

THE CAP-AND-TRADE SIP CALL

**POLICY ISSUES AND ALTERNATIVE APPROACHES
TO DEALING WITH THEM**

May 4, 1999

(discussions in this paper focus on EGU's only)

I. A few general considerations

1. Issues related to the EPD's decisions concerning emissions standards and limits within the State of Georgia are *separate and distinct* from issues related to the EPD's decisions concerning the allocation of emissions allowances. The former set of decisions are based on such things as the EPD's responsibilities for protecting and managing air quality in the State, its goals for the attainment of National Air Quality Standards in the Atlanta metropolitan area, and its responsibilities for complying with federal regulations related to State Implementation Plans.

2. The State's decisions concerning the *costless* distribution of its allowances pool (approximately 30,000 emission allowances) for ozone seasons beginning in the year 2003 are based on considerations distinct from those relevant for establishing emissions permit limitations. Due to Federal regulatory and other considerations, the EPD will allocate some 30,000 allowances at no cost to firms.¹ Beyond 30,000 tons, emissions will cost firms an amount equal to the price of allowances established in the EPA's market for NO_x allowances (expected to be \$2,000 to \$5,000/allowance).

It then follows that the EPD's allocation of the emissions allowance pool entails its judgement concerning who is entitled to pollute "free" and who must pay for the right to pollute. The EPD's judgement in these regards will reflect the following premises.

(A) When air pollution is a significant by-product of a firm's production activities, the *costs* of pollution should be included in their costs to as great an extent that is possible and practical.

(B) EPD policies should have as small effect as is reasonably possible in distorting competitive relationships among firms in any industry.

3. The EPD's acceptance of premises 2.A and 2.B may be viewed as having specific

¹Basic to this process is the notion: in distributing allowances to EGUs without cost, we are acting *as if* emissions up to 30,000 tons results in no social pollution costs and, therefore, are appropriately not included in a firm's costs.

implications for limits on any allocation of emissions allowances to new or existing gas turbine plants. EPD-issued permits to gas turbine EGUs include an emissions limit of .05lb/MMBtu. We argue that this limit should be taken to imply an upper bound on any allocation of emission allowances to such firms.

The rationale for this limit is fairly straightforward. Consider, for example, that Georgia now has in operation several plants operated by the Southern Company and one small gas plant operated by Harwell Energy, for a total generating capacity of 16,300 MW with annual heat input (HI) of about 365 million MMBtu. Since 1995, nine plants -- all gas-fueled combustion-turbine plants, accounting for 4,900 MW of generation, are either in-the-ground, will have broken-ground, or have contracts for generation. HI for these nine plants, using the EPD's estimate for new combustion turbines, would be $HI = 11 \text{ MMBtu/MW-hr} \times 1102 \text{ hours} \times 4900 \text{ MW} = 59,397,800 \text{ MMBtu}$. Based on the EPD emissions limit, these plants emissions can be no greater than $(.05)(59.4 \text{ million})/2000 = \mathbf{1,485 \text{ tons}}$.

Suppose that these nine plants were receive an allocation of allowances equal to their "share" of total HI. Their share of HI is approximately 14%: $(59.4 \text{ million})/(365 \text{ million} + 59.4 \text{ million})$. They would then receive 14% of 30,000, or **4,200 allowances**. Their production would require no more than 1,485 allowances, leaving more than 2,700 allowances that could be sold in the market. At an allowance price of \$5,000, this would provide annual income of some \$13.5 million (a bit under \$3,000/MW) that has the effect of reducing production costs. Thus, if firms are allocated larger amounts (as would result, e.g., from an allocation based on a firm's proportion of total heat input) the effect of the allocation would be to violate *both* premises 2.A and 2.B. Excess allowances could be sold in the market, revenues from which would effectively subsidize production costs. Pollution then lowers costs rather than increasing them in opposition to premise 2.A. Lower costs can offer a firm competitive advantages in contrast with 2.B.

We find no justification that would rationalize a gratuitous allocation to gas plants in excess of that amount required to comply with the EPD-established limit. Once allocated, we do find justification for allowing the allocation to stand until a later up-date (i.e., not requiring the surrender if unused allowances) because this provides plants additional incentives to reduce emissions below the .05lb/MMBtu limit.

4. Finally, we wish to briefly address a concern that we have heard expressed, however informally, on several occasions: if new gas-fueled EGUs must purchase allowances, rather than have them provided "free," they will be at a competitive disadvantage.

