Industrial Use of Cogeneration Under Marginal Cost Electricity Pricing in Sweden

Frank Camm
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PREFACE

This report is one of a series of Rand Corporation papers and reports written on the European industrial response to time-of-use electricity pricing. Past papers and reports, produced under Rand's Energy Policy Program and funded by a variety of sponsors, have examined various aspects of the formation of electricity tariffs for industry and the pattern of industrial response in England and Wales, Finland, France, the Federal Republic of Germany, Norway, and Sweden. By providing data on and insights into the long-term experience of European industry with electricity prices based on marginal cost, these studies make it possible to predict with greater accuracy the reaction of American industry to similar electricity tariffs.

The present report, one of two funded under Electric Power Research Institute Contract Number RP-1212-1, concentrates on the industrial use of electricity in Sweden. It produces two types of information. First, it provides information on the operation of Sweden's national power system and on the industrial tariffs within that country. In addition to setting the stage for the second type of information developed, this information should facilitate more detailed examinations of Swedish electricity provision in the future, by Rand and by others. Second, the report provides detailed information on Swedish industry's cogeneration of heat and power and the relationship of this form of self-generation to industrial electricity tariffs in Sweden. The report finds that the two are linked fundamentally, often in unanticipated ways.

The report should interest several types of readers. While it is written from an economist's point of view, it aims for a broader audience of policy analysts in general. The nontechnical reader will gain something of an overview of Swedish provision of electric power, tariffmaking, and industrial use of cogeneration, and of the broad interactions among these. Readers with some technical understanding of current policy issues associated with tariffmaking or the application of cogeneration should derive a more subtle understanding of these interactions in a system context. The ultimate goal of the study is to provide data on Swedish tariffmaking principles and practice which can be used to improve the use of marginal cost-based tariffs and cogeneration in the United States. For the reader addressing these policy issues in the United States, the report provides a coherent characterization of a successful industrial democracy's experience with these issues, a characterization against which can be weighed policy options for the United States.

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1 An excellent compendium of work performed up to 1978 may be found in Mitchell, Manning, and Acton (1978). See Bibliography, below.
2 The other is Acton and McKay (forthcoming).
SUMMARY

Cogeneration, widely recognized as a highly efficient energy conversion technique, is a family of technologies that generate both usable heat and usable electrical power in a single process. Energy's increasing cost in recent years has stimulated considerable interest in the use of cogeneration in industry and elsewhere as a way to conserve energy.

The way industry uses cogeneration depends on the electricity price structure it faces. How will the current move of the United States toward electricity pricing based on social marginal costs affect U.S. industry's use of cogeneration? In particular, how will such pricing affect the type of cogeneration industry chooses, the contractual arrangements through which it uses it, and the way industry uses cogeneration capacity over time? This report seeks answers to these questions by looking at how industry uses cogeneration in Sweden, a country that has marginal cost pricing now.

Based on a broad system study of electricity pricing and industrial use of cogeneration in Sweden, the report draws on Swedish documents and publicly available data files as well as interviews with Swedish government officials, businessmen and women, and researchers. A detailed picture of industrial use of cogeneration in Sweden is developed, and relevant similarities and differences between the Swedish and U.S. experiences with industrial cogeneration are identified. This picture of Swedish cogeneration is used to posit hypotheses about the future of industrial cogeneration under marginal cost pricing of electricity in the United States. Careful examination of these hypotheses in the light of U.S. data could change the current U.S. policy perspective on industrial cogeneration in a number of important ways.

SWEDISH POWER PRODUCTION AND PRICING

As in the United States, the power supply system in Sweden includes publicly and privately owned producers of many sizes. Unlike U.S. industry, however, Swedish industry is well integrated into the general power supply system. Industrial firms—particularly in the pulp and paper industry—and power companies owned by industry are among the largest power producers in the country. They trade and transmit power on an extensive high voltage grid that is nationally owned and operated.

These producers sell electricity under two pricing regimes: First, a bulk power market, centered on the national grid and on a national power market made possible by the grid, permits relatively competitive pricing of electricity. Bulk power exchanges are made through privately negotiated contracts, one reason why Sweden's major producers and consumers understand and support pricing electricity on the basis of marginal costs. Second, a pricing regime of formal administrative tariffs, with neither competition nor close regulation of price to police it, maintains and updates a remarkably sophisticated and flexible set of formal tariffs for industry throughout the country. These tariffs appear to be approaching relevant costs more closely over time as producers and consumers get more experience and understanding. Together, competition in bulk power supply and the pricing doctrine underlying formal tariffs appear to reflect relevant costs in the electricity prices which Swedish industrial firms face.

This system of production and pricing offers a number of features which the United States might choose to exploit as it moves toward marginal cost pricing of electricity. Active competi-
tion in a significant portion of the market is possible without the sacrifice of important political goals like local preference and profit control. Experience and broad participation in pricing—rather than abstract principles and administrative accounting rules—are used as the ultimate basis for determining costs related to pricing. In sum, it offers a mixed approach to pricing and production. While the compromises implicit in such a mixed approach are bound to raise important problems, they also offer a potential for considerable political support in the United States.

SWEDISH INDUSTRY AND THE POWER GRID

Almost without exception, everyone who produces power in Sweden interconnects with the national grid because electricity prices reflect its relevant costs and low transmission losses. We can expect a comparable situation in the United States as we move toward marginal cost pricing.

This pattern of interconnection and the pricing underlying it implicitly force every potential producer of electricity to "compete" on nearly equal footing with every other producer in the country. That is, because grid prices tend to reflect the costs of efficient units in the system, an industrial firm must be able to achieve even lower costs before it decides to self-generate. This sort of competition induces a number of distinctive patterns in Swedish industry's use of cogeneration.

First, despite the fact that they are not always required to do so, all Swedish industrial cogenerators facing standard tariffs subscribe to reserve tariffs to back up their units. The Law of Large Numbers makes it less costly to obtain reserve power from the grid than from power sources on site. Reserve tariffs apparently reflect this cost differential and hence induce heavy reliance on the grid to assure reliability in industrial power production.

Second, Swedish industry relies almost exclusively on cogeneration and hydropower to produce its power. This is because the power requirements of a typical industrial firm are not large enough to justify building condensing and gas turbines on an efficient scale. Because interconnection forces industry to compete with the efficient central condensing and gas turbines of the major producers, industry must rely on generating assets which the major producers cannot exploit at an optimal scale. These include cogeneration, whose cost competitiveness depends on the presence of a heat load which major producers typically do not have, and hydro, whose costs depend more on site than on scale factors.

Third, industrial cogenerators employ topping steam turbines almost without exception. Interconnection and cost "competition" appear to favor such turbines. The relatively slow starts typical of steam turbines are acceptable because industrial cogenerators can obtain fast starts at a lower cost from central gas turbines and hydro resources in the grid. Similarly, they can maintain the high power-to-heat consumption ratios that diesel cogeneration allows at a lower cost by meeting "excess" power needs from large central plants in the grid. When fast starts and the power-to-heat ratio are not important issues, the low cost of power from steam turbines allows them to dominate cogeneration.

Fourth, Swedish industrial firms do not participate in industrial energy centers, which jointly meet the power and heating needs of several companies. The increased reliability and matching of power and heat consumption and production levels provided by such centers are not important in an interconnected "competitive" grid. Centers allow greater scale economies, but this benefit alone apparently does not justify their contractual costs.

Prices based on relevant costs and an efficient, extensive grid appear to create a regime
of price competition which naturally leads to these four outcomes. To the extent that this is true, we might expect similar patterns of industrial cogeneration use in the United States under similar pricing.

HEAT DEMAND AND THE USE OF COGENERATION

Power is available from cogeneration only when a heat load is present. This simple insight has two implications for industry's response to price in its use of cogeneration.

First, cogeneration resembles baseload capacity in Sweden. Cogeneration is so fuel-efficient that until recently only hydropower could achieve a lower running cost in Sweden. As a result, with the exception of short periods when hydropower is relatively abundant, cogeneration turbines in Sweden run whenever a heat load exists to justify their use. Given the normal range of variation in short run marginal cost over time in Sweden, cogeneration almost always runs when heat loads are present. Further, although steam turbines can be built to change their power-to-heat output ratio in the short run, Swedish industrial cogeneration turbines rarely have much of this capacity. When they do have it, they rarely use it to increase power output in response to short run increases in electricity prices. This is because cogenerators must effectively condense steam in order to expand power output in such turbines. This would put them into competition with central condensing plants with lower marginal costs. The presence of such central plants tempers price variation enough to limit the opportunities for cogenerators to produce condensing power. Thus Sweden's integrated grid and cogeneration's dependence on a heat load make cogeneration relatively unresponsive to the structure of prices over time.

Second, despite this lack of price responsiveness, a significant portion of Swedish cogeneration tends to displace cycling plant in the Swedish power supply system. This is because the heat load that makes this cogeneration possible is closely correlated over the seasons of the year with demand for power in the national power system. Hence, just as the power demand comprising intermediate power system load occurs, this cogeneration becomes available to meet it. This cogeneration is associated with district heating loads which vary dramatically with the seasons. Industrial cogeneration, because it draws on a flatter heat load through the year, tends to displace baseload in the national power supply system.

Whether similar patterns would occur in the United States is problematic. Marginal cost pricing will surely dampen cost variations over time in the United States, but for some time to come, it is unlikely that existing generating assets will justify prices that discourage condensing at industrial cogeneration plants. And until district heating systems meet cooling loads, cogeneration can displace cycling plant only in the winter peaking systems. In summer peaking systems, it could not only displace baseload, but increase demand for new cycling and peaking units.

OIL PRICE AND INDUSTRIAL COGENERATION

Although Swedish cogeneration appears relatively unresponsive to the structure of electricity prices, it is quite responsive to the level of prices of electricity, fuel, and capital. As noted above, the rising cost of energy, caused most directly by the rising cost of oil, is a principal reason for recent interest in cogeneration. It is somewhat ironic, then, that in the Swedish experience, rising oil prices threaten to reduce the role of industrial cogeneration, not increase it. This is true for two reasons.
First, rising oil prices induce fuel switching, which promotes the use of coal because Sweden lacks a natural gas infrastructure. But coal is cost effective at larger scales than oil. The increase in scale associated with coal use is sufficient to eliminate many opportunities to use cogeneration in industry at smaller scales. On net, this is expected to reduce the role of cogeneration in Swedish industry.

Second, coal-fired cogeneration will remain attractive at larger scales, scales that can be realized in the presence of large heat loads. District heating systems and industrial energy centers offer large heat loads. Unfortunately, they tend to occur in urbanized areas where the air pollution associated with coal makes its use less attractive. Sweden is proceeding only hesitantly with coal-fired cogeneration in urban areas.

The United States could expect similar problems with industrial cogeneration as the price of oil continues to rise. The availability of gas could temper the fuel switching problem, although many policy advocates appear ready to restrict industry's access to gas. Because of differences in U.S. and Swedish environmental regulations, the United States would probably be even more averse to the use of coal in urban areas than Sweden has been. In sum, while the rising cost of oil may not affect industrial cogeneration as much in the United States as in Sweden, similar issues arise in both countries.

This study draws most directly on data about the Swedish experience, and our conjectures about the United States are only hypotheses; the statements about Sweden, however, are empirically well grounded. The basic commonalities between Sweden and the United States suggested above and developed more fully in the report give these hypotheses some force. Additional examination of U.S. data is needed before we can convert these hypotheses into explicit policy recommendations for the United States. The Swedish experience should help to frame that examination and to interpret the U.S. data as they are examined.
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GLOSSARY*

AB. "Aktiebolag" or joint stock company. Equivalent to "Incorporated."

AB Aroskraft. A power company with cogeneration facilities in Västerås, held jointly by Stora Kopparberg, Krångede, Gullspångs Kraft, Bergslagens Gemensamma Kraftförvaltning, and the city of Västerås.

Avesta Jernverks AB. Producer primarily of stainless steel in central Sweden.

Ågesta. Suburb of Stockholm. Location of Sweden’s first experimental nuclear plant, a cogeneration plant.


Bergman and Co. A prominent Swedish engineering consulting firm.


Billerud Uddeholm AB. A forestry products firm in west central Sweden. Billerud was the fourteenth largest power producer in Sweden in 1976.

Centrala Drifstledning. The Central Operating Organization, the principal association of major Swedish power producers. Better known as CDL.

EFAM. A formal tariff offered during selected spring and summer periods, when run-of-the-river hydro offers a producer’s marginal source of power.

Effekt. Capacity.

Fagersta AB. An integrated iron mining and iron and steel firm in central Sweden.

Fjärrvärme. District heating.

Forsmarks Kraftgrupp AB. The jointly owned company that owns and manages the nuclear plants at Forsmark on the eastern Swedish coast. Owned jointly by Gullspångs Kraft, Krångede, Statens Vattenfallsverk, Stora Kopparberg, Svarthålsforsen, and Varmlands Kraft.


Göteborg. City of 647,000 on Sweden’s west coast. Home of several recent innovations in the industrial use of cogeneration. Also known as Gothenburg.

Gränges Group. Diversified Swedish conglomerate based on non-ferrous metals and engineering.

*This listing builds on the English alphabet by placing ö and å after a and å after o, rather than at the end of the alphabet, as is the Swedish practice.


Hälsovårdsnämnd. Public Health Department, a local government agency that plays an important role in setting kommun policy on allowed emissions from cogeneration.


Karlskrona. Site of a major oil-fired condensing plant on the southern Swedish coast.

Kaskräk. Krångede’s 65 MW(e), 230 MW(e) combustion condensing cogeneration turbine and 47 MW(e) cogeneration turbine outside Gävle. It coordinates production with the town of Gävle and Korsnäs-Marma’s Korsnäsverken pulp and paper mill.

Kommun. Municipality or township. Sweden’s principal form of local government.

Koncessionsnämnden för Miljöskydd. The Swedish Environmental Franchise Board, the national agency responsible for setting environmental standards for industrial plants.

Korsnäs-Marma AB. A forestry products company in north central Sweden.

Kraft. Electric power.

Kraftavärme. Cogeneration.

Kraftverken. Electric power division.


Krångederuppengens Samkörningsföretag. Krångede Group Joint Operating Company. A large Swedish power pool which includes the assets of Krångede and its owners, Stora Kopparberg, and Gullspång.

Kvarnsveden. An integrated paper mill owned by Stora Kopparberg with a 12 MW(e) cogeneration turbine.

Luleå. A coastal town of 36,400 in far northern Sweden, site of a proposed industrial/district heating cogeneration installation.

Mass- och Pappersindustrins Energiförbrukning. Pulp and paper industry energy consumption.

Mottvecksverk. Back-pressure power from steam cogeneration turbines.

Naturvårdsverket. The Swedish Environmental Protection Agency, the national agency responsible for administering environmental standards for industry.

Norrland. The northern half of Sweden, location of most of Sweden’s hydroelectric production.

Nyköping. A town of 31,200 in central Sweden considering the use of heat from the Gränges cogeneration plant at Oxelösund for district heating.
Öre. One hundredth of a Swedish crown, worth about 2.1 U.S. mills.

Oskarshamns Kraftgrupp AB. The jointly owned company that owns and manages the nuclear plants at Oskarshamn on the southeastern Swedish coast. Owned jointly by AB Bergslagens Gemensamma Kraftförvaltning, Bålforsens Kraft, Gullspångs Kraft, Krångeda, Stora Kopparberg, Svarthålsforsen, Sydsvenska Kraft, Uddeholm, and Voxnans Kraft.

Oxelösund. Coastal town of 14,800 in south central Sweden, site of Granges' 40 MW(e), 130 MW(th) combination condensing-cogeneration turbine.

Ramsey pricing. Second best pricing used to meet revenue constraints. Technically, Ramsey prices induce equally proportional departures from optimal levels of consumption at all margins.


Sandvik AB. A steel and carbide company based in north central Sweden.

Skoghall. A suburb of Karlstad in west central Sweden. Site of Billerud Uddeholm's 58 MW(e) and 19 MW(e) cogeneration turbine.

Skr. Swedish crowns, worth about U.S. $0.21 each.

Skutskär. Site of a Stora Kopparberg pulp mill, with a 45 MW(e) cogeneration turbine.

Statens Industridepartementet. Swedish national Ministry of Industry, the policy office which published the 1974 report of Energidirektoratet (the Energy Prognosis Committee) and the 1978 report of Energikommissionen (the Energy Commission) which outline the basis for Sweden's current energy policy.

Statens Industriverk. The Swedish national Industrial Board, the bureau responsible for administering Sweden's national industrial policy and, in particular, its subsidy program for industrial energy conservation.

Statens Prisregleringsnämnden för Elektrisk Ström. Swedish national Price Regulation Board for Electric Power, a board which hears and resolves complaints about electricity tariffs.

Statens Pris- och Kartellnämnden. Swedish national Price and Cartel Board, a board which oversees, among other things, Sweden's price control programs.

Statens Vattenfallsverk. Swedish national State Power Board, the largest power producer in Sweden, supervisor of the national grid, and a central force in the national power market and tariffmaking doctrine in general. Often called "Vattenfall."

Stockholm. Located in east central Sweden, Sweden's capital and largest city (1,289,000). Headquarters for many industrial firms and most associations. Major user of district heating.


Svarthålsforsen AB. The city of Stockholm's wholly owned power company with Stockholms Energifverk, the sixth largest power producer in Sweden in 1976.

Svenska Elverksföreningen. Swedish Association of Electricity Supply Undertakings, a trade association primarily for distributors of electricity.

AB Svenska Kullagerfabriken. A steel and engineering company based in Sweden. Better known as SKF.

Svenska Värmeverksföreningen. Swedish District Heating Association, an association of towns and cities with district heating.

Svenskt Stål AB. Nationalized Swedish steel company, owned half by the national government and a quarter each by Gränges and Stora Kopparberg, whose previously owned steel plants at Oxelösund and Domnarvit represent its principal assets.


Uddeholms AB. A steel, chemical, and power company in west central Sweden. Its forestry product assets were recently merged into Billerud Uddeholm. Ninth largest power producer in Sweden in 1976.

Uppsala. City of 97,300 in east central Sweden. Site of a large district heating system.

Varmlands Kraft AB. A small power producer in west central Sweden.

Västerås. City of 111,000 in central Sweden. The leader in the use of district heating in Sweden.

Västerås Stads Kraftvärmeverk AB. City of Västerås Cogeneration Works, Inc., the wholly owned company producing heat for Västerås' district heating system.
I. INTRODUCTION

Cogeneration of heat and electrical power, a family of technologies that uses one process to generate both usable heat and usable electrical power, is widely recognized as a highly efficient energy conversion technique. In some applications, it delivers over 90 percent of the heat content of the original fuel in usable energy. As a result, it can be an environmentally clean energy conversion technique, requiring fewer air and thermal emissions to deliver a given quantity of energy than other electricity generating technologies.

It is not surprising, then, that the increasing cost of fuel and the increasing conflict between energy and environmental goals of recent years have generated considerable interest in cogeneration. At the same time, the Public Utility Regulatory Policy Act of 1978 has forced the United States to consider electricity pricing based on marginal social costs. How will such pricing affect U.S. industry’s use of cogeneration? Will it have predictable effects on industry’s inclination to invest in new cogeneration technology, the type of technology and contractual arrangements industry will prefer, or the way industry will use existing cogeneration capacity over time? The answers to these difficult questions will most likely be found if we can observe how industrial use responds to marginal cost pricing in a setting similar to what we expect in the United States in the future. This study seeks such a setting in Sweden.

Sweden and the United States display a number of useful similarities. Both countries have similar standards of living and similar average electricity prices; they display similar per capita consumption of electricity (Doernberg, 1975, pp. 16-17). Both have similar energy-using industries, though in very different mixes. And in both countries, ownership of electricity-generating assets is diffused among publicly and privately held producers of varying sizes. This last point makes electricity pricing play an especially important role in the coordination of power production in both countries.

From our point of view, the greatest difference between the countries is the vertical disintegration and marginal cost pricing of the Swedish power supply system. This difference is important because the U.S. power supply system appears to be moving toward arrangements very much like those in place in Sweden today. Examining industrial cogeneration in the Swedish context gives us an appreciation both of the arrangements the United States might use to promote efficient use of cogeneration and of the ways in which industrial cogeneration might respond to marginal cost-based electricity pricing as it grows in importance in the United States.

This report is based on a broad system-oriented study of industrial cogeneration in Sweden. That study collected information through interviews, documents, and publicly available data from officials in Swedish business, research, and government organizations during late 1979 and early 1980. It looked at the specific relationship between electricity prices and industrial use of cogeneration in a broad context in order to develop insights that could be transferred to the United States.

After establishing a rationale for the specific approach to “industrial response” taken in this study, the report presents increasingly suggestive descriptive information which it then uses to analyze response in Sweden and its implications for the United States. Section II, which compares the concepts of industrial response to arbitrary electricity price variation and response to structural price change, concludes that an analysis of industrial response to structural change will provide the more useful insights about future use of cogeneration in the United States.
States. Section III provides detailed data on the Swedish power supply system and Section IV on the industrial use of cogeneration in Sweden. They stress the integration of industrial cogeneration of power into the general supply system and the basic commonalities in industrial use of cogeneration that transcend its diverse applications in Swedish industry. Section V reviews the administrative and market pricing mechanisms in Sweden's power supply system, explaining their differences and the dynamic underlying formal tariffmaking which appears to move Swedish tariffs ever closer to perceived social marginal costs. Section VI brings the material developed in Sections III, IV, and V together to illustrate how Swedish electricity prices reflect actual production costs and how this relationship affects industrial response to Swedish pricing. Section VII concludes the report by recapping the report's major findings and by suggesting their likely implications for U.S. policy on electricity pricing and industrial use of cogeneration. Two appendixes provide a detailed discussion of two specific Swedish standard and reserve tariffs, and some amplifications on cost comparisons in the body of the report.
II. ELECTRICITY PRICING AND INDUSTRY'S
USE OF SELF-GENERATION: SOME BASIC
CONCEPTUAL ISSUES

Self-generation gives an industrial user two capabilities: The user can generate some or all of its own electricity instead of buying it, and it can sell electricity to other users or to the grid to which it is connected. These capabilities in turn suggest two principal relationships between electricity prices and the use of self-generation. First, electricity prices affect how much self-generation capacity a user chooses and how it chooses to employ this capacity over time. Second, the presence of self-generation can affect the electricity prices that users face and hence change how they use electricity in general. This section examines these two relationships in a very simple conceptual framework.

The form of electricity prices relevant to industrial self-generation and the problem of costing electrical output from cogeneration are first reviewed. Then we present a simple model to illustrate the complex relationship between electricity prices and both the use of self-generation and the effect of self-generation on a user's general demand for electricity. Finally, we suggest that the Swedish experience will be most helpful to U.S. energy policy if used to emphasize how self-generation and general industrial demand for electricity respond to a price structure that reflects social marginal costs. This emphasis provides the basis for our study.

PRICES AND COSTS OF SELF-GENERATION

Decisions about whether to purchase electricity or to use self-generation ultimately depend on a variety of prices and production costs. The complex price structure typically associated with industrial electricity use becomes even more complex with self-generation. The electricity user must also consider issues about production costs that do not arise when the user buys all its electricity from the grid. This subsection reviews briefly the types of electricity prices important to self-generation and the problem of defining production costs for one type of self-generation, cogeneration.

Electricity Prices

While the prices embodied in only one tariff—the "standard" tariff—are typically relevant to the study of industrial demand for electricity, three tariffs actually affect the use of industrial cogeneration:

1. The standard tariff is the set of prices and conditions under which industrial users can buy electricity from the grid or local utility on a regular basis. It effectively embodies "offer" prices and includes: a connection charge which may be keyed to the capacity of the connection; maximum demand, subscribed capacity, or other charges

1These may either be prescribed in formal administrative tariffs or reflected in market prices. Section V discusses the important differences between these pricing regimes.
based on the maximum number of megawatts used in any prescribed period; and
energy charges for the megawatt hours of electricity used in various periods.

2. The reserve tariff, a set of prices and conditions for power to back up self-generation
units, allows industrial firms to exceed their subscribed capacity or increase their
maximum demand without penalty. These prices can include capacity and energy
charges for occasions when reserve power is drawn and a connection charge and
"insurance premium" paid whether reserve power is drawn or not. The "premium" is
typically keyed to the reserve power subscribed.

3. The buyback tariff sets terms for sales of electricity to the grid or local utility: "bid"
prices. It includes energy charges and sometimes capacity charges; all are typically
lower than their counterparts in the standard tariff unless these prices are determined
in a market.

The terms of each of these tariffs can vary by voltage level, geographical location, customer
class, and so on.

The prices in these tariffs are relevant to basic decisions about connection to the grid (yes
or no), capacity (how much self-generation, how much purchased), energy (how much self-
generated, how much purchased in any period), and reserves (how much capacity purchased,
how much self-provided, how much used in any period). The interrelationships involved in
these decisions lead to far more complicated relationships between price and electricity produc-
tion and consumption than one typically encounters in studies of electricity prices and industri-
al use of electricity.

Costing Electricity from Cogeneration

An important form of self-generation—what we shall find may be the most important
form—is cogeneration. Because cogeneration produces power and heat jointly, it presents some
ambiguities about how to cost the electricity it provides. The typical solution (see Section V)
is to allocate all the joint cost savings of cogeneration to electricity. That is, to find the energy
cost of cogenerated electricity, we use the difference between (a) the cost of fuel to increase
cogenerated electricity output incrementally by, say, one megawatt and (b) the hypothesized
cost of producing the heat jointly produced from this increment in the most cost effective
stand-alone boiler. Capacity and reserve costs can be calculated in a similar way.

This allocation of cost savings is less asymmetric than it might first appear to be. Because
there is no competitive grid for heat, it is easier to define the costs of providing heat from sources
other than cogeneration than to define the costs of electricity from the grid. Once the relatively
easily identified costs of stand-alone boilers are figured, a reservation price for electricity can
be set to assure that it displaces as much purchased electricity and sells as much self-generated
electricity as it can from its chosen cogeneration capacity. Just as with other self-generation
options, of course, how much electricity the user can sell or displace simultaneously affects how
much cogeneration capacity it chooses.

Unless otherwise indicated, this report uses this net cost approach to define the cost of
electricity from cogeneration. Only when clear alternatives to user-owned stand-alone boilers
exist, as in district heating applications where home-specific boilers are an option, will a more
obviously symmetric approach be suggested.
A SIMPLE MODEL OF THE MARKET FOR SELF-GENERATION

A user’s demand for self-generation is simply its excess demand for nonpurchased electricity, given its total electricity demand and the terms for purchased electricity. By combining this excess demand with a supply function for self-generation based on its costs, we can construct a simple model of a user’s implicit market for self-generation that illustrates the complexity of the price relationships associated with the three tariffs noted earlier.

Such a model can be considered in any of the dimensions suggested above by the decisions about connection, capacity, energy, and reserve.

