AIR POLLUTION CONTROL DISTRICT
COUNTY OF SAN DIEGO

September 21, 1993

TO: Workshop Participants and Other Interested Parties

FROM: Richard J. Smith
Deputy Director

RULE 69 - ELECTRICAL GENERATING STEAM BOILERS, REPLACEMENT UNITS AND NEW UNITS WORKSHOP REPORT, SIA EXECUTIVE SUMMARY, AND PROPOSED RULE

On June 3, 1993, the San Diego County Air Pollution Control District held a public workshop to receive comments regarding proposed District Rule 69 - Electrical Generating Steam Boilers, Replacement Units and New Units. The District has prepared a workshop report which summarizes the comments received at the workshop, and in writing, and the District's response to each. As a result of comments received, some changes to proposed Rule 69 have been made. In addition, a District consultant has completed a socioeconomic impact analysis of Rule 69, as required by state law.

Enclosed are copies of the workshop report, revised proposed Rule 69 and the Executive Summary for the Socioeconomic Impact Analysis. These documents are being made available to all workshop participants and other interested parties for their review. If you have any comments regarding these enclosures, please submit them to the District, in writing, by October 13, 1993. Copies of the complete socioeconomic impact analysis are available by calling Juanita Ogata at (619) 694-8851. If you have any questions concerning this matter, please call Michael Lake at (619) 694-3313 or me at (619) 694-3303.

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Enclosures: Proposed Rule 69
Workshop Report
Socioeconomic Analysis-Executive Summary

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PROPOSED RULE 69

ELECTRICAL GENERATING STEAM BOILERS, REPLACEMENT UNITS AND NEW UNITS

WORKSHOP REPORT

A workshop notice was mailed to each company that might potentially be subject to the rule, to each participant at a previous workshop, to all interested parties, and to the U.S. Environmental Protection Agency (EPA), the California Air Resources Board (ARB), the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC).

The workshop was held on June 3, 1993 and was attended by 18 people. Written comments were also received. The following are the comments received and District responses.

1. <u>ARB WORKSHOP COMMENT</u>

The ARB has been reviewing various drafts of Rule 69 for two and a half years. With the current standards proposed, particularly for the large units for both gas and oil burning, the ARB is having a very difficult time finding equivalency for best available retrofit control technology (BARCT) which is required by the CCAA. There have been a couple of utility boiler rules adopted in the state and four are in development at this time and proposed to be adopted this year. The ARB has spent a lot of time working with the air districts and the utility companies on what are appropriate BARCT standards and is questioning how the San Diego District is determining that the proposed standards should be equivalent to BARCT.

The ARB also questions the need for oil burning, except in natural gas curtailment situations, and the exemption for units less than or equal to 10% capacity factor with a much higher rate allowable emission rate limit. The proposed Rule 69 limit for these low capacity factor boilers exceeds the limit which has been proposed as BARCT for industrial and commercial boilers - 30 ppmv. That particular guideline, which is consistent with many local districts' adopted rules, has a cutoff of 90,000 therms as an exemption level. Based on cost or technology or whatever the district is using as its guideline, the ARB does not understand how that 10% capacity factor cutoff can qualify under the guideline of what BARCT should be and under the CCAA requirements. The ARB is also questioning the compliance schedule. The schedule proposed is not in keeping with the District's plan, which estimated full compliance within five years. Basically the ARB is questioning how the District has determined all of these rates and cutoffs and how the District determined that Rule 69 is appropriate for BARCT in the state?

<u>DISTRICT RESPONSE</u>

The ARB has been reviewing draft proposals for Rule 69 for some time. The District has provided ARB with considerable technical information with regard to how the District arrived at the limits that are proposed in the rule. The District considered the NOx emission rate limits that are prescribed in South Coast AQMD Rule 1135 and by Ventura County APCD Rule 59, the only utility NOx control rules that have been adopted in California to date.

Southern California Edison (SCE) units in South Coast operating under Rule 1135 and SCE units in Ventura operating under Rule 59 operate more fuel efficiently and at a lower base emission rate (in pounds of NOx per megawatt hour produced) than do the SDG&E boilers. The District considered the allowable emission rate limits of these rules, the current emission rates of the SDG&E units, and what level of NOx emission reductions would be needed to achieve the same level of control that was being required by either Rule 59 in Ventura or Rule 1135 in South Coast. Proposed Rule 69 accomplishes the same level of NOx emission reduction as does Ventura's Rule

59 and South Coast's Rule 1135, provides as much operational flexibility to SDG&E as possible, and considers the cost-effectiveness of less stringent NOx controls for those SDG&E units that are used infrequently and are expected to have very low capacity factors.

The 10% capacity factor exemption that allows a higher NOx emission rate limit for these low usage units is intended to apply only to SDG&E's Silvergate units and the South Bay power plant unit #4, which are used very little and then only to meet peak capacity needs. In fact, the Silvergate units have not been operated at all for the past several years. However, some peak demand use of these units may be necessary in the future if planned resource additions are not forthcoming or are delayed. If the Silvergate units and South Bay Unit #4 had to be retrofitted with controls to meet a NOx emission rate limit of 0.18 lbs/MW-hr the cost would be very high in terms of dollars per pound of NOx emissions reduced. The District considered this in proposing standards that would apply to such units. Even the level that is being proposed, 0.6 lbs/MW-hr, has a relatively high cost-effectiveness value associated with it, much higher than the overall cost-effectiveness for the SDG&E system and much higher than the cost-effectiveness of NOx controls for SCE under the South Coast or Ventura rules. To ensure that the low capacity factor NOx emission rate limits will only apply to the Silvergate units and South Bay Unit #4, they will be specifically identified in the rule as well as limited in maximum annual use.

The BARCT guidance for industrial and commercial boilers referred to by ARB recommends a 30 ppm NOx emission rate limit for boilers with annual usage greater than 90,000 therms. The District believes that controls at such a low usage level for industrial and commercial boilers are not cost-effective for San Diego, and the District will likely propose a higher usage exemption level. Nevertheless, this limit is based on the application of flue gas recirculation and low-NOx burners to control NOx emissions by approximately 70 percent. The proposed emission rate limit for the Silvergate boilers and South Bay Unit #4 of 0.6 lbs/MW-hr represents an emission reduction of approximately 50 to 60 percent. This is consistent with an independent engineering study, performed under contract to SDG&E, which concluded that low-NOx burners and flue gas recirculation combined, would effect an approximate 60 percent NOx reduction in these units. Alternatively, urea injection could be used to achieve a comparable level of emission reduction. In both cases, the cost-effectiveness is approximately $8500/ton. By comparison, the cost-effectiveness of requiring full SCR for the Silvergate units jumps to approximately $135,000/ton. The District does not believe that the marginal additional emission reductions, at greatly increased costs, warrant a lower NOx emission rate limit for these units.

It is not correct to state that Rule 69 lacks a prohibition on oil burning. To protect short-term air quality, the proposed rule prohibits oil burning on days when an exceedance of a state or national ambient air quality standard for ozone is expected to be exceeded. Further restrictions on oil burning are not warranted. SDG&E primarily burns natural gas. During the 1980's oil burning constituted only about 15 percent of their fuel consumption, with some years as low as 5 percent and some years as high as 60 percent. SDG&E has argued that they need the capability to burn oil as leverage when they are negotiating purchases of natural gas supplies, their primary fuel. Furthermore, they have stated that it is not their intent to routinely burn oil, except as necessary.

While oil burning does result in increased NOx emissions, the allowable NOx emission rate after application of controls required by Rule 69 is an approximate 67 percent reduction from current NOx emission rates on gas. To ensure that there is a disincentive for SDG&E to burn oil, the annual NOx emissions cap is based on natural gas burning only. Thus, if SDG&E does burn oil for economic reasons, they must either reduce their emission rates to stay below the cap or obtain external emission offsets to mitigate any exceedance of the cap. In this way, the District is creating operating flexibility for the utility while ensuring that NOx emission reductions are achieved.

The compliance schedule proposed in Rule 69 is consistent with that projected in the tactics upon which the Regional Air Quality Strategy was based. Rule 69 would have at least one of SDG&E's units retrofitted with NOx controls by the end of 1996, and at least one additional unit each year thereafter. All units must be in compliance by January 1, 2001. An additional period of up to two years is allowed for replacement units and associated boilers that are scheduled to startup between January 1, 2001 and January 1, 2003 since it would be unreasonable to require that the existing units be retrofitted if they are scheduled to be replaced. Planning for the replacement units would likely start at least 4 to 5 years before actual unit startup.

The tactics contained in the Regional Air Quality Strategy evaluated several levels of NOx controls for electrical generating steam boilers. For the most stringent level of controls, as will be required by Rule 69, the tactic estimated full implementation over five years. The proposed Rule 69 compliance schedule has full implementation over five years commencing 1996 and ending by the close of 2000. The schedule begins in 1996 because it must allow sufficient time after rule adoption to thoroughly evaluate existing unit NOx emission rates, load and structural characteristics and develop detailed retrofit system designs. In addition, construction permits must be obtained for the control equipment as well as ancillary equipment such as ammonia storage tanks. Design and construction contracts must be executed, units must be scheduled to be off-line, and actual construction, operational shakedown and testing must occur. The five year schedule for retrofitting all units should not be accelerated because it may require that too many units be off-line simultaneously, jeopardizing the reliability of the electricity delivery system in San Diego County.

<u>SDG&E RESPONSE</u>

To the best of our knowledge, emission rates less than what are proposed in Rule 69 have never been achieved in practice. SDG&E does not know whether or not it is technically feasible to achieve a rate of less than 0.15 lbs/MW-hr on our boilers, nor do we know for sure what the cost will be. All the cost-effectiveness calculations are based on some very preliminary engineering, some best guesses. SDG&E does not know whether we can even meet the limits that are proposed or what the cost is going to be. SDG&E is very concerned that there not be a rule that would require us to do something that would not be physically possible.

We do know that CCAA requires BARCT. It did not define it, but it did say you should take economics and energy into account. It did not specify that it has to be uniform statewide, although the District has attempted to try to make it somewhat equivalent. San Diego County is not in anywhere near as bad a shape, air quality wise, as South Coast. Electric rates are very dependent upon these emission controls. SDG&E expects to spend somewhere around $100 million dollars just to try to achieve the rates that have been proposed in Rule 69. It will have an impact on the San Diego economy. We believe that the approximate 85% reduction that is being proposed in Rule 69 now probably goes beyond what is going to be required of any other type of emission source. Even though we may be only 6% of the problem in San Diego County, SDG&E will be bearing a very substantial cost to reduce NOx emissions. That cost will simply be passed on to all the residents of San Diego County.