After consulting a number of data sources,² we submit as a reasonable characterization for the cost structure of a gas turbine plant the following: annual fixed costs: \$60/KW-year; annual

² Utility Data Institute, *Production Costs: U.S. Gas Turbine Plants (1996)*; Power Resources Task Force Report for the ACT/ACF Comprehensive Study; data made available by telephone to Pete Terrebonne by Mike Evans, GA Power Company; and data made available to Laura Taylor by local consultants to the power industry.

variable costs, with gas priced at \$2/MMBtu and assuming operation at 1,000 hours: \$7.5 million. Thus, a 300 MW unit operating at 11 MMBtu/MW (for 1,000 hours) would have total fixed costs at \$18 million, variable costs of \$7.5 million, yielding **total costs (which include returns on equity of 11-12%) of \$25.5 million.**

Peak prices for electricity have been steadily increasing over the last several years. The summer average peak price (per MW-hour) was \$26.11 in 1996, \$33.74 in 1997, and \$194.04 in 1998; indeed, on several days during the summer '98 period, peak prices were in excess of \$1,000! We are told that energy planners presently base expansion plans for peak, gas turbine plants, on an assumed contract price of \$140/MWh, 16 hours/day, 5 days/week, for July and August. For our 300 MW plant, this 720-hour contract would yield **annual revenues in excess of \$30 million.**

The 300 MW plant, if operating at the .05lb/MMBtu limit, would require 82.5 allowances. At \$5,000/allowance, allowance cost would be approximately .4 million. Allowance costs would then increase annual total costs by 1.6%, and would reduce "excess profits" (the difference between revenues and costs [which include an 11-12% return on equity]: \$30 million - \$25.5 million) by less than 9%.

With exceptions noted below for the 9 "new" gas turbine EGUs for whom applications are pending or in process, we are aware of no expected competitive conditions wherein allowances costs on the order considered above could have the effect of placing a new entrant at a substantive competitive disadvantage. Existing firms -- Georgia Power or new IPPs -- must incur the same costs either as a direct market purchase of allowances or by absorbing the opportunity costs of any excess allowances on hand. Of course, the value of such opportunity costs is the market value (cost) of emissions allowances -- exactly what the new entrant must pay. Furthermore, new entrants compete for new contracts that would presumably reflect the increased costs of electricity generation, and thus include higher prices.

II. How is the initial (September, 1999) emissions allowances pool to be allocated?

Attention is now turned to this question of central interest for the EPD. We have considered a number of alternative approaches that might be used for responding to this question. Among these is the option of providing for the allowances needs of existing (including plants that have been permitted or that have pending permits) gas turbine plants, and then giving the balance to Georgia Power. We find no objective basis for fully satisfying the needs of one set of producers (IPPs) and only part of the needs of another (Georgia Power).

We have been able to come up with only one general approach which we feel can adequately address the EPD's concerns for equity and fairness. We begin by discussing the initial (September 1999) allocation of allowances which is relevant for the 2003 ozone season. Attention will then turn to later allocations and the related question of how "new growth" is to be handled.

A. The September 1999 allocation. The NOX budget was created using the 1995 in-the-ground heat-input inventory. As a result the budget is based on the heat input of plants that were operating at the time (1995), which includes several plants operated by the Southern Company and one small gas plant operated by Harwell Energy, for a total generation of 16,300MW. These plants are considered "in the pool" for the initial allocation of NOx permits in that they should be given all due consideration for some portion of the permit budget.

However, since 1995, and prior to the new regulation, nine plants accounting for 4,900 MW of generation, are either in-the-ground, will have broken-ground, or have contracts for generation. We wish to argue that these plants should be treated *as if* they too are "in the pool." These plants may be considered to have committed (invested/expended) *real resources* to the production of electricity. Contracted prices and/or investment feasibility considerations can be expected to have been determined within the context of competitive conditions extant at the time of their actual or planned entry into the market. Imposition of unanticipated costs -- costs of acquiring emissions permits that may run between \$2,000 and \$5,000 per permit, may be viewed as violating premise 2B. Thus, the fact that these entities have committed real resources to electricity generation makes compelling (arguably) the notion that they should be treated on a basis that leaves reasonably unaffected the pre-1999 competitive "playing field." Thus, under this alternative all plants who can demonstrate that real resources have been committed (i.e., that at a *minimum* contracts for generation have been signed) by, say, August, 1999, are treated as if they were included in the original (1995) pool.³

Our suggested alternative for the initial allocation of the State's allowances pool of 30,000

³ An alternative statement is to say that there is an immediate update that includes all plants in operation, or who have committed resources to production by end of calendar year 1999. Or, another way to say this is that all plants with real resources committed to electricity will be given some portion of the budget, and in some instances, that may mean a set-aside is developed for producers who have real resources invested in generation by end of year, 1999, but who did not exist in 1995.

tons is the following.

1. The allowances *need* of each EGU unit is determined based on permitted emissions that have been established by the EPD. We know that emissions limits on gas turbine units is .05lb/MMBtu of heat input (HI). We know that the HI for Harwell’s two gas turbine units is 250,000 MMBtu. For the nine plants with permits or pending permits, if we use the EPD’s assumptions, heat input for these nine plants would be: $HI = 11 \text{ MMBtu/MWh} \times 1102 \text{ hours} \times 4,900 \text{ MW} = 59.4$ million MMBtu. For gas turbine units (we exclude here any such units that Georgia Power may have in operation), the limit on their emissions is then $.05(250,000 + 59.4 \text{ million})/2000 = 1,491$ tons. We do not know the present permit limits on emissions for Georgia Power units. For purposes of this discussion, we simply assume that they total 50,000 tons.⁴ Allowances “needs” by these units is then:

Gas turbine EGUs	1,491
Georgia Power	<u>50,000</u>
Total	51,491

2. An equitable distribution of allowances — *free* allowances to pollute — is one where (we argue) all units receive the same proportion of their permitted needs. The 30,000 permits can satisfy only 58% of permitted needs. Thus, all units receive free allowances equal to 58% of their needs and must purchase the residual. In this example, the distribution would be as follows.

	<u>Needs</u>	<u>“Free” Allowances</u>	<u>Purchased Allowances</u>
Gas turbine	1,491	869	622
Georgia Power	50,000	29,131	20,869

A potential argument against this allocation mechanism is that Georgia Power can adopt investment strategies in which this allocation will yield them excess allowances. However, the same argument can apply to gas turbine units — they certainly have available to them technological alternatives that can reduce emissions below the .05lbs/MMBtu limit. This argument is only applicable to the extent that firms are able to increase their permitted emissions. This is an issue of permitting, not of the ‘free’ allocation of a set of allowances.

B. Beyond 2003: How is “new growth” to be accommodated? There are at least two approaches that one might adopt for accommodating new growth, each of which has distinct implications for the length of up-dating periods.

One approach gives a preference to present producers (current members of the pool which

⁴ We are aware that the present limit is an average of .46lbs/MMBtu, with limits on plants in the non-attainment area falling to .30lb/MMBtu in the year 2000. We are also aware, however, of likely changes in these limits. We use 50,000 here simply for the purpose of exposition.

includes those that have yet to come into production) over future growth. These firms get the allowances as described above, and then up-dating is not be used, or at least up-dating periods are very long. All new growth — growth by current operators or new firms — pay the full cost of pollution *via* purchasing required emissions allowances.

An arguments that might be raised as criticisms of this approach is that the initial distribution provides unfair competitive advantage to these firms over new entrants to the Georgia market. We find this argument to be lacking in merit for the following reason. Whether or not involved parties follow up on their commitments (see memoranda to Harold Reheis) to sell any unused permits in the open market, if (as we must assume) the market for NO_x allowances is robust, the price of a permit should reflect the marginal cost of NO_x emissions abatement. Thus, the opportunity cost of any unused allowance held by members of the initial “pool” is the same value as the market price of an allowance. If these firms install new units in the future, they incur the same cost as a new entrant whether they use internal, unused allowances or purchases allowances in the open market.

A second approach would simply extend the “equal share” principle of the initial allocation. If new growth requiring (as an example) 2,000 allowances comes into place, we then would have (continuing the example used above) “needs” of 53,491, only 56% of which can be accommodated by the pool of 30,000 allowances. EGUs, all EGUs, then receive an allocation of free allowances in an amount equal to 56% limit-based needs. The appeal of this approach may be seen with reference to premise 2.A: over time, all firms will be including an increasingly large proportion of their pollution costs in their production costs. This approach would allow for frequent updating — as frequently as new permits are issued.