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Proceedings of the Flexible, Midsize Gas Turbine Program Planning Workshop

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Executive Summary

The U.S. Department of Energy (DOE) and the California Energy Commission (CEC) held a program planning workshop on March 4-5, 1997 in Sacramento, California on the subject of a flexible, midsize gas turbine (FMGT). The workshop was also co-sponsored by the Electric Power Research Institute (EPRI), the Gas Research Institute (GRI), the Gas Turbine Association (GTA), and the Collaborative Advanced Gas Turbine Program (CAGT). The purpose of the workshop was to bring together a broad cross section of knowledgeable people to discuss the potential benefits, markets, technical attributes, development costs, and development funding approaches associated with making this new technology available in the commercial marketplace.

The attributes envisioned for the FMGT include a product that is:

- In the 30-150 MW size range, which is not covered by the DOE Advanced Turbine Systems (ATS) Program.

- Designed to serve a market for mid-range power, in the range of 500 to 5,000 hours per year. In order to do this, the gas turbine needs to be more efficient than a simple cycle (mid to high 40-percent efficiency) and needs to have a cost in $/kW closer to that of a large, simple-cycle gas turbine than to a combined cycle.

- Designed to have rapid-start capability (cold-start to full-power in 10 minutes), and be able to take many full-load start-stop cycles without a significant reduction in useful life.

- Designed to enable the partial repowering of existing steam plants so they can be more competitive without investing in a full repowering project.

The participants in the workshop included representatives from the sponsoring organizations, electric utilities, gas utilities, independent power producers, gas turbine manufacturers, gas turbine packagers, and consultants knowledgeable in the power generation field. Thirteen presentations were given on the technical and commercial aspects of the subject, followed by informal breakout sessions that dealt with sets of questions on markets, technology requirements, funding sources and cost sharing, and links to other programs. Following the breakout discussions, leaders of the breakout sessions reported to the whole group and discussed conclusions.

The consensus of the overall group on the major subject areas was as follows.

Development and Technology Requirements: The capabilities listed above were the consensus view of the technical attributes required for the product. The development effort should include a university research and development (R&D) program as an extension of the one currently underway in the ATS Program, which is viewed as a highly effective approach to facilitate and manage university R&D work. A private-public partnership is required because of the high development cost and risk confronting gas turbine manufacturers who would consider developing the product. It was determined that the development program will need to address combustion conditions that are outside the range of current developments for candidate gas turbine technologies. Other aspects considered important are the need to be as flexible as possible with fuel characteristics and the ability to operate over a wide range of loads and ambient temperatures. The consensus view was that the manufacturers should be free to meet single digit NOx with or without selective catalytic reduction (SCR), as the technical risk, flexibility of the product, and the economics of the overall plant are best optimized.

Domestic and International Markets: A key target market for the FMGT is the more than 120,000 MW of aging oil and natural gas fired cycling steam plants in the United States, which will need to be replaced in the post-2000 time frame. California, New England, Mid-Atlantic States, Florida, and Texas have among the highest concentration of such plants. Competition from wholesale power marketing, retail wheeling, and the requirement for environmental upgrades could accelerate the retirement of these units.

On-Peak and Intermediate-Load Power: The market value of on-peak and intermediate load power in the United States is forecast to grow at a rapid pace while prices for off-peak power are anticipated to remain low, because of excess amounts of base load power. The higher value indicates the need for an FMGT with costs significantly lower then those of a combined cycle. Distributed firming capacity for wholesale power marketing and electric and gas arbitrating, coal-gas repowering hybrids and renewable-gas repowering hybrids, particularly in California and New England, were all identified as important post-2000 markets for the FMGT. Other market attributes identified as highly desirable in an FMGT were rapid cold-start (just-in-time dispatch), high residual value (salvage value), rapid installation time (just-in-time capacity), and the opportunity for phased construction of a bottoming cycle.

Development of the FMGT: Support for the development of the FMGT at the workshop was broad, including all regions of the U.S. for a wide range of central, distributed, repowering and renewable applications by electric utilities, independent power producers, municipal utilities, industrial self-generators, and energy market companies. Strong market support was shown from Europe and Canada and demand for the FMGT was also forecast to be significant in Asia.

Funding Sources and Cost: A private-public partnership is required to make this new technology available in the commercial marketplace. It was also the consensus of the workshop that in the development of a FMGT program plan and budget, the government must first maintain its primary commitment and obligation to the timely completion of the DOE ATS program. The availability of CEC funding was considered to be more immediate (as early as calendar year 1998 for a period of four years or less), but smaller in magnitude that traditional DOE R&D program funding levels.

A consensus preliminary program plan was developed as follows.

- **Phase 1: Studies**
  Time frame: 1998-2001
  Total cost shared funds: $5 million
  Likely public funding source: California Energy Commission

- **Phase 2: Development**
  Time frame: 1999-2002
  Total cost shared funds: $50 million
  Likely public funding source: Department of Energy

- **Phase 3: Full-Scale Demonstration**
  Time frame: 2001-2004, with testing beginning in early 2003
  Total cost shared funds: $100 million per manufacturer
  Likely funding source: Department of Energy

Links to Other Programs: Other programs currently underway that could relate to the FMGT Program include ATS and Combustion 2000. It was also considered important to incorporate renewable energy sources into the FMGT Program and to partner with or link to government programs dedicated to the development of this resource. On a technical basis, one example of integrating renewable energy capability into the FMGT program is to develop technologies capable of operating on a gasified biomass/natural gas blended fuel.

Another example is repowering of the more than 10,000 MW of small Public Utility Regulatory Policy Act (PURPA) steam plants operating on biomass, geothermal, and solar thermal fuel sources, by integrating the renewables plant with the bottoming side of an FMGT in a combined-cycle configuration. This could improve the economics of the renewable plant as well as the FMGT combined cycle, and could enable the new plant to deliver firm power contracts and thus accommodate the variability of the renewable fuel source. This strategy may allow the PURPA plants to remain competitive in a deregulated environment, which would not be possible otherwise.

A third example is in the Combustion 2000 cycle, in which compressor discharge air from the gas turbine is run through a heat exchanger in a coal-fired furnace, then back to the gas turbine where natural gas is used to reach the design firing temperature. The furnace could take a blend of biomass and coal, or biomass itself. Cleanup of the products of biomass fuel combustion would only be necessary to meet emissions requirements and is not an issue of gas turbine combustion capability or parts life.

Next Steps: A Program Advisory Board will be set up, including representatives from the sponsors of this workshop. The board will set the program characteristics and work to gain the required support from the public and private entities that is required to launch the program.

Welcome and California Energy Commission Perspective

David Rohy
Commissioner, California Energy Commission

Summary

Commissioner David Rohy of CEC gave opening remarks and explained AB 1890 electric industry restructuring legislation. He described the law's impacts on the transition to a competitive market, how competitive transition charges would be used to pay-off stranded utility stranded costs, and the public interest surcharge for renewable energy, energy efficiency and RD&D. He described the CEC process for determining how the funds over which the CEC has jurisdiction will be allocated.

Presentation

Good morning and welcome to Sacramento.

Today I'd like to give you a little snapshot of what's happening in the California world of electric industry restructuring, and I want to focus on the R&D functions. I suspect that's where most of you have your interests.

In California, we have some agencies that are maybe a bit confusing and I won't dwell on them. We have a California Public Utilities Commission that sets rates for electricity, gas, transportation, and telecommunications; handles rate cases and complaints; and often sets some of the restructuring issues. The California Public Utilities Commission only deals with investor owned utilities.

The California Energy Commission, on the other hand, deals with all electric and energy issues, both investor owned and municipal, in the State of California. We don't regulate these industries. We work with them to get energy efficiency, to put emergency plans in place, to site all large (over 50 MW) thermal power plants in the State of California. Or, we hear siting cases, but we don't always approve them.

And we have about 430 professional folks in the Commission. There are five commissioners that are appointed by the Governor. Working together, we manage the programs I just mentioned. We set policy and long-range vision for the State of California in energy matters.

The big news, however, is the restructuring of the electric industry. Many of you were involved in that over the last few years. The California Public Utilities Commission started it with their blue books, green books, yellow books — whatever color they were — and that got a lot of public attention, national press. It led to the California Legislature spending night and day for about four to six weeks last summer hammering out a bill that we know now as AB 1890.

That bill was passed unanimously and signed by the Governor last September. It is now the law of California.

The law is a particularly California solution to California problems. Our problem has been very high rates. Our rates are 40 to 50 percent above national rates in the investor-owned utility areas. Those rates don't mean a lot to the residential folks because our efficiency programs, conservation programs, and good weather have helped keep the bills in California for small users down to about the national average.

The real issue is in the industrial area where our industrial folks use the electricity and pay extremely high prices and their potential relocation of plants outside of California made restructuring imperative.

One can argue over the reasons why our rates are high. I'm not going to dwell on that today, but suffice it to say there are numerous reasons.

In the new restructured world, transmission and distribution will remain monopolies; however, transmission will be operated by an independent system operator (ISO): one operator for the State of California rather than three independent, investor-owned control centers. I suspect that the three investor-owned utilities will contribute qualified control folks to that independent system operator.

That ISO will be regulated by the Future Energy Resources Corporation (FERC). The distribution will be run by the local wires company. Generation, however, will be competitive. That process is starting now — where the investor-owned utilities are beginning to put their power plants up for sale. Southern California Edison has all of their thermal power plants on the block. Pacific Gas and Electric (PG&E) has put half of their thermal power plants up for sale.

There will also be a power exchange. This will be separate from the ISO. The power exchange will be like a regular market for trading electricity back and forth. It will be priced on an hourly basis. Bids will go in; and the price will be decided as the highest auction price offered to meet the demand. All recipients will get the highest price that is accepted.

And we will accept direct access in California. So people will have a choice. They can make a deal with a power plant, and they will obtain all their electricity from that power plant. It will be wheeled to them over the transmission and distribution lines, or they can buy on an hourly basis. Or, if they're very small users, they'll probably work on some basis with their local utility that will have an assumed load profile in it and they'll pay a fixed rate.

We believe most people and small users will default to their local provider. At least initially, that is a good assumption. However, the industrial users are already setting up deals for direct access. They plan to get their rates down to look for the lowest priced electricity, some of them on a very active basis, some, perhaps, on a long-term contract basis.

Now I said everyone gets a little bit out of this bill. The investor-owned utilities don't lose. They come out recovering many of their stranded assets. These are power plants that were built with the public knowledge and the public approval.

Plants such as the nuclear plants, the deals that were made on PURPA plants with cogeneration or renewables, have some very high rates in them. Those will all be paid back to the investor-owned utilities. They will not lose money on this deal.

That bill is approximately $30 billion. And it will be paid off over the next four to six years and collected as a competition transition charge. We don't know the exact number per kilowatt hour at this time. It could range from 30 to 40 percent of the entire price of electricity for the next four to five years.

If a user were to go to direct access and buy power from a provider other than PG&E, for example, the user must still pay the competition transition charge. It is mandatory that the charge be paid off.

We talked about industry getting the large gains. Irrigation districts will become competitors under a special rule here in California. They may be customers for a midsized gas turbine. They are getting special exemptions from the CTC. There are a limited number of exemptions, and the irrigation districts will be awarded exemptions by the California Energy Commission.

I'm a Presiding Member, and I can tell you that we haven't made an official decision. I can't tell you what we're going to decide.

Renewables people were concerned because as we go into restructuring, the electric utilities were saying we're not going to spend money on renewables, R&D, and energy efficiency. So the California Legislature allocated $109 million per year for the next four years, starting January 1, 1998, for renewables. And that includes existing renewable plants, new renewable plants, and emerging technologies. Emerging technologies right now are primarily photovoltaic.

So the idea is to get these renewable plants ready for competition. At the end of four years, according to the legislation, the money will stop. By then they should have been weaned from a subsidy to a market-based environment where they can compete.

The low income programs will basically continue as they are. Energy efficiency is another area where there's been concern. The investor-owned utilities have been spending a lot of money with the express approval of the California Public Utilities Commission for energy efficiency, and over the next four years there will be $220 million a year spent on energy efficiency programs.

That will be run by the California Public Utilities Commission setting up an independent board. That board is in the process of being formed right now. The board will make decisions on who the administrators of the money are and what the goals and vision for the spending of that money are.

Again, the idea is to bring energy efficiency to market readiness so that the market is transformed and people will buy energy efficient products.

And the last area is the R&D area that I want to briefly mention. R&D will receive about $62 million a year in California for public interest science and technology work. That's how it's stated in the bill.

There is a certain amount of transmission and distribution work in there. That will continue to be done by investor-owned utilities. In a recent decision by the Public Utilities Commission, that number was put down as $700,000 out of the $62.5 million. The remaining money will go to the California Energy Commission to put together a public interest program.

Now these monies don't just come out of the air. They come out of the ratepayer's pocket. And for the programs I've just mentioned (the $62.5 million for R&D and the $220 million for energy efficiency), they all add up to 2.9 percent of the electric bill in California. And that will be listed on the bill as a public goods surcharge. At least for the next four years starting in January 1, 1998, these monies will be collected in that manner.

At the end of that period, however, other mechanisms will have to be thought of or the programs will die. That is an important message to give to everyone that is working on any of these programs, especially the R&D programs. If we're not successful in the R&D programs, and success can be defined in many ways but I'm talking from a legislative point of view, there will be no further funding. On the other hand, I believe there's strong support that a successful program could be continued beyond four years.

I'd like to talk about the focus areas of the R&D program. First off, the California Energy Commission is working with the California Public Utilities Commission in an almost historic partnership. We are very closely allied to make sure that the programs are operating for the public benefit.

In addition, it is my hope that as we move forward that we can bring the colleges and universities into the program, that we can bring EPRI, perhaps GRI, and perhaps the Department of Energy in on different types of alliances.

This program will be successful if we use the money wisely in the infrastructure that exists and if the programs that are selected are the best programs for the citizens of California.

I'll be very parochial with you non-California folks. I have to represent California, and I'm glad to do it, but the focus areas of the research have been put together so far by an R&D working group. This working group has about 40 or 50 members in it, some of you here today, and they have decided that there will be **three primary focus areas**.

The first is **energy efficiency**, and there's been a lot of discussion on what energy efficiency really is. I'll tell you my definition of it. It's all energy efficiency — supply side, demand side, any type of energy efficiency. That's not universally agreed on. That's my own personal view.

The process we'll go through is that the working group will submit something to the R&D Committee. I am on the R&D Committee at the Energy Commission. We'll review it, submit it to the full Commission for approval, and then it goes to the State Legislature for approval. Hopefully this will happen by the end of June. That's a lot to happen in a short time.

The second area is **environmental issues**. The investor-owned utilities are doing a lot of environmental work in the State of California — the effect of CO_2 on plants and the environment, different types of land use. I expect those programs will continue in a very robust manner.

And the third area is **renewables**. Renewables activities would fall under what I mentioned earlier — the emerging renewables, those that are not yet market ready, that need to have R&D in place. They could be mechanical devices, they could be fuels, it could be a number of different areas. I'm not closing my mind to what those are.

And in this case, the renewable part of the R&D program must work very closely with the other renewable fund that's funding the plants that are providing renewable power — in the same way that the efficiency programs in the R&D must work with the energy efficiency market transformation program that exists.

So again, we have entered intersections, we have alliances, and we have different ways of working together.