Without a specific definition of BARCT, which seems to be a moving target, and without an absolute knowledge as to what the cost is going to be or whether it is technologically feasible, SDG&E is willing to try to meet the NOx emission rate limits that are in the current proposed rule, with the understanding that we don't know for sure whether we can do it. But if you try to lower those rates even further, then I think there will be significant problems in our being able to economically achieve them, if they can physically be done at all.

With regard to oil burning, SDG&E has agreed to not burn oil on days when the ambient air quality is in violation of the standards. We see no reason for any further limitations on oil burning if it is not for an air quality control purpose. Being able to continue to burn oil is a valuable way to enable us to keep our rates down and keep California competitive.

2. **ARB WORKSHOP COMMENT**

The ARB agrees it is appropriate to consider all these factors - unit efficiencies, cost-effectiveness and capacity factors. However, the ARB cannot find that proposed Rule 69 is equivalent to either of the two adopted South Coast and Ventura rules. The ARB has been working closely with the three other air districts that are proposing rules. There are some particular provisions in those proposed rules which leads ARB to believe that the current proposed Rule 69 is not equivalent with those proposed rules. The ARB still would like additional information to show, for example, the current proposed Rule 69 is equivalent in emission rate to South Coast Rule 1135 or Ventura County Rule 59. ARB wants to see all the information that the District has used to determine this equivalency.

DISTRICT RESPONSE

The District has already provided the ARB with considerable amounts of information that were used in developing this rule. The District recently provided to the ARB additional information with regards to the appropriateness of the 0.15 pounds per megawatt hour emission rate limits for the large units and also the appropriateness of the calendar day averaging period for the emission rate limits. The District will consider any additional comments that ARB may have with regard to that additional material.

The District concluded that Rule 1135, as it would apply to Southern California Edison, accomplishes an 84% emissions reductions in NOx from SCE's pre-regulatory levels. Ventura's Rule 59 would result in an approximate 87% emission reduction from the SCE units in Ventura. Proposed Rule 69 accomplishes an 86% to 87% emission reductions from SDG&E units. This is comparable to both Rule 1135 and Rule 59. The information the District has provided the ARB justifies these conclusions. The District would also point out that the more stringent emission rate limit of Ventura Rule 59 applies to more fuel efficient and much larger 750 megawatts units. These are not representative of the SDG&E boilers that would be controlled under proposed Rule 69.

It should be noted that ARB has not issued a BARCT determination for utility boilers. ARB has specifically refrained from doing so and has indicated that ARB would be working with local air districts to develop rules that reflect the operations of the utility boilers within each district. The District would encourage ARB to consider the total NOx emission reductions that will be achieved by Rule 69, as the District has done with regard to Rules 1135 and 59. The ARB should not focus on only the rule NOx emission rate limits in pounds per megawatt hour but should consider also the total emission reduction effectiveness of Rule 69 which the District believes is equivalent to these other rules.

3. **ARB WORKSHOP COMMENT**

Not only is ARB looking at the actual allowable emission rates for BARCT, but also the cost-effectiveness of the limits and what the District has proposed in their analyses of cost-effectiveness. The cost-effectiveness for Rule 69 appears to be much lower, perhaps as much as 50% lower than what was developed in the South Coast Rule 1135 analysis and 30 to 40% lower than what was developed in the Ventura County Rule 59 analysis. According to the Health & Safety Code, ARB must consider economic and energy impacts in terms of relative economic impacts. ARB is having a hard time seeing a BARCT equivalency.

DISTRICT RESPONSE

Rule 69 should not be criticized by ARB for achieving equivalent emission reductions to the South Coast and Ventura rules at less cost to SDG&E rate payers. The Rule 69 cost-effectiveness is in the range of $9000 to $14,000 per ton of emissions reduced, depending on whether any of the SDG&E units are repowered in the future. The average cost-effectiveness of South Coast Rule 1135 (for SCE units) is approximately $17,000 per ton. The average for Ventura Rule 59 (for SCE units) is approximately $14,000 per ton. Further, the District has not traditionally regulated NOx as an ozone precursor. Rules to reduce NOx emissions are only now being developed in San Diego. As such, there is not a track record of cost-effectiveness for NOx control measures that would serve as a benchmark as additional control measures are adopted. However, the cost-effectiveness of proposed Rule 69 is significant compared to the cost-effectiveness of other control measures that are required of new sources. The current cost-effectiveness of NOx BACT under New Source Review in San Diego is approximately $7500 per ton.

It is important to further note that under the District's New Source Review rules, the level for determining when BACT is not cost-effective must be at least 50% higher than any other NOx control requirement that has been imposed through regulation on stationary sources. Whatever level of cost-effectiveness results from Rule 69 or other stationary source control regulation, one result will be an immediate increase in the cost-effectiveness threshold for BACT on all new sources of NOx. Rule 69 already represents a significant increase in cost-effectiveness for NOx control in the San Diego region. To further increase the cost of Rule 69 by increasing the stringency of its limits, with very little further NOx emission reductions resulting, will not only increase the compliance costs that SDG&E will pass on to all rate payers in San Diego County, but will also impose greater compliance costs on all new businesses with NOx emissions over BACT thresholds locating in San Diego County.

4. **ARB WORKSHOP COMMENT**

Back in 1991, the District put out a May 10, 1991 draft on which they received letters of approval from both the CARB and USEPA. In that draft the emission rate limits were lower, the caps were different at that time, and we recommended that the District and the ARB work with the California Energy Commission to determine the appropriateness of the caps. The ARB believes the Rule 69 proposed in 1991 was a better version in terms of BARCT standards.

DISTRICT RESPONSE

Again, it must be emphasized that there is no single BARCT standard for utility boiler NOx control in California. The May, 1991 draft rule represented expected operations of the SDG&E system under the proposed merger of SDG&E and Southern California Edison. That merger was not approved and is no longer a factor in projecting SDG&E's operations. As such, the May, 1991 draft rule must be dismissed and should not be used as a benchmark for judging Rule 69 as currently proposed.

5. **ARB WORKSHOP COMMENT**

Since the NOx offset exemption relies on meeting an annual emission cap, we were wondering why the first cap is in 1997 when the exemption is upon adoption of the rule?

DISTRICT RESPONSE

The special treatment of NOx emission offsets refers to those required for new and replacement utility resources. Only one such project is under active review and, if approved, is not expected to become operational until 1997 or 1998. Emission offsets, if required, would not need to be implemented until startup. The first emission cap will be in place at that time and some of the emission reductions required by Rule 69 will have been implemented. However, the provisions regarding this waiver should be in place and in effect at the time that the project is being considered for approval.

6. **ARB WORKSHOP COMMENT**

Has the District done any analysis, based on different scenarios of retrofitting, of what costs would be passed along to the rate payer?

DISTRICT RESPONSE

The District has hired a consultant to prepare a Socioeconomic Impact Analysis of the rule. This analysis is required by state law for any new or modified rules or regulations that significantly impact air quality. The analysis will include estimates of the rate impacts of Rule 69. That analysis has now been completed and is available for review and comment prior to adoption of the rule.

7. **ARB WORKSHOP COMMENT**

ARB is having difficulty finding that the cap is really designed as BARCT on utility boilers, because there is a proposal for the exemption from offsets for NOx emissions on new and replaced units. ARB would expect the cap to be set at a level which is representative of emissions from utility boilers which have been retrofitted to a degree compatible with BARCT. Particularly since various revisions have been made since May 10, 1991, we haven't seen detailed analysis of the caps and equivalency with BARCT for utility boilers.

DISTRICT RESPONSE

The District has provided the ARB with the calculations and the production cost modeling used to project the level at which SDG&E units would operate each year up to year 2010 under both repower and no-repower scenarios. The District applied the emission rate limits that are proposed in Rule 69, for natural gas burning only, to those production levels, on a unit-specific basis. For both the repower and the no-repower scenarios, the analysis showed compliant NOx emissions at or above the 800 tons year level in approximately year 2008 and beyond. However, there is considerable uncertainty with regard to what the actual SDG&E operating levels will be. Those levels will depend upon whether there will be repowers of one or more of the existing SDG&E units, whether a new combined cycle facility will be located in or out-of-County, whether future geothermal and renewable resources will be available to the levels projected, whether surplus power from the Southwest will continue to be available, and whether the San Onofre nuclear power plant will continue to provide power at expected levels.

While using these projections, the District has tried to keep in mind these uncertainties. If the District were to set a very stringent emissions cap initially, with a high degree of uncertainty, and find only much later that SDG&E's system must generate more locally than was anticipated, it may be very difficult to change the rule to raise that limit under current rule relaxation policies. The proposed Rule 69 annual emission cap strikes an appropriate balance between what is a technically stringent emission rate limit and the uncertainty in projecting SDG&E's level of operations for the next 15 or more years.

Because of these uncertainties, actual generation levels may be less than that currently projected. To ensure that such a circumstance does not result in real emission increases from other projects, the rule does not allow SDG&E to bank any emission reductions below the emission caps if they are able to operate at a lower level, but does allow SDG&E to operate above the emission cap if it provides offsetting emission reductions at a 1.3 to 1.0 ratio.

Subsequent to the workshop, the California Energy Commission staff, at the request of the Air Resources Board, conducted additional computer modeling of SDG&E's expected electricity generation levels to the year 2011 for several different possible operating scenarios. Some scenarios modeled indicated annual emission levels below 800 tons per year, others showed annual emission levels above. In particular, models based on continued operation of the existing SDG&E system with no in-basin resource additions indicated emissions at or above 800 tons per year at about year 2006. Given that there remain considerable uncertainties with these forecasts, that emission levels below the cap cannot be banked for use as offsets, and that emission levels above the cap must be offset at a 1.3 to 1.0 ratio, the proposed Rule 69 annual NOx emission cap of 800 tons is an appropriate regulatory level.

SDG&E COMMENT

The proposed 800 ton annual emissions cap was based somewhat arbitrarily on what our existing system is likely to be emitting after the Rule 69 controls have been applied, somewhere around the year 2003. After 2003, absent the cap, SDG&E's NOx emissions would be higher than 800 tons. The cap is going to be a definite constraint on SDG&E operations. This depends a lot on our resource plan. The California Clean Air Act does not require a cap, but SDG&E is willing to accept one as long it does not get any more restrictive on our operations than it already will be.

8. **CEC WORKSHOP COMMENT**

Subsection (c)(15) defines "utility" as a municipality or other government agency that is involved in production, distribution or sale of electricity and which is regulated by the California Public Utilities Commission (CPUC). However, electrical generating systems operated by municipalities and government agencies are not regulated by the CPUC. Also, is the term "utility" meant to apply to qualifying facilities, which in fact are regulated but regulated on a limited basis by the CPUC? It is not certain whether QF's would be considered utilities because they are excused from most regulations, but they are regulated in that limited sphere. There would be a question as to whether they would not qualify as a utility by your definition.

