MORE ON THE COST-BENEFIT ANALYSIS OF ELECTRICITY PROJECTS

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This paper builds on the basis of its predecessor "The ABCs of Electricity Project Analysis", introducing a series of additional factors that are relevant in many real-world settings. This added relevance is bought, however, at the cost of increased complexity of the analysis. I hope that the earlier paper will have given readers enough of an intuitive understanding of the subject so as to permit them to incorporate these added complications without difficulty.

Heterogeneous Thermal Capacity -- A Vintage Approach

The assumption of homogeneous thermal capacity, which was carried throughout the previous paper, made it easy to describe what we called the "standard alternative" to each of the types of hydro projects that were analyzed there. This assumption is abandoned in this paper, in favor of a more realistic assumption of heterogeneous thermal capacity. But even here there are two distinct ways of introducing heterogeneity -- one which considers changes taking place over time in the characteristics of the thermal plants that are being added to the system, and the other which looks at different design characteristics of thermal plants that have different functional roles within the system.

In this section we will be concerned with the first kind of heterogeneity. Our thermal system is here assumed to compromise plants dating from different prior years -- the oldest are assumed to be the least "thermally efficient" and therefore to have the highest running cost per kwh. The newer is the plant, the more efficient it is assumed to be, hence the lower will be its running cost per kwh. These assumptions lead to a "stacking pattern" in which the newest thermal plant will be the first one to be turned on (after run-of-the stream capacity is fully used). This will be followed by the second newest, then the third, then the fourth newest thermal plant, in ascending order of running cost as older and older plants are turned on. There is nothing that is difficult to understand up to this point. It is simply an application of the idea that whatever is the level of demand, we try to use that mix of generating equipment which satisfies that demand at the lowest running cost.

But now we have to modify the scenario that ruled in the previous paper. There, when we added a new plant, its natural function was to fill a "thermal peak" of demand that would otherwise go unmet. Since the equipment being added was fully homogeneous with the already existing thermal plants, it was right to consider this added plant as the last one to be turned on. Now, however, we are assuming that the newest plant is more efficient than the older ones, hence if we install it, it should be not the last but the <u>first</u> thermal plant to be turned on.

This shift of function gives rise to a new possibility, namely that it may be worthwhile to add a new thermal plant (say plant E) to an existing structure consisting initially of plants A, B, C, and D -- even if the system demand for energy remains the same (i.e., is not growing through time). The motive for this addition would in such a case be exclusively the saving of running cost. The "new" system would not produce more energy than the "old" one -- the number of kilowatt hours would not change, but the saving in running cost might be sufficient to justify the construction of plant E.

Table 1 gives an illustration of how a new plant (here plant E) might turn out to be justified even if the system demand for energy is not increasing. The table is concerned only with the thermal part of the system. There may be run-of-the stream capacity serving as baseload, and daily reservoir or seasonal storage capacity serving at peak times, but their contributions are quite naturally assumed to remain the same, since system demand is not changing.

The "old" system (Panel 1) of Table 1 is what would occur if plant E is not built at this time, while the "new" system (Panel 2) represents what would occur if plant E is in fact constructed. The figures refer to the first year that plant E would operate if that investment is made.

Panel 1 shows the stacking pattern that would prevail if plant E is not built. Each plant is assumed to have a capacity of 50 MW, so in Panel 1, plant D (the newest) is assumed to be operating for 6000 hours, plant C for 4800, plant B for 3600, and plant A for 2400 hours. Multiply these by 50 MW in order to get the megawatt hours shown in the first column of Panel 1. The assumed running costs per kilowatt hour are shown in Column 2, and the total running costs for each plant appear in Column 3 (recall that one megawatt hour equals 1000 kwh).

Panel 2 shows what would happen if project E were undertaken, in the absence of any increase in system demand. Since all the plants are assumed to have a 50 MW capacity, and since system demand is unchanged, the net effect of adding plant E is that plant A will be retired (or relegated to a standby role). Plant E now becomes the first thermal plant to be turned on, and plant B becomes the last. As a result, system running

TABLE 1

JUSTIFYING A NEW THERMAL PLANT

EVEN WHEN SYSTEM DEMAND IS CONSTANT

PANEL 1 -- "OLD" SYSTEM

	Megawatt Hours	Running Cost Per kwh	Total Running Cost Per Plant
Plant D	300,000	3¢	$ 9 million
Plant C	240,000	3 1/2¢	$ 8.4 million
Plant B	180,000	4¢	$ 7.2 million
Plant A	120,000	5¢	$ 6 million
Total running cost of thermal plants			$30.6 million

PANEL 2 -- "NEW" SYSTEM

	Megawatt Hours	Running Cost Per kwh	Total Running Cost Per Plant
Plant E	300,000	2 1/2¢	$ 7.5 million
Plant D	240,000	3¢	$ 7.2 million
Plant C	180,000	3 1/2¢	$ 6.3 million
Plant B	120,000	4¢	$ 4.8 million
Total running cost of thermal plants			$25.8 million
Saving of running cost =			$ 4.8 million/ year
Capital cost of Plant E @ $600/KW × 50 MW =			$30 million

costs end up lower than in Panel 1, the total saving being \$4.8 million over the year. If the capital cost of building plant E is \$600/KW, for a total of \$30 million for a 50 MW plant, the project would appear to be worthwhile using the criteria applied in the previous paper (a 10% discount rate plus a 5% rate of depreciation for the plant). The required yearly return on capital for plant E would then be \$4.5 million, while the estimated actual return is \$4.8 million.

