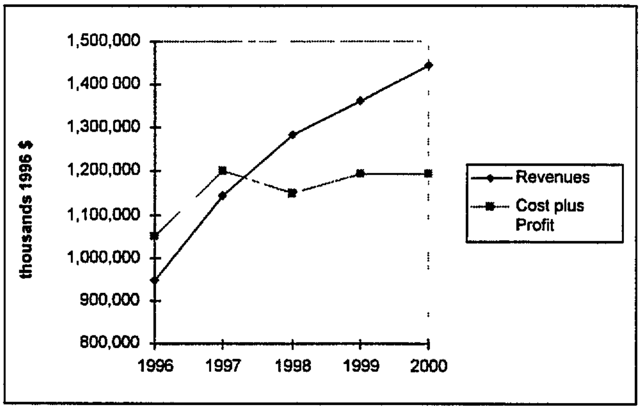
Transmission charge	1 0
Distribution charge	
High Voltage	0 3
Medium Voltage	2 0
Low Voltage	8 0

Cost of Service- 2000



42

Balancing Revenues and Cost



Fixed Cost Plus Premium

- **Generator is paid for power delivered to the Buyer**
- **Generator optimizes operations and expenditures with minimal central control**
- **Incentive mechanisms**
  - Establish predetermined cost ceilings for capital expenditures and operating expenses
  - Recovery of capital expenditures subject to performance measured by availability of capacity and delivery of energy
  - Recovery of operating expenses subject to performance measured by delivery of energy, consumption of fuel per kWh, success minimizing the costs of fuel and O&M, reduction of emissions, etc

Fixed Cost Plus Premium
Example Risk Sharing Mechanisms

- **Fuel Cost**
  - Reward/penalty if actual cost differs from index
    - International fuel price index
    - GNP Implicit Price Deflator
    - Buyer's cost of coal
  - Fuel price ceilings
  - Pre-specified fuel consumption curve (Gcal/kWh)
  - Guaranteed weekly/monthly/annual dispatch (MWh)
  - Periodic redetermination of pre-specified indexes
- **Operating and Maintenance costs**
  - Reward/penalty if actual costs differ from benchmark costs by activity

Fixed Cost Plus Premium
Example Risk Sharing Mechanisms

- **Performance Criteria**
  - Increased/decreased capacity payments based on
    - Energy delivery relative to maximum possible ("capacity factor")
      - Usually used for high capacity factor plants such as coal, nuclear
      - Required performance level set relative to particular plant
    - Availability of capacity
      - Usually used for low capacity factor plants
  - Allowance to carry forward "unused" forced outage days into the following year
  - Periodic capacity testing
    - Penalties for reduced capacity exceeding a pre-determined ceiling

Examples of Fixed Cost Plus Premium

- **Hungary: Power Purchase Agreements for Privatized Existing Generating Plants**
- **Background**
  - Several existing generating plants privatized
  - MVM promised tariff increases to increase revenues to pay Generators and Distribution Companies
  - MVM developed a Power Purchase Agreement for each plant in advance of bidding There have been several difficulties with the contracts
    - Payment indexes and incentives
    - Excessive risk for the Bidder, making the PPA unacceptable to banks
    - Inadequate revenues available to pay the new Plant Owners

45

Examples of Fixed Cost Plus Premium

- **Hungary: clauses for termination and pricing in the Power Purchase Agreements**
  - Agreement terminates at end of useful life of plant (3 to 10 years)
  - Capacity payment for fixed costs (depreciation of revalued assets, debt service, profit on investment, taxes, etc)
    - Capacity Component of payment was determined by MVM, and the rationale was not made public
    - Capacity payment subject to achieved results for capacity availability
  - Energy payment based on delivered energy multiplied by a fuel price index, plus allowance for non-fuel operating costs
    - The fuel cost index has become controversial because the price component for energy has not kept pace with actual fuel costs
- **For new and expanded capacity in Hungary, Power Purchase Agreements are being developed using negotiation**

Examples of Fixed Cost Plus Premium

- **Performance-based Regulation at San Diego Gas & Electric Company**
  - Gas procurement mechanism
    - Penalties/rewards based on achieved results relative to fuel price benchmark
  - Electric generation and dispatch mechanism
    - Detailed computer modeling establishes benchmark forecast of operations for comparison with actual performance
    - Penalties/rewards for performance in the following areas
      - Long-term and short term power purchase cost performance
      - Fossil unit availability of capacity
  - RPI - X for operations and maintenance expenses
  - Other monetary rewards for
    - Safety performance
    - Customer satisfaction
    - Customer outage minutes

40

Examples of Fixed Cost Plus Premium

- **IPP Pricing**
  - Price for power purchase based on competitive auction or negotiation
  - Revenues to IPP = Bid Price = Cost + Required Profit
  - Most Regulatory Bodies allow direct negotiation between utility and IPP to achieve lowest price and best delivery conditions that the IPP is willing to provide
  - Some Regulatory Bodies require "second price auction" price to winning bidders based on lowest priced losing bid
  - Dispatch of IPP based on energy price in the IPP's bid
  - Actual capacity and energy payments based on performance