SDG&E WORKSHOP COMMENT

Municipal utilities are not regulated by the CPUC. Under typical industry circumstances a QF is not considered a utility. The pricing provisions, if they sell to an IOU, are regulated by the CPUC but in terms of anything beyond the pricing, they are not typically considered a public utility. A QF would not be considered a utility by either by the CPUC, or any statues affecting them, nor by the Public Utilities Holding Company Act.

DISTRICT RESPONSE

The term "utility" would apply to a qualifying facility if it is meets the rule definition and is regulated by the CPUC. However, the rule uses the term utility in the context of the annual emissions cap and the waiver from NOx emission offsets under New Source Review. Since these issues, as well as the capacity factor thresholds of the rule, were developed specifically with reference to San Diego Gas and Electric Company operations, and in order to ensure that the applicability of these provisions is clear, the District has revised the proposed rule to apply these provisions specifically to existing SDG&E facilities and to any new, modified or replacement units, operated by SDG&E or by any other power producer. The term "utility" is no longer used in the rule and has been deleted.

9. **CEC WORKSHOP COMMENT**

Regarding the proposed definition of "utility" in Rule 69, if it encompass qualifying facilities (QF's), does that mean that according to Section (d)(9) their emissions from boilers greater 100 million BTU's per hour would be counted in the annual emissions cap?

SDG&E WORKSHOP COMMENT

From a practical administrative perspective, it would be impossible to have an entity outside of the SDG&E system fall under the same cap - to try to allocate a portion of that cap to a company over which SDG&E would have no control. I believe it would make an enforcement nightmare for the District also.

DISTRICT RESPONSE

The District's intent was not to have independent power producers (i.e. QF's), either individually or collectively, under the same cap as SDG&E. The annual emissions cap was developed based on projected future operations of SDG&E. If an independent power producer were to locate in the County it would be required to meet the emission rate limits of Rule 69 as well as the requirements of the District's New Source Review rules - Best Available Control Technology, air quality impact analysis, Lowest Achievable Emission Rate, emission offsets, etc. The cap was not intended to apply to each QF as a utility.

The District has decided to modify proposed Rule 69 to deal more clearly with this issue. The proposed rule will specify that the annual emission cap will apply to emissions from existing, modified, replacement and new units operated by SDG&E. The term utility will be removed. The rule will also specify that if in the future an independent power producer were to propose to operate a new or replacement unit and the power producer were to demonstrate, using forecasting methods approved by the Air Pollution Control Officer and the California Energy Commission, that the NOx emissions from the new or replacement unit would be completely offset by emissions associated with electrical generation displaced by the project from the SDG&E E system, the project could also qualify for the waiver of NOx emission offsets required under New Source Review.

10. **CEC WORKSHOP COMMENT**

Do you know if there are any existing QF's that would be subject to the requirements of your rule?

DISTRICT RESPONSE

None that the District is aware of.

11. **CEC WORKSHOP COMMENT**

Is there any problem with specifically identifying San Diego Gas & Electric by name as the one utility subject to this rule?

DISTRICT RESPONSE

In order to ensure that the rule provisions are applied appropriately, the rule will be revised to specifically refer to existing, new and replacement units operated by SDG&E with regard to the provisions that are currently applied to utilities. The remainder of the rule provisions will continue to apply to all electrical generating steam boilers, new units and replacement units, regardless of ownership.

12. **SDG&E WORKSHOP COMMENT**

Paragraph (e)(1)(i) of the proposed rule would probably apply to our Silvergate power plant. It would create a situation where we would not be able to bring that plant back on-line unless we had first retrofitted the Silvergate units to comply with Rule 69. There should be some provision made that would allow SDG&E to identify a compliance schedule for the Silvergate plant consistent with all other SDG&E units, regardless of whether or not the Silvergate units have been operating. Such a provision would give us time to do the necessary engineering and retrofitting or whatever instead of having to immediately go in and try to do something on a unit that hasn't operated for ten years, before we could bring it back. Nor would we be able to do some of the preliminary testing and engineering necessary to determine what kind of retrofit is actually required for those units, unless they are operating. Our current resource plan has us possibly bringing that unit back on-line as early as next summer under some resource plan scenarios and we would not be able to retrofit that unit by that time. There would be insufficient time and information to develop and implement a compliant retrofit system in the period.

DISTRICT RESPONSE

The District agrees and will modify paragraph (e)(1)(i) to only require that new and replacement units be in compliance on and after initial startup.

13. **WORKSHOP COMMENT**

Paragraph (f)(1) talks about continuous emission monitors to record and preserve emissions information in the manner and form prescribed by the APCO. What does the APCO have in mind for this? What form? What manner? Any guidance available?

DISTRICT RESPONSE

Rule 69(f) provides specific guidance on what information must be monitored and recorded, and with what frequency. Guidance on certification of continuous emissions monitors is available from the District's Monitoring and Technical Services staff. Operators required to install such monitors would be expected to consult with District technical staff, investigate available systems, choose a system which would meet rule requirements as well as operator needs, and propose the system to the District for approval. SDG&E already has a system of continuous emission monitors for their units. Those monitors could continue to collect that information, plus the additional information necessary to arrive at an emission rate, to accumulate that information, process it by computer and have available printouts of the hourly and daily information such as the pounds of NOx and megawatt-hours of electricity generated for each unit.

14. **WORKSHOP COMMENT**

Could the utility submit their existing equipment for approval by the APCO?

DISTRICT RESPONSE

Yes, if it meets the requirements specified in Section (f). Some modifications, or system additions may be necessary to comply with requirements.

15. **WORKSHOP COMMENT**

Does the APCO have any scheduling requirements on this (CEM's) as far as being submitted, how long does it take for the APCO to review it, etc. If the utility is limited to operating with a continuous emissions monitoring system that has been approved, then they need to apply accordingly.

DISTRICT RESPONSE

Rule 69 provides for a compliance plan to be submitted six months after adoption of the rule. This would mean that in the first half of 1994, operators will be required to submit the initial compliance plan. Thereafter there is an annual compliance report where the plan is updated. The monitoring required by this rule must be in place by January 1, 1997. The District anticipates that an operator subject to the rule would, as part of their compliance plan, propose a monitoring system that would meet the rule requirements. The District will likely need up to six months for the approval process. The operator will also need to consider the time needed to install a monitoring system or implement any changes to an existing monitoring system - additional monitors, additional software, hardware, etc. - in order to meet the January 1, 1997 compliance date.

16. <u>WORKSHOP COMMENT</u>

Even though the compliance plan required in Subsection (e)(2) does not specifically state that the proposed emission monitoring system should be included, you are implying that it should.

<u>DISTRICT RESPONSE</u>

Yes. The compliance plan, and subsequent reports, should address the schedule or status of compliance with all applicable requirements, including the requirements for continuous monitors.

17. <u>SDG&E WORKSHOP COMMENT</u>

When is the rule scheduled to go before the Board of Supervisors for adoption?

<u>DISTRICT RESPONSE</u>

The rule workshop report and socioeconomic impact analysis should be completed by the end of August, 1993. Final rule revisions to address ARB, EPA and SDG&E concerns should be completed by that time. To date, the District has received no formal written comments from ARB, nor complete comments from EPA. If all comments are received and necessary changes can be made by the end of July, the revised rule proposal, workshop report and socioeconomic analysis will be made available for 30 days for public review and comment. Following the close of that comment period, the rule will be considered by the Air Pollution Control District Advisory Committee, then docketed with the Board for public hearing. The rule hearing date will likely not be until December, 1993.

18. <u>CEC WORKSHOP COMMENT</u>

With regard to Subsection (d)(8), a new cogeneration power plant would have to install Best Available Control Technology (BACT) or they would have to have an emission rate lower than 0.15 lbs/MW-hr. However, some days cogeneration power plants are producing more heat than power. Then the emission rate limit in pounds per megawatt-hour may be more stringent than the BACT requirement. Thus, you could have an emission concentration of 2 or 3 ppm NOx, yet still exceed the daily pounds per megawatt-hour limit because the megawatt-hours generated is low compared to the energy used to produce heat. This should be considered.

<u>SDG&E WORKSHOP COMMENT</u>

There is one circumstance where this concern might apply and that is if there was a desalinization plant associated with a replacement unit. In such a case a significant amount of heat may go to desalinization instead of energy production.

<u>DISTRICT RESPONSE</u>

The District agrees. Subsection (d)(8) has been clarified to specify that in the case of a cogeneration unit subject to the rule, the NOx emissions shall be prorated by the ratio of the electrical energy generated to the total energy produced by the unit for purposes of comparing the NOx emission rate per megawatt-hour of electrical energy produced, after application of BACT, to the NOx emission rate limit specified in paragraph (d)(2)(i).

19. **EPA WRITTEN COMMENT**

Subsections (a)(2), (d)(8), (d)(10) and (e)(2)(ii). Rule 69 cannot be approved as a revision to the SIP until Rules 68, 20.1 and 19.3 have also been approved into the SIP.

DISTRICT RESPONSE

Rule 68 is being revised to apply federally mandated RACT to identified major sources of NOx. The revised rule will be adopted in 1994 and submitted to EPA as a SIP revision. Rule 20.1 is a part of the District's New Source Review rules, a version of which is part of the SIP. Those rules are also being revised to meet more stringent federal and state mandated requirements for permitting of new sources. When revised, Rule 20.1 will be sent to EPA as a SIP revision. Rule 19.3 was adopted in early 1993, to meet a federal mandate for certified Emissions Statements for major sources of VOC and NOx emissions. It has been forwarded to EPA through ARB as a SIP revision. Because electrical generating steam boilers are already subject to the requirements of District Rule 68, and those requirements already meet the federal requirements for RACT for such boilers, the District has not yet decided if and when Rule 69 will be sent to EPA as a SIP revision.

20. **EPA WRITTEN COMMENT**

Subsection (g)(1). EPA policy requires that all non-EPA developed test methods be first evaluated and approved by the agency before any rule referencing those methods can be approved into a SIP. Method 20 should be submitted to EPA for evaluation since it has not yet been approved. It is also unclear to us whether or not Method 20 will be used to determine the NOx emissions in Subsection (g)(4). The five (5) minute or less averaging requirement does not appear to follow EPA guidelines since we are unaware of an accurate velocity measurement for such a short averaging time.

DISTRICT RESPONSE

Method 20 has been submitted to EPA for approval in conjunction with proposed Rule 69.2 to control NOx emissions from commercial and industrial boilers. The District has been informally notified by EPA that Method 20 will be approved for Rule 69.2. If Rule 69 is submitted to EPA as a SIP revision, the District will ensure that the reference test method has received EPA approval. The NOx emissions specified in Subsection (g)(4) will be developed from CEM data which will record NOx emission concentrations, exhaust gas temperatures and exhaust gas oxygen content. Exhaust gas flow rates will be either measured directly or determined from fuel flow rates. The former approach will need to meet the requirements of Part 75. If the latter approach is applied, or some combination of the two, relationships will be developed, through unit-specific testing, that will enable the exhaust gas flow rate to be determined from the fuel type and fuel flow rate. Exhaust gas NOx concentrations measured by the CEM's use the same scientific principles as Method 20 and will be validated by comparisons with parallel testing conducted using Method 20. These validations will be done in a manner to ensure the minimum measurement time specified by Method 20 is obtained.