Each of those three areas will be subdivided into further areas. And those areas have not yet been determined. But for energy efficiency, let me go down one path to give you an example. We may go down to building efficiency, and we might go down to residential building efficiency. And then, what is the key problem that Californians have in building in residential building efficiency?

The biggest energy consumer right now that is wasteful is the duct systems in our heating and air conditioning. And they waste about 30 percent of the energy that goes into air conditioning. And air conditioning is a major issue now as Californians move from the coast toward inland desert areas.

The ducts do not leak the first year, but starting about the second year, the tape that's put on them starts to fall off and other things happen. So as an example, we may have a program, and this is a "may," that looks at a cheap and effective way to make a long-term sealed-duct system in an air conditioning system.

So that's how I go from energy efficiency all the way down. One can do it in an energy generation area. I wanted to stay away from that this morning because that's what you folks are going to be working on the next day and a half.

And so we look at these programs, and, again, what is the advantage to California? Do we save energy? Do we create jobs here?

I wanted to talk a bit about public interest R&D again. What is public interest R&D? That is the research and development that's not being done in the regulated market, and it's not being done in the competitive market, but yet has very high potential gains for the State of California.

So it must have several aspects to it. We must have a high potential gain, and there must be a reason — such as long term or high risk or other issues — that have made the competitive market shy away from funding that research. Often it's the front end. It's the critical issue that stops the application of some technology. One bit of technology is needed to make something big happen that doesn't exist today. That could be put in the definition of public interest R&D.

Much of the work that will be under public interest R&D will be publicly publishable and probably contain very little proprietary work. Again, that's not been decided, but it is a general direction when you're doing public-interest R&D that the work may be less proprietary and more generic so that it's not diminished by multiple use.

We look at working with the university system as a very important part because I believe, as an example, that the folks at FETC have a very good gas turbine program, and I often use that as an example here in California with the South Carolina people.

I think that gas turbine research program is an excellent example of what I'd see happen in California. On other technologies, where we get the universities working together with industry, we would publish the work make it available. So we're training people, we're bringing technology to the industries, and, in fact, doing it in a public manner where the people in the market determine what R&D is being done so we're not just doing R&D for R&D sake.

I use that often, as a prime example of where the DOE/ATS program has done an excellent job. And I've used it with legislators here, and they tend to understand it. At least they nod their heads knowingly.

Now I would like to focus a little bit on how I would see some of the gas turbine projects coming to be. But before I do that, I have to give you an admonition. some of you from the Energy Commission know this. There are a lot of folks saying that we should not spend any R&D money on fossil fuel projects. That is a current battle that's going on in California as to whether we, in fact, do spend money on fossil projects.

Having said that, it just means that the justification for any fossil fuel projects has to be extremely good. And I believe that the justification for any project should be very good so that we put together a program that stretches the current technology, one that brings benefits beyond what's available today, one that, in fact, can be accomplished — rather than doing research that may lead to something that might not ever be accomplished.

If we look toward those stretch goals, the goals that will make a project not only successful in the marketplace, but highly successful, the probability of funding any program is going to be increased.

In addition, as we go forward, I plan to put together advisory groups so that it's just not the California Energy Commission that's deciding which programs are funded. These advisory groups should have a cross-cut of the experts in many industries to help us make sure that the program is on target and is positioned within the national or international framework of technologies so we're not duplicating other work.

We plan to have an annual R&D review meeting in California where the programs are reviewed and open for public inspection and comments so that we can make adjustments. It is very difficult, I know, to kill programs. Some of them should be killed after a while, and that's a process that we plan to do and to re-allocate the money to more deserving projects as we go forward.

I give you my great encouragement to make a project that would meet those goals and give you all the satisfaction of working in cutting-edge technology. I look forward to working with all of you, and I wish you the best of good work in the next day and a half. Thank you.

Objectives of the Conference and Department of Energy Perspective

Victor Der
Director, Office of Power Systems Technology, Fossil Energy

Summary

Mr. Der gave an overview of the variables influencing the U.S. energy situation, the DOE ATS Program, and the Washington budget situation, in the context of a changing energy industry. He suggested using this meeting as a forum of re-examining public/private roles in an R&D partnership.

Presentation

I'm pleased on behalf of the Department of Energy to join with the California Energy Commission to hold this workshop on flexible midsize turbines. The focus of this workshop is to assess some of the opportunities and needs for these turbines in a restructured market-oriented electric generation industry.

I believe that the workshop is driven by two notions. First, given the current market conditions and the conditions that we anticipate to see in the future, industry on its own is not positioned to assume all the development risks associated with this turbine development work. In fact, there are limitations in terms of the R&D funding available from industry, the states, and also the federal government to address these risks, thereby creating market hurdles for getting this particular technology into the marketplace.

On these bases, the workshop should also assess the viability of an R&D program and the viability of looking at the prospective state, federal, and industry roles and perhaps an R&D partnership.

Now, regarding the restructuring of the generation market, the Department of Energy has also dealt with some of the same issues that California has dealt with. In fact we've offered up some of our testimony in the past to the state prior to the passage of AB 1890.

We are still looking at the policy issues to help shape pending legislation that is before the Congress. There are probably over ten bills, including Schaeffer's bill, that are in various forms and states of flux, and the Department of Energy through its Policy Office are taking into consideration a lot of the issues that we've discussed before.

For example, what are the proper avenues for getting some of these more advanced, cleaner, more efficient technologies into the marketplace and over the cost hurdles? How do we account for the retention of the conservation measures and integrated resources planning? And how do we preserve universal access for everyone, including the poor?

In addition, we're concerned about continuation of reliable service and sufficient reserve margins, and, of course, the issue of stranded assets. And we're hoping that the states will be able to address in a large measure these particular issues.

But I say this in the context that we should probably keep these in the back of our mind as we work through this workshop for the next couple of days, looking at a potential R&D program to address the intermediate load power market.

As your program announcement stated, there are about nine major product attributes that you're going to be examining today. And I think that the way the workshop has been organized for the next two days will allow us to address some of these issues and flush out some of these attributes, such as relative capital cost and the value of just-in-time capacity and dispatch.

What I'd like to do this morning is to briefly describe the fossil energy power systems program and share our perspectives with you in terms of what the current and future situation for energy R&D is with the Department of Energy. I'll briefly touch on some of the issues and program drivers that we have, and give you a glimpse of the power systems portfolio and how our advance turbine program fits within that portfolio.

I do this in the hopes of providing a framework for you to carry on some of the discussions and how best to address some of these issues as we look at the possibility of launching a new R&D program for midsize turbines.

We see that over the next 20 years or so, there is a projected growth of about 19 percent in energy consumption in the U.S. We're currently using 85- or 86-percent fossil fuels to address the energy consumption in this country, and that's projected to grow to a number something like 88 percent.

The power generation market is expected to grow about 30 percent. The current usage of fossil fuels for that market is around 66 percent, and it's projected to rise to about 76 percent. As the energy demand grows, you see an increased reliance on fossil fuels.

Now, the opportunity for small energy improvements could yield major economic benefits. I'll just touch on two that relate to electricity.

The U.S. consumes about $200 billion worth of electricity per year. And that's a subset of the energy consumption that we have in this country which is about $500 billion per year. In that consumption, U.S. utilities spend more than $6 billion per year to meet the Clean Air Act amendments and regulations put out by EPA. And with the advent of potentially more stringent emission regulations, this compliance cost is going to increase unless we do something about it through our R&D to reduce these costs.

So the driver for our program is very simple. It's public benefit — public benefit in the area of improving environmental quality, maintaining our energy security, and, of course, enhancing our economic environment and creating new jobs.

And in that context, there are several issues that shape the portfolio of R&D for fossil energy. I'm going to sort of touch on four of the five, leaving out the oil security because that relates more to fuels. The four are: climate change, air quality, utility restructuring, which Dave discussed at length this morning, and, the issue of declining R&D budgets.

The United States is entering into potential international agreements on climate change, and we are officially an active proponent for stabilizing these targets of emission for greenhouse gas with some sort of flexibility built in so that we don't hurt our economy. North America, most of which is the U.S., is a hog in terms of CO_2 production.

China's production is low now, but starts ramping up very fast towards the year 2010. The things that we do relative to CO_2 in this country may very well be overtaken by things that are not done in the rest of the world.

There is a running debate among some of the scientists as to whether or not CO_2, man made CO_2, contributes to the greenhouse gas effect in global warming. But the reality of the fact is that the policy has overtaken the science question on CO_2, so that is development issue that we have to deal with.

The next issue that we are focusing on in our R&D portfolio is air quality. The Environmental Protection Agency (EPA) is set, very likely, to put out more stringent requirements on sulfur dioxides, introducing more stringent limits on nitrogen oxides and ozone non-attainment as well as small particulates (e.g., in the 2.5 μm range) and air toxics (e.g., mercury and selenium). So the R&D challenge here is to find more cost effective ways of compliance with these new more stringent emission standards.

In the area of utility restructuring, I think Dave's probably put it better than I can, but we need to look at what and how utility restructuring is going to affect the power industry and the power producers.

Some people are going to shed some of that generation capacity by selling it off. Some of the other utilities, such as in the coal area, are going to look at life extensions and ask management to maximize what they have in their fleet of power plants. Any new capacities are going to be driving some of these industries into smaller more modular technologies with, of course, increasing use of natural gas. And there are some downward pressures on the market entry costs for some of the new technologies into the marketplace.

So the challenges that we have in our R&D is: How do we get these new technologies with initial higher capital costs down this learning curve that we talked about in the past and into a competitive market? And, second, with the pressures of regulation and increased competition, how do we keep the R&D pipeline flowing for new products in the face of reduced R&D investments?

Which brings me to the last issue that is shaping our R&D portfolio. The private sector has seen in a decline in terms of R&D since the mid 1980s; somewhere between 30 and 35 percent reduction in the R&D investments have been made. Some of the major U.S. energy producers spend only about one percent of their sales on R&D, which is a pronounced decrease over the past five or six or seven years.

Even more so, their commitment to long-term R&D in oil and gas and utility arena has dropped sharply. Their focus is on the here and now.

Referencing a paper that Kurt Yeager put out in 1995 or 1996, the focus on their investments, whether they be R&D or anything else, is in the six-months-to-one-year arena versus a three-to-five-year focus. And the investment has to show that it will return some kind of bottom line profit for the investments that they make. That includes R&D.

So this points up the need that if the R&D from the private sector is dropping, perhaps the avenue is to go to the public sector such as the Department of Energy. But since 1978, DOE investments in energy R&D have dropped about 75 percent, even granted that some of the projects worked on, such as synfuels in 1978, were huge ticket items.

So right now the Department of Energy across the board is spending something less than $2.5 billion per year. Industry on its own is roughly spending about $3 billion per year. If you take that as a collective expenditure, we are at about one percent of the annual national $500 billion expenditure on energy.

I'd like to give you a brief glimpse of the power systems portfolio in coal and the power systems program in the context of these issues. The coal and power systems program includes coal fuels, advanced power systems, and some of the clean coal technology demonstration areas. The advanced power systems R&D area also includes R&D.

This portfolio is grouped in two categories: coal-based and natural-gas-based. Within the coal-based area, we have low emission boiler systems for the nearer term, integrated gasification combined cycle, pressurized fluidized-bed combustion, and indirectly fired cycles in the longer term. These are high temperature furnace technologies.

In the natural-gas-based technologies, the two main products/programs are the high efficiency gas turbine, through our advanced turbine systems program, and the advanced fuel cells program.

What you see here is a portfolio of where we're headed with these types of technologies. You'll see that our goal is to strive for increasing efficiency in our power portfolio. Six out of these eight portfolio power systems rely an advanced turbines to get to these higher efficiencies.

So this points up to the fact that the ATS program that we have under our natural gas budget does a lot more than just produce high efficiency gas turbines for gas power usage. It is a cornerstone and integral part of the portfolio that we have in power systems as a whole so that we can achieve some of these future efficiencies that we're striving for. And, of course, trying to bring capital cost down to a level where they can enter the marketplace.

The U.S. currently owns about 80 percent of the world market, and given that, my question is, Why do we need to assist our industry in that regard?

Well, the plain fact of the matter is that the foreign competition's closing the technology and market gap rapidly. They are also assisted by their governments in trying to get their technologies into the global marketplace. And what we want to be able to do is to assist our industries to maintain a level competitive playing field in that regard. But our primary driver is to try to increase the public benefits through these types of programs.

Very briefly, there are two pieces of the program that we're pursuing. In the fossil energy area, we're looking at the utility scale technology. And in our Energy Efficiency Office in the Department of Energy, they're looking at the industrial scale.

We are also looking at some innovations in revolutionary technologies to keep our edge on the global market. You're probably very familiar with the goal for the year 2000 time frame, that we're shooting for 60 percent efficiency, less than 10 or 9 parts per million in NOx and trying to lower the cost of these turbine systems by about 10 to 20 percent in terms of the cost of electricity.

What we're looking for in the year 2010 is maybe an enhancement to 70 percent efficiency and less than 5 parts per million on the NOx with the same goals of market entry in terms of its capital cost.

I'd just like to say that what we're doing today in the ATS program is probably something that has some relevance to what you're trying to do here in the midsize turbine R&D. We are conducting some research on humid air turbines and combustors; we're looking at some of the materials for the turbines, some of the critical testing associated with the critical components, and some of the coatings for these turbine systems; and we are involving a host of universities and national labs such as Oakridge National Laboratory.

We have about 83 universities that are participating in the program. And South Carolina Energy Research Center is a major focal point for a lot of that coordination. And we are currently working on our Phase 3 full-scale component testing.

Our 1996 budget is about $166.5 million. In 1997 it's about $167 million or so, and the congressional request for 1998 has dropped to $144 million.

Now, regardless of what Congress does or doesn't do relative to our request, you'll see something that's very clear. The budgets are flat or potentially on a slight decline. Both turbines and fuel cells garner a majority share of the budget. Keep that in mind as you look at some of these issues in the breakout sessions this afternoon.

Along with energy efficiency, fossil energy is beginning to turn its focus on some of the new innovative breakthrough technologies and revolutionary concepts for a post-2000 development program that will address some of the great challenges in the environmental and energy arenas.

And we would like to include a portfolio of these innovative technology options that have a tremendous potential for achieving some of the long-term and sustainable public benefits while at the same time will help our industry be more competitive, creating more jobs, and improving our economy in the nearer term.

But we also must be reminded of budget realities. Budgets are tight. We expect these budgets, these tight budgets, to continue. Therefore, one of the messages I would like to leave with you is that in your discussions this afternoon, we should really take a good hard look at what the timing and the window of opportunity is for the market. And we should examine that closely against what is the required lead time for the R&D and what are the opportunities in terms of the time frame for securing the necessary funding should such a program be undertaken.

We are looking at the next step, what I call the ATS 2000. And perhaps the midsize flexible turbines would clearly be a candidate should such a program go forward.

And I think one other thing that we should focus on in this workshop is to make sure that we assist the viability of the candidacy of midsize turbines as part of that portfolio.

So in closing, on behalf of Fossil Energy and the Energy Efficiency Offices of the Department, I would like to express our thanks to the Gas Turbine Association and all the other stakeholders for participating in this workshop, for their past and continued support for this important government industry partnership in the advanced turbine systems program. We look forward to a productive workshop that will provide us your valuable input and insights that will help shape the future of any R&D programs that we might have in the power systems area.

Thank you very much.