Figure 1 illustrates such a model in the capacity dimension. 2 D in Panel (a) is the user’s general demand for capacity with some specified level of reliability and is a function of energy and connection charges not shown in this dimension. P_r and P_s are, respectively, the grid’s exogenously fixed offer and bid prices for capacity. Excess demand for self-generation, ED in Panel (b), can be derived by subtracting the supply implicit in P_r from the horizontal sum of D and the demand implicit in P_s. S_r are three different reservation loci for self-generation capacity and reserve capacity to meet the reliability level specified in D. They are functions of submerged energy, connection, and reserve charges, and, in the case of cogeneration, the user’s heat load. Their shape reflects a negatively sloped section associated with scale economies and an upward sloping section associated with the increasing cost of increasing the power/heat ratio in cogeneration.

The intersection of ED and S_r defines the desired level of capacity. With S_r, for example, the user demands ("consumes") K_r in capacity and supplies ("produces") K_s; it buys K_s – K_r from the grid. With S_s, the user demands and supplies K_s; it does not deal with the grid in capacity. Note, however, that it may still buy and sell energy and reserve electricity. With S_p, the user demands K_p and supplies K_p “exporting” K_p – K_s to the grid.

The model provides a number of important implications for the relationship among prices, self-generation, and general electricity use. First, and simplest, in this model the presence of self-generation does not affect the general use of electricity or its response to price unless a gap exists between the grid’s offer and bid prices. Otherwise, self-generation cannot affect the effective price of electricity. Gaps are most likely to emerge in the capacity and reserve dimensions because the grid rarely offers to buy either of these at a positive price in formal tariffs. In alternative models, where grid prices depend on the presence of self-generation or are linked to the cost of self-generation in some way, this is no longer true. Under these alternatives, changes in the grid price can change the effective price and hence user behavior in a wide variety of ways. Second, either a larger gap between grid offer and bid prices or a more elastic demand reduces the probability that these grid capacity prices will affect the desired level of self-generation capacity. Similar relationships exist in other dimensions. Third, in general, changes in submerged charges in any dimension can have a wide range of effects on capacity demanded and supplied; and changes in capacity charges can similarly affect other dimensions.

In sum, even in this very simplified model, the range of interaction among prices, self-generation use, and general electricity use is complex. Not even qualitative outcomes are easily derived without detail about the explicit tariffs and technologies under consideration. The general effects of prices on cogeneration patterns and behavior would be difficult to isolate even in one utility area or industry, to say nothing of trying to draw insights from one nation to apply

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2 Panels (a) and (b) show offer and bid prices on the ordinate and capacity on the abscissa.
Fig. 1—The implicit market for self-generation
to another. The European experience approached in this way is unlikely to help us much in understanding relationships between pricing and self-generation in the United States.

A CONCEPTUAL FRAMEWORK FOR STUDYING PRICING AND COGENERATION IN SWEDEN

A simple way to make the relationship between the use of self-generation and electricity pricing more manageable is to restrict the type of prices considered. Instead of attempting to determine how industrial self-generation and industrial electricity use in general respond to arbitrary price changes, suppose we restrict our inquiry to price changes that reflect some definition of cost. If we look at how industrial self-generation and electricity use respond to a move toward marginal cost-based prices, then our emphasis shifts from how they respond to individual price changes within a given tariff structure to how they respond to changes in the pricing structure itself.

Sweden offers an excellent opportunity to study the likely effects of responses to structural pricing changes in the United States. The United States is rapidly moving toward adoption of electricity pricing mechanisms—both market-oriented and administrative—that emphasize the relationship between prices and social marginal costs. Sweden uses such mechanisms now. Properly applied, these mechanisms make the price of electricity a veil, forcing industrial self-generation alternatives to compete on an equal footing with generating assets throughout the electricity supply system. An understanding of a few basic technological relationships among generating alternatives can tell us a great deal about how industry would use self-generation under such a pricing regime. Sweden's pricing regime can help us understand how industrial self-generation in the United States will change as the United States moves toward such a regime also. To the extent that Swedish prices fail to reflect relevant costs we can also understand the consequences of prices that provide an imperfect veil and forces that prevent the use of prices that facilitate social cost reductions. The current effects of political, regulatory, and environmental considerations as well as transactions costs in Sweden, properly understood, can provide insights into how similar concerns in the United States will affect industrial self-generation as prices based on social marginal cost gain broader use in the United States.

In the remainder of this report we examine the extent to which Swedish electricity prices reflect social marginal costs, develop the implications of such social marginal cost pricing and departures from it for industrial use of cogeneration in Sweden, and look for differences between Sweden and the United States that relate to these implications in future industrial cogeneration in the United States.
III. GENERATION AND TRANSMISSION IN
THE SWEDISH POWER SYSTEM

The Swedish power supply system consists of about 24 gigawatts of generating capacity interconnected by over 8000 miles of high voltage transmission lines. The generating capacity is owned by the national government, municipalities, and private industry; the national government owns and operates the transmission system. This section outlines Sweden's national power supply system, giving special attention to cogeneration's place in it.

TYPES OF GENERATION

The Swedish power system has a hydro base and significant quantities of nuclear and fossil-fired thermal capacity. As Table 1 indicates, over half of Sweden's capacity and almost two-thirds of its production of electricity is hydroelectric. The Swedish power system uses it as peaking, cycling, and baseload capacity (see Fig. 2). The fraction of hydro is falling; although it accounted for almost 80 percent of production only ten years ago, new hydro production has not kept pace with the growth of electricity demand. Sweden is rapidly exhausting its viable hydro sites, and environmentalists are attempting to stop development of the remaining sites (Hambraeus and Stilesjö, 1977, p. 425). The United States has a similar situation in the major hydro-based regions of the Pacific Northwest and the Tennessee Valley.

Sweden is turning primarily to nuclear power to meet continuing growth in baseload demand. Ten years ago, nuclear power was experimental in Sweden, but by 1977 it accounted for 15 percent of capacity and 25 percent of production. Nuclear capacity continues to expand so fast today that the Swedes anticipate excess capacity over the next decade. A referendum in March 1980 meant to settle the future of nuclear power in Sweden predictably failed to do so. As a result, nuclear's role beyond the 1980s is not yet clear.

Swedish fossil fuel capacity differs from that in the United States in two significant ways. First, all of it is oil-fired. Sweden has no natural gas infrastructure and coal is used primarily

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1 Figure 2 displays a representative annual load curve for the Swedish system, with system capacity on the ordinate and annual duration of capacity utilization on the abscissa. It shows "non-regulated hydro-electric power" being used to meet loads of the longest duration—baseload—and "regulated hydro-electric power" meeting loads of intermediate duration—cycling. Pumped storage is used in the peak.

2 Sweden's first experimental nuclear plant, at Ågesta, was a cogeneration plant. While all of the nuclear capacity operating today is condensing capacity, serious thought is being given to converting some existing capacity to large, central nuclear cogenerating plants that would ship heat to the cities.

3 When the Swedes first began to consider nuclear power in the early 1960s, they saw it as a clean, cheap fuel that could relieve Sweden's dependence on foreign oil (because of domestic uranium deposits). Strong political support emerged for a development program that has made Sweden more dependent on nuclear power than any other country in the world. Over the 1970s, however, the public began to lose confidence in nuclear power. Concern over nuclear power became so important that it helped topple the Swedish government in 1976. The 1980 referendum was scheduled to avoid further political fallout from the debate. Thirty-nine percent voted to open no more nuclear plants and to phase out existing plants over the next ten years. Fifty-eight percent voted to retain nuclear power for another twenty-five years, effectively leaving a decision about phasing out nuclear to a later date. Though the Swedish government has promised to implement the results of the referendum, the large vote against nuclear power suggests that a broad consensus does not exist. Swedes generally expect this dispute over nuclear power to continue, leaving its future uncertain.
in industry. Only three power plants can burn coal and even then they require significant modification before coal can be burned.

Second, cogeneration is more prominent in Sweden, particularly relative to fossil-fueled condensing capacity. Only in dry years, like 1976/77, does condensing retain its traditional share of the market. Even as new central condensing plants are added, the share of condensing in capacity and production is falling as smaller plants are retired or used less often. This will continue as nuclear power grows, leaving fossil-fueled condensing in the cycling/peaking role suggested in Fig. 2. Industrial cogeneration, cogeneration producing heat for industrial application, has held its share over time at about 3 percent of total capacity and 4 percent of production. District heating cogeneration, which provides its heat to district heating networks, is steadily growing in capacity and production. By 1977 it accounted for over 8 percent of national capacity and 6 percent of production.

In a typical year, total cogeneration dominates fossil fuel condensing production by a factor of two or three. This is because the higher efficiency of cogeneration induces its owners to use it to meet loads of long duration. It typically runs whenever a heat load exists to accept its heat output, or effectively all year long for industrial cogeneration which is typically stopped only for maintenance or because of interruptions in industrial production. Hence industrial cogeneration appears as a baseload-type capacity in Fig. 2.

District heating cogeneration, on the other hand, follows a seasonal heat load that allows it to run efficiently from about September to May, allowing 3200-4000 hours per year.

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4As in the United States, coal was common in many plants until the 1960s when falling oil prices led to oil’s total replacement of coal (Lönnroth, p. 35).

5They are Billerud Uddevalla’s Skoghall plant, Svartholmsforsen’s Hässelby plant, and Sydsvenska Kraft’s Öresund plant. Hässelby stockpiles coal now for emergency use, but has not been allowed to use it. Statens Vattenfallverk, the nationally owned State Power Board, wants to build two additional coal-fired 600 MW cogeneration plants at Oxelösund and Nyköping and storage capacity for 240 days of supply to reduce the problem of foreign dependence (European Energy Review, 29 July 1980, p. 5).

6Massa- och Pappersindustrins Energiförbrukning 1990 (1977) suggests that pulp and paper cogeneration has a planned annual running time of about 5700 hours. Statens Industridirektoratet expects even greater use of 6000-8000 hours per year.

Fig. 2—Schematic stack of alternative Swedish power sources

the national electric load and heat load are closely correlated in Sweden, district heating cogeneration can provide power to meet loads of intermediate duration, giving this cogeneration the appearance of cycling capacity despite its high efficiency. This is reflected in the marked difference in load factors for industrial and district heating cogeneration in Table 1. But even district heating cogeneration has a higher load factor than fossil-fuel condensing capacity. The difference would be even more marked if Table 1 did not include the dry year 1976/77. In dry years Sweden uses all its thermal resources more extensively, and lightly loaded capacity like fossil-fuel condensing can provide substantial additions to production.8

THE HIGH VOLTAGE GRID

With one or two minor exceptions, all of the capacity discussed above is interconnected directly or indirectly to Sweden’s high-voltage national grid (Fig. 3). Nationalized and placed under the aegis of Statens Vattenfallsverk in 1946, the grid now consists of over 8300 miles of 220 kV and 400 kV transmission lines.9 Transmission lines with 130 kV, operated by other agencies and companies, complement this system. As the map in Fig. 3 suggests, the grid is meant primarily to move power from the hydro plants in the Norrland districts of northern Sweden to the population centers and thermal plants in central and southern Sweden. Norrland produces over half of Sweden’s electricity; over half of that goes south on the grid. Hence, it is not surprising that transmission contracts in effect during 1977/78 totaled 3,060,100 MWkm, enough if fully utilized to move 5773 MW of power 330 miles from Norrland to central Sweden via the national grid.10 In recent years, slightly over 6 percent of this power has been consumed in transmission losses (Centralra Driftledning, 1978, p. 39).

OWNERSHIP OF GENERATING CAPACITY

Unlike systems in many western European countries, the power supply system in Sweden has many different owners. Table 2 breaks down Sweden’s thermal capacity by type of direct owner. It is important to distinguish direct from ultimate ownership in Sweden because the category that dominates this table, power corporations, is made up of firms with many different types of owners, for example, a firm owned wholly by the city of Stockholm, another owned primarily by a consortium of towns in southern Sweden, another owned primarily by a consortium of industrial firms, and yet another owned outright by one industrial conglomerate.11 Similarly, while Statens Vattenfallsverk owns only 42 percent of Sweden’s nuclear capacity directly, its ownership shares in power corporations give it actual ownership of almost 75 percent of that capacity.

One of the keys to understanding the Swedish power system, and industrial power genera-

8For example, during 1976/77, the share of fossil-fuel condensing units in total production expanded over threefold from the normal year of 1975/76. In the normal year of 1977/78, it fell back to its previous level (Centralra Driftledning, 1978). Section VI discusses these points in more detail.
9Several power companies retain ownership of parts of the transmission system built before 1946. Statens Vattenfallsverk leases these under a 24-year arrangement with their owners and operates them as undifferentiated components of a unified national grid (Centralra Driftledning, 1978, p. 38).
10As Section V explains, power producers lease capacity on the national grid in units of MWkm or megawatt-kilometers. Each unit entitles the lessee to move one megawatt one kilometer on the national grid.
11These are, respectively, Svarthällsforsen, Sydvenska Kraft, Krångåse, and Gränse Kraft.
SOURCE: Centrala Driftledning, 1978, p. 42

Fig. 3—Swedish high-voltage transmission grid
<table>
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<tr>
<th>Item</th>
<th>Statens Vattenfallenverk</th>
<th>Municipal Power Agencies</th>
<th>Power Corporations</th>
<th>Industrial Power</th>
<th>Institutions</th>
<th>Total</th>
<th>Percent of Total</th>
</tr>
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<td>Installations</td>
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<td>35</td>
<td>36</td>
<td>144</td>
<td>32</td>
<td>263</td>
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<td></td>
<td>Total MW</td>
<td>3979.0</td>
<td>741.9</td>
<td>6196.9</td>
<td>1092.2</td>
<td>295</td>
<td>12093.5</td>
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<td></td>
<td>Ave. MW</td>
<td>248.6</td>
<td>21.2</td>
<td>172.1</td>
<td>7.88</td>
<td>.9</td>
<td>45.8</td>
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<td>4</td>
<td>0</td>
<td>0</td>
<td>32.1</td>
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<td></td>
<td>Total MW</td>
<td>1620.0</td>
<td>0</td>
<td>2240.0</td>
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<td>3860.0</td>
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<td></td>
<td>Ave. MW</td>
<td>810</td>
<td>560.0</td>
<td>560.0</td>
<td>643.3</td>
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<td>Oil-fired condensing units</td>
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<td>9</td>
<td>16</td>
<td>36</td>
<td>0</td>
<td>74</td>
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<td></td>
<td>Total MW</td>
<td>1311.0</td>
<td>111.5</td>
<td>1498.5</td>
<td>187.4</td>
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<td></td>
<td>Ave. MW</td>
<td>100.9</td>
<td>12.4</td>
<td>93.7</td>
<td>5.21</td>
<td>42.0</td>
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<td>2</td>
<td>2</td>
<td>132</td>
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<td>136</td>
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<tr>
<td>Units</td>
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<td>55.0</td>
<td>886.5</td>
<td>946.2</td>
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<td></td>
<td>Ave. MW</td>
<td>2.35</td>
<td>27.5</td>
<td>6.72</td>
<td>6.96</td>
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<td>District heating</td>
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<td>15</td>
<td>25</td>
<td>10</td>
<td>10</td>
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<td>cogeneration units</td>
<td>Total MW</td>
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<td>535.9</td>
<td>1807.0</td>
<td>16.0</td>
<td>2364.9</td>
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<td></td>
<td>Ave. MW</td>
<td>6.00</td>
<td>35.7</td>
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<td>0</td>
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<td>Total MW</td>
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<td></td>
<td>Ave. MW</td>
<td>50.9</td>
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<td>Diesel units</td>
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<td>171</td>
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<td></td>
<td>Total MW</td>
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<td>18.3</td>
<td>13.5</td>
<td>87.4</td>
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<td>Ave. MW</td>
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<td>.26</td>
<td>1.59</td>
<td>.23</td>
<td>.33</td>
<td>.51</td>
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<tr>
<td>Percent of total</td>
<td>No. Install.</td>
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<td>13.3</td>
<td>13.7</td>
<td>54.8</td>
<td>12.2</td>
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<tr>
<td>Capacity</td>
<td></td>
<td>33.1</td>
<td>6.2</td>
<td>52.5</td>
<td>9.1</td>
<td>.3</td>
<td></td>
</tr>
</tbody>
</table>

NOTE: The number of units does not sum to the number of installations by owner type because an installation often has more than one production unit.

SOURCE: Calculated from data compiled by Bergman and Co.
tion in particular, is understanding that such diverse forms of power corporations are possible and significant to the system as a whole.

**BASIC PATTERNS OF INDUSTRIAL OWNERSHIP**

Table 2 reveals three patterns relevant to general industrial power production.

1. Industry owns directly almost all cogeneration units with industrial applications, and although it participates actively in the ownership of various central generating assets, nonindustrial firms have not in turn sought to participate in industrial cogeneration. Cogeneration units at industrial sites are typically wholly owned by the firms using the units' heat. Such a pattern does not extend to district heating cogeneration, where joint ownership is relatively common.

2. Cogeneration units differ markedly in size according to the heat loads in their different applications. On average, district heating units are six times larger than industrial units; over half of all industrial units are smaller than 5 MW, apparently because Swedish industry is disinclined to amalgamate company energy demands to justify jointly owned energy centers. Note, however, that industrially owned condensing and cogeneration units are of similar size, as are nonindustrial condensing and district heating cogeneration units. Local electricity demand may also be a factor in determining the size of these units.

3. Cogeneration is the principal form of industrially owned thermal generation capacity, accounting for about 81 percent of the total. Oil-fired condensing units account for almost all of the remainder, although Swedish industry also employs a large number of very small diesels. Significantly, Swedish industry uses no gas turbines. Only major power companies own them; they use them in very large sizes at central locations in the grid.

**Examples of Industrial Ownership Patterns**

Industry's participation in power corporations helps integrate it into the power supply system. This integration is reflected in ownership arrangements that ultimately make it difficult to distinguish publicly from privately owned power plants, or plants owned by general industry from those owned by "the power industry." A number of examples will help illustrate these patterns in Swedish power:

First, a Swedish industrial firm often owns internal generating capacity, which it supplements with a variety of power sources. Occasionally it maintains its own wholly owned subsidiary to provide the firm's electricity. Typically, a firm maintains only enough total capacity to meet its own firm needs, but some firms also maintain sufficient capacity to supply firm power to external customers. Some firms' generating assets include hydropower and thermal, as well as cogeneration.12 Three examples are the Gränges Group, a metals-based conglomerate; Billerud Uddevholm AB, a forestry firm; and Stora Kopparbergs Bergslags AB, a pulp and paper firm.

12The firms rely on hydropower and cogeneration during normal years. They maintain other thermal assets, typically steam condensing turbines, to maintain reliability in dry years, expected every ten years or so.
Gränges Kraft AB, the wholly owned power subsidiary of the Gränges Group, owns a 69 MW(e) industrial cogeneration plant\textsuperscript{13} and part or all of twenty-two hydroelectric stations (Gränges Group, 1979).

Billerud Uddeholm owns generating assets in several different divisions. Its Power Division owns various hydroelectric assets as well as shares in the 1018 MW oil-fired Karlshamn condensing plant and in two power companies.\textsuperscript{14} These power companies, in turn, own shares of nuclear power installations at Oskarshamn and Forsmark, giving the industrial firm, Billerud Uddeholm, an ownership interest in nuclear power (Billerud Uddeholm, 1978). Outside its Power Division, in its production divisions, Billerud Uddeholm owns an additional 144 MW of thermal capacity, mostly in industrial cogeneration units.

Stora Kopparberg also draws on wholly, partly, and indirectly owned generation assets. In 1977 and 1978, it provided 94 percent of its own electricity needs from hydropower (67 percent), nuclear power (13 percent), and oil-fired cogeneration and condensing plants (19 percent) (Stora Kopparberg, 1978).

Second, Swedish industry sets up jointly owned power companies to help meet its power needs. In some ways, these arrangements are similar to those used to govern jointly owned baseload plants in the United States. But they include direct participation by industrial firms and can involve baseload, cycling, and peaking assets at diverse locations. Examples include two of Sweden’s nuclear installations: AB Aroskraft, a district heating cogeneration firm; and Kränged AB, a diversified power company.

Oskarshamn Kraftgrupp AB and Forsmark Kraftgrupp AB, each representing a nuclear power installation, especially resemble their jointly owned American counterparts. They both have numerous power companies participating as shareholders, but they also have industry participants, as direct shareholders or as shareholders of the direct participants in these joint ventures. As noted above, Stora Kopparberg is an example of a direct owner; Billerud Uddeholm is an indirect owner (Swedish Nuclear Industry Group, 1974).

AB Aroskraft owns two 250 MW(e) combustion cogeneration-condensing turbines that provide heat to the district heating system in Västerås and power to its five owners: an industrial firm, a power firm owned by industry, two other power companies, and the city of Västerås.\textsuperscript{15} Aroskraft comes as close as any arrangement in Sweden to the concept of an industrial energy center, a large cogeneration installation jointly owned by industrial firms to meet their energy needs. But it provides all of its heat to district heating, providing only transmitted power to its industrial owners.

Kränged AB, one of Aroskraft’s owners, is itself owned by four industrial firms and three power companies,\textsuperscript{16} one of which in turn has other industrial owners. Kränged AB maintains a diversified portfolio of assets, with 750 MW of hydroelectric power, a 175 MW(e) industrial cogeneration plant,\textsuperscript{17} and shares of the Forsmark (30 MW), Oskarshamn (70 MW), and Aroskraft (145 MW(e)) installations.

\textsuperscript{13}This is collocated with the Svenskt Stål steel mill at Oxelösund. Gränges formerly owned the steel mill as well and retains an interest in it through its participation in Svenskt Stål.

\textsuperscript{14}Värmlandskraft AB and AB Bergslagens Gemensamma Kraftförvaltning.

\textsuperscript{15}The firms are, respectively, Stora Kopparberg (27.5 percent), Kränged (29.0 percent), Gullspångs Kraft (15.0 percent), and Bergslagens Gemensamma Kraftförvaltning (11.0 percent) (Västerås Stads Kraftvärmeverk AB, 1978, p. 1).

\textsuperscript{16}The industrial owners, who jointly own 63 percent, are Korndins-Marma AB, a pulp and paper company; Sandvik AB and Fagersta AB, steel companies; and AB SKF, an equipment manufacturing firm. The power companies owning the remainder are Sydvenska Kraft AB, a municipally owned cooperative (8 percent); Svarthålsforsen AB, owned by the city of Stockholm (17 percent); and Bergslagens Gemensamma Kraftförvaltning, mentioned above (12 percent).

\textsuperscript{17}The Karskår plant, collocated with the Korndins-Marma mill at Gävle.
Pulp and Paper and Power Production

Firms in the Swedish pulp and paper industry show a special affinity to power production from both hydroelectric resources and cogeneration. These firms acquired valuable riparian rights to exploit waterfalls on their forest properties for power generation. They also use a manufacturing process ideally suited to coordination with industrial cogeneration. As a result, five of Sweden's eighteen largest power producers are also pulp and paper companies (Table 3). Clearly, not every major paper and pulp firm produces significant amounts of power, but these firms, among the largest in Sweden, are all direct owners of significant thermal generating assets and, in particular, cogeneration assets. Together, they directly own 39 percent of Sweden's industrial cogeneration capacity. Through their subsidiaries they hold even more, much of it in pulp and paper applications as well.

Table 3

| Firm                                | Electricity Production 1978 | Total Paper and Pulp Capacity | Total Thermal Capacity | Total Cogeneration Capacity |
|-------------------------------------|-----------------------------|-------------------------------|------------------------|-----------------------------
| Stora Kopparbergs Bergslags AB and Bergvik och Ala AB | 4885 5.1 6 | 920 3 | 186 1 | 80 3 |
| Billerud Uddeholm AB                | 1810 1.9 12                  | 860 6 | 144 3 | 106 1 |
| Holmens Bruk AB                    | 1750 1.8 13                   | 890 4 | 88 5 | 73 4 |
| Korsnäs-Marma AB                    | 1305 1.4 16                   | 515 9 | 180 2 | 55 6 |
| Mo och Domsjö AB                   | 1250 1.3 17                   | 865 5 | 55 8 | 54 7 |

Source: Electricity production: Swedish Power Association, 1979; Paper, board, and pulp: Svenska Cellulosa- och Pappersbruksföreningen; Electrical capacity: Data compiled by Bergman and Co.

SUMMARY

Like that in the United States, Sweden's generating capacity is owned by a diverse set of public and private power producers. But a number of important factors distinguish Swedish and U.S. power production. First, several of the largest power producers in Sweden are primarily interested in other industrial activities, most prominently pulp and paper manufacturing. Second, Swedish producers cooperate in joint ventures of all kinds, making it difficult to distinguish the exact nature of the ultimate ownership of many generating plants. Third, and most important of all, all generating assets in Sweden are interconnected in a nationally supervised, extensive, and efficient transmission grid. All of these factors encourage a closer integration of industrial power production into Sweden's power supply system than we observe in the United States.

Sweden also displays some distinctive patterns in the types of capacity it uses. Hydroelectric power continues to dominate Swedish power production, but the system also uses signifi-
cant quantities of nuclear and oil-fired thermal capacity. Nuclear condensing is rapidly replacing oil-fired condensing capacity, which now plays a significant role in Swedish power supply only during dry years. Cogeneration accounts for most oil-fired power production.

Both industry and district heating systems use cogeneration capacity in Sweden. Industrial firms own all the cogeneration installations they use and appear to size them to be compatible with their own firm-specific heat loads. Despite significant economies of scale in cogeneration, Swedish industry does not typically employ jointly owned “industrial energy centers” to provide cogeneration services. District heating systems use much larger cogeneration units.

The energy efficiency of cogeneration allows both types of capacity to run almost whenever a compatible heat load is present. The steady all-year-long heat load present in most industry gives industrial cogeneration the appearance of baseload capacity. Because the seasonal demand for district heat varies significantly and is correlated with system demand for electricity, district heating cogeneration displaces cycling plant, coming on- and off-line as the general seasonal demand for power rises and falls. But it too acts like baseload capacity whenever a district heating load is present.
IV. INDUSTRIAL SELF-GENERATION IN SWEDEN

As noted in Section III, cogeneration is the dominant form of thermal capacity held directly by Swedish industry. This section examines industry's use of cogeneration in more detail, with special attention given to general patterns of cogeneration's coordination with other generating assets and to industry-specific factors that affect cogeneration's use in different applications. Despite substantial diversity in the ways Swedish industry uses cogeneration, a set of basic common traits transcends industry-specific differences. These common traits are important when we examine industrial response to prices relevant to cogeneration in Section VI.

GENERAL PATTERNS OF SELF-GENERATION

The importance of industrial cogeneration is even greater than that suggested by its 81 percent share of industrial capacity. Installations accounting for 97 percent of Swedish industry's generation capacity employ cogeneration (see Table 4). Installations without cogeneration typically employ only small—247 kW on average—diesel generators. These diesels tend to be in installations in mines, airports, communications centers, and other locations that demand a higher level of reliability than the grid can provide. They are used only when power from the grid is not available—which is almost never. At installations generating industrial power on a regular basis, then, cogeneration is almost always present and important.

Cogeneration in Swedish industry has three distinguishing features: the dominance of steam turbines in Swedish cogeneration; cogeneration's relationship to condensing capacity; and the way the configuration of cogeneration units changes at an installation as its size grows.