21. **EPA WRITTEN COMMENT**

Subsection (d)(4)(iii). The language "do not exceed the limits in Subsections (d)(2)(i) and (d)(2)(ii)" is ambiguous since the emissions limit, EL, as defined will always be a value between Lg and 0.40, and Lg can be either 0.15 or 0.18 lb/MW-hr. The limit specified in (d)(2)(i) is 0.15 lb/MW-hr.

DISTRICT RESPONSE

There was a referencing error in the cited wording. It has been corrected to specify the limits in Subsections (d)(1)(i) and (d)(2)(i).

22. **EPA WRITTEN COMMENT**

Subsection (d)(11). It is unclear whether or not the District is requiring the lowest achievable emission rate (LAER) subject to the New Source Performance Standards (NSPS) for ammonia emission control. If LAER is not being required, an emissions limit may need to be specified.

DISTRICT RESPONSE

The District is not aware of any federal NSPS for ammonia emission sources either proposed or promulgated by EPA. Subsection (d)(11) does not require LAER for ammonia emissions. It requires that the emissions of ammonia be kept as low as possible but consistent with the requirements of the rule and protection of public health. The District will not specify an ammonia emission limit. Instead, each unit using ammonia will be evaluated for compliance with the NOx emission limits of the rule, will undergo a screening or formal health risk assessment to ensure protection of public health, and will be evaluated under New Source Review for potential increases in particulate emissions that may result from ammonia reactions with fuel oil constituents.

Given these evaluations will occur whether or not an ammonia emission limit is specified, it is not appropriate to prescribe an emission limit and thus unnecessarily fix a control equipment variable that an operator can use to affect the performance and costs of emission controls.

23. **EPA WRITTEN COMMENT**

Subsection (f)(2). We understand the District's intent in being general in specifying the guidelines for Continuous Emission Monitors (CEMs). However, the guidelines for CEMs as outlined in 40 Code of Federal Regulations (CFR) Part 60, Appendices B and F, and Parts 72 and 75, concerning acid rain and utility boilers, also need to be considered.

DISTRICT RESPONSE

The CEM requirements of Rule 69 are not intended to waive any other applicable requirements but rather to ensure that information needed to monitor compliance with Rule 69 is measured and recorded. Any other applicable requirements for CEM's contained in federal or state law, or District regulations, will continue to apply.

24. **EPA WRITTEN COMMENT**

Subsection (f) (2)(iv). Subsection (g)(5) is referenced but is not included.

DISTRICT RESPONSE

The correct reference to Subsection (g)(4) has been inserted.

25. **VENTURA APCD WRITTEN COMMENT**

Subsection (b)(1). This set of exemptions, especially (b)(1)(i), seems unnecessary since you have established in Section (a) that the rule applies to "electrical generating steam boilers". Do you really have electrical generating boilers in the 100 MMBTU range?

DISTRICT RESPONSE

The exemption level of 100 MMBTU per hour proposed in Rule 69 is consistent with the boiler NOx control tactic contained in the 1991 San Diego Regional Air Quality Strategy. There are five boilers in the County which have fuel input ratings between 150 and 270 MMBTU per hour. They are currently used for steam generation and are operated by a cogeneration company and by SDG&E. These boilers would become subject to the rule if they were to be also used for electrical generation in the future.

26. **VCAPCD WRITTEN COMMENT**

Subsection (c)(4) - "Capacity Factor". Since the rule regulates emissions from the boiler only, we think that actual fuel use and average boiler heat rate is the best way to determine capacity factor. In any event, the proposed definition is unclear on how "actual" use is determined; do you sum annual MW produced? Annual fuel use seems much easier to determine.

DISTRICT RESPONSE

The capacity factor used in Rule 69 is an annual capacity factor, not an instantaneous value. Annual megawatt-hours would be used to determine a unit's annual capacity factor. The actual megawatt-hour output of each boiler subject to the rule will be measured continuously under the rule. Thus, it will be already available for determining capacity factor.

27. **VCAPCD WRITTEN COMMENT**

Subsection (c)(10) - "Megawatt-Hour (MW-hr)". When you say "total electrical energy generation", it sounds like this is a unit capacity definition. MW-hr is just another unit of energy or work, like BTU's or foot-pounds. What is your intention here?

DISTRICT RESPONSE

The definition refers to the quantity of electrical energy produced by a boiler, new unit or replacement unit, not the capacity of that boiler or unit.

28. **VCAPCD WRITTEN COMMENT**

Subsection (c)(13) - "Startup" and Subsection (c)(4) - "Shutdown". Most of the SCE units in Ventura County are capable of sustained operation well under 25 percent capacity. The two-215 MW units operate down to 20 MW, or about 10 percent load; in our recent work on revising Rule 59, we discovered that these units operate below 20 percent load up to 13 percent of the year (about 730 hours per year). One 750 MW unit operates down to 250 MW, which is 33 percent, but the other operates down to 50 MW. We feel that startups must occur after periods of idle time when no fuel flows. Shutdowns should also involve a lack of fuel flow, although we don't exempt shutdowns because emission exceedances don't occur.

DISTRICT RESPONSE

The startup and shutdown periods, as defined in Rule 69, are also constrained by achieving the minimum required operating temperatures of the NOx control devices, as well as the 25 percent load level. The specific duration of these transients will be defined in permit conditions when the unit-specific NOx controls have been determined. In addition, to ensure that the startup and shutdown exemptions are not abused, emissions occurring during startups and shutdowns will be included in determining compliance with the annual NOx emission caps. It does not appear that there is any significant incentive for an operator to abuse these exemptions. However, should the District find that a significant amount of emissions are occurring under the proposed startup and shutdown provisions, the District will propose revisions to the rule to make the exemptions more restrictive.

29. **VCAPCD WRITTEN COMMENT**

Subsection (d)(4)(iv) and Subsection (d)(5)(iv). As you may know, EPA refused to accept this "ozone prediction" concept when we proposed it in Rule 59. The issue was resolved by adopting a separate Rule 59 with the offending section removed; EPA was willing to federally enforce this version. We have since amended the rule to prohibit all but emergency fuel oil use. SDG&E may not be willing to go "gas only" at this time, as SCE did, but be advised that EPA was inflexible on this issue. Attached is a copy of their comment letter on the subject.

DISTRICT RESPONSE

As noted above, proposed Rule 69 does restrict oil burning by limiting the NOx emissions rate during oil burning, restricting oil burning to those days when the state ozone standard is not expected to be exceeded, and basing the annual NOx emissions cap for SDG&E on gas burning only. The San Diego Air Basin is in attainment of both the federal and state NO_2 standards. Rule 69 is being proposed as a part of the District's state ozone attainment strategy although it should also help to maintain attainment of the NO_2 standards. The proposed NOx emission rate limit for most boilers burning oil represents a 67 percent reduction from the current emission rates when burning gas. Thus, even when oil burning occurs, the NO_2 ambient air quality standards should be protected. To ensure that progress towards attainment of the ozone standards is not compromised, Rule 69 would prohibit oil burning on those days when an exceedance of an ozone standard is predicted, except during periods of natural gas curtailment. The District has received no comments from EPA on this issue.

Proposed Rule 69
Electrical Generating Steam Boilers, Replacement Units and New Units

Generating Level Forecast Modeling for SDG&E
Summary

In evaluating an appropriate annual NOx emissions cap for the SDG&E system, the operation of the current system, with and without anticipated resource additions, was modeled under several scenarios. The following summarizes the scenarios modeled. Modeling performed by Henwood Energy Systems, Inc. (HES) was done for SDG&E and was based on ER-92 inputs. Modeling performed by the California Energy Commission (CEC) staff was done at the request of the Air Resources Board staff and was based on the ER-92 decision.

Scenario No.	Scenario Description	Max. Gen. (GWhr)	Max. NOx (Tons)	Year of Max.	Year above 800 tons
HES #1	Existing boilers. No repowers.	8769	838	2009	2008
HES #2	Repower So. Bay3, Encina 1&2	12,958	869	2009	2008
CEC #1	ER-92 resources, no In-County CC	8853	571	2005	N/A
CEC #2	CEC #1 with Songs 2 Outage	9966	645	2005	N/A
CEC #3	Delayed In-County CC & non-BRPU additions	11,554	666	2010	N/A
CEC #4	ER-92 resources, In-County CC, non-BRPU resources delay 5 yrs., Songs 2 out.	12,766	732	2010	N/A
CEC #5a	Existing boilers. No resources added.	10,294	926	2011	2005
CEC #5b	CEC #5a with Songs 2 outage.	10,776	970	2011	2002
CEC #6	Geothermal IDR's added.	9029	813	2011	2011
CEC #7	One repwr, geoth. IDR's added.	10,807	778	2011	N/A

AIR POLLUTION CONTROL DISTRICT

Proposed New Rule 69 is to Read as Follow:

RULE 69. ELECTRICAL GENERATING STEAM BOILERS, REPLACEMENT UNITS AND NEW UNITS

(a) APPLICABILITY

(1) Except as provided in Section (b) or otherwise specified in this rule, this rule is applicable to all electrical generating steam boilers, including any auxiliary boiler used in conjunction with an electrical generating boiler, and to replacement units and new units.

(2) Equipment subject to this rule shall also comply with the emission limitations and exemptions set forth in Rule 68.

(b) EXEMPTIONS

(1) The provisions of Section (d) shall not apply to:

(i) Any electrical generating steam boiler with a maximum heat input capacity of less than 100 million Btu's per hour.

(ii) Boilers which generate steam used exclusively for space heat or process heat and not used for electrical generation.

(2) The provisions of Subsection (d)(9) shall not apply to boilers, replacement units and new units, operated by any person other than the San Diego Gas and Electric Company (SDG&E) or a company in which SDG&E has a controlling interest.

(c) DEFINITIONS

For the purposes of this rule, the following definitions shall apply:

(1) **"Boiler"** means any combustion equipment fired with solid, liquid and/or gaseous fuels and used to produce steam, excluding electrical generating gas turbines.

(2) **"Calendar Day"** means the 24-hour period starting on the 00:00 hour and ending on the 24:00 hour.

(3) **"Calendar Year"** means the consecutive 12-month period beginning January 1 and ending December 31.

(4) **"Capacity Factor"** means the fraction of an electrical generating steam boiler's, replacement unit's or new unit's maximum electrical generating capacity that is actually utilized during a calendar year. The maximum electrical generating capacity shall be determined by multiplying the maximum rated capacity of a boiler, replacement unit or new unit, in megawatts, by 8760 maximum operating hours per year (8784 hours for a leap year).