The Flexible, Midsize Gas Turbine Program

William Day
Chairman of the Board, Gas Turbine Association

Summary

Mr. Day outlined GTA support for the DOE ATS Program. He described characteristics of flexible, midsize gas turbines (FMGTs) and intercooled aeroderivative (ICAD) turbines. The GTA position is that a flexible, midsized gas turbine program is needed, oriented towards the intermediate load and innovative repowering market with the emphasis on attributes such as capital costs lower than combined cycle, higher efficiencies than operating steam units, and quick cold start time. Manufacturers want to see the FMGT developed, but lack of market certainty and shrinking RD&D budgets are barriers.

Presentation

The Gas Turbine Association strongly supports the sharing of risks in private/public partnerships such as between government and industry. The first on our agenda is, in fact, the ATS program.

As many of you know, the Gas Turbine Association itself was formed in the summer of 1995, and we faced an immediate task of helping to defend the budget for the ATS program. With a new Congress that had cost cutting as number one on its agenda, we mounted a grass-roots lobbying effort to defend the budget for that program. No one will ever know who influenced what exactly how much, but we think we moved things in the right direction, and the program did survive.

Again in the summer of 1996, we had a similar problem, and we mounted a similar grass-roots campaign to help defend the program. And that remains, in fact, number one on our agenda for gas turbine R&D.

The ATS program, as most of you know, is focused on very large and, depending on how you are calibrated, very small gas turbines. On the large utility size, you're talking 400 MW for a combined cycle with one gas turbine if it's 60 hertz, and typically around 500 MW if it's 50 hertz.

The industrial size or small branch of the ATS program by definition is under 20 MW. There's a huge gap in between.

The Gas Turbine Association has worked up a program, working originally with Tom Bechtel, to fill the gap between the two extremes of the ATS program. And that's what this workshop is all about.

The original idea for a product that fills the needs that we're talking about came from the Collaborative Advanced Gas Turbine Project or CAGT. CAGT was originally led by Pacific Gas and Electric Company, then shifted to the Electric Power Research Institute (EPRI) before spinning off into its current form as an independent outfit.

But during the initial work of the CAGT, all three aircraft engine manufacturers, ourselves — Pratt & Whitney, GE, and Rolls, were under contract to look at what new products could they develop based on their largest aircraft engines for industrial gas turbine use. All three of us independently selected the intercooled aeroderivative as the product that would make the most sense.

In the intercooled aeroderivative, or ICAD as it's known, air goes through the low-pressure compressor, after which it's taken off board and cooled with either air or water, goes back to the high-pressure compressor, and then through the rest of the gas turbine cycle.

The intercooling does several things simultaneously that make a big difference to the performance. First of all, as most people think of intercooling, it reduces the work of compression for the high-pressure (HP) compressor. But that's not all. Because the air is cold, the density is increased, so the mass flow must increase to keep the velocity where it needs to be to match the HP compressor. That increase in mass flow also increases net output.

In addition, the fact that it's intercooled means that the compressor discharge temperature is also much lower than it was originally designed for. That's good from the point of view of NOx because low temperature means a long time before auto ignition, giving plenty of time to premix in a lean premix combustor. The compressor discharge air is also the source for the cooling air for the turbine.

So cooler cooling air means you can run a higher firing temperature for the life of given turbine parts, with reasonable cooling air consumption. All of that's great for performance. It ends up producing around twice the output of the simple cycle, which helps dollars per kilowatt.

A typical simple-cycle gas turbine based on the largest aircraft engines is, say, 50 MW in size. We're talking about the 100-MW size class for the intercooled version of this. The additional dollars for the intercooler and all that are not as much percentage-wise as the additional output.

Aeroderivatives traditionally have yielded higher dollars per kilowatt than big frame machines. Intercooling brings the dollars per kilowatt down a lot closer to a big frame simple cycle than aeroderivatives have been in the past.

The efficiency ends up in the mid to high 40-percent range, depending on the exact cycle conditions. That produces a competitive product at mid-range capacity factor. In addition, because this ICAD derives from an aircraft engine, it's designed for a long life of many cycles, rapid start from a cold condition to full load, and that enables quick dispatch to meet fluctuating load demand.

Now all of those are very good attributes as a product, which, of course, is what attracted us to this product, but it also it turns out to be a rather expensive proposition to start with either an aircraft engine or a simple-cycle aeroderivative and make one of these beasts.

First of all, the low pressure (LP) compressor has to be different to handle a lot more air flow than a simple cycle. The HP compressor can handle it, but you have a lot more mass flow going through the combustor under different conditions, and a lot more mass flow going through the turbine. A lot of change has to happen. It's not an evolutionary step, it's a revolutionary step.

The technology issues, I would say, are probably less than they are in the ATS program. In the ATS program, at least the utility size, you're talking about different cooling mediums, steam cooling in both GE and Westinghouse going that route, and many changes to the cycle. Here, I would say that the cooling technology is just plain old air cooling and enjoying a low cooling temperature. The objectives are the same. You want long life for the turbine and little cooling air.

The biggest issue I see is combustion. You've got an overall pressure ratio that can be in the vicinity of 50:1, maybe the 40 range, and maybe as high as 50, simultaneously with a high firing temperature. Those are higher conditions than anybody has used before. And I think most people would agree the biggest technical issue in the industry is low NOx combustion.

In fact, one of the issues that we'll be discussing in the technical group breakout session as well as the marketing one on development strategy for this product could be to run the firing temperature high and take advantage of the technology that exists in the aircraft engines and put an SCR on to get low NOx.

Some studies that have been done indicate that's a better way to go, on balance, in terms of economics than it would be to force yourself to meet single digit NOx without an SCR.

Anyway, that's one of the technical issues to be discussed. But the point is that enough changes have to be made to this product that it's a large investment.

And, in fact, I think I'm speaking correctly for the industry, not just for Pratt & Whitney, when I say that all three manufacturers have looked seriously at this product, and all three have concluded that we're not going to go ahead on our own. It's not a prudent business decision to do so unless we have some substantial support from the public side of a private/public partnership.

The reason is that you're talking about a lot of money to be laid out for a product that's not been made before for a market that no one has specifically served before, namely the mid-range market. We think it makes sense, but we need some help to mitigate the risks to go ahead.

Another technology possibility that meets the same objectives is the cascaded humidified advanced turbine (CHAT). This has been pushed a lot by EPRI. CHAT involves a low pressure spool, in this example an F class gas turbine, starting with a low pressure compressor, then an intercooler, and then a high pressure turbine machinery shaft. That is a custom-made shaft by someone like Dresser Rand, who makes that sort of equipment. Then, after the HP compressor, comes the saturator, recouperator, HP combustor, turbine expander, LP combustor, then through the LP turbine and back through the recouperator. This is like a humid air turbine (HAT) cycle, but it's got a separate shaft. That, too, has been studied to a fair level of detail and is aimed at the same type of market, same type of customer need, as the ICAD.

As part of this workshop we may also identify other applications, other technologies, that would address the same market need.

So in summary, the premise of this workshop, is that a worthwhile private/public partnership would make sense. From the private side, we have the manufacturers, and I should say presumably the universities. I would presume that the ATS university program would extend here, since the issues are basically the same. There should be more emphasis on combustion, I would say, and less on some of the cooling technologies. But a private/public partnership makes sense, with the manufacturers and the universities on the private side, and people like DOE and the California Energy Commission on the public side.

The premise is a product that fits the size class not covered by the ATS program, designed to serve a market for a mid-range capacity of say 500 to 5,000 hours a year. To do this, the product needs to be more efficient than a simple cycle, but it needs to have a cost close to that of a large frame simple-cycle in dollars per kilowatt.

It needs to have rapid start capability, say cold-start to full-load in less than five minutes, be able to take many full-load start and stop cycles without a significant reduction in life, and also be designed to enable the economic partial repowering of existing steam plants.

There are many old steam plants around the country, around the world in fact, that something has to happen to when full competition arrives. Either they'll be shut down because they're not economic, or one way or another, they need to be repowered.

And one attribute of this product would be the ability to undertake a partial repowering without a large investment, for example, throwing away everything but the steam turbine and putting in a new combined cycle. But something on the order of economic feedwater heating with an ICAD saves the boiler, provides economic mid-range power, and increases the performance of the original plant when it is in operation.

And the final premise is that the market worldwide would be large enough to make sense to go forward with this program.

So in the panel discussions, the breakout sessions, and in the general discussions that follow, we want to examine that premise and determine whether we believe this program or some modification of it would make sense for going forward.

Thank you.

Opening Session Questions and Answers

Audience Speaker to Mr. Day: I'm just curious as to what extent these advanced turbine cycles have been out on smaller platforms, you know a three, four, five megawatt kind of size, and then looked at for scaling up. Wouldn't that be a more cost effective way of developing the techniques?

Mr. Day: Well, the idea of an intercooled gas turbine is not a new one, of course. There is the intercooled regenerative cycle, the WR21 that was Westinghouse's Rolls Royce, now not by Westinghouse any longer, but it is a Navy application. That's already happening in the vicinity of 20 megawatts or thereabouts.

In this case the pressure level is enormously higher. But the idea of intercooling itself I don't think needs a whole program preceding anything like this. But if one thinks it is necessary, then you could say, well, that one (the WR21) is doing it.

Oh, I should also answer as if the question was should we start with a small version, physically small version of an intercooled aerodererivative prior to the big ones? My opinion is, no, we shouldn't for two reasons. One, I don't think it's needed, and two, it's happening anyway.

Mr. Day Responds to a Question: The question was: What would motivate one of the large aeroderivative aero engine manufacturers to do this relative to keeping proprietary information proprietary?

I would assume that the rules of the game will be the same as they are in the ATS program. And there will be cost sharing. This partnership is not all public. That would not be realistic.

There would be protection of proprietary interests as there is currently in the ATS program, and there would, I would assume, be cost sharing. Depending on the phase of the program, the cost sharing percentage would be increasing as the phases increase.

For example, on ATS in the four phases, the minimum requirements went something like 25 percent, 30, 35 and 50 percent, where the fourth phase is the full plant demo. The first phase was studies, and then the technology development and component development stages are in between.

Audience Speaker to Mr. Der: I wanted to ask Vic to discuss the considerable consolidation in DOE, the consolidation of the Pittsburgh Energy Technology Management Center in Morgantown. Is that a trend that's going to continue? Do you see DOE becoming more of a less of a specialized shop and more of a consolidated operation? In headquarters as well as in the sectors?

Mr. Der: Let me answer your question in the following context.

A couple years ago I served on the Department of Energy's Strategic Alignment Initiative. And at that time Secretary O'Leary's driver for this whole thing was to see whether or not we could do more with less. That was part of the downsizing of government.

And one of the items that came out of that group that I had served on was looking at a more efficient way of restructuring the Office of Fossil Energy, both at headquarters and in the field. And one of the recommendations from that group was to maybe consolidate some of the management operations between the two centers.

So the driver there is really to focus on streamlining to give the public a better bang for the buck, and also to integrate the operations in the field centers with headquarters. Because headquarters was also undergoing a streamlining cost savings, and there were various targets that were put out by the Secretary that we all had to achieve in terms of dollars cost savings and also the number of personnel.

So that is the primary driver. I don't think that the driver is to become more specialized and narrow. Because if you look at the charter for the Federal Energy Technology Center, I would say that it is broadening to look at other things because of the project management and the R&D capabilities that they have in-house. For instance, they are also taking on projects relating to environmental management.

Audience Speaker: Victor, can you give us a feel for how much fossil-energy use in the year 2000 and beyond is coal-based, like pulverized coal, coal gasification, and coal-based fuel systems?

Mr. Der: That really depends on the specific technologies. I can't answer that question because that depends on how successful we are in the R&D program for getting some of these advanced technologies into the marketplace.

But I do believe that if you look at the Energy Information Administration projections that are in their Annual Energy Outlook, I believe that in coal-based technologies will retain roughly 50 percent of the market in terms of coal-based generation. But in terms of absolute megawatts, I think that number is slated to go up.

We project somewhere on the order of perhaps 25 gigawatts in terms of new capacity based on coal to the year 2015. There is a larger assumption in terms of megawatt demand that will be served by gas systems, primarily turbines.

Question on Budget Priorities: I think it has to do with a couple of points. One, we're trying to look at things on a balance. And one of the things that I had shown you earlier here is that if you take a look at the natural gas portfolio relative to the individual technologies in the coal side, they are quite hefty.

And given that, our priorities, and the time frame that we're dealing with, the resulting budget was probably the best balancing act that we could come up with. Within the administration, as you may or may not know, we are given sort of bottom-line targets to meet. As a result of these cuts, we may have to rethink certain pieces of our program, including the gas turbine program.

Question From Mr. Whitney: In your presentation, you mentioned that there were other global coal-use projections in your forecasts of fossil fuel use. I understand we acknowledge that as a potentiality, but how do we evaluate the risks of a political backlash against the consumption of fossil fuels?

While natural gas improves the situation, it does **not** eliminate the production of greenhouse gases. So the question really is, how do you assess that risk? Is it a risk that we should be concerned about? What do we have as a fall-back position?

Mr. Der: If you take a look at what the natural resources are, at the power demands that we're projecting, and in a lot of the developing nations, you will see that there is no way to escape the usage of fossil fuels.

So the bottom line question comes: Do we allow these countries to do as they wish? If developing nations are truly concerned on a policy basis about the issues of CO_2 and global climate change, do we do nothing and allow developing countries to use coal or natural gas or whatever indigenous fuels they chose in less efficient ways, thereby increasing the production of CO_2? Or, do we come to grips with the reality, and that reality is that fossil fuels will be used, and maybe perhaps we should engage in the process of making sure that the incentives are there for them to be using them more efficiently?

That same issue also applies to some of the more developed nations as well. And one of the positions that the U.S. government has taken relative to joint implementation and global climate changes is to set a particular target of emissions that each of the countries can sign up to, but we would like to do this in a flexible way. And that's sort of a code word for saying that we do not want to hinder our economy in the process if we can help that.

We are also faced with the issue of some of the developing nations taking a different position relative to CO_2 emissions. They see that developed nations are penalizing them by forcing them into a particular mode, and they will never get to the economic level of the developed nations. That is a problem for the more developed nations,

Yes, sir.

Mr Der Responds to Question About Fuel Cell/Turbine Hybrids: One of the areas that we are contemplating doing some small-scale research in as the next step in the post-2000 arena is to look at some fashion of a combined cycle with turbines and fuel cells that could, at least on paper, give us more than 70 percent in terms of its efficiency.

Mr. Der Responds to Audience Question: The main focus of the IGCC piece and our pressurized bid program looks at the filters and some of the combustion technologies associated with that in terms of being able to come out with gas that's clean enough to combust for the advanced turbines.

Presently we're not working on improving the gasifier. That's something that we are assuming the industry, through evolution and improved processes, will handle on their own.

Audience Question: A question for Bill Day. Relative to the mission for this workshop, you talked about a low capital cost for a mid-range efficiency kind of product, one that could be cycled very often and very frequently.

But you confused the requirements a bit by also talking about repowering existing steam plants. Are there two different missions there?

Mr. Day: There are two different needs that can be met. We know the ICAD can do both. There may be others that also can.

Panel Discussion: Changing Electric Markets

Summary of Presentations

George Touchton, Electric Power Research Institute - Moderator: Mr. Touchton pointed out EPRI support for FMGT concepts like intercooled aeroderivative (ICAD) and cascaded humidified advanced turbine (CHAT); and that EPRI believes intermediate load and flexibility will be prominent features of future gas turbine markets in the United States under deregulation. Described likely market niches for FMGT in the context of a restructured energy market.