Dominance of Steam Turbines

Setting its emergency diesels aside, all but two of Swedish industry's generation facilities use only steam turbines.¹ A similar pattern carries over to district heating cogeneration plants. A number of reasons contribute to this distinct pattern.

First, the industries that use cogeneration, especially pulp and paper, have heat demands that are compatible with the heat output of steam turbines. Steam is typically extracted from these turbines at several temperatures and pressures to preheat air, fuel, or feed water, and to meet the heat demands of the industrial process. Paper and pulp, for example, demand steam at 10 and 4 bar and an extraction steam turbine can easily accommodate these requirements (Swedish Association of Pulp and Paper Engineers, 1975; Norrström, Widell, and Wohlfahrt, 1977).

Second, while gas turbines and diesels typically require high quality liquid fuels—distillate fuel oil or even higher—steam turbines can accept any fuel. Bark, wood waste, black liquor,² and even garbage supplement the bunker oil #5 typically burned in steam turbines.

¹One is a 15 MW(e) heavily subsidized combined cycle gas/steam turbine at a petroleum refinery that will deliver heat to the district heating system in Goteborg. The other is a subsidized, experimental steam engine that delivers direct motive power to a sawmill.

²Black liquor is a waste product from chemical pulp mills and the most important cogeneration fuel in Sweden after residual fuel oil. The next subsection will explain this in more detail.
### Table 4

**Industrial Self-Generation Configurations, 1979**

<table>
<thead>
<tr>
<th>Self-Generation Configuration</th>
<th>Installations</th>
<th>Cogeneration</th>
<th>Condensing</th>
<th>Diesel</th>
<th>Share</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>No.</td>
<td>MW/No.</td>
<td>No.</td>
<td>MW/No.</td>
<td>No.</td>
</tr>
<tr>
<td>Cogeneration only</td>
<td>51</td>
<td>4.43</td>
<td>51</td>
<td>4.43</td>
<td>2</td>
</tr>
<tr>
<td>Cogeneration only &gt;1</td>
<td>17</td>
<td>18.50</td>
<td>37</td>
<td>8.50</td>
<td>2</td>
</tr>
<tr>
<td>Condensing only</td>
<td>8</td>
<td>.90</td>
<td>8</td>
<td>.90</td>
<td>2</td>
</tr>
<tr>
<td>Condensing only &gt;1</td>
<td>0</td>
<td>—</td>
<td>0</td>
<td>—</td>
<td>2</td>
</tr>
<tr>
<td>Diesel only</td>
<td>19</td>
<td>.33</td>
<td>19</td>
<td>.33</td>
<td>48</td>
</tr>
<tr>
<td>Diesel only &gt;1</td>
<td>20</td>
<td>.50</td>
<td>48</td>
<td>.21</td>
<td>.92</td>
</tr>
<tr>
<td>Cogeneration and condensing</td>
<td>23</td>
<td>22.00</td>
<td>37</td>
<td>9.09</td>
<td>25</td>
</tr>
<tr>
<td>Cogeneration and diesel</td>
<td>4</td>
<td>2.83</td>
<td>7</td>
<td>1.41</td>
<td>9</td>
</tr>
<tr>
<td>Condensing and diesel</td>
<td>2</td>
<td>5.55</td>
<td>3</td>
<td>3.47</td>
<td>2</td>
</tr>
<tr>
<td>Total</td>
<td>144</td>
<td>7.58</td>
<td>132</td>
<td>6.72</td>
<td>36</td>
</tr>
<tr>
<td>Share</td>
<td>—</td>
<td>—</td>
<td>81.22</td>
<td>—</td>
<td>17.17</td>
</tr>
</tbody>
</table>

**Source:** Calculated from data compiled by Bergman & Co.
Third, Swedish familiarity with steam turbines goes back to the nineteenth century. Swedish engineers have designed specially adapted turbines to exploit the full opportunities offered by cogeneration. This long association with steam turbines and the resulting technical expertise raise artificial barriers to the use of other technologies.

Fourth, the ratio of heat and power from a steam turbine is easier to vary, especially the short run within an existing system, than the ratio from diesels or gas turbines. This is recognized as an important asset in district heating stations, whose large scale allows the construction of combination condensing-cogeneration plants with variable heat-to-power ratios. But we do not typically observe such combinations in Swedish industry; the opportunity offered by steam turbines to build such combinations cannot explain the use of steam turbines there.

Finally, over the load durations typical of industrial applications, steam turbines are more efficient than gas turbines or diesels. Given a heat load, steam turbines require less incremental fuel to meet any electricity load, and when electricity and/or heat can be freely exchanged at cost, those special characteristics that make gas turbines and diesels attractive (primarily quick starts and high power-to-usable heat output ratios) are not particularly important. If an industrial firm can draw power from the national grid at reasonable rates, it can rely for quick starts on remote hydro resources (its own or someone else's), or large-scale, utility-owned gas turbines. And it can buy the excess power required by a steam turbine's low power-to-usable heat output ratio rather than produce it on site with diesel or a gas turbine. This is precisely what we see in Sweden. In the end, the dominance of the steam turbine appears to depend on the presence of the national power grid. Sections V and VI expand on this point.

Cogeneration and Condensing Capacity

The second distinguishing feature of cogeneration in Sweden is its relationship to condensing power on-site. According to Table 4, about a quarter of the industrial installations using cogeneration, installations accounting for half of industry's cogeneration capacity, also have condensing capacity. This suggests some complementarity between condensing and cogeneration capacity. In fact, while some may have existed in the past, none is present today.

Industrial condensing power is a production mode of the past. Half of all the condensing turbines in Swedish industry date from before 1946, and only two of them have been rebuilt. Almost a third of Sweden's current industrial condensing turbines and half of its current capacity in this generating form were added during the short building binge of 1957-1962. Only three turbines, all small, have been added since then; none has been added since 1969. The apparent reason for this passing of interest appears to be the emergence of large, efficient oil-fired and, especially, nuclear condensing plants to back up Sweden's hydro resources in dry years. Given the great scale economies in condensing steam turbines, industry simply cannot compete with these large centralized sources when the grid makes their services available.

Similar scale economies exist in cogeneration plants with condensing capability. About 100 MW(e) is required before full condensing capability in a cogeneration plant is cost effective in the Swedish grid (Köhler, 1975, p. 4). As a result, the condensing capability often observed in the large cogeneration plants used in district heating is observed in industry only in very large units. Even dump condensers are not common.3

3Where they are employed, it is to meet local ordinances about noise pollution.
Furthermore, the large industrial cogeneration plants with condensing capability are rarely used in a condensing mode. For example, two of the largest industrial cogeneration turbines in Sweden, those at Stora Kopparberg's Kvarnsveden and Skutskär plants, have not used their condensing capability to produce real power since the dry year of 1969. That was before Stora Kopparberg's shares in the Aroskraft, Karlshamn, and Oskarshamn installations gave it more efficient centralized condensing power. Krängede's Karskär plant has run in a condensing mode for only about 1000 hours since it was commissioned in 1972. Industrial-sized condensing plants, even relatively new ones like those in Stora Kopparberg and Krängede, simply cannot compete in the national power market with these more efficient, centralized machines. Stora Kopparberg's machines are now used only to regulate reactive power in its system. The distinct possibility exists that they will never provide real power again.

In sum, despite the presence of condensing capacity in Swedish industry, in straight condensing turbines and cogeneration turbines, Swedish industry rarely produces condensing power. Under normal circumstances, all its power production comes from cogeneration.

Changes as Cogeneration Plants Grow

Finally, the configuration of plants tends to change as the plants get larger. Table 4 shows that larger cogeneration installations have more units as well as larger units; a quadrupling in installation size doubles number of units and unit size. Given the scale economies in cogeneration, the willingness to forgo these economies as demand for capacity grows suggests that some economies result from increasing the number of units at an installation.

Local reliability is one possible source of cost savings. Increasing the number of units used to provide a given amount of capacity increases the reliability of a portion of that load. The grid can provide a given level of reliability at lower cost by pooling the risk of failure at any particular installation with that at many others. Hence, the pursuit of local reliability could raise doubts about the price the grid charges to provide reliability.

A more likely explanation is that the number and size of cogeneration units are a product of the history of each cogeneration installation. At any site, cogeneration is added incrementally to exploit a growing heat load. The median length of time between commissioning dates for units at Swedish installations with two or more units is twelve years. In addition, the size of unit chosen has grown by an average of 3.5 percent per year, which shows that the installations are recognizing scale economies in the technology and cost reductions in the grid over time. Adding units incrementally reduces the scale economies a firm can exploit but also reduces the divergence between the firm's desired and actual cogeneration capacity over time by adjusting the actual to the desired more often. Where possible, firms attempt to exploit scale economies. Hence, if large and small installations grow at the same rates—and they appear to—larger installations will tend to prefer larger units. That is what we observe.

These three features of cogeneration prevail in Swedish industry, regardless of the specific

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4. Stora Kopparberg continues to use these plants to meet its reactive power requirements.
5. The average is 13.4 years. These statistics are based on 37 differences for commissioning dates from 1913 to the present.
6. U.S. utilities experience the same problem, but are increasingly resolving it by cooperating with one another to stagger plant additions and coordinate short term power surpluses and deficits. Such cooperation is complicated in cogeneration by the difficulty of transporting heat between plants.
industry we observe. Nonetheless, the application of cogeneration differs significantly across industries.

USE IN SPECIFIC INDUSTRIES

Swedish industry uses cogeneration in many different applications. Sweden pursues most of the major manufacturing activities we typically observe in modern industrialized economies, and some cogeneration occurs in most of these activities. Table 5 provides some basic statistics on Swedish industry and its use of energy. It shows that while the manufacture of machinery—industrial equipment, vehicles, aircraft, and other high technology goods—dominates the Swedish manufacturing sector, wood products, including paper and pulp, dominate Swedish industrial use of energy. Taken together, chemicals, iron and steel, and paper and pulp account for almost three-quarters of Swedish industrial energy use and over two-thirds of Swedish industrial electricity use. Each of these uses cogeneration in Sweden; pulp and paper is by far the most important user.

Table 5

<table>
<thead>
<tr>
<th>Industrial Sector</th>
<th>Percent of Total Manufacturing Production, 1975</th>
<th>Percent of Total Industrial Energy Use, 1974</th>
<th>Percent of Total Industrial Electricity Use, 1975</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wood industries except (a) paper and pulp</td>
<td>7.5</td>
<td>45.5</td>
<td>(d)</td>
</tr>
<tr>
<td>and (b) printing and publishing</td>
<td>12.0</td>
<td>.4</td>
<td>32.6</td>
</tr>
<tr>
<td>Paper and pulp</td>
<td>12.0</td>
<td>6.9</td>
<td>14.0</td>
</tr>
<tr>
<td>Printing and publishing</td>
<td>5.7</td>
<td>9.0</td>
<td>20.4</td>
</tr>
<tr>
<td>Chemicals, petroleum, rubber and plastics</td>
<td>3.5</td>
<td>9.8</td>
<td>2.3</td>
</tr>
<tr>
<td>Iron, steel, and other metals</td>
<td>6.1</td>
<td>3.7</td>
<td>2.2</td>
</tr>
<tr>
<td>Earth, stone, and nonmetallic minerals</td>
<td>4.6</td>
<td>1.4</td>
<td>12.2</td>
</tr>
<tr>
<td>Mining and quarrying</td>
<td>4.6</td>
<td>1.4</td>
<td>12.2</td>
</tr>
<tr>
<td>Machinery (&quot;engineer&quot;)</td>
<td>8.4</td>
<td>4.5</td>
<td>6.1</td>
</tr>
<tr>
<td>Food processing</td>
<td>3.1</td>
<td>.7</td>
<td>10.0</td>
</tr>
<tr>
<td>Textiles</td>
<td>3.1</td>
<td>.7</td>
<td>10.0</td>
</tr>
<tr>
<td>Other manufacturing</td>
<td>3.1</td>
<td>.7</td>
<td>10.0</td>
</tr>
<tr>
<td>Total</td>
<td>100.0</td>
<td>100.0</td>
<td>100.0</td>
</tr>
</tbody>
</table>

aSkandinaviska Enskilda Banken, 1979, p. 21.
bStatens Industridepartementet, 1978, p. 149.
cÅngpanneföreningen, 1978.
dIncluded with "Other manufacturing."

The Swedes call this "engineer."

Other sources, using different measurement methods, offer different measures of paper and pulp's share of energy use. For example, Norström, Widell, and Wohlfahrt (1977) find a share for 1973 of 40 percent, 22 percent of which is provided within the industry. Ångpanneföreningen (1978), when corrected for internal generation of energy, suggests a share of 31.4 percent. In all cases, pulp and paper dominates industrial use of energy.

Näringslivets Stifelse för Forskning och Utveckling på Energimrådet (1979) confirms these magnitudes.
Pulp and Paper

Paper and pulp accounts for 87 percent of all generation capacity in Swedish industry and about the same percent of its cogeneration capacity (see Tables 6 and 7). On average, it employs units at least twice as large as those used in the rest of the industry. Furthermore, we can expect pulp and paper applications to dominate future use of cogeneration as well. A recent, widely respected study suggests that they account for 80 percent of the industrial generating capacity that would be desirable by 1985 and 76 percent of the total potential for backpressure turbines in Swedish industry.\(^\text{10}\)

A number of factors help explain this dominance. First, as noted in Table 5, pulp and paper accounts for about 40 percent of total industrial demand for energy and 33 percent of industrial demand for electricity. Second, the Swedish pulp and paper industry is familiar with cogeneration. It has generated its own power since the last century. The industry employed literally hundreds of cogeneration steam turbines in the 1930s, before rationalization. Third, and most important, the production processes used in the pulp and paper industry are compatible with cogeneration. These processes (a) have an appropriate steam demand, (b) produce cheap usable waste fuels, and (c) display great enough scale economies to make cogeneration cost effective. An examination of the manufacturing processes used to produce pulp and paper will reveal the importance of each of these three points.

The pulp and paper industry produces a variety of products with a number of different techniques. Table 8 presents the industry’s production for 1978, broken down in various categories of pulp, paper, and board. The categories of pulp are effectively different techniques used for producing pulp from wood; each technique produces a different kind of product.\(^\text{11}\) Pulp is either used to make paper or board or sold as “market pulp” to someone else who wants to make paper or board. Where pulp is converted on-site to another product, the mill is called an “integrated” mill. Such mills accounted for 91 percent of total capacity in the paper/board segment of the industry in 1972.\(^\text{12}\) As we shall see, pulp mills, integrated paper mills, and nonintegrated paper mills demand different amounts of cogeneration. Different types of pulp and paper also call for different amounts of cogeneration.

The prototypical cogeneration installation in pulp and paper is located at a chemical pulp mill. Figure 4 illustrates such an arrangement. The pulp production process is shown at the left. It combines wood, electric energy, low pressure steam, and chemicals to produce chemical pulp, bark and wood residuals, chemicals and spent liquor, losses, and perhaps heat for district heating. The process requires steam at 4 and 10 bar, pressures that are ideal for a cogeneration steam turbine.\(^\text{13}\) Because steam is best generated at high temperatures and pressures, a demand for low pressure steam opens the opportunity to generate high pressure steam and reduce its pressure through a turbine, thereby producing electricity. That is the essence of steam turbine cogeneration and that is what we observe happening on the right in Fig. 4. Two

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\(^{10}\)See Table 7 for the details of that study relevant to this report.

\(^{11}\)Dissolving, sulfite and sulfate pulps are different forms of “chemical” pulps and are typically contrasted with mechanical pulp. Where chemical processes are used to form chemical pulp from wood fibers, mechanical processes are used to form mechanical pulp. "Semi-chemical" pulps result from a combination of these processes.

\(^{12}\)This included 12 percent of capacity combined with mechanical pulp mills, 51 percent with chemical, and 27 with some of each. Nonintegrated paper and board mills typically produced fine or creped paper and board or paperboard. The integrated mills produced standardized newsprint, magazine paper, or kraft paper and liner on a large scale. Table 8 suggests that about 44 percent of pulp is sold to another company who then makes it into paper or board. This fraction varies markedly from one kind of pulp to another. Of the pulp that mills do not sell, about 80 percent is used on-site in an integrated paper mill. The mill owner uses the remaining 20 percent at a paper mill that he owns elsewhere (Svenska Cellulosa- och Pappersbruksföringen, 1973).

\(^{13}\)Steam at one pressure, 10 bar, is extracted, for example, to heat kraft pulp. That at the other, from the turbine exhaust, evaporates liquor, dries chips, paper, and pulp; and heats buildings.
### Table 6

**Thermal Generating Capacity in Swedish Industry, 1979**

<table>
<thead>
<tr>
<th>Industry</th>
<th>Installations</th>
<th>Diesels</th>
<th>Condensing</th>
<th>Cogeneration</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>No.</td>
<td>MW</td>
<td>MW/No.</td>
<td>No.</td>
</tr>
<tr>
<td>Pulp and paper</td>
<td>65</td>
<td>946.0</td>
<td>14.55</td>
<td>0</td>
</tr>
<tr>
<td>Sawmills</td>
<td>7</td>
<td>5.9</td>
<td>.84</td>
<td>0</td>
</tr>
<tr>
<td>Sugar refining</td>
<td>9</td>
<td>56.7</td>
<td>6.3</td>
<td>2</td>
</tr>
<tr>
<td>Other food processing</td>
<td>3</td>
<td>1.5</td>
<td>3</td>
<td>0</td>
</tr>
<tr>
<td>Chemicals</td>
<td>13</td>
<td>27.8</td>
<td>2.14</td>
<td>9</td>
</tr>
<tr>
<td>Petroleum refining</td>
<td>1</td>
<td>1.3</td>
<td>1.3</td>
<td>6</td>
</tr>
<tr>
<td>Glass, porcelain</td>
<td>3</td>
<td>1.1</td>
<td>.37</td>
<td>3</td>
</tr>
<tr>
<td>Textiles, leather</td>
<td>6</td>
<td>16.2</td>
<td>2.7</td>
<td>1</td>
</tr>
<tr>
<td>Iron and steel</td>
<td>4</td>
<td>15.7</td>
<td>3.93</td>
<td>3</td>
</tr>
<tr>
<td>Machinery, equipment</td>
<td>7</td>
<td>7.5</td>
<td>1.11</td>
<td>6</td>
</tr>
<tr>
<td>Other manufacturing</td>
<td>5</td>
<td>2.4</td>
<td>.48</td>
<td>4</td>
</tr>
<tr>
<td>Communications</td>
<td>6</td>
<td>1.9</td>
<td>.32</td>
<td>10</td>
</tr>
<tr>
<td>Transportation</td>
<td>10</td>
<td>3.5</td>
<td>.35</td>
<td>22</td>
</tr>
<tr>
<td>Shipyards</td>
<td>1</td>
<td>2.0</td>
<td>2.0</td>
<td>3</td>
</tr>
<tr>
<td>Publishing</td>
<td>1</td>
<td>.9</td>
<td>.9</td>
<td>3</td>
</tr>
<tr>
<td>Wholesaling</td>
<td>1</td>
<td>.8</td>
<td>.8</td>
<td>4</td>
</tr>
<tr>
<td>Mining</td>
<td>1</td>
<td>.6</td>
<td>.6</td>
<td>1</td>
</tr>
<tr>
<td>Agriculture</td>
<td>1</td>
<td>.1</td>
<td>.1</td>
<td>1</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>144</td>
<td>1092.2</td>
<td>7.58</td>
<td>78</td>
</tr>
</tbody>
</table>

**Source:** Calculated from data compiled by Bergman & Co.
### Table 7

**Backpressure Capacity: Results of the Ångpanneforeningen Study of April 1976**

<table>
<thead>
<tr>
<th>Industry</th>
<th>No. of Industrial Plants Examined</th>
<th>Backpressure Capacity in 1975 (MW)</th>
<th>Additional Backpressure Capacity that Could be Cost-effective by 1985 (MW)</th>
<th>Total Potential for Backpressure Capacity in the Industry (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pulp and paper</td>
<td>73</td>
<td>650</td>
<td>700</td>
<td>1350</td>
</tr>
<tr>
<td>Agriculture and stone</td>
<td>12</td>
<td>—</td>
<td>3</td>
<td>7</td>
</tr>
<tr>
<td>Food processing, except sugar refining</td>
<td>37</td>
<td>8</td>
<td>3</td>
<td>15</td>
</tr>
<tr>
<td>Sugar refining</td>
<td>8</td>
<td>43</td>
<td>23</td>
<td>66</td>
</tr>
<tr>
<td>Chemicals, except rubber</td>
<td>57</td>
<td>26</td>
<td>52</td>
<td>129</td>
</tr>
<tr>
<td>Rubber</td>
<td>9</td>
<td>—</td>
<td>10</td>
<td>30</td>
</tr>
<tr>
<td>Petroleum refining</td>
<td>5</td>
<td>—</td>
<td>34</td>
<td>69</td>
</tr>
<tr>
<td>Iron and steel</td>
<td>33</td>
<td>25</td>
<td>50</td>
<td>125</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>234</td>
<td>752</td>
<td>875</td>
<td>1781</td>
</tr>
</tbody>
</table>

### Table 8

**Disaggregation of Pulp and Paper Industry Production, 1978**

<table>
<thead>
<tr>
<th>Product</th>
<th>Total Output</th>
<th>Output for Sale&lt;sup&gt;a&lt;/sup&gt;</th>
<th>Output Exported&lt;sup&gt;b&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Tons</td>
<td>%</td>
<td>% of Output for Sale</td>
</tr>
<tr>
<td>Pulp, total</td>
<td>8557</td>
<td>60.0</td>
<td>3766</td>
</tr>
<tr>
<td>Mechanical</td>
<td>1748</td>
<td>12.3</td>
<td>393</td>
</tr>
<tr>
<td>Semi-chemical</td>
<td>351</td>
<td>2.5</td>
<td>25</td>
</tr>
<tr>
<td>Dissolving</td>
<td>231</td>
<td>1.6</td>
<td>231</td>
</tr>
<tr>
<td>Bleached sulfite</td>
<td>635</td>
<td>4.5</td>
<td>481</td>
</tr>
<tr>
<td>Unbleached sulfite</td>
<td>374</td>
<td>2.6</td>
<td>94</td>
</tr>
<tr>
<td>Bleached sulfate</td>
<td>2945</td>
<td>20.7</td>
<td>2116</td>
</tr>
<tr>
<td>Unbleached sulfate</td>
<td>2273</td>
<td>15.9</td>
<td>420</td>
</tr>
<tr>
<td>Paper, total</td>
<td>3940</td>
<td>27.6</td>
<td>3940</td>
</tr>
<tr>
<td>Newprint</td>
<td>1258</td>
<td>8.8</td>
<td>1258</td>
</tr>
<tr>
<td>Magazine</td>
<td>367</td>
<td>2.6</td>
<td>367</td>
</tr>
<tr>
<td>Kraft</td>
<td>1074</td>
<td>7.5</td>
<td>1074</td>
</tr>
<tr>
<td>Tissue</td>
<td>207</td>
<td>1.5</td>
<td>207</td>
</tr>
<tr>
<td>Sulphite</td>
<td>23</td>
<td>.2</td>
<td>23</td>
</tr>
<tr>
<td>Greaseproof and glassine</td>
<td>20</td>
<td>.1</td>
<td>20</td>
</tr>
<tr>
<td>Fine</td>
<td>557</td>
<td>3.9</td>
<td>557</td>
</tr>
<tr>
<td>Other</td>
<td>434</td>
<td>3.0</td>
<td>434</td>
</tr>
<tr>
<td>Board, total</td>
<td>1762</td>
<td>12.4</td>
<td>1762</td>
</tr>
<tr>
<td>Kraftliner</td>
<td>921</td>
<td>6.5</td>
<td>921</td>
</tr>
<tr>
<td>Other</td>
<td>841</td>
<td>5.9</td>
<td>841</td>
</tr>
<tr>
<td>Total</td>
<td>14259</td>
<td>100.0</td>
<td>9468</td>
</tr>
</tbody>
</table>


<sup>a</sup>All paper and board is assumed to be produced for final sale. While some of these products are converted into paper products onsite, this practice is relatively rare.

<sup>b</sup>Export figures for pulp were unavailable for 1978. The share in this column for pulp is the 1972 export share. Tons of output exported is estimated by applying this share to the output for sale.

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Boilers generate high-pressure steam which is used to generate power and low pressure steam for the pulping process. The type of boilers used to produce this steam introduces our supply of waste fuels.

The pulping process yields cheap fuels that can heat the steam. Two fuels are important. First, bark and wood residuals have no other use; if they were not burned, they would have to be carried away. Hence, the heat from this combustion has a negative cost. Second, the pulping process yields chemicals and spent liquors. The chemicals include sulfates or sulfites, depending on the process used. Sulfates must be recovered and reused to make pulping economical. Sulfites must be recovered for environmental reasons. Today, the easiest way to

---

<sup>14</sup>This is not quite correct; some bark and wood residuals can remain in the pulp if a high-quality pulp is not required. Hence, a potential opportunity cost for this waste is its value as a constituent in lower quality paper. While not important now, this may become important in the future.
Fig. 4—A schematic flow diagram of energy and chemicals in a chemical pulp mill.

do this is to concentrate the liquor where they reside after use and to burn it.13 Today, bark
and black liquor provide about 60 percent of the fuel used in Swedish pulp and paper (Schipper

These two technological reasons for cogeneration’s attractiveness in pulp and paper—the
presence of the right steam demands and the generation of cheap fuel—do not carry over
completely to other processes in the industry. In particular, we expect processes with lower heat
demands and/or less production of waste fuels to (a) be less likely to use cogeneration on-site,
(b) produce a smaller share of their own power demand, (c) have smaller ratios of cogeneration
capacity pulp and paper output, and (d) use less cogeneration capacity per unit of additional
output. Table 9 provides measures of (a), (c), and (d).14 Table 10 provides measures of (b).

For example, by the criteria above, nonintegrated chemical pulping should be more compat-
ible with cogeneration than nonintegrated mechanical pulp. Tables 9 and 10 reveal several
facts: In recent years chemical pulping (a) has been more likely to have cogeneration (16 of 19
installations versus 1 of 4); (b) has produced a higher fraction of plant power demand (.42 to
.58 percent versus none); and (c) has used more cogeneration capacity per ton of output (.0843
versus .0050 MW/ton).17 Tables 9 and 10 similarly support the predictions that chemical-based
integrated mills should use more cogeneration than mechanical-based mills,18 and that
chemical pulp mills should use more cogeneration than nonintegrated paper mills.19 Use of
cogeneration, then, appears to be strongly affected by heat load and production of waste fuels.

Table 9 also gives us some insights into the effect of scale on demand for cogeneration in
the pulp and paper industry. Small demand densities discourage the use of cogeneration in pulp
and paper. At first, the relatively high coefficients of variation within each production category-
cogeneration cell (most around .65 but some as high as 1.25) suggest great variety in the
production capacity, with and without cogeneration. Certainly, there is no minimum produc-
tion level within each production category below which cogeneration is not used. But the
"t-value for P_{wth} - P_{wo} " column in Table 9 measures the significance of differences, within each
production category, in mean production capacities for mills with cogeneration (P_{wth}) and
without (P_{wo}). Though none of the individual tests has many degrees of freedom and degrees of
freedom differ from one test to the next, the general pattern is clear. Significant differences
exist in almost every case.20

In sum, a great deal of diversity exists in the Swedish pulp and paper industry and that
diversity leads to predictable differences in the use of cogeneration within the industry. When
we move to other industries, diverse circumstances should induce even greater variation in the
use of cogeneration.