(5) **"Clock Hour"** means every 60-minute period starting on the hour.

(6) **"Electrical Generating Steam Boiler"** means any boiler used to produce steam to be expanded in a turbine generator used for the generation of electric power.

(7) **"Electrical Generating Gas Turbine"** means any combustion turbine fired with solid, liquid and/or gaseous fuels and used to provide direct shaft work for the generation of electric power.

(8) **"Force Majeure Natural Gas Curtailment"** means an interruption in natural gas service such that the daily fuel needs of a boiler or replacement unit subject to this rule cannot be met with the natural gas available due to:

(i) Unforeseeable natural disaster or other cause resulting in the failure or malfunction of natural gas supply, delivery or storage system facilities, not resulting from an intentional or negligent act or omission on the part of an owner or operator of a boiler, a new unit or a replacement unit, or

(ii) A supply restriction resulting from a California Public Utilities Commission priority allocation ruling, or

(iii) Delivery restrictions due to pipeline capacity limitations of the natural gas supplier or upstream transports or within a gas utility's delivery system.

(9) **"Heat Input"** means the heat derived from combustion of fuel in an electrical generating unit and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc. The maximum heat input rating means the lesser of the steady state heat input capacity of an electrical generating unit, as limited by its design and construction or as limited by an Authority to Construct or Permit to Operate.

(10) **"Megawatt-hour (MW-hr)"** means the total electrical energy generation of a boiler, new unit or replacement unit subject to this rule.

(11) **"New Unit"** means any electrical generating steam boiler or gas turbine for which the first Authority to Construct is issued on or after (*date of adoption*).

(12) **"Replacement Unit"** means any electrical generating steam boiler or gas turbine which permanently replaces or augments, on or after (*date of adoption*), an existing electrical generating steam boiler subject to this rule. For purposes of this rule, a replacement unit need not be limited to the same electrical generating capacity as the existing boiler being replaced.

(13) **"Startup"** means the period of time during which a boiler, replacement unit or new unit, and associated emissions control device(s) are being heated to the minimum functional operating temperatures of the emission control device(s), or when electrical generation equals or exceeds 25 percent of rated capacity, whichever is sooner.

(14) **"Shutdown"** means the period of time during which a boiler, replacement unit or new unit, and its associated emissions control device(s) are allowed to cool from the minimum functional operating temperatures of the emission control device(s) or when electrical generation drops below 25 percent of rated capacity, whichever is later.

(d) STANDARDS

A person shall not operate an electrical generating steam boiler, replacement unit or new unit subject to this rule unless only natural gas, alternative fuel and/or fuel oil is burned and the following requirements are met. If an alternative fuel is burned, the operator shall have previously demonstrated to the satisfaction of the Air Pollution Control Officer that the emissions of oxides of nitrogen (NOx) per megawatt-hour of electricity generated is not greater than would be the emissions from the burning of natural gas in the same boiler, replacement unit or new unit.

(1) Except as provided in Subsections (d)(2) through (d)(6), a person shall not operate an electrical generating steam boiler unless:

(i) The emissions of oxides of nitrogen, expressed as nitrogen dioxide, from the boiler do not exceed 0.15 pounds per megawatt-hour, and

(ii) The person has met the compliance schedule specified in Section (e).

(2) Except as provided in Subsections (d)(3), (d)(4) and (d)(5), the San Diego Gas & Electric Company (SDG&E) shall not operate the electrical generating steam boilers listed below unless the emissions of oxides of nitrogen, expressed as nitrogen dioxide, from the boiler do not exceed 0.18 pounds per megawatt-hour and SDG&E has met the compliance schedule specified in Section (e).

Encina Power Plant Units 1, 2, 3 and 4
South Bay Power Plant Units 1,2 and 4

(3) The provisions of Subsection (d)(2) shall not apply and the provisions of Subsection (d)(1) shall apply if the capacity factor of an electrical generating boiler with a maximum heat input rating of equal to or greater than 2100 million Btu's per hour is greater than 0.15 over any calendar year.

(4) Fuel Oil Firing NOx Emission Rate Limits

A person shall not operate an electrical generating steam boiler when burning fuel oil unless:

(i) The requirements of Subsection (d)(1), (d)(2) or (d)(3), as applicable, are met by the operator of an affected boiler when burning natural gas exclusively in that boiler, and

(ii) The emissions of oxides of nitrogen, expressed as nitrogen dioxide, from an affected boiler do not exceed 0.40 pounds per megawatt-hour when burning fuel oil exclusively in that boiler, and

(iii) The emissions of oxides of nitrogen, expressed as nitrogen dioxide, from the boiler when fired on a mixture of fuel oil and natural gas do not exceed the limits prescribed in Subsections (d)(4)(i) and (d)(4)(ii), prorated for the relative heat input from fuel oil and natural gas, as follows:

$$EL = \frac{[(Lo)(Qo)(HHVo)] + [(Lg)(Qg)(HHVg)]}{(Qo)(HHVo) + (Qg)(HHVg)}$$

where,

EL	=	Emission limit, pounds per megawatt-hour
Lo	=	0.40 pounds per megawatt-hour
Qo	=	Quantity of fuel oil burned, barrels per hour
HHVo	=	Higher heating value of fuel oil, Btu's per barrel
Lg	=	0.15 or 0.18 pounds per megawatt-hour, as applicable
Qg	=	Quantity of natural gas burned, scf per hour
HHVg	=	Higher heating value of natural gas, Btu per scf,

and

(iv) The Air Pollution Control Officer has determined that an exceedance of the state ambient air quality standard for ozone is not predicted at any location in the air basin at any time during the fuel oil burning. This paragraph shall not apply when burning of fuel oil is required due to a force majeure natural gas curtailment. Prior to January 1, 1997, this paragraph shall not apply to fuel oil burning in the existing SDG&E South Bay Power Plant Unit 4 boiler on days when fuel oil burning is needed to meet peak electrical generation demand.

(5) Low Capacity Factor Boiler NOx Emission Rate Limits

The provisions of Subsections (d)(1)(i), (d)(2)(i) and (d)(4)(i), (ii) and (iii), shall not apply to the operation of SDG&E's existing electrical generating steam boilers located at the Silvergate Power Plant nor to the existing Unit 4 boiler at the South Bay Power Plant provided:

(i) The capacity factor for each such boiler, over each calendar year, does not exceed 0.10, and

(ii) The emissions of oxides of nitrogen, expressed as nitrogen dioxide, do not exceed 0.60 pounds per megawatt-hour when burning natural gas, and

(iii) Fuel oil shall not be burned in the Silvergate Power Plant boilers, and may only be burned in the South Bay Unit 4 boiler during force majeure natural gas curtailments on and after January 1, 1997. Prior to January 1, 1997, this limitation shall not apply to fuel oil burning in the South Bay Power Plant Unit 4 boiler on days when fuel oil burning is needed to meet peak electrical generation demand. The emissions of oxides of nitrogen, expressed as nitrogen dioxide, from the South Bay Unit 4 boiler when burning fuel oil shall not exceed 1.20 pounds per megawatt-hour and when fired on a mixture of fuel oil and natural gas shall not exceed the limits prescribed in Subsections (d)(5)(ii) and (d)(5)(iii), prorated for the relative heat input from fuel oil and natural gas, as follows:

$$EL = \frac{[(Lo)(Qo)(HHVo)] + [(Lg)(Qg)(HHVg)]}{(Qo)(HHVo) + (Qg)(HHVg)}$$

where,

EL	=	Emission limit, pounds per megawatt-hour
Lo	=	1.20 pounds per megawatt-hour
Qo	=	Quantity of fuel oil burned, barrels per hour
HHVo	=	Higher heating value of fuel oil, Btu's per barrel
Lg	=	0.60 pounds per megawatt-hour
Qg	=	Quantity of natural gas burned, scf per hour
HHVg	=	Higher heating value of natural gas, Btu per scf,

and

(iv) The Air Pollution Control Officer has determined that an exceedance of the state ambient air quality standard for ozone is not predicted at any location in the air basin at any time during the fuel oil burning. This paragraph shall not apply when burning of fuel oil is required due to a force majeure natural gas curtailment.

(6) Compliance with the standards of Subsections (d)(1) through (d)(5) shall be based on emissions of oxides of nitrogen from an affected boiler averaged over each calendar day of operation, or portion thereof, excluding periods of startups and shutdowns.

(7) Startups and Shutdowns

The provisions of Subsections (d)(1)(i), (d)(2)(i), (d)(3), (d)(4) and (d)(5) shall not apply to electrical generating steam boilers during periods of startup or shutdown provided the startup or shutdown does not exceed fifteen hours.

(8) Replacement Units and New Units NOx Emission Rate Limits

Notwithstanding the requirements of Subsections (d)(1) through (d)(7), no person shall operate a replacement unit or new unit subject to this rule unless such unit has been built with, and is operated in conjunction with, Best Available Control Technology as defined in Rule 20.1 for emissions of oxides of nitrogen. Emissions of oxides of nitrogen from any replacement unit or new unit shall not be greater than the emission rate limit of Subsection (d)(1)(i) except that for a cogeneration unit which generates process steam as well as electricity, the emissions of oxides of nitrogen per megawatt-hour of electrical energy generated shall be determined by prorating the total unit emissions of oxides of nitrogen by the ratio of the gross electrical energy generated to the total energy produced by the unit.

(9) Aggregate NOx Emission Limit for Utilities

Except as provided in Subsection (d)(10), neither SDG&E nor any company in which SDG&E has a controlling interest shall operate any electrical generating steam boiler, replacement unit or new unit subject to this rule unless SDG&E or such company has demonstrated that the aggregate emissions of oxides of nitrogen, expressed as nitrogen dioxide, from all boilers, replacement units and new units, located in San Diego County and owned or operated by SDG&E, and any boilers, replacement units and new units that are owned or operated by a company in which SDG&E has a controlling interest, are not greater than:

(i) On and after January 1, 1997, 2100 tons during every calendar year.

(ii) On and after January 1, 2001, 800 tons during every calendar year.

The annual oxides of nitrogen emission limits specified in this subsection shall be adjusted to account for fuel oil burning that results from a force majeure natural gas curtailment or is due to compliance emissions testing. The adjustment shall be made by adding to the applicable limit the product of the megawatt-hours generated by each boiler, replacement unit, or new unit during such fuel oil burning and the difference between the applicable oxides of nitrogen emission rate limits for fuel oil burning and natural gas burning in that boiler, replacement unit or new unit. The adjustment shall be prorated for the relative heat inputs of fuel oil and natural gas when co-firing both fuels.