Mark Axford, Stewart and Stevenson: The presentation indicated that next big market in the U.S. is for intermediate load power with significant flexibility, as opposed to "jumbo" turbine designs that are great for baseload but decrease flexibility. The intermediate load market will result from the need to replace oil/gas steam units. The increasing importance of dispatchability and the growing role of power marketing would accelerate the retirement of these units. Mr. Axford gave an example of Northeast Utilities just-in-time capacity lease of 200 MW of LM 6000's operating in 45 days when a shut-down of nuclear units occurred. He emphasized that quick cold starts and operational "efficiency" are better measures than full-load efficiency for intermediate load. High tech "jumbo's" may be too high risk for mid-range applications, with many on-off and part-load operation. He indicated the Stewart and Stevenson desire to supply 100-MW sized FMGT units that are based on an aeroderivative.

Barry Davidson, National Power PLC: Mr. Davidson gave a European Perspective for changing electric markets. He presented a summary of the key issues that the United Kingdom has faced over the last 5 years since privatization of the electric power industry. International market changes were presented, and the role of flexible midsize gas turbines was defined for European and U.S. power generation industries.

George Hay, California Advanced Gas Turbine, LLC: Mr. Hay provided the status of California Advanced Gas Turbine on small and large ICADs. The huge steam plant replacement market of >100,000 GW of aging, cycling oil and gas steams units in the U.S. (California, New England, Mid-Atlantic states, Florida, and Texas) represents the key target market for FMGT. Power marketing of coal and hydro energy into California and New England, in conjunction with environmental retrofit requirements, could create huge market for the FMGT in 2002-2005 time frame.

Robert Nicholson, Bank of America: He presented a Bank of America assessment of emerging market for new power in Western United States. The analysis is contained in an article on "Deal Triage." The analysis forecasts that off-peak power prices will remain flat, while on-peak prices will escalate upward. This split market is because of regional electric transmission constraints on peak. The analysis suggests that simple-cycle gas turbines with efficiencies near those of gas-fired steam units will become an economic new capacity sooner than combined-cycle systems since the extra efficiency of combined cycles and the cost of the bottoming cycle do not make them competitive with regional coal and hydro power. He emphasized the new importance of partnerships in projects, with leverage ratios approaching 50:50, and noted the importance of trends in consolidation of the industry and the importance of environmental issues.

Dale Simbeck, SFA Pacific: Mr. Simbeck pointed out advantages of advanced aeroderivatives like ICAD for various applications over convention gas turbines. Advanced turbines could take a share of the combined-cycle market. There is a large international market for midsized combined cycles and cogeneration. He raised the issue of how the development costs of advanced aeroderivatives would be paid for.

David Walls, Arthur D. Little (Unable to attend - sent copy of presentation): Mr. Walls presented results of a CAGT-sponsored study indicating a global point market for ICAD/FMGT of 3,000-5000 MW per year after the year 2000.

Presentation by
George Touchton

Panel Chair, Electric Power Research Institute

Good morning, ladies and gentlemen. I'd like to thank the California Energy Commission and the Department of Energy on behalf of EPRI for asking us to participate in this conference.

We view this as a continuation of the workshop series that we have been conducting with DOE, with various stakeholders, the Gas Research Institute (GRI), the National Renewable Energy Laboratory (NREL), and others, and we're very pleased to be here today to talk about changing electric markets.

I guess one of the things about putting a conference together quickly over the Internet is you have second thoughts right up to the very last minute. I think I would say now that it is a changing energy market: that is, whether it's electricity or gas may be relatively immaterial to the end user, so long as his needs are met.

I think David Rohy has indicated to us that a lot of planning and thought have gone into creating new competitive markets. California is one of the leading examples of that, but I would stress that the exact shape, context, and outcomes are not known, as other markets that have developed in the United Kingdom and in Australia have shown us.

One certain thing, though, is that there will be a lot of disaggregation of these markets. We've seen that in the airlines where we have hub and spoke competitors, point-to-point competitors, low-price specialized-market competitors and long-haul specialized-market competitors.

And I think in our market, very simply, that the peaking ancillary services for which there will be a market next year in California will be one segment of that market: a very high margin market and limited in scope.

Another segment of that market is certainly going to be commodity priced bulk power provided by hydro, nuclear, coal, coal by wire — a very low margin, very high volume business.

And a third segment, which is what we're here to talk about today, is the potential for a mid-range market that would be higher margin, more opportunistic than bulk power, but less specialized and less of a niche market than peaking and ancillary services.

And what I want to try to focus on in this panel, and I think we have an excellent set of people to give us a perspective on that, is the fact that it's really going to be what the market needs as to what is going to drive the development of the technology that serves it.

And in particular, I'm a little perturbed by the development of discussions of things like fossil versus renewable. In my mind, it's an energy mix that meets the needs of the consumer.

And if that can be enhanced by the use both of gas and renewable energy in a power plant or in, essentially let's say, a supplier alliance, or other mechanisms of this type, then that's what should be supplied.

And I think the dichotomy between the kind of fuel or how green you are or how green you are not just stymies us and leaves us in terms of the old debate. I think the market is going to drive it. And that's the focus of what this panel is here to talk about.

What we want to talk about is what technology serves this market, how do we finance it in the public and private sector, government agencies, DOE, the California Energy Commission, private institutes like EPRI and GRI, and associations like CAGT and GTA.

Presentation by
Mark Axford
Stewart & Stevenson

Stewart and Stevenson is a builder of gas-turbine generator systems. We are an affiliate of the General Electric Company, so my thoughts and comments really evolve from what we see in the marketplace and what we're doing with those programs.

The U.S. market is a mess right now. We've got a shell game going on called the "avoided-cost shell game." All the utilities are trying to recover as much as they can of their stranded costs. In California, they got a pretty good deal. They're going to get most all of them. They probably won't do so well in other states, but, nonetheless, in most every state there is not a lot of generation capacity being put in — gas turbine or otherwise.

In fact, one of the things that's forming what's left of the market right now is industrials trying to bail off the grid before they get handed a toll bill for being charged with leaving the system. You see, if there's no place to put these stranded costs but into the transmission and distribution bill, industrials won't buy any transmission and distribution services, but will make their own electricity. And we have some of that going on right now as the smart people realize that's where the bill's going to come from.

A few words on gas turbine history, primarily in the United States. A truck-load of gas turbines were installed in and around 1970. We blacked out New York City for a week and scared the daylights out of every person and every utility company. When the grid went down, they couldn't restart it, and they realized that there needed to be a lot of simple-cycle machines, basically black start units, so there were thousands and thousands of megawatts of that type of technology put in all over the country.

This was not terrific technology. Gas turbines weren't something anybody wanted. It was the only solution to the problem that was cheap.

Then as they got over that Band-Aid-type technology, PURPA came along in the 80's, and this game had a different set of rules. If you could make a machine that would give someone 42 percent combined-cycle efficiency in a cogeneration mode, you could run a printing press that made money. And people figured this out, and they put in a lot of them.

And all of a sudden, a new breed of gas turbines was on the market. Efficiency mattered, and we started driving into this independent power business. High efficiency gas turbines, aeroderivatives, which really weren't very popular before then, started taking on more popularity in the PURPA game because they could give a buyer the highest score card and win a power sales agreement.

This is what the market looks like for calendar year 1996, so this is pretty fresh data. The size of the market is about 30 gigawatts. And that's holding pretty steady for the last five or six years. It has been between 25 and 30 gigawatts every year, with a slight increase each year in the gas turbine power being sold.

The gas turbines listed here are only machines 10 megawatts and bigger. Those are the ones that are followed by the McCoy Power Reports, which is used as the bible, if you will, by most of the gas turbine manufacturers.

The big number, 44 percent, are the jumbos. This isn't G or H technology, this is J technology because these are jumbo gas turbines. What's small, what's medium, what's large? Well, it depends on your viewpoint. But, you know, only 10 years ago, 80 megawatts was a big gas turbine. Nowadays, 80 megawatts is really more of a medium-sized gas turbine.

So you've got the jumbos and the "bigs" coming up to two-thirds of the market, and then the smalls and the mediums kind of sharing the rest.

The sum total of the jumbos and the "bigs" keeps growing. And we're squeezing the others out of the marketplace.

This mid-range focus that George and Dale were talking about is not something that customers want or something that we're deciding we want to offer. It's just the marketplace taking its cold cruel outlook and showing itself to be what it is. This is what we're finding out, not something that anyone is really promoting or trying to make happen. This is just the way gas turbines seem to be run more and more.

The utilities are going back to all those independent power producer (IPP) sellers under base-load contracts and saying, what would it take to convince you to sell us less electricity? You've made your point. You can run these things 8,500 hours a year. We'd like you to run them 5,000 hours a year. We don't want all this electricity, especially at nights and weekends. Maybe we can work something out during the day, if you run mid-range for us.

As to the market for ICAD technology, and I think Bill Day made a good point, is that anyone that knows gas turbine technology can quickly tell you that when you intercool any gas turbine, you'll boost its power output, and you'll improve its efficiency. So why haven't we done that? We just haven't gotten around to it, and the marketplace never drove us all hard enough to do that. But with a gas-fired technology now coming into place and a market for, perhaps, larger aeroderivatives, we could see this ICAD technology becoming more important.

The midsize market for gas turbines is being ignored from a development standpoint, not only by the manufacturers but by the R&D providers. We're funding lots of research on the small end, we're funding lots of jumbo research, and maybe the question should be: Is this the research that our constituents and our customers want us to fund?

We talked about the deregulation of the market. We are way behind the United Kingdom. We need to look at what they've done and what they're doing. But we can also see this coming not only for what I would call real progressive markets, but the United States. If we don't get on to this quickly, we're going to end up being a third world country.

We've got countries like Peru, Chile, and all of Latin America selling off their government-owned electric companies to private companies. Argentina's on a full dispatch right now; and, you know, we need to get on the program to see what it's going to look like.

Now, these are smaller grids than in the United States. So whatever we might come up with on this midsize flexible gas turbine, this dispatchable product, might show itself very important in markets outside of the United States. And if it's at all important how many of these types of machines might be made by American companies, this is where the big markets are going to be. Not necessarily here in the U.S. for the next few years.

I want to spend a few seconds on the word Adispatch. If you're not using the AD word a lot, you need to think about it more. It's going to be part of your vocabulary big time. We'll focus on California because we're here today. They've got assets of all types. Nuclear: the nukes are going to run all the time. For God's sake don't stop them. You might not be able to restart them.

Hydro: if the dam's got water behind it and it's ready to go over the top, how about letting it through the dam, and making some electricity? When it's raining, you're going to use that.

Coal: big coal is in place. Some of it must run because of the situation of the plant geographically. When you get down to it, those types of power plants are almost preordained to run when they're technically okay.

So what's left? We've got the gas fired steamers, we've got the wind plants, we've got the renewable plants. This is a relatively small amount of capacity. And then you've got the gas turbines. Better than any other type of technology, gas turbines can be turned on and turned off quickly.

So that means when something else breaks or there's a demand spike, they call on gas turbines because that technology can do it best.

In a picture of California today, you see lots and lots of plants. That's the natural gas fired stuff that George was talking about, and that's going to be kilowatt history as soon as we get into the deregulated market.

After deregulation, some of this will be replaced with a couple types of power. Your power marketer — that might be coal by wire, hydro by wire, take your pick there; then you've got the modern gas turbines. There will be some jumbo combined-cycles in there perhaps, and there will be some machines like ICADs if we invent them, but this is a big block of power.

And it's not something that just plays in California. You could go to any region in the United States and draw a dispatch map like this. It might be more coal heavy in some parts of the country. If you went to Chicago, it would be very heavily flavored towards the nukes.

But there are a lot of nukes that are in trouble right now. They're getting older, their reliability isn't what it used to be, so each region has its own particular problem to solve. And the quick start dispatchable gas turbine is going to be part of that solution. But it's not going to be all of it.

So how are they going to do this? We don't know for sure in this country because we haven't done it yet. So how are they doing it in other places?

You will take a phone call from the dispatcher. He's going to tell you that he wants you to start your power plant. Well, how long do you think I'm going to run the plant? Probably at least four hours. Probably not less than eight hours. But after that you're guessing.

And from what we've seen in markets that have deregulated, dispatchers are not normally going to call a dispatchable plant and promise them they'll get to run for the next two weeks or the next two days. They're going to get four to eight hours. That seems to be what the marketplace is saying.

So what would that look like if we started plugging in power plants in the United States, new ones, that had to maybe turn on and off twice a day for four to eight hours at a time? How would the machinery be able to deal with this, if it could? From a financial perspective could people make money doing this, the people that own these power plants? And from an operation and maintenance standpoint, can we take care of a power plant that has this type of characteristic if the market calls for it?

Start time is very important. Aeroderivatives are very quick to start and synchronize from a warm restart. You can take an aeroderivative, Stewart and Stevenson's or anybody's else's, push the button and have the power plant synchronized and making full power in less than 30 minutes, in combined cycle mode. On a simple cycle basis, this can be done in less than 10 minutes.

The medium-size frame turbines, because the machinery is just so much larger and the casings are thicker, have to be more gently ramped-up to speed and ramped-down, it takes longer. And then with the jumbos you're looking at almost 100 minutes in a combined-cycle before you've got a power plant at full power.

Now, wait a minute. You just got a telephone call that says you're supposed to run for four to eight hours. If it takes you two hours to ramp-up to full power, you're starting to lose some of the edge of this game.

In fact, if you were to measure how much fuel would be consumed, say the dispatcher scratches his head and says, I need 250 megawatts for four hours, that's 1,000 megawatt hours, how might I get this? These three bar charts illustrate how you would do it with four 45-megawatt aeros, the middle with two medium-sized frames, and the right with one jumbo combined cycle.

When you look up the ratings for these different machines in *Gas Turbine World* or wherever the numbers are posted, every person that makes machinery wants to tell you how efficient it is at base load. But the problem is it's not going to run at base load only.

Because you're going to be starting it up, and during that warm-up period, it's going to use much more fuel per kilowatt than it does at base load, and then the dispatcher's going to say, turn it down. Well, you can't just yank the plug out of the wall. You have to gently ramp it down so the casing doesn't warp and the machinery doesn't break. So during those warm-up and cool-down periods your Btus per kilowatt are much higher than advertised.

So, with aeroderivative technology, if you had a flexible-type machine that could fit this mold, you could shrink the amount of losses in those warm-up and cool-down times, and get your effective heat rate — the real-world heat rate. It's kind of like EPA mileage. Your mileage may vary. This is the real McCoy. This is what, you know, you have to pay to the guy selling gas to you.

So bigger is not necessarily better on this. The more jumbo you get, the more losses you have during dispatch.

This is a plant that we were part of at Stewart & Stevenson in Colorado. There are five LM 6000's and a pair of steam turbines in this plant. There will be a sixth one some day on the left. It's a funny looking plant, but they built it for a 300-megawatt nominal load. And they start and stop these turbines every day. This would be the world's greatest power plant but for one thing. It cost too much.

And this plant cost about $500 per kilowatt to build. Now six or seven years ago, people would have said, hey, you know, that's a pretty good deal. Fifty-three percent efficient plant, $500 a kilowatt. Well, that's not such a good deal anymore because the price of this machinery has gone down.

But that's what you can do probably with 50-megawatt-type gas turbine aeroderivative technology. But it's not good enough. To get the economy of scale to get down below that $300 a kilowatt number, we're going to need aeroderivatives bigger than 100 MW in size.

