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At a Glance

The World Bank FPD Note No. 16 July 1994

Power Sector Investment

How Market Forces Are Challenging the Least-Cost Plans of Power Utilities

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Most of the power industry's engineers and planners have gained their work experience in vertically integrated public utilities, where investments are identified through least-cost planning models and bids are invited for precisely specified types of plant. Now, however, private producers are "contesting" the least-cost investment plans of public utilities on the grounds that they can build and operate power stations more cheaply and more quickly than public utilities can. Private producers—together with the new energy technologies—are driving a new approach to least-cost investments in electricity supply. They are willing to absorb technical and financial risks—something that least-cost planning has never dealt with satisfactorily—and to find more innovative ways to reduce risk—for example, by turning to more modular technologies with shorter lead times.

Traditional approaches to least-cost planning need to be overhauled. As private investment increases, least-cost planning models will become less useful for identifying the best investment choices. Under the new paradigm, competition should lead to lower-cost supplies. However, the least-cost models still will be useful for monitoring industry performance because they can help show whether investments, plant operating (dispatching) schedules, and prices are indeed being competitively determined.

Massive change in the power sector

Institutionally and technologically, the electric power industry is undergoing the most far-reaching changes in nearly six decades. From 1900 until around 1940, independent producers were the main drivers of industry expansion. But rapidly declining marginal costs arising from scale economies and technical progress, together with economies of interconnection, led to the consolidation of the independent producers into "natural" public monopolies. Least-cost planning models were

Table 1 Private sector power development opportunities in the next five to ten years *(gigawatts)*

Region	*Current capacity*	*Future need*	*Private sector potential*
Asia	280	170	55
Latin America	135	70	30

Source: Unpublished indicative data compiled by Mangesh Hoskote, World Bank.

FPD
Industry and Energy Department
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Forces shaping the power industry

- growth of privatization and independent generation.
- increased range of power plant types now available. In addition to conventional pulverized coal and stoker boilers, there are combined-cycle gas-fired, fluidized bed combustion, aeroderivatives, and integrated coal gasification combined-cycle plants. There are also renewable energy technologies: thermal solar; wind power; cogeneration; photovoltaics for off-grid and (now being tested) decentralized grid connected supplies; and biomass-fired power plants using conventional boilers or gasification processes and combined-cycle technology.
- modularity in power plant technologies. This modularity has changed the locus of scale economies from the power plant to the factory. A consequence of this change is that investments in small, modular power plants are becoming feasible for independent producers. In the past, by contrast, economies of scale favored the large power plants built and operated by public utilities.

developed in response to this situation, and have since been in widespread use.

Now, however, changes in technologies and costs are working in the opposite direction, and the industry is becoming more "unbundled." Budgetary and other stresses arising from poor operational and financial performance are also encouraging governments to open up the industry to independent producers.

The numbers of private bids, unsolicited or otherwise, and the challenges to existing plans of public utilities, will increase as private generation grows. There are many cases already—for example, in India (gas versus coal), the Czech Republic (alternative types of coal plant), and Honduras (wind versus diesel). Table 1 illustrates the scope for change by providing a recent assessment of private investment opportunities in the power sector over the next five to ten years.

Narrower role for least-cost models

The economic characteristics of the least-cost solution are the same in theory whether the investments are public or private. In privately as in publicly owned systems:

- base-load plant with higher thermal efficiencies are still needed.
- peak-load plant will usually be the older thermal plant on the system, supplemented by low-capital-cost plant, such as gas turbines.
- thermal plant will still be operated in merit order, except that the dispatching schedules will be decided by competitive bids rather than by a central dispatcher relying on the fuel and operating cost coefficients provided by the utilities' engineers.
- where hydro plants provide a large share of the output, thermal complementation will often be needed in dry years.
- the cost and operating characteristics of small-scale plant, of the decentralized forms of generation noted above, and of intermittent supplies with or without storage, will be the same in principle whether the supplies are public or private.

So the cost simulation models developed by public enterprises could be used to predict how a competitive system of private generation is likely to evolve or, alternatively, to assess whether private investment is taking place under genuinely competitive arrangements. The models also can be adapted to analyze the prospects for new technologies, to estimate the marginal costs of supply (for example, for regulation and oversight), and to examine questions of the cost and price efficiency of private or public arrangements for the provision of supply.

Private producers drive radical new approach

Private generation entails few, if any, changes in methodology, but it does involve a radical change in the approach to deciding on least-cost arrangements. Rather than identifying capacity and energy requirements first and then using simulation studies to identify the least-cost program, as the public utilities do, in the private model both capacity requirements and the choice of plant are determined by competitive bidding and licensing. In other words, the algorithms in the computer software of the public utilities are replaced by the market, and simulation studies are no longer required to determine the least-cost investment plan. There is an intermediate

Table 2 Methods for determining investments

	Capacity requirements	*Choice of power plant*
Traditional model	Estimated by utility	Cost simulation ⟶ Invite bids
Intermediate case	Estimated by utility	Open bidding ⟶ Cost simulation studies
Private model	Market-determined	Market-determined ⟶ Cost simulation for monitoring only

case in which private generation is allowed to compete with public generation on an essentially public system; in such cases, bids are solicited from private producers before the simulation studies are performed, to help determine the least-cost investment. This approach, similar to that used in the United States,[1] is relevant for countries that prefer a phased approach to privatization or for those that see value in using the models for indicative planning. In a fully privatized industry, planning and simulation models may be used for looking backward rather than forward, to assess market behavior—whether prices are reflecting costs, whether there are questions of antitrust and integrity in private investment, and so on. The three cases are summarized in table 2.

Investment choice and risks

The technical and institutional changes in the power sector suggest that the industry is likely to change rapidly and unpredictably. Already private investment is producing a wider range of technical options. There is more emphasis on modular units with shorter lead times. Another possibility is the emergence of decentralized generation, the "distributed utility."

How investment decisions are made through least-cost planning

The traditional approach to least-cost planning starts with a forecast of demand. Forecasts take into account a range of factors—the growth of per capita incomes and populations; urbanization; the growth of industry and whether new electricity-intensive industries are emerging; the number of people who lack electric service and would like to have it (more than 2 billion in developing countries); and improved efficiency of consumer equipment and appliances.

The next step is to define an investment program that would enable the power system to meet forecast energy and peak power demands with a reasonable probability of avoiding brownouts and blackouts. The investment program is not confined to new power plants, but could also include, for example, the reinforcement of transmission links with other regions that have lower-cost supplies or spare peaking capacity (for example, if their peak demands occur at different times).

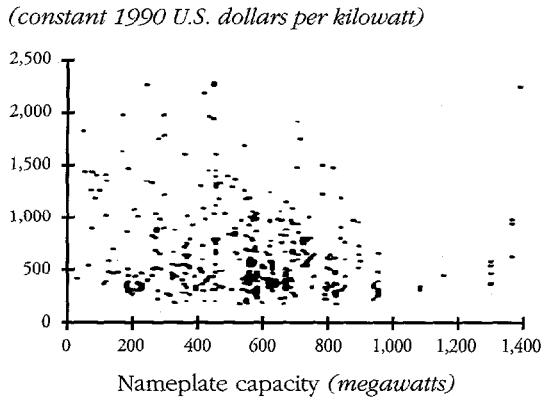
Simulation studies are then made of how the system would be operated to minimize costs; from these studies, total system operating costs are then estimated. The capital costs of the investment program are calculated separately and added to system operating costs to give the overall costs of the program being considered. Several alternatives and their technical feasibility are usually examined under this approach.

Once the least-cost investments have been identified and agreed upon, bids are invited for each type of plant—for example, for a coal-fired station of a given capacity, for a hydro plant, for so many megawatts of gas turbines for meeting peak loads, or for a gas, diesel, or coal plant to provide the thermal complement to a hydro scheme. Consistency with efficiency in end-use is sought through commercial pricing policies in which prices reflect the marginal costs of supply by time of day, voltage level, and (depending on the system) season.

How risks are allowed for and who bears them will lead to different investment decisions—for example, a move to investments with shorter lead times, such as a gas-fired combined-cycle power plant. A more dramatic example is the reaction of private producers to nuclear power. Private producers have been distinctly more circumspect than public producers. Privatization has made the real costs of the environmental risks associated with nuclear power more transparent.

Technical, economic, or other risks have never been "modeled" in a fully satisfactory way in the least-cost investment planning of public utilities. They have often been ignored. Investments normally have been compared on the basis of expected costs, with risks addressed through sensitivity analysis. Allowances for contingencies (typically 10 to 25 percent, and slippages of up to one year) usually are included in the cost estimates. But in reality the dispersion of costs ex post is much greater than the ranges commonly assumed in sensitivity studies. Cost overruns of 20 to 50 percent are not uncommon.[2] Even for a mature technology such as coal-fired plant in an industrial country, ex post costs can vary enormously (figure 1).

Figure 1 Coal-fired power plants in the United States: Cost versus size



Note: Costs were calculated using nameplate capacity and including allowance for funds used during construction. Sample size is 401 plants.

Private producers have to allow for risks in their bids. (Exceptions arise only when contracts needlessly transfer technical and financial risks to the public purse, something that good contractual arrangements should avoid.) That helps to explain why high discount rates (20 percent or more) are often quoted for private investment. The high discount rates allow for cost escalation and slippages. They will also include an allowance for country and political risks—an area where public insurance or risk guarantees may legitimately help to reduce private costs. But as company records and reported returns in the financial markets show, real returns of this magnitude are not widely realized in practice. Where high returns are achieved initially, they are better seen as a benefit to the early risk-takers—unless there is evidence of disorderliness and a loss of integrity in the bidding process. As risks decline, investment will increase, and the returns should decline to more normal rates. So too should the real costs of electricity production.

[1] See Hirst and Coldman in *Annual Review of Energy and the Environment*, Vol. 17, 1992.

[2] Refer to forthcoming survey by John Besant-Jones (Energy and Industry Department Paper, World Bank).

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