(10) Exceedances of an Aggregate NOx Emission Limit

SDG&E, or a company in which SDG&E has a controlling interest, may operate its electrical generating steam boilers, replacement units and new units when aggregate oxides of nitrogen emissions exceed the calendar year limits specified in Subsection (d)(9) provided:

(i) SDG&E or such company has demonstrated, to the satisfaction of the Air Pollution Control Officer, that the exceedance is due to an unforeseen event, such as a forced outage of one or more generating units or a disruption in the supply of imported power, and is not due to an intentional or negligent act or omission on the part of SDG&E or such company, and

(ii) The Air Pollution Control Officer has approved the exceedance in advance and has issued modified permits to operate for the affected equipment adding conditions that establish a new, enforceable calendar year aggregate emission limit, and

(iii) SDG&E or such company has provided offsetting emission reductions, on an annual basis and at a 1.3 to 1.0 offset ratio, for all emissions of oxides of nitrogen in excess of the calendar year limits specified in Subsection (d)(9).

The new calendar year aggregate oxides of nitrogen emission limit established pursuant to Subsection (d)(10)(ii) above, shall be based on the maximum expected calendar year emissions in compliance with this rule. The quantity of offsetting emission reductions required shall be 1.3 times the difference between the new calendar year aggregate oxides of nitrogen emission limit and the applicable calendar year limit specified in Subsection (d)(9). Offsetting emission reductions shall conform to the criteria for emission offsets specified in Rule 20.1.

(11) Waiver from New Source Review NOx Offset Requirements

Oxides of nitrogen emission increases from any new, modified or replacement units owned or operated by SDG&E or a company in which SDG&E has a controlling interest, subject to and in compliance with Subsections (d)(9) and (d)(10) of this rule, shall not be subject to the offset provisions of Rule 20.4 of these Rules and Regulations. Only oxides of nitrogen emission increases associated with generating capacity which the California Energy Commission or the California Public Utilities Commission has determined a need for shall be eligible for this waiver.

A new unit or replacement unit that is owned or operated by a person other than SDG&E and in which SDG&E does not have a controlling interest may qualify for this waiver of oxides of nitrogen emission offset requirements provided that the new or replacement unit has a maximum electrical generating capacity of 50 megawatts or greater and the owner or operator demonstrates, to the satisfaction of the Air Pollution Control Officer, that the emissions of oxides of nitrogen from the new or replacement unit will be offset, in their entirety and at a 1.0 to 1.0 ratio, by a reduction in emissions of oxides of nitrogen, above and beyond the reductions in emissions of oxides of nitrogen required by this rule, from existing electrical generating steam boilers, modified boilers, replacement units or new units owned or operated by SDG&E or a company in which SDG&E has a controlling interest. Such demonstration shall be made using electrical generation forecasting models and analysis techniques approved by the Air Pollution Control Officer and the California Energy Commission for this purpose. Only oxides of nitrogen emission increases associated with generating capacity which the California Energy Commission or the California Public Utilities

Commission has determined a need for shall be eligible for this waiver. If a new or replacement unit is approved pursuant to this subsection, the Air Pollution Control Officer may impose permit conditions that limit the calendar year emissions of oxides of nitrogen from such unit. Such limit may only be increased pursuant to the provisions of Subsection (d)(10).

(12) Emission Standards for Ammonia

The emissions of ammonia from any electrical generating steam boiler, replacement unit or new unit subject to the requirements of this rule, or from any emissions control device used to achieve compliance with this rule, shall not be greater than the lowest emission rate achievable, consistent with the requirements of this rule, taking into consideration the costs of achieving that emission rate and the potential public health impacts associated with such emissions.

(13) Banking of Excess Emission Reductions

No person shall be eligible to obtain emission reduction credits for emissions of oxides of nitrogen below the limits specified in this Section (d).

(e) COMPLIANCE SCHEDULE

(1) Increments of Progress

A person subject to the provisions of Section (d) shall comply with the following increments of progress:

(i) Any replacement unit or any new unit shall be in compliance with the applicable requirements of Section (d) on and after initial startup.

(ii) Not later than *(3 years after date of adoption)*, be in compliance with the applicable requirements of Section (d) for not fewer than one electrical generating steam boiler, replacement unit or new unit and each calendar year thereafter bring into compliance a minimum of one additional boiler, replacement unit or new unit owned or operated by such person.

(iii) Except as provided in Subsection (e)(1)(iv) below, on and after January 1, 2001, be in compliance with the requirements of Section (d) for all operating electrical generating steam boilers, replacement units and new units owned or operated by such person.

(iv) Be in compliance with Section (d) by January 1, 2003, or upon initial startup, whichever is sooner, for all replacement units, and associated boiler(s), scheduled for initial startup between January 1, 2001 and January 1, 2003.

(2) Compliance Plan/Report

(i) The owner or operator of any equipment subject to the provisions of this rule shall submit by (*six months after date of adoption*) a Compliance Plan describing the actions, and contingencies, which are proposed by the owner or operator to meet the requirements of Section (d) and Subsection (e)(1). The Compliance Plan shall contain, at a minimum, the following applicable information for each electrical generating steam boiler, replacement unit and new unit subject to this rule:

- District Permit to Operate number.
- Equipment location.
- Manufacturer.
- Model number.
- Maximum permitted heat input rating.
- Primary and backup fuels to be used.
- Proposed method to measure and record megawatt-hours generated and watt transducer calibration method with supporting documentation.
- Maximum hourly, daily and annual pre-controlled NOx emission rates.
- Method and type of emission controls to be used.
- Expected performance of the emission controls.
- Proposed schedule for applications for Authorities to Construct, issuing purchase orders for emission controls, commencing construction, completing construction, conducting compliance tests and demonstrating compliance with the provisions of this rule.

The initial Compliance Plan submittal need not contain detailed information regarding emission control specifications, performance and schedules, but must contain at least preliminary information regarding the type of control equipment and the anticipated final compliance date for each affected unit. A copy of the Compliance Plan shall be kept at each affected site and shall be made available for District inspection upon request. Adherence to a Compliance Plan does not relieve the owner or operator from complying with any other provisions of this rule. The Compliance Plan shall be updated annually.

(ii) The owner or operator of any equipment subject to the provisions of this rule shall submit by the submittal date in 1997 of the Emissions Statement Form(s) required by Rule 19.3, and each year thereafter, a Compliance Report which describes the measures taken in the preceding calendar year to achieve compliance with the requirements of Section (d) and Subsection (e)(1). The Compliance Report shall contain, at a minimum, the following information for the preceding calendar year for each electrical generating steam boiler, replacement unit and new unit subject to Section (d) of this rule:

- District Permit to Operate number.
- Number of hours of operation.
- Types and amounts of fuels consumed, and the number of hours on each fuel type.
- Dates and times of any force majeure natural gas curtailments that occurred.
- Mass emissions of oxides of nitrogen for each calendar day and for the calendar year.
- Megawatt-hours generated each calendar day and for the calendar year.
- Indication of whether the unit is on schedule to meet the Compliance Plan(s) submitted pursuant to Subsection (e)(1).
- Identification of each exceedance of the applicable requirements of Section (d).

The Compliance Report shall also contain any proposed revisions to the Compliance Plan. These revisions shall include the justification for the changes and a demonstration that the changes will ensure compliance with the requirements of Section (d) and Subsection (e)(1).

Documentation and calculations used to prepare the material presented in the Compliance Report shall be maintained by the owner or operator for at least two years and shall be made available to the District upon request.

(f) RECORDKEEPING

(1) On and after January 1, 1997, neither SDG&E, any company in which SDG&E has a controlling interest, nor any owner or operator of a new or replacement unit permitted pursuant to Subsection (d)(11) shall operate any electrical generating steam boiler, replacement unit or new unit subject to this rule unless such boiler or unit is equipped with continuous emission monitors which record and preserve, on a daily basis and in the manner and form prescribed by the Air Pollution Control Officer, all of the information needed to demonstrate compliance with Subsections (d)(9) and (d)(10) of this rule, including but not limited to:

(i) The daily emissions, in pounds, of oxides of nitrogen from each boiler, replacement unit or new unit;

(ii) The aggregate daily emissions, in pounds, of oxides of nitrogen from all such boilers, replacement units or new units;

(iii) The cumulative annual emissions, in tons, of oxides of nitrogen, commencing with January 1 of the current calendar year, for each such boiler, replacement unit or new unit; and

(iv) The cumulative annual emissions, in tons, of oxides of nitrogen, commencing with January 1 of the current calendar year, for the aggregate of all such boilers, replacement units or new units under common ownership or control.

(2) On and after the final compliance date specified in the Compliance Plan, a person shall not operate any electrical generating steam boiler, replacement unit or new unit subject to this rule unless such boiler or unit is equipped with continuous monitors, approved by the Air Pollution Control Officer, which record and preserve all of the information needed to determine compliance with Subsections (d)(1) through (d)(5) and (d)(7), including but not limited to:

(i) The hours of operation of the unit.

(ii) The emission concentration of oxides of nitrogen, calculated as parts per million by volume (ppmv) of nitrogen dioxide at three percent oxygen on a dry basis, averaged over every clock hour of operation, or portion thereof. The emission concentration shall be measured at equally spaced intervals, not to be less frequent than once every five minutes, and averaged up to each clock hour, or portion thereof. Only the clock hour average data, or portion thereof, must be recorded and preserved.

(iii) The unit exhaust flue gas flow rate, calculated as cubic feet per hour at standard conditions and at three percent oxygen on a dry basis, averaged over every clock hour of operation, or portion thereof. The exhaust flue gas flow rate shall be measured at the same interval as emission concentration measurements. If unit exhaust flue gas flow rate is not measured directly but instead calculated from fuel flow rate or other operating parameter, such parameter shall be measured at the specified concentration measurement interval, the parameter measurement shall be recorded, and the exhaust flue gas flow rate shall be calculated for each such interval. The exhaust flue gas flow rate measurements shall be averaged up to each clock hour, or portion thereof. Only the clock hour average data, or portion thereof, must be recorded and preserved.

(iv) The emissions of oxides of nitrogen shall be calculated, as pounds of nitrogen dioxide, during every interval of emission concentration measurement using the emission concentration and exhaust flue gas flow rate measurements required in Subsections (f)(2)(ii) and (f)(2)(iii) above. The emissions of oxides of nitrogen during every clock hour of operation, or portion thereof, shall be calculated by summing the emissions calculated for each measurement interval, following the methods described in Subsection (g)(5), and shall be recorded.

(v) The megawatt-hours of electrical energy generated by the unit during every clock hour of operation, or portion thereof shall be measured and recorded.

(vi) The cumulative emissions of oxides of nitrogen, expressed as pounds of nitrogen dioxide; the total megawatt-hours of electrical energy generated; and, the average emission rate of oxides of nitrogen, expressed as pounds of nitrogen dioxide per megawatt-hour of energy generated, for every calendar day of operation, or portion thereof, shall be calculated and recorded.