I like to ask people, what do you do to make a turbine fast? Sometimes the way you explain that is tell them what to do to make it slow.

And if you wanted to make a power plant as slow as you possibly could, use the largest machine you can possibly find, staple a steam turbine to the back end of it so it'll take a long time to warm up, go to a 2,000-pound steam system so there's all kinds of heat recovery equipment that's massive and takes a long time to heat. In fact, use a double-heat reheat system. That will impress them a lot that you're really technologically astute.

But all the things that people are doing to reach this high efficiency number are the exact same things that slow you down, and there's a net loss in what customers are going to get and what people are doing to get this efficiency.

There's also maintenance penalties to pay. The thing about aeroderivative technology is that they were designed for planes. They pull up to a gate, let passengers off, put passengers on, and fly again. Most major airlines start and stop their planes three or four times a day. That's how these engines were designed. There is no penalty, per se, to stop and start an aircraft engine because they were designed to avoid that penalty.

Heavy-frame, land-based gas turbines pay a charge for stopping and starting. It's a little different from one machine to a next, but in general that charge is about 25 hours of maintenance life for each start on a frame gas turbine. That's for the medium size ones. For the jumbos, we don't know yet. But I think it would be unrealistic to think that it's smaller than the medium size.

People might not buy any gas turbines anymore. The market forecast is so short term that the concept of buying something that would look stupid five years from now worries a lot of people. So maybe you don't buy them. Maybe you lease them. And if your forecast was wrong, maybe you move them some place else.

In order to have a lease market for anything, airplanes, cars, turbines, you have to have a mass market. You can't have a factory making five widgets a year, and say, I think I'll make a lease market for widgets. You have to have dozens and dozens or hundreds of these things being made so that when one person is done leasing it another person might lease it.

And as an example of this, last spring we got a pretty urgent call from Northeast Utilities. I think Erik is here someplace in the audience, and they had a problem when a nuclear plant gave them a surprise. So we raced five 40-megawatt gas turbines up there, got them synchronized and on line in less than 60 days from the phone call, but what I think is the big wow in the deal is they didn't even buy them. They leased them.

And will they solve their nuclear problems in the next couple years? We hope so. They hope so. But if not, they'll just renew the lease. And if they do, they'll send them back, and we'll move them somewhere else.

An advanced aeroderivative could be moved. It could be relocated to where the demand was if the demand moved or if other technologies become available. And I think that's going to be an important thing into the strategic advantage of companies that buy turbo machinery in the coming years. We talked about the foreign markets. There's big tax advantages in many of these markets.

Will deregulation bring bigger aeroderivatives? We all know how large these are likely to be: in the 100 to 125 MW size. We all know what type of efficiency we would be able to achieve: something between 45 and 50 percent efficiency. And the question of whether or not these are going to be built gets down to who's going to pay for it.

Because right now funding is a problem. This is hugely expensive. Successful companies in the aeroderivative business, like GE, Pratt and Whitney, and Rolls Royce, aren't going to do this all by themselves. They want market buy in. They want to know that customers want these machines, and that there is a resolve to share the cost to assure that the program will be successful.

So I say, "Stay tuned." We've done our market research. We know there is a market for these gadgets. Now we have to figure out how to get the product to market and pay for that research.

Thank you.

Presentation by

Barry J. Davidson
National Power PLC

A European Perspective: National Power is the largest Generator in the United Kingdom (UK) at about 17 GW and is ranked within the top 30 companies in the FTSE 100. We are an Independent Power Company and we see ourselves as a global operator in an increasingly competitive market. National Power currently has interests in 11 operational power stations outside the UK corresponding to 7.5 GW of capacity. Total foreign investment is of order $1,300 million in equity, and we expect to at least double this by the year 2000.

As a world independent power producer, we are doing business in the U.S. with Offices in Houston, Atlanta, Milford, and increasingly elsewhere. We are a customer for U.S. products within and outside the U.S. In the U.S. at Milford, we have Westinghouse gas turbines; at Hartwell, Mecklenburg, and Oyster Creek, we have GE machines; at Hopewell, it happens to be ABB technology.

In the UK, following privatization in 1991, we have seen competition in generation with encouragement for new generators and open access to the national transmission and local distribution networks. The choice of supplier for large customers as a feature and choice for all customers will occur after 1998.

It is worth recapping some of the key issues that we have faced over the last 5 years or so in the UK, from the point of view of surplus capacity, the cost base, the market imperfections, and the environment. This will help provide a perspective to address the following question viz. : Does National Power see a business opportunity for flexible midsized gas turbines in the UK? In some respects, it could be perceived as a threat. I offer a brief glimpse at the European scene in addressing this question.

At privatization in 1991, the UK capacity planning margin was typically 24 percent, the historical mission statement being " Security of Supply." Since then, there have been a number of plant closures, but this has not postponed base-load additions running at over 13 GW of gas-fired capacity. Old, small coal plants of low efficiency by today's standards, were not financially remunerated in the UK Pool system and as a result, most have been closed. The environmental threat of this inherited plant would have been a serious cost burden to us also. The basic tenet is that the low cost producer wins, as price is the principle driver in a commodity market.

The small coal plant and open cycle gas turbines are a very small fraction of generation capacity. Large coal-fired stations dominate and combined-cycle gas turbines (CCGTs) and the nuclear stations are significant fractions. The large coal and oil fired plants are relatively young and quite efficient, but are subject to asset renewal for commercial reasons and to maintain our environmental reputation. Part of this renewal is to switch away from coal or oil over to gas and if consent is granted on all conversions, National Power will have over 4 GW in converted gas plants. In practice, these stations will not be run at the high load factors of CCGTs because of their higher operating costs; but conversion represents an attractive option to new construction in the mid-merit generation sector.

A coal plant is not the ideal base-load plant either because its operating costs are comparatively too high, and so, it actually performs mid-merit duty on the UK system (i.e., cycling and lower load factor duty). It is this marginal plant that sets the Pool price. Existing gas plants in the UK, mainly in the form of CCGTs, are used for base-load duty, but this could change with more entrants.

The Government initiatives to increase competition have resulted in National Power being required to dispose of 4 GW of large coal plants. This has gone to Eastern Group, who are now a significant UK player. National Power's market share has subsequently fallen, amplified by other independent power producers also entering the market and comprising over 14 percent of our generation capacity. There are many other IPPs that are currently applying for planning consents. If successful, this could lead to a plant margin of over 40 percent or nearly 76 GW by the year 2000 (assuming no closures). This is unlikely, but there will be no shortage of capacity. The drivers for IPP entry are not based on signals from the pool for the requirement for new capacity. The thrust from the Distribution Companies, for example, has been to make investments covered by contractual revenues, not relying on pool income. These are known as " sweetheart deals" and are essentially a risk pass through arrangement with the comfort that the customer would pay in a franchise market not open to competition (i.e., the under 100-kW customer). The customer will have a choice after 1998. The low gas prices following the slump in 1995 stimulated a revival of gas fired projects; and current interest in CCGT projects remains undimmed, despite uncertainties with franchise removal. Most of the backers are large overseas concerns prepared to take offtake risk. If developers can lock in today's gas prices, the resultant new plant will be able to undercut existing gas stations in the merit order. Generators not receiving adequate revenue with reliance on pool income have had little alternative other than to offer higher prices to compensate for the expected reduced running in merit. This is perceived as the price setting power of the two big generators, National Power and Power Gen.

The capacity that is needed is not just a total plant decision but needs to take account the correct mix between base load, mid merit, and peaking. The viability of the flexible mid-merit plant is linked to the time weighted average of the pool purchase price (PPP) over a year. In the past, the PPP has been too flat to compensate the existing mid-merit plant properly, and companies like National Power with a portfolio have subsidized them from their base-load income. The use of a smoothed demand curve rather than actual demand for predicting plant schedules to determine the pool price means that the peaking plant does not set system marginal price enough and its distribution is undervalued at the high end. Consequently, while total capacity signals from the pool are working, signals to indicate the need for marginal capacity in the UK are weak. There is no real incentive to encourage marginal plant flexibility and in a single energy market, this leads to base load construction where possible, i.e., CCGTs.

If we look at the situation at the turn of the century, assuming a high entrant scenario, then the plant may be a flexible mid-merit for a number of reasons. First, it could be specifically designed in the future to take advantage of its location on the system. Currently, locational pricing signaling is less than perfect in the UK market. A second kind of plant may find itself running as mid-merit even though it was intended to be base load. This is because it could be constrained off quite frequently, because of insufficient transmission capacity, making the output unusable. Another option is the natural switch from an existing base-load role to a mid-merit role with age. Assuming a high entrant case at the turn of the century, and even allowing for Magnox plants coming off the system and freeing up part of the base load market, existing CCGTs could be asked to load follow and/or to have lower capacity factors, and thus to appear further down the merit order.

For locational advantages, there are moves in the UK to new flexible, small to midsized plants. One of the Distribution Companies, Northern Electric, in combination with Rolls Royce Power Ventures, has signed a joint venture agreement to develop, own, and operate 50+ MW open-cycle gas turbine (OCGT) plant, perhaps to avoid National Grid transmission charges. Southern Electric plans to build up to five 50 MW OCGTs in the south of England on natural gas. Except for DESTEC's Indian Queen proposal, this is the first order for an OCGT. The specifications suggest that Southern is looking to build modular stations based on high efficiency aeroderivative gas turbines. Southern's decision for peak plant suggests that it considers that the winter pool price spikes will continue well into the next decade.

The European liberalization position is summarized on a schematic. "Ownership" is on the y-axis viz. Public vs. Private, and "Organization" is on the x-axis and spans the Centralized to de-Centralized situations. A reference point is the UK in the bottom right corner. The extent and speed at which the intermediate/base-load market for the flexible, midsized plant will grow will depend in part on the speed and nature of deregulation. It is too early to tell how some of these countries will respond. For example, in Spain, the domestic customers will have a choice from 2008 and 20 GWhrs beginning in January 1998. In the Netherlands, legislation is in effect beginning in January 1998, and domestic customers have the choice beginning in January 2007. In Germany, the market is opening up in 1997 and all customers can choose. Belgium and Ireland have until the year 2000 and Greece until the year 2001.

To summarize, the new midsize flexible plant may be a rapid, key, market-entry vehicle because of lower financial risk exposure and the potential for greater availability of sites. There is the possibility of competitive first costs, shorter construction times, and reduced operator requirements from the new flexible technology to challenge the large CCGT option where fierce competition has reduced UK-wide project costs by 50 to 60 percent over the last 8 years. In the U.S. context, a perceived more dynamic pool system than is currently evident in the UK could provide incentives to encourage marginal plant flexibility. Very little baseload capacity is apparently needed in the U.S. during the next decade because of existing over-capacity. Most new capacity need is for peaking power. There are, however, a number of planned retirements of small, older steam plants currently used for cycling dispatch. These will be viewed either as a valuable future resource (with plant life extension programs) as base-load capacity declines and deregulation takes effect, or will be seen as an opportunity for new builds for this duty as new flexible engines make the market place.

Acknowledgements. National Power makes no warranty or representation whatsoever that the information is accurate or can be used for any particular purpose. Any person intending to use the information should satisfy himself as to the accuracy thereof and the suitability for the purpose for which he intends to use it.

Presentation by

George Hay
California Advanced Gas Turbine

We had a very strong distributed generation group at PG&E looking at very small generating technologies and an engineering department looking at 500 and 1,000 MW size plants. And my management in the research program one day said: "Boy, we hear all these different arguments, and what's the answer? Is it one large trained elephant, is it a million trained fleas, or is it something in between?"

And I think that's essentially the gist of what the midsize workshop is looking at: are there things in between that have a story line and a scenario? Over the last five or six years, we've validated the story line we're discussing and debating at today's workshop.

My perspectives are on a flexible midsize gas turbine in a changing electric market. CAGT was mentioned as a for-profit entity, a California small business, and some people have even pointed out that CAGT spells California gas turbine.

Why should we look at gas turbines? Why should we care about trying to forecast the future of them? A slide by Charles Bayless (the CEO of Tucson Electric) from an article in *Public Utilities Nightly* a year or two back shows the implications of the steam plant era, and what happened in the 1970s when electric utilities misforecast steam plant technologies and perhaps overbuilt the units.

A fundamental shift occurred in the electric utility industry. Gas became cheap, gas turbines became efficient, and the result was a fundamental shift, a technological driver for industry restructuring. That's why we really should care about forecasting technology. We need to know where it's going to be in the future to make sure we don't miss the turning points, particularly in a new market where we're beginning to value different things than in historic markets.

One of the trade offs between economies of scale and flexibility with gas turbines is: as you get above 100 MW, some of the economies of scale dissipate relative to the losses of flexibility.

The CAGT program was started at the California Energy Commission Energy Efficiency hearings in 1991 as a collaborative of the California electric and gas utilities and the California Energy Commission. The vision was that there are 20,000 MW of aging natural-gas-fired steam units in California, and the question was what would replace them with in the 2000-2010 time frame.

It is interesting to note that some of those units are now up for sale. It's also interesting to note that most of the research programs of the electric utilities no longer do generation R&D in California. It's been an interesting five years.

In looking at that market, we began realizing that California's really just a small but important player in a world-wide market for gas turbines, and we needed to pull in buyer perspectives from all over the world. And CAGT has grown into an international consortium of buyers.

The $5 million Phase 1 study initially looked at highest efficiency turbines. There were a lot of parallels with the DOE ATS program, but as we began examining the market for the replacement of these steam units, we began to realize that they were cycling units and perhaps highest efficiency full-load wasn't the best criteria for evaluation.

We came to the conclusion that ICAD or ICAD-like technologies were an important future player in the market. They might be 20 to 40 percent lower in costs than a combined cycle, with efficiencies better than steam units, and superior attributes for the ancillary services George Touchton just described that may be coming in the future competitive markets.

An ICAD simple-cycle turbine without heat recovery is going to be getting efficiencies in the mid-40 percent range. At 100 MW, it gets pretty good economies of scale and has good quick-start capability. The competition is the aging steam units that are currently operating for cycling purposes, but ICAD efficiencies are better than those steam units.

Steam units that are very large frequently operate at part loads and really aren't necessarily 40 percent efficient. Frequently, they're operating at stand-by heat rates that are perhaps zero percent efficiency, if they're on hot stand-by.

What we identified for ICAD is this market niche between peaking turbines and large combined cycles, fitting the portion of the load duration curve for intermediate load — a whole new product class. For electric utilities thinking in terms of capacity or energy, base load or peaking, this is something new and different

In U.S. markets, it appears that excess coal and hydro are handling the off-peak periods. Load growth is coming. Electricity prices are dropping. We're seeing instances where people are pushing reserve margins more and more, and the resource choice may be some type of a simple cycle turbine with just-in-time capacity.

The huge market that we really should be discussing at this workshop is in the 2000 to 2010 time frame. This is the replacement market for these large natural-gas cycling units. It may dwarf load growth, and these units are an average 30 to 50 years old, at 5 percent to 50 percent capacity factor. The ICAD, or flexible midsize gas turbine, will perhaps accelerate the replacement.

The new economics of the IPPs and merchant plants make risks an incredibly important consideration. Issues are profit maximization rather than levelized cost for 30 years. Can I get financing from the bank? Can I get insurance from the insurance company?