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13The liquor burns because it contains lignin, the binding agent in living wood. Lignin has alternative uses both
as a chemical feedstock and as a constituent in paper (Holmens Bruk, 1975). That is, nonchemical pulping processes
can retain the lignin, which accounts for about half the content of wood by weight, in pulp that can then be used to
make lower quality papers. The value of the lignin in this role must be weighed against its value as a fuel to (a) recover
chemicals and (b) heat steam for cogeneration.

14The number for point (d) is calculated by regressing cogeneration capacity (c_r) on production (p_r) for each process
type (i = 1, ..., 6):

   c_r = \alpha_i + \beta p_r + \mu_i + \mu_r \sim N(\Omega, \sigma)

15Point (d) is not defined for this comparison.

16To make this comparison in Table 10, compare the integrated kraftliner mill, which uses chemical sulphate pulp,
with the integrated newsprint mill, which uses chemical and mechanical pulps. The relevant comparisons are (a) 15
of 16 versus 9 of 12; (b) .28 versus .17; (c) .0495 versus .0270; and (d) .0576 versus .0338.

17(a) 15 of 19 versus 12 of 24; (b) .42 to .58 versus .20; (c) .0843 versus .0576; and (d) .126 versus .0626.

20No difference exists for mechanical pulp, but for all intents and purposes, this production category has no
cogeneration anyway. The fact that the manufacture of hard board requires steam at a higher pressure than the other
processes represented in Table 9 may help explain the relatively low significance of the difference for board production
### Table 9

**Pulp and Paper Production With and Without Cogeneration, 1979**

<table>
<thead>
<tr>
<th>Production Category</th>
<th>Installations with Cogeneration</th>
<th>Installations Without Cogeneration</th>
<th>( \frac{dC}{dP_{\text{with}}} )</th>
<th>( \bar{C} )</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Tons of Production (( P_{\text{with}} ))</td>
<td>MW of CHP Capacity (( C ))</td>
<td>t-value for ( P_{\text{with}}/P_{w/o} )</td>
<td>Estimate of Mean Difference from Zero</td>
</tr>
<tr>
<td>Nos.</td>
<td>Mean</td>
<td>s.d.</td>
<td>No.</td>
<td>Mean</td>
</tr>
<tr>
<td>Chemical pulp</td>
<td>16</td>
<td>176.7</td>
<td>106.9</td>
<td>14.9</td>
</tr>
<tr>
<td>Mechanical pulp</td>
<td>1</td>
<td>100.0</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Integrated, chemical base</td>
<td>15</td>
<td>426.9</td>
<td>251.7</td>
<td>21.1</td>
</tr>
<tr>
<td>Integrated, mechanical base</td>
<td>9</td>
<td>484.0</td>
<td>336.1</td>
<td>13.0</td>
</tr>
<tr>
<td>Paper</td>
<td>12</td>
<td>107.0</td>
<td>117.2</td>
<td>6.2</td>
</tr>
<tr>
<td>Board</td>
<td>4</td>
<td>97.5</td>
<td>58.9</td>
<td>1.4</td>
</tr>
</tbody>
</table>

**SOURCE:** Bergman & Co; Arvidsson (1979); Svenska Cellulosa- och Pappersbruksföreningen, 1973.
Table 10  
AVERAGE ENERGY CONSUMPTION IN SWEDISH PAPER AND PULP, 1973

<table>
<thead>
<tr>
<th>Production Category</th>
<th>Steam(loe/t\text{\textdegree}90)</th>
<th>Electric Energy(kwh/t\text{\textdegree}90)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>From Waste Fuels</td>
<td>Share of Waste Fuels</td>
</tr>
<tr>
<td>Nonintegrated chemical pulp</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Unbleached sulphate</td>
<td>530</td>
<td>.81</td>
</tr>
<tr>
<td>Bleached sulphate</td>
<td>570</td>
<td>.75</td>
</tr>
<tr>
<td>Unbleached sulphite</td>
<td>390</td>
<td>.44</td>
</tr>
<tr>
<td>Bleached sulphite</td>
<td>500</td>
<td>.61</td>
</tr>
<tr>
<td>Nonintegrated mechanical pulp</td>
<td>99</td>
<td>.09</td>
</tr>
<tr>
<td>Integrated paper mills</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kraftliner</td>
<td>510</td>
<td>.71</td>
</tr>
<tr>
<td>Newsprint</td>
<td>310</td>
<td>.26</td>
</tr>
<tr>
<td>Nonintegrated paper mills</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fine paper</td>
<td>280</td>
<td>.04</td>
</tr>
<tr>
<td>Tissue paper</td>
<td>350</td>
<td>—</td>
</tr>
<tr>
<td>Cardboard</td>
<td>270</td>
<td>.07</td>
</tr>
</tbody>
</table>

NOTE: loe = litres of oil equivalent.  
t\text{\textdegree}90 = tons of 90 percent dry product.

Industries Other Than Pulp and Paper

The remaining 12 percent of Swedish industry’s cogeneration is scattered across a variety of applications. A quick overview of these applications reveals considerable variety.\footnote{21}

Sugar Refining. The nationally owned Svenska Sockerfabriks AB dominates Sweden’s processing of sugar beets into sugar. Although cogeneration units in sugar refining are somewhat older than average in Swedish industry, they are still second largest. Power generation is distinguished by the industry’s unusual seasonal pattern of production; cogeneration units operate at full load only during a production period of three months and are idle for the rest of the year.

Other Food Processing. Other food processing industries use little cogeneration. The existing turbines are the last machines remaining from the 1930s and early 1940s when cogeneration was much more common in the industry. The food processing industry had about 50 small (typically 200 kW) turbines in the 1930s. Rationalization of the industry has consolidated many of the small plants using cogeneration and with them, their power demands. Ironically, the scale at which cogeneration is efficient in the industry has increased even faster than the scale of processing plants. As a result, though many heat demand densities of about

\footnote{21}{Because of the low density of cogeneration outside the pulp and paper industry, this presentation does not attempt the sort of numerical comparison used for pulp and paper.}
1 MW can be identified in the dairy, meat, and other processing industries, these industries have opted to buy rather than produce power.

**Chemicals.** The chemical industry uses cogeneration in the manufacture of products as diverse as ammunition, pharmaceuticals, and glue. Two applications in sulfuric acid plants illustrate the diversity that is possible in this industry. Stora Kopparberg's 800 kW turbine at Falun is an old one and delivers its heat internally. Boliden AB's 7.5 MW turbine, commissioned in 1974, is part of the move toward combining industrial and district heating applications of cogeneration. Waste heat from the manufacture of sulfuric acid produces steam, which in turn generates power and heat for Boliden and the town of Helsingborg. The plant provides heat and power on a baseload basis (Svenska Värmeverksföreningen, 1979).

**Iron and Steel.** The iron and steel industry is emphasizing the use of large district heating applications not included in Tables 6 and 7. The Granges cogeneration plant at Svenskt Stål's Oxelösund steel mill dominates cogeneration in the industry. Built originally as a condensing plant with 69 MW(e), it was converted in 1978 to a cogeneration unit with 40 MW(e), 130 MW(th) in the pure cogeneration mode. The plant uses waste blast furnace gas to generate steam, which in turn produces power and heat for Svenskt Stål and the town of Oxelösund. Svenskt Stål is currently planning a similar 80 MW(e) 170 MW(th) combination cogeneration-condensing plant for its steel mill in Luleå. A company, owned half by Svenskt Stål and half by Luleå, will own the plant. It will produce process heat and heat for the town of Luleå. Unfortunately, few Swedish steel mills are located near towns large enough to exploit their waste heat for district heating.22

**Petroleum Refining.** Petroleum refining uses little cogeneration now, but Table 7 suggests that it has a significant potential for cogeneration in the future. Two important projects are now under way to install cogeneration. One is a 15 MW gas turbine to be fired by refinery gas at the British Petroleum refinery in Göteborg; the exhaust heat from the gas turbine generates process steam for the refinery.23 The other is a 10 MW steam turbine fired by refinery gas at the Shell refinery in Göteborg; it delivers heat to Göteborg's district heating grid. The new gas turbine is an innovation not only in petroleum refining but also in Swedish industry as a whole.

In addition, a form of cogeneration not typically reported in statistics is quite common in Swedish petroleum refining. The industry has several hundred small units that use steam to generate heat and direct shaft power. By avoiding the generation of electricity, such units avoid a tax that must be paid on electricity generation. Avoiding the tax more than makes up for the additional inconvenience created by the absence of flexible electrical power.24

Industries other than pulp and paper, then, display a variety of scales, load durations, heat loads, waste fuels, and so on. And, predictably, this variety leads to a greater diversity of cogeneration application than we observed in the pulp and paper industry. But the interconnection with the grid, use of steam turbines and dominance of cogeneration in self-generation that we observed in pulp and paper persist almost without exception in other industries.

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22 More traditional industrial cogeneration is not common in the industry. Sandvik AB and Fagersta AB have considered more traditional cogeneration and apparently only concluded that they prefer steam turbines to gas turbines or diesels. The Statens Industrieverk recently awarded Surahammers Bruk AB a grant to cover half the construction costs of a new cogeneration turbine. It will use blast furnace gas now being burned for heating or simply flared into the atmosphere to generate heat that will drive a cogeneration turbine.

23 Another installation at the British Petroleum refinery delivers waste heat from the refinery to a nearby Volvo manufacturing plant. It is unrelated to the new cogeneration installation.

24 Cogeneration is not the only source of such shaft power. Hydro turbines sometimes produce direct shaft power, again, simply to avoid the tax. Stora Kopparberg, for example, produces about 100 million kWh of shaft power per year from hydro turbines.
SUMMARY

Swedish industry uses cogeneration in a wide variety of applications. Though most cogeneration capacity resides in the pulp and paper industry, it also appears in a diverse variety of chemical and food processing applications, and shows potential in a variety of iron and steel and petroleum refining applications. Even within pulp and paper, the use of cogeneration changes markedly and predictably as we move from one production process to another. Taken together, these cogeneration applications display significant variations in local industrial demand for energy, scale of cogeneration units and installations, industrial and district heating loads, and availability and use of waste fuels.

Despite this diversity, Swedish industrial cogeneration displays overriding commonalities wherever it occurs. It is always interconnected to the national grid. It is always owned by industry. One installation never serves more than one industrial heat load. With minor, effectively experimental, exceptions, industrial cogeneration always uses a steam topping cycle. While it may be collocated with condensing and diesel units, cogeneration provides nearly all industrial production of electricity during normal years. Even installations with significant condensing capacity, often integrated into cogeneration units themselves, use that condensing capacity only in abnormally dry years. Many in Swedish industry believe that the growing importance of nuclear capacity in the grid may make it unnecessary to use any industrial condensing capacity in the future.

These commonalities are all consistent with a system of pricing that allows Swedish industry to weigh the costs of cogeneration on equal terms with other sources of electricity in the Swedish grid. Consider a few hypotheses. Cogeneration dominates other forms of generation in industry because all others are best exploited in the larger scales that centralized plants allow. The steam topping cycle dominates all others because interconnection with the grid eliminates the need to match local heat and power loads. Industrial energy centers are not attractive for the same reason. These hypotheses are attractive only if the Swedish power supply system provides industrial firms with appropriate electricity prices. That is the focus of the next section.
V. THE STRUCTURE OF ELECTRICITY PRICES AND COSTS RELEVANT TO INDUSTRIAL COGENERATION

Sweden’s electric power supply system uses a mix of market and administrative pricing. Bulk power is produced and exchanged in a highly competitive environment facilitated by the national power grid and a formal national power market. Below the bulk supply system, Sweden places greater reliance on administrative pricing mechanisms guided by a widely accepted doctrine of marginal cost pricing and a deterrent form of regulation. The supply system as a whole is coordinated through a diverse array of contracts. This section describes the principal types of contracts used and their structural relationships to costs in the Swedish power system. It emphasizes contracts relevant to the integration of industrial power supply into the general supply system.

BULK POWER SUPPLY SYSTEM

The fifteen or so largest power producers in Sweden, some of them industrial firms, produce, transmit, and exchange power in a highly competitive environment. Although they regularly interact with one another bilaterally, three specific institutions act as foci to coordinate their activities: the national power grid, the national power market, and a major power pool, Kranegadegruppens Samkorningsforetag.

The National Power Grid

As noted in Section III, the national power grid includes all transmission lines 220 kV and larger in Sweden. Statens Vattenfallsverk, which has supervised the operation of this grid since 1946, leases the grid’s capacity to individual power producers each year. Anyone with over 5 kilowatts of productive capacity can interconnect to the grid, but power is typically traded in 1-megawatt blocks in the grid. Further, the annual fixed fee for leasing a portion of the grid is so high that fewer than twenty firms actually lease capacity on the system. A number of these are industrial firms.¹ Other firms rely on the 130 kV grid and on contracts with these “members” of the national grid for transmission.

The lease contract Statens Vattenfallsverk offers members of the national grid is relatively restrictive. First, no subleases are allowed. If a member’s needs for capacity at any time depart from the capacity it has leased, it can buy or sell capacity on a spot basis, but only by dealing with Statens Vattenfallsverk. According to Statens Vattenfallsverk subleasing could reduce its effective control of the national grid to the point that the grid’s reliability would be threatened.

Second, although third party wheeling is available on the grid, for a price, members of the

¹The industrial firms include Stora Kopparberg and the industrial owners of Krånged, all discussed in Section III.
grid only use second party wheeling. The national power grid, then, enhances the ability of firms to move power within their own systems but does not effectively expand the number of firms with whom any producer can exchange power.

Within these restrictions, the contract for second party wheeling is remarkably simple and consists of two charges: an annual fixed charge, independent of the extent of use, and an annual capacity-distance charge. The charge applies to a customer's right to use a given number of megawatt-kilometers at any instant. That is, at any given time, it is possible to calculate a sum

\[
C = \sum_{i} \sum_{j} k_{ij} \text{MW}_{ij}
\]

where \(k_{ij}\) is the distance in kilometers between points \(i\) and \(j\) on the national grid, and \(\text{MW}_{ij}\) is the capacity in megawatts required between points \(i\) and \(j\). The annual capacity-distance charge corresponds to a set level of \(C\) which may not be exceeded during the contract period. Statens Vattenfallsverk negotiates the levels of these two charges with each customer separately and secretly each year. The resulting contract includes no energy charge. Each customer uses a simple loss algorithm to determine how much power it loses between points of shipment. It then puts enough power in at its entry point to cover losses and its demand at the exit point.

Although relatively few firms use the national power grid directly, many others benefit from it. The most direct way this occurs is in a forward freight consolidation service that grid members provide to smaller power producers. For a fee more in keeping with a small customer’s ability to pay—defined in fixed, capacity-kilometer, and energy components and special fees for voltage transformation—the consolidator takes delivery of the customer’s power at a point within the consolidator’s system, ships it on the national grid under its imprimatur to another point within its system, and returns it to the small customer. Like Statens Vattenfallsverk, grid members restrict such contracts to second party wheeling.

More generally, by allowing members to exploit scale economies of high voltage transmission that none of them could achieve individually, the grid permits members to locate their power production and demand centers in more advantageous places. To the extent that the cost savings the grid allows within its member-firms are reflected in their bilateral relationships with nonmembers, these nonmembers garner benefits from the grid despite their exclusion.

The National Power Market

Like the national grid, the national power market basically consists of exchange contracts between Statens Vattenfallsverk and its "members," the firms allowed to participate. Membership differs slightly between the two institutions. A producer must be able to cover its own firm demands in a dry year to exchange power in the national power market. This criterion is tested at the beginning of each year. It restricts membership to about fifteen firms, four of them industrial. Most but not all are also members of the national grid.

Contracts differ little in form from those executed between any two contiguous producers,

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2In second party wheeling, a firm transmits power over the grid from one point in its system to another; the grid is a second party to the transmission. Third party wheeling transmits power over the grid from one firm to another, making the grid a third party to the transmission.

3Violations of this level automatically increase the size of the user's contract and hence its annual charge. Users do not violate their contracts voluntarily. They recontract as necessary in the spot market for capacity.

4Stora Kopparberg's Kraftverken, Gränges Kraft, Avesta Jernverks AB, and Krängede. Avesta is an iron and steel firm; Section III describes the others.
but the right to exchange power with Statens Vattenfallsverk gives a producer access to the most complete market in the country. Through the national grid, Statens Vattenfallsverk can deal with every major producer in the country. Hence, through the national power market, Statens Vattenfallsverk can provide the wheeling that producers have chosen not to pursue under the third party wheeling contracts offered in the national grid. It provides such wheeling not by acting as a third party, but by coordinating bilateral agreements between itself and other firms and their fulfilling them by wheeling power under its own imprimatur.

Industrial bilateral contracts in the national power market can become quite complex, including many individual components, each designed to deal with a different cost of service or contingency. But the most common exchange is one with only an energy component.\(^5\) The charge is equal to the arithmetic mean of the member’s system or installation marginal cost and the relevant price in the national market. Most contracts use the “T-price,” based on agreements made as little as two hours before exchange, or the “G-price,” based on agreements made a week or so ahead. The further ahead an agreement can be made, the more attractive the national market becomes, reflecting Statens Vattenfallsverk’s ability to adjust its production and other contracts to meet the contract in question. Whatever the national market price, however, Statens Vattenfallsverk and the customer each take half the difference between their “costs.” This allows Statens Vattenfallsverk to share directly in the cost savings that such exchanges allow in a way that it cannot through its stewardship of the national power grid.

Krångedegruppens Samkörningsföretag (KGS)\(^6\)

KGS is a power pool which coordinates the power production of Krångede, its owners, Stora Kopparberg, and Gullspång AB,\(^7\) which together account for about 35 percent of Sweden’s capacity. KGS centrally dispatches this capacity on a routine daily basis, effectively acting as a broker among its members and between them and Statens Vattenfallsverk in the national power market.

Because each member of KGS must deal with Statens Vattenfallsverk separately in the national grid, KGS must work around the company-specific capacity constraints in the national grid. To do so, KGS uses a model to optimize the KGS system as a whole each day and checks for any violations in capacity-distance constraints. If any exist, it reoptimizes the system subject to these active constraints and uses this second optimization to dispatch the system. It then monitors the system every three seconds to assure that no constraints are violated and dispatches power minute-to-minute accordingly. This coordinated dispatch allows KGS members to meet their national grid contracts in the most jointly advantageous fashion. By coupling such high voltage transmissions with continuous exchanges between contiguous members of the pool, KGS allows implicit third party wheeling among its members. If it is successful in its current efforts to deal with the national grid as a unit, even further optimization will be possible.

\(^5\)The power exchanged is not firm power. The buyer provides reserves to cover the transaction. Contracts for reserve power are possible but less common.

\(^6\)In English, the “Krångede Group Joint Operating Company.”

\(^7\)For a discussion of these firms, see Section III. Other producers have attempted to set up power pools, but KGS is the only formal pool in Sweden today. Statens Vattenfallsverk has generally resisted pooling attempts.
Costs and Prices in Bulk Power Supply

When profit-maximizing producers trade in a freely competitive market, they drive the prices in contracts toward the marginal costs relevant to those contracts. While Sweden's bulk power supply system is clearly market-oriented, it does not operate in a perfect market. To see how closely the prices it generates approach relevant marginal costs, we must consider how important the departures in the system from a perfect market are. The discussion above suggests that they are potentially significant.

First, not all the power producers in Sweden are profit maximizers. Publicly owned producers like Statens Vattenfallsverk and Svartholmsforsen operate within strict revenue constraints. They may earn only what a competitive firm would "normally" earn in their position. Even producers with private owners, like Aroskraft, are sometimes operated at zero profit to avoid taxes. In fact, power producers earning private profits probably account for a small proportion of Sweden's power production.

Nonetheless, failure to minimize the cost of meeting a given load is rare. Knowledgeable observers in Sweden consistently point to one form of aberration to illustrate the pervasive nature of cost minimization in Swedish bulk power production. Stockholm and several smaller cities refuse to sell cheap nighttime power from their district heating cogeneration plants into the grid. Instead, they retain this cheap power for their own customers, practicing a form of local preference by selling power locally below its opportunity cost. Otherwise, Swedish power producers tend to maintain a reservation price for their power based on its variable cost and continually compare this price with that offered in the grid to make their production decisions. Such use of variable costs naturally leads to their reflection in bid and offer prices. Where such prices do not yield appropriate revenues, Swedish producers appear either to adjust revenues with inframarginal rebates or surcharges or adjust prices—typically administratively determined prices—where such adjustment will not affect production or consumption decisions. The discussion of formal administrative tariffs below considers this in more detail.

Second, although competitive pricing mechanisms dominate Sweden's bulk supply system, transmission capacity prices in the national grid are administratively determined. The kilometer-megawatt charge is meant to reflect amortization costs, a "normal" rate of return on investment, and what business taxes would have been if the grid were privately owned (Sporrn, 1971, p. 23). Theoretically, these costs can be calculated to reflect the social cost of capacity, but this is not necessary. Because Statens Vattenfallsverk does not raise capital for transmission investments in the capital market, it need only recover an administrative estimate of capital costs to meet its revenue requirements. Again, the discussion of formal administrative tariffs below covers this issue in more detail.

Third, Statens Vattenfallsverk and the other major producers impose two distinct restric-

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8 The difference between their revenues and costs may cover "normal" returns to capital and a sufficient surplus to cover business taxes if the producers were privately owned with 25 percent equity.
9 In fact, Swedish accounting conventions make it possible in such cases to pass positive profits to the owners, leaving the jointly owned firm with zero book profits.
10 There is some evidence that cities with older plants purchased at low historical costs practice a similar form of local preference by distributing the rents from these plants to their citizens in lower prices.
11 Because Swedish producers assume that each generating machine has a constant operating cost per unit of output, average and marginal variable costs are equal. There is no need to draw a distinction.
12 The Riksdag, or Swedish Parliament, appropriates funds for transmission investments. Investments recommended are subject to an administrative net present value test, but not to a market test.
13 Note that, technically, the effective operating cost of transmission—the calculated losses that a user must cover when he transmits—is also administratively determined. But the determination of losses is so much integrated into routine operations that it is not subject to the sorts of ambiguities typically associated with administrative pricing.
tions on the type of bulk power contracts available. First, Statens Vattenfallsverk prohibits subleasing of transmission capacity under any circumstances unless the capacity is subleased back to the company. Although it states that it pursues this policy to maintain reliability, over half the generating capacity that might be affected by such a policy is reliably controlled and centrally dispatched by KGS. That current restrictions on recontracting constrain KGS's central dispatch suggests that gains are available from a reallocation of transmission capacity within KGS. Presumably, if reliability were the only issue, one would expect Statens Vattenfallsverk to allow recontracting within KGS. Such an arrangement is being negotiated, but under existing arrangements, competition is tightly constrained in the spot market for transmission capacity.

The other important restriction on bulk power contracts is that on third party wheeling. This restriction has three important effects. First, it reduces the number of firms a producer can deal with directly. This can allow strategic behavior where a producer has only one or two direct connections. Second, it allows a dispersion of prices to persist in the market. With third party wheeling, each firm can deal with every other firm. Arbitrage in such a market automatically leads to uniformity of prices. Without third party wheeling, price differentials can persist without inducing arbitrage. Third, it redistributes the cost savings associated with power exchanges.

Figure 5 illustrates these last two points in the context of the Swedish national power market. With third party wheeling, the market would clear at \( E \) and the price for all buyers and sellers would be \( P_{sv} \). The first three bids, the first offer, and part of the second offer would succeed. Without third party wheeling, the market would still clear at \( E \) and the same bids and offers would succeed. But different prices would occur. Statens Vattenfallsverk would choose \( P_{sv} \) as its reference price and contract prices would be calculated as the mean of \( P_{sv} \) and the various bid and offer prices involved. For example, the price for the first sale to Statens Vattenfallsverk would be \( P_{1v} \); that for the second, \( P_{sv} \). Statens Vattenfallsverk's first sale would occur at \( P_{v} \); subsequent sales would occur at progressively declining prices. The shaded area, which under third party wheeling accrues to those offering and bidding in the market, accrues to Statens Vattenfallsverk in the absence of third party wheeling.

The social significance of these effects is not immediately clear. Although the absence of third party wheeling reduces the number of firms a producer can deal with directly, it need not reduce competition much. For example, one power producer with connections to Statens Vattenfallsverk and KGS routinely retains the full cost savings of an exchange with either one by playing one off against the other. Just two trading partners are needed here to induce strong competition. Similarly, the split-the-difference pricing that restrictions on third party wheeling allow does not change the pattern of trades that occur among existing generating assets; it merely changes the prices and distribution of income associated with such trades. Persistent differences in prices can lead to suboptimal allocation of energy consumption among members of the market. Reduction in "rents" from sales can discourage investment in assets that can be offered in such economy exchanges. But it can also transfer revenue to Statens Vattenfallsverk in a relatively costless way, a transfer which may be considered socially desirable. While

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Fig. 5—Sharing cost savings in the national power market
these difficulties may be important, economists, businessmen, and government officials in Sweden believe they are not. In the end, 85 percent of Sweden's generating capacity is centrally dispatched within two closely coordinated systems—Statens Vattenfallverk and KGS. The pricing difficulties encountered within these systems and the others associated with the national power market and grid are certainly less important than those faced by industrial firms without direct access to bulk power in the national power market.

**FORMAL ADMINISTERED TARIFFS RELEVANT TO SWEDISH INDUSTRY**

Prices not determined by the market forces in Sweden's bulk power system are negotiated between power producers and their customers in secret; the resulting contracts are not publicly available. But formal administered tariffs, which evolve out of ongoing discussions between Sweden's major electricity producers and consumers, act as models for this negotiation, and executed contracts typically do not depart much from these formal tariffs. They draw heavily on a broad consensus favoring marginal cost pricing. Regulatory support for marginal cost pricing lends support to this consensus. This subsection reviews briefly the pricing doctrine underlying the four formal administrative tariffs relevant to Swedish industries and then discusses some difficulties in matching prices to costs in these tariffs.

**Tariff Doctrine in Four Formal Tariffs**

The tariffs most important to Swedish industry are the standard tariff, under which firms buy firm power on a regular basis; the reserve tariff, under which owners of cogeneration insure the power they draw from their own generators against their failure; the buy-back tariff, under which producers who do have access to the national power market can sell economy energy; and the EFAM tariff, which owners of run-of-the-river hydroelectric plants use to induce owners of cogeneration to shut down their self-generated power when run-of-the-river hydroelectric power is the marginal source of power in the system. Each of these tariffs is structured to reflect a relevant set of costs.