It is worth taking time to note the composition of this \$4.8 million benefit. Simply looking at the two panels of Table 1, one sees that in Panel 2, plant E occupies the role that plant D played in Panel 1, plant D does what C did in Panel 1, plant C occupies the role previously played by B, and plant B does what A previously did. This is a perfectly accurate description of the difference between the two panels, but thinking of the new plant E as taking the place formerly occupied by plant D is not a helpful way of describing the change. To maximize insight, we have to focus on the fact that it is plant E that is being introduced into the system. We then have to ask, as E generates its 300,000 megawatt hours, what sources is it in effect replacing. The answer can be found by asking what change takes place in the output of each of the other plants, as we move from Panel 1 to Panel 2. The answer is that D, C, and B, each "lose" 60,000 megawatt hours of output, while A loses all of its 120,000 megawatts. These "losses" add up precisely to the 300,000 megawatt hours generated by plant E in Panel 2.

But this is only the beginning. When E supplants D for 60,000 megawatt hours, the saving of running cost is 1/2¢ per kwh or \$5 per megawatt hour. When E supplants C, the saving is \$10 per mwh, when it substitutes for B, \$15 per mwh is saved. And finally, vis-a-vis A, the saving is 2 1/2¢ per kwh, or \$25 per megawatt hour. Now, as if by magic, if we take (\$5 × 60,000) plus (\$10 × 60,000) plus (\$15 × 60,000) + (\$25 × 120,000), the result is \$300,000 + \$600,000 + \$900,000 + \$3,000,000, equal precisely (and necessarily) to the \$4.8 million of saving in total cost, which we calculated directly in Table 1. Thus the cost saving for any year t can be represented by $\sum_j H_{jt}(C_j - C_n)$, where C_n is the running cost per kwh of the new plant, C_j is the running cost per kwh of old plant j, and H_{jt} is the number of kwh for which plant j is being displaced by the new plant, during year t.

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The above analysis works without modification for all cases in which total demand remains the same "with" the new plant as "without" it. However, that is a rather special case. We get a clue as to what the general case looks like when we recall that in the earlier paper, the output of the new plant went 100% to producing energy at the thermal peak, and that the peaktime surcharge was actually calculated by asking what that surcharge would have to be in order for investment in a new plant (aimed at covering the increase in demand in the hours of thermal peak) to be justified.

What we are going to do now in Table 2 and Table 3 is to create a situation in which investing in plant E is not justified if system demand is not increasing, but can be justified if there is a sufficient rate of increase in system demand. Table 2 should be self-explanatory as it simply repeats the calculation of Table 1, but with lower output for each plant. Now, in Panel 1, plant D produces 200,000 kwh rather than 300,000. Similarly each of the other plants has only 2/3 the output it had in Table 1. This simply would reflect different demand characteristics in the system. Here D would be operating for 4000 rather than 6000 hours per year, and A would be operating for 1600 rather than

TABLE 2

SHOWING A CASE WHERE INVESTING IN A NEW PLANT

IS NOT JUSTIFIED WHILE SYSTEM DEMAND REMAINS CONSTANT

PANEL 1 -- “OLD” SYSTEM

	Megawatt Hours	Running Cost Per kwh	Total Running Cost Per Plant
Plant D	200,000	3¢	$ 6 million
Plant C	160,000	3 1/2¢	$ 5.6 million
Plant B	120,000	4¢	$ 4.8 million
Plant A	80,000	5¢	$ 4 million
Total running cost of thermal plants			$20.4 million

PANEL 2 -- “NEW” SYSTEM

	Megawatt Hours	Running Cost Per kwh	Total Running Cost Per Plant
Plant E	200,000	2 1/2¢	$ 5 million
Plant D	160,000	3¢	$ 4.8 million
Plant C	120,000	3 1/2¢	$ 4.2 million
Plant B	80,000	4¢	$ 3.2 million
Total running cost of thermal plants			$17.2 million
Saving of running cost =			$ 3.2 million/ year
Capital cost of Plant E @ $600/KW × 50 MW =			$30 million

2400. In such a system, our cost-benefit analysis would tell us to say no to plant E, if system demand were constant through time. However, suppose demand were growing. If we say no to plant E, we must do something to contain demand so that it stays within the combined capacity of plants A, B, C, and D. How to do this? Via a peaktime surcharge, of course.