A very great free-for-all is about to occur in the electric utility industry of wholesale and retail wheeling. Flexible, midsize gas turbines may be one of the technology strategies that marries up with energy and electricity and gas marketing when you're trying to bring power down from Canada and serve somebody in New Jersey. How do you firm up and guarantee the reliability of New Jersey when you're bringing that power down from Canada? Or the West Coast version of it, with BC Hydro in California?

On the issue of the steam-plant replacement market, if you add up California and Texas and New Jersey and New England and Florida, there's something on the order of 100,000 MW of these plants that fall into this 30 to 50 year-old category.

It's important to note the 2000 to 2010 time frame. I don't think we're dealing with a today issue, but we're dealing with a what's going to happen in that time frame. That's a huge market for replacement of intermediate load capacity and the shift to gas turbines from steam turbines.

From a power marketing perspective in the base-load market, you can get phenomenal deals on low cost hydro or coal flowing into U.S. markets. The off-peak energy in California is somewhere on the order of a cent per kilowatt hour. On-peak becomes a much higher value, and you can't get that power from those remote regions through the transmission system on peak. So in a way, we're really dealing with an intermediate load technology that's a large form of distributed generation.

Now one of the potential impacts of this is that as the power marketers come into these different markets, the capacity factor of the steam units may go down and environmental regulations after the year 2000 in changing market rules may accelerate the retirement of these units.

The energy service company perspective gets you to the question of who is the customer in the future? Who is going to buy the electricity? What does an aggregated electric customer look like, a local distribution company look like, and what are the technology strategies for serving them? Many people think it may be wholesale power contracts with a cycling gas turbine at the load center.

Now, as you'll hear from some of the folks in Europe, people are also looking in the wholesale markets for these coal plants that will become more valuable in the U.S. under deregulation. Other people are looking at putting simple-cycle turbines as feedwater preheating to get 60 percent efficiency for potential cycling capacity on large coal plants. It's a fascinating hybrid opportunity where we're looking at a new version of mixing gas and coal and different capacity factors in one unit.

To summarize, we're seeing a definite market for flexible midsize turbines and growing consensus of manufacturers and industry to develop the technology, but the question in the current environment is where do we get the R&D funds to do it? And in some cases, we may have to wait until it's too late to really define the companies that may best benefit by these technologies.

Arthur D. Little wasn't able to make it to today's presentation. They were snowed in New York, but a hard copy of the Arthur D. Little presentation is available. They worked with CAGT on an assessment of the world-wide market for ICAD a number of years back, and the conclusion was that for ICAD-technologies, we may be able to find a market for 3,000 to 4,000 MW a year.

As we begin to look at the feedwater preheating market niche, or the firming power intermediate niche, those markets may actually dwarf the ones that have already been identified. But that's the point of research, and the point of these forums. Let's discuss the assumptions and discuss the forecasts.

Presentation by
Robert Nicholson
Bank of America

Good morning, and thanks very much for inviting me. I think I'm going to take a bit of a step back. I think you're all very directed towards one issue, the aeroderivatives issue. I will get to that a little later — I think there's some great potential there.

I spend a lot of my day trying to understand your business. And so what I'd like to ask you to do right now is try and understand a little bit of my business.

Project finance is definitely a changing world. We've heard about the international aspects of it. There's no question we are on planes constantly. Someone said that that's where the business is. Right now that's where a lot of the business is.

However, I want to assure you that as a financier who's traveled all over Asia and Latin America, I'm getting tired of it, and I'm really looking forward to coming home. So we're really interested in what's going on in California

There are more deals every day. Project finance is a sort of off-balance sheet. Everybody's really interested in that. You speak to your Chief Financial Officer and he's always probably pounding on you saying: I don't want any more debt in my books. S&P's giving me a bad rating.

What can we do to avoid that? Well, typically people come to us.

We just see a lot of deal flow. And, as potential developers, I want you to understand that the deal flow is a good thing for us. Absolutely a good thing. But it also causes us a lot of stress. One of the themes of my talk is going to be the fact that I think it's going to be very important as we progress with deregulation that you build a relationship with your financier.

Because to be honest, from Bank of America's perspective, more and more, Alan Rosenberg who heads up our Project Finance group says, the days of the cogen cowboy are gone. We are backing large customers, large clients who have shown a will to get projects done, and also who are moving and treating us not just as a source of funds but as a partner in the deal. And we truly believe we are partners.

I should have prefaced my whole discussion today by saying that I have more questions than answers. And I hope that's okay. But that's sort of the role as a financier. We just ask a lot of questions and hopefully you're the folks that have a lot of answers for us. And if you do, then away we go, and we've got a business deal.

But some other things are happening in project finance — from our perspective — tremendous consolidation in the industry. The industry is being viewed by the finance world as a real opportunity.

I'm sure many of you know the firm KKR, down on Sandhill Road in Palo Alto. I was down there last week making a presentation about the power business, and George Roberts of KKR sat in on it. So I think that, to me, indicates there's a lot of really big players out there who are interested in your industry. And I think there's a lot of opportunity in the industry.

We've gained an awful lot of experience from international deals. There are, as colleagues of mine have already mentioned here on the panel, a tremendous number of deregulated markets that already exist out there. The U.S. is definitely behind. That's not to say we can't catch up. I think this fits in very well with the aeroderivatives market.

In Chile, what we in Bank of America have seen is that there is a very short time frame of tremendous profitability if you can hit that shoulder of the peak. And potentially this is an opportunity where aeroderivatives work very well.

I don't know the aeroderivatives business very well. What I do know is what, to some extent, the market needs. And if you can marry what the market needs with a technology that works, I think you have a great product.

So project finance has been very dynamic. Lot of activity going on. A lot of pressure. It's a relatively small business. On the international scale, there are probably somewhere in the neighborhood of two dozen banks in the world that really do the business. Bank of America has one of the largest shops in the world in project financing. We've got 55 professionals.

So when you look at the faces, when you break it down to the actual people, there aren't a lot of people out there. Now, project finance in Bank of America also includes telecommunication systems, oil and gas fields, processing and chemical plants, so we're all not just power. So there aren't a lot of us out here. And all the more reason, I think, to encourage you to build relationships with certain folks because I think that's going to be very important.

I co-authored an article with a colleague of mine, I think it's in your packet — it's a discussion point. That's the way I'd like everybody to read it. The concept of deal triage is very prominent, at least in our shop.

What we look for are people that are strong sponsors — people who have the will to get a project done and who have made a corporate decision that, yes, they're backing this and they're going to go forward with this.

You know, two years ago, we were all in India. We were all in India because our developers were all in India. We follow our clients, typically. But right now, there's not a lot of activity in India for a variety of reasons.

Certainly we are the lead on the ENRON project in India, and everybody knows that maybe when that wall breaks down, things will go forward again. But the concept is that it is a fluid market, and you have to be able to move where you are needed. And, again, this is where aeroderivatives are a tremendous opportunity.

In deal triage, appropriate technology is definitely an issue. We need to understand your business needs. No longer do you bring to us a series of contracts, an engineering contract, procurement contract, a field supply contract, an off-take contract, and we marry them together and say, okay, I can loan you this.

You're not bringing those to us anymore, and you won't be in the future in a deregulated market. And as a result, we as financiers are going to need to understand your business a lot better. And we, Bank of America, are definitely in the midst of making that step forward.

We've been out of the business of power in California in many of the PURPA plants, many of the alternative energy plants. We don't have a lot of things on our books that are falling off the cliff. Mainly, that was because Bank of America was in its own financial straits in the mid 80's. And so we were not in the market at that point in time.

Since then, we've definitely identified power as a very important sector. You'll notice that in leading tables of international project finance, we're always up there. But I think what that says is that there's a commitment. We've made a commitment to look into this industry.

The contractual relationships don't exist anymore. Effectively you're asking a bank, someone who provides a debt, to take market risks. That truly is what's going on in today's market. And that's not something we can't get over, but we're going to try and extract things from you for it.

And I think the best example of that is the fact that a leverage ratio of 80:20 just doesn't work anymore. And I think that is going to be difficult for a lot of people to really grasp, but I think that is a reality of business because you're fundamentally changing the business. Before, we really literally had to marry some contracts together and take some risks. But now you're actually asking us to take sort of market risks. And that is a different game.

I'll give you an example of that. In the telecommunications industry which we do a lot of work in, typically the debt to equity ratio's 50:50. Sprint's PCS system that's being built out of all of the cellular systems was financed at a very different debt to equity ratio. And I think that's something that power developers are going to be facing also.

I just wanted to give you a heads up on that. I know that when we say we have the money or we make the final decisions, you're fundamentally asking us to go into a different business. And we're excited about it. Don't get me wrong. We are very excited about that. But it does have certain implications for us.

We're going to be asking you to prove that you have a will to get these projects done. Frankly, you should be asking us the same questions. I think it truly is a partnership from now on. It's much more of a partnership.

While we ask questions of you, you should be just as demanding of us. It's a two-way street. That's what a partnership's all about. And I think that will help you decide in the future which financial institution to go forward with.

I would like to discuss briefly some of the things we see occurring with AB 1890 here in California, because I think that AB 1890 will lead the rest of the country forward. Different parts will move at different rates, but certainly the Northeast.

We're a California-based bank, so we definitely have a sort of a bias towards California simply because we live it every day. We're either in *The Chronicle* or *The Bee* or whichever newspaper you're reading.

So I think we know a little bit more about California. We also think it's going to lead the market, and we're looking forward to playing in California. But there's going to be intense competition. I think everybody knows that, but I think there's going to be offshore people coming in, which we typically haven't seen.

You're going to get a lot of IPPs that are fundamentally going to be driving the business. They're going to be trying to cherry pick the good parts of the generation market. For the utilities, that's going to be a tremendous competition, something that's going to be difficult to deal with.

I think there's going to be gaming in pool bid system bids, certainly in the early stage. Everybody's heard the story that in Argentina, the effective bid price for almost a month was below the cost to operate. I don't think it's going to reach that in California, but I think you are going to see a lot of strategy around gaming.

Again I'm going to go back to the telecommunications industry, when the licenses were issued by the Federal Communications Commission (FCC), an awful lot of the large players — the MCIs, the Sprints — had University of Chicago strategists on board on their team to work in their bidding process. I don't think you're going to see that, necessarily, because it's a day-to-day bidding electrical pool, but I think you're going to need to think about the strategy of how bidding works in a new generating environment.

Many plants are not going to be dispatched. We heard the D word. I think it's very true. I think there are a lot of big old dinosaurs out there. I'm sure you know that better than we do, but I think as a lender, it's going to be something we're going to be very careful of.

Our perspective is that the most efficient plant is not necessarily going to be the most successful plant. It may be, but success is not defined by being most efficient. Success is defined by being able to play in the right price market on the demand curve. The two may be the same, but I don't think they're necessarily the same. That's where flexible generating capacity, such as aeroderivatives, may play a big role.

There are many outstanding issues in California. Some of the biggest ones for us are the designation of must-run plants and the pricing for ancillary services out of the ISO, power marketing issues, and as one of my colleagues mentioned, the environmental issue.

We see the environmental issues actually changing the way power is generated — not because of emission restrictions, but more along the lines of hydro. The Pacific Northwest is going to play a large role in how things work in California. Sure there are restrictions at the tie line, there's no question, and maybe Washington and Oregon are growing at tremendous rates and will eventually use up all the power they have. But think about this: If there is an environmental mandate that says you must spill so much water through this river, which is effectively what's happening, because we want you to support the fish, that is going to be changed the way hydro projects are dispatched. And modeling and understanding that is going to play a big role in pricing in California.

And again, I think that just opens up another opportunity. If the hydros have a mandate to spill, even if they would like not to, because they'd like to store their water for a higher price point, that may be an opportunity for the aeroderivatives to come in. Or a flexible system.

In the paper I co-authored, we looked at the pricing that we think may happen in the near future. The co-author I wrote this with is a fellow who does some advisory work for the ISO and also would like to be a power developer. So he and I always argued about whether we really should put pricing on this graph, or whether we should just let people draw their own conclusions. Because as a financier, I hate to be held to a price.

But the prices are up there. He and I don't necessarily agree on exactly what the prices are, but I think what's important is the illustration. And the illustration is that we believe there's going to be a diverging price between on peak and off peak.

There is going to be an opportunity for the simple cycle turbine, which is a little less efficient on the Btu heat-rate basis, but it's a lot less capital cost up front and a little more flexible. Those are some of the things that I think do work in the new changing environment.

And it is a brave new world out there. A brave new world creates an interesting dynamic. First of all, change creates opportunity. There's no question. Some are going to win, some are going to lose. But there's a tremendous opportunity out there, and that's indicated by different financial buyers interested in making bids on assets.

That's where you see the DESTECS of the world having a market cap prior to their divestiture process of being somewhere in the neighborhood of $750 million and being sold for $1.2 billion. That's an indicator to me that people are really paying attention to this industry.

There's been a lot of development offshore. There hasn't been a lot of development in the U.S. for awhile. I think people view this and deregulation as a real opportunity.

How's the airline industry really changing? Well, the small regional jets are becoming very important. American Airline pilots are striking over the fact that they don't want American Eagle pilots to be flying jets. That's because the pilots realize that the small flexible airplane is becoming more and more important in the spoke and hub system. And because spoke and hub is going a little bit more point to point, and that's where regional jets work in.

When you draw the parallels between a deregulated industry, whether it be telecom or the transportation industry, even the gas pipeline industry, all of those should be evaluated in trying to understand how the electrical industry is going to work.

Two points in conclusion. First point: changing environment creates opportunity. Second point: uncertainty creates a need for higher returns.

I mentioned already that you're fundamentally asking us to do something a little different now, in that we don't have a sort of a marriage contract where everybody matches up. You're asking us to do something a little bit different. We're going to ask of you higher equity ratios, we may ask for higher returns, but in turn you should be asking for the same things from that market.

I was recently in India on a power bid for a plant over there, and the company I was working for was using a rate of return of 18 percent. Because for them that was a good return on the U.S. dollar basis. Well, debt in India is 18 percent. And as a financier, we tried to explain to our clients that an equity return of 18 percent and a debt return of 18 percent doesn't make a lot of sense.

So don't sell yourself short. You're taking greater risks now, and that provides a lot of opportunity, and there is going to be a margin out there for you to get those returns.

It's exciting times. It's not going to be easy. But I think there's great opportunity, and that's what I'd like to conclude with. So thank you very much.

Presentation by

Dale Simbeck

SFA Pacific

We do mostly private work for the private energy companies. What we supply is objectivity, an outside view with no vested interest. That's rather unique. From a researcher's standpoint, we're your worst nightmare. We work with the banks and higher levels of the private energy companies.

We do work for international companies on the power side, and a third of our work is outside the U.S. We do work across a broad cross-section of the industry — the utilities, the IPPs, and the vendors. Personally, I like doing work for the vendors the most. They tend to be, by far, the most objective because they have to live life close to the ground and look at the truth.

The greatest change in my entire career is what we've seen over the last 25 years in power generation. Every time you think things can't get any worse for the regulated utilities, they get a lot worse.

A part of that has been the big growth in non-utility power generation. PURPA began in 1978, and very quickly people realized this was a license to steal from utilities. They were able to get extra base load into an industry that had too much base load, based on replacement power costs, when the utility wanted to build a new coal plant that was not cost effective. They got very good rates for the power.

Even after that was corrected, the trend continued, until now 11 percent of the total electricity in this country is not produced by regulated electric utilities. That's all happened in just 12 years. That's rather amazing.