The records required by this section shall be retained on site for at least three years and shall be made available to the District upon request. Records of aggregate daily emissions required by Subsection (f)(1)(ii) shall be available within two working days of a request. Records of cumulative annual emissions required by Subsections (f)(1)(iii) and (f)(1)(iv) shall be available within twenty working days of a request.

(g) TEST METHODS

The following methods shall be used to determine compliance with the requirements of this rule:

(1) Oxides of nitrogen emissions shall be measured utilizing District modified Method 20, as it exists on *(date of adoption)*. This method shall not apply to continuous emission monitors required by Subsections (f)(1) and (f)(2).

(2) Total energy generation in megawatt-hours shall be measured using watt transducers calibrated according to methods approved by the Air Pollution Control Officer. The methods shall be submitted by the owner or operator of a boiler or unit as part of the compliance plan required by Subsection (e)(2), and shall include a description of the principal of measurement, the frequency of measurement and basis therefore, and the calculations used to determine the megawatt hours (MW-hr) generated. The method shall also include the techniques and procedures used to calibrate each measurement device. Each measurement device shall be calibrated against standards which are based on the National Institute of Standards and Technology (NIST) standards or equivalent if no NIST standards exist. The calibration accuracy tolerance of each measurement device shall be (+/-) 0.5 percent of each measured value.

(3) The oxides of nitrogen (NOx) emission rate, in pounds per megawatt-hour, for each clock hour of operation, or portion thereof, for each boiler subject to the requirements of Subsections (d)(1) or (d)(2), shall be calculated as follows:

$$NOx_{lb/MW\text{-}hr} = \frac{NOx_{lb}}{MW\text{-}hr_{Total}}$$

where,

$NOx_{lb/MW\text{-}hr}$ = NOx emission rate in lb/MW-hr, for each clock hour of operation, or portion thereof.

NOx_{lb} = NOx emissions in pounds during each clock hour, as calculated in Subsection (g)(4) below.

$MW\text{-}hr_{Total}$ = Total megawatt-hours generated for each clock hour.

(4) The emissions of oxides of nitrogen (NOx) for each applicable unit during each clock hour, or portion thereof, shall be calculated as follows:

$$NOx_{lb} = \sum_{i=1}^{n} NOx_i$$

where,

NOx_{lb} = Emissions of oxides of nitrogen, in pounds, during each clock hour of operation.

NOx_i = Emission of oxides of nitrogen, in pounds, calculated for each five minute or shorter time interval within each clock hour, or portion thereof.

n = Number of valid data points during each clock hour of operation, or portion thereof. There shall not be fewer than 10 valid data points during each clock hour.

Emissions occuring during periods of no electrical generation shall not be included when calculating oxides of nitrogen emissions per megawatt-hour but shall be included when calculating aggregate oxides of nitrogen emissions for a calendar year.

DRAFT
SOCIOECONOMIC IMPACT ANALYSIS
EXECUTIVE SUMMARY

of

PROPOSED RULE 69

ELECTRICAL GENERATING STEAM BOILERS, REPLACEMENT UNITS AND NEW UNITS

September 20, 1993

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DRAFT
September 20, 1993

SOCIOECONOMIC IMPACT ANALYSIS EXECUTIVE SUMMARY PROPOSED RULE 69

I. BACKGROUND

Effective January 1, 1992, state law[1] requires that whenever the District intends to propose the adoption, amendment or repeal of a rule or regulation significantly affecting air quality or emission limitations, a socioeconomic impact assessment must be prepared, to the extent data are available. The Air Pollution Control Board (Board) is also required to consider socioeconomic impacts and make good faith efforts to minimize adverse impacts. State law specifies the following six elements be included in a socioeconomic impact assessment:

1. Identification of the types of industries or business, including small business[2], affected by the rule or regulation;
2. The impact of the rule or regulation on employment and the economy of the region;
3. Examination of the range of probable costs to industry or business, including small business, of the rule or regulation;
4. The availability and cost effectiveness of alternatives to the rule or regulation being proposed or amended;
5. The emission reduction potential of the rule or regulation; and
6. The necessity of adopting or repealing the rule or regulation to attain state and federal ambient air standards.

This socioeconomic impact assessment has been prepared for proposed Rule 69 (Electrical Generating Steam Boilers, Replacement Units and New Units) to satisfy these requirements. To help determine the impact of rules or regulations on employment and the economy of the region, the District has contracted with Regional Economic Models, Inc. (REMI) to prepare their EDFS-53 econometric model using San Diego County economic data and evaluate the impacts of proposed Rule 69.

On June 30, 1992, the Air Pollution Control Board adopted the 1991 San Diego Regional Air Quality Strategy to satisfy the requirements of the California Clean Air Act[3]. The Air Resources Board (ARB) conditionally approved the Strategy on November 12, 1992.

The Act's fundamental requirement is to reduce smog-generating emissions by five percent annually, measured from a 1987 baseline. Because this requirement cannot be met in San Diego, all feasible measures are included in the Strategy. Additionally, the Act requires Best Available Retrofit Control Technology for serious nonattainment areas, limiting emissions for existing

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[1] California Health and Safety Code §40728.5.

[2] A small businesses as defined under the federal Small Business Act (15 U.S.C. Sec. 631, et seq.) and employing 100 or fewer individuals, pursuant to California Health and Safety Code §42323.

[3] AB 2588, Sher (Ch. 1568, Stats. 1988).

permitted stationary sources based on the maximum degree of reduction achievable, considering environmental, energy, and economic impacts.

Included in the Strategy are control measures for reducing Reactive Organic Gases (ROG) and Oxides of Nitrogen (NOx), smog-forming pollutants, which are implemented when adopted as District rules. Proposed Rule 69 emission standards are consistent with the boiler NO_x control measure in the Strategy and satisfy Best Available Retrofit Control Technology and other state requirements.

II. SOCIOECONOMIC IMPACTS OF PROPOSED RULE 69

Proposed Rule 69 implements a Strategy NOx control measure by requiring additional emission controls on all electrical generating steam boilers, replacement units and new units in San Diego County with heat input ratings equal to or greater than 100 million Btu's per hour. The rule principally affects electric utility boilers currently operated by the San Diego Gas and Electric Company (SDG&E) and any new or replacement electric generating units operated by SDG&E or other companies.

NO_x emission limits of 0.15 or 0.18 pounds per Megawatt-hour are expected to be met through installation of selective catalytic reduction on all utility boilers in San Diego County with the exception of five low usage boilers. The low usage units will have an alternative emission standard of 0.6 pounds per Megawatt-hour which is expected to be met through installation of urea injection control systems, combustion modifications or a combination of techniques. The proposed rule would also set annual NO_x emission caps and limit fuel oil burning to days when exceedance of the state ambient air quality standard for ozone is not expected, except during periods of force majeure natural gas curtailments.

Retrofitting existing boilers with NO_x emission controls would begin in 1996 and must be completed by the year 2001, with at least one additional boiler equipped with emission controls each year. The rule allows an extension to January 1, 2003 for any units which are scheduled to be replaced or repowered between the year 2001 and 2003.

Existing electrical generating steam boilers operated by SDG&E in San Diego County are located at three power plants: the South Bay plant in Chula Vista, the Encina plant in Carlsbad, and the Silvergate plant in San Diego. The California Energy Commission and the California Public Utilities Commission have both concluded that SDG&E will need to add new electrical generation resources in the future. Consequently, repowering of some existing units, and/or the addition of new electrical generating equipment is likely in the future.

These future resource needs may be met by a competitive bidding process, allowing independent power producers and other electrical generating facilities to compete with SDG&E for the right to provide these new resources. Under the competitive bidding process, the new resources and their related emissions could be located in San Diego County, out-of-County, or both, and could be owned and operated by SDG&E or other companies. Proposed Rule 69 only affects in-County facilities, and only SDG&E and companies other than SDG&E that operate a new or replacement electrical generating unit. Due to the high capital costs of such projects[4] no small businesses are expected to be directly affected by proposed Rule 69.

[4] The proposed SDG&E South Bay Unit 3 repower project cost is estimated at $419 million.

Electric utility boilers represent the largest category of stationary source NOx emissions in San Diego. The Strategy projected reducing baseline emissions of 9.6 tons per day by 7.32 tons per day, or about 76 percent, to 2.28 tons per day using selective catalytic reduction control technology. NO_x emissions from SDG&E's utility boilers over the past five years (1988-1992) have averaged about 3,550 tons per year. Proposed Rule 69 requires that these emissions, and any NO_x emissions from new or replacement units, be reduced to not more than 2,100 tons per year on and after January 1, 1997, a reduction of 41 percent. Effective January 1, 2001, maximum annual NOx emissions are limited to 800 tons per year, a reduction of about 78 percent. The emission reductions required by Rule 69 also represent an overall reduction in NO_x emission rate per unit of electrical energy produced (pounds of NOx per Megawatt-hour) of approximately 87 percent.

SDG&E is expected to incur capital costs of up to $73 million[5]. Capital spending is expected to rise to a maximum of $20.6 million in 1995, and end in 2001 at $0.3 million. Total operating and maintenance costs were estimated to begin in 1996 at $0.5 million and increase to a constant annual amount of $3.0 million in 2002 and beyond. Increased costs are passed on to purchasers of electricity by a 2.17 percent increase in the cost of electricity for all the various industrial, commercial and residential rates.

Table 1: REMI EDFS 53 Model Key Outputs

Rule 69	1995	2010	Annual Average
Employment	183	-375	-355
% Change	.013	-.022	-.022
Small Business Employment	148	-219	-195
% Change	.019	-.022	-.023
Gross Regional Product (Billions 87$)	.005	-.021	-.026
% Change	.009	-.027	-.026
Population	60	-1,148	-808
% Change	.002	-.036	-.028

The EDFS-53 econometric model's key outputs are shown in Table 1, based on projected utility spending for compliance equipment and maintenance and the resulting increase in electric rates. Not reflected in the modeling analysis are economic effects from improved air quality, such as improved health and increased visibility. These benefits will be analyzed when the socioeconomic impact assessment is performed for the entire Strategy. Consequently, the impacts of proposed Rule 69 on the regional economy and employment may be partially or entirely offset by other quality of life benefits.

Total employment in San Diego County is projected to increase by 325,000 from 1994 to 2010 without Rule 69. As shown in Figure 1, implementation of Rule 69 will have a relatively small impact on the rate of employment growth projected for San Diego, decreasing employment growth by 375 jobs and reducing projected total employment by 0.02%. Of this reduction in job growth, 219 jobs will be from small business (<100 employees) as a result of indirect impacts, reducing total small business employment by 0.02%. The reduction in job growth is due to the impact of

[5]Capital and Operations & Maintenance costs expressed in benchmark 1987 dollars.