For simplicity, let us assume that the thermal peak is equal to the 1600 hours that plant A was running in Panel 1 of Table 2. Then we would derive the peaktime surcharge by asking what peaktime surcharge it would take, in order for the "next" addition to capacity to be justified. Using our discount rate of 10% and our depreciation rate of 5% we would have a "required" return of \$4.5 million on the investment (\$30 million) in plant E. We would have cost savings of 1/2¢, 1¢, and 1 1/2¢ with respect to plants D, C, and B, and these would apply to 40,000 mwh each. The dollar amounts saved would be \$200,000, \$400,000 and \$600,000 respectively, adding up to \$1.2 million. Thus plant E's energy at peaktime (1600 hours) would have to generate (\$4.5-\$1.2) million of return to capital if the investment in E is to be worthwhile. This would be created over 1600 hours × 50,000 KW of capacity, or 80 million kwh. The peaktime surcharge (over and above plant B's running cost) would then have to be \$3.3 million ÷ 80 million kwh = 4.125¢ per kwh. The peaktime price would be 8.125¢ per kwh.

The calculation would be different if the system peak were equal to, say, 1000 hours (rather than 1600). Assuming A's turbines to be used at full capacity during this 1000 hour peak, they would produce 50,000 megawatt hours during this period. Plant E would not be substituting for plant A during this time, but it would do so (if E is built) for the remaining 30,000 mwh of A's output (as shown in Panel 1). Thus H_{at} would be 30 million kwh while H_{bt}, H_{ct} and H_{dt} would each be 40 million kwh. These substitutions would account for a combined saving in running cost of $1.95 million (= $200,000 + $400,000 + $600,000 for plants D, C, and B, as before, plus $750,000 for plant A, covering the 30,000 mwh that we have calculated for H_{at}). In order to generate the $4.5 million of benefits that are required to justify investing in plant E, the peaktime surcharge (over A's running cost of 5¢) would have to generate benefits of $2.55 million (= $4.5 million minus $1.95 million). Per kwh, this "surcharge" would be 5.1¢ per kwh. The peaktime price of energy in this case would be $10.1¢/kwh.[1]

Readers should be aware that the peaktime "prices" that we calculate here do not in any way have to be put into practice (i.e., be actually collected from the power company's customers). They really are measures of the actual economic cost of bringing peaktime energy in line by way of constructing plant E. Our $4.5 million figure reflects the economic cost of the capital invested in plant E. If plant E only worked at peaktime one would have to assign this full $4.5 million of capital cost to the peak period. In our case, the bulk of this cost is being covered by savings of running cost during the offpeak

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In this calculation we assume that the timing of plant E's introduction into the system would be such that even in E's presence both A and E would be fully utilized during the 1000 hours of system peak. This gives rise to the question, how is the system managed during the interval in which system peak demand exceeds 200 MW (the sum of the capacities of A, B, C, and D) but falls short of 250 MW (where all five plants would be operating at capacity). The economist's answer to this question is that the peaktime price of energy would move up gradually from 3¢ (= A's running cost) to 8.4¢ (the level that would justify introducing plant E). The object of such a gradually increasing peaktime price would be to contain peak demand within the 200 MW limit, until the point where the introduction of plant E is optimal. This answer, however, involves too much fine-tuning for the practical world. The practical solution is simply to set the peaktime price at 7.9¢ soon as system peak demand threatens to exceed 200 MW at a price of 3¢, and then introduce plant E at the point where it can fully substitute for plant A.

period. The peaktime price we calculated represents the remaining part of this cost, and thus reflects the true cost of supplying peaktime energy via the investment in plant E.

Thus we would use the peaktime prices that we have calculated to measure the benefits of a daily reservoir project's adding to the supply of energy at a system peak of 1000, or the benefits of a seasonal hydro project's increasing the supply of energy during a system peak of 1600 hours. The underlying purpose of our calculating peaktime prices based on thermal costs is therefore to give us a cost-based way of assigning a value to peaktime energy coming from alternative sources of energy.

Thermal Capacity That Differs by Type of Plant

In this section we will consider differences in the capital and running costs of thermal plants, based on their physical (engineering) characteristics. For simplicity, we will confine out examples to three types of facility -- big thermal, combined cycle and gas turbine. There used to be many more relevant variations by type, as there would be significant variations in capital and running costs for coal-fired plants of different sizes. This sort of variation has been greatly reduced as a consequence of the introduction of combined cycle generating plants. These plants use petroleum or natural gas as fuel, and use jet engines or similar equipment to generate energy in the first cycle. The second cycle then uses the heat produced in the first cycle in order to create steam, which then produces additional energy in the second cycle. Once combined cycle technology came onto the scene, it turned out to be the cheapest way of generating electricity under a very substantial range of demand conditions. Thus our choice of just three types of generating equipment pretty well reflects the realities of contemporary thermal power industries.