Table 11 lists these four tariffs, with their principal components and brief notes on how these components are defined and what costs each component reflects. We do not intend to prove that these tariffs actually reflect the costs that Swedish tariff doctrine says they should. But we can use Table 11, which summarizes some of the basic cost notions embodied in industrial

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19The Centrala Driftledning (CDL), or Central Operating Organization, represents major producers in these discussions. Svenska Elverksföreningen (SEF) of the Swedish Association of Electricity Undertakings, an association chiefly of distribution companies and agencies, represents consumers. Statens Vattenfallverk dominates discussions in both on the high voltage tariffs relevant to industry. Major industrial companies not included in these groups also participate.

17Two regulatory bodies are potentially important to industrial tariffs. Statens Prisregleringsnämnden for Elektrisk Ström (SPR), or the State Price Regulation Committee for Electrical Power, reviews negotiated tariffs only if one party believes they are unfair. This rarely occurs, suggesting either that the SPR is unimportant or that it has a strong deterrence effect in negotiations. Statens Pris- och Kartellnämnden (SPK), or the State Price and Cartel Board, currently plays no active role in electricity pricing. But its control of prices elsewhere in the Swedish economy may provide another deterrent during negotiation.

18Major producers offer EFAM tariffs on selected summer weekends and sometimes during the national industrial holiday during July when they need only run-of-the-river hydropower to meet their demand. Occasions when this occurs are becoming rarer as Swedish system demand grows relative to its available hydro resources.
<table>
<thead>
<tr>
<th>Tariff and Tariff Component</th>
<th>Unit of Measure for Component Price</th>
<th>Basis for Tariff and Component Prices</th>
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<tbody>
<tr>
<td><strong>Standard tariff</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fixed charge</td>
<td>Lump sum (Skr)</td>
<td>Estimated long run marginal costs</td>
</tr>
<tr>
<td>Contractual or subscription charge</td>
<td>90 percent of total subscribed load or an actual maximum demand for one hour (Skr/MW)</td>
<td>Accounting and metering costs, revenue adjustments</td>
</tr>
<tr>
<td>Peak-load charge</td>
<td>Maximum demand for six consecutive hours (Skr/MW)</td>
<td>Cost of local distribution grid specific to consumer</td>
</tr>
<tr>
<td>Energy charge</td>
<td>Consumption during season to which charge applies (Skr/MWh)</td>
<td>Cost of generation, transmission, and other distribution capacity</td>
</tr>
<tr>
<td><strong>Reserve tariff</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fixed charge</td>
<td>Lump sum (Skr); present only if standard tariff is absent</td>
<td>Estimated long run marginal costs</td>
</tr>
<tr>
<td>Contractual or subscription charge</td>
<td>Same component price as standard tariff (Skr/MW); applies only to cogeneration capacity &quot;insured&quot;</td>
<td>Same as standard tariff</td>
</tr>
<tr>
<td>Insured unit charge</td>
<td>Maximum demand for six consecutive hours (Skr/MW); applies only to reserve capacity drawn in first 7 days</td>
<td>Same as standard tariff peak-load charge, adjusted for days of coverage, likelihood of failure, difference in mix of generation plant used on peak</td>
</tr>
<tr>
<td>Daily capacity charge</td>
<td>Maximum demand for six consecutive hours (Skr/MW); applies for reserve capacity drawn beyond first 7 days</td>
<td>Same as insured unit charge, appropriately adjusted</td>
</tr>
<tr>
<td>Energy charge</td>
<td>Consumption or energy under reserve tariff (Skr/MWh)</td>
<td>Average of system marginal running costs expected during cogeneration outages implied by current oil price</td>
</tr>
<tr>
<td><strong>Buy-back tariff</strong></td>
<td>Cogenerated energy sold to grid (Skr/MWh)</td>
<td>1.1 to 1.15 times estimated current cogeneration marginal running cost</td>
</tr>
<tr>
<td><strong>EFAM tariff</strong></td>
<td>Consumption of firm energy under EFAM tariff (Skr/MWh)</td>
<td>.85 to .9 times estimated current cogeneration marginal running cost, up to current capacity</td>
</tr>
</tbody>
</table>
tariffs, to suggest how Swedish tariff makers view costs.\textsuperscript{19} In particular, the table examines the distinction Swedish tariff makers make between short run and long run, notes some basic relations between tariff components within and between major producer tariffs, and touches on the problems posed by revenue constraints in matching prices to relevant marginal costs.

**Short Run versus Long Run.** Note first that while the standard and reserve tariffs reflect estimated long run marginal costs, the buy-back and EFAM tariffs reflect current marginal operating costs. Swedish tariff makers believe that both are important but that tariffs should reflect them in different ways.

Short run marginal costs—the costs of changing system output today by one megawatt from one hour to the next—vary significantly in Sweden. Figure 6 displays Statens Vattenfallsverk's short term prices in the national power market ("T-prices") during 1977-1979.\textsuperscript{20} As noted above, these prices reflect short run marginal operating costs in the power supply system. They measure the relative scarcity of power in the supply system. Swedish tariff makers use the buy-back tariff, based on the current running costs of a company's selling units, to encourage increased supply from existing units whenever the system price is high. They use the EFAM tariff, again based on the current running costs of a selling company's generation, to discourage private generation from existing units whenever the system price is low. In sum, they use these formal tariffs to optimize the dispatch of generation from existing assets outside the immediate circle of the national power market.

Longer term marginal costs—for example, the costs of adding one megawatt to production five to ten years from now—are more relevant to decisions to add generating capacity and to choose among alternative generating sources. Swedish tariff makers believe they can assist industry when it makes investment choices that affect its electricity use, and in particular its investment in cogeneration, if the principal formal tariffs industry faces reflect electricity costs likely to exist five to ten years in the future. Considerable sophistication is required to project relevant system costs so far into the future; Swedish tariff makers appear to possess such sophistication.\textsuperscript{21} They use it to write their standard and reserve tariffs.

**Tariff Components, Relevant Decisions Margins, and Internal Consistency.** The way the standard and reserve tariffs are broken down into components reflects the various decisions a firm makes implicitly in choosing its pattern of electricity use. The internal consistency in the charges associated with these components suggests that the tariffs are designed to force users to internalize the producer's costs.\textsuperscript{22} For example, when a firm decides to deal with a major producer, it imposes accounting and metering costs on the producer. The fixed charge in the standard and reserve tariffs, which is conditional on connection and not on the choice of tariffs, reflects these costs. The firm's decision on the maximum power to use during a year imposes local distribution costs on the producer; the producer recovers them with identical

\textsuperscript{19}Appendix A carries this discussion further by describing the tariffs in more detail and comparing the standard and reserve tariffs of two Swedish power producers, one in central Sweden, with the bulk of Sweden's industry, and the other in northern Sweden, with the bulk of Sweden's hydroelectric generating capacity. This comparison supports the hypothesis that these producers reflect appropriate costs in their tariffs. For a more detailed discussion of Swedish doctrine, see Edblad et al. (1975) and Lundberg et al. (1975). This subsection benefits considerably from their discussions.

\textsuperscript{20}Dotted bars illustrate the range of prices in each month. Upper and lower ends of the shaded bars show monthly averages for prices during, respectively, the 70 "peak" hours in each week and the 98 "offpeak" hours. The ordinate shows prices in Swedish crowns (Skr) on the left and U.S. dollars on the right.

\textsuperscript{21}For example, tariff makers must consider a weighted average of future costs in which both costs and weights are uncertain. They must consider both the fact that a long horizon provides more time to optimize a system, thereby lowering expected system costs and the fact that the future toward which they optimize is uncertain, limiting their ability to reduce system costs (see, for example, McKay, 1979). Swedish tariff makers are aware of these problems.

\textsuperscript{22}See Appendix B for a more detailed defense of these assertions.
Fig. 6—Monthly short run marginal electricity costs
subscription charges in the standard and reserve tariffs. Similarly, the firm's decision on how much power to draw over the system peak affects costs of generation and transmission capacity, costs recovered in various forms in the standard tariff's peak-load charge and the reserve tariff's insured unit and daily capacity charges. The relationships among these three components clearly illustrate the integral role of marginal costs in their determination. Finally, a firm's decision to draw energy from existing assets (assets that exist five to ten years in the future) imposes costs that depend on the mix of units likely to be on line, reflected in the season-specific energy charges of the standard tariff and the reserve tariff's general energy charge.

This careful matching of the electricity user's key decisions, the prices the user must face in those decisions, and the costs of these decisions to the producer illustrate the central precept of Swedish pricing doctrine: users should face the costs their decisions impose. The consistency hinted at above within producers' tariffs carries over to comparisons of tariffs between producers as well. Almost identical tariff components occur across firms. And price differentials between firms for similar components are predictable on cost grounds. In the absence of direct competition for service to users under formal tariffs, this pattern of consistency provides considerable evidence of general acceptance of Swedish pricing doctrine among producers.

**Revenue Constraints.** As noted above, prices based strictly on marginal cost principles need not yield revenues consistent with producers' revenue constraints or profit requirements. Swedish tariff doctrine suggests two ways to deal with revenue problems caused by the pricing structure. First, alter the tariffs. In particular, change the fixed charge, which is assumed to have minimal effects on behavior, and, if necessary, the energy charges. Such adjustments are typically made to bring expected revenues into line with required revenues. Second, use rebates or surcharges not specifically delineated in the formal tariffs. Formal tariffs contain a clause allowing such adjustments when the producer faces "unexpected circumstances." These measures have been used *ex post* to realize required revenues when unexpected cost changes prevented the collection of such revenues. To some extent the rebates and surcharges have been related to usage rate, suggesting some undesirable incentive effects. As a rule, however, Swedish tariffmaking doctrine dictates that revenue problems be resolved with as little effect as possible on the decision-sensitive margins discussed above.

### Costs and Prices in Formal Administrative Tariffs

Because administrative tariffs cannot rely on the objectivity of a free market for their legitimacy, the prices in them are more difficult to justify satisfactorily. Even where such tariffs are based solely on the best cost estimates available, questions about the legitimacy of these estimates and their use in tariffmaking can persist. Furthermore, the costs of drawing up tariffs force tariffmakers to simplify, leaving opportunities for the prices in tariffs to depart from

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22. Though these components are defined in terms of each user's peak use, the nature of the Swedish power supply system and special tariff clauses tends to assure that power use relevant to these components is measured during the system peak. See Appendix A for details.
23. The energy charge actually represents an interesting compromise between short and long run concerns. All energy charges depend on the current oil price and a simple functional form that calculates what the average marginal running cost for the mix of generating units appropriate to the specific charge would be five to ten years from now if oil costs then what it does today. Hence, while the standard and reserve tariffs do not reflect short run variations in cost like those in Fig. 5, they are responsive to a less volatile current determinant of electricity costs, the oil price.
24. Explicitly excluded as an option is a direct government subsidy or tax for dealing with strict revenue issues. Such policies would appear to be inconsistent with Sweden's view of power production activities—by Statens Vattenfallsverk and others—as more or less independent, self-sustaining activities. They also create the opportunity for politically motivated pricing that could move Swedish tariffs even further from marginal costs than they are under current arrangements.
relevant costs and raise doubt about the tariffs. Despite their sophistication, then, Swedish tariff makers suffer from many of the same problems that officials responsible for setting prices administratively endure everywhere. Consider three types of problems.

Implicit Subsidies in Administrative Tariffs. The formal tariffs that Statens Vattenfallsverk and other major producers use appear to subsidize some activities at the expense of others. Critics claim that such pricing patterns systematically favor these producers by allowing them to increase their revenues, their output, or both. Consider three examples.

First, the decision to use long run marginal costs for tariff making lowers the administrative cost of electricity. This is because perceived long run marginal costs have tended to remain on average below short run marginal costs in Sweden during the post-war period.\(^{26}\) Electricity prices based on long run concepts are then lower than current operating costs and can encourage electricity consumption. Presumably Sweden’s electricity producers benefit from expanded consumption. They cover their revenue needs by raising revenue in places that do not affect consumption.

Second, Statens Vattenfallsverk has normally used 8 percent as the real social cost of capital in making its investment decisions. Because Statens Vattenfallsverk does not face the capital market directly, its cost of capital need not reflect any objective market determination of cost. During the late 1970s, when inflation pushed the nominal social cost of capital toward 20 percent, Statens Vattenfallsverk lowered its estimate of the real social cost. Critics suggest that it did this to avoid prejudicing the capital-intensive options in its long term strategy, and with them the relatively low long run marginal costs used for pricing decisions.

Third, because prices based on long run marginal costs are too low to cover allowable or required revenues, the major producers must raise some prices above the levels suggested by long run costs. They have tended to raise prices where customers had few options and hence had little ability to substitute away from electricity. This is the socially desirable way to deal with revenue problems in a system based on marginal cost.\(^{27}\) But critics suggest that it also looks suspiciously like monopolistic price discrimination, particularly when the revenue constraint requires collection of more revenues than marginal cost pricing by itself makes possible.

An instance of particular difficulty to Statens Vattenfallsverk was its decision in the 1960s to price below current costs electricity contracts to communities where district heating was a viable option. Statens Vattenfallsverk’s rationale was that nuclear power, when it came on line in the 1970s, would provide power at lower prices. But if district heating were built before nuclear came on-line, these prices would not be available. While the social basis for this argument could certainly be correct, critics have suggested that it could just as easily represent a convenient rationale for closing district heating out of the market.\(^{29}\) Statens Vattenfallsverk apparently pursued a similar policy with respect to competition from industrial cogeneration during the 1960s. It does not do so any longer.

\(^{26}\)During the 1950s and 1960s, falling marginal thermal generating costs tended to make prices based on long term marginal costs lower than those based on short run costs. Long run costs jumped abruptly following the 1973 oil crisis, but short run costs jumped even more. Because the increased oil prices associated with the crisis made the existing generating mix suboptimal, a new mix based on nuclear power could actually continue to keep long run costs below the short run costs currently experienced. Hence, long run marginal costs remained below short run costs in the 1970s.

\(^{27}\)It is known as “Ramsey pricing.” When an agency must meet a budget constraint, Ramsey pricing calls for price changes large enough to meet the constraint where such departures of price from marginal cost affect consumption choices very little. For details, see Ramsey (1922).

\(^{29}\)Statens Vattenfallsverk’s administrative determination became an embarrassment in 1973 when it concluded that nuclear would cost more than it had thought. It ended the low price program in that year on this cost basis. Note, however, that the price of oil quadrupled in 1973 also, reducing competition from oil-fired district heating. Even if Statens Vattenfallsverk had not concluded that nuclear would cost more, Ramsey pricing would dictate that, with this removal of competition, Statens Vattenfallsverk should remove the low prices.
In sum, though each of these examples can be justified as an appropriate action under marginal cost pricing, each also raises doubts about the motives underlying it. Such doubts are inevitable under administrative pricing. They may or may not be justified.

Sharing Cost Savings Under the Buy-Back and EFAM Tariffs. Our discussion of split-the-difference pricing above suggested that the cost sharing implicit in these tariffs will not affect the dispatch from existing assets. But it has two other effects of interest.20

First, it shifts income toward the major producers by giving them most of the likely cost savings from any exchange that occurs under the tariffs. Because an industrial firm typically connects with only one major producer, the firm cannot easily substitute away from the major producer in the short run. According to the discussion of revenue constraints above, this is an ideal place for major producers to recover revenues they need to balance prices elsewhere based on long run marginal costs. This is because the tariffs do not affect short run decisions.

Second, the tariffs do affect longer term decisions. Because the buy-back tariff is designed to deal only with exchanges that involve existing capacity, it provides no capacity charges. But that need not deter industrial firms from providing capacity for surplus sales and recovering capacity costs from the difference between their sales price and running costs. In fact the comparison of such rents with capacity costs is fundamental to the provision of an appropriate mix of generating plant in a system. It is also central to decisions about self-generation. The standard and reserve tariffs provide appropriate incentives to firms to displace purchased power by allowing them to displace capacity and energy charges based on system costs. But the appropriate incentives end when firms attempt to sell power back to the grid.

This represents a significant divergence between costs and prices only if industry would sell power back to the grid on a regular basis if buy-back rates allowed for relevant capacity costs. Two types of evidence suggest that this is not a serious problem for industrial cogenerators. First, studies of industrial cogeneration show that most industrial cogenerators can minimize their cost of electricity use by sizing their self-generation units so that they import power from the grid.20 Second, while observers of Swedish tariffs in business and government do not hesitate to object when they observe problems in administrative tariffs, they typically do not see any significant social gains in changing the current buy-back tariff. In sum, while the current tariff could cause distorted long-term business decisions about industrial cogeneration, it does not appear to do so.

On the other hand, the EFAM tariff, because it is available only to firms with self-generation, provides an unjustified incentive to own self-generation. But because EFAM tariffs are so seldom available and because the incentive—10 to 15 percent of running costs—is so small, this is not a serious problem.

Special Problems in the Reserve Tariff. A number of customer objections about the reserve tariff have led to a nationwide study of alternatives to existing arrangements.

One objection states that, because outages in cogeneration are typically met by hydropower, it is unfair to base the reserve tariff on the cost of oil-fired assets. This objection appears to

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20 Actually, the cost-plus and cost-minus pricing formulas do affect dispatch when the major producer's reservation price moves within 10 to 15 percent of an industrial cogeneration's own running costs. But that is a relatively minor problem in the short run. Exchanges on the national power market where any cost difference can justify an exchange typically involve much greater differences than that.

20 See, for example, Dow Chemical Company, 1975; Thermo Electron Corporation, 1976. This result appears related to Swedish industry's demonstrated preference for steam turbines. For a given heat load, steam turbines allow the lowest cost power production available from cogeneration for most load durations. Because steam turbines have a low power-to-heat output ratio, choosing the lowest cost cogeneration technology typically leads a firm to be a net and regular importer of power.
ignore the need to price hydropower at its opportunity cost, a principle central to Swedish tariffmaking. In particular it ignores the mix of oil-fired plant which must be used to produce power that the hydro resources devoted to cogeneration outages cannot cover. This mix is now used to write reserve tariffs, but Swedish tariffmakers are reviewing their assumptions about the mix and its costs.

Another objection states that the reserve tariff is not sufficiently responsive to special circumstances that can force a customer to exceed his subscribed capacity under the standard tariff. One example is the difficult period in April and September when internal steam demands are not high enough to justify full power production, but electricity demands are high. Customers face no problems with this in the summer because they can shut off their peak-load demand meters. April and September, however, represent parts of winter from a tariff point of view, and the maximum net demand for external power during the winter tariff period often occurs in these months. Customers go to great expense to limit their net demand during this period, expense that is not justified from a social point of view. This problem is now under active review.

A related problem is how best to recover from a general blackout. Central generating plants typically recover from a blackout more quickly than cogeneration units do, leading to a short period following the outage in which a cogeneration owner draws excess power from the grid unless he shuts down his production line until his cogeneration recovers. Though this is a rare event, the review will consider it.

What should be clear is that customers have no fundamental objections to the form of the reserve tariff or the costing principles underlying it. They simply want to fine tune the tariff to approach its principles more closely. And the specific and limited nature of objections suggests that the tariff is already quite close.

In sum, while broad consensus exists on the general logic underlying Sweden's formal administrative tariffs, critics are not always confident that that logic is applied properly. Tariffmakers are clearly responsive to many objections and appear to be dealing with extremely subtle costing problems in some cases. The ability of electricity consumers to express their problems clearly and the response of formal tariffmaking to those problems combine to advance Sweden's formal tariffs into more and more intricate issues. Nonetheless, the basic administrative nature of the tariffs leaves nagging doubts that no degree of sophistication can resolve. In fact, the willingness of Sweden's major producers to use some of tariffmaking's more sophisticated concepts may even feed that doubt, perhaps justifiably.

OTHER PRICING ISSUES IN SWEDISH INDUSTRY

So far, this section has discussed only the prices of electricity exchanged between firms; the prices used within firms can differ. The price of waste heat used in cogeneration and heat produced by it, for exchanges either within or between firms, can also be important. A few examples will illustrate how Swedish industry attempts to internalize costs.

31It is also helpful in meeting revenue constraints when prices are lower than current operating costs. Revenue collected on the 60 percent of Swedish electrical energy produced by hydropower helps significantly in meeting oil costs not actually incurred by the hydroelectric plants.
Electricity Prices Within Firms

As a general rule, an industrial firm attempts to reflect its external cost of power internally. Firms facing formal tariffs, for example, typically pass these tariffs on to their internal divisions and their cogeneration installations. Holmens Bruk, a pulp and paper firm, passes its external standard and reserve tariffs on word for word. Billerud Uddevolm uses the exact standard tariffs it has negotiated with Statens Vattenfallsverk and Uddevolm AB, another major producer, internally. The reserve tariff Billerud Uddevolm's production divisions face is less formal but based on the firm's formal contract with Statens Vattenfallsverk. When these major producers offer EFAM tariffs to industry, they can either deal directly with individual cogeneration installations or have their offers transmitted by an intermediary power division, depending on the firm.

Industrial firms who are members of the national power market may simply pass market price offers to their internal divisions or simplify them into informal tariffs. Granges and Stora Kopparberg, for example, use national power market prices internally. Krängede, on the other hand, changes its owners' day and night energy charges that are weekly anticipated averages of relevant power market prices; the owners share capacity costs in proportion to their ownership. These firms do not normally buy reserve capacity.

Heat and Waste Heat Prices

As a general rule, Swedish industry values both cogenerated heat and waste heat at the cost of producing either in a conventional boiler. This is true for transfers both within and between firms. For example, Krängede pays Korsnas-Marma for recovery boiler steam delivered into their Kaskar plant on this basis. Billerud Uddevolm uses a similar arrangement to value waste heat transferred from its pulp and paper mill to its cogeneration plant at Skoghall. Similarly, Västerås pays Aroskraft energy and capacity charges based on conventional boiler costs for firm cogeneration heat transferred to the Västeras district heating system. Krängede charges Gävle in a similar way for firm heat transferred to Gävle's district heating system.

One exception to this arrangement may be found in the contracts Gränges' Oxelösund plant uses to buy waste fuel and sell cogenerated heat. Normal national power market prices justify running the plant only when it can burn furnace gas as fuel. Gränges pays for blast furnace gas from Svenskt Stål's Oxelösund steel plant by splitting the profits from its Oxelösund cogeneration plant evenly with Svenskt Stål. Svenskt Stål in turn provides gas only when it makes more money from the cogeneration profits than it would by retaining the gas for internal use. Simultaneously, Granges sells heat from its cogeneration plant to Oxelösund's district heating system on a non-firm basis at a negotiated price below the cost of heat from conventional boilers. These contracts have evolved out of complex negotiations that seek a joint optimum. They may also result from Gränges' previous ownership of the Svenskt Stål steel plant. Similar arrangements do not appear to be common elsewhere, though the towns of Nyköping and Luleå are considering similar arrangements for their district heating systems.

In general, then, Swedish industry attempts to internalize its external costs of electricity as much as possible by using contracts negotiated outside a firm for transactions within the firm as well. Industry overcomes the difficult problem of valuing heat when it is a joint product, either of industrial output or of cogeneration, by using a simple rule of thumb. The rule has the added virtue that it tends to allocate joint benefits of joint production to products that can
easily be traded in a market. Because heat is not easily traded, these joint benefits are best used to allow lower reservation prices for other products. Note, however, that these are only general trends. Swedish industry displays important exceptions to them.

SUMMARY

The Swedish power supply system can be called a mixed system for a number of reasons:

- Ownership is mixed among profit-seeking private firms, government agencies, and a spectrum of variations in between.
- Goals of cost minimization, local preference, and "fair" profits coexist successfully in the system.
- Fifteen to twenty of Sweden's largest power producers interact with one another within a relatively competitive bulk supply system and well-integrated transmission system. The rest of Sweden's producers—and there are many—face more formal administrative pricing arrangements and rely less heavily on transmission under their own control.
- All of the major producers and consumers of power work together to formulate acceptable pricing doctrine and administrative tariffs based on this doctrine. As we move beyond the competitive pricing of the bulk supply system, this consensual doctrine is fundamental to the pricing regime industrial cogenerators experience.

Swedish pricing doctrine evolves in response to continuing challenges from both producers and consumers. The internal consistency of current administrative tariffs and general agreement on how to value heat point to a broad consensus on the form that prices should take. Formal regulation plays a relatively minor role in creating or maintaining this consensus. This sense of stability coexists with negotiated contracts, particularly in bilateral contracts in the bulk power system. Such contracts build understanding and acceptance that prices should reflect relevant costs among many producers and provide a basis for creative and constructive challenges to the current consensus.

Such challenges stretch that consensus to allow increasingly subtle exchanges and cost savings. The subtle reserve tariff issues being reviewed now are an example of this. They illustrate how a general and consistent doctrine can evolve out of practical difficulties that no theory of tariffmaking available today could be expected to anticipate. This does not eliminate the persistent skepticism that any administrative pricing scheme is likely to raise about the motives of those with ultimate authority to set prices. But it provides an informed forum for challenging whatever administrative pricing decisions are made in a constructive way without resorting to active regulation.

While the Swedish pricing system may be evolving toward prices that fully reflect social costs, it is harder to say how far it has to go before it achieves them. Prices in bulk supply, informal tariffs, and within firms are relevant here.

Within the bulk supply system, central dispatch of 85 percent of Sweden's capacity within two systems points to efficient allocation of most existing capacity. More generally, competition in the bulk supply system rarely allows price differentials in Statens Vattenfallsverk's reference prices throughout the country that transmission costs do not justify. The principal difficulty in the bulk supply system is the absence of third party wheeling that sustains split-the-difference contracts. Such contracts sustain a dispersion in effective prices in the short
run and probably discourage some investment in capacity outside Statens Vattenfallsverk. Beyond this, however, bulk supply prices appear likely to reflect relevant costs.

Formal administrative tariffs present greater problems. Basing standard and reserve tariffs on long run cost concepts tends to reduce prices below current cost levels, aggravating revenue constraints and raising doubts about the major producers' motives. It also makes prices relatively unresponsive to short run cost changes, leaving the bulk supply system to respond to them. EFAM tariffs introduce some short run signals, but they treat only one very special form of short term cost variation. Buy-back tariffs also provide short run signals, but they too account for only a small fraction of the market. More generally, formal tariffs also tend to oversimplify longer term expectations of temporal cost variations.

Within firms, electricity prices appear to resemble the external prices the firms face, suggesting that intrafirm pricing rules introduce few additional difficulties.

Recognizing all these difficulties is important in understanding how Swedish industry uses cogeneration, particularly in terms that provide insights transferable to the United States. But it is also important to keep them in perspective. The fact that all Swedish generating capacity interconnects with the grid to take part in this pricing system, and the fact that a strong consensus exists throughout Sweden in support of current pricing doctrine suggest that none of these problems is seriously debilitating.
VI. THE RESPONSE OF INDUSTRIAL SELF-GENERATION TO SWEDISH ELECTRICITY PRICES

If we accept that Sweden's administrative pricing mechanisms actually reflect the long-run marginal costs that they are said to reflect—and a strong consensus throughout Sweden supports this point of view—Swedish electricity prices appear quite well designed to induce socially desirable investments in generating assets and use of these assets. Split-the-difference contracts in the bulk power market will introduce some problems associated with price dispersion, but the only serious problems likely to persist will occur in the formal administrative tariffs. In particular, these tariffs do not induce short run responsiveness to cost changes and, because they are based on averages over long time periods, during the year they do not reflect the full system cost structure as well as they might. We can expect these difficulties to lead to some unusual response behavior under administrative tariffs. Otherwise, industrial self-generation should operate as a well integrated part of the power supply system as a whole.