The impact of that competition in power generation is that, when those IPP and PURPA plants started to come on line, utilities had to lower rates to avoid a death spiral and loss of customers.

Utilities and regulators learned that you can abuse the industrials and subsidize the residential rates with their electricity. Traditionally the U.S. abuses the commercial sectors and charges them more than they really should be charged. And that's why there's great interest in distributed generation. The residentials in this country do not pay their fair share. They are subsidized. And right now they're subsidized mostly by the commercial sector.

IPPs keep winning a higher share of the market for capacity additions in the U.S., a market that keeps going towards zero. The reason for that capacity addition trend is we have embarrassing amounts of excess capacity in this country, particularly base load. That was because of the oil shocks of the 70's, with the aggressive nuclear programs that were going on, and then no load growth, and then the PURPA generators coming with additional base load.

We have a lot higher reserve margins in this country than a lot of people like to admit to. How they avoid admitting to that is they take an ostrich approach with their head in the sand to the non-utility generators. If you pretend they don't exist, you can show a lot lower reserve margins than the real reserve margins in this country.

The market for the U.S. utilities and the independent power producers is a market that's uglier than sin for the next 10 years — that is nothing's going on. Everyone's waiting for deregulation to roll through and see what's going to happen. Since we basically only need a little bit of peaking capacity in the Southeast, there isn't a real concern. Since everyone's perception is that deregulation will bring their prices of electricity down, no one's going to do anything until that rolls through the system and we see what really happens.

The key result is that everyone has moved offshore. The action is in Asia, and our company spends about a third of our time in Asia. Our president today is in China meeting with them because they're looking at refinery upgrades that include a lot of power generation. I have to fly to Australia in three weeks. So we're in that market quite a lot.

The reason is it doesn't take a mental giant to see that that's where the power generation business is. You're in Asia or you're going out of business. It's as clear as that. That's why all the power producers and generators are spending so much time and effort in Asia.

The key thing that's turned this power market totally upside down is deregulation. And it's here to stay and it's going to continue for two main reasons: it's been very successful. It brings down costs, makes plants more efficient, results in lower emissions — it works.

The U.S. began deregulation, but England and Australia have passed us by very quickly. And they're doing a great job, and we should learn from what they're doing.

The other key thing, and with gas turbines I think it's the most important, is the true potential of cogen. Everyone in power generation tends to confuse efficiency with honor. Well, efficiency has nothing to do with honor. It's the economics. And the economics of high efficiency are not pushing technology to the wall at very high capital costs and very poor reliability; it's looking at cogen. And that's what deregulation does.

Siemens has done projections for world markets in five-year sectors, which is the way to do it because from year to year these numbers fluctuate a lot. They predict the worldwide growth in non-utility generators, independent power producers.

A deregulated market favors some items, while a regulated market favors other. In particular, a deregulated market favors smaller units. That's the key. And that's why all the turbine manufacturers have spent a lot of money to develop the GE 6F, the Westinghouse 401, the Siemens 64.3As. These are machines getting into this mid-range size. They're lower capital costs and aeroderivatives, as they stand right now.

These vendors are a lot of things, but one thing they're not is stupid. And they see a market, and they're going to adapt to the market change.

There are a lot of confusing issues in the environmental arena. The good thing is that over kill's gone. We look at the trading and conclude that's worked very well. The bizarre part is global climate change in CO_2. It's very unclear whether there's an issue, a problem, or not, but that doesn't matter. It's become a political issue, and perception becomes reality. Forget about technical issues. It's a political issue, and it's here to stay.

So you have to face up to that, and the future is right there, China. It's not technology. It's China improving efficiency.

Technologies favor gas turbines. We have seen growth in gas turbine sales and reciprocating engines on a worldwide basis. That's where the action is. That's where I'm spending a lot of my time these days.

True cogen, not to be confused with PURPA machines, favors combustion turbines. If you're looking at true cogen, you're heat-host limited. You want aeroderivatives or you want these advanced intercooled aeroderivatives that are even higher powered to cogen heat ratios.

The future is gas turbines. Everyone here, I think, understands that. The intercooled turbine has two great things. One is that it is ideal for cycling load for utilities, the other is industrial cogen. It's a designer-type cogen. You can match whatever you need, dump the rest of the energy back into the cycle. It's God's gift to cogen. It's a central-steam power-plant engineer's worst nightmare.

You're going to hear a lot about advanced turbines. All these programs are very good. The key thing is there's cost share. And by that I mean that the vendors have to cost share. The big ones are very important for the U.S. in about 10 to 15 years. The little ones go after that commercial sector, where we pay too much in this country. The intercooled aeros have a lot of potential. The key thing is they meet this changing market very well and can live with strategic uncertainties more effectively than traditional machines.

There are great opportunities out there, but everyone tends to get confused by the short-term issues. There's too much capacity, wheeling, regulatory delays, too many promoters out there. Don't get confused by the nonsense you'll see in the market right now. Look at the bottom line. The lowest cost producers win long term.

All the key issues drive you to combustion turbines because of the three E's: Economy, Efficiency, Environment. Ultimately I think there is a place for these intercooled aeros because they do have the flexibility to meet this incredibly changing market.

Thank you very much for your time.

Presentation by

David Walls
Arthur D. Little

In January 1995, Arthur D. Little completed a worldwide market analysis for a 120-MW, intercooled, aeroderivative (ICAD) gas turbine product for CAGT and EPRI.

Arthur D. Little was retained to conduct a market analysis and provide guidance to their market entry and commercialization strategy. The focus was on traditional market applications:

- Peak, intermediate and baseload, and greenfield applications.
- Combined cycle repowering.
- Industrial cogeneration.
- Utility and independent power producer (IPP) ownership.

The analysis was based on accepted regulatory practices. However, since that time, there have been many changes. Results of our previous study are presented here, and I discuss the implications of worldwide regulatory and market changes.

Based on the 1995 analysis, the ICAD market has the potential to approach 40 units per year within ten years of introduction, with the majority in simple-cycle configurations. North America and Asia/Pacific appear to be the most attractive regions. The analysis showed: 13 units per year in North America by the year 2008, as a result of the competitive economics of gas/gas turbines; and 9 units per year in Asia Pacific by 2008, driven by the growing gas market.

Up to 35 units per year by the year 2008 could be sold in intermediate load applications, that is 600 to 4,000 hours per year, using a simple-cycle configuration. In combined-cycle configurations, ICAD technology appears less attractive, with likely sales of only 5 units per year by the year 2008. ICAD gas turbine combined-cycle (GTCC) does not have an economic advantage over conventional GTCC.

Note that we had assumed that the first commercial products would be available in 1999.

Worldwide power-generation capacity additions were expected to be 90 to 100 GW per year during the 1999-2008 time period. The core ICAD market was estimated to be a portion of the oil- and gas-fueled market, which is likely to be approximately 30 GW per year.

We concluded that the ICAD has the potential to obtain up to 15 percent of the large industrial and utility gas-turbine market over the 10 year period of 1999 to 2008. This assumed a typical market penetration rate over the time frame.

The 1995 study noted that creating a multi-unit launch order by a mechanism like the CAGT could accelerate the ICAD market penetration by 2 to 3 years during the critical period of market entry. Based on historical data on market acceptance, market penetration by the ICAD would otherwise be expected to take 7 to 9 years.

At the baseline installed cost, a market of approximately 4,500 to 5,000 MW per year appeared achievable with at least 80 percent of the market being in simple-cycle unit sales. This market penetration scenario assumed a traditional market introduction and commercialization process, involving a limited number of initial customers and applications.

All these forecasts were based on our 1995 study. Since 1995, the pace of change in the global power industry has increased rapidly with many privatizations, deregulation, and widespread use of competitive bidding. The end-state of this change appears to be pooled or merchant power markets, with an emphasis on risk management in most segments of the electricity value chain.

In a pooled power market, a Genco (company involved only in generation) adds value through three principal activities in the electricity-supply industry value-chain. Activities in the electricity-supply industry value-chain are: fuel - generation - transmission - distribution - supply; and the Genco value chain is involved in energy (fuel) - capacity (generation) - ancillary and operational services (transmission). Through these three main Genco services, the Genco is able to influence the value of each section of the chain.

The potential for profitable operation of intermediate and peak capacity plants is resulting in a significant increase in new GTCC additions in the United Kingdom. In these competitive markets, it is becoming evident that there is room for new competition, even though there are no real capacity constraints in the United Kingdom.

In order for a technology to provide a competitive advantage to its owners, it will need to add value, or provide a cost advantage in all three Genco services areas:

- **Energy Payments:** fuel costs, variable operating and maintenance costs, efficiency, start-up costs.

- **Capacity Payments:** capital costs, fixed operating and maintenance costs.

- **Uplift Payments:** Ancillary Services — voltage control, frequency control, back-up resources, black start; Operational Services — transmission constraints, spinning reserve, demand forecasting errors, load following, unscheduled availability.

These market mechanisms should provide significant upside potential to the markets for technologies such as midsized, flexible gas turbines that can add value in all three segments.

Many of the changes occurring in the world have the potential to create technology needs that midsized, flexible gas turbines could meet. These changes could easily increase the market potential for the ICAD and similar technologies.

Opportunity	Technology Need
Pool/Merchant Markets	Capacity to capture market share; extract hidden value
New LNG Markets	Bridging capacity to establish market; 2,000 MW needed to support LND infrastructure
Tolling Facilities	Technology to support gas/electricity convergence; plant becomes a processing station
Stranded Gas Development	Capacity that balances efficiency, size, portability, and service issues.

Technology decisions in many non-traditional markets are strongly influenced by non-economic product attributes, which may favor the ICAD or other midsized, flexible gas-turbine products. Project developers are beginning to understand many of the non-economic attributes of aeroderivative technology. Product attributes such as compact size, high availability, mobility, serviceability, and maintainability are highly valued in many emerging applications.

Deregulation may lead to increased demand for technologies like the ICAD that offer increased project flexibility. Increased project flexibility may result from lower capital cost, shorter delivery cycles, portability, or unique operating and maintenance features that minimize downtime. Alternative financing techniques and project structures may be able to take advantage of the flexibility attributes. Business products involving leasing, operation and service contracts, and BOT schemes are likely to become more important in the future. New entrants into the power generation market (e.g., oil and gas companies, E&C firms, and arbitrage and trading companies) may be more willing to accept and exploit new technology features.

Integration of intermediate-load gas-turbine capacity with the gas supply system may take some time to evolve. Gas supply strategies will need to incorporate more short-term storage, back-up fuel supplies, and diverse supply portfolios to minimize pipeline capacity charges.

End Users' Panel on Market Needs

Summary of Presentations

Paul Bautista, Gas Research Institute - Moderator (no presentation): Intermediate power products and market are more important than peaking, because they allow higher gas line asset utilization. Indicated GRI's shrinking RD&D budgets with focus on creating new high value markets for natural gas, particularly distributed generation and pointed out their New Distributed Generation forum. GRI is supporting the development of FMGTs as a gas industry objective by participating in CAGT.

Christophe Bellot, Electricité de France: Mr. Bellot shared his analysis of ICAD. He indicated a large potential need in the range of 8,000-10,000 MW for intermediate load power like ICAD/FMGT in 2006-2010+ time frame for 2,000 to 3,000 hours per year. He also indicated the potential for nearer projects based on distributed generation "niche".

Ron Belval, City of Burlington, Vermont: Mr. Belval noted the interest in green power in New England and gave an overview of the New Millennium project, involving biomass gasification and the small gas-turbine RD&D demo retrofit to 50 MW biomass unit in Vermont. He indicated interest in looking at the ICAD/FMGT as a potential full scale commercial project, and encouraged the FMGT community to place more emphasis on integration with renewable technologies.

Jeff King, Pacific Northwest Planning Council: Mr. King indicated that the hydro system in Pacific Northwest requires fossil units that would sit idle for wet hydro years and would operate on baseload for long periods in dry hydro years. He noted that least capital cost with good efficiency was important. He also indicated that hydro environmental issues in the Western U.S. could reduce the ability of hydro electricity to meet needs for peaking power. He discussed the importance of green power.

Niels Laursen, ELKRAFT: Mr. Laursen presented the conditions for power generation in Denmark. In Denmark, the use of natural gas as a fuel for power generation is increasing. The use of gas turbines as feedwater heaters was presented as an option for gas-fueled based power generation.

James McCallum, Georgia Power Company: Mr. McCallum gave an overview of key features in gas turbine designs for competitive markets and applications, reflecting a recent IGTI article. He indicated that designs for intermediate load considered different product attribute mixes than peaking or baseload units. He said that a lower first cost was more important than for baseload units and efficiency was not as important.

David McCue, CNG Energy Services: Mr. McCue indicated that deregulation holds great promise for the future of power generation development. Key changes include: excess capacity loses its relevance when all power competes on an equivalent basis, new cost recovery mechanisms are available, and different methods of unit operation can be used. Risks will continue to be on the provider to guarantee a price, and customers will continue to demand low prices. Markets will develop for arbitrage between gas and electric markets in transmission constrained areas. Gas turbines can be an enabling technology, with quick-start, cycling gas turbines providing firming between markets.

Robert Reed, U.S. Generating Company: There is a disconnect between the power generation segment and the customers that will be bridged by power marketers. Technologies will be one of the drivers of change in the market structure. To compete, turbine technologies must approach the spot-market power price. U.S. Generating Company analyzed feedwater preheating projects in Florida and concluded that current aeroderivatives are not good enough — advanced turbines are required.

Eric Rorstrom, Northeast Utilities: Mr. Rorstrom described the results of analyzing simple cycle ICAD/FGMT benefits for intermediate load, and also feedwater preheating applications, from a user perspective. He emphasized the importance of short start-up time and the need to address turbine performance degradation with temperature increase.

Dan Whitney, Sacramento Municipal Utility District, California Advanced Gas Turbine chairman: Mr. Whitney shared his analysis of ICAD simple-cycle California superiority to combined cycles. Competition is displacing existing steam units with efficiencies in the 30 to 40 percent range, and competitive markets will favor least cost over efficiency. He described the changing investment climate, highly influenced by IPPS and new assessment of risks and rewards. This new climate will favor technologies that are efficient, cost-effective, and dispatchable. Green power applications would also likely be important in California where retailing, wheeling, and customers will favor projects or power portfolios with some renewables.

Presentation by
Christophe Bellot
Electricité de France

George asked me to give a few words about our prospects in the field of the intercooled aeroderivative, so I picked up some slides from a previously released paper.

EdF is generating and distributing the bulk of electric power in France, roughly 400 TWh (Tera Watt hour) to 30 million customers for a total capacity of 100 gigawatts.

George Hay would say that we are a dinosaur. But this dinosaur is still alive. We still think that he has a great future in front of him, and we'll see how we intend to survive.

EdF has made a shift to nuclear energy after the oil shocks — now there are roughly 60 gigawatts of nuclear, roughly 15 gigawatts of oil and coal, and hydro power is still important with 25 gigawatts.

Where are we now in the generation system? First of all, we have very high availability in our nuclear plants. The availability figure is now 82 percent, which is higher than expected during the design of the plant. That leads to an overall use of our fossil fuel plants that is quite low now. Eighty percent of the generation is made from nuclear, and roughly five percent only is made from fossil-fuel power plants.

So that means that according to the load growth, which is roughly two percent per year, we have no needs for peakers in the near term, we have no need for additional mid-range load units, and the only new capacity that will have to be commissioned is to replace the aging existing fossil-fuel mix. It's a bit difficult now to say when it will come. It depends on the policy of the company.