The characteristics of our three types of equipment are:

	Capital Cost (K)	Annualized Capital Cost (= .15×K)	Running Cost
Big Thermal	$2000/KW	$300	$200 per KW/yr
Combined Cycle	$1200/KW	$180	5¢ per kwh
Gas Turbine	$ 600/KW	$ 90	9¢ per kwh

Readers will note that the running costs of big thermal are expressed on an annual basis per KW of capacity, rather than on a per-kilowatt-hour basis. The reason for this is that big coal-fired units cannot be turned on and off to meet variations in system demand. As is the case with nuclear capacity, turning them on and off is a costly operation, leading to their characteristic use as baseload capacity which only gets turned off for maintenance and repairs.

Table 3 examines the total annual costs of using these three types of capacity in order to meet different durations of energy demand. It is easily seen there that big thermal is the most efficient way to meet an annual energy demand (per KW of installed capacity) lasting 7500 hours, while combined cycle is best for a demand covering 5000 hours in the year, and also for one covering 3000 hours. For demands lasting 2000 and 1000 hours, however, gas turbines provide the most efficient answer.

If different types of capacity are best for different numbers of hours, there have to exist critical numbers of hours marking the “borderline” between two types. These borderlines are found by equating the total costs for two adjacent kinds of capacity. Thus at 6400 hours the total annualized cost of combined cycle capacity is equal to $180 + $.05(6400) = $500, exactly the same as the full-year cost ($300 + $200) of a KW of big thermal capacity. Demands with durations longer than 6400 hours can thus be accommodated most cheaply by big thermal capacity, while new demands lasting

TABLE 3

ELECTRICITY SYSTEM INVESTMENT DECISIONS WITH

THREE DIFFERENT TYPES OF GENERATING CAPACITY

	Annualized Capital Costs/KW	Running Costs Per Year	Total Costs/KW Per Year
Use for 7500 hours/yr.			
Big Thermal	\$300	\$200	\$500
Combined Cycle	\$180	5¢×7500 = \$375	\$555
Gas Turbine	\$90	9¢×7500 = \$675	\$765
Use for 5000 hours/yr.			
Big Thermal	\$300	\$200	\$500
Combined Cycle	\$180	5¢×5000 = \$250	\$430
Gas Turbine	\$ 90	9¢×5000 = \$450	\$540
Use for 3000 hours/yr.			
Big Thermal	\$300	\$200	\$500
Combined Cycle	\$180	5¢×3000 = \$150	\$330
Gas Turbine	\$ 90	9¢×3000 = \$270	\$360
Use for 2000 hours/yr.			
Big Thermal	\$300	\$200	\$500
Combined Cycle	\$180	5¢×2000 = \$100	\$280
Gas Turbine	\$ 90	9¢×2000 = \$180	\$270
Use for 1000 hours/yr.			
Big Thermal	\$300	\$200	\$500
Combined Cycle	\$180	5¢×1000 = \$50	\$230
Gas Turbine	\$ 90	9¢×1000 = \$90	\$180

Borderline between big thermal and combined cycle

$$\$300 + \$200 = \$180 + .05\,N_1$$
$$\$320 = \$.05\,N_1$$
$$6400 = N_1$$

Borderline between combined cycle and gas turbine

$$\$180 + .05\,N_2 = \$90 + .09\,N_2$$
$$\$90 = (.09-.05)\,N_2$$

$2250 = N_2$

somewhat less than 6400 hours can be more efficiently served by combined cycle capacity. These answers apply a) when the new demand stands alone (i.e., when we are building capacity just to satisfy this demand) and b) when the new demand is added to an already optimized system.

In an exactly analogous fashion we can find that the borderline between combined cycle and gas turbine capacity is 2250 hours. For this number of hours, total annual costs of combined cycle capacity amount to \$180 + (2250 × 5¢), or \$292.50, exactly the same as the annual total for at capacity, equal to \$90 + (2250 × 9¢) = \$90 + 202.50 = \$292.50. So again, either for a stand-alone demand or for a new demand within an already optimized system, we would install GT capacity for demands lasting less than 2250 hours, and combined cycle capacity for demands going up from this point.

Table 4 explores cases in which capacity is being added to an already optimized system. The first step is to identify system marginal costs -- these are equal to 3¢/kwh, the marginal running costs of big thermal, when it is the most expensive capacity at work (i.e., during hours of quite low system demand). Similarly, system marginal costs equal 5¢/kwh when combined cycle is the most expensive capacity at work (i.e., during periods of intermediate system demand). Then we have system marginal costs equal to 9¢/kwh when gas turbine capacity is marginal. These are times when the system's big thermal and combined cycle plants are all operating at full capacity, and therefore have to be supplemented by gas turbines in order to accommodate the system's full demand. The system marginal cost of 9¢ occurs when this is the case <u>and</u> when the system's gas turbine capacity is not fully utilized -- i.e., when the system is not yet at peak demand.