This view of industrial cogeneration has several important implications for response behavior in Sweden. This section first examines the costs of alternative generating technologies in a system context, then develops the relationship between these costs and the electricity prices Swedish industry faces, and finally reviews four basic responses to these prices.

COSTS IN A SYSTEM CONTEXT

Ideally, the relative social costs of alternative technologies would determine the mix of plant used to meet electricity demands. Table 12 offers some rough capital and running cost estimates for generating technologies being considered in Sweden. They do not include premiums to reflect the costs of environmental degradation or import dependence associated with oil or coal. The costs of hydropower depend fundamentally on the characteristics of the hydro site. Otherwise, each estimate represents a plant built at the optimal scale for the technology concerned. Smaller plants of each type would typically have higher capital and running costs.

Figure 7 compares the annual costs per kilowatt of each of these technologies.¹ The dashed loci show the costs associated with technologies that do not depend on the presence of appropriate terrain, like hydro, or a favorable heat load, like cogeneration. These form an envelope shown by the bold locus; this is the minimum per kilowatt cost available from these technologies taken together. The power system can expand these technologies to any level required, thereby suggesting that in an appropriately configured system, this locus traces out the long run marginal cost of meeting each load duration in the system. If no hydro or cogeneration were available, gas turbines would meet all loads shorter than 1000 hours per year, oil condensing would meet loads of 1000 to 1667 hours per year, and nuclear would meet all longer loads. Although coal condensing is available, it would not be used.

Where the conditions for hydro or cogeneration are present, they could displace some of this

¹For example, the locus for nuclear condensing shows that it costs Skr 240 per year per kilowatt if it produces no electricity and Skr 512 per year per kilowatt if it runs all year long. The comparisons which Fig. 7 allows are meaningful only under a number of assumptions considered briefly in Appendix B.
### Table 12

**Costs and Efficiencies for Condensing and Cogeneration Generating Plants**

<table>
<thead>
<tr>
<th>Plant Scale</th>
<th>Efficiency in Conversion (%)</th>
<th>Plant Cost/KW(e)</th>
<th>Annual Fixed Costs/KW(e)</th>
<th>Running Cost/KWH(e)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydroelectric Condensing</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nuclear</td>
<td>Varies</td>
<td>2000-5000</td>
<td>476-1190</td>
<td>100-250</td>
</tr>
<tr>
<td>Oil</td>
<td>2x1000 MW</td>
<td>3000</td>
<td>714</td>
<td>240</td>
</tr>
<tr>
<td>Coal</td>
<td>2x1000 MW</td>
<td>1900</td>
<td>452</td>
<td>145</td>
</tr>
<tr>
<td>Steam cogeneration</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil</td>
<td>250 MW</td>
<td>2200</td>
<td>548</td>
<td>185</td>
</tr>
<tr>
<td>Coal</td>
<td>250 MW</td>
<td>3100</td>
<td>738</td>
<td>240</td>
</tr>
<tr>
<td>Diesel cogeneration</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>19 MW</td>
<td>2000</td>
<td>476</td>
<td>160</td>
<td>38.10</td>
</tr>
<tr>
<td>Gas turbine</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2x60 MW</td>
<td>900</td>
<td>214</td>
<td>70</td>
<td>16.67</td>
</tr>
</tbody>
</table>

**Source:** Ångpanneföreningen, 1978; Statens Industridepartementet, 1978.

*1976 price levels.

*Assumes 4 percent real cost of capital and various appropriate plant lives.

*Estimates from running cost relative to that of oil-fired condensing and cogeneration.
capacity. Hydro could displace all but the shortest durations, which gas turbines would continue to meet. Diesel cogeneration would prevail for loads of 865 to 1786 hours per year; steam turbine cogenerators would prevail for loads of 1786 to 3929 hours per year. Again, coal-fired cogeneration is not used. Unless these sources could satisfy all the demand at any of these durations, the bold locus would continue to determine the system's marginal cost. These "special" sources of power would remain inframarginal.

This simplified presentation ignores several important features of the Swedish power supply system. First, although district heating may justify steam turbine cogeneration installations as large as those represented in Table 12 and Fig. 7, industrial heat loads never do. Hence, industrial steam turbine cogeneration will tend to be more costly than that shown here.

Second, the bold locus represents relevant marginal costs only if the system can achieve the optimal configuration implied by this locus. If nuclear cannot be expanded to meet marginal load at higher load durations, for example, nuclear may be the inframarginal source, leaving oil or coal cogeneration to dominate the system at longer durations and hence to set the marginal cost at those durations.

Third, as noted above, these costs do not include the costs of environmental effects or import dependence. Because these effects are not easily quantified, they tend to blur the sharp cost distinctions shown here. All sources have potentially serious problems in both areas, suggesting a balanced approach to system expansion that hedges against the contingency in which one or more are found to be unacceptable.

Fourth, real world oil prices almost doubled during 1979. Unless this was anticipated in the costs in Table 12, which is unlikely, Fig. 7 shows a plant mix too rich in oil-fired capacity. If we raise the real cost of oil, by rotating the loci for oil-fired capacity counterclockwise, nuclear condensing takes an increasing share of the bold locus in Fig. 7 and coal-fired capacity becomes relatively more attractive. What Fig. 7 does not show is that, because coal-fired capacity displays greater scale economies from oil-fired capacity, a shift toward coal places the smaller cogeneration installations typical of Swedish industry at an increasing disadvantage. Ironically, a rising real oil price works to the detriment of fuel-efficient industrial cogeneration.

Finally, the Swedish government has shown a marked policy preference for industrial cogeneration in the form of large grants for new installations and exemptions from the general excise tax on electricity. To the extent that this preference reflects underlying differences in

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2Like the United States, Sweden favors an administrative over a market approach to environmental control. It uses regional and city targets as well as negotiated site specific maxima for sulfur and particulate emissions. Sweden gives the local kommun or city more authority than the United States does. While the national Konkessionsnämnd för Miljökrydd or Environmental Franchise Board can stop a cogeneration plant on the grounds of regional or national interest, the local kommun still plays the principal role in negotiating the emission standards for a new plant. While kommuns apply a concept of the "best-available technology that is economically feasible," standards differ significantly from one plant to the next (Norrström, Widdell, and Wohlfahrt, 1977, p. 20). Sweden favors oil over coal on narrow environmental grounds and nuclear over either in terms of water and air pollution. But general safety concerns raise serious doubts about nuclear itself. On grounds of import dependence, Sweden also prefers nuclear, although it depends heavily on other countries for fuel processing. Among imported fossil fuels, it prefers coal over oil. Sweden shows the relative importance it places on environmental and import problems today by requiring that all new generating plants be coal capable, though not necessarily coal-burning.

3For example, the average cost of residual fuel oil delivered to U.S. steam-electric utility plants rose 86 percent from $2.39 in January 1975 to $4.405 in January 1980 per million BTU (DOE/EIA-0635/89/99, p. 89).

4Since 1975, the Statens Industriwerk has offered grants of up to 55 percent of the investment cost of industrial cogeneration. Some of the grants are meant to make otherwise uncompetitive cogeneration competitive; they are made on the grounds that business uses a discount rate higher than the socially desirable one, particularly for investments like those in cogeneration which are not crucial to a firm's primary line of business. This suggests that the grants should not affect the cost figures in Table 12. There is also some evidence that subsidies were provided to help create a viable alternative to nuclear power, against the contingency that the Swedish electorate would reject nuclear. Figures in Table 12 must be adjusted to reflect this. Another part of the grants has been used for countercyclical policy. All but two of Sweden's industrial cogeneration installations built since 1975 have received aid, an outcome which should not
social costs, the loci representing cogeneration in Fig. 7 should fall, making cogeneration more competitive when an appropriate heat load is present.

On the whole, however, if the major producers believe the plant mix implied by the bold locus in Fig. 7 is attainable, we can use these costs to illustrate what prices could have prevailed in the power system before the rise in oil prices in 1979 was perceived. Just how prices reflect these costs is the topic of the next subsection.

SYSTEM COSTS AND ELECTRICITY PRICES

Recall that national power market prices and formal tariffs reflect costs in very different ways. We can represent both in terms of firm-specific annual load duration diagrams analogous to the systemwide diagram in Fig. 7 if a simple condition applies: the firm's load curve must behave like that of the power system as a whole. Because electricity loads in Sweden, with few exceptions, peak during the winter, the system as a whole is winter peaking. Hence, system and firm-specific annual load curves tend to be correlated.

To see why this is important, consider an autonomous firm. Like a power system it will invest in capacity with high marginal running costs to cover a capacity demand that exists infrequently; it will use capacity with progressively lower marginal running costs to cover a frequent and enduring capacity demand through the year. The firm's capacity choice will map an expected marginal running cost into every hour of the year; that marginal running cost will be negatively correlated with load. Now suppose we rank the hours of the year with respect to marginal running cost, starting with the hour with the highest marginal running cost and moving through hours with progressively lower marginal running costs. Do the same thing with any time-differentiated set of prices the firm faces through the year. If the days of the year all have the same rank in both rankings, the prices can be represented simply as a locus like those in Fig. 7. This assures that the marginal running costs of the firm's internal options are highest during the tariff period with the highest marginal rate and that the marginal running costs fall consistently in each succeeding tariff period with a lower marginal rate. Hence, any annual duration in Fig. 7 refers to the same set of hours for each process represented. As a result, a time-differentiated set of prices can be represented like a technology with a capacity cost equal to its subscribed capacity charge and progressively falling marginal costs as the cumulative duration of application rises.

Under this simple condition, long term contracts in the national power market will likely

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be surprising if potential cogenerators face prices which actually reflect the relative costs shown in Fig. 7. (The two installations not aided were rejected on technicalities.) Significantly, aid to cogeneration was scheduled to end if the March 1980 referendum allowed nuclear power to continue expanding, suggesting that the Swedish government recognizes the increasing social desirability of nuclear power as the oil price rises. In July 1979, the Swedish government reduced the effective tax on cogenerated electricity used on-site from the 2 ore/kwh standard for most electricity production to 1.6 ore/kwh for all industrial cogeneration. A quick glance at Table 12 will verify that the 4 öre advantage implied by this change is not likely to affect plant choice much. The Industriverk subsidy has more than seven times as great an effect on typical cogeneration costs as the tax change (Statens Industriverk, 1979).

5 This is as strict as it sounds. Under our assumption, marginal cost, like a time differential tariff, varies in steps through the year. All our technique requires is that days within a step within each ranking can be ordered in a way that makes the ordering of days identical in both rankings. This becomes more plausible as the number of steps in each ranking falls.

6 That is, the locus in Fig. 7 would be a spline whose segments (a) represent annual durations of pricing periods; (b) have slopes equal to the price in each period; (c) are each as long as the annual duration of their respective pricing periods; and (d) fall in scope as cumulative annual duration rises. Such a locus is still useful for comparisons if hours do not all have the same rankings in the two series. But it becomes progressively less useful as these rankings diverge more.
use prices very much like those in the bold locus in Fig. 7. These are the prices that clear the market for long run power. Investment in self-generation displaces a firm's demand for capacity in the national power market and hence saves the amounts indicated in the bold locus. Actual transactions in the national power market, of course, are likely to involve split-the-difference contracts that will move the effective price away from that on the locus. But because members of the national power market tend to trade only on the margin, their primary investment decisions displace firm power and hence reflect the locus itself.

Under a formal tariff, the industrial firm faces a different situation. Figure 8 reproduces the bold locus from Fig. 7 as a firm-specific locus. It also divides the year into an eight month (September to April) winter season with high marginal costs and a four month (May to August) summer season with lower marginal costs. These are the seasons in typical Swedish high voltage tariffs. In our illustration, nuclear condensing accounts for all central station thermal power during the summer season—not a bad assumption. Energy charges, under Swedish tariffmaking doctrine, then should reflect the marginal running cost of nuclear power. The power system uses oil-fired turbines, cogeneration, and condensing, as well as nuclear condensing, to meet winter load. Here doctrine calls for average energy and capacity charges, which are represented by the dashed line in Fig. 8. That is, the formal tariff departs from actual costs in the same way that the dashed and solid bold loci in Fig. 8 differ. This is the locus of prices for purchases of power.\(^7\) Sales, of course, occur on a cost plus percentage with no payment for capacity.

The self-generation investments that look attractive under national grid prices and formal tariffs, then, differ slightly. Because the formal tariff averages costs in the peak season, it overestimates costs in the extreme peak and underestimates costs in the period that might be called the shoulder. This result is not an artifact of the specific costs shown here; it is inherent in the averaging used in the peak period charges. Given the costs suggested by the subsidized cogeneration locus shown in Fig. 8,\(^8\) this difference will affect the firm's decision about cogeneration only with regard to loads with very short durations. The large difference between the loci at short durations also raises other problems which we discuss below.

**INDUSTRIAL RESPONSE TO MARGINAL COST PRICING**

We are finally in a position to understand a number of the patterns of self-generation observed earlier, the connections between those patterns and others, and the marginal cost pricing that characterizes the Swedish power supply system.

**Industry's Choice of Generating Types**

In particular, industrial firms tend not to buy generating assets that display less than full scale economies unless they cannot be exploited at their most desirable scale in Sweden. The reason is simple. Figure 8 suggests that grid prices and tariffs make power from optimally scaled generating assets available to industry at very near their marginal costs. If industry

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\(^7\) In fact, the actual energy charges in Statens Vattenfallsever's Central Sweden tariff closely approximate those implied by the tariff in Fig. 8. Actual peak and off-peak energy charges of 3.5 and 3.0 ore per kwh are only slightly lower than the charges implied in Fig. 8 of 3.6 and 3.1. See Mitchell, Manning, and Acton (1976, p. 63).

\(^8\) This locus incorporates a 35 percent subsidy on capacity costs. Recall that because of the smaller scale of industrial cogeneration applications, costs will likely lie above this locus. But such cost adjustments do not change the general argument here. Higher subsidies are available.
Fig. 8—Cost comparisons for a Swedish industrial firm
attempted to use these in smaller scales, it would face higher costs and hence prefer power from the grid to self-generated power. As a result, industry generates its own power only when it can do at least as well as it can with power from the grid. This is a direct industrial response to Sweden's marginal-cost based electricity prices.

This response leads to a number of different investments. Marginal cost pricing of transmission services induces major industrial power producers to participate directly in large centralized nuclear and fossil-fuel condensing plants. And prices and tariffs in general induce all industry to avoid new investments in smaller condensing assets of all kinds. Although condensing capacity accounts for 17 percent of directly owned industrial capacity, it is used only on special occasions, and, more important, almost all condensing capacity is vintage stock left over from an earlier era of Sweden's electricity pricing and transmission. Instead, industry produces most of its power from two sources not so susceptible to scale economies: hydropower, whose costs depend more on locale than on scale, and cogeneration, which must have a heat load not typically available to major power producers on a large scale.

The major producers' inability to exploit cogeneration on a large enough scale to displace industrial cogeneration, however, does not guarantee the place of industrial cogeneration in the power supply system. As Fig. 8 indicates, only large subsidies make new cogeneration a viable alternative to nuclear. While these cost estimates are too crude to allow conclusions on the basis of these illustrations alone, Swedish industry recognizes the importance of the nuclear option. It also recognizes that as the price of oil continues to rise, new plants will tend to be coal fired and will likely require larger sizes to compete with the grid. That could make many local industrial heat loads too small to exploit. Hence, the same pricing system that currently makes a place for industrial cogeneration could reduce its importance in the near future. The Swedish pricing system, by showing industrial social marginal costs, induces these investment responses from industry.

**Grid Pricing and Self-Generation**

By making electricity available at prices that reflect costs closely, the grid makes cost-effective reserve power available to all industrial power generators and reduces the cogenerator's problem of matching local heat and power production to local heat and power demand. These in turn appear to encourage industry's almost exclusive use of steam turbines and to discourage industry's use of energy centers which coordinate different firms' production of heat and power. Consider these points in turn.

Even though directly owned industrial generation assets usually operate in niches "sheltered" from the scale economies of centralized plants, they also exploit the scale economies of the grid as a whole in an important way. Although major producers typically do not make a firm's connection to the grid conditional on its use of a reserve tariff for its self-generation, all cogeneration plants in Swedish industry exploit reserve tariffs instead of self-insuring. This strong reaction endorses the Swedish administrative pricing system.

Availability of power from the grid at prices near cost has also encouraged cogenerators to choose technologies strictly on the basis of the cost of producing electricity, and not on the basis of local ratios of heat and power loads or the speed with which cogeneration machines can be brought on line and "ramped" up and down. As noted in Section V, however, Sweden's administrative tariffs still make these "noncost" issues important in some cases. During the transitional months of September and April, a district heating system's ratio of heat to power demand is often so far below its winter norm that the system must buy grid power for a short
period. Similarly, following blackouts, industrial cogeneration machines recover so slowly that industry must either buy grid power for short periods or shut down industrial production. Industrial firms facing administrative tariffs find grid power too expensive to justify using it for these short periods.

These problems reflect the gap shown in Fig. 8 between tariffs and market prices for short duration loads. While that gap is strictly relevant only to short durations in the national system peak, a similar gap exists any time industry must buy power to cover loads of very short duration during the winter season.\textsuperscript{9}

Industrial firms that are members of the national power market do not face these problems—they result directly from inaccuracies in administrative tariffs. This difference between pricing arrangements has two important implications.

First, consumers under tariffs have often responded to these problems and similar ones by increasing their local power to heat production in an inefficient way: they "blow steam." Members of the national power market never do this. Blowing steam, a primitive and costly form of condensing that simply condenses steam into the atmosphere, is typically considered an emergency measure for releasing steam when the heat load stops unexpectedly. But it causes no damage to equipment and can be used for periods of up to one hour to enhance power production. Although local authorities may require the firm to install noise abatement equipment to reduce the loud noise associated with the practice, they never ban the blowing itself.

The practice is relatively common in Swedish industry. For example, Billerud Uddeholms 58 MW(e) cogeneration plant at Skoghall can increase its power production by 3 to 4 MW(e), or 5 to 7 percent. The Skoghall plant blows steam to generate less than .2 percent of its total production, but that production comes at critical times when the plant has sudden shutdowns or worse, when the plant might otherwise violate its capacity subscription. Holmens Bruk blows steam for up to 400 hours a year at its plants, in individual episodes never lasting more than an hour. Again, blowing accounts for a trivial percentage of Holmens Bruk's production, but it comes at critical moments.

Blowing steam is an extraordinarily expensive way to produce electricity. At the Skoghall plant, it costs about five times as much as normal cogeneration production costs. The running costs of blowing steam are two to three times as much per hour as those of condensing in a dump condenser; and a dump condenser is not an efficient condenser. But Swedish industry rarely uses a dump condenser. It is occasionally added for noise abatement but never as a way to enhance electricity production. Swedish industry sees a very simple trade-off. Using a dump condenser saves oil by allowing greater efficiency and saves feed water by not releasing purified steam into the atmosphere. To blow steam, a cogeneration plant needs more feed water capacity but need not invest in condensing capacity. In the end, the trade-off is between a relatively capital intensive but efficient option—the dump condenser—and a less capital intensive but inefficient alternative—the feed water capacity. Incidents in which condensing or blowing steam occur are infrequent enough that the more capital intensive option is not justified. In other circumstances, it might be.

Members of the national power grid meet short demands for power in more efficient ways. Stora Kopparberg and Krängede meet their peaks with hydro power. They and others can also

\textsuperscript{9}In fact, it is probably more pronounced. Off the national peak, only running costs of existing and unutilized production units need be incurred in the system to meet the short industrial demand. Hence, it is quite possible that system costs could be even lower than those suggested by the national power market locus in Fig. 8. For any purchases in the winter season, whether on the actual system peak or not, industry must pay for additional subscribed and peak-load capacity in accordance with that in the tariff locus in Fig. 8. This is precisely the season in which consumers' problems with local matching of heat and power and recovery from blackouts arise.
arrange short term power exchanges on the national power market without regard to capacity constraints. Both have recently installed dump condensers at their major cogeneration plants, but both agree that power production even from a dump condenser is costlier than the alternative. Greater variation in price would be required to make such production worthwhile. For both firms, a dump condenser offers an attractive form of noise abatement for the locales in which their plants stand.\textsuperscript{10}

The second implication of the gap between administrative and power market prices is that it allows the detection of some rather subtle costing problems in the administrative tariffs. Because they faced prices more clearly based on social costs than the tariffs were, the major power producers could recognize the inefficiency of inducing steam blowing in their tariffs. In addition to the tariff review mentioned in Section V, two reforms are under consideration. One is quite straightforward. It allows an industrial customer to draw up to a set number of megawatt hours over its contracted capacity limit (or equivalently, exclude a set number of megawatt hours from the determination of its peak-load charge), and then pay a high energy charge for those megawatt hours. In one experiment, one major power producer has stopped an industrial customer from blowing steam by giving him, with no capacity penalty, up to 500 MWh over his contracted capacity at 30 öre/kwh (71.34 mills/kwh). Both the producer and the industrial customer benefit from the change.

The second reform is slightly more subtle. The peak-load charge is based on an average of four maximum 6-hour consumption periods, each in a different month.\textsuperscript{11} By cutting one megawatt off the maximum in any one month, then, a customer can cut the capacity it is charged for by a quarter megawatt. By changing the average to include maxima in eight months, the major producers reason that the customer's incentive to remove any one megawatt from purchased power falls in half. But its incentive to make changes which affect its load throughout the peak period remains the same. Steam blowing is among the undesirable actions it will tend to discourage.

In the decision of what form of self-generation to choose, these problems with grid prices have been of second order significance. Most of the time, grid prices allow industry to avoid the problems of providing reserve power, matching heat and power loads, and meeting power loads rapidly. These features brought the steam turbine topping cycle to the forefront. While diesel cogeneration allows high power-to-heat production ratios and gas turbines allow fast starts and adjustments, steam turbines display low costs. These costs are so low that steam turbines have dominated diesels and gas turbines in the smallest cogeneration applications Swedish industry attempts. Because gas turbines and diesels are most cost-competitive at small scales, steam turbines have dominated the entire industrial and district heating market for Swedish cogeneration.

For similar reasons, Swedish industry to date has generally rejected the use of industrial energy centers where firms coordinate their heat and power production. Only two Swedish firms currently coordinate their activities in this manner, and they just began in 1979. Prices in the grid reduce the benefits obtainable from such arrangements.

Energy centers provide three basic benefits. First, they can facilitate matching the cogeneration plant's output to local heat and power needs. Second, increased local demand for heat and power makes it possible to use more separate cogeneration units, thereby increasing the reliability of the center. Third, holding the number of cogeneration units constant, increased local demand allows the use of larger units which, because of scale economies, allows lower

\textsuperscript{10} District heating systems also use a condensing technique called "recooling."
\textsuperscript{11} See Appendix A.
production costs. Appropriate pricing in the grid eliminates the relevance of the first two virtues. The third remains but, by itself, has apparently not been significant enough to justify the contractual costs of energy centers and to induce Swedish firms to coordinate their cogeneration activities.

In sum, while quirks still remain in Sweden's administrative tariffs, they are relatively minor and are being examined. On the whole, the basis of tariffs and market prices on social costs has led to universal industrial participation in the grid, a participation which appears to encourage simple and distinct patterns of industrial cogeneration.

The Importance of Short Run Response

With the exception of EFAM tariffs, industrial firms under administrative tariffs face no incentives to adjust to short run variations in system costs. While formal tariffs offer a simple two season pricing differential with the possibility of distinguishing a third in the extreme peak period, Fig. 6 (p. 42) shows that in recent years the short run national power market price has varied from marginally higher than zero to 24 ore/kwh (almost 6 cents). Variations of over 15 ore/kwh within a single month over which formal tariffs are constant are not at all unusual. As effective spot market prices, these prices show the marginal cost of the generating assets required to clear the market. Table 13 shows the shifts in generation made over a similar period to clear the market. Because administrative tariffs provide no information on short run cost shifts, these generating shifts must be met by members of the national power market.

Table 13 provides information both on generation shifts over the course of a year and on shifts between two markedly different years. Consider the inter-year shift between 1976/77 and 1977/78 first:

The two years show similar production levels; production during months in 1977/78 exceeds that in the corresponding months in 1976/77 by about 1.5 percent. But a water shortage during the winter season (October to April) of 1976/77 required a marked increase in production from thermal assets over that in the winter of 1977/78. With 7.8 percent less thermal capacity in 1976/77 than in 1977/78, the Swedish power system produced 22.5 percent more electricity during winter 1976/77 than during winter 1977/78; from given capacity thermal production was over 30 percent higher in the first winter than in the second. The power system met this primarily by producing more from conventional condensing and cogeneration assets. Correcting for asset changes between the winters, production expanded 25-fold from conventional condensing and 23 percent from cogeneration. Condensing was more responsive by two orders of magnitude.

We see a similar pattern within years. Demand for thermal production varies by a factor of 2.7 to 4.6 each of the years. Production from specific forms of thermal capacity varies over each year by factors of 2.4 (in both years) for nuclear, 5.2 to 5.7 for cogeneration, and 22.7 to 193 for condensing. The patterns of response are similar in both years and far more regular than the administrative tariff. The national power market is clearly at work here. This pattern is reinforced when we compare the data in Table 13 with data on the national power market.

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12 Unless otherwise indicated, all annual differences in this discussion are unweighted arithmetic averages of one year changes across months.
13 Based on system capacity measured on December 31.
14 There may have been some response from nuclear as well, but it was growing so fast during this period—17 percent annually—that the effects of breaking in new plants are impossible to distinguish from the efforts to respond to demand.
15 Note the similarity between the order of responsiveness here and that in the dispatch "stack" in Fig. 2.
Table 13
ESTIMATES OF MONTHLY PRODUCTION (GWH) FOR BUDGET YEARS
1976/77 AND 1977/78

<table>
<thead>
<tr>
<th>Date</th>
<th>Hydro From Current Flow</th>
<th>Hydro From Seasonal Storage</th>
<th>Total</th>
<th>Condensing Nuclear</th>
<th>Condensing Conventional</th>
<th>Cogeneration</th>
<th>Total</th>
</tr>
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<tr>
<td>July 1976</td>
<td>3659</td>
<td>0</td>
<td>3659</td>
<td>810</td>
<td>9</td>
<td>179</td>
<td>998</td>
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<td>August</td>
<td>2697</td>
<td>1084</td>
<td>3781</td>
<td>1016</td>
<td>394</td>
<td>369</td>
<td>1779</td>
</tr>
<tr>
<td>September</td>
<td>2545</td>
<td>1452</td>
<td>3997</td>
<td>946</td>
<td>766</td>
<td>524</td>
<td>2236</td>
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<tr>
<td>October</td>
<td>1574</td>
<td>2530</td>
<td>4104</td>
<td>1403</td>
<td>1376</td>
<td>744</td>
<td>3523</td>
</tr>
<tr>
<td>November</td>
<td>1976</td>
<td>2616</td>
<td>4492</td>
<td>1172</td>
<td>1740</td>
<td>851</td>
<td>3763</td>
</tr>
<tr>
<td>December</td>
<td>1601</td>
<td>2554</td>
<td>4155</td>
<td>1916</td>
<td>1709</td>
<td>949</td>
<td>4574</td>
</tr>
<tr>
<td>January</td>
<td>1507</td>
<td>2791</td>
<td>4298</td>
<td>1618</td>
<td>1734</td>
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<td>4573</td>
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<tr>
<td>February</td>
<td>877</td>
<td>3329</td>
<td>4206</td>
<td>1571</td>
<td>1511</td>
<td>989</td>
<td>4071</td>
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<tr>
<td>March</td>
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<td>1056</td>
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<td>3462</td>
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<td>4881</td>
<td>0</td>
<td>4881</td>
<td>1220</td>
<td>246</td>
<td>422</td>
<td>1888</td>
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<td>4771</td>
<td>0</td>
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<td>1134</td>
<td>56</td>
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<tr>
<td>August</td>
<td>3977</td>
<td>749</td>
<td>4726</td>
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<td>207</td>
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<td>4211</td>
<td>1512</td>
<td>750</td>
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<td>661</td>
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<td>914</td>
<td>3786</td>
<td>4700</td>
<td>1941</td>
<td>147</td>
<td>958</td>
<td>3046</td>
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<tr>
<td>March</td>
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<td>3649</td>
<td>5064</td>
<td>2296</td>
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<td>2345</td>
<td>4359</td>
<td>1961</td>
<td>86</td>
<td>893</td>
<td>2940</td>
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<tr>
<td>May</td>
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<td>4092</td>
<td>1504</td>
<td>249</td>
<td>569</td>
<td>2312</td>
</tr>
<tr>
<td>June</td>
<td>3874</td>
<td>0</td>
<td>3874</td>
<td>1601</td>
<td>84</td>
<td>311</td>
<td>1996</td>
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</tbody>
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The data in Fig. 6 (p. 42) offer a crude measure of average monthly prices in this market. By regressing monthly production data from the table on average monthly price data for January 1977 to June 1978, we find that a 1 percent increase in price is associated with a .2 percent increase in nuclear production, a 1.2 percent increase in cogeneration production, and a 4.1 percent increase in conventional condensing production. These point to considerable price responsiveness by cogeneration and condensing capacity, responsiveness that only the national power market could elicit.

An examination of the ownership of condensing capacity confirms this suggestion. As noted

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16 These are calculated by using an unweighted average of the prices at the top and bottom of each shaded block in Fig. 6. These prices are themselves averages of prices in "peak" and "off-peak" production in each month. While this is obviously a very crude measure of price, the price variation among months appears large enough relative to that within months to suggest that the prices calculated reflect some relevant information.

17 More specifically, a model of the form

\[ \ln Q = a + b \ln P + u, u \sim N(0,\sigma^2) \]

is posited where Q is the relevant quantity produced and P is the price. b measures the elasticities reported in the text. All estimates of b are significant at at least the .001 level in a one-sided test. Even over this very short period, the structure of the power system is not stable. Table 13 reveals that nuclear grew significantly over the period and a resulting drop in cost over time can be detected visually in the data. Given the crudeness of the data, however, further statistical refinement seems unwarranted.
earlier, Statens Vattenfallsverk owns three-quarters of the nuclear capacity in Sweden; of the remainder only a small fraction belongs to firms outside the national power market. Those within the market have a clear incentive to assure that nuclear power responds to the national power market. Similarly, 93 percent of Sweden's condensing capacity is directly owned by members of the national power market. Furthermore, members of the market have acquired over two-thirds of their condensing capacity during the last fifteen years; nonmembers have acquired only 1.3 percent of theirs during the same period. Nonmembers do not buy condensing capacity because they do not use it. These numbers suggest that the condensing response we observe in Table 13 is all by members of the national power market. We can go further to say that it is the response of members with large condensing machines. As noted in Section IV, industrial members of the market like Stora Kopparberg, Gränges, and Krängede only rarely find it profitable to run their large combination condensing-cogeneration turbines in a condensing mode.

Ownership of cogeneration, however, raises serious doubts about the hypothesis that cogeneration responds because it too is held by producers who face national power market prices. Eighty-five percent of industrial cogeneration and 47 percent of district heating cogeneration are directly owned by firms facing administrative tariffs. If cogeneration responds to prices, only a portion of Sweden's capacity can be doing so. Why would firms facing such different pricing structures use such similar generating assets? We now look into this puzzle.

Cogeneration and Baseload Capability

The data presented thus far place cogeneration somewhere between fossil-fueled condensing plants, which provide cycling capacity in Sweden, and nuclear condensing plants, which provide baseload capacity. Figure 2 (p. 10) places it between these two in the dispatching stack. Table 12 and Fig. 7 suggest that its costs are consistent with this placement. And the relationship of cogeneration production and power market prices suggests the same conclusion. In fact, cogeneration's position in the dispatching stack and its apparent price responsiveness result from its dependence on an available heat load. We first document that point and then examine two exceptional forms of socially desirable price responsiveness associated with cogeneration.

Figure 9 illustrates the strong similarity of seasonal patterns in Sweden's national heat load and its production from cogeneration. District heating accounts for most of this variation. While industry's demand for heat is driven primarily by the rate of industrial output production, which is typically more or less constant over the year, district heating demand closely reflects the temperature changes that affect the total national demand for heat. The apparent price responsiveness of cogeneration, then, is spurious. It results from the fact that (a) national heat demand, district heating demand, and demand for electricity production from thermal sources are closely correlated over the year; (b) national power prices are closely correlated to electricity production from thermal sources; and hence (c) high demand for heat tends to make cogeneration available when national electricity prices are high.

Swedish industry and district heating officials confirm the central importance of the heat load for cogeneration and the relative insensitivity of cogeneration to price variations. They

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18Fraction of maximum monthly heat load and cogenersted electricity production appear on the ordinate; months of the year occupy the abscissa. The production figures are calculated from the two years of data in Table 13. The heat load pattern is Centrals Driftledning's 1975 forecast for 1980, reported in Västerås Stads Kraftvärmeverk AB, 1975.
19The major exception is the sugar refining industry.
Source: Centrale Driftslneg

Fig. 9—Comparison of national heat load and cogeneration electricity production
also stress, however, the importance of two limited but significant sources of socially desirable price response. The first is response to low prices and EFAM tariffs when hydro resources are plentiful; the second is a special form of condensing that allows district heating systems to enhance their power-to-heat production ratios.

The first occurs in specific periods during the spring and summer. During Sweden’s spring flood, water runs out of storage magazines unexploited (May to July in Table 13). And during Sweden’s July industrial holiday and summer weekends (1700 Friday evening to 0600 Monday morning), demand for electricity slackens significantly. During these periods, the national power market price can drop to as low as .3 öre (.7 mills) per kilowatt-hour.20 Industrial cogenerators recognize this situation immediately in the national power market or through EFAM rates which the major producers offer during this period.

The total amount of power drawn by industry under such circumstances can be significant. For example, Billerud Uddeholm’s Skoghall plant obtained about 7 percent of its total electricity energy needs and over 15 percent of its electricity purchases under EFAM tariffs during 1979—not an atypical year. Under these circumstances, the plant simply turns off its turbines, turns back its boilers, and shunts steam from the boilers through pressure reduction valves to its points of heat demand. Stora Kopparberg’s plants respond in a similar way. Other plants shut down their cogeneration turbines and boilers and turn to standby boilers for heat needs. Recall that Billerud Uddeholm faces administrative tariffs; Stora Kopparberg is a member of the national power grid.

On occasion, prices are so low that it pays to turn the oil-fired boilers off as well. In a typical year, this occurs for about 15 days in spring flood and summer holiday. In rainy years, however, it occurs for up to 70 days during the spring and summer. Again, summer weekends are the most common times. Energy charges for the electricity are so low that it pays for firms to maintain electric boilers for precisely this purpose. Alternatively, a major producer can keep electric boilers on site. For example, Statens Vattenfallsverk maintains boilers in Västerås with sufficient capacity to meet 55 MW(th) of Västerås’ 80 MW(th) requirement in July. Through one arrangement or another, then, many large industrial customers have access to electric boilers with which to exploit EFAM tariffs.

The second form of response, a practice in district heating systems known as “recooling,” enhances the power-to-heat output ratio by creating an artificial heat load. While not important in Swedish industrial cogeneration now, this practice may become more important as coordination between industrial and district heating applications of cogeneration grows.

If a district heating cogeneration turbine is running below its rated capacity, “recooling” to create an artificial heat load on the district heating grid can increase the power output of the turbine associated with a given real heat load. For example, either air or cold water can be pumped past heat exchangers in the grid to increase the heat load. It can have a significant effect: recooling in the Uppsala municipal district heating system can produce 210 MW(e) in conjunction with a real heat load that would typically allow production of only 170 MW(e).

This concept grows out of a recognition that district heating cogeneration turbines effectively condense into a heating grid; by increasing the heat load in the “condenser,” recooling effectively allows the turbine to produce condensing power. And in fact, the cost of this electricity is not much higher than that from central station condensing plants.21 As a result, recooling capacity is typically provided in new district heating grids. This condensing capability can

20Compare Fig. 6, p. 42.
21With admission steam at 105 bar and 590 degree C, recooling has a heat rate of 2240 kcal/kwh (8889 MBtu/kwh) Kühler, 1973, p. 25)
compete with central condensing plants because it is contingent on the presence of cogeneration. The presence of cogeneration, a technology not available at central plants, keeps the cost of this condensing capability down, giving recooling a competitive place in the power supply system.

District heating systems have used this condensing capability to deal successfully with the sorts of price-induced problems associated with blowing steam. It allows district heating systems to avoid violating their subscribed capacity and peak-load maxima when the local power-to-heat demand ratio is abnormally high. What differentiates recooling from blowing steam is that recooling is also used by district heating systems that are members of the national power market. It is cost effective from a social point of view.

Thus, while electricity prices induce cogenerators to shut down for periods during the spring and summer and to condense via recooling to meet local short term power demands, these forms of price responsiveness are of limited importance. Most of the time, both industrial cogeneration and district heating cogeneration are unresponsive to price because cogeneration is so fuel efficient. This is true of cogeneration units which face both formal tariffs and national power market prices. In the face of significant price variation in the Swedish electrical supply system, cogeneration runs primarily as baseload capacity.

SUMMARY

Accepting that formal administrative tariffs reflect relevant social costs now appears more reasonable than it did before we began this discussion. We observed that what appears to be undesirable behavior occurs in circumstances where formal tariffs and relevant costs can be shown to diverge. More typically, both administrative tariffs and national power market prices appear to induce the application and use of cogeneration in Swedish industry. This suggests that, on the whole, Swedish electricity prices act as a veil for underlying social costs.

Formal tariffs diverge from relevant costs in the short run by providing only limited information on the variation in short run marginal cost. As a result, only members of the national power market respond to changes in excess demand for power. The principal plants used to meet short term variations—oil-fired condensing plants—are owned and operated almost exclusively by members of the market. In the longer run, formal tariffs encourage cogenerators to be self-reliant for loads of very short duration when social costs dictate greater dependence on the grid. This leads to a costly form of condensing known as blowing steam, which members of the national market never use.

More typically, both tariffs and market prices induce desirable responses in the use of industrial cogeneration. All cogenerators interconnect with the grid, relying on grid power to provide reserve power and in most cases, to make up the difference between local production and consumption of heat and power. As a result, almost all cogenerators also use steam turbines and do not participate in industrial energy centers. Industrial firms either buy into centralized power plants or, under either tariffs or market prices, exploit local generation sources like cogeneration and hydropower that depend on factors—local heat loads and terrain—not available to central generators. Through EFAM tariffs and the power market, all cogenerators respond to national surpluses of hydropower by stopping local power production and sometimes even local heat production. District heating systems under administrative and market pricing respond to power demands of short duration by recooling or condensing additional steam into their district heating grids.

Within such a power supply system, cogeneration provides baseload capacity for industry
and district heating. Although EFAM tariffs and their power market analog and recouping opportunities do induce cogenerators to change power production in response to price, price is a far less important determination of cogeneration use than are variations in available heat load. Given a heat load, cogeneration stops only when surplus hydro power is available, an increasingly rare occasion. And cogenerators rarely sacrifice heat production to get more power. This is not only an effect of administrative tariffs. Even members of the national power market with combination condensing-cogeneration units use these units less and less in a condensing mode.

The principal implication is that within the range of current variation in Swedish national power market prices, cogeneration responds far more to the level of prices than to their structure. Despite this, the seasonal pattern of heat and power demands in Sweden allows cogeneration to displace, not baseload capacity, but more costly cycling capacity.

The general level of production costs is critical to the future use of cogeneration. Nuclear power is now very competitive with cogeneration in Sweden. Coal-fired condensing will become competitive as oil prices continue to rise. Despite industrial cogeneration's fuel-efficiency, rising oil prices hurt it by making coal-fired alternatives more attractive. These alternatives are attractive only at larger scales than many current industrial cogeneration applications can justify. They also emit more air pollution than current cogeneration units, raising a question about the relative desirability of remotely sited central generating plants over industrial and district heating plants that are more typically located near population centers. In the end, then, rising oil prices could cripple one of Sweden's most energy-efficient electricity generating options.
VII. CONCLUSIONS AND IMPLICATIONS FOR U.S. ENERGY POLICY

In Sweden, where the pricing system for electricity is closely linked to the industrial use of cogeneration, a well-coordinated electricity grid and national power market assure at least some price competition among all electricity sources—including industrial cogeneration. Although the pricing in that electricity grid may not always lead to socially efficient use of cogeneration, divergences from efficiency are predictable and correctable. And Swedish rate-makers appear to be moving toward eliminating these divergences.

This study is not meant to generate direct recommendations for U.S. energy policy, but its major findings discussed here point to certain implications and raise questions that deserve more attention than they now receive in the United States. The Swedish experience often answers these questions, but more information about the United States itself is needed before the Swedish electricity supply system—with its mix of pricing mechanisms, interconnection via a national power grid, and benefits of industrial cogeneration—will be transferable to this country.

A MIXED PRICING SYSTEM

- Sweden uses a mix of administrative and market electricity pricing mechanisms.

On one hand, the Swedish national power market allows vigorous competition among Sweden’s major power producers; the prices that result furnish objective measures of social cost, thus allowing cost-efficient coordination of Swedish power production over a variety of time horizons without central direction. On the other hand, access to this market is limited to only a small number of power producers by effective restrictions on third party wheeling. Other electricity consumers must rely on local competition among producers or, where they are connected to only one producer, on negotiation with that producer to set a price. That negotiation rarely moves far from a standard formal tariff set by the producer, on the basis of stated marginal-cost based pricing principles. Such formal tariffs are subject to a regulatory review, but this occurs only when the consumer refuses to accept a negotiated price, which is rare.

While such a mixed pricing system differs significantly from that used in the United States today, it represents a viable option for America’s future. It also raises serious issues about marginal cost pricing of electricity that are likely to be relevant to America’s future experience with such pricing.

- Sweden demonstrates the viability of a mixed pricing system that could be adopted in the United States.

At a minimum, the system demonstrates the feasibility of vertical disintegration of the U.S. electrical utilities and competition among generators, policy proposals that are gaining support in the United States today. It demonstrates that high system reliability and efficient production of power are possible in such a system without central dispatch or unit commitment. More important, it demonstrates that vertical disintegration and competition need not force the abandonment of deeply rooted U.S. beliefs about regional preference for power and “fair” profits
from the provision of electrical services. The Swedish system, by preserving local preference and various profit controls, shows that a mixed system can achieve many of the goals of people who favor competition in electrical markets, without sacrificing the political and social goals of those who oppose it. As a result, it presents a mixed form of pricing which the United States might find quite attractive.

- **Sweden illustrates the practical compromises that arise in a mixed pricing system.**

Pricing systems that mix economic and political goals can be expected to be complex. Sweden provides innumerable practical examples of the implications of such a system, examples that simply would not be deduced from tariffmaking theory, at least in its present state. While the electricity pricing experience of other Western European countries yields similar surprises from a theoretical point of view, the interaction of competition and administered pricing in Sweden adds a special sophistication to ratemaking there. It is a form of sophistication one would expect to arise in such a mixed system—a form, for example, that might appear in the United States under similar pricing.

Competition in Sweden requires each producer to give special attention to his own offer and bid prices for various kinds of contracts, and this decentralized concern for marginal cost inevitably leads to diverse views about the meaning of marginal cost. Further, the cost of creating contracts prevents perfect matches between price and marginal costs, which means that many specialized forms of contracts are needed. These forms, which evolve over time with changing perceptions of marginal cost, in turn change the general concepts about marginal cost, thus creating a dynamic source of new ideas about how to form desirable new contracts for electricity. Ultimately these concepts form the basis for the social marginal costs that are used to justify administered prices.

Major producers and consumers, with the state-owned producer Statens Vattenfallsverk in a particularly prominent position, continually update a consensus to accept marginal cost based pricing. Hence even where electricity users do not have direct access to competitive electricity markets, such markets support a conceptual dynamic which ultimately results in improved administered tariffs. By the same token, this dynamic depends on a diversity of perceptions of social marginal cost which reduces the credibility of any particular version used to justify existing administrative tariffs. This apparent paradox is reflected in a simultaneous discontent with electricity pricing in Swedish industry and elsewhere, and pricing that continually improves over time. The net result is increasingly sophisticated and efficacious administered prices.

- **Serious problems of administered pricing can persist in a mixed pricing system.**

Despite market competition, the Swedish system does not provide an independent, objective test of the marginal costs used to justify formal tariffs. As a result, serious differences about the adequacy of estimated costs can persist and even raise doubts about the motives underlying certain formal tariffs. For example, Statens Vattenfallsverk and the other major producers use expected long run marginal costs as a basis for their standard tariffs. This choice can be interpreted either as a way to force the proper perception of costs over the long run and hence the proper investment in electricity-using equipment today, or as a way to subsidize electricity use at the margin, increase demand, and hence enhance the position of the producer both in the energy market and in a larger social/political context. Profit constraints that require departures from marginal cost to generate allowed revenues compound the confusion. The socially conscious producer and the output maximizing producer will raise prices above marginal cost for the same services—electrical services that consumers will take at almost any price.
Prohibitive pricing of third party wheeling can also be seen as a mechanism for achieving either end. Distinguishing between these without an objective test of actual marginal costs in a totally free market is difficult in a mixed pricing system of the Swedish type. We should expect similar problems in the United States.

In sum, while Sweden's mixed pricing system offers compromises that might provide a basis for a viable system in the United States, such a system would carry predictable problems with it. Over the years, the Swedes have brought increasing sophistication to the resolution of these problems, and we should expect that to continue. The United States will find the sophistication evident in Sweden's decentralized system useful in its move to marginal cost pricing, whether it chooses to move to a similar mixed system or not.

INTERCONNECTION VIA A NATIONAL POWER GRID

- Swedish industrial cogenerators always interconnect with the national power grid.

This practice, which is markedly different than U.S. practice to date, reflects two important features of the Swedish electricity supply system. First, in itself, it strongly indicates the social desirability of backup rates in the Swedish electricity grid. The statistical Law of Large Numbers creates indefinite scale economies in reliability as more electricity sources coordinate their production. Interconnection allows precisely such coordination and hence provides an unambiguous social benefit. That Swedish tariffs lead to interconnection suggests that they provide a viable way to split these benefits. Second, it reflects a relatively low level of transmission losses in the grid and the rigorous competition this low level allows throughout Sweden. On average, high voltage transmission losses consume less than 7 percent of Sweden's transmitted power. With grid prices reflecting costs in the grid, each electricity source in Sweden must compete on very close to equal terms with every other source in the country. Only areas isolated from the grid do not have this competition, and they are almost pathological cases.

Transmission losses in the United States are even lower on average than those in Sweden. Hence, we should expect to see a similar pattern of interconnection and competition emerge in the United States as it moves toward more appropriate electricity prices. The Swedish experience suggests that such interconnection will have two important effects on industry's choice of generation technology.

- Sweden's interconnection and pricing practically eliminate the need to match cogeneration heat and power outputs to local needs.

With appropriate tariffs, a cogenerator can size his capacity to the local heat load and depend on the grid to take excess power or cover power deficits. Under such circumstances, cogeneration competes with other power sources in the grid on equal terms, yielding two significant outcomes:

1. With few exceptions, Swedish industry and district heating systems use only one form of cogeneration outside of an experimental context: the topping steam-turbine. Given the annual load typical of Swedish cogeneration applications, the topping steam turbine displays the lowest net electricity production costs of any cogeneration technology. An integrated grid with prices that mirror production costs in the system as a whole dictates the choice of the least costly electricity source.

This striking pattern is particularly relevant to U.S. energy policy because of the diversity of cogeneration technologies currently receiving attention in the United States. While some
technologies other than the steam topping cycle are promoted to meet shorter annual loads or other special requirements, the most important factors that support such diversity are the perceived need to match a cogeneration installation's output to local heat and power demands and the need for quick starts. The pattern of interconnection that Swedish electricity pricing leads to raises serious doubts about the relevance of many of these varieties of cogeneration when the United States achieves prices based on marginal cost.

2. Swedish industry does not use "industrial energy centers," in which several industrial plants draw on a single cogeneration plant. To understand the importance of this pattern to the United States, we review the principal perceived costs and benefits of such energy centers.

The principal cost of such centers comes from the complexity of the contracts required to split whatever benefits arise from cooperation. While the Swedes and Americans have both overcome this problem in jointly owned electricity plants, the additional jointness added by cogeneration creates problems that Swedish industry has handled in only the crudest manner. Given the relative lack of experience in pricing cogeneration in the United States, we could expect U.S. firms to have even greater difficulties. On the basis of costs alone, then, Sweden would appear more likely than the United States to attempt the complex contractual invention required to allow industrial energy centers to exist.

On the benefit side, energy centers display three principal virtues. First, they can facilitate matching the cogeneration plant's output to local heat and power needs. Second, increased local demand for heat and power makes it possible to use more separate cogeneration units, thereby increasing the reliability of the center. Third, holding the number of cogeneration units constant, increased local demand allows the use of larger units which, because of scale economies, allows lower production costs. Interconnection with appropriate pricing practically eliminates the relevance of the first two virtues. The third remains, but by itself has apparently not been significant enough to justify the contractual costs of energy centers and induce Swedish firms to coordinate their cogeneration activities. We have no a priori reason to believe that the benefits of such scale economies would look any more attractive in the United States than in Sweden.

Hence Sweden's failure to use energy centers raises serious doubts about their efficacy in the United States under appropriate marginal cost pricing. Note, however, that as coal becomes increasingly less costly than oil, the scale economies associated with coal use in cogeneration could promote the future use of such centers in both countries.

- Sweden's interconnection and socially desirable tariffs make cogeneration the dominant industrial self-generation technology.

As noted above, interconnection and grid pricing that mirrors costs force each electricity source to compete with every other on equal terms. Scale economies in all forms of electricity generation over the ranges of interest to industry and most district heating schemes make centralized production attractive whenever possible. Hence generators located at industrial plants can compete with central generating plants only if they have some factor the central plants cannot use. In Sweden, the "factor" that keeps the net costs of electricity down for industrial cogeneration, despite its typically small scale, is an industrial heat load.

This explains the dominance of cogeneration in Swedish industrial electricity generation. While Swedish industry holds condensing capacity, it has added none since 1969 and it is converting condensing units to back-pressure configurations. Existing industrial condensing capacity is now typically used only once in ten years to meet the energy deficits that accompany dry years. The dominance of cogeneration over condensing extends even to dominance over combination condensing-cogeneration configurations, a point discussed in more detail below.
Swedish industry does maintain a significant number of small diesel generators without cogeneration capacity, but only to protect vital local functions from a failure of the grid as a whole.

In sum, low transmission losses and appropriate pricing in the Swedish grid lead to nearly universal participation in the grid. This in turn strongly favors the use of only one form of industrial generation, the steam topping cogeneration cycle, and reduces the need to coordinate industrial energy needs around energy centers. It appears reasonable to expect similar patterns in U.S. industry as marginal cost electricity pricing advances in the United States.

**BENEFITS OF INDUSTRIAL COGENERATION**

- A *compatible heat load drives the use of cogeneration to generate power in Sweden.*

What makes cogeneration interesting is its ability to provide heat and power at lower total cost than separate sources of heat and power can achieve. This ability is important only in circumstances where a demand for both heat and power exists. Because electricity is easy to transport and to trade in a competitive market, while heat is not, the viability of cogeneration in any locale requires the presence of a heat load in that locale. In itself, this is relatively straightforward, but it leads to two less obvious points.

- *Swedish industrial cogeneration is only slightly responsive to the structure of electricity prices.*

The general level of electricity prices is obviously important to the decision to invest in cogeneration. Swedish government subsidies to industrial cogeneration in fact allow it to be competitive at a significantly lower electricity price level than would be required otherwise. But two factors limit Swedish cogeneration’s response to variations in system prices over time.

First, system prices reflect short run marginal costs of the marginal units in the Swedish system. With an appropriate heat load, industrial cogeneration is so energy efficient that its low running costs make it inframarginal almost all of the time. System prices fall below cogeneration running costs only when hydroelectric power is the marginal source of electricity in the system, an occurrence of falling importance and certainly one not likely to be important in the United States. As nuclear power grows in Sweden, with running costs lower than those of oil-fired cogeneration, it could occupy the margin much as hydro does and hence force cogeneration to respond to prices. Nuclear is expected to be less important in the United States than in Sweden. In any case, given a heat load, cogeneration is so efficient that it behaves much like a baseload plant, which we do not expect to respond to changing electricity prices over time.

Note that such behavior need not suggest that cogeneration displaces baseload capacity in an electricity system. For example, because Swedish district heating loads are strongly correlated through time with electricity demand, they create an opportunity for cogeneration just as the demand for intermediate capacity begins to rise. Such cogeneration displaces not baseload plants but cycling plants.

Second, adding condensing capability to Swedish cogeneration units raises their running costs so high that they are typically not competitive with centralized peaking and cycling plants interconnected to the Swedish grid. Hence, Swedish grid prices do not rise high enough often enough to allow Swedish industry to recover its investment in such additions. There are two exceptions to this disinclination to run cogeneration units in a condensing mode. One is blowing steam, which is too costly to justify on social grounds, but which occurs where tariffs fail to
reflect social marginal costs. The other is recouping, through which cogeneration running below capacity "condenses" into a district heating net to increase its heat load and hence its electrical output. The latter is an increasingly important example of a cost efficient condensing mode for Swedish cogeneration. It must occur on a large scale to compete with central generating units and is currently used only in district heating cogeneration installations.

Whether we should expect a similar lack of response in the United States is somewhat problematical. On the one hand, with the exception of areas dominated by hydro, the United States displays far greater variation in short run marginal cost over time than does Sweden. This increases the attractiveness of running cogeneration in a condensing mode by increasing the likelihood that it can compete with larger scale central power sources. On the other, we can expect the variation in short run marginal cost over time to fall in the United States as more appropriate rates progress and more coordination occurs in the grid.

- The availability of a power demand can drive the use of cogeneration to generate heat in Sweden.

While this observation simply results from the symmetry of the joint products of cogeneration, it is often neglected. For example, the most important U.S. studies of the penetration of cogeneration start with existing or projected industrial heat loads and use these to determine where cogeneration would be viable (Dow, 1975; Thermo Electron, 1976; Resource Planning Associates, 1977). Similarly, Swedish industry typically values and prices the heat output of its cogeneration at the cost of providing heat in stand-alone boilers, implicitly allocating all the joint benefits of cogeneration to power production. But when the grid effectively sets the price of electricity, cogenerators can set the value of their power production at that price and allocate the joint benefits of cogeneration to heat production, thereby lowering their reservation price for heat. This is the basis for a number of proposals by Swedish engineering firms for district heating systems supplied by cogeneration, in Sweden and in the United States.

As our acceptance of the symmetry of heat and power in cogeneration grows, we should expect more proposals of this kind, in district heating and perhaps within industry as well. As it progresses, proper pricing of heat will become a more important issue. Even if demand for heat does not vary over time, we can expect its price to vary in order to reflect the changing value of the cogeneration plants' power output over time. Because heat demand is time dependent, at least in district heating systems, it could in a symmetrical manner affect the time dependent offer price of power. These are pricing issues which, to date, have received little attention in Sweden or the United States.

In sum, the relationship between the heat and power outputs of cogeneration significantly affect its use and pricing. When a heat load is present in Sweden, the net cost of power from cogeneration is so low that cogeneration is typically inframarginal and hence unresponsive to price. Cogeneration can be run in various condensing modes, effectively by wasting usable heat output. But with one exception, recouping, their short run marginal costs are typically too high to justify such practice in the Swedish grid. It is more likely to be appropriate in the United States grid, which currently displays much greater variation in marginal cost over time than the Swedish grid does. To date, Swedes and Americans typically allocate the joint benefits of cogeneration to power, but it is equally valid to allocate benefits to heat. This is done in grid-connected district heating applications of cogeneration. More sophisticated pricing of heat and power from cogeneration than exists in Sweden or the United States will be required to reflect fully their production relationship and its implications for their joint application in an integrated grid.
OIL, COAL, AND COGENERATION

- *Despite its energy efficiency, Swedish cogeneration is hurt by rising oil prices.*

As oil prices rise, the fuel costs of electricity generation rise relative to its capital costs. That increases the attractiveness of fuel-saving generation technologies like cogeneration. But it also induces substitution away from oil toward coal, natural gas, and nuclear fuels. This fuel switching hurts Swedish cogeneration in two ways.

- *Greater scale economies in Swedish alternatives to oil discourage industrial use of cogeneration.*

Because Sweden has no natural gas infrastructure, its primary alternatives to oil are coal and nuclear. Generation units that use both these fuels display greater economies of scale than do oil-fired units. Because industrial cogeneration units are typically small—less than 10 MW—it is harder for them to compete with central generating units in a grid with cost-based pricing. It effectively eliminates the market for smaller industrial cogeneration units. Continuing uncertainty about nonprice aspects of these alternatives—environmental and safety issues—mitigate the price effect to some extent. But, *ceteris paribus*, we can expect continuing oil price rises to continue to raise the relative attractiveness of these alternatives and thereby reduce the market for industrial cogeneration.

With its extensive gas infrastructure and apparently abundant gas supplies at high enough prices, the United States has a gas alternative to oil which, properly exploited, makes this problem less important to the United States. But if gas is withheld from U.S. cogenerators, as some American policymakers recommend, U.S. industry could face a problem quite similar to that of Swedish industry.

- *Use of coal in cogeneration raises serious environmental problems.*

One natural reaction to the Swedish problem is to use larger cogeneration units in order to exploit the economies of scale of coal. This can be done either by building large cogeneration plants to supply district heating systems, an option Sweden is actively exploiting now, or aggregating industrial demands for cogeneration in large, industrial energy centers, an option seldom used in Sweden. Both options typically require that the cogeneration units involved be located near urban areas. While that has been acceptable to local Swedish officials when oil was burned, the same officials are less comfortable with burning coal near their homes. They fear its consequences.

A comparison of environmental regulations in Sweden and the United States suggests that this sort of problem could be even more severe in the United States. Local Swedish officials tend to have more control over environmental matters than their counterparts in the United States. They have favored oil-fired cogeneration in the past as a way of making district heating cost efficient. District heating has demonstrably lowered sulfur and particulate levels in local Swedish communities. It does this in part by “exporting” pollution from the community via high stacks at the cogeneration plant. Because communities receiving this pollution do not have nearly the power that local officials do with respect to the decision to allow it, Swedish communities have been more willing to cogenerate in populated areas than their U.S. counterparts might be. Hence, if these same officials now oppose the use of coal in populated areas, we might well expect even greater resistance in the United States. This in turn suggests that a general move toward coal could be even more detrimental to cogeneration in the United States than in Sweden.
In sum, rising oil prices in Sweden hurt industrial cogeneration by inducing fuel switching to coal and nuclear fuels which require technologies with greater economies of scale than oil-fired technologies. Availability of gas to U.S. industry could mitigate this effect in the United States. Where switches to coal induce the use of larger cogeneration units, in district heating and industrial energy centers, they also force the use of coal in populated areas. U.S. environmental regulations could raise even greater barriers to this practice than do the relatively high barriers evident in Sweden today. These barriers in turn discourage the use of cogeneration.

In closing, it is important to emphasize once again that each of these conclusions about Sweden and implications for U.S. policy is based on a more detailed understanding of cogeneration and electricity pricing in Sweden than of their counterparts in the United States. The study this report draws on was initiated to understand Sweden, not the United States, and its results must be understood in that light. Hence, while the conclusions about Sweden stand on relatively firm empirical ground, the implications for the United States are better viewed as hypotheses about policy than as policy recommendations. They are meant to use the Swedish experience to raise questions about practice in the United States. While the Swedish experience can also help answer these questions, final answers await a more detailed examination of circumstances in the United States.
Appendix A

STANDARD AND RESERVE TARIFFS FOR TWO MAJOR POWER PRODUCERS

The two administrative tariffs most important to Swedish industry are the standard and reserve tariffs. This appendix presents the price components offered by two major Swedish power producers in their published standard and reserve tariffs. Table A.1 presents information on Statens Vattenfallsverk’s high voltage tariffs for customers in central Sweden, where most industry lies.1 Table A.2 presents price information from high voltage tariffs offered by Bålforsens Kraft AB, a power producer in northern Sweden, closer to Sweden’s principal hydro sources of power. A close look at these tariffs helps illustrate how notions of long run marginal costs are incorporated into Swedish tariffs.

THE STANDARD TARIFF

The "standard" high tension tariff provides for firm purchase of electricity. It is the tariff most often offered by members of the national power market to municipal and industrial customers that are typically connected to only one power producer and hence maintain only one standard tariff. In the past, this tariff could be written for fifteen years. Currently, tariffs are written for one or two years at a time.

The tariff has four distinct parts: fixed charge, a contractual or subscribed charge, a peak-load charge, and an energy charge. As Tables A.1 and A.2 indicate, the types of tariff components (charges) are identical for the standard tariffs of our two producers. The tariff blocks differ only slightly. Vattenfall offers a greater variety of lower voltage tariffs (Tariff Block 3), differentiating them in part on the size of capacity demanded. Bålforsen also offers differentiated lower voltage tariffs but uses total hours of electricity demanded during the year to differentiate them. While Vattenfall offers energy charges differentiated by time of day, Bålforsen does not. A marked similarity continues when we compare specific magnitudes of charges, but these do differ between the tariffs. To understand these differences, let us consider the doctrinal cost basis for each charge.2

First, the fixed charge is designed to cover accounting and metering costs. It is also used to make adjustments in the tariff when total revenues are not expected to equal actual system costs. As Tables A.1 and A.2 indicate, it can be a very large sum but varies substantially by tariff block. Because accounting and metering costs are unlikely to vary this dramatically across these blocks, the revenue adjustment would appear to be significant. Note, however, that while Bålforsen does not face the same revenue constraint Vattenfall sees, the charges are identical. The reason cannot be competition. Absence of third-party wheeling gives the typical high voltage customer no choice about his supplier. More likely, Vattenfall's choice of fixed

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1For convenience, this appendix refers to Statens Vattenfallsverk by its commonly used, abbreviated name, "Vattenfall."

2For a more detailed cost justification of those charges, see Edblad et al. (1975) or Mitchell, Manning, and Acton (1978).
Table A.1

**HIGHT VOLTAGE TARIFFS FOR STATENS VATTENFALLSVERK, 1978-1979**

<table>
<thead>
<tr>
<th>Item</th>
<th>Standard Tariff</th>
<th>Cogeneration Reserve Tariff</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Block 1 70-130 kv</td>
<td>Block 2 20-40 kv</td>
</tr>
<tr>
<td>Fixed charge</td>
<td>Skr/10³</td>
<td>200</td>
</tr>
<tr>
<td></td>
<td>$ 10²</td>
<td>47.62</td>
</tr>
<tr>
<td>Contractual (subscribed) charge (1 hr)</td>
<td>Skr/kw</td>
<td>15</td>
</tr>
<tr>
<td>Peak-load charge (6 hrs)</td>
<td>Skr/kw</td>
<td>140</td>
</tr>
<tr>
<td></td>
<td>$/kw</td>
<td>33.33</td>
</tr>
<tr>
<td>Insured unit charge</td>
<td>Skr/kw</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$/kw</td>
<td></td>
</tr>
<tr>
<td>Daily capacity charge</td>
<td>Skr/kw</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$/kw</td>
<td></td>
</tr>
<tr>
<td>Energy charge May-August</td>
<td>üre/kwh</td>
<td>5.8</td>
</tr>
<tr>
<td></td>
<td>mills/kwh</td>
<td>13.3</td>
</tr>
<tr>
<td>September-April</td>
<td>üre/kwh</td>
<td>6.7</td>
</tr>
<tr>
<td></td>
<td>mills/kwh</td>
<td>16.0</td>
</tr>
<tr>
<td>0600-2200</td>
<td>üre/kwh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>mills/kwh</td>
<td></td>
</tr>
<tr>
<td>2200-0600</td>
<td>üre/kwh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>mills/kwh</td>
<td></td>
</tr>
<tr>
<td>Energy price surcharge</td>
<td>üre/kwh</td>
<td>.50 (C-3.5)</td>
</tr>
</tbody>
</table>

*aThese are all adjusted by a cost-of-living index, defined by a percentage surcharge equal to .2 (K-415), for K the Swedish CPI with a basis of 1949.

*bThis is the tariff for administration codes DT, DA, and DM; that for codes DN and DP is slightly lower.

*cThree alternative tariffs are available within Tariff Block 3. D3 and Ed are available only to customers who demand less than 1000 kw.

*dC is an officially established cost of fuel oil #5 in üre/kwh.
### Table A.2

**High Voltage Tariffs for Bålforsens Kraft AB, 1978-1979**

<table>
<thead>
<tr>
<th>Item</th>
<th>Standard Tariff</th>
<th>Cogeneration Reserve Tariff</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Block 1</td>
<td>Block 2</td>
</tr>
<tr>
<td></td>
<td>70-130 kv</td>
<td>40 kv</td>
</tr>
<tr>
<td>Fixed charge</td>
<td>$10^{3}$</td>
<td>200</td>
</tr>
<tr>
<td>Contractual (subscribed) charge (1 hr)</td>
<td>Skr/kw</td>
<td>15</td>
</tr>
<tr>
<td></td>
<td>$/kw</td>
<td>3.57</td>
</tr>
<tr>
<td>Peak-load charge (6 hrs)</td>
<td>Skr/kw</td>
<td>117</td>
</tr>
<tr>
<td></td>
<td>$/kw</td>
<td>27.86</td>
</tr>
<tr>
<td>Insured unit charge</td>
<td>Skr/kw</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>$/kw</td>
<td>-</td>
</tr>
<tr>
<td>Daily capacity</td>
<td>Skr/kw</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>$/kw</td>
<td>-</td>
</tr>
<tr>
<td>Energy charge</td>
<td>Öre/kwh</td>
<td>5.4</td>
</tr>
<tr>
<td>May-August</td>
<td>mills/kwh</td>
<td>12.9</td>
</tr>
<tr>
<td></td>
<td>Öre/kwh</td>
<td>6.4</td>
</tr>
<tr>
<td>September-April</td>
<td>mills/kwh</td>
<td>15.2</td>
</tr>
<tr>
<td></td>
<td>Öre/kwh</td>
<td>.40 (C-3.5)</td>
</tr>
</tbody>
</table>

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*aThese are all adjusted by a cost of living index, defined by a percentage surcharge equal to .2 (K-415), for K the Swedish CPI with a basis of 1949.

*bC is an officially established cost of fuel oil #5 in Öre/kwh.
charges legitimizes a similar choice by other producers in the eyes of the Prisregleringsnämnd and others who might question the company's tariffmaking. Because the charge (by assumption) affects no consumption decisions, it does not affect social efficiency; it simply facilitates a transfer from the consumer's profits to the producer's.\footnote{It could transfer resources in the other direction as well. But because prices based on long run marginal costs typically fail to cover revenues in Sweden, a transfer to Vattenfall is required to generate adequate revenue.}

Second, the contractual or subscription charge is designed to cover the cost of the local distribution grid associated with the consumer. Hence, there is a good cost justification for it to rise as delivery voltage falls and for it to be identical for Vattenfall and Bålforsen. The size of the subscription is set ahead of time and may not be violated on average during any one-hour period. The subscription charge, however, has some of the characteristics of a demand charge. The actual amount paid is based on the average of the two highest hourly average demands in different months. Either this average or 90 percent of the subscribed capability, whichever is higher, is used to compute the charge.

Third, the peak-load charge covers all other capacity-related costs. Until 1973, it was based on a one-hour average. But the six-hour peak-load charge now dominates the one-hour contractual charge by 7 to 1 or more per kilowatt. The Swedes find that a six-hour average gives a more reliable measure of the consumer's "typical" peak demand than a one-hour average. Although the peak demand measured is that of the consumer and not the system, peak high voltage demands tend to coincide in cold winter daytime hours. By measuring a user's "average" peak during such periods, the six-hour measure automatically reflects the degree of simultaneity in high voltage demand at the peak and therefore reflects the user's true share of peak capacity costs. Note that the costs are Skr 23/kw or about 9 to 16 percent lower for Bålforsen's customers than for Vattenfall's. This is because northern hydropower is Sweden's primary electricity source, and the Vattenfall tariff must reflect the higher costs associated with the greater transmission capacity needed for more southerly consumption.

The peak-load charge acts as a true demand charge and is based on an average of four actual consumption points during the year. First, the six-hour period in each month with the highest average demand over the period is determined. Then four of these monthly values—at least three of which must be from the period September to April—are averaged to determine the peak-load consumption relevant to the peak-load charge. For industrial and district heating cogeneration, these values often come from the early and late winter period when steam demand is not high enough to justify full utilization of own capacity. Although this charge is not specifically related to the system peak, system and customer peaks tend to coincide on winter days. If a customer has a totally noncoincident peak, it can typically have its peak-load meter disconnected during the summer, on weekends, or even at night.

Finally, the energy charge is meant to be an average of the short run marginal costs over the period to which each energy charge applies.\footnote{Hence, hydro is valued at the alternative cost of producing the hydropower required with a thermal source. As a result, these marginal costs need not sum to the total fuel costs experienced over the period.} In practice, the highest voltage tariffs have different charges for winter and summer. In this case, the winter energy charge typically equals the variable cost of production during a winter night. The somewhat higher variable cost during winter days is captured in a surcharge to reflect that charge in the peak-load charge. The summer energy charge is a simple average of all variable costs during summer days and nights. Hence, taken together, the Swedish high voltage tariff provides a peak charge for winter days, a shoulder charge for winter nights, and an off-peak charge for summer days and nights, all based on the relevant costs. Swedish tariffmaking doctrine also suggests that the energy...
charge be adjusted to help equate actual costs and revenues when all adjustments cannot be made in the fixed charge.\footnote{This would suggest that energy charges were too high from an efficiency point of view. Ironically, the few cogeneration owners I interviewed who objected to the standard tariff suggested that energy charges based on long run marginal costs were too low and discriminated against cogeneration for that reason.}

Looking at Tables A.1 and A.2, we find a basic energy charge and an energy price surcharge based on the price of oil. Once again, Vattenfall has basic energy charges .3 to .4 öre/kwh or 4 to 7 percent higher than Bålforsen’s. And, again, these result from a difference in costs. The Swedes experience losses of up to 7 percent on power transmitted from the north. The transmission losses between the two areas represented by these tariffs effect a permanent energy price differential between the areas equal to the losses and that differential is about 5 to 7 percent. Other energy charges are available at lower voltages and, where comparable, they reflect similar cost differentials.

The energy price surcharge is also lower for Bålforsen, about 20 percent lower. Part of this difference can be justified on the basis of the transmission loss, but the rest is more difficult to understand. The formulas given suggest both that (a) oil price increases affect Vattenfall more than Bålforsen and (b) Vattenfall’s price rises relative to that of Bålforsen as the oil price rises. This could occur because the power system substitutes hydro for oil as the price of oil rises, leading to greater transmission from the north and hence greater percentage losses. It may also reflect some expectation that not enough hydro can be shipped south to equalize prices in the future, leaving the south (Vattenfall) to use a more heavily oil-dependent thermal system than the north (Bålforsen).

The important point here is that Swedish tariffs appear cost-justified. Though the Vattenfall and Bålforsen tariffs use similar charges and delivery voltage levels, they adjust their specific charges to reflect costs within their own systems in what is typically a readily understandable way. The tariffs shown here are of course only suggestive. Further adjustments in specific charges continue in the secret negotiations each producer holds with each of its high voltage customers. But those negotiations do not change the basic structure of the tariffs or their general dedication to long run marginal cost.\footnote{Tables A.1 and A.2 display only a portion of the high voltage tariffs. Other tariff sections deal with special connection charges, reactive power, fees for unforeseen cost charges, and so on.}

THE RESERVE TARIFF

The second major tariff of importance to cogeneration is the “reserve tariff for cogeneration installations.” The fact that the tariff is written specifically for cogeneration units demonstrates their dominant position in self-generation. A reserve tariff effectively provides insurance against a failure in cogeneration which would force the user either to shut down its industrial load or to increase its contractual and peak-load charges to levels that do not reflect its typical coincident demand for power. More specifically, it entitles the user to free reserve capacity for seven days a year, the average number of days in which a cogeneration owner needs reserve power. If the user requires more than seven days of assistance, the contract provides capacity on a daily rather than yearly basis, as the standard tariff does. As a result, although cogeneration owners are not required to insure themselves with a reserve tariff in order to connect to the grid, they all do.

These reserve tariffs are closely coordinated with the standard tariff; their structure is similar and they differ very little from one major producer to the next. Tables A.1 and A.2
display representative reserve tariffs for Vattenfall and Bålforsen. Both of them display similar structures of five component charges. Consider each in turn.

The fixed charge serves a purpose similar to that for the standard tariff and is charged only if the customer does not have a standard tariff. This occurs in cases where the cogeneration installation produces all the power required on-site, cases which Section IV suggests are unusual. In any case, the reserve tariff requires that a fixed fee at least as large as the fee in the reserve tariff be paid by any customer with a reserve tariff. This fixed fee covers metering and accounting costs and is the same for both utilities.

Second, a contractual or subscription charge is used, once again, to pay for local distribution costs attributable to the cogeneration user. Serving the same purpose as the analogous charge in the standard tariff, this charge is set at the same level per kilowatt in both tariffs.

The customer has a choice of how much insurance to buy—that is, how many kilowatts to pay for in this charge. The simplest approach is to insure its entire cogeneration installation, but under certain circumstances it can insure less than this. For example, Vattenfall allows a cogeneration owner to leave some cogeneration units uninsured if it has more than one. Vattenfall also allows the cogeneration owner to limit its insured capacity to the level it believes reflects its "capacity requirements." An alternative arrangement requires the cogeneration owner to pay 100 percent of the per-kilowatt fee for its first unit, 50 percent for its second, 33 percent for its third, and so on. The owner remains covered for the whole installation under this arrangement.

If the cogeneration owner exceeds its subscribed capacity during the contract period, Vattenfall reserves the right to (a) raise its subscription level to the actual level experienced, effective as of the beginning of the contract period, (b) raise its subscription level for the next contract period to at least this level, and (c) impose a penalty fee on top of these. The first two encourage the cogeneration user to stay within its contract; the third encourages the user to estimate its subscribed needs accurately. Other producers impose similar sanctions.

The third charge, the insured unit charge, complements the contractual charge under the standard tariff. It covers all capacity costs not covered by the contractual charge, mostly transmission and generation costs. The cogeneration owner pays this fee on all the capacity it insured under the contractual charge, and the charge is adjusted in a similar manner if the owner draws more reserve power than it has contracted for. As before, Vattenfall is the more costly of the two and for similar reasons; Vattenfall requires more transmission capacity. The more dramatic cost comparison is that between this unit charge and its analog in the standard tariff, the peak-load charge. They differ by factors ranging from 29 to 36.

Three factors account for the difference. First, the peak-load charge includes a weighted average of capacity charges for all units on peak. The insured unit charge is based on capacity charges for peakers like gas turbines which are likely to be lower on average than system capacity costs. Second, the reserve tariff covers fewer days. While the reserve tariff provides only seven days of capacity, the peak-load tariff provides capacity for the entire peak period. Third, and most important, the insured unit charge reflects the diversity of failure in cogeneration units on-line. Vattenfall estimates that it needs only 1 megawatt of peaker capacity to back up 7 megawatts of cogeneration units on line. One megawatt of capacity is required to cover every megawatt of demand under the peak-load charge. In sum, the difference between peak-load and insured unit charges is cost-based.7

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7A simple review of the assumptions required to make the costs of capacity the same within each Vattenfall charge suggests that the charges are reasonable. For example, if we assume that capacity used to back up cogeneration costs 20 percent less per kilowatt than capacity typically used on peak, capacity costs per kilowatt per day are equal in the
The fourth component, the daily capacity charge, is the charge for every kilowatt of reserve capacity required for more than seven days in the year of the contract. It reflects the daily cost of capacity used to meet this load. Note that these charges are very similar to the daily capacity charges implicit in the insured unit charge. The capacity on which this charge is paid differs from one producer to the next. Vattenfall, for example, defines the capacity as the difference, in each hour, between the average power drawn by the cogeneration owner and either its contractual capacity or its peak-load capacity under the standard tariff, whichever the owner prefers. Other utilities define it as the smallest sum of the rated capacities of cogeneration units on the owner's installation that could have met the outage. In the absence of lumpiness, this matches the Vattenfall measure.

Finally, the cogeneration owner pays an energy charge for all the energy he draws under the reserve tariff. The rate is tied explicitly to the cost of oil and reflects the conversion efficiency of a large oil-fired condensing plant, about 35 percent (or 1/2.86) (Köhler, Norhammer, and Nordstrom, 1977, p. 39). In fact, the charge is simply an average of the short run marginal costs of plants which the power system expects will be used to meet cogeneration outages. The capacity types included have marginal running costs higher and lower than those of condensing plants; the weighted average of these costs is by coincidence similar to that of condensing plants. Payments attributable to this charge usually dominate those for reserve capacity in an actual cogeneration outage. The seven percent difference between the Vattenfall and private producer energy charges can once again be attributed to expected transmission losses.

Again, then, we see a tariff (a) based on appropriate cost concepts, (b) similar in structure across producers, despite the absence of direct competition, and (c) different from producer to producer in specific charge levels. Again, the tariffs shown above are only representative; Vattenfall and other producers negotiate the reserve tariff secretly and individually with each of their high voltage customers. And, as with the standard tariff, a customer can contract for a separate reserve tariff for each of its installations or for all installations taken together, again allowing some self-insurance.

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charges if peak-load charges are attributable to demand on 35-43 days, depending on the voltage level chosen. If back-up capacity is 46 percent less costly, the effective peak period must include 46 to 57 days. None of these numbers is unreasonable. Review of the tariffs in Table A.2 yields similar results.

*Multiplying each daily capacity charge by seven and rounding yields the insured unit charge.
Appendix B

CAVEATS ON THE USE OF COST COMPARISONS IN SECTION VI

The cost estimates in Table 12 and the loci in Fig. 7 are too crude to allow final decisions based on them alone. They are meant strictly to provide illustrations. Even to serve as illustrations, these numbers must be interpreted in light of some important caveats.

In particular, one should be aware of two assumptions implicit in the use of such numbers and loci as illustrated. They suggest that each process has a well defined annual capacity cost and a constant running cost per kilowatthour. They also suggest that neither the number of individual segments of operation within the annual duration of load shown nor the timing of these segments affects the operating costs of a process. This appendix reviews these assumptions and considers their importance in the Swedish power supply system.

ANNUAL CAPACITY COSTS AND CONSTANT RUNNING COSTS

Consider the capacity cost first. In principle, a full optimization would determine economic lifetimes for each process, depreciation rates from which to derive capacity costs, and utilization rates for each process before they were compared (see, for example, Weingartner, 1963). Such an optimization can yield annualized capital costs with which to compare processes. Long run marginal cost estimates do not suffer much from relying on such summary parameters as annualized capital costs.

Restricting ourselves to constant operation costs excludes the possibility of neoclassical marginal cost functions which rise with the level of production (Panzar, 1976). This is not necessary. The presence of curvilinear cost loci, presumably concave upward, in a diagram like Fig. 7 does not change our analysis in a significant way. It is useful to note, however, that the Swedes are quite comfortable in representing their generation assets with simplified stepwise functions. They routinely speak of one running cost for a given turbine. For combination condensing-cogeneration turbines, they speak of one running cost for each mode and both dispatch and bill services from such turbines on the basis of these quoted costs. Hence, the concept of a segmented process is not alien to them. And most processes are assumed to have only one running cost.

NUMBER AND TIMING OF LOAD SEGMENTS

Our comparison technique suffers from the same difficulties associated with using a load duration curve to represent system load. The number of time segments becomes more important

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1 They define it in terms of the efficiency of the turbine, which differs significantly from one machine to another, and the price of oil. Given the price of oil, then, the running cost of any one turbine is fixed by its (demonstrated) efficiency.

2 Again, this cost is the product of an efficiency and the price of oil.
(a) the larger are start-up and shut-down costs and (b) the more important is storage in the options. We can detect the extent of these costs only with a detailed load curve for the system. Beyond that, we can only say that, where Fig. 7 suggests little difference between the costs of two processes, we should examine the additional costs associated with these dynamic factors.

Such dynamic cost problems are less severe in Sweden than elsewhere. The absence of expected daily variations in cost eliminates most short segments of load at high cost. Typically, the shortest segment of load at an identifiable expected marginal cost occurs on summer weekends, about 60 hours long. While start-up and shut-down costs make it impossible for Sweden's largest units and even many large cogeneration units to meet such short segments of load, they are accessible for many smaller turbines, particularly cogeneration turbines. Dynamic cost problems associated with pump storage, the only realistic option for storing electricity on a large scale, are also attenuated by its relative lack of importance in Sweden.

In sum, with some caveats, cost comparisons like those in Table 12 and Fig. 7 should apply well to Swedish industry. They are likely to be less helpful in understanding the use of industrial cogeneration in the United States under similar pricing circumstances.
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