There are two alternatives. The first one is to keep these aging fossil-fired units alive, to run them as far as possible because the cost of the kilowatt hour produced is only the cost of the fuel and the cost of the operation and maintenance. It could be cheap.

The second alternative is to get rid of that aging fossil-fuel units and to use new ones.

This chart shows our load duration curve projected for the year 2010. Nuclear will be, of course, mainly used for base load. In addition, we'll have coal and oil fueled plants and the peakers, (gas turbines but also reciprocating engines as well).

In 2010 we'll have to replace these aging fossil fuel plants. What will be the best solution? This chart shows the cost of electricity versus the capacity factor. It is the cost for the electricity at the customer terminal.

Assuming that the ICAD would be 25 percent lower in capital costs than a large heavy-frame combined cycle, it can be seen that ICADs are more interesting than combined cycles for dispatch at lower than 5,000 hours per year.

There are three curves on this chart because I tried to show the difference between the multiple unit ICAD system and the single unit ICAD plant. I assume 10 percent lower cost for the multiple ICAD unit. Nevertheless, the cost of electricity of the single unit is lower because this single unit can be connected to a lower voltage level. It's a sort of distributed generation.

The additional advantage as we can see it now for EdF is, of course, higher operational flexibility, which is for us of first importance. I think that these ICADs could replace our oil and coal fossil plants used today as peaking units. Because of the very rapid start up, the ICAD is of high interest.

We expect an easy siting because of the reduced cold-source requirement. I think that you can put this machine very close to the load. It's usable for urban areas because of its compactness.

We hope that we'll have reduced operation and maintenance cost because there are not so many people to operate the plant.

And, finally, we hope to have short construction time.

One concern may be specific to France. As you may know, natural gas is 90 percent imported to France. And mainly through liquified form. And that means that the natural-gas transportation system is highly capital intensive. There is very low flexibility on the annual gas deliveries because of the liquified natural gas chain.

Second, gas is supplied continuously through the year. But power plants will be operated mainly during winter, because France is a winter peaking country. So we have to store the natural gas during the summer to use it during the winter. And it's a real constraint because the storage capacity is not so high.

As a conclusion, I would say that: because of the present capacity of our generation mix, there is no real need for new capacity before 2010.

We have a limited storage capacity, so we think now that the total capacity of natural-gas fueled units that can be installed could be around 2- to 3,000 MW. The optimum annual operating hours seems to be between 3,000 and 5,000 hours per year. And we think that for this application, the ICAD could be the best solution.

I want to emphasize the fact that mid-range load is the first driver for EdF to take part in the CAGT program. Potentially, there are also other applications that could be feedwater preheating for our coal plants. But it's a smaller market for us.

Thank you.

Presentation by
Ron Belval
City of Burlington, Vermont

I should start off by saying a few words about the Burlington Electric Department, given that I'm among the largest power marketers and power producers in the world today and they described their companies. I didn't bring a map, but if you were to look at a map of Vermont, you would have to look hard to find what might look like a tiny smudge in the northwest corner. That would be the Burlington Electric service territory. Let me assure you that I do not have a poor self-image, I simply didn't bring a map as the speakers before me did.

Nevertheless, I do want to tell you a little bit about Burlington Electric. We have about 18,000 customers with a system peak load of about 60 MW. One of the distinguishing features of the City of Burlington is that its citizens are active in setting the direction of their municipal utility. Over 12 years ago, Burlington voters approved funding for the construction of what was then the largest wood-fueled power plant in the U.S. This decision was based, in part, on the belief that environmental protection was important, and they wanted to reduce dependence on imported oil. This would be accomplished through the use of local indigenous fuels in a 50 MW wood-fired power plant. That plant has been operating for over 12 years, it's been supported by the local ratepayers, and it has provided over $90 million in economic benefits to the State economy.

People in Vermont thought this project was important then and they continue to think it's important today. Judging from what I heard earlier at this workshop, the use of biomass and other renewable fuels is becoming more important nationally. There are a number of federal restructuring initiatives under consideration that speak to this point. Bills have been introduced that would provide incentives to keep existing renewable plants operating and also support emerging new renewable technologies. These bills are necessary if renewable resources are to overcome market barriers until they can become more competitive on their own merits. Today I want to focus on overcoming barriers to the sustainable use of biomass fuel for power generation.

The primary barrier is the relative price of electricity generated from sustainable, renewable fuel such as wood. To continue operating in the future competitive market, there will have to be some mechanism for reducing the overall cost of power production, including the required capital investment. The price of fuel is not likely to be reduced very much from its present level, primarily because of the physical requirements for harvesting and delivery. Competing markets for wood products also tend to drive the price of wood in general. The only variables then are plant first-cost and energy conversion efficiency. This means that existing facilities will have to eventually be repowered or replaced.

In the interim, or until more competitive renewable technologies are commercially available, existing biomass plants will rely on subsidies to continue operation. With that in mind, I believe the challenge is to determine the amount of subsidy that will be equivalent to local economic and national environmental benefits created by continuing to operate existing plants. It goes without saying that stronger local economies enhance the national economy. Then, by definition, there would not be a subsidy. There would simply be compensation for the value of benefits provided.

After the complete transformation to a well-informed customer-choice of power supplier, buyers of electricity will more readily consider the implications of side effects of power production. If we don't recognize, in some way, the value of those economic and environmental benefits during the transition to the restructured electric utility industry, we will just have uneconomic facilities that could be forced to cease operation. If the remaining biomass power plants were to close, I wonder if the next generation of biomass conversion facilities would ever be developed. We should look around to see if there are options available today or that are likely to be implemented to replace or phase out existing less efficient technology. We may find that there is no such thing. Therefore we have to ensure, today, that new technology will be developed.

Development of new technologies will depend upon the continuing operation of key existing power plants. No matter how sophisticated or efficient new energy conversion plants may become, they will continue to rely on fuel procurement infrastructures, and the availability of experienced and skilled personnel and test facilities. Demonstrating technologies that are candidates for commercial application will depend upon well-run, existing, biomass power plants for umbilical services such as fuel supply, steam, electrical service, and human expertise.

This brings me to the point I want to make here today. I want to suggest the relationship of this project to midsized turbines. I have to admit that I have struggled with how to diplomatically present this point to this esteemed gas-turbine interest group. I understand that gas turbines are normally associated with the fossil fuel industry and that placing more emphasis on renewable fuels could be perceived as a threat.

Fortunately this topic has already been broached today and in fact has been discussed a number of times. Someone commented this morning that there is no escaping reliance on fossil fuels. I agree. Another comment was that the enhanced use of renewable along with fossil fuels is important. Both comments make sense and they don't have to be conflicting objectives. It seems to me that any proposal that meets both objectives should be supported.

A number of restructuring initiatives seem to support that belief. Some are federal, others are state sponsored. California is supporting a renewables portfolio concept. In Vermont, there is a proposal for an emission standard that would have to be met by all power marketers that wish to conduct business in the State of Vermont. This includes a disclosure requirement to identify the power sources and their attendant emissions. The Vermont Senate is also considering renewable portfolio standards as well as an R&D charge for renewable energy technologies development. Those portfolio standards are clear statements that some relatively small, and appropriate, amount of renewable fuels complementing other fuels is desirable.

The other point I want to emphasize was clearly described by our colleague from Northeast Utilities. New generating capacity is needed, if not now, very soon. The New England Power Pool has transmission system limitations. This problem has been exacerbated in certain areas because the transmission system was developed to support the large, central-station generating stations that will be out of service for an extended time-period. This is in addition to tie-line capacity limitations between control areas such as New York and New England. The New York to New England transmission system transfer limit is roughly 10 to 15 percent of the total New England load.

So all that adds up to what everybody's been saying this morning — new capacity is going to be needed soon. The opportunities are coming upon us.

This morning we also heard about a need for making significant advancement in technology. We recognize the need for some mechanism for making a quantum leap in efficiency. The McNeil plant generates power based upon a proven and reliable steam cycle. Most of the fuel that this plant burns is 40 to 50 percent moisture cull-wood that comes from the forest. Inherently in a steam cycle with high moisture fuel, it's impossible to achieve efficiency significantly greater than 25 percent. The McNeil Station efficiency is a little higher than that at about 26 percent.

We, the joint owners of the plant, are hosting a gasification demonstration project primarily because of the collective interest in increasing conversion efficiency. Battelle Memorial Institute invented the biomass gasification process and the license was purchased by Future Energy Resources Corporation for commercialization and development. It is being built through multiple agreements between the Future Energy Resources Corporation (FERCO) and the McNeil Joint Owners and with DOE. We hope that it will become operational by the end of March or early April. The first phase of the demonstration, taking place during the summer and through the fall, will be to prove that the gasification concept will work on a commercial scale. The next step will be to determine how well an industrial gas turbine will operate on the product gas.

The expectation is that the efficiency of gasification integrated with a simple-cycle turbine will achieve an efficiency of on the order of 30 percent. This milestone is considered the first step to achieving the ultimate goal of double the efficiency of current technology.

I will describe biomass gasification process. Some of you may already be familiar with it. There are two chambers. The first is a combustion chamber to heat sand, which is transferred to the gasification chamber, which indirectly heats the wood chips. The process starts by burning natural gas to heat sand to somewhere in the vicinity of 1,700 °F. Wood fuel is fed into the other chamber where gasification takes place without the need for blowing in combustion air. This is an important feature of the process, because it helps to keep the NOx production down and also ensures that the product gas has a consistent quality while the moisture content of the wood varies. One of the objectives of the demonstration will be to understand the limits of moisture content that the gasifier will be able to accommodate.

The heated sand is blown into the gasifier chamber where the entrained heat gets transferred from the sand to the wood chips. As the fuel gasifies, the product gas goes through a cyclone, where the sand and some of the char returns to the combustion chamber. The char then becomes the primary fuel replacing the natural gas and the cycle continues.

To prepare for power generation, the next step will be to clean up the product gas, reduce the temperature and compress it meet the gas turbine specifications. When this has been accomplished, the first goal in advancing the state of gasification for power generation technology will be achieved.

As I have said, the ultimate advance is to double the existing conversion efficiency. This morning, Victor talked about gas turbines and fuel cells in hybrid configuration being able to achieve 70 percent efficiency operating on natural gas. The New Millennium Biomass Power Program is based upon this concept. Natural gas would be replaced by biomass product gas. Biomass gasification integrated with hybrid high efficiency technology may be configured in many ways to match site characteristics and fuels availability. Biomass product gas could be the primary fuel with natural gas backup, or biomass could be co-fired with natural gas as the primary fuel. We believe it is possible to achieve somewhere in the range of 50 to 60 percent conversion from biomass to electricity. The ability to substitute for fossil fuels increases the value of such power generation projects by enhancing reliability and meeting portfolio standards for environmental protection.

Integration of gasification with hybrid systems makes a lot of sense. It turns out that the gasifier itself has some nice synergies with both gas turbines and fuel cells. With respect to the fuel cell, the product gas happens to come out at around 1,100 or 1,200 °F, and the fuel cell operates on hydrocarbon fuel at about the same temperature. These additional synergies seem to be an ideal match to enhance the high efficiency hybrid system.

As you can see we are not trying to reinvent the wheel. The ultra high conversion efficiency can be achieved by proper application of technologies that are already being developed. The idea is to tie together the three basic technologies, gasification, fuel cells, and gas turbines.

I want to wrap up by giving you a sense of the challenge. The upper line on the curve on this chart is pretty representative of the cost of power from the McNeil Generation Station, assuming an 80-percent capacity factor and allowing for return of capital investment.

The line in the middle represents the long-run marginal cost for a combined-cycle plant fueled by natural gas. The line below is a contract that we recently negotiated for fully dispatchable power. These, therefore, are pretty realistic benchmarks. This shows that large cost reductions and huge efficiency improvement are necessary for biomass power plants to achieve a competitive status with the combined cycle technology. Gasifier capital cost would have to be somewhere on the order of $300 to $500 per kilowatt equivalent. Figures as low as $300 per kilowatt for gas turbine power plants were thrown out today. Maybe that's possible, but achieving that cost for a turnkey combined-cycle project is certainly a significant challenge. A biomass plant at these costs would certainly be attractive if it were realistic.

Assuming the cost goals are achievable, another important characteristic of gasification/generation would be their modular and scalable nature. These traits would lend these technologies to a wide variety of applications. I think this is where the connection and potential opportunity lies with flexible, midsized turbines. If midsized turbines range from 20 MW to say

200 MW, then there should be great opportunities for repowering fossil fired steam plants and applications in the wood products industry. We are also interested in small-scale applications.

I think one of the bigger issues regarding the ability to utilize biomass fuel or renewable fuel as a supplement to fossil fuel is policy. Such a policy would have to say that the industry could burn some optimum portion of biomass fuel and allow the predominate fuel to be natural gas. This would encourage the utilization of renewable biomass fuel to its maximum potential while continuing to maintain or expand on a viable natural gas industry.

Cost of development, obviously, is also very important. In order for any commercialization initiative to be successful, there must be a promising revenue stream to attract market interest. The development strategy should therefore ensure the ability to spin technologies out and put them into the commercial marketplace as quickly as possible.

This first phase, for example, envisions application of the gasifier integrated with an existing turbine in the pulp and paper industry. There are a number of wood-products facilities, in the range of 50 to 100 MW that are ready to be repowered. So there's a short-term market out for this first technology, even though it hasn't achieved the ultimate high efficiency.

A fair amount of thought has been put into the overall process itself. There's a lot more detail behind this. Phase zero is the gasifier integrated with a turbine, which will be completed in 1998. The additional work that would have to be done in order to get the other technologies in place would have to be taken care of concurrently with that. Some is laboratory work and gas characterization that would be necessary to modify the design of the gasifier and the turbines or the fuel cells. The engineering and design work would be next, followed with the proof-of-concept taking place as appropriate.

Up to this point, there have been four players actively involved in the development of the New Millennium concept. They are Battelle, Future Energy Resources Corporation, Energy Research Corporation and the Burlington Electric Department. We believe that the Department of Energy would appropriately be a key player and among the principal coordinators of the overall project.

What we need to complete the group is a turbine vendor who would be interested in both participating in the existing gasification demonstration project, taking that to a conclusion, and then participating in the develop of the longer-term New Millennium project.

I look forward to more conversations on this topic. Thank you.

Presentation by

Jeff King

Pacific Power Northwest Planning Council

George asked me to say a few words about the situation in the Pacific Northwest and how it might bear on the possible demand for midsize, high efficiency, low capital-cost combustion turbines.

When I speak of the Pacific Northwest, I'm speaking of the states of Washington, Oregon, Idaho, and Montana. Those are the four states that are members of the organization I work for. It's the Northwest Power Planning Council, an intrastate compact agency, and we deal with power and fish-related issues that involve the four states.

Within the four states is installed roughly 44,000 MW of generating capacity, producing about 24,000 average megawatts. Hydropower comprises roughly 76 percent of that capacity. The balance of is mostly thermal, including coal, one remaining nuclear plant, an increasing amount of gas-fired combined-cycle plants, and a couple of simple-cycle combustion turbines.

Most of that hydro, something between 90 and 95 percent, is on the Columbia River system. And there's a fair amount of additional hydro, across the border to the north in British Columbia that's also on the Columbia River system and gets caught up in some of the issues that I'll discuss.

The Northwest is part of the integrated, synchronized western system and is interconnected to the south with California, and through California, to the Desert Southwest, and interconnