MASTER

DEVELOPMENT OF A JOINT-COST-
ALLOCATION MANUAL FOR INTEGRATED
COMMUNITY ENERGY SYSTEMS (ICES)

ARGONNE NATIONAL LABORATORY

ENERGY AND ENVIRONMENTAL SYSTEMS
DIVISION

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DEVELOPMENT OF A JOINT-COST—
ALLOCATION MANUAL FOR INTEGRATED
COMMUNITY ENERGY SYSTEMS (ICES)

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a 50 Prepared by
Ernst & Ernst
for

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EXECUTIVE SUMMARY

Ernst & Ernst has completed Phase 1 of the project, "Development of a Joint Cost Allocation Manual for Integrated Community Energy Systems," for Argonne National Laboratory. In fulfillment of this effort, we have:

- Examined technical factors
- Reviewed and synthesized the relevant economic theory
- Assessed three generic approaches to cost allocation:
 - public projects approach
 - cost accounting approach
 - mathematical programming approach
- Surveyed current utility and regulatory allocation procedures.

Based on these steps, our conclusions to date include the following:

- Economic theory suggests that cost allocation is unnecessary for optimal feasibility, pricing, and output decisions
- But reasonable and practicable allocations are required for regulatory purposes and cost-sharing arrangements
- No single approach to cost allocation in practice is wholly satisfactory
- The mathematical programming approach seems most promising at this juncture
- Implementation of any method is dependent on data availability.

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I. INTRODUCTION

Argonne National Laboratory contracted with Ernst & Ernst to develop a method of allocating the joint costs associated with an Integrated Community Energy System.^{1/} This Interim Report describes the work we have completed in Phase 1 of this study, which encompasses the first six steps of the work scope. We have determined that strict adherence to the ordering of these steps would not be advisable in reporting on our research. Nonetheless the informational content in this report is the same with the exception of the difficulties caused by the lack of suitable engineering cost data. This problem was detailed in our progress report to Argonne on September 14, 1978.

Chapter II is the statement of the problem, including the background development of ICES, the objectives of our cost allocation analysis, and the desirability of performing such an analysis. Chapter III provides a discussion of the results we have obtained. The material upon which these results are based is included in the Appendices.

^{1/} Contract No. 31-109-38-4458.

II. STATEMENT OF THE PROBLEM

BACKGROUND

An Integrated Community Energy System, or ICES, is a comprehensive approach to the provision of energy services to a community. The principal purpose of the ICES approach is to minimize the total fuel resources required to meet the community's energy applications, which may include electricity generation, space and water heating, industrial process steam, and air conditioning.

The ICES approach embodies a combination of innovative technological systems, community design, and implementation mechanisms. Although all three are essential to the approach, the attractiveness of an ICES from the standpoint of energy conservation is grounded on its technological features. Technical integration of the equipment for production of each type of energy permits more efficient utilization of the energy released from the fuel; simply stated, less energy is wasted.

Cogeneration is the term applied to technical integration of equipment for generation of useful thermal and electrical energy from the same primary energy source.^{1,2/} Some sort of cogenerating facility is a central component of an ICES. Other components include a resource system (to furnish the primary fuel), a distribution and storage system, and an end-use system.

One form of cogeneration may be constructed around diesel generation of electricity. A diesel engine generates electricity at an efficiency of about 40%, exhausting 60% of the input energy to the atmosphere. A waste heat boiler can recover about half of the heat in the exhaust and cooling

^{1/} In the broadest sense, cogeneration may include production of mechanical energy.

^{2/} Appendix A provides a technical description of cogeneration options.

water jacket, raising the total efficiency to about 70%. Thus, for the capital cost of a waste heat boiler and minor incremental fuel cost,^{1/} steam or hot water is provided for space or process heating. Schematically, cogeneration using a diesel system is shown below.

The cogeneration concept is equally applicable to the use of a combustion turbine as the prime mover of the generator. However, the efficiencies change in several respects. A combustion turbine will generally produce less electricity per unit of fuel burned. Its exhaust will be of higher quality than the diesel (hotter, at higher pressure) and will yield more heat to the waste heat boiler.

The third type of cogeneration facility applicable to ICES is a steam turbine. While a diesel generator can be viewed as a source of

^{1/} A diesel's efficiency is dependent upon its exhaust pressure. Constraining the exhaust to pass through a waste heat boiler can decrease the diesel's efficiency and raise the fuel cost necessary for a specific electrical output.

thermal energy at low incremental cost, a steam turbine can be viewed as a source of electrical energy at low incremental cost. A cogeneration facility based on a steam turbine is shown schematically below.

Essentially, this constitutes a heating system in which a turbine has been inserted between the boiler and the heating line. This necessitates some changes in the system: more fuel is required, and the boiler must be of higher quality. The turbine illustrated above is called a backpressure turbine because the exhaust into the heating system is at a pressure above atmospheric pressure. The incremental conversion efficiency to electricity achieved by such a system is in the range of 70%, much higher than the 34% efficiency typical of utility generators.

Another physical arrangement involves the extraction of steam in the middle of the turbine. The extracted steam still follows a path similar to that shown in the backpressure turbine system. The steam exhausted to the condenser produces electricity at an efficiency level comparable to most utility generators. An extraction condensing turbine is illustrated below.

OBJECTIVES OF THE ANALYSIS

The problem addressed in the present engagement is the determination of an appropriate cost allocation system for an ICES. The use of a central cogenerating facility at the heart of the ICES means that some portion of the system costs are "joint": that is, some system components, and their associated costs, are not clearly identifiable with any single system output. An allocated portion of the joint costs must be added to the costs that are clearly assignable to each ICES function to arrive at a reasonable estimate of the total costs of providing each type of energy output.

The long-run objectives of the cost allocation project are to complete the following basic steps:

- Formulate and examine the range of possible allocation methods, and establish criteria for evaluation
- Select the procedure which best meets the established criteria
- Apply the selected procedure in a case study
- Develop a manual to guide others in the application of the procedure.

Each of these basic steps entails several tasks. For example, the first step includes examination of theoretical allocation procedures and ascertainment of allocation procedures currently in use.

This report summarizes our efforts and findings in carrying out tasks that are part of the first two steps listed above.

THE INTEREST IN COST ALLOCATION

Why might the allocation of joint ICES costs be of interest? At least three reasons may be delineated: project feasibility analysis, cost-sharing arrangements, and regulatory requirements.

Proponents, analysts, and parties interested in the ICES concept may seek allocated cost data as a guide to feasibility decisions. It may be deemed desirable to know, for example, whether the expected revenues from a potential ICES function, such as supply of chilled water, would be sufficient to recoup the costs involved. Ostensibly, the decision to include this function in the ICES would rest, in part, on knowledge of the total costs associated with the function, plus an allocated portion of the joint costs. We show in Appendix B, however, that allocation is unnecessary to feasibility decisions, because such decisions should be made only on the basis of incremental cost data. The relevant incremental costs can be determined in all cases without reference to an allocation.

Joint cost allocation may be required for certain kinds of project cost-sharing arrangements. For example, an ICES might be designed in which one function, process heat, is included solely for the benefit of an industrial firm in the community. If the project arrangements specify that the process

heat user is responsible for all costs associated with that function, including an appropriate portion of the system's joint costs, then an allocation is required.

The most important reason for developing a joint cost allocation for an ICES is to satisfy the requirements of public utilities regulation. In our technical discussion of the economics of joint production (Appendix B), we argue that cost allocations are theoretically unnecessary for efficient resource use. Nonetheless, the fact remains that cost of service is the dominant basis for rate regulation. The regulatory authority uses the cost of service to arrive at a revenue requirement and appropriate set of rates for each service. In this traditional regulatory setting, a reasonable and practicable joint cost allocation procedure is necessary.

III. RESULTS OF THE STUDY TO DATE

THEORETICAL WORK

A major portion of our efforts to date has consisted of a review of cost allocation from several standpoints. The economic theory pertaining to cost allocation is found in the theory of joint production. An industrial process is characterized as "joint" if common equipment or facilities are used to produce two or more products. We therefore examined an ICES as a particular case of joint production.

The basic economic analysis of joint production is detailed in Appendix B. Briefly stated, it is the concurrence of economists that allocation of cost is irrelevant to the determination of optimal input usage, output, and prices. This conclusion has withstood the scrutiny of economists for several decades, and there is no evidence that recent theoretical advancements would alter it. Cost allocation also is irrelevant to the economically correct investment decision, i.e., the examination of the economic feasibility of constructing an ICES, or augmenting an existing system to serve multiple energy needs.

The rejection of cost allocation from the economic standpoint is based on the principle of marginal analysis. Essentially, this means that selection from several alternatives should be guided by marginal considerations. Marginal concepts are pervasive in economic theory, covering all aspects of production

and pricing behavior. The result that is most important for our purposes is that joint products should be priced at their respective marginal costs. In physical terms, this means that the price of an additional unit of thermal energy from an ICES should be equal to the additional costs (in the entire system) of producing that energy; the same rule, of course, holds for electrical energy, or any other ICES output. In the theoretical framework, it can be shown that pricing in this manner is "efficient"--that is, it ensures that the greatest possible value of output is obtained from society's scarce resources. As a practical matter, strict marginal cost pricing may not be feasible in the institutional setting in which an ICES would operate, since it would not necessarily lead to fulfillment of the "revenue requirement" determined through regulation. Additionally, the absence of a fairly extensive data base on ICES projects complicates the empirical determination of marginal costs. This problem is discussed in Appendix C. Nonetheless, theoretical results discussed in Appendix B show that the marginal costs should still be used as base prices, and adjusted to yield the specified revenue requirement.

Allocation of costs is irrelevant to economic decisions because it deals with total, historical costs (i.e., costs that were actually incurred) of the joint production process. In contrast, theory dictates that economic decisions should be based on marginal costs (i.e., changes in costs) that would be incurred if the level of output were changed. Furthermore, economists say that any method used to allocate costs--for whatever reason--is wholly arbitrary, and has no analytical usefulness.

It is interesting to note that cost accountants concur in this judgment. Since allocation of cost is one of the major tasks of the cost accountant, this statement may seem paradoxical. The explanation lies in the fact that allocated costs serve only limited, "score-keeping" objectives; the cost accountant would not furnish them as input to a decision process. Horngren writes:

Joint costs permeate accounting. Costs are joint with respect to time, facilities, and products. Accountants attempt to split joint costs among products having relatively important sales values No matter what the joint-product situation, any assignment of a joint cost is useless for purposes of managerial decision-making. The only use for allocating joint-product cost is for purposes of "reasonable" inventory valuations and income determinations.^{1/}

For the reasons we have outlined earlier, however, it is almost inevitable that cost allocations will be required for ICES. To the extent that these cost allocations are used to set rates, they will affect the purchasing decisions of ICES customers. Therefore, it is desirable that the allocation procedure provide customers with price signals that approximate those that would be received under marginal cost pricing.

COST ALLOCATION METHODS IN THE LITERATURE

Our search of the literature for descriptions of cost allocation procedures has shown that most can be classified under one of three approaches:

- The public projects approach
- The cost accounting approach
- The mathematical programming approach.

The public projects approach to cost allocation views it in the context of large-scale, multiple-purpose public works projects. Most of the literature grew up around Federally-sponsored water resource projects, which typically serve two or more purposes (including water supply, irrigation, flood control, hydroelectric power, and recreation). Where specific beneficiaries of these projects can be identified, statutes and executive orders have historically required that the beneficiaries be required to repay some portion of the costs incurred.

^{1/} Charles T. Horngren, Cost Accounting: A Managerial Emphasis, 3rd edition (Englewood Cliffs, NJ: Prentice-Hall, 1972), p. 581.

Appendix D provides detailed numerical examples of the principal allocation procedures that have been employed for public projects. Briefly, four methods can be delineated: the benefit method, the alternative justifiable expenditures method, the use of facilities method, and the substitute pricing method.

A necessary input to the benefit method is an estimate, in monetary terms, of the benefits conferred by each project function. For a particular project, estimation of the benefits may be straightforward or arcane; in any event, such estimates typically exist for public works projects prior to the allocation stage because they have been developed for the benefit-cost analysis used to justify the project. In the benefit method, the joint project costs are allocated to the project functions in proportion to the benefits conferred by each function.

The alternative justifiable expenditure method is similar. Instead of allocation in proportion to benefit, however, this method looks at the minimum cost of performing each function separately. For a two-purpose water project, for example, the relevant figures might be the costs of constructing separate dams for flood control only and hydroelectric power only.

The use of facilities method allocates the common costs in proportion to some common physical measurement that indicates the share of facilities attributable to each function. For example, it might be possible to identify the percentages of a dam's total water storage capacity that are necessary for flood control and hydroelectric power, respectively. Clearly, application of this method is contingent upon the ability to define a single yardstick against which each function can be measured.

The cost accounting approach to allocation of joint product costs, discussed in Appendix E, is based on the needs for reasonable and consistent valuations of inventory and construction of financial statements. The traditional

function of the cost accountant is to arrive at a cost figure for each product that values the portion of firm's expenses that should be attributed, or "attached," to the product. Although the emphasis is on valuation of physical, inventoriable products, the methodologies of cost accounting are applicable, with some modification, to the valuation of other types of costs. As was noted earlier, when the production process is truly joint, allocation only serves these limited "scorekeeping" functions, and is not an appropriate basis for decision-making.

The two basic cost accounting methods are the relative sales value method and the physical measure method. The relative sales value method is based on the assumption that costs should be assigned according to a product's ability to generate revenue. Thus, the costs that are attached to the product are proportional to the revenues that can be expected from sale of the product. To the extent that prices (and revenues) indicate a lower bound on the benefits received by a product purchaser, this method is analogous to the benefit method of the public projects approach.

The physical measures method is the counterpart of the use of facilities method. Costs are allocated in proportion to the relative magnitudes of some physical denominator common to the joint products. An example might be where a refinery process produces X gallons of one product and Y gallons of another, so the costs are assigned in proportion to the volumes of each product.

The mathematical programming approach is geared to the same objectives as the accounting approach, namely, to provide a valuation, for "scorekeeping" purposes, of the output of each joint product. In this case, however, the basis for the scorekeeping is economic theory. The general approach consists of formulating mathematical demand and cost functions, and using them to choose the appropriate level of inputs and output to maximize profit. The result is

a ceiling value for each joint product, showing the marginal value to the producer and a measure of benefits to the consumer. The mathematical properties of the procedure ensure that these ceiling values sum to the joint production costs; thus, they can be regarded as allocations. This is discussed in Appendix F.

CHOICE OF AN ALLOCATION PROCEDURE

We discussed above the desirability of choosing the allocation procedure that comes closest to providing customers with the same signals that would be received under marginal cost pricing. At this stage, our preliminary judgment is that the mathematical programming approach is superior according to this criterion. An intuitive explanation is that this approach furnishes the producer with estimates of the separate value of each product that are consistent with the economic concept of opportunity cost.

Other criteria that must be considered in selection of an allocation method include the availability and selection of the necessary data, and the difficulty of implementing the procedure once the data is in hand. Our preliminary judgments indicate that no approach is wholly satisfactory by these criteria. The benefit method, for example, requires some arbitrary determination of the benefits received by the users of the products; how this could be accomplished for a particular case of joint production is problematic. The alternative justifiable expenditure method requires detailed engineering assessments to approximate the cost of serving each function separately. The physical measures and use of facilities methods require some common physical denominator, which may not always exist. The price substitute method requires connection to a grid. The relative sales value approach is based on product price information, and thus introduces the problem of circular reasoning if the ultimate objective is to base prices or rates on the allocation. The mathematical programming approach requires extensive data to estimate the demand and production functions.

To summarize: our investigation of the theory of joint production has shown that cost allocation is irrelevant to theoretically correct pricing and output decisions. Thus, there can be no "ideal" allocation procedure; rather, there is an "ideal" procedure (marginal analysis) for making the decisions that might otherwise be based on a cost allocation. Institutional realities, however, necessitate choice of a reasonable allocation procedure, and it is inevitable that allocations will enter into the rate-making process. The end toward which we are working is to design an allocation procedure that will produce end results that are closest to those that would be obtained under an "ideal" approach.

SURVEY OF COST ALLOCATION IN PRACTICE

Concurrently, we have been surveying utilities that are involved in cogeneration and district heating activities. Such systems embody the essential technological and economic characteristics that would be present in an ICES. Preliminary results indicate that very few utilities have had to confront the allocation question, for a variety of reasons. Owing to the small scale and experimental nature of existing systems (perhaps including government funding), the task of allocation is not cost-justified in many cases. Cogeneration for industrial purposes has generally been installed on a contract basis for an individual customer, outside the purview of regulation. In some cases, electrical output is simply sold for the prevailing rate, and the balance of costs is recovered through sale of the additional product (steam or hot water), or goes partially unrecovered.

To date, we have identified only one allocation procedure that has been approved by a regulatory body. Our efforts in this area are continuing, although they have been hampered by the inability or unwillingness of contacted utilities to provide us with useful descriptive information. In light of the regulatory uncertainties that apparently face utilities that

confront the allocation question, it is apparent that the regulatory bodies should be queried to discern their current inclinations and policies on the subject.

THE RELATIONSHIP OF OUR WORK TO THE STEPS IN THE WORK SCOPE

The six steps in the Work Scope have been successfully analyzed with the exception of those that require data that has not been available.

1. Review of factors affecting the operation of cost allocation method. Several methods of cost allocation have been discussed. The factors that are accounted for by each method differ substantially, hence the resulting allocations would be expected to differ substantially. Our analysis thus far indicates that choice of the method is far more important than the operating characteristics of the defined systems we are to examine. Grid connection may be an exception.
2. Development of "ideal" rules to assign costs to either service. The discussions of the different methods (Appendices C-F) point out the degree of separations required for each method. The basic benefits method, the substitute pricing method, the relative sales value method, and the programming method require no separation whereas the remaining methods do require assignment of costs.
3. Determine if the different technologies result in different sizes of joint-cost pools. The lack of detailed component data described in our September 14, 1978 report to Argonne has caused difficulty in completing this step. This will be pursued in Phase 2 of the study.
4. Indicate Magnitude of Joint Costs and Review Allocation Methods Currently Used. Appendix D presents four allocation methods and Appendix G details our review of currently used and proposed allocation methods. Appendix A addressed the cost question, but lack of detailed data prevents us from indicating the magnitude of joint costs.
5. Review the economics literature of joint cost. This is reported in Appendix B.
6. Synthesize the results into an idealized joint cost allocation method(s). Our tentative conclusions are presented above. Appendices B-F provide the basis for these tentative conclusions.

APPENDIX A

TECHNICAL DESCRIPTION OF COGENERATION

INTRODUCTION

Cogeneration is a system where the same energy source is used to produce both electricity and useable heat, typically in the form of steam or hot water. When electricity is produced before heat is made available, the system is referred to as a topping cycle, that is, electricity is produced off the top of the system's cycle. This is contrasted to a bottoming cycle where electricity is produced after heat has been made available to its user.

Cogeneration systems typically use a topping cycle. Typical topping cycles include diesels or combustion turbines firing heat recovery boilers, or turbine-generators exhausting steam to be used for industrial processing or heating. Bottoming cycles produce electricity last and are most useful when the process requires extremely high pressure steam or extremely high temperatures. Some exotic bottoming cycles use hydrocarbons with a low boiling point to improve the efficiency of the electrical production. Similarly, the exhaust from a brick oven can fire a conventional broiler. Bottoming cycles are generally not of interest to integrated community energy systems and will not be treated in this paper.

The most obvious topping cycle uses the exhaust of a diesel or combustion turbine to fire a boiler for production of steam. The diesel or combustion turbines will be similar to or even identical to the engine generator set used by many utilities for generating electricity alone. These heat recovery boiler systems are typical of the "Total Energy" systems promoted by many gas companies in the 1960's and early 1970's. These

systems produce higher electricity to steam ratios than do most other systems, making them ideal for cogeneration projects where electrical production is primary.

Clark University in Worcester, Massachusetts proposes to install a reasonably typical diesel cogeneration system (see Figure A-1). This system is planned around a 2160 bhp Fairbanks Morse cylinder diesel, model 38TD, attached to a 1531 kilowatt generator. Clark anticipates using #2 fuel oil to fire the diesel, costing roughly \$3.00/MBtu. To burn the slightly cheaper #6 fuel oil (\$2.50/MBtu) would require Clark to include a centrifuge in the fuel line from the storage tank to the day tank.

The diesel cooling water will go to a ebullient boiler producing 15 psig steam. Heat in excess of the needs of the 15 psig steam system will be sent to a cooling tower. The diesel exhaust will be fed to a waste heat boiler with evaporation and economizer sections. Both sections will consist of spirally wound, finned tubes. The boiler will produce steam at 125 psig. Both steam systems will return condensate to the system clean enough for direct entry to the deaerator.

The system is designed to produce 1531 KW of power and steam flows of 979 lbs/hr of 15 psig steam and 2983 lbs/hr of 125 psig steam.

Clark University proposes housing the diesel and its boilers in a new building adjacent to its present system, costing \$308,000. The diesel, generator, switchgear and associated equipment will cost \$543,000. The boilers and modification to the school's existing heating system will cost \$141,000. The ebullient boiler and cooling towers will cost \$14,000.

An attractive feature of Clark University's plan is the ability to interchange energy with the New England Electric System. Clark has

PROPOSED CLARK UNIVERSITY ICES

(Adopted from "Fig. 3.1-1: Steam System" of Clark University's Preliminary Feasibility Study)

arranged to sell energy to NEES at a price closely approximating NEES's marginal cost of displaced fuel, which currently runs 2.4¢/kWh on weekdays and 2.0¢/kWh on nights and weekends. Purchases from NEES will be at NEES's posted rates, between 4.2 and 4.5¢/kWh.

A second frequent topping cycle used is the extraction condensing turbine, occasionally referred to as a variable pressure turbine. Most utility turbines exhaust to a condenser. A condenser changes the voluminous steam to water, providing the turbine with a subatmospheric pressure at its exhaust. The subatmospheric exhaust yields a greater pressure differential between the turbine inlet and the exhaust. This additional pressure differential allows the steam to expand further, the steam to do more work on the turbine, and the turbine to extract more energy from each pound of steam. However, the turbine exhaust is worthless for process steam. Process steam can be extracted from the turbine at intermediate pressure levels after the steam has done some mechanical work, but still retains some useful energy.

The University of Florida, Gainesville, has proposed installing an integrated utility system incorporating two combination coal/refuse fired boilers with standby oil and gas firing capability. One of the proposed steam turbines will have three extraction points at 30, 75, and 265 psia and will exhaust into a .15 psia condenser (Figure A-2). The second turbine also rated 6.25 MW, will be recondensing with a 30 psia exhaust and extraction points of 75 and 265 psia (Figure A-3). Both turbines will drive generators rated 9.374 MVA. The multiple extraction points were designed to match the existing steam needs of the University's physical plant (Figure A-4).

The University of Florida's Heating Plant 1 provided steam to the campus until equipment age and economics led to the retirement of its

EXHIBIT A-2

PROPOSED UNIVERSITY OF FLORIDA TURBINE

(Adopted from "FIGURE VII-7 THREE FEEDWATER HEATERS, CONDENSING TURBINE/BOILER FLOW DIAGRAM" of Feasibility Study and Conceptual Designs at the University of Florida)

EXHIBIT A-3

PROPOSED UNIVERSITY OF FLORIDA TURBINE

(Adopted from "FIGURE VII-8 THREE FEEDWATER HEATER, NON CONDENSING TURBINE/BOILER FLOW DIAGRAM" of Feasibility Study and Conceptual Design at the University of Florida)

EXHIBIT A-4

PROPOSED UNIVERSITY OF FLORIDA ICES

(Adopted from "FIGURE VII-1 THERMAL DISTRIBUTION SYSTEM IUS" of Feasibility Study and Conceptual Design at the University of Florida)

steam generation facilities. Now Heating Plant 1 serves as a pressure reducing and steam distribution center with Heating Plant 2 providing the steam. The steam distribution pressure is 75 psia.

Heating Plant 2 was placed in operation in 1957 and initially served an isolated steam system. It now supplies 265 psia steam to Heating Plant 1 and to a 1 MW turbine which in turn exhausts into the 75 psia steam distribution system.

The University also has five chillers providing chilled water for air conditioning in its Integrated Utility System. Three chillers are steam turbine centrifuge chillers using 265 psia steam with 5900 tons of cooling capacity.

The new boilers will each produce 120,000 lb./hr of steam at 900 psia and 900°F. The steam will feed two 6.25 MW turbine and, as necessary, will be stepped down to 265 psia to drive the existing system. The first two extraction points on the turbine will be at 265 psia and 75 psia to match the pressure requirements of the existing system. The third extraction point at 30 psia will provide steam for proposed absorption chillers and proposed low temperature hot water (LTHW) heating. The proposed absorption chillers and LTHW heating should eventually replace the existing electric driven centrifugal chillers and the existing 75 psia steam distribution system. As the higher pressure steam requirements are replaced by the proposed low pressure systems, byproduct power should increase. All the extraction points also provide feedwater heating.

The University of Florida proposes to load the boiler first to meet the heating load, then to meet the chiller requirements. Any excess

steam would be used to produce condensing power. Any steam deficiency in meeting the chiller requirements would be met by the existing electric driven chillers. Loading the system in this manner is expected to produce 118 million kWh or some 85% of the school's electrical consumption. To provide the steam for the two boilers, the school anticipates burning 94,500 tons of coal each year with a heating value of 2,457,000 MBtu or a heat content of 13,000 Btu/lb. The estimated cost of coal is \$35.00/ton or \$1.35/MBtu for a 1981 annual fuel cost of \$3,950,000 when escalated for 4% general inflation and for FEA's projection that coal prices will escalate 0.7% slower than general inflation. Electricity costs are expected to escalate 2.3% faster than general inflation. 1981 operating costs are summarized below:

	Existing	Proposed
Electricity	\$5.77M	\$.99M
Fuel	\$3.45M	\$3.95M
O&M Change		\$.24M
	<u>\$9.22M</u>	<u>\$5.18M</u>

The fuel costs reflects the lower unit price of coal versus oil and increased consumption to produce electricity and to supply the absorption chillers.

The system which the University of Florida proposes to install will cost \$14,745,000. This includes \$5,674,000 for the boiler and related equipment, including pollution control and fuel handling. The two turbine generators are expected to cost \$3,876,000; heat exchangers, pumps, and piping \$1,940,000; controls and electrical equipment \$1,587,000; building and general construction \$731,000; and miscellaneous mechanical equipment and distribution system \$937,000.

The third topping cycle used is the back pressure or non-condensing turbine. The back pressure turbine exhausts steam for the

process from its final stage. It is essentially a utility turbine with the condenser and low pressure blades removed. Back pressure turbines are typically used in industrial plants with large steam requirements relative to their electrical requirements. Without the larger pressure differential of the condensing turbine, the back pressure turbine produces the smallest amount of electrical energy per pound of process steam of the common topping cycles. As such, it is also rather inflexible in reacting to drops in the process steam requirement. The heat balance determined by the inlet and exhaust pressures of the backpressure turbine essentially determine the ratio of steam to electricity. However, the amount of steam relative to electricity can be increased by bypassing the turbine, not an infrequent practice. Decreasing the amount of steam relative to electricity production would require bypassing the process either by means of venting the expensive steam to the air or by using a condenser.

The old turbine generator at the University of Florida is typical of most backpressure turbine operations, skimming a small amount of electricity off the top of the steam production. The 1,000 kW unit uses 265 psia steam and exhausts into a 75 psia distribution network. In 1975 it had a 68% load factor, considerably better than the 56% load factor the University placed on Florida Power Corporation. Steam is the primary product and 95% of the University's electricity comes from Florida Power Corporation. The University's proposed plant similarly shows the dependence of backpressure turbines on other systems since the school only plans one backpressure and one condensing turbine. The feasibility study repeatedly emphasizes that condensing power will be produced only in sufficient quantities to cool the low pressure blades of the condensing turbine and at most as excess steam is available from the heating and chilled water requirements.

Though cogeneration facilities are operated to produce both products, either steam or electricity can usually be identified as a primary product. The higher ratios of electricity to steam for diesels and condensing turbines point to the importance of electric production for such systems. Similarly, the deliberately lower ratio of electricity to steam for backpressure turbines confirms the importance of steam at such installations. The following matrix indicates that for grid connected systems, diesels and condensing turbines are unlikely to be used when heat is the primary output. Similarly, backpressure turbines are unlikely to be used when electricity is the primary product. An exception occurs when primary heat systems have a variable heat load and a utility contract or rate with sufficient flexibility to allow competitive condensing generation. The neat compartmentalization is distorted when the facility is not connected to a utility electric grid, because of the inflexibility of electric production from the backpressure turbine. Hence, the facilities with higher steam requirements may require a condensing turbine if the facility is not connected to a utility grid, for whatever reason, be it grid unreliability or high standby charges.

	Grid Connected		No Grid Connected	
	Heat Primary	Electric Primary	Heat Primary	Electric Primary
Diesel/Combustion Turbines	Unlikely		Unlikely ¹	
Condensing Turbine ³	Unlikely ²		Unlikely ¹	
Backpressure Turbine		Unlikely	Inflexible ¹	Unlikely

1 Some facilities can operate independent of the utility grid with backpressure turbines if a small fraction of the power is produced by condensing turbines or diesels. The condensing turbines or diesels provide an electric source, similar to the utility grid, independent of the process steam requirement.

2 When the steam load is variable, condensing power capability can sometimes be used to lower electric utility bills, subject to utility tariff constraints.

3 Extraction condensing turbine also known as variable pressure turbine.

APPENDIX B
ECONOMIC ANALYSIS OF JOINT PRODUCTION

INTRODUCTION

The purpose of this appendix is to approach the cost allocation problem in Integrated Community Energy Systems (ICES) from the standpoint of theoretical economics. Analytically, an ICES may be viewed as a particular case of joint production--the production of two or more outputs from a common plant--for which there exists a rich body of economic literature. This appendix draws upon that literature to present a consistent approach to those situations where the question of cost allocation may arise.

The industrial setting in which an ICES would operate includes rate regulation by a public utilities commission (PUC). Increasingly, the PUC approach requires cost-based rates; this is where a cost allocation procedure is called for. In the following pages, we will examine the economic approach to determine the form of cost data that will support economically efficient pricing. In addition, we will examine the need for proper cost information as an input to the decision to construct an ICES.

It is important to recognize that the models and tools of microeconomics--that branch of economics concerned with the behavior and

interactions of individuals and firms--are based on simplified and idealized conceptions of market forces, availability of perfect information, and rational decision-making. To the extent that real-world conditions diverge from the states implied by these assumptions, conclusions must be qualified. These caveats will be noted where appropriate in the discussion that follows. The overall focus of this section, however, will be on theoretical, "ideal" approaches. Empirical investigations of the cost allocation problem are reserved for other appendices.

The material that follows is organized into three parts. First, historic and current interpretations of the occurrence of joint product and joint cost situations are examined. Second, the economic approach to proper cost allocation in the decision to invest in joint production is presented. The balance of the material is devoted to pricing and output decisions. The analysis is developed first for the perfectly competitive model, then for industries that operate in a monopolistic setting under regulation, such as utilities, and finally for regulated monopolies producing joint products.

JOINT PRODUCTS AND JOINT COSTS

Recognition of the particular issues involved in joint production can be traced back at least as far as the nineteenth century. In a chapter entitled, "Of Some Peculiar Cases of Value," the English philosopher and economist John Stuart Mill wrote:

It sometimes happens that two different commodities have what may be termed a joint cost of production. They are both products of the same operation, or a set of operations, and the outlay

is incurred for the sake of both together, not part for one and part for the other. The same outlay would have to be incurred for either of the two, if the other were not wanted or used at all.^{1/}

He cited several examples of joint production, including coke and coal-gas; mutton and wool; beef, hides, and tallow; calves and dairy products; and chickens and eggs. Mill considered these to be "peculiar cases" because he discerned no way to divide the cost of production so as to arrive at a value (equivalent to price, in Mill's terminology) for each product: "Cost of production can have nothing to do with deciding the value of the associated commodities relatively to each other. It only decides their joint value."^{2/}

In other words, Mill recognized that information on the total cost of producing joint products is insufficient to arrive at a proper price for each product. This apparent quandary, which will be discussed below in the section on pricing, has been the main concern of economists studying joint costs in the century following Mill's enunciation of the problem.

Writing in 1891, F.W. Taussig broadened the scope of the joint production problem to include cases where only a part of the production process--and hence, the cost--is joint. Clearly, most examples of joint production, including those cited by Mill, entail some separate production or processing before the individual goods are marketed. The raising of sheep, for example, is the joint process necessary for production of mutton

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1. John Stuart Mill, Principles of Political Economy, Book III, Chapter XVI.
 2. Ibid.

and wool; but the finished products are obtained only after butchering and spinning, which clearly are not joint activities. Taussig concluded that the product pricing problem set forth by Mill still applies; however, he asserted that the minimum equilibrium price for a joint product would be the cost incurred in processing it separately.^{1/}

Taussig's remarks were framed in the context of an analysis of railroad rates, in which he used the concept of joint costs to explain different freight rates for different commodities. Virtually all of the literature from the first quarter of the twentieth century considers joint production in this context. Of principal interest is a series of exchanges between Taussig and A.C. Pigou, carried out in the Quarterly Journal of Economics in 1913.^{2/} The controversy began with the publication of Pigou's Wealth and Welfare,^{3/} in which he claimed that differential freight rates could not be justified by reference to the joint cost concept. His argument, as explicated in his rebuttals to Taussig's critiques, was that differences in, say, the rates per ton-mile of copper and coal arise only through the railroad's ability to engage in price discrimination--that is, to charge different rates for the same service ("transport") as if two different services were provided ("transport of

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1. F.W. Taussig, "A Contribution to the Theory of Railway Rates," Quarterly Journal of Economics, 5 (July, 1891), 443-444.
 2. F.W. Taussig, "Railway Rates and Joint Costs Once More," Quarterly Journal of Economics, 27 (February 1913), 378-84; A.C. Pigou and F.W. Taussig, "Railway Rates and Joint Cost," Quarterly Journal of Economics, 27 (May, 1913), 535-538; A.C. Pigou and F.W. Taussig, "Railway Rates and Joint Costs," Quarterly Journal of Economics, 27 (August 1913), 687-694. For a summary of this debate, see Lewis H. Haney, "Joint Costs with Especial Regard to Railways," Quarterly Journal of Economics, 30 (February 1916), 233-252.
 3. A.C. Pigou, Wealth and Welfare (London and New York: MacMillan, 1913).

copper" and "transport of coal"). Pigou believed that this ability to discriminate stems from the railroad's monopolistic power; under free competition in the supply of transport, he maintained, freight rates would be the same for coal and copper (assuming that transport of one or the other would not affect a railroad's costs). Taussig, on the other hand, contended that the supply of transport to different customer groups--who have different demand schedules--amounts to the supply of heterogeneous commodities.

In the course of their exchange, Pigou developed a distinction between common costs and joint costs. To a large degree, their disagreement turned on whether railroad freight costs were common or joint. When an element or portion of the production process can be utilized to produce either product A or product B, the costs incurred are said to be common.

A corollary to this definition is that common products can be produced in any proportion (within the limits of technical feasibility), since an increment to the common activity could be used to produce additional output of A, B, or both. Pigou limited his use of "joint" to those situations in which goods are produced in fixed proportions; a joint cost is that which, when incurred, necessarily leads to an increase in the output of both products. Because Pigou viewed the additional costs of providing coal transport or copper transport as entirely common, he maintained there is no basis for differential rates other than discrimination.^{1/} This distinction between common production and joint

1. Quarterly Journal of Economics, 27 (August 1913), 690-691.

production--or, stated another way, between production in variable proportions and production in fixed proportions--remains important in modern theoretical treatments of the pricing problem, to be discussed below. It would seem, however, that there are few cases in which production necessarily occurs in fixed proportions--at least in the long run. Sheep can be bred to give more or less mutton per pound of wool; even the refining of oil into separate products, formerly governed by chemical characteristics, can now be altered via cracking to produce different yields.^{1/}

Since the Pigou-Taussig controversy, the terminology and definitions seem to have remained unchanged. Modern writers generally do not reserve the terms "joint" and "common" for production in fixed and variable proportions, respectively.^{2/} In the balance of this section, both cases are subsumed under "joint," with appropriate modifiers used where a distinction is necessary.

THE INVESTMENT DECISION

The process of deciding whether to construct an ICES, or any joint production facility, may raise questions regarding the allocation of costs. consider the following examples:

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1. Alfred E. Kahn, The Economics of Regulation: Principles and Institutions (New York: John Wiley & Sons, Inc., 1970, 2 volumes), Vol. 1, p. 79.
 2. See, for example, the sections on "Joint Products Produced in Fixed Proportions" and "Joint Products Produced in Variable Proportions" in Eugene F. Brigham and James L. Papas, Managerial Economics (Hinsdale, Ill: The Dryden Press, 1972), pp. 304-309. An exception is Kahn, who uses the Pigouvian joint-common distinction in The Economics of Regulation.

- A dam currently provides irrigation benefits. The addition of hydroelectric generating facilities is under consideration.
- A dam that would provide both irrigation and hydroelectric benefits is under consideration. There are no existing facilities for either purpose.

The allocation questions in each of these cases can be framed as follows:

- For the first case, what portion of the historical costs of the existing dam should be used in deciding whether to invest in hydroelectric capacity?
- For the second case, how are the costs of the total project to be divided between irrigation and hydroelectric functions?

The economic approach to these questions is based on consistent application of the principle of incremental analysis. This means that the correct decision is based only on analysis of the increments, or changes, that occur when an investment is made. "Sunk" or historical costs are irrelevant; if the net changes (benefits less costs) that occur are favorable, a project is worth undertaking--regardless of whether the previously existing situation is favorable or unfavorable.^{1/}

When incremental analysis is applied to the case of an existing dam, the allocation problem is eliminated. The only costs that must be considered are those that will be incurred in making the additions and modifications needed to produce hydroelectric power. The costs of the dam equipment already in place are irrelevant--even though the hydroelectric

1. Correct application of incremental analysis to an investment decision is based on a comparison of benefits and costs, with future values discounted by an appropriate interest rate to reflect the time value of money.

production could not take place without that equipment. Similarly, the benefits to be considered are those which occur because of the change--i.e., the benefits of the hydroelectric power.^{1/}

In the second case, there is also no need to allocate costs for the investment decision. Since the facility would be new, the "incremental" costs are the costs of the entire project. The benefits to be compared against these costs are the sum of the separate benefits from irrigation and power. Only if the project as a whole yields benefits that are favorable to costs should the entire project be undertaken.

The rules sketched out in the examples above can be generalized to any investment decision. The temptation to allocate joint costs must be resisted. Some sort of allocation may be desirable for accounting purposes, but it is irrelevant with respect to the question of economic feasibility.^{2/}

THE PRICING AND OUTPUT DECISIONS

The cost allocation problem is most frequently faced when decisions must be made as to prices and levels of output for joint products. Firms that have some freedom to set prices for their goods, and regulatory bodies that must determine "fair" prices for joint public utility services and assess the need for additional production facilities, may rely on allocated cost data.

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1. If addition of the hydroelectric power somehow reduces the amount of irrigation benefits, the changes must be netted against the hydroelectric benefits.
 2. The preceding argument is adopted from a discussion of multiple-purpose water projects in Jack Hirshleifer, Water Supply: Economics, Technology and Policy (Chicago: University of Chicago Press, 1960), pp. 93-94.

This section presents the economic approach to the pricing and output decisions of joint production. Since the appropriate rules are derived from the theory used to explain pricing and choice of output in single-product firms, the analysis is built up in several stages. First, the basic outline of marginal cost and price analysis is presented. Second, the rules for optimal firm behavior in the perfectly competitive model are developed. Third, the pricing and output practices of unregulated monopolists are explained, and the appropriate rules for monopoly regulation are developed. Finally, the analysis is extended to joint products produced under monopoly.

Marginal Analysis

Central to the microeconomic interpretation of pricing and output decisions is the concept of marginal analysis. Formally, a marginal quantity is the change in the dependent variable of a function associated with a one-unit change in one of the independent variables;^{1/} in terms of calculus, it is the derivative of the function. The marginal concept is intuitively grasped by reference to the definitions of marginal revenue and marginal cost. Marginal revenue is the change (positive or negative) in total revenues received by a firm when it sells one more unit of a product. Similarly, marginal cost is the change in total production cost incurred by a one unit increase in production.

These marginal concepts are key to the explanation of a firm's profit-maximizing behavior. For any firm, whether it operates under

1. Brigham and Pappas, Managerial Economics, p. 19.

perfect competition or monopoly, profits are the difference between revenues and costs:

$$\Pi = R(Q) - C(Q) \quad (1)$$

where Π = profit
 R = revenues
 C = costs
 Q = quantity produced.

The notations $R(q)$ and $C(Q)$ mean that both revenues and costs depend on the quantity of goods produced. The first-order conditions for maximization of the profit function are:

$$\frac{d\Pi}{dQ} = \frac{dR}{dQ} - \frac{dC}{dQ} = 0 \quad (2)$$

Therefore,

$$\frac{dR}{dQ} = \frac{dC}{dQ} \quad (3)$$

But dR/dQ is the calculus definition of marginal revenue, and dC/dQ is the calculus definition of marginal costs. Therefore,

$$MR = MC \quad (4)$$

for profit maximization. In other words, the firm should produce up to that point at which the added revenue from an additional unit of output exactly offsets the added cost of producing that unit.

Exhibit B-1 shows this result in geometric form. It shows hypothetical total revenue and total cost curves for a firm producing a single product. Since profit is defined as revenues less costs, it is shown by the vertical distance between the two curves. Below Q_1 and above Q_2 , costs are above revenues, and profit is negative (i.e., the firm loses money). By the rules of geometry, the vertical difference

EXHIBIT B-1

GEOMETRIC INTERPRETATION OF THE PROFIT MAXIMIZATION RULE

between the two curves is greatest when lines that are tangent to the curves are parallel. Therefore, profits are greatest at Q^* , where the tangents are parallel. Since the slope of the tangent is equal to the derivative of the curve at the point of tangency, Q^* is also the point where the derivative of total revenue--the marginal revenue--is equal to the derivative of total cost--the marginal cost. In other words, the profit-maximizing firm should produce that quantity for which marginal revenue equals marginal cost.

The Efficiency of Perfect Competition

The hypothetical state of perfect competition serves as the prototype for a significant portion of microeconomic theory. Since perfect competition per se cannot be said to exist in any real-world market, the results must be qualified. Nevertheless, the insights provided by the model are useful in analyzing real world behavior, and serve as benchmarks for gauging the degree of market imperfections. From the economist's standpoint, perfect competition represents an unattainable but desirable objective, for as will be shown presently, it ensures that society's scarce resources are allocated efficiently.

It is important to realize, however, that efficiency is not an overriding criterion, even from the economist's point of view. Society also is concerned with equity, or fairness, and may let equity concerns override efficiency concerns. Many social programs--for example, the establishment of "lifeline" utility rates for certain classes of customers--do not measure up by efficiency standards, but may be socially desirable due to notions of equity.

The assumptions of the perfectly competitive model are as follows:

- There are a large number of firms, each producing an identical product.
- No firm is large relative to the market or industry as a whole. Therefore, no firm alone can exert an influence on price, and each firm can sell all of its output at the going market price.
- Firms can freely enter or leave the industry.
- Entry is costless, i.e., the only costs faced by new firms are the same production costs faced by existing firms.
- All goods are completely mobile.
- There are no added costs of making transactions.^{1/}

Based on these assumptions and the rules of marginal analysis developed above, the output decision of the perfectly competitive firm is shown in Exhibit B-2. The horizontal line at P^* shows the effective demand curve facing a single firm. Since it is assumed the firm cannot affect the market price, the effective demand curve is horizontal; the firm can sell all it wants at the market price. Hence, both the average revenue (AR) and marginal revenue (MR) received by the firm are constant at P^* across all possible choice of output.

Exhibit B-2 also shows a portion of the firm's marginal cost curve. Since any profit-maximizing firm will choose to operate where $MR = MC$, the firm will produce Q^* units of output. If exogenous market influences (i.e., forces beyond the control of the single firm) lead to a

1. Walter Nicholson, Microeconomic Theory: Basic Principles and Extensions (Hinsdale, Ill: The Dryden Press, 1972), p. 266.

EXHIBIT B-2

SHORT-RUN OUTPUT DECISION FOR A FIRM IN PERFECT COMPETITION

change in price, the firm's effective demand curve and optimal output will shift. Thus, the firm's MC curve is equivalent to its supply curve: it shows the quantity of goods that will be produced at any price, other things being equal.^{1/}

The supply curves of each firm can be summed horizontally to obtain an industry supply curve, which shows the quantity produced by the industry as a whole at each price.^{2/} This is shown in Exhibit B-3 along with the industry demand curve, which is negatively sloped to reflect the usual case that more goods are demanded at a lower price. The intersection, at P^* and Q^* , shows the determination of price and output in equilibrium.

The social efficiency of the equilibrium output under perfect competition can be explained as follows. The demand curve shows the value society places on each unit of output, as reflected in the price it is willing to pay. The supply curve--the sum of many firms' marginal cost curves--shows the additional cost of producing an additional unit of the good. At Q^* , consumers are willing to pay exactly the cost of producing another unit. At any output less than Q^* , consumers are willing to pay more for one more unit of output than it would cost to produce that unit; therefore, output is too low from the social point of view. Above Q^* , consumers value the added output at less than the cost of the labor and

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1. Strictly speaking, the MC curve is the firm's supply curve only above the point of minimum average variable cost. Below this point, there is a loss on each unit produced (in addition to fixed costs that the firm must cover), so it will choose to shut down.
 2. Interaction effects among firms may alter cost curves such that the industry supply curve is not simply the horizontal sum of the firms' curves. Nonetheless, the industry supply curve is normally expected to be positively sloped. Nicholson, Microeconomic Theory, p. 269.

EXHIBIT B-3

INDUSTRY PRICE-OUTPUT DETERMINATION IN PERFECT COMPETITION

capital required to produce it; in this case, output would be too high. Only at G^* , where price equals marginal cost, are society's preferences--as measured by the demand curve--and the application of society's scarce resources in harmony.^{1/}

The preceding discussion requires some elaboration to account for distinctions between short-run and long-run conditions. Economists define the short-run as the period over which at least one of the inputs used for production cannot be altered; essentially, this is equivalent to the period over which the physical plant is fixed, and only labor or material inputs can be altered. Correspondingly, the long-run is the period over which all inputs are variable. The actual period that constitutes the short-run may vary greatly across industries and firms. A fair generalization, however, is that the short-run for capital-intensive industries may be of several years' duration, because of heavy investment in long-lived capital assets.

In the long run, the perfectly competitive firm will strive to operate at the minimum on its long-run average cost (LRAC) curve, by altering those inputs that are fixed in the short run. Changes in technology and the prices of inputs may make this minimum a "moving target," so attainment of the minimum in practice may be an elusive goal. Concurrent with adjustment of firms' scale of plant, entry to or exit from

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1. An important caveat is noted by Kahn: "the allocation of resources [that follows from production at G^*] can be described as 'optimal' only on the basis of two essentially unprovable assumptions or value judgments: that the "best" economy is the one that gives consumers what they individually want; and that income is either distributed optimally or can best be redistributed without departing from marginal cost pricing." The Economics of Regulation, Vol. 1, p. 67.

the industry will take place in response to profits or losses.^{1/} (Recall that freedom of entry is an assumption of the perfectly competitive model.) Changes in the number of producing firms will shift the short-run industry supply curve, and consequently also cause a shift in price. Equilibrium will be established only when all firms are in a zero-profit condition (in the economic sense). At the equilibrium point, price, short-run marginal cost, long-run marginal cost, short-run average cost, and long-run average cost are all equal.

Earlier, it was indicated that social efficiency is served when price is equal to marginal cost. The question arises, Does this refer to short-run cost or long-run cost? If the perfectly competitive model is valid, this point is irrelevant, because short-run and long-run marginal costs will coincide in equilibrium. From a policy standpoint, however, the question is important, because violation of any of the qualifying assumptions of perfect competition may suggest the appropriateness of intervention in the market to serve the goal of social efficiency. Kahn answers the short-run/long-run question in this way, from the strict economic viewpoint:

. . . it is short-run marginal cost to which price should at any given time--hence always--be equated, because it is short-run marginal cost that reflects the social opportunity cost of providing the additional unit that buyers are at any given time trying to decide whether to buy.^{2/}

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1. Economists' definition of costs includes a "normal" rate of return on investment. Therefore, "profits" might be viewed as "excess profits," or return in excess of that required by investors.
 2. Kahn, The Economics of Regulation, p. 71.

Pricing in Monopoly Firms

Although the microeconomic analysis developed above is built upon the perfectly competitive model, many of the same principles and concepts apply to markets which diverge from perfect competition. Our interest here will be in the application of these principles to the analysis of monopoly firms. This will bring us one step closer to the industrial setting in which an ICES would most likely function.

Strictly speaking, the market for a particular good is described as a monopoly if there is only one producer of that good.^{1/} Thus, the single producer faces the entire market demand curve, which is downward-sloping for all normal goods. Because they are awarded franchises to provide exclusive service within a geographic area, and thus are the sole producers of services, public utilities are monopoly firms. Although the term "monopoly" typically has negative connotations, usage here is purely descriptive and is based on the conditions of demand in which the firm operates.

It was shown earlier that any profit-maximizing firm will strive to produce where marginal revenue equals marginal cost. Exhibit B-4 shows the implications of this rule for monopoly firms. The monopolist will produce at Q^{**} , where the MR and MC curves intersect. This will yield a price of P^{**} , which is read off the demand curve. In this case, monopoly profits will be received. The total cost of producing quantity Q^{**} is the quantity times the average cost, or the rectangle $OQ^{**}AC$. Total revenues, which are given by the price times the quantity, correspond to the rectangle $OQ^{**}BP^{**}$. The excess of revenues over costs, then, is the

1. Nicholson, Microeconomic Theory, p. 291.

EXHIBIT B-4

PROFIT MAXIMIZATION AND PRICE DETERMINATION IN MONOPOLY

rectangle CABP**; this is the monopolist's profit. Note that this is profit in the economic sense, i.e., it exceeds the "normal" market return required by investors.

Whether a monopolist earns excess profit depends on the shape of the cost curves. The result is unambiguous, however, that unregulated monopoly leads to a reduction in output from that which would be produced under perfect competition. This is shown in Exhibit B-5. For simplicity, it is assumed that production takes place with constant marginal costs across the relevant range, for either a monopolist or a competitive industry. The perfectly competitive industry will produce at Q^* , where price is equal to marginal cost, because for each individual producer price is equivalent to marginal revenue. The monopolist, however, "sees" the downward sloping demand curve, and behaves in accordance with the associated marginal revenue curve. Monopoly output will be at Q^{**} (where $MR = MC$), and the divergence in output from competition will be $(Q^* - Q^{**})$. In addition, monopoly price will be at P^{**} , above the price of P^* attained in competition.

Regulation of monopolies by public utility commissions or other governmental bodies is one approach to these problems. The traditional regulatory approach, however, diverges from the economic approach in several respects. The most important of these is pricing of utility services according to average cost, as opposed to marginal cost. The traditional calculation of a utility's rate base, and determination of a "fair" or "normal" rate of return on the rate base, yields the utility's "revenue requirement," which is an approximation to the economic concept of average cost for a particular scale of operation. (Recall that the economist's

EXHIBIT B-5

MARKET PRICE AND OUTPUT DETERMINATION IN MONOPOLY
AND PERFECT COMPETITION

Adapted from Walter Nicholson, Microeconomic Theory: Basic Principles and Extensions (Hinsdale, Ill.: The Dryden Press, Inc., 1972), Figure 15.4.

definition of cost includes a normal rate of return on investment.) A second difference is that regulatory bodies generally base their decisions on historical accounting costs, whereas the economic concept of cost is based on current opportunity costs. In general, the revenue received by a utility under traditional regulation will differ from that which would be received if pricing according to marginal cost were imposed by regulation. Exhibit B-4, above, can be used to show one variant of this problem. While theory tells us that price and output should be determined by the intersection of the marginal cost and demand curves, this would result in revenues in excess of a normal return on the rate base, since marginal cost is above average cost at this point.

The opposite situation occurs if the monopolist is operating in the range of decreasing costs. If average cost is declining at the socially desirable level of output (where marginal cost intersects the demand curve), then by definition marginal cost must be below average cost. Hence, marginal cost pricing would yield revenues that are deficient with respect to average cost, and thus are less than those dictated by traditional utility regulation. Perhaps more importantly, any firm must cover its average total costs in the long run, or go out of business; so some means must be found to make up the deficiency.

Several solutions have been proposed by economists to deal with the case where marginal cost-based prices are insufficient to cover variable costs. The simplest view, which has been termed the "Hotelling-Lerner Solution,"^{1/} is that the difference should be made up by the

1. R. H. Coase, "The Marginal Cost Controversy," Economica (new series), 13 (August, 1946), pp. 169-170.

government through taxation. This view is based on the presumption that adherence to marginal cost-based pricing is paramount, for the reasons of social efficiency outlined earlier. The problem with this view is that any practical system of taxation introduces its own distortions into the pricing system, causing other prices to diverge from marginal cost.^{1,2/}

Another solution is to institute a two-part price, under which each customer must pay a lump-sum fee for the privilege of being allowed to purchase output. A distortion introduced by this system, however, is that some customers who want just a few units of output may decide to forego purchases entirely; but as long as they are willing to cover the marginal cost of production, theory states that these customers should be supplied.^{3/}

A third solution is for the monopolist to engage in price discrimination--that is, to charge different prices to different customers although the costs of service do not actually differ. So doing allows the firm to recover revenues from some customers in excess of what would be received if all goods were sold at a single price.^{4/} It is this solution which is most similar to utility rate-making in practice.^{5/}

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1. William J. Baumol and David F. Bradford, "Optimal Departures from Marginal Cost Pricing," American Economic Review, 60 (June, 1970), 265-266.
 2. Actually, a "Pigouvian poll tax"--a flat-rate, lump-sum tax assessed against every member of the population--is not distortionary, but is not a realistic option. Ibid., p. 265.
 3. Hirshleifer, Water Supply, p. 92.
 4. For an elaborate graphical exposition of price discrimination for this purpose, see Kahn, The Economics of Regulation, Vol. 1, pp. 137-140.
 5. Hirshleifer, Water Supply, p. 92.

A prerequisite for price discrimination is the existence of separable markets: the monopolist can supply each market separately, but inter-market transfers cannot take place. Establishment of customer classes (e.g., commercial, industrial, residential, etc.) where not justified by differences in the cost of serving the classes, is a form of price discrimination.

For price discrimination to be worthwhile (from the monopolist's perspective) the separate markets must have demand curves of different elasticity. (Elasticity of a demand curve is a measure of the degree to which the quantity demanded changes in response to a change in price.) When this condition holds, the market that has the less elastic demand curve will be charged a higher price. Exhibit B-6 shows that a profit-maximizing monopolist will produce in each market where $MR = MC$, resulting in different prices and quantities in each market.

Pricing and Output Decisions With Joint Production

In this section, the microeconomic analysis of pricing and output decisions is extended to cases of joint production. It is assumed here that the firm supplies the joint products under monopoly conditions; that is, it faces downward sloping demand and marginal revenue curves, rather than the flat effective demand curve facing perfect competitors. Earlier, two types of joint production were delineated: production in fixed proportions, and production in variable proportions. The analysis here will proceed in the same order.

The pricing and output decisions for joint production in fixed proportions can be demonstrated graphically. Exhibit B-7 shows separate

EXHIBIT B-6.

PRICE DISCRIMINATION BY ELASTICITY OF DEMAND

Adapted from Walter Nicholson, Microeconomic Theory: Basic Principles and Extensions (Hinsdale, Ill.: The Dryden Press, Inc., 1972), Figure 15.2.

EXHIBIT B-7

OPTIMAL PRICE-OUTPUT DECISION FOR JOINT PRODUCTION
IN FIXED PROPORTIONS

Adapted from Eugene F. Brigham and James L. Pappas, Managerial Economics (Hinsdale, Ill.: The Dryden Press, Inc., 1972), Figure 11-3.

demand curves for two joint products, D_A and D_B , and their associated marginal revenue curves. The horizontal axis measures the combined output of the production package in fixed proportions. For example, if the process yields products A and B in the ratio of 3:1, then one point along the horizontal axis might correspond to 30 units of A and 10 units of B.

The marginal revenue curves for each product are summed vertically over the positive range of each to derive a marginal revenue curve for the output package. Because MR_A reaches zero at Q_2 , the combined MR curve for production in excess of Q_2 coincides with MR_B . The combined MR curve, then, is given by the "kinked" heavy line connecting points x, y, and z. Exhibit B-7 also shows a single marginal cost curve. Since the outputs are produced as a package, it is impossible to distinguish separate marginal cost curves for each.

The profit-maximizing monopolist, following the rule that marginal revenue should equal marginal cost, will produce combined output of Q_1 , which corresponds to the point where the MC curve intersects the MR curve for the package. The price that will be received for each product in the market is determined by the separate demand curves at output Q_1 . Products A and B will be priced at P_A and P_B , respectively.

This is essentially the same solution that was described in the nineteenth century by Mill, in his Principles of Political Economy:

Equilibrium will be obtained when the demand for each article fits so well with the demand for the other, that the quantity required of each is exactly as much as is generated in producing the quantity required of the other. . . . When there-

fore, two or more commodities have a joint cost of production, their natural values relatively to each other are those which will create a demand for each, in the ratio of the quantities in which they are sent forth by the productive process.^{1/}

Exhibit B-8 shows a special case of the pricing and output decisions described above. In this figure, marginal cost intersects the combined marginal revenue at Q_3 , indicating the appropriate level of joint production. Note, however, that marginal revenue from product A reaches 0 at Q_2 ; in fact, if it were extended, the MR_A curve would have a negative value. It is therefore in the firm's profit-maximizing interest to limit sales of A to the output at Q_2 ; additional sales beyond this point will diminish total profit. Production of the output package will still take place at Q_3 ; however, the output of A in excess of that produced at Q_2 should be destroyed in order to avoid depressing the market price.^{2,3/} The price for A that will be received in the market is given by the demand curve at Q_2 .

Both of the graphical analyses presented above are based on the simplest case of joint production, in which a single process yields two marketable products. In fact, most situations involve some common activity and cost, and some additional activities and costs that are clearly

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1. Mill, Principles of Political Economy, Book III, Chapter XVI.
 2. This curious situation apparently occurred in the joint production of sliced pineapple and pineapple juice. For a time, producers destroyed some of the juice, instead of placing it on the market and lowering their profits. Eventually, however, producers brought about a shift in the demand curve for juice through advertising. Brigham and Papas, Managerial Economics, p. 306n.
 3. The analysis would be somewhat more complicated if disposal costs were taken into account.

EXHIBIT B-8

OPTIMAL PRICE-OUTPUT DECISION FOR JOINT PRODUCTION
IN FIXED PROPORTIONS, WITH EXCESS
PRODUCTION OF ONE PRODUCT

Adapted from Eugene F. Brigham and James L. Pappas, Managerial Economics (Hinsdale, Ill.: The Dryden Press, Inc., 1972), Figure 11-4.

attributable to one product or the other. Kahn presents a complex graphical treatment which includes separate production costs; basically, his analysis proceeds in the same fashion as the simple cases illustrated above.^{1/}

Earlier, it has been argued that production in proportions that are truly fixed is rare; most joint production can be altered, even if only in the long run, to yield varying ratios of output. Exhibit B-9 shows a "cost/output matrix" for two joint products that can be produced in variable proportions. Each entry in the table shows the total cost of producing a particular package of output. From this matrix, we can determine marginal cost directly. For variable-ratio production, the marginal cost of A is the change in the cost of the entire output package resulting from a change in the output of A, holding the output of B constant. Thus, the marginal cost of the third unit of A, if output of B is fixed at four units, is \$10 (= \$53 - \$43); this is the additional cost incurred in producing three units of A instead of two, in conjunction with production of four units of B.

When the physical characteristics of a process permit production in variable proportions, no single cost curve can represent all of the production possibilities. However, the cost relationships can be illustrated in an isocost map, shown in Exhibit B-10. Each curve shows the quantities of A and B that can be produced for a given total cost; thus, for a total cost of \$45, one possible output combination is A_1 , B_2 ; another possible combination is A_2 , B_1 . The curves are drawn as concave to the origin because, in general, repeated

1. Kahn, The Economics of Regulation, Vol. 1, pp. 79-83.

EXHIBIT B-9

COST/OUTPUT MATRIX FOR JOINT PRODUCTION IN
VARIABLE PROPORTIONS

Output of B	Total Cost of Package				
	Output of A				
	1	2	3	4	5
1	\$ 5	\$ 7	\$10	\$15	\$ 22
2	10	13	18	23	31
3	20	25	33	40	50
4	35	43	53	63	75
5	55	67	78	90	105

EXHIBIT B-10

ISOCOST MAP

substitution of one product for another eventually yields smaller additional outputs.^{1/}

In a similar fashion, we can construct isorevenue curves for the two products based on information on the prices that would be received for various combinations of products. Isorevenue curves show all possible combinations of the products that, when sold, yield a given total revenue. The shapes of isorevenue curves cannot be assumed. If goods are sold at constant prices, as in perfect competition, the isorevenue curves are straight lines. When the industry diverges from perfect competition, or when there are interdependencies such that the price of one product affects the price of the other, the isorevenue curves may have complicated shapes. Typically, they are drawn as straight lines for simplicity; the analysis for other shapes, however, would be essentially the same.

In Exhibit B-11, the isorevenue curves are drawn so that one is tangent to each of the isocost curves. The points of tangency show the highest revenue that can be received for production at a given cost. Therefore, the difference between the values of the isorevenue and isocost curves at the points of tangency show various profit possibilities. The profit-maximizing firm will operate at the point of tangency where the difference between the values is the greatest; in Exhibit B-11, this would be where revenue is \$30, cost is \$18, and profit is \$12. At this point of tangency, the marginal revenue of each product is equal to its marginal cost.

1. George J. Stigler, The Theory of Price, 3d ed. (New York, The MacMillan Company, 1966), p. 164.

EXHIBIT B-11

OPTIMAL PRICE-OUTPUT DECISION FOR JOINT PRODUCTION
IN VARIABLE PROPORTIONS

Adapted from Eugene F. Brigham and James L. Pappas, Managerial Economics (Hinsdale, Ill.: The Dryden Press, Inc., 1972), Figure 11-5.

It is important to note that the pricing and output decision follows strictly from the marginal relationships. No average cost figures need be derived for either product; in fact, it is not possible to determine an average cost for each product where production is joint. Yet, as Stigler wryly comments, "It is worth noticing that even though impossible, it is done everyday."^{1/} Calculation of such specious "average costs" requires the allocation of the joint costs to the individual projects. While this procedure has intuitive appeal, it lacks a sound economic basis.

With reference to regulation of monopolies in general, it was shown earlier that setting price equal to marginal cost is the socially correct decision. Yet this may not be practicable if (on the one hand) it would lead to "excessive" monopoly profits, or if (on the other hand) it would not permit the firm to recover average cost in the long run. In either case, some alternative to strict marginal cost pricing is required.

The same problem arises when the regulated monopoly engages in joint production. The problem may be framed this way: How should the marginal cost-based prices of joint products be adjusted so as to fulfill a specific revenue requirement? Manne first addressed this question with respect to public enterprises in 1952 as a problem of constrained maximization.^{2/} He sought a rule that would maximize net social product (the excess of social benefits over social costs) subject to the requirement that the revenues from the joint products must be sufficient to prevent the public enterprise from operating at a loss. More recently,

1. Ibid., p. 165.

2. Alan S. Manne, "Multiple-Product Public Enterprises--Criteria for Pricing," Economica (new series), 19 (August, 1952), 322-326.

Baumol and Bradford have formulated what they believe to be a completely general rule for "quasi-optimal" pricing, encompassing cases where the demands for the joint products are interdependent.^{1/} (By "interdependent," it is meant that the demand for one product affects the demand for the other. This situation might arise in an ICES if some customers could substitute thermal energy for electric energy, or vice versa.) One variant of their theorem, which is derived mathematically, states:

Quasi-optimal prices must yield outputs that deviate by (approximately) the same proportion from those which would result from pricing at the marginal costs corresponding to the quasi-optimal output levels.^{2/}

Baumol and Bradford's article continues to receive the scrutiny of economists. Whether or not it is ultimately accepted as valid, it embodies the economic approach to the problem: prices should be set at marginal cost, and then adjusted in a systematic fashion to fulfill the revenue requirement imposed through regulation.

SUMMARY AND CONCLUSIONS

In this appendix we have examined the appropriateness of joint cost allocation from the standpoint of theoretical economics. Cost allocation in an ICES, or in any joint production process, may be sought as a first step in investment and pricing/output decisions. In no case, however, is allocation required; rather, application of incremental and marginal principles is sufficient to achieve the economically efficient result.

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1. Baumol and Bradford, Optimal Departures from Marginal Cost Pricing.
 2. Ibid., p. 268.

We have assumed that an ICES would operate in a monopoly setting under traditional regulatory constraints. Under these conditions, the ratesetting problem reduces to the problem of adjusting the marginal prices for each product so as to fulfill the aggregate revenue requirement.

The limitations of economic theory suggest why departure from the strict theoretical results may be warranted. As we have noted, achievement of the economically efficient outcome is an important, but not overriding, objective; in many cases, the value society attaches to its standards of equity may allow a conflicting outcome to prevail. Also, the theoretical results are predicated on the availability of accurate data on marginal costs, demand curves, and so forth. To the extent that our knowledge is imperfect and incomplete, we must rely on practically-achievable approximations. In subsequent appendices, we will address the "real world" counterparts to the theoretical rules we have presented.

APPENDIX C

ECONOMIC ESTIMATION OF MARGINAL COSTS

INTRODUCTION

Economic theory indicates that prices of jointly produced products should be set at marginal cost. In our discussion of the economic literature it was noted that marginal cost pricing may not be satisfactory in a regulated industry since it may result in collecting revenues greater or less than the revenue requirement. Nonetheless, marginal cost is the starting point for adjusting these rates to meet the revenue requirement. For this reason there have been several attempts to describe how the marginal costs of jointly produced products can be determined using econometric techniques. Here we report on one of the successful techniques. In the paper^{1/} we review, the authors develop a technique of estimating a joint cost function for the jointly produced products. They apply this technique to estimate the joint cost function for passenger rail service and freight rail service. We have attempted to write this in non-technical terms, yet briefly describe the major factors. In addition we describe the strengths and weaknesses and how they relate to the applicability of this approach to the joint costs associated with ICES projects.

^{1/} The discussion here draws heavily on an unpublished paper by R. S. Brown, D. W. Caves, and L. R. Christensen entitled "Modeling the Structure of Production with a Joint Cost Function." This technique is also used in L. R. Christensen and W. H. Greene, "Economies of Scale in U.S. Electric Power Generation," Journal of Political Economy, August, 1976.

THE ECONOMETRIC METHOD ^{1/}

Consider a joint production process where $[y_1, y_2, \dots, y_n] = Y$ is the vector of outputs and $[x_1, x_2, \dots, x_n] = X$ is a vector of inputs used to produce the outputs. If the prices of the inputs are given by $[w_1, w_2, \dots, w_n] = W$, then the joint cost function C is given by

$$C(Y, W) = \min_X \sum_{i=1}^n w_i x_i$$

where, clearly the minimum amounts of the inputs, X , depend upon the levels of the joint outputs, Y . The relation between inputs and outputs, the joint production function, can be expressed in implicit form as:

$$F(Y, X) = 0$$

This production function determines the minimum levels of inputs that can be used to produce various output combinations. Our primary concern is with the joint cost function, $C(Y, W)$. Note that the input levels are not included. Rather, it is assumed that through the process of minimizing the costs of production, the input levels will be determined that can be expressed as functions of the levels of output and input prices.^{2/}

It is possible to use econometric techniques to estimate the function with no other information, but this ignores the restrictions resulting from economic analysis. For example, inputs are used to the point where the ratio of their additional costs equal the ratio of their additional values in production. Direct estimation of the cost function also ignores any conditions associated

^{1/} In general, "econometric method" refers to the use of regression techniques to relate a set of independent variables to dependent variables.

^{2/} This is the result if one selects inputs to minimize $C = \sum_{i=1}^n w_i x_i$ subject to the production function constraint $F(Y, X) = 0$.

with production, such as economies of scale or substitutions possibilities between inputs. More meaningful and more precise estimates can be obtained if these factors are taken into account. It can also increase the possibility of obtaining statistical results that cannot pass the test of reasonableness, such as having a significant statistical relationship between the output level of electricity and the money spent on steam pipes in an ICES. This statistical anomaly could occur if the production relations, embodied in the production function, ignored the concept that steam pipes relate to steam production and do not relate to electricity production.

By careful choice of the cost function and the restrictions, the authors of the reviewed paper were able to explicitly take into account economies of scale and measures of substitution possibilities. This could not be accomplished if $C(Y, W)$ were estimated in isolation. In this particular case, the joint cost function of freight and passenger rail service was estimated using a translog cost function^{1/} together with equations that specified that the level of usage of an input was equal to the partial derivative of the cost function with respect to the input's price. From this analysis it was possible to determine the marginal cost of freight service, passenger service and the level of economies of scale. Based upon the rates that railroad regulatory authorities allowed, it was also possible to demonstrate that freight traffic was more profitable.

^{1/} A translog function is a logarithmic function with logarithmic exponents. Although it sounds complex it can be easily estimated and allows the analyst to test for economies of scale, substitutability between inputs, and homogeneity.

STRENGTHS AND WEAKNESSES OF THIS APPROACH

The major strength of this approach is that it is an objective procedure that allows the data to determine the results. This is important because with other methods, the choice of the method may determine the result. Furthermore, this method can be repeated by any other researcher and the same results would be obtained if the procedures were correctly followed.

The econometric approach has one other major advantage. Through the process of analysis it provides a great deal of information including information on the level of economies of scale and substitution possibilities. Other tests of hypotheses can also be constructed.

The econometric approach has several weaknesses, particularly with respect to its use on ICES projects. The major disadvantage is that a fairly extensive data base is required to carry out the statistical analysis. Since this data should all come from the ICES system under consideration, it would require a set of time series data which do not exist at this time. The second drawback with this approach is that it requires a level of statistical analysis that is not generally available. While this problem could be overcome through the use of computer programs, the lack of data precludes serious consideration of this method for cost allocation for ICES.

APPENDIX D

PUBLIC PROJECTS. APPROACHES TO COST ALLOCATION

INTRODUCTION

The use of one project to fulfill many purposes is common to both the public and private sectors. In such projects it is frequently the case that parts of the project are used for two or more of the many purposes involved in the project. In this section, we discuss ways in which the costs related to joint use portions can be allocated to the several purposes. A substantial body of literature about diverse purposes being served by a common project deals with federal water projects, which typically provide such benefits as irrigation, navigation, flood control, and electricity. Below we build on the methods and definitions of this literature, and discuss its applicability to cost allocation for an ICES.

BENEFITS METHOD

The simplest cost allocation method allocates costs on the basis of the benefits derived from each purpose of the project. For a water project, these benefits might include:

- Flood control - evaluated as the difference between flood damage anticipated with and without the project

- Navigation - the difference in shipping costs with and without the project, estimated as the difference in standard shipping rates times the tonnage of freight expected to move over the waterway improvement
- Irrigation - based on the increased productivity of the land less the increased cost of irrigation farming

The benefits that might be provided by an ICES include:

- Electricity - a lower bound on the benefits is the price of electricity under existing utility traffic
- Heat - a lower bound on the benefits is the cost of obtaining heat from individual heating units
- Air quality - reduced emissions and/or lower control costs from using a multiple-purpose facility instead of several single-purpose facilities.

Some functions, such as the improved air quality, produce no revenue and have no way of paying the associated costs except for a tax on the community as a whole. In other cases the government may redistribute the costs so that more is paid by the community and less is paid by individuals for private goods. For example, the Federal government may allocate higher costs to flood control and simultaneously lower the amount the government collects for water and electricity. A private system could not do that and still survive in a competitive market.

The benefits method allocates cost between the functions in proportion to each function's share of the total benefits. If one third of the total benefits come from electricity, one third of the costs would be allocated to electricity. Allocation of the total costs based on the share of total benefits does not, in most cases, utilize all the information that is available. There are costs that are directly related to either the production of heat or the production of electricity.

An example would be the steam distribution system or the electric generator since their costs are independent of the other function. There are also costs (separable costs) that are avoidable if one of the functions were eliminated. For example, the extra costs of a sophisticated boiler to handle high pressures for the production of electricity is a separable cost since these extra costs over and above the cost of a regular boiler could be avoided if no electricity were produced. In determining the joint costs that must be allocated, the total separable costs (direct costs plus other separable costs) should be subtracted from the total benefits to obtain the net benefits. This minimizes the costs that are subject to an allocation procedure and thereby reduces the possible controversy.

Table D-1 illustrates the basic benefits method where none of the separable costs is recognized; the modified benefits method that recognizes only the direct portion of the total separable costs; and the modified benefits method that recognizes all of the total separable costs. For simplicity, we have limited the project to two functions, heat and electricity, even though ICES could include other functions.

Basic Benefits Method

Table D-1 begins with the basic benefit method, with the project having a heat benefit of \$18,000,000 and an electricity benefit of \$7,000,000. These are taken to be the market value of heat and electricity, respectively. Since heat produces 72% of the project's total benefits of \$25,000,000, heat is allocated 72% of the project's \$20,000,000 costs, or \$14,400,000. The ICES project can be considered to provide a 20% savings in the cost of each function.

Benefits Method Including Direct Costs

If further analysis shows that the same system has direct costs for heat of \$7,000,000 (say for the heat distribution system) and direct

TABLE D-1
THE BENEFITS METHOD OF COST ALLOCATION

	<u>HEAT</u>	<u>ELECTRICITY</u>	<u>TOTAL</u>
<u>Basic Benefits Method</u>			
Benefits	18,000,000	7,000,000	25,000,000
Share	.72	.28	1.00
Total Costs	14,400,000	5,600,000	20,000,000
<u>Benefits Method Including Direct Cost Only</u>			
Benefits	18,000,000	7,000,000	25,000,000
Direct Costs	7,000,000	2,000,000	9,000,000
Net Benefits	11,000,000	5,000,000	16,000,000
Share	.6875	.3125	1.00
Joint Use Costs	7,562,500	3,437,500	11,000,000
Direct Costs	7,000,000	2,000,000	9,000,000
Total Costs	14,562,500	5,437,500	20,000,000
<u>Benefits Method Including Total Separable Costs</u>			
Benefits	18,000,000	7,000,000	25,000,000
Direct Costs	7,000,000	2,000,000	9,000,000
Other Separable Costs	2,500,000	3,500,000	6,000,000
Total Separable Costs	9,500,000	5,500,000	15,000,000
Net Benefits	8,500,000	1,500,000	10,000,000
Share	.85	.15	1.00
Joint Costs	4,250,000	750,000	5,000,000
Separable Costs	9,500,000	5,500,000	15,000,000
Total Costs	13,750,000	6,250,000	20,000,000

electricity costs of \$2,000,000 (the turbine generator and associated electrical equipment), the benefits and direct cost method would produce the results shown in the second section of Table D-1. The first four lines are straight forward: benefits as previously presented, direct costs as hypothesized, benefits net of direct costs, and the share of net benefits contributed by each function. These fractional shares are used to allocate the joint use cost of the following line. The total joint use cost (\$11,000,000) is the difference between the project's total cost of \$20,000,000 and the project's direct cost of \$9,000,000 and might typically be composed of boiler cost, fuel and fuel handling costs, etc. The direct costs are then added to the allocated joint use costs to derive the total costs for each function.

Benefits Method Including Total Separable Costs

The benefits/separable cost method, illustrated in the bottom section of Table D-1, requires further assumptions on the boiler system. If the boiler were designed for use solely for either electricity or heat, it could be built and operated less expensively, say \$7,500,000 for a heating system boiler and \$8,500,000 for an electric generating boiler. Separable heat costs are therefore \$9,500,000, which include the \$7,000,000 direct costs plus \$2,500,000 in avoidable boiler costs if heat were not supplied by the ICES boiler. Similarly, electric separable costs are \$5,500,000 consisting of \$2,000,000 of direct costs and \$3,500,000 of avoidable boiler costs. The first few lines have been explained and are straightforward. The net benefits differ from the previous net benefits by the additional separable costs of the boiler. The total joint costs of \$5,000,000 represent the difference between the project's total cost and its total separable cost and are allocated on the basis of each function's share of net benefits. Adding the allocated joint costs and the separable costs gives each function's total cost.

Advantages and Disadvantages of this Approach

The major advantage of this method of cost allocation is that those who receive the benefits bear the costs. This appeals to most concepts of equity. A secondary advantage is that, at least at the broad conceptual level, the approach is simple and easily followed.

There are two major disadvantages. First, the concept itself does not necessarily lead to cost/price signals that convey the proper information for decision making. For example, we know the investment decision should be based on incremental costs versus incremental benefits, but the benefit signals here are cost benefits, not benefits to consumers. We also know that efficient allocation of resources requires that prices be set equal to marginal costs. This costing method provides no information on marginal costs since it is designed for total costs. Thus it cannot be useful in the pricing decision.

The second disadvantage is that in general, it is very difficult to measure the benefits. Detailed engineering cost estimates are required to obtain the avoidable costs. To go one step further and measure the benefits to consumers is even more difficult since this requires knowledge of the demand curve.

ALTERNATIVE JUSTIFIABLE EXPENDITURE METHOD

The alternative justifiable expenditure method compares the benefits of the project to the cost of the least expensive alternative single function project and uses the lesser of the two in the allocation process. Essentially the same basic allocation procedure is used as in the benefits method except that the least cost alternative is used as an upper limit to the benefits. The alternative justifiable expenditure method can be

considered a variation of the benefits method even though it is frequently referred to as being distinctly different from the benefits method. However, the benefits used for the benefits method frequently are derived from alternative ways of meeting the demand of the function. Alternative expenditures for heat would include district heating without cogeneration, several small disjoint district heating systems, building central heating systems, or room-sized heaters. Included earlier as the benefits of heating was use of the most economic individual heating plants, which is included here as possible alternative cost. The main factor differentiating benefits and alternative costs is that alternative cost projects are generally restricted to projects meeting the functional goals in the same general manner, e.g., the cost of district heating versus the cost of operating individual heating systems for each building.

The example used for the benefits method can be used to illustrate the working of the alternative justifiable expenditure method with a very few additional, but crucial, assumptions.^{1/} The additional assumptions relate to the cost of alternative projects meeting the same goal. Hence, we postulate \$17,000,000 as the cost of an alternative district heating system and \$8,000,000 as the alternative cost of an electric power plant producing the same power and energy. That the cost of the alternative district heating system is less than the benefits would normally indicate that a district heating system is economically justifiable, even though other constraints, such as previously sunk costs in the existing heating systems or regulatory problems, might prevent its installation. The alternative project cost for electricity is higher than its benefits (\$8,000,000 versus \$7,000,000). Since the alternative justifiable expenditure method requires using the lesser of the two

^{1/} In Table D-2 below we carry this out for the three cases illustrated in Table D-1.

amounts, we enter the smaller number in Table D-2. Such a result would normally indicate the project is infeasible on a stand-alone basis. This could occur if the benefits were calculated using utility rates which include large, efficient units and the proposed system is too small to be economical.

The calculations for this example are shown in Table D-2. The benefits are presented first, followed by the cost of the alternative project. The alternative justifiable expenditure is the lesser of the two previous items. Table D-2 continues in the same format as Table D-1 with the Alternative Justifiable Expenditures being substituted for the benefits indicated in Table D-1.

The concept of the alternative justifiable expenditure method of allocating costs is not alien to most utility systems, though the concept goes under a different name. Most utilities participate in hourly or daily transactions with other systems, transferring power from low cost systems to high cost systems, generally under the name of "economy energy." The transaction price is based on both the alternative cost to the purchaser and the cost to the seller, much as in the alternative justifiable expenditure method of cost allocation. The alternative cost to the purchaser is evaluated as the purchaser's least cost alternative for self generating the power. Traditionally the price is the average of the cost and the benefits though it usually is referred to as the cost plus half the savings. Though economy energy transactions refer to one function, the relation to the multifunction benefits method of cost allocation is obvious. Economy energy

TABLE D-2

THE ALTERNATIVE JUSTIFIABLE EXPENDITURE METHOD
OF COST ALLOCATION

	<u>HEAT</u>	<u>ELECTRICITY</u>	<u>TOTAL</u>
<u>Basic</u>			
Benefits	18,000,000	7,000,000	
Cost of Alternative Project	17,000,000	7,000,000	
Alternative Justifiable			
Expenditure	17,000,000	7,000,000	24,000,000
Share	.7083	.2917	1.0000
Total Costs	14,166,000	5,834,000	20,000,000
<u>Including Direct Costs</u>			
Alternative Justifiable			
Expenditure	17,000,000	7,000,000	24,000,000
Direct Costs	7,000,000	2,000,000	9,000,000
Net Benefits	10,000,000	5,000,000	15,000,000
Share	.6667	.3333	1.0000
Joint Use Costs	7,333,700	3,666,300	11,000,000
Direct Costs	7,000,000	2,000,000	9,000,000
Total Costs	14,333,700	5,666,300	20,000,000
<u>Including Total Separable Costs</u>			
Alternative Justifiable			
Expenditure	17,000,000	7,000,000	24,000,000
Direct Costs	7,000,000	2,000,000	9,000,000
Other Separable Costs	2,500,000	3,500,000	6,000,000
Separable Costs	9,500,000	5,500,000	15,000,000
Net Benefits	7,500,000	1,500,000	9,000,000
Share	.8333	.1667	1.0000
Joint Costs	4,166,500	833,500	5,000,000
Separable Costs	9,500,000	5,500,000	15,000,000
Total Costs	13,666,500	6,333,500	20,000,000

such as PJM (Pennsylvania-New Jersey-Maryland) operate with each of its many members either buying or selling each hour with direct costs of sellers being paid outright and with a joint pool of savings being shared by each participant.

Advantages and Disadvantages of this Approach

The alternative justifiable expenditures method has two major advantages. The first is its conceptual simplicity which, given a solution to the measurement problem, would make it easy to apply. The second is that costs are allocated to the function according to the cost savings. In this way the allocation method is analogous to using opportunity costs to determine the cost curves of economics. This is a correct approach since it looks at the real cost of using resources in a particular project as compared to their value (cost) in other projects. This provides an incremental cost basis where the increment is the entire project.

The major disadvantages are that we still face a difficult measurement problem, and that even though opportunity costs are introduced, it is done at the total project level, not at the more micro level of a unit of output.

The measurements necessary to implement this method include engineering cost data on alternative projects and measures of the benefits since the method uses the smaller of the two. Clearly the data requirements exceed those of the benefits method. The total separable costs must also be determined. The practical difficulty of obtaining the cost data will vary depending upon how many different technologies are considered to be cost-efficient substitutes for the ICES.

This method of allocating joint costs considers the opportunity costs for the entire project. While this can be used for the investment decision, it cannot be used as a basis for the pricing decision which requires opportunity costs be known at the more micro level of a unit of output.

USE OF FACILITIES METHOD

The method frequently used by utilities for splitting joint costs between groups of customers can be called the use of facilities method. This method has several variations, some based on the use of the facility at time(s) of maximum demand, others based on the average use of facilities, and more still based on a combination of peak and average demand. For cogeneration facilities, some writers suggest allocation based on maximum design conditions. Paul Leung^{1/} postulated a double extraction backpressure turbine. The turbine generator is designed to produce 51,473 kW when provided with 865 psia steam. The extractions and exhausts are 100,000 lbs./hr. at 335 psia; 200,000 lbs./hr. at 150 psia and 500,000 lbs./hr. at 35 psia of which 400,000 lbs./hr. are used in a process and 100,000 lbs./hr. are used in the feedwater heater/deaerator. The basic system is shown in Exhibit D-1.

Leung proposes allocating direct costs to heat and electricity. He includes the turbine as part of the joint use costs. His rationale is that a single purpose turbine would cost less and thus the postulated turbine has a separable cost assignable to heat. To the extent that a multipurpose turbine does cost more than a single purpose turbine it is appropriate to assign the separable cost to heat.

^{1/} Principal engineer, Bechtel Corporation, Proceeding of the American Power Conference, 1972, pp. 390-404.

EXHIBIT D-1

POSTULATED DOUBLE EXTRACTION BACK PRESSURE TURBINE

For allocating the capital costs of the boiler feeding the postulated turbine, Leung determine how much heat is added by the boiler to the feedwater for each purpose. The calculations are shown in Table D-3. The feedwater goes "to the boiler" as hot water containing 228 Btu/lb. and emerges as 865 psia steam containing 1,482 Btu/lb., for a net gain of 1,254 Btu/lb. of steam. Some of the heat in the steam is used to generate electricity and some is used by the process. The first line of Table D-3 indicates that 1,160 Btu/lb. of the heat added by the boiler is used by the high pressure, 335 psia process. That is, 100,000 pounds of water flows through the boiler each hour, picks up 1,254 Btu/lb. (125.4 MBtu/hr.) from the boiler, delivers 94 Btu/lb. (116.0 MBtu/hr.) for the process. The calculation on the first line determines how much heat added by the boiler gets to the high pressure process, shortcutting the above procedure. For electricity, an ideal (number pounds) turbine generator is postulated. The heat which is added to the water for electricity production is thus 3,413 Btu/kWh. Using this factor for converting the generator output of 51,743 kW yields 176.6 Btu/hr. added to the steam for the production of electricity. The last column expresses the heat added for each function as a fraction of the total and Leung proposes allocating capital costs based on these percentages, i.e., 12.82% of the capital costs should be assigned to high pressure steam. This use of facilities method essentially treats electricity as a byproduct, charging electrical production with the minimum amount of added boiler capacity necessary to add the additional amounts of heat to the water.

Leung also applies the use of facilities concept to the allocation of fuel costs. The development of his allocation factors is shown in Table D-4.

TABLE D-3
BOILER CAPITAL COST ALLOCATION

<u>Function</u>	<u>Flow</u>	<u>Unit Heat Content (Btu/lb.)</u>			<u>Heat Added</u>	
		<u>To Process</u>	<u>To Boiler</u>	<u>Added</u>	<u>MBtu/hr.</u>	<u>%</u>
335 psia	100,000 lb./hr.	1388	228	1160	116.0	12.82
150 psia	200,000 lb./hr.	1316	228	1088	217.6	24.06
35 psia	400,000 lb./hr.	1214	228	986	394.4	43.60
Electricity	51,743 kw	—	—	3413	176.6	19.52

TABLE D-4
FUEL COST ALLOCATION

<u>Function</u>	<u>Flow</u>	<u>Unit Heat Content (Btu/lb.)</u>			<u>Heat Used</u>	
		<u>To Process</u>	<u>"To Condenser"</u>	<u>Usable</u>	<u>MBtu/hr.</u>	<u>%</u>
335 psia	100,000 lb./hr.	1388	1032	356	35.6	10.41
150 psia	200,000 lb./hr.	1316	1032	284	56.8	16.62
35 psia	400,000 lb./hr.	1214	1032	182	72.8	21.30
Electricity	51,743 kw	—	—	3413	176.6	51.67

A different table of allocation factors is brought about by a different view of the process. For allocating fuel costs, Leung looked at electricity as the primary product rather than as a secondary product. Each pound of extracted or exhausted steam represented lost electrical production. The lost production is the additional electricity that a condensing utility turbine would have been able to produce. Leung postulates 1.75 Hg Abs as the condenser pressure. At that pressure, steam would contain 1,032 Btu/lb., as indicated in the "To Condenser" column of Table D-4. The first line shows that extracting steam at 335 psia prevents 356 Btu/lb. (35.6 MBtu/hr.) from being used to generate electricity. This enthalpy difference (356 Btu/lb.) in the steam is, again, the difference between the heat content (1,388 Btu/lb.) of the extracted steam and the heat content (1,032 Btu/lb.) of steam exhausted into the theoretical condenser. The energy used by electricity is evaluated, as before, using the ideal factor of 3,3413 Btu/kWh.

The results demonstrated in Table D-3 and Table D-4, showing the use of facility method of cost allocation, may not be as important as the results derived from the comparison of Table D-3 and D-4. Using one method, a reasonable man derived two reasonable results, which seem to be contradictory. As mentioned earlier, the difference is explained by the point of view; that is, whether the primary function of the facility is electric production or steam production.

Advantages and Disadvantages

This method is easy to evaluate. Its advantage is that it is simple and depends on engineering data for the system that is relatively easy to obtain. The major disadvantage is that it is based on physical units and therefore we cannot assume it reflects value (either benefits or costs) in any

THE SUBSTITUTE PRICE METHOD

The substitute price method is another method used by Leung for his double extraction, backpressure turbines system. This approach uses the price of substitute goods to allocate costs. For example, if an ICES is connected to a grid, then the expense that would have been incurred if the electricity had been purchased from the grid instead of produced by the ICES is the amount of money that is credited to the cost of heat. These expenses are determined by the existing tariffs. Using this method, the heating cost is treated strictly as a residual regardless of the size of the separable costs. If a cogeneration facility is integrated into a system with a wide range of generators, the substitute energy costs will not only cover typical fuel costs but also a substantial amount of capital costs. In fact, some studies show the substitute price recovering over 125% of the annual cost of all generation, both operating costs and capital costs.

The ICES system proposed for Clark University is an example of the use of this method. Clark University has an agreement with the New England Electric System (NEES) that establishes a set of tariffs for the purchase and sale of electricity by Clark. This provides a set of market prices to determine Clark's expenses for electricity, with the same load, without its own ICES system. These expenses can then be used to allocate costs. It is interesting to note that Clark's diesel should be run at full capacity whenever its marginal costs are less than NEES buying rate; should be run to meet school load whenever its marginal costs are between NEES's buying and selling rate; and should never be run in the range where its marginal costs exceed NEES's selling rate.

Advantages and Disadvantages

Substitute pricing of electricity offers the advantage that alternative costs are considered and in this case, it merely requires that appropriate tariffs be available. Thus it appears practical and approaches opportunity cost. Since actual prices per kWh are available from the tariffs, this method allows one to make marginal allocations as well as gross determinations for the whole project.

This method can "overkill" the problem since it does not take account of direct or separable costs. Thus, this method allocates costs that could have been classified as separable.

APPENDIX E
THE COST ACCOUNTING APPROACH
TO COST ALLOCATION

The cost accounting approach to allocation of joint product costs is based on the needs for reasonable and consistent valuations of inventory, and construction of financial statements. The traditional function of the cost accountant is to arrive at a cost figure for each product that values the portion of firm's expenses that should be attributed, or "attached," to the product. Although the emphasis is on valuation of physical, inventoriable products, the methodologies of cost accounting are applicable, with some modification, to the valuation of other costs. In this appendix, we review the basic cost accounting methods, and discuss their relevance and applicability to cost allocation in an ICES.

Cost allocation constitutes a fundamental portion of the cost accountant's role. Allocation of cost to products, purposes, and organizational divisions is fundamental to sound managerial reporting and control. Conceptionally the task of allocation has three facets:

- Choice of the cost objects. The objects may be products, processes, departments or some other entities.
- Identification and accumulation of the costs that are to be related to the cost objects.
- Choice of a basis for associating the costs with the specific cost objects.

There are numerous bases that can be used to perform an allocation. However, where production costs are truly joint -- that is, where a single process simultaneously yields two or more products -- the choice is reduced to two methods.

The relative sales value method is based on the assumption that costs should be assigned according to a product's ability to generate revenue. Thus, the costs that are attached to the product are proportional to the revenues that can be expected from sale of the product. To the extent that prices (and revenues) indicate a lower bound on the benefits received by a product purchaser, this method is analogous to the benefit method of the public projects approach.

The following example illustrates the application of this method.^{1/} A single process produces products A and B at a joint cost of \$900 from a common source. One complete cycle of the process yields 1,000 gallons of product A, which has a sales value of \$0.55/gallon. 500 gallons of product B are produced, with a sales value of \$0.90/gallon. The costs are allocated to the products in proportion to their relative sales values, as shown in Exhibit E-1.

From the accountant's viewpoint, the relative sales value method is sound, because the records of goods in inventory will approximately reflect the revenue-producing potential of those goods upon sale. Intuitively, this method seems "fair", because the distribution of costs in proportion to their revenue-earning potential is somewhat akin to charging according to one's ability to pay.

The principal difficulty with this method, however, is that it requires data on the market price of the goods before the allocation is rendered. Where goods are sold in perfect competition, the producer is a "price-taker," and thus has price data at hand before the allocation. But in the regulatory setting, the allocation must serve as the basis for establish-

^{1/} This is adopted from Charles T. Horngren, Cost Accounting: A Managerial Emphasis, 3d ed. (Englewood Cliffs, N.J.: Prentice-Hall, 1972), pp. 570-575.

EXHIBIT E-1

RELATIVE SALES VALUE METHOD

	PRODUCTION IN TERMS OF SALES <u>VALUE</u>	<u>WEIGHTING</u>	<u>COSTS ALLOCATED</u>
Product A	\$ 550	$550/1,000 \times \$900$	\$ 495
Product B	$\frac{450}{\$1,000}$	$450/1,000 \times \$900$	$\frac{405}{\$ 900}$

ment of rates. An attempt to apply this method, then, would become enmeshed in circulatory reasoning. A possible alternative is to use average industry data as the basis for the revenues that would be expected for each service. This solution, however, would entail collection and updating of considerable data, and the resulting allocation would not be suitably specific to the facility under study.

The second cost accounting method is the physical measures method. This is the counterpart of the use of facilities method, discussed elsewhere in relation to cost allocation for public projects. In this method, costs are allocated in proportion to the relative magnitudes of some physical denominator common to the joint products. In the example, this common denominator is gallons; Exhibit E-2 shows the resultant allocation.

The physical measures method, although frequently applied, is flawed from the cost accounting standpoint, because it assigns costs without regard to the revenue-producing potential of the products. When products that are costed in this way are eventually sold, some might consistently show profits (on paper), while others might consistently show a loss. A difficulty in implementation of this method is that there might be several possible common denominators -- or there might be none at all. In principle, there is no reason why the basis for allocation in the example could not be pounds of liquid product, instead of gallons. Selection of a basis, then, is likely to be wholly arbitrary.

We have indicated above that the relative sales value method is not useful for making price or rate decisions, because of the circularity that would arise. In fact, cost accounting allocations in general should not be used as the basis for price or output decisions, since they do not reveal the incremental effects of actions. This point is stressed by Horngren:

EXHIBIT E-2
PHYSICAL MEASURES METHOD

	<u>PRODUCTION IN TERMS OF QUANTITY</u>	<u>WEIGHTING</u>	<u>COSTS ALLOCATED</u>
Product A	1,000 gal.	1,000/1,500x\$900	\$ 600
Product B	<u>500 gal.</u>	500/1,500x\$900	<u>300</u>
	1,500 gal.		\$ 900

Joint costs permeate accounting. Costs are joint with respect to time, facilities, and products. Accountants attempt to split joint costs among products having relatively important sales values. ...No matter what the joint-product situation, any assignment of a joint cost is useless for purposes of managerial decision-making. The only use for allocating joint-product cost is for purposes of "reasonable" inventory valuations and income determinations.1/

1/ Ibid., p. 581

APPENDIX F MATHEMATICAL PROGRAMMING

Description of the Method

R.L. Weil ^{1/} recently suggested that a mathematical programming approach be used to allocate joint costs. This approach employs economic analysis so it is not surprising that marginal values are used in the allocation process. The method in its simplest form is illustrated in Figure F-1 below:

Figure F-1

^{1/} R.L. Weil, Jr., "Allocating Joint Costs," American Economic Review, 58 (December, 1968), 1342-1345.

Suppose marginal cost (MC) is constant and equal to average cost (AC), and that MR_1 and MR_2 are the marginal revenue curves associated with the demands for the two products. MR is the sum of the two marginal revenue curves. The use of only one measure for output implies that the two outputs are jointly produced in fixed proportions. This restrictive assumption and the constant marginal cost assumption permit a simple graphic description of the method, but both can be dispensed within a mathematical model without substantively altering the results. In this situation, the profit maximizing firm will equate marginal revenue with marginal cost and produce OQ, collecting marginal revenue equal to OR_1 and OR_2 in the two markets. By construction, the sum of these two marginal revenues will just cover marginal costs (and average costs). Using these two values we will allocate the total pool of joint costs. Referring to Figure F-1, costs equal to OR_1E_1Q will be allocated to the first product and OR_2E_2Q will be allocated to the second product. These costs sum to the total cost of production OREQ. The interesting features of this allocation method are that the marginal value to the seller determines the allocation factors, and that this marginal value is determined by the market interaction of suppliers and demanders and the desire of the sellers to maximize profit.

ADVANTAGES AND DISADVANTAGES

The major advantage of the programming approach is that it allocates on the basis of the opportunity costs of the seller at the margin using marginal revenues and it reflects profit-maximizing behavior by the firm. Clearly, this method does not establish prices -- they are read off the demand curves (not included in the diagram) -- it is only an allocation method.

Nonetheless the buyer and the seller receive the same, correct signal. This method in an unregulated market is not circular in the sense of costs affecting prices, which through changes in quantity demanded, affect costs, thus starting the cycle again.

The major disadvantage is that this method requires information on either the demand side or the production function. It is not clear that the required information is available. In a regulated setting it may also result in circularity between rates and cost allocation. Finally, this method allocates total costs, not just joint costs, which may result in some unreasonable allocations.

APPENDIX G
CURRENT COST ALLOCATION METHODS

INTRODUCTION

The purpose of this section is to report the results of our investigation of current cost allocation methods used by utility systems that produce and sell both electric and heat services to ICES communities. Part of this investigation is to determine the joint cost allocation methods that have been approved by regulatory agencies. Because of the recent development of ICES, and lack of publicly available information, utilities with district heating systems were approached regarding their allocation of costs between electricity and steam or electricity and hot water.

BACKGROUND

Recent changes of relative economics, fuels availability, and siting factors have stimulated intense interest by federal government and state regulatory agencies in cogeneration projects. Current technology appears to be adequate for many cogeneration, district heating, and ICES projects. In spite of this, few utilities have initiated cogeneration projects without the support of government funding. Some of the suggested barriers to utility involvement include the following:^{1/}

^{1/} Noyes Data Corporation, "RPA-Potential for Co-generation Development." Cogeneration of Steam and Electric Power, Noyes Data Corporation, Park Ridge, New Jersey, 1978, p. 175.

- Low returns and the risk of industrial cogeneration.
- Large capital requirements.
- Lack of economies of scale.
- Practical limitations associated with cogeneration technologies for small users cause low returns.
- The prospect of producing and supplying excess electric power to the utility system creates a fear of regulation.
- Higher risks that are associated with steam or hot water business by utilities as compared with their normal electricity business.
- Uncertainty regarding FERC and state public utility commission jurisdiction over joint venture or ICES systems.

Given these potential barriers to utility involvement, there are few utilities that have entered into cogeneration, and still fewer have developed cost allocation methods that have been acceptable to regulatory bodies. For these reasons utilities have paid little attention to cost allocation methods and to the development of data sets related to ICES.

SURVEY APPROACH

In spite of these problems, a survey has been ongoing of utility and commission involvement in cogeneration in an effort to determine cost allocation methodologies applied to electric and thermal energy. It has met with limited success.

The desired information includes the utilities' evaluation and resolution of cost, technical design, and regulatory questions. Twenty utilities have been contacted thus far, as well as four public service

commissions, in an effort to determine what utilities are doing to cost and price their electric power versus their thermal power from cogeneration facilities, and, in addition, how regulatory restrictions affect these costs and prices. The utilities were selected on the basis of known (mostly from DOE grants) or planned ICES or cogeneration plants, membership in the International District Heating Association (IDHA), or participation in Edison Electric Institute's cogeneration task force. Contacts included managers, supervising engineers or vice presidents of the steam distribution departments, heating systems application departments, conservation services, energy utilizations, rate analysis, or electric services.

Companies contacted included Boston Edison, Baltimore Gas & Electric, Detroit Edison, Pennsylvania Power & Light, Gulf States Utilities, Cleveland Electric Illuminating, Philadelphia Electric, Electric Light Department of Braintree (Massachusetts), Alabama Power Company, Arkansas Power & Light, Rochester Gas & Electric, Consumers Power, Public Service Electric & Gas, Missouri Power & Light, Consolidated Edison, Indianapolis Power & Light, New Orleans Public Service, Wisconsin Electric, and Independence Power & Light. Not all contacts with these utilities met with success due to (1) the complexity of cost allocation, (2) insufficient responses from persons unaware of all facets of cost allocation, and (3) the lack of regulatory pressure and/or incentive to allocate costs. In addition to the twenty utilities, four commissions were contacted. These regulatory bodies included the Texas Public Utility Commission, the New York Public Service Commission, the New Jersey Board of Public Utilities, and the California Public Utility Commission.

UTILITY SURVEY QUESTIONS

Fourteen questions were asked of utility personnel regarding cost allocation and its applicable production (system) technology to determine actual methods for cost allocation between electric power and process heat.

Those questions asked of the utilities included the following:

- What type of production technology (system) is being used? Gas turbine, diesel, boiler with turbine condenser, etc.
- What is the by-product?
- Who owns the system? Utility-owned, joint ownership, industry owned, etc.? If jointly owned, with whom?
- What is the load capacity of the plant and the size of output in kWh at Btu levels?
- What is being produced--steam or hot water and at what temperature? If an ICES system, how is it distributed?
- What type of fuel is being used and what is its cost? Is there a dual fuel use, and if so, how is it priced?
- What fraction of the fuel is allocated to heat versus electricity and how is the cost allocation decision made? In other words, is an allocation analysis performed on a Btu requirement basis since there may be Btu requirements through makeup water and condensate return?
- How are costs allocated between electric power and heat--a methodology? For example, how are capital costs of the boiler, gas turbine, etc., allocated? Other equipment?
- How are operation and maintenance costs allocated?
- How are rates set or proposed? Is there a steam or electric tariff?
- Is there a demand charge?

- Will the system stand alone or as an integrated part of an existing system? If it stands alone, is there an additional cost of securing reserves?
- Are there economies of scale in the production technology used? If so, how are joint services provided that lead to unit sizes that maximize the gains from the situation? How do the benefits flow back to each set of ratepayers?
- What are the actual capital costs (subsidized or not) versus the system output?

UTILITY SURVEY RESULTS

Generally, the answers to the above questions can be summarized as follows. Production technologies vary somewhat, however, most systems were combustion turbine or steam turbine systems using Number 2 or Number 6 oil as fuel. The utility in all cases owned the system with steam as the by-product and most utilities distributed this steam through a single pipe steam distribution system. Generally, rates depended on the size of load, fuel adjustments, and cost of service. Other than those systems in existence for twenty years or more (primarily district heating) and now having a steam system which is totally self-supporting, most ICES or cogeneration projects were subsidized by government grants. Baltimore Gas & Electric, Detroit Edison, Philadelphia Electric, and Wisconsin Electric had district heating systems with self-supporting steam systems. Consolidated Edison and Public Service Electric & Gas have government grants subsidizing their development of ICES systems and at this time have not had to be concerned with cost allocation but with the technical feasibility of such a system. Any cost allocation methods indicated were preliminary and had not been submitted for regulatory approval. In many cases, the utilities charge their production

process steam costs (capital as well as O&M) to electric costs in their allocation and therefore charge the regular electric rate, which includes steam production, for each class of customer. Thus, the cost burden of a cogeneration system is passed on to all ratepayers.

In spite of the general lack of accepted allocation procedures, several methods of cost allocation that are illustrative of current practices are described as follows. These methods, identified by some of the utilities, were the only cost allocation methods that were approved or even expected to meet regulatory guidelines. These cost allocations include Philadelphia Electric's accounting method for a dual service concept; the hypothetical "societal approach" of Public Service Electric & Gas's Trenton ICES, which results in a rebate for both the community and the utility; Wisconsin Electric's "steam production method;" and Indianapolis Power & Light's "steam heating service allocation method." Common to all four methods is a component breakdown of capital costs for steam only, operating and maintenance costs for steam only and fuel costs for steam production only with the end result being a separate rate for steam versus electricity.

Philadelphia Electric Company

The following is an excerpt provided by the company to Ernst & Ernst that explains how charges are transferred in Philadelphia Electric's present accounting method for dual service cost allocation between steam and electricity.

"The present accounting method for steam transfer is based on the dual service concept. At the present time, No. 23, No. 24 and No. 26 high pressure boilers and No. 2 and No. 3 low pressure boilers generate steam

which is used for electric generation and for steam transfer. Normally, steam from the high pressure boilers is passed through the No. 3 topping turbine to produce efficient electric generation in response to load demands of either the electric or steam system. A third source of steam transfer is No. 1 turbine bleed which is utilized as hot standby reserve, and is normally not used on a day-to-day basis. This source provides economical reserve capacity for the steam system and is also part of the electric system base load capacity.

"Fixed charges for dual service boiler capacity are split equally, and 50 percent is charged to the steam system as a component part of the monthly steam transfer credit. Boiler plant labor charges pertinent to dual service capacity are segregated and split equally on the same basis as fixed charges.

"Fuel and maintenance expenses, in cents per million Btu used, are allocated monthly to the steam system according to a 'Steam Transfer Factor' which defines the percentage of the total fuel used to generate steam for transfer. Other operating charges for treated feedwater, water treatment plant maintenance, and sewer rental charges are charged on the basis of the amount of treated water used to produce transfer steam.

"Economic production of steam for transfer is achieved by maximizing the production of steam from the high pressure boilers and passing this steam through the No. 3 turbine before exhausting it to the steam mains. The portion of the No. 3 generation related to steam transfer is determined by the 'Steam Transfer Factor' previously used to determine fuel and maintenance costs. This generation from the No. 3 turbine is obtained at an average rate

of 4,800 Btu per net kWh compared to the average steam system rate of approximately 11,000 Btu per net kWh. The economic benefit of this low cost generation incidental to steam transfer is shared equally between the steam and electric systems. A steam system credit is established based on sharing equally the saving between the price of Schuylkill No. 3 generation and the average electric system fossil fuel generation price. Also, the equivalent fuel which No. 3 turbine consumed for electric generation is credited to the steam transfer fuel expense so that fuel charges represents only the fuel cost of steam delivered to the steam system mains."

Public Service Electric & Gas

Public Service Electric & Gas (PSE&G) of New Jersey's technical design of their Trenton ICES plant is centered on a combustion turbine system with the exhaust passing through unfired heat recovery bodies. The basic module is a 2.5 MW gas turbine/generator set with a capacity to satisfy approximately 25 percent of the peak thermal demand. The enclosure for the ICES plant is integrated into a parking garage for 1,200 vehicles to service the Capital Place Complex with capacity for the Departments of Labor and Industry, Health and Agriculture, the Detention Center, and commercial buildings adjacent to the demonstration community. Thermal distribution from the ICES plant is run in chases beneath the elevated walkways.

The basic distribution system consists of primary 150 psig steam distributed to six central equipment centers which use the steam to produce hot water for heating, domestic and process use, reduce pressure steam for process use, and chilled water for space cooling. The preliminary estimate based on 1977 dollars for the total cost of the ICES system is approximately

\$11 million. This total cost includes both direct and joint costs. The cost of the central ICES plant including equipment is approximately \$6.6 million. The cost of the distribution system is approximately \$1.4 million and the cost of the terminal equipment is around \$3 million. In comparing the fuel input and the energy output which was 73,364 barrels of oil for one year, and steam output of 176,822,000 lbs., respectively, to the actual cost of the system, there was no fuel savings in relation to energy output.^{1/}

Realizing that the need for energy conservation is better understood by a community in terms of dollars that can be saved as compared to energy savings, the "societal approach" to allocate the savings was developed to appeal to this need. In this methodology total costs of the proposed ICES were compared to the present costs (base needs) of the conventional system. In other words, the present or existing service needs of PSE&G's conventional electric system (for all customers) and the costs of supplying them were calculated. The steps involved determining:

- Annual fixed charges for capital cost
- Annual fuel, operation, and maintenance costs
- Administrative costs.

Then, the total costs of the ICES and the costs to supply the needs of those customers were calculated. These two figures, the existing system versus the ICES system, were compared to determine the cost/benefit viability of the system--the benefit being expressed in dollars not energy savings. In comparing the two systems by 1977 dollars for one year, \$100,000 could be saved with the ICES system. This savings would be distributed equally between the community and the utility; thus, it is termed the "societal approach."

^{1/} ERDA, Trenton ICES, Volume 1, Phase 1, Final Report, July 1977, p. 33.

The savings to the utility would eventually flow back to the consumer through lower rates.

The following steps illustrate how the savings was determined:

- ICES Costs

- Those direct and joint costs associated with the total ICES energy production including capital, fuel, operating and maintenance.
- The savings associated with supplying less electric energy required by the community as compared to the conventional system at applicable rates (steam and electric separated).
- A credit for the value to PSE&G of the energy and capacity provided by the ICES plant.
- A credit for PSE&G transmission and distribution long-term savings resulting from the generation of the ICES plant.

- Conventional System Costs

- The costs associated with the conventional heating facilities to provide steam output equivalent to that of ICES, including capital, fuel, operating and maintenance.

The \$100,000 savings was the result of a comparison of ICES costs and conventional system costs based on the present worth of all future annual revenue requirements. There would be a separate rate for electricity versus steam. The steam rate would be determined by a component breakdown among electrical, thermal, and joint costs. For purposes of cost allocation, steam would be considered the by-product, however, electricity is actually the by-product. Based on the premise that steam is the by-product, the following procedure was developed to determine a separate rate for steam:

- Determine the capital cost for each major component or subsection of the ICES plant, carefully separating electrical, thermal, and joint components.

- Determine the capital cost for the distribution system and appurtenances.
- Determine the capital cost for any terminal equipment to be included as an ICES cost.
- Determine the operating costs.
- Determine the cost of service connections, meter readings, billing, uncollectibles, etc.
- Identify each above item as thermal, electrical or electrical/thermal in nature.
- Apportion the electrical/thermal items.
- The electrical costs will become part of PSE&G's electrical rate base and be treated separately.
- The remaining thermal items are used to calculate the production cost for steam. After a reasonable return and overheads are added this net cost represents the total steam revenue requirement.

It must be noted that the above methodology is theoretical at this time since the Trenton ICES is still in preliminary stages and that those factors that make up what would be categorized as joint costs have not been determined yet.

Wisconsin Electric Power

Wisconsin Electric Power has three cogeneration plants that use steam turbine systems with coal as the fuel. One system is a back pressure turbine and one small plant uses boilers. It is a utility-owned system with a plant capacity (for steam only) of 1.6 million pounds of steam per hour with a peak output of 1.1 million pounds of steam. The utility has a single pipe steam distribution system with a pressure of 175-180 psig. Steam is the by-product with coal being the only fuel used at a price of \$1.25/MBtu.

Steam production is priced on an incremental cost basis. This incremental cost takes into consideration initial capital outlays for the distribution system. Costs are allocated by a combination of Btus, incremental capital costs, and incremental operating and maintenance costs. Electricity is priced on regular rates for customers, thus, separating steam from electricity for regulatory purposes so all ratepayers that are not being serviced do not share the cost of cogeneration. Wisconsin Electric is making a profit from this system with its steam production being totally self-supporting.

Indianapolis Power & Light

Indianapolis Power & Light's allocation method for its two cogeneration plants is based on a joint use of boiler capacity for its steam-turbine systems. Electric service is charged for adequate boiler capacity at the regular electric rate; reserve capacity is charged to steam service. Thus, it is appropriate that steam service carries a share of the fixed and running costs of these joint-use (boiler) facilities. Allocation methods are based on the assumption that property devoted to, and expenses of, production and delivery of steam to the mains, including any steam delivered for the production of power by a customer under any existing tariff provisions, are chargeable to steam service.

REGULATORY AGENCY SURVEY RESULTS

Only a handful of state regulatory agencies are trying to encourage energy conservation by utilities through cogeneration. There are even fewer state regulatory agencies that are regulating prices or costs for joint services or encouraging the regulation of direct and joint costs for

ratemaking purposes. The states we have found that have tried to clear up some regulatory problems inhibiting cogeneration and that have attempted in various ways to encourage its use include Texas, New York, and New Jersey.

Texas Public Utility Commission

In 1977, the Texas PUC issued an order to exempt industrial cogenerators from state regulation as utilities. However, the PUC is only now attempting to study the economic viability of regulating joint costs.

New Jersey Board of Public Utilities

In 1977, the New Jersey state legislature passed a bill that requires the State Department of Energy and the Board of Public Utilities to study the feasibility of cogeneration and its potential for saving energy. Part of this study requires that rates and prices for energy be monitored.

New York Public Service Commission

In New York, the Senate has passed a bill that exempts cogenerators from regulation by the Public Service Commission. Under the bill, electricity and steam produced by cogenerators would be exempt from the sales and use tax. Utilities would be required to buy excess power at reasonable rates from cogenerators.

Additionally, the Public Service Commission is engaged in a rate action concerning Consolidated Edison's charges for steam produced in cogeneration with electricity. Historically,

the exhaust steam in the combined operation was, in effect, priced as a by-product of electric generation. This was accomplished by assigning to the electric sendout a heat input based upon the heat required to generate the same amount of electricity elsewhere on

the system at the average electric system heat rate. The remaining heat input was assigned to steam send-out. Thus, the fuel savings realized from the combined operation were conferred solely on the steam system.

In 1975, the Commission ruled that the pricing of steam as a by-product was no longer justified:

. . . the Commission found that a change in steam from a by-product to the primary output of the steam-electric stations and . . . the higher cost of steam production required a more equal sharing of fuel and processing charges between the two products.^{1/} It was noted that the topping turbine systems, which had originally been installed to permit the use of exhaust steam for sendout as a by-product of electric generation, were operated at the time of the decision primarily to produce steam for sendout. The Commission also observed that the electric generating capacity of the steam-electric stations in megawatts and as percentage of total system capacity had been reduced substantially from 1960 to 1973, while the steam sendout capability and sendout increased significantly and electric generation decreased substantially at these stations.^{2/}

In current action, Con Edison has requested a reallocation of certain costs from steam to electricity. In effect, Con Edison has requested a return to the old system of pricing steam according to the costs that are incremental to the generation of electricity.

Con Edison's request was motivated, in part, by a desire to reduce its rates for steam service. The administrative law judge agreed with Con Edison's assertion that if rates are not lowered, many steam customers will convert to on-site generation and thus be lost as customers. Additionally, Con Edison maintained that the reallocation is justified by a change in operating conditions:

^{1/} State of New York Public Service Commission, Case 27276, Recommended Decision by Administrative Law Judge Block, August 18, 1978, p. 24.

^{2/} Ibid., p. 25.

Recent emphasis on electric operations and a change in the dispatch of steam-electric generating stations under the company's new "Thunderstorm Procedure," which grew out of the blackout of July 13, 1977, were said to have reversed the prior trend toward de-emphasis of the importance of the steam-electric stations to the electric department. The new procedures require greater reliance on in-city electric generation during periods of thunderstorm alerts According to Con Edison, the new procedures resulted in the steam-electric generating stations being used more heavily by the electric department since the blackout.^{1/}

The ruling by the administrative law judge upholds Con Edison's claims:

The recent changes in the dispatch procedure for the steam-electric stations give the generation of electricity a priority which entails an extra cost responsibility to the electric department. The increase in generation of electricity at these stations since the blackout is of sufficient magnitude to demonstrate that the new company policy is in force in a meaningful way. The reallocation of the processing charges and rents at the steam-electric stations to the steam department on an incremental basis, as proposed by Con Edison, is a fair method to recognize the change in conditions. The \$14.4 million revenue equivalent of the recommended reallocation of the processing charges, etc., should be applied to reduce the revenue requirement of the company's steam department and the rates for its steam service.^{2/}

SUMMARY

Our investigation of cost allocation methods used by utility systems that produce and sell both electric and heat services shows that few are accepted by regulatory bodies. In part, this is attributed to a

^{1/} Ibid., pp. 26-27.

^{2/} Ibid., p. 31.

lack of regulatory pressure and incentives for cogeneration. Since ICES communities are in the process of development, there is very little information that any utility personnel have at present regarding cost allocation for joint services. Cost allocation of joint services in the industrial sector should be explored; however, due to the barriers to utility involvement in cogeneration and the lack of incentives, it is doubtful that much information will be found in this area either.