Examples of Fixed Cost Plus Premium

- **Transfer Pricing for California Nuclear Plants**
  - Sunk costs recovered in fixed component
    - Depreciated asset value
    - Taxes
    - Shareholder profit of 7%
  - Incentive pricing
    - Fixed price ranges from $38 per MWH in 1996 to $42 per MWH in 2003 (based on cost of gas turbine)
    - Factor of 1 2 applied to price between 10 a.m and 10 p.m during summer peak period (totals 800 hours)
    - Factor of 0 8 applied for first 800 hours of operation outside summer peak period
  - Funds for decommissioning and spent fuel outside of transfer price

Examples of Fixed Cost Plus Premium

- **Transfer Pricing for California Nuclear Plants**
  - Plants operate only if operating costs less than $38 per MWH
  - Plants allowed to sell power outside of California
  - Plants can close down voluntarily at any time
  - After 2003 plants will operate as IPPs and gradually assume liability for decommissioning costs

Examples of Fixed Cost Plus Premium

- **Power Pricing for Sales between Utilities**
  - Market pricing based on competitive negotiation
  - Incentive and Indexes
  - Typical pricing based on average of seller's marginal costs and buyer's marginal cost savings
  - Typical pricing includes price indexation for regional fuel price index, RPI, etc
  - Price subject to renegotiation under prespecified conditions

48

Examples of Fixed Cost Plus Premium

- **Pricing for Renewable Power Plants and Energy Conservation in California**
  - Cost-based energy and capacity pricing
  - Special incentive payments for renewable IPPs
    - Emissions adder
    - Fuel diversity adder
  - Special incentives to shareholders for utility-sponsored energy conservation
  - Increasing use of integrated bidding mechanisms for new generation and conservation

Example of Fixed Cost Plus Premium for Existing Generator

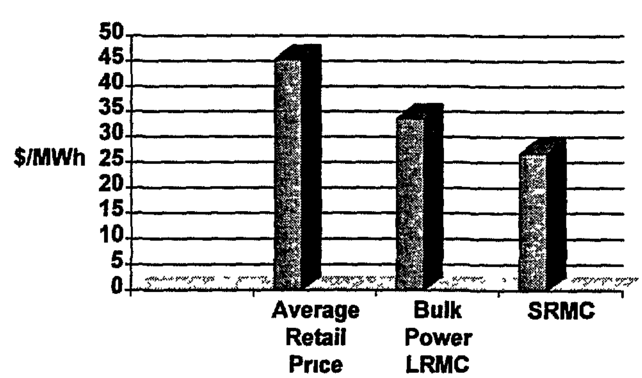
- **Transfer Price**
  - **Energy Payment** - Predetermined expected variable cost of operation
  - **Capacity Payment** - system marginal capacity cost
  - **Capital Cost Payment** - difference between Budgeted Fixed Cost and Capacity Payment
- **Fixed Cost Components**
  - Fixed O&M
  - Capital Requirements for replacement of plant
- **Adjustments for Achieved Results**
  - Energy payments for delivered energy
  - Buyer must take __ MWh/year to satisfy coal supply contracts
  - Buyer pays Generator's fixed coal costs if minimum take condition not met
  - Capacity and Capital Cost payments subject to achieved results for availability of capacity and delivery of energy

49

Pseudo-market Pricing
California IPP Pricing (prior to competitive bidding for generation)

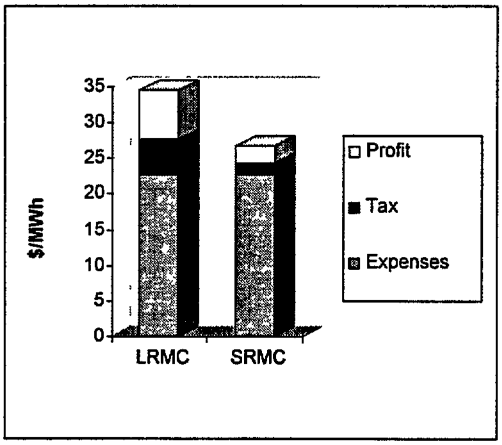
- **Long-term purchase with guaranteed energy and capacity prices based on utility's LRMC**
- **Fixed energy prices for up to 10 years; fixed capacity prices for up to 30 years**
  - Fixed prices requires fuel and capacity price projections In California, projections were generally high Therefore, purchase prices were generally higher than the cost of power
- **No dispatch; IPP variable operating cost not known to utility**
- **Limited right for utility to refuse deliveries**

Pseudo Market Pricing
Bulk Power Vs. Retail Tariffs

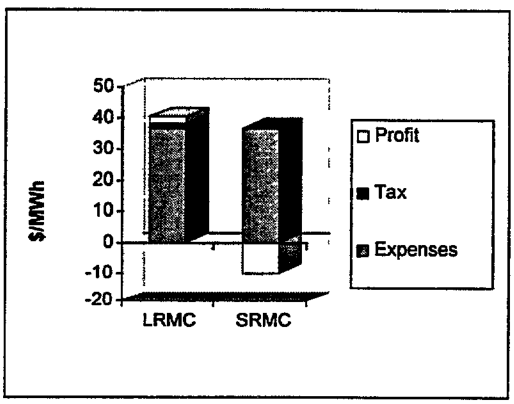


50

Example of Pseudo Market Pricing
Kozloduy Business Unit



Example of Pseudo Market Pricing
Varna Business Unit



53

The Power Purchase Contract

Power Purchase Contract Components

- Conditions Precedent
- Term and Termination
- Interconnection Facilities
- Metering
- **Operation and Dispatch**
- **Ancillary Services**
- **Purchase and Pricing**
- Emissions

Operation and Dispatch

- **Prudent Operation**
- **Coordinated Planning and Operations**
- **Maintenance Scheduling**
- **Guaranteed Dispatch**

Operation and Dispatch

- **Prudent Operation**
  - Prudent electrical practices
  - Reactive power
  - Protection
  - Communications with switching center
  - Daily records
  - Telemetering

Operation and Dispatch

- **Yearly Planning**
  - Buyer provides
    - Forecast use of available capacity for each period
    - Proposed schedule of Scheduled Maintenance
    - Estimated capacity and energy prices for the year
    - Forecast of demand for energy
  - Generator provides
    - Forecast use of available capacity for each period
    - Proposed schedule of Scheduled Maintenance
  - Best efforts to agree on availability schedule for the year

Operation and Dispatch

- **Monthly Planning**
- **Weekly Availability Declaration**
- **Obligation of Buyer during system interruption**
  - Buyer will not be obligated to accept or pay for and may require Generator to interrupt or reduce deliveries of energy under the following conditions
    - when necessary in order to construct, install, maintain, repair, replace, remove, investigate, or inspect equipment or any part of the system
    - when interruption is necessary because of
      - system emergencies
      - forced outages
      - force majeure
      - compliance with prudent electrical practices

54

Operation and Dispatch

- **Maintenance Scheduling**
  - Annual maintenance schedule
  - Monthly update of annual schedule
  - Notice for scheduled maintenance
  - Allowed maximum maintenance days per year
  - Best efforts to schedule maintenance outside of Peak Months
  - Reporting of maintenance expenses

Operation and Dispatch

- **Guaranteed Dispatch**
  - Minimum daily dispatch level (MW)
  - Buyer will dispatch the Generator for a minimum of ___ MWh per year
  - In the event that Buyer fails to dispatch the Generator for the Guaranteed dispatch
    - Buyer pays for all increased fuel costs, excluding energy not dispatched due to
      - Force Majeure affecting the Generator
      - Forced Outage
      - Maintenance rescheduled at the request of the Generator
    - Buyer has limited obligation to use best efforts to reschedule the amount of Guaranteed Dispatch lost due to Force Majeure or Forced Outage

55

Ancillary Services

- **Voltage and frequency control**
- **Reserve capacity**
- **Black start**
- **Grid reliability**
- **Emergencies**

Energy and Capacity Purchase

- **Energy Purchase**
  - Energy delivery
  - Guaranteed minimum purchase of energy
  - Energy pricing
    - For guaranteed energy
    - For non-guaranteed energy
- **Capacity Purchase**
  - Capacity delivery
  - Capacity pricing

56

Energy and Capacity Purchase

- **Energy Payment**
  - Payment based on Generator's Average Fuel Consumption per kWh x Fuel Cost, plus Allowance for Variable O&M
    - Regulatory Option 1 Average Fuel Consumption per kWh, Fuel Cost and Allowance for Variable O&M set in advance subject to update every 3-5 years (advantage provides Generator with incentive to reduce costs)
    - Regulatory Option 2 Actual variable costs transferred from Generator to Buyer subject to reasonableness review
  - If Buyer purchases less than the Guaranteed Dispatch, Buyer pays Generator's fixed fuel costs

Energy and Capacity Purchase

- **Capacity Payment (optional)**
  - Price based on System Marginal Capacity Cost = System Reliability Index x Amortization of Combustion Turbine Capital Cost
  - Time differentiated
  - Buyer provides Capacity Price a year in advance based on annual system forecasting, Buyer also provides a ten year non-binding forecast of Capacity Price
  - Payment based on capacity availability
- **Fixed Cost Payment**
  - Negotiated payment based on Generator Fixed Cost (less capacity payment)
  - Capped relative to cost of new generation
  - Generator must meet performance requirement of 90% availability to receive full payment

59

Power Purchase Contract Key Issues

- **Determination of fixed and variable costs**
  - existing plant
  - plant expansion projects
- **Link between performance and payment component for capacity and energy**
  - No link actual expenses transferred
  - Payment components based on achieved results
    - Payment component for energy
    - Payment component(s) for fixed costs

Power Purchase Contract Key Issues

- **Fixed Cost Payment performance mechanism**
  - Simple Alternative single $/kW-month price component, with payment based on availability of capacity
  - More Complex Alternative fixed cost payment consists of two $/kW-month components
    - Capacity payment component based on the marginal capacity cost of NEK
    - Capital cost payment component (fixed cost less availability payment) paid to Generator on the basis of energy delivery
- **Performance benchmarks**
  - Index of capacity availability
  - Index of energy availability
- **Contract termination**

Power Purchase Contract
Key Issues

- **Guaranteed amount of dispatch**
  - Minimum allowed coal consumption
  - Restrictions on minimum loading of plant in MW
- **Maintenance coordination**
  - Administrative Alternative Buyer schedules maintenance for all plants
  - Internal Market Alternative Generator schedules maintenance, subject to review of Buyer
    - Buyer has option to change capacity price to induce more/less maintenance
- **Emissions requirements/payments/incentives**
- **Decommissioning and waste disposal**

59

Example Power Purchase Contracts

- Pricing
- Mechanisms for stimulating results
- Delivery Provisions

Georgia Power (USA) Power Purchase Pricing Example

- **Energy Payment**
  - Fuel Payment
  - Variable O&M Payment
  - Sulfur Dioxide Allowance Payment
  - Startup Payment
- **Capacity Payment**
  - Capital Investment Payment
  - Fixed O&M Payment

62

Georgia Power (USA) Power Purchase Pricing Example

■ Monthly Energy Payment

Fuel Payment
= Energy delivery in MWh
* Fuel Price based on index for regional market in $/Gcal
* Net fuel consumption in Gcal/MWh

Variable O&M Payment
= Energy delivery in MWh
* Variable O&M allowance for base year in $/MWh
* O&M price escalation factor for current year relative to base year

Georgia Power (USA) Power Purchase Pricing Example

■ Monthly Energy Payment (continued)

Payment for mitigation of sulfur dioxide
= Energy delivery in MWh
* SO2 emission rate, kilo/Gcal
* Fuel consumption in Gcal/MWh
* Value of SO2 allowance in $/kilo (based on market price for SO2 allowances)

Startup Payment
= Number of startups
* (Fuel Price in $/Gcal x Gcal fuel use allowance per startup
+ Fixed cost of startup in $)

61

Georgia Power (USA) Power Purchase Pricing Example

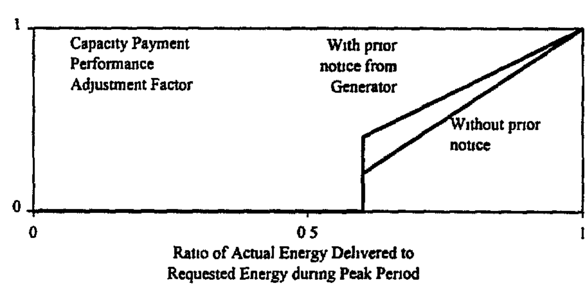
- **Monthly Capacity Payment**

Capital Investment Payment
= Capacity Purchase in kW for the month
* Capital Investment Payment in $/kW-year
* Capacity Value Monthly Allocation Factor
* Performance Adjustment Factor

Fixed O&M Payment
= Capacity Purchase in MW for the month
* Fixed O&M for base year in $/kW-year
* O&M price escalation factor for current year relative to base year
* Capacity Value Monthly Allocation Factor
* Performance Adjustment Factor

Georgia Power (USA) Power Purchase Pricing Example

Capacity Payment Adjustment for Non-delivery



California Pricing Example 1

- **General Terms**
  - Payment on the basis of delivered energy and capacity
  - Generator is expected to deliver unless the Buyer schedules zero purchase
  - Zero Capacity Payments during
    - Maintenance period exceeding maximum allowable hours
    - Generator forced outage
    - Force Majeure in excess of 90 days
  - Capacity Payments continue during
    - Reduction of generation at request of Buyer
    - Interruption for grid system requirements
    - Maintenance period up to maximum allowable hours
    - Force Majeure of less than 90 days

California Pricing Example 1

- **General Terms (continued)**
  - Two levels of reduction of generation at Buyer's discretion
    - Economic reduction Generator's Energy Price exceeds Buyer's marginal cost
      - Generator has option to deliver at Economic Curtailment Price
    - Physical reduction Generator must shut down
    - Buyer can request that Generator reduce output to zero up to 3000 hours per year
  - Periodic capacity testing to establish plant dependable capacity
- **Termination**
  - Contract extends until plant end-of-life
  - Negotiated options for the Buyer to terminate early

California Pricing Example 1

- **Scheduled Maintenance**
  - By September 1 each year, Generator provides Buyer a schedule of when Generator intends to perform scheduled maintenance for the following year
  - Generator provides quarterly updates of maintenance schedules
  - Scheduled maintenance is not to exceed 840 hours per year
  - Generator may accumulate unused maintenance hours from one calendar year to another up to a maximum of 1080 hours
  - Buyer notifies Generator
    - 24 hours in advance for maintenance less than 1 day
    - 1 week in advance for maintenance one day or more, except Major Overhauls
    - 6 months in advance for Major Overhauls
  - Generator will not schedule Major Overhauls during peak months

California Pricing Example 1

- **Total Payment**
  - = Energy Payment
  - \+ Capacity Component of Payment related to System Marginal Cost of Capacity
  - \+ Capital Cost Component of Payment related to energy production
  - \+ Air Emissions Adder or Subtractor
  - \+ Renewables Adder or Subtractor

California Pricing Example 1

- **Energy Payment**

Energy Payment
=Energy delivery in MWh
*Fuel Price index for base year in $/Gcal
*Fuel price escalation factor for current year relative to base year
*Net fuel consumption in MWh/Gcal

Energy Payment (if Buyer asks Generator to reduce energy delivery, but Generator delivers energy anyway)
=Energy delivery in MWh
*System marginal energy cost

California Pricing Example 1

- **Capacity Payment**

Capacity Component of Payment
= Capacity Purchase in kW for the month
* System Marginal Reliability Index (between 0 and 1)
* Amortization of Capital Cost of Combustion Turbine for Base Year
* Monthly allocation factors for system marginal capacity cost
* Combustion turbine capital cost escalation factor for current year relative to base year
* Peak Period Performance Factor

65

California Pricing Example 1

■ Capacity Payment (continued)

System Marginal Reliability Index:

- Is less than 1 for a year in which system reliability exceeds the Target Reserve Margin
- Equals 1 for a year in which system reliability is equal to or less than the Target Reserve Margin

Peak Period Performance Factor (not to exceed 1)

= kWh delivered during peak period (excluding reduction of generation at request of Buyer)

/ Dependable Capacity x Number of hours in month (excluding reduction of generation at request of Buyer)

/ 0 8 Target Availability

California Pricing Example 1

■ Energy Related Capital Cost Payment

Energy Related Capital Cost Payment

= Firm Capacity in kW

* Base Year Fixed Costs of the Plant (in excess of Shortage Cost) in $/kW-year

* 1/12

* Capital cost escalation factor for current year relative to base year

* Period Performance Factor / 0 9 Target Availability

Period Performance Factor

= Average achieved Availability for the prior 12 months, where availability is calculated as

$$\frac{\text{kWh Delivered energy delivered during non-reduction hours}}{\text{kWh Expected firm capacity x number of non-reduction hours}}$$

66

California Pricing Example 1

■ Air Emissions Adders or Subtractors

Air Emissions Adders or Subtractors
= Energy delivery in MWh
* Pollutant emission rates, kilo/Gcal (net of target emission rates)
  - CO2, NOx, Particulates, SOx, Reactive Organics
* Fuel consumption in MWh/Gcal
* Emissions value in $/kilo

Note
- Air emissions subject to monthly monitoring
- Air emissions monitoring equipment subject to annual inspection by certified engineer

California Pricing Example 2

■ General Terms

- Payment on the basis of delivered energy and capacity
- Zero Energy and Capacity Payments during
  - Scheduled maintenance
  - Forced outage
  - Interruption for grid system requirements
  - Force Majeure in excess of 90 days
- Zero Energy Payments during
  - Reduction of generation at request of Buyer
  - Force Majeure less than 90 days
- No guaranteed minimum energy purchase, however annual reduction of generation at request of Buyer not to exceed ___ hours per year
- Periodic capacity testing

C1

California Pricing Example 2

- **Total Payment**
  - = Energy Payment
    - Fuel Payment
    - Startup Payment
  - \+ Capacity Payment

California Pricing Example 2

- **Monthly Energy Payment**

  Fuel Payment
  - = Energy delivery in MWh
  - * Fuel Price index for base year in $/Gcal
  - * Fuel price escalation factor for current year relative to base year
  - * Net fuel consumption in MWh/Gcal

  Startup Payment (only paid if startup required on order of Buyer)
  - = Number of startups
  - * Startup compensation in $ (negotiated)

6?

California Pricing Example 2

■ Monthly Capacity Payment

Capacity Payment

= Capacity Purchase in kW for the month
* Base year Capacity Price in $/kW-year
* Capacity Payment price escalation factor for current year relative to base year
* Capacity Value Monthly Allocation Factor
* Adjustment Coefficient for Achieved Results

California Pricing Example 2

■ Monthly Capacity Payment (continued)

Adjustment coefficient for achieved results:

= [kWh delivered during period
  + (number of hours of zero production at the request of the Buyer x average kW delivered during 8 hours prior to the limitation and 8 hours following the limitation)]
* Minimum Reliable Capacity x Number of hours in period
* Coefficient of expected availability of capacity (specific to plant)

Note:

- If the Performance Adjustment Factor is less than 80%, the Capacity Payment is reduced to zero
- Generator will use best efforts to deliver energy during an Emergency

69

California Pricing Example 2

- **Maintenance Scheduling**
  - By September 1 each year, Generator provides Buyer a schedule of when Generator intends to perform scheduled maintenance for the following year
  - Buyer has the right to approve the timing for any outage periods for scheduled maintenance that exceed 6 calendar days
  - $__/day penalty for failure to reschedule maintenance outage on request of Buyer
  - Generator provides quarterly updates of maintenance schedules

California Pricing Example 2

- **Reduction of Generation at Request of Buyer**
  - By September 1 each year, Generator provides Buyer a Schedule showing expected schedule of limitations
  - Limitation Schedule is updated monthly, showing expected hourly reduction levels
  - Buyer has right to revise schedule one day in advance of reduction.
  - Annual reduction by Buyer not to exceed ___ hours per year, excluding
    - Maintenance outage declared by Generator
    - Forced outage
    - Interruption due to grid system requirements

70

Transfer Pricing for Electric Supply Branches ("Local Distribution Companies")

Alternative Transfer Pricing for Electricity Supply Branches

- **Actual Cost of Electricity Supply Branches Transferred to Consumer**
  - Transmission and generation payments to Central Buyer passed through directly to consumers
  - Actual cost of operating Electricity Supply Branches plus fixed profit is transferred to consumers, subject to periodic review by Regulatory Body
    - Requires surveillance by Regulatory Body
  - Non-cost performance are subject to periodic review by Regulator, or separate incentive mechanism(s)
    - Customer service
    - Supply reliability
    - Employee safety
    - Environmental
    - Losses
    - Conservation

71

Alternative Transfer Pricing for Electricity Supply Branches

- **Base Revenue Target ("RPI-X")**
  - Costs not directly under control of Electricity Supply Branch, such as payments to Central Buyer for transmission and generation, are transferred directly to consumers
  - Set base distribution revenues that are subject to distribution incentive mechanism, base revenues reset every 3-5 years
    - Historic cost trends
    - Cost determined by benchmarking
    - Electricity loss target used to determine base revenue target, variance of actual losses from loss target affects Distribution Company profits
  - Annual indexation of the base revenue, using previous year retail price index (RPI) and expected productivity improvement (X)
  - Separate RPI-X mechanisms for
    - costs that vary with demand
    - fixed costs
  - Non-cost performance subject to periodic review by Regulator, or separate incentive mechanism(s)

Pricing for Electricity Supply Branches: Key Issues

- **Setting Base Revenues**
  - Fixed components (e g office space)
  - Variable components
    - Cost per kWh sold
    - Cost per customer, different for each customer class
    - Cost per kilometer of conductor
      - overhead/underground
      - rural/urban
    - Cost per employee
- **Use of benchmarking**
  - For determining base revenues (RPI-X)
    - Use of expected cost per unit
    - Use of historic cost and performance information
  - For after-the-fact allocation of incentives
    - Use of comparative evaluation of achieved results

72

Pricing for Electricity Supply Branches: Key Issues

- **Standards for measuring achieved results**
  - Service to customers
  - Reliability of supply
  - Employee safety
  - Environmental
  - Losses
  - Conservation achievements
- **Incentives for Loss Reduction**
  - Establish factor for expected losses for setting base revenue to supply branches
    - Achieved savings on actual energy losses relative to expected losses are shared between electricity supply branch and consumers

Pricing for Electricity Supply Branches: Key Issues

- **Incentives for Consumption**
  - Minimize profit incentive for overaggressive promotion of increased electricity consumption
  - Provide opportunities for profit on conservation programs
    - Alternative incentive mechanisms
      - Electricity Supply Branch capitalizes investments for conservation and earns profit on such investments
      - Electricity Supply Branch keeps a portion of the difference between the cost of conservation programs and LRMC
      - Possibility for a premium to the Supply Branch based on qualitative or quantitative evaluation of its programs for conservation
  - Incentive for energy conservation must be carefully designed to work together with any RPI-X mechanism based on sales in kWh

Pricing for Electricity Supply Branches: Key Issues

- **Pricing for energy produced by Electricity Supply Branches**
  - Must sell to Central Buyer?
  - Should the revenue requirements for the plant be transferred to the consumers of the Electricity Supply Branch?
- **Regional differentiation of tariffs**
- **Program for coordination of allocating energy to Supply Branches during shortages**

Transfer Pricing for Electricity Supply Branches: International Experience

- **RPI-X in Great Britain**
  - Originally X ranged from 0 to 2 5% productivity *reduction*
  - 1994 review suggested base revenue levels and productivity factors were too favorable to the Electricity Supply Branches
    - Reduced ceiling revenues 11 to 17%, and adopted 2% productivity *improvement*
  - According to the original privatization scheme, the revenues to the companies increased directly with increasing kWh sales, subsequently this was changed so that 50% of revenues were fixed and 50% related to sales
    - More appropriate incentives to companies
    - More accurately reflect the effect of sales on costs
  - Has proved difficult for Regulatory Body to set revenues and to exercise surveillance, however a cost reduction was achieved

Transfer Pricing for Electricity Supply Branches: International Experience

■ RPI-X in California (proposed)

- Initial index of *revenue-per-customer,* subject to approval of Regulatory Body
  - Revenues increase directly with increasing number of customers
- Revenue level for subsequent 5 years is determined using *external benchmarks* replacing the existing annual procedure in which the Regulatory Body approves costs
- Portion of profit shared with customers
- Financial rewards and penalties for
  - Customer Service
  - Reliability of service
  - Safety
- Provision for adjustments to revenues for extraordinary events

75

Business Unit Performance Management Concepts for the Bulgarian Power Sector

Sofia, Bulgaria
June 1996
Bechtel Consulting

Goals

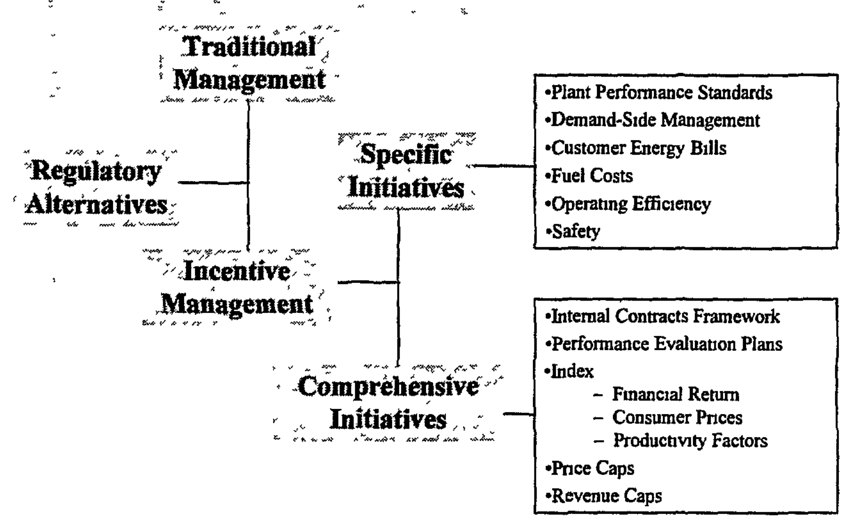
- Develop improved management cost signals and performance incentives and penalties
- Promote rational cost-based decision-making within business units
- Establish business units as profit centers
- Minimize need for centralized "command-and-control"
- Promote appropriate social programs
- Evolve to market-based competitive model to attract required capital

76

To Achieve these Goals . . .

- Introduce reward and penalty potentials for performance
  - utility employees
  - utility shareholders
  - IPPs
  - Energy Efficiency
- Develop transparent framework that allows private participation in energy sector development
- Include a quality control mechanism
  - system reliability
  - safety
  - environment
  - customer satisfaction

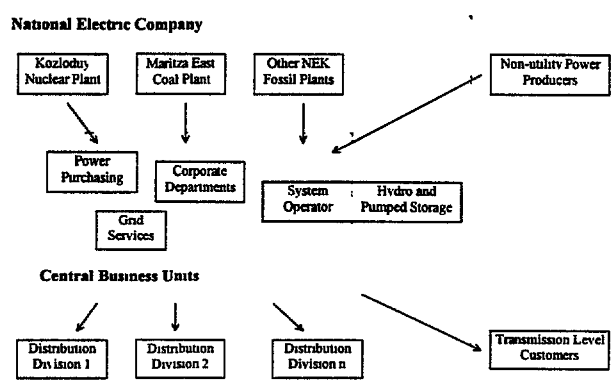
Alternative Performance Management Mechanisms



Performance Management Components

- Status Quo
- Standards and Regulation
  - Operating standards
  - Guidelines for economic analysis
  - Administrative guidelines
  - Prudency reviews by regulator
- Inject competition
  - Bidding for new generation
  - Competition between IPPs, utility alternatives, and demand-side
  - Competitive procurement procedures
- System of Internal and External Contracts
- Fully Competitive System
  - Pool
  - "Bilateral"

Framework of Internal and External Contracts

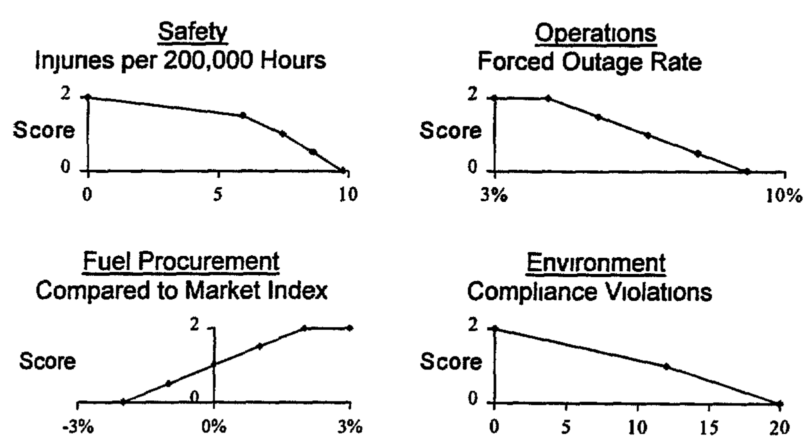


18

Example: Generating Company Performance Objectives

- Safety
  - Recordable Injuries
- Operations
  - Equivalent Forced Outage Rate
  - Heat Rate Deviation
  - Hydro Optimization
  - Expense Target (excluding fuel)
- Fuel Procurement
- Management
- Environment
  - Compliance violations

Example: Generating Company Performance Objectives

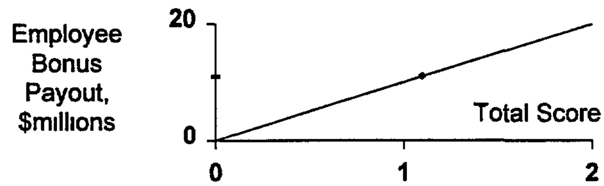


79

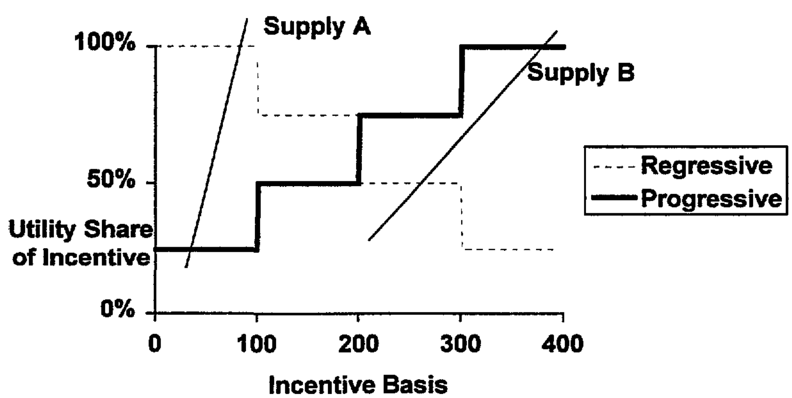
Example: Generating Company Performance Objectives

- Performance Weighting

– Safety Performance	15%	1.5
– Operations	35%	1.2
– Fuel Procurement	25%	0.8
– Management	10%	1.0
– Environment	15%	1.0
– Total	100%	1.1



Cost-based Incentive Sharing Mechanisms: Progressive versus Regressive



80

Example Incentive Mechanism: Transfer Pricing for Generating Plants

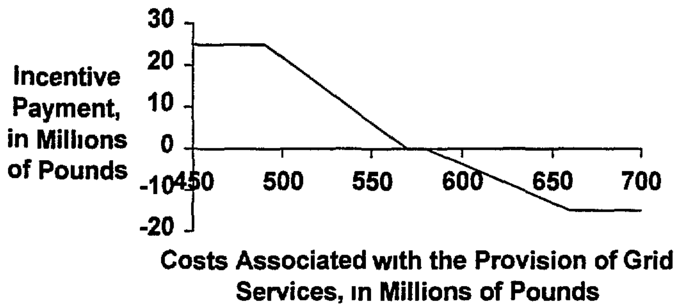
- Transfer Pricing Approach
  - Each plant is a cost center paid according to its production
  - Transfer pricing
    - » system marginal cost basis
    - » operating cost plus performance bonus system
  - Plant optimizes dispatch, outage, and fuel related expenses, subject to minimal central control
  - Strong incentive to control costs at the plant to maximize "profits"
  - Requires supplemental incentive system to prevent plants from cutting quality to achieve cost savings

Transfer Pricing Incentive Approach Contrasted with Traditional Approach

- Traditional Approach
  - Administrative control of dispatch and outages
  - Costs passed through to corporate entity
  - Weak incentives at the plant to optimize cost efficiency
  - Traditional utilities can impose cost-efficiency for capital and expense programs by publicizing use of system marginal costs for decision-making
  - Requires strong centralized review and approval of expenditures

Example Incentive Mechanism: Grid Services

Cost Efficiency Incentives for the National Grid Company, U.K.



Example Incentive Mechanism: Grid Services

- The incentive mechanism applies to the cost of grid services
  - Out-of-merit production costs due to transmission constraints
  - Transmission losses
  - Reactive power
  - Generating reserves
  - Imperfect dispatch
- Grid operating standards ensure that the utility does not pursue cost savings at the expense of service quality

82

Example Incentive Mechanism: Grid Services

- Results of the incentive system
  - shortened transmission outages
  - optimized transmission constraints by improved load flow analysis and by more precise rating of transmission plant
  - innovative approaches to grid constraints, such as generation intertrip schemes

Grid Services Employee Incentive Mechanisms

- Safety
  - Safe work environment
  - Recordable incidents
- Cost
  - Cost performance on budgeted work
- Customer service
  - Customer outages
  - Coordination of outages with distribution units
- Grid system management effectiveness
  - Efficient operation of resources
  - Continuing development of control systems
  - Cost-effectiveness of power purchases and sales to neighboring systems
  - Management of non-utility generation