Now consider the fact that if gas turbine plants were to generate revenues of 9¢ per kwh for all their hours of operation, this would just cover their running costs, but would make no contribution to their capital costs. Thus, just as in the previous paper the peaktime surcharge was in a first example set at 6¢ and a thermal peak surcharge in a later example was set at 3¢ in order to cover the annualized capital cost of new homogeneous thermal capacity, we now set a peaktime surcharge of 9¢, in order to cover the annualized \$90/KW capital costs of gas turbine capacity, over a system peak of 1000 hours per year.[2]

In Table 4 we deal with three cases, each dealing with how the system should respond to a new set of energy demands -- Case #1 considers a new demand with a duration of 7000 hours per KW per year; Case #2 considers a new demand lasting 4000 hours; and in Case #3 the new demand has a duration of 1500 hours. These cases illustrate how, in an optimized system of the kind we are working with, a) each new demand can be met by its appropriate type of capacity, and b) when this is done and that new capacity is remunerated at system marginal cost for each hour that it runs, the total remuneration precisely covers the sum of annualized capital costs plus annual running costs for the appropriate type of capacity.

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When we deal with peaktime in this paper, we act as if the relevant capacity (here gas turbines) is absolutely fully utilized over the assumed duration (here 1000 hours) for peak demand. In reality, an electricity administration would define peaktime hours in a very sensible way (say 5-11 p.m. for a lighting peak in winter, 8-11 p.m. in summer) fully recognizing that the GT part of the system would not be operating at absolutely full capacity during these times. The rest of the system (big thermal and combined cycle) would, however, be at full capacity. Setting the peaktime surcharge at precisely 9¢ turns out to "right" from the standpoint of big thermal and combined cycle capacity; as is shown in Table 4. It is also "right" from the standpoint of GT capacity if it is indeed fully used for the 1000 hour peak. This is what we assume here. An upward modification of the peaktime surcharge would lead to excess rewards for big thermal and combined cycle.

Thus, in Case #1, big thermal is the "right" capacity to meet a new demand for 7000 hours a year. If it earns system marginal costs, it will get 18¢/kwh during1000 peaktime hours, 9¢/kwh during 1250 hours, 5¢/kwh during 3750 hours, and finally 3¢./kwh during the 1000 hours when big thermal is the system's marginal capacity. As is shown for Case #1 remuneration at these marginal costs will <u>precisely</u> cover by thermal's annualized capital costs of $300/KW plus its annual running cost (at 7000 hours) of 7000 × 3¢ = $210/KW.

Similarly, in Case #2 we have combined cycle capacity being built to accommodate a new demand lasting 4000 hours per year. Here remuneration at system marginal cost covers 1000 hours at 18¢ plus 1250 hours at 9¢ plus 1750 hours at 5¢ per kwh. The total of these "earnings" is $380 per KW per year, which precisely equals the sum of an annualized capital cost of $180/KW plus a running cost of 5¢/kwh for 4000 hours in the year.

Finally, Case #3 explores a new demand lasting 1500 hours, and met by adding new gas turbine capacity. Here that capacity "earns" 18¢/kwh for 1000 hours and 9¢/kwh for 500 hours for a total of $225/KW per year. Once again, this amount precisely covers the GT annualized capital cost of $90 per KW plus the GT running cost of 9¢/kwh for 1500 hours per year.

It almost looks like a "miracle" that a single peaktime surcharge turns out to be the only supplement to system marginal running cost that is needed, in order to fully cover both capital and running cost of each type of capacity in a fully optimized system.

TABLE 4

INVESTMENT POLICY IN A SYSTEM WITH OPTIMIZED

CAPACITIES AND SYSTEM PEAK OF 1000 HOURS

System Marginal Costs

<u>Big Thermal Capacity</u> -- Operates for 6400 hours or more. System Marginal Costs when Big Thermal Operation is the marginal capacity = zero

<u>Combined Cycle Capacity</u> -- Operates for more than 2250 hours and less then 6400 hours when this is the system's marginal capacity. System marginal costs = 5¢/kwh

<u>Gas Turbine Capacity</u> -- Operates for less than 2250 hours per year. When this capacity is only partially used (not at system peak), System marginal costs = 9¢/kwh

<u>Peaktime Surcharge</u> -- Sufficient to cover capital costs of gas turbine capacity during 1000 hours of system peak. Annualized capital costs of $90.00 ÷ 1000 peaktime hours = peaktime surcharge of 9¢/kwh. System marginal cost during 1000 peaktime hours = 9¢ running cost + 9¢ peaktime surcharge = 18¢/kwh

<u>Case #1</u>: New demand arises (new factory working 3 shifts per day), operating for 7000 hours per year.

<u>Answer</u>: build big thermal capacity to meet this demand

"earns" 18¢/kwh during 1000 peaktime hours	= $180
"earns" 9¢/kwh during 1250 hours when gas turbine is marginal capacity	= $112.50
"earns" 5¢/kwh during (6400-2250) = 4150 hours when combined cycle is marg. corp.	= $207.50
"earns" zero during 1000 hours when big thermal is marginal capacity	= 0
Total "earnings"	= $500

Cost of this new capacity = $300 annualized corp. cost + $200 running cost = $500

Big Thermal's costs are exactly covered by system marginal costs including peaktime surcharge.

Table 4 (continued)

Case #2: New demand arises (new factory working 2 shifts per day), operating for 4000 hours per year.

Answer: build combined cycle capacity to meet this demand

"earns" 18¢/kwh during 1000 peaktime hours	= $180
"earns" 9¢/kwh during 1250 hours when gas turbine is marginal capacity	= $112.50
"earns" 5¢/kwh during (4000-2250) = 1750 hours	= $87.50
Total "earnings"	= $380

Cost of this new capacity = $180 annualized

Capital cost + 5¢ × 4000 hours = $200

running cost = $380

Case #3 -- New demand arises (population growth leads to new residential demand plus commercial and street lighting), operating for 1500 hours per year.

Answer: build gas turbine capacity to meet this demand

"earns" 18¢/kwh during 1000 peakload hours	= $180
"earns" 9¢/kwh during 500 hours when gas turbine is marginal capacity	= $ 45
Total "earnings"	= $225

Cost of this new capacity = $90 annualized capital cost + 9¢/kwh during 1500 hours = $225

Perhaps with an excess of zeal I have called this proposition "the fundamental theorem of modern electricity pricing" At any rate, it was a noteworthy discovery in the annals of electricity economics.

As we shall see, a system which follows the rules of marginal cost pricing will tend over time to approach an optimized level. But many of the world's systems fall far short of this point at the present time and probably will still be non-optimized for quite some time into the future. In most of these cases the non-optimality of the system stems from two sources -- a) the presence of older steam and gas turbine plants that will naturally be retired as they live out their economic lives, and b) the fact that combined cycle technology has not had enough time to reach the levels needed for a fully optimized system. Table 5 explores two cases, both dealing with a system that does not net have its optimal amount of combined cycle capacity. These cases deal, respectively, with increases of demand of long (7000 hours) and short (1000 hours) duration. These new demands would "normally" (i.e., in a fully optimized system) be met by adding, respectively, big thermal capacity (for the 7000 hour increment of demand), and gas turbine capacity (for the 1000 hour increment). However, because of the non-optimality of the system, it turns out that the best response, even to these very long-duration and very short-duration increments of demand, is to add combined cycle capacity. This strategy is not only the cheapest way of accommodating the new demands; it also moves the system closer to optimality.

In Case #4, the new demand has a duration of 7000 hours. At first glance it seems natural that this demand should be filled by big thermal, which is the most efficient type of capacity for demands of this length. That is true in an optimized system. But in a non-

TABLE 5

INVESTMENT POLICY IN A NON-OPTIMIZED SYSTEM

WITH "TOO LITTLE" COMBINED CYCLE CAPACITY

- System has "too much" big thermal capacity, which ends up satisfying demands of 4500 hours or more.

- System has "too much" gas turbine capacity, which ends up satisfying all demands of 3000 hours or less.

- System has "too little" combined cycle capacity, which ends up satisfying demands between 3000 and 4500 hours per year. Recall that, combined cycle capacity has an economic advantage (based on capital and running costs.) for demands all the way from 2250 to 6400 hours per year. So quite naturally, if a new demand arises within the 2250-6400 range, it should be filled by adding combined cycle capacity. However, owing to the non-optimality of the system, it turns out that the answer to <u>any</u> increase in demand is to add combined cycle capacity, as this brings the system closer to an optimum. The following examples show why this is so.

<u>Case #4</u> -- New demand arises for 7000 hours per year.

<u>Answer</u>: Meet this demand by taking away big thermal from its "margin" at 4500 hours per year and shifting it to satisfy the new demand of 7000 hours. No capital cost or marginal running cost is involved since this capacity operates full time in either case.

Now add combined cycle capacity to fill the void of 4500 hours created by shift. This entails \$180 of annualized capital cost plus 4500 $\times$ 5¢ = \$225 of additional running cost	= \$405
Total Cost of meeting new demand	= \$405
Total cost of meeting this new demand by directly building big thermal capacity for this purpose = \$300 annualized capital cost plus \$200 of annual running cost	= \$500

Hence -- <u>It is cheaper to add combined cycle than to install new big thermal capacity to meet this new demand</u>.

<u>Table 5 (continued)</u>

<u>Case 5</u> -- New Demand arises for just 1000 hours of peak (say commercial establishments adding to demand for lighting during evening hours).

<u>Answer</u>: Meet this demand by taking away gas turbine capacity from its "margin" of 3000 hours and shifting it to met the new peaktime demand of 1000 hours. No capital cost, and there is a saving of running cost of (3000-1000) = 2000 hours × 9¢/kwh	= -$180
However, we now have the capital cost of combined cycle (= $180) plus (running costs combined cycle (= 3000 × 5¢) = $150 for 3000 hours	
Total combined cycle cost	= $330
Net cost per KW of building combined cycle to meet the new demand	= $150
Total cost of meeting the new demand by directly building GT capacity for this purpose = $90 of capital cost + 9¢ × 1000 hours = $900 of running cost, for a total cost of	= $180

Hence, <u>it is cheaper to add combined cyclical than to install new gas turbine capacity to meet the new demand</u>.

optimized system we may already have some big thermal capacity doing what it shouldn't (optimally) do. This is true in our Case #4, where we have some big thermal capacity that is meeting demands of only 4500 hours a year. The right answer is to shift this big thermal capacity out of this slot (where it doesn't belong), to move it to the new 7000 hour slot (where it does belong) and to replace it in the 4500 hour slot by combined cycle capacity, which is optimal for that duration. As the table shows, this set of moves meets the new demand at a total (capital plus running) cost that is lower than the cost of meeting the new demand with new big thermal capacity.

Similarly, we have Case #5, of a new demand with a duration of just 1000 hours. This is taken to be at peaktime, because if it were away from the peak this new demand could be met by simply making more intensive use of the system's existing capacity. Here the casual observer might think that the best way to respond to the new demand would be to add new gas turbine capacity. Again, this would be the right answer if the system was starting from an optimized position. But given the non-optimality of having some GT capacity working as long as 3000 hours, the best answer is to shift this GT capacity to the new 1000-hour slot. This saves 9¢ × 2000 hours of GT running cost per KW of shifted capacity. To replace this shifted GT capacity in the 3000 hour slot, we introduced new combined cycle capacity, having an annualized capital cost of $180 and an annual running cost of $150 (= 3000 × 5¢). The total cost of this CC operation is $330 per year, but deducting the saving of running cost on the shifted GT capacity, we find a net cost of $330 - $180 = $150. This is obviously lower than the $180 cost of satisfying the new 1000 hour demand by adding new gas turbine capacity.

Cases #4 and #5 show why it is true that in a non-optimized system that has too little combined cycle capacity, adding to that particular type of capacity will be the cost-minimizing way of responding to new demands of essentially <u>any</u> duration.

SOME NOTES ON SOLAR AND WIND POWER

The right way to think about solar and wind power is to consider them as the modern counterparts of run-of-the-stream generation. All of these have the characteristic that the ultimate source of energy experiences natural variations that are beyond our direct control. In the case of run-of-the-stream projects, we have the possibility of adding daily reservoirs, at which point we do control the flow of energy into the system. The counterpart of daily reservoirs would be to use wind or solar energy to pump water from a lower to a higher level, with the intention of generating electricity through hydro turbines during peaktime hours. This is known as pump storage, and involves two dams, one above and the other below the incline down which the water flows to the turbines. Pump storage projects have existed at least since the 1930s, but they have not become very widespread because of the heavy capital costs that they involve. Aside from pump storage, another means of controlling the flow of electricity from wind and solar sources would be through batteries -- generate electricity as the wind and sun permit, but use batteries to store that energy, so that it can be used at times of high value per kilowatt hour. To our knowledge, such use of batteries is still far from being cost-effective.

Thus our discussion of wind and solar energy will concentrate on the standard case, directly analogous to run-of-the-stream projects, where the electricity generated by the project is delivered to the system at the time and in the volume determined by the whims of nature.

Solar and wind projects differ from run-of-the-stream operations in that one does not always encounter diminishing returns to adding turbines or solar panels at a given site. Ten solar panels will catch ten times as much sunlight as one panel, and ten turbines will catch ten times as much wind as one of them (with some exceptions in cases of canyons, etc. which channel the wind in special ways). The generating capacity of solar and wind projects will therefore be determined mainly by the costs of installing more turbines or panels, and by the needs of the electricity system.

The standard way of dealing with capacity of these kinds is to assign to their output the relevant system marginal costs. Reverting to our example of Table 4, suppose a solar or wind project had a maximum output of 10MW. To value its expected output for any future year we would first assign system marginal costs for each hour of operation. Thus, following Table 4, we would have 2360 (= 8760 - 6400) hours at zero marginal cost (when big thermal was expected to be the marginal capacity), 4150 hours at 5¢ (when combined cycle was expected to be at the margin), and 2250 hours at 9¢, the marginal running cost of gas turbine capacity. These add up to $410 per KW per year. However, the solar or wind project would be expected to operate only at a fraction of its capacity, owing to fluctuations in the availability of wind and sunlight. We here assume the relevant fraction to be 30%, which reduces the benefit to $123 per KW of capacity.

The above calculations assign no part of the peaktime surcharge to the wind or solar project. This is because in both cases there are likely to be many peaktime hours during which the project will have zero output. In order to meet peaktime demand at such times, some sort of other standby capacity would have to be available. This might consist of older capacity, mainly retired from the system but held for standby purposes for just this kind of contingency. But within the framework of Table 4, it would be gas turbine capacity. There may be places where the wind or sun is so reliable that it can be counted on, at a specified intensity, in peaktime hours. If we assume that intensity to be 20% of the maximum intensity, then we would add to the above figure of $123, an amount equal to 20% of the 9¢ peaktime surcharge, times the 1000 hours of peaktime use. This would add $18; for a total benefit of $141 per KW.

Some discussions of wind and solar power speak of a "necessity" of supplementing these projects with backup peaking capacity (which in our case would be gas turbines). These discussions focus on the unreliability of these sources to provide peaktime power. The backup capacity enters the picture in order to fill precisely this role. We feel that such "packaging" is unnecessary. In coming to this conclusion we rely on a fundamental principle of project evaluation -- namely, the principle of "separable components". This principle says that if we have two projects X and Y, we can define their combined benefit (in present value) as B_{x+y}, their separate, stand-alone benefits as B_x and B_y and the benefits of each, conditional on the presence of the other, as $B_{x|y}$ and $B_{y|x}$. It is easy to see that:

$$B_{x+y} = B_x + B_{y|x} = B_y + B_{x|y}$$

Similarly, for costs:

$$B_{x+y} = C_x + C_{y|x} = C_y + C_{x|y}$$

Now if the "joint project" (X+Y) is the best option, this means that

$$(B_{x+y}-C_{x+y}) > (B_x-C_x)$$

$$(B_{x+y}-C_{x+y}) - (B_x-C_x) > 0$$

and therefore $B_{y\square x} > C_{y\square x}$.

That is, if the joint project is acceptable, project Y must pass the test as the marginal project -- it must be worthwhile to add project Y to an initial package consisting only of project X.

Similarly, it can be shown that if the joint project is best, project X must pass the test as the marginal project -- it must be worthwhile to add project X to an initial package consisting only of project Y.

There is no escaping the rigorous mathematical logic of this argument. If a package consisting of a wind project and a backup GT project is the best option. Then each of these two components must pass the cost-benefit test as the marginal project, measuring its contribution as what it would add (to benefits and costs, respectively) in the presence of the other. We therefore must evaluate a wind or solar project as being additional to any GT or other standby peaking project with which some would argue it ought to be "packaged".

POSTSCRIPT

In this and the preceding paper, the main objective is to convey an understanding of the underlying economic principles that characterize the provision of electric energy. The starting point is that the value of the kilowatt hour -- the standard "product" that electricity customers buy and consume -- will normally exhibit wide variations by hour of the day and season of the year. This occurs in spite of the fact that there is probably no item more physically homogenous from unit to unit than kilowatt hours of 120 volts and 60 cycles. The reason for the variation in value stems from different effective marginal costs of providing energy at different times. When an electricity system is not working at capacity, the effective marginal cost is the highest running cost among the different plants that are operating at the time. As plants are turned on, in ascending order of running cost, the effective marginal cost will be low at times of low demand, and high at times of heavy demand on the system's resources. System marginal cost is highest at peak periods, because here the true cost must also cover a provision for capital cost recovery of the type of capacity that has to be expanded when peaktime demand increases.

The key to evaluating investments in new generating capacity is to value their expected output at "system marginal cost", at each moment they are expected to operate. Put another way, the benefits that are to be expected from a new plant are the costs that will be saved due to its presence in the system. This is something that seems straightforward and easy to understand, but in fact it is anything but simple. The subtleties arise because the output of a new plant stretches many years into the future, so the bulk of its cost-saving will take place then. The principle guiding the estimation of these future cost savings is that year by year and into the future, the system will continue to follow good cost-benefit principles as it retires old plants and invests in new ones. Any given plant will almost certainly have a trajectory of benefits that starts high, and then declines over time. For thermal plants, one can expect that future additions will be more efficient than the current ones, so that today's new plant, which may start as the most efficient one of its class, may end its life as the least efficient of the class, having been bumped from a heavy load factor (high hours of use) at the beginning of its life to lower and lower hours of use as time goes on. Finally, it will be relegated to standby capacity, and ultimately to the scrap heap. Hydro storage dams have a similar trajectory of benefits, in this case stemming from their inevitable accumulation of mud and silt. As this occurs, their effective storage capacity inevitably declines. Perhaps run-of-the-stream projects and daily reservoirs (which can be desilted quite easily) are the only ones whose benefit streams may escape an inevitable downward drift through time.

The downward trend of benefits of a given project is incorporated in our analysis via an allowance for depreciation. Investment in an asset that does not depreciate can be justified if that asset just yields the required rate of return (opportunity cost of capital). It is the expectation of declining (or ultimately terminating) benefits that leads to first-year benefits covering more than the required rate of return. The use in our exposition of a required rate of return-plus-depreciation in the first year of a project's operating life is intended to capture all of the subtleties referred to in this note.

The fact that the future benefits of electricity projects are measured by their expected savings of costs gives rise to another possibility -- that the electricity system in question may have already in place a modern and highly sophisticated system of cost control and future investment programming. That is to say, those enterprises or public authorities may already have done a lot of the work needed in order to see how a given new plant will fit into the system, and which particular costs it will likely be saving, hour by hour and year by year, at least for a few years into the future. All we can say here is that, as cost-benefit analysts, we should be grateful when such pieces of luck relieve us of a great deal of work!!