Figure 1
Total Employment Impacts

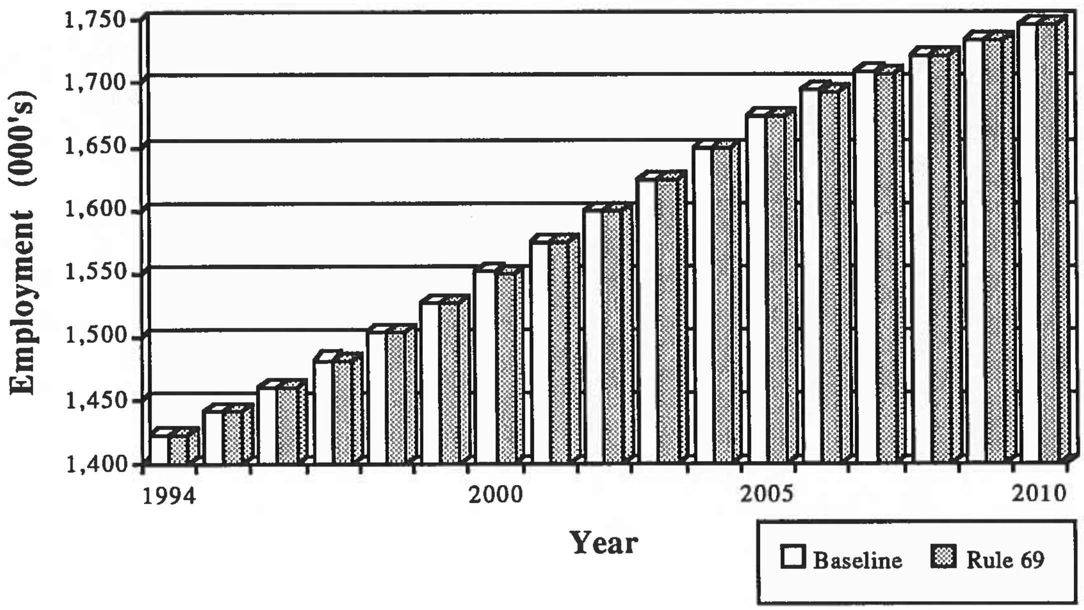
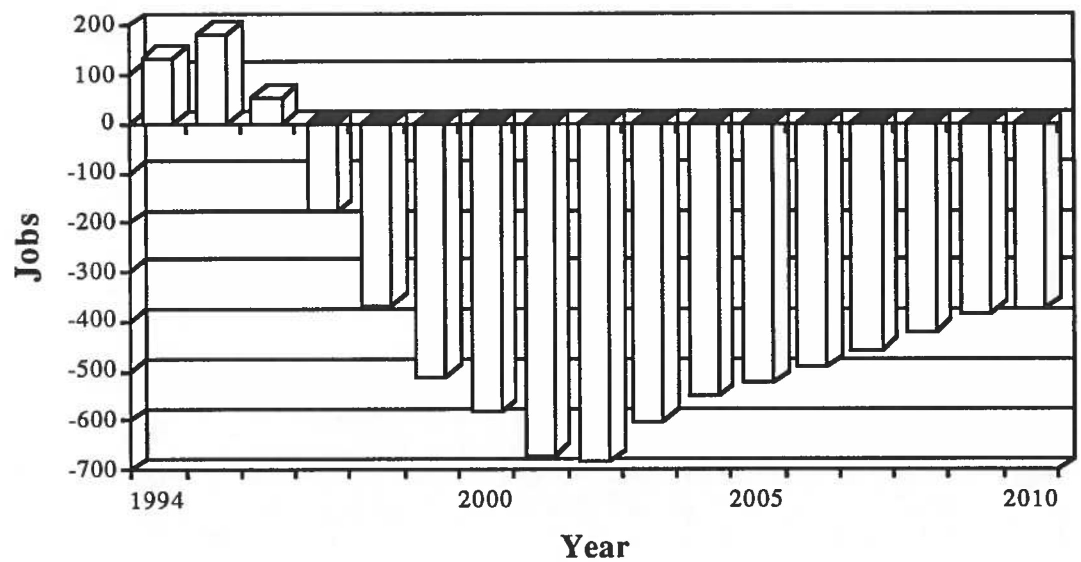


Figure 2
Job Growth Impacts



increased costs of electricity to all sectors of the economy, decreasing profitability of industries that must compete in national and international markets, decreasing consumer purchasing power caused by the cost increase in goods and services provided by regional industries as well as the increase cost of home utilities.

While job growth will be decreased by 375 jobs in 2010, employment impacts for intermediate years vary significantly, as shown in Figure 2. The purchase and installation of control equipment would result in employment gains during the first three years, peaking at 183 additional jobs in 1995. Following this initial effect, the negative impacts of higher electric rates would overtake these benefits as well as the small benefits associated with operation and maintenance of the control equipment. Reduced job growth would peak in 2002 with 685 jobs lost, falling to 375 jobs lost in 2010.

Related to the increased cost to business and decreasing consumer purchasing power is the decline in the growth of Gross Regional Product (GRP). Figure 3 shows that San Diego's Gross Regional Product is forecast to increase by $18.88 billion from 1994 to 2010. Rule 69 will decrease 2010 forecast GRP by $27 million, or 0.03%.

Figure 3
Total Gross Regional Product Impacts

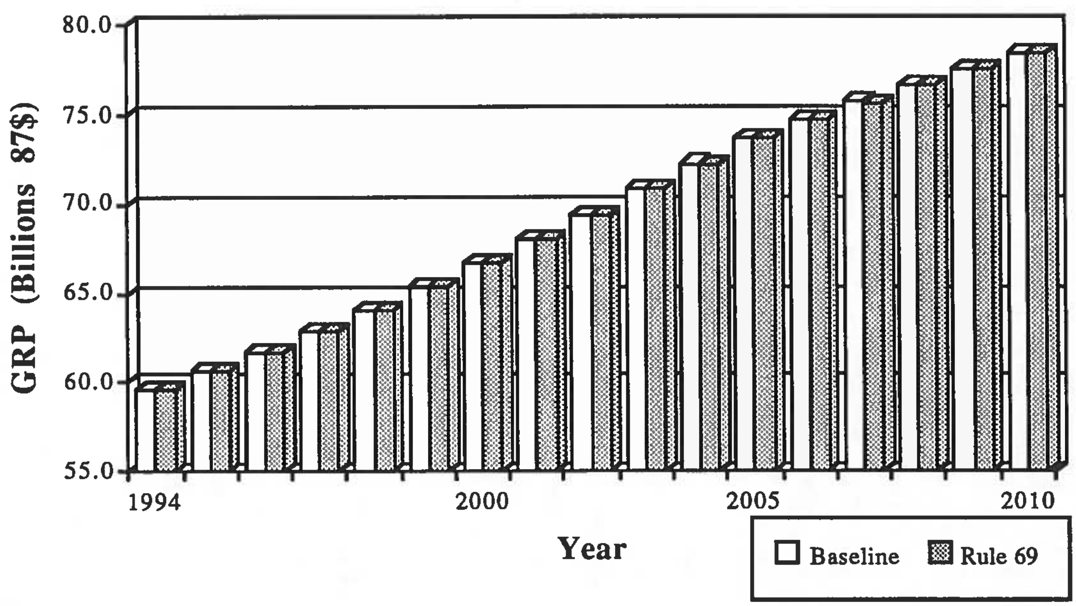


Figure 4 shows that total population in San Diego County is forecast to increase by 526,000 from 1994 to 2010. Implementation of Rule 69 will decrease population growth by 1,148, reducing total forecast 2010 population by 0.04%. The decreased population growth is due to reduced employment opportunities from the increased cost of electricity to business and consumers.

The control efficiency, emission reduction potential and cost-effectiveness of various NOx emission control alternatives for utility boilers considered during Strategy development are listed in Table 2. Strategy emission reductions are based on application of selective catalytic reduction to all utility boilers to satisfy Best Available Retrofit Control Technology requirements. While there are less costly alternatives, selective catalytic reduction provides over 40 percent more emission reductions than the next most effective control technology. However, under Rule 69 some low-use units will likely be fitted with less costly and less effective urea injection or combustion modification control systems. The reduced level of control on these low-use units will be offset through slightly more effective control of the remaining units than the Strategy anticipated.

Rule 69 will maintain the Strategy's emission reduction commitment while providing flexibility to SDG&E in control costs.

Figure 4
Total Population Impacts

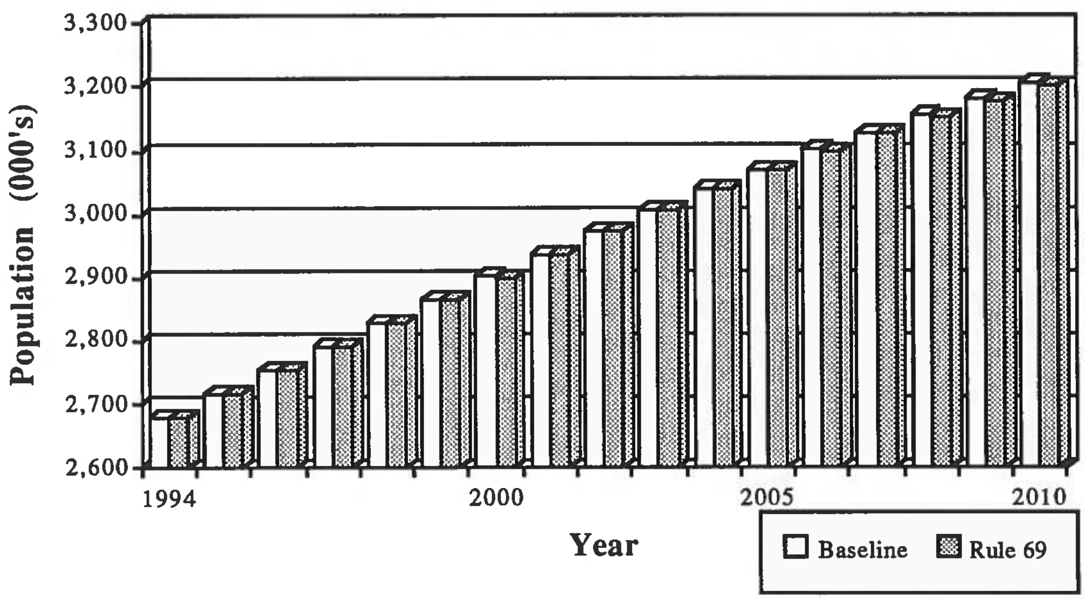


Table 2
Utility Boiler Control Options

Control Technology	Control Efficiency	Emission Reduction (tons/day)	Cost Effectiveness ($/pound)
Low NO_x burners	36%	3.45	$0.64
Flue gas recirculation	27%	2.60	$2.02
Selective non-catalytic reduction	45%	4.32	$1.13
Urea injection	54%	5.20	$0.87
Low NO_x burners with flue gas recirculation	54%	5.17	$1.40
Selective Catalytic Reduction	76%	7.32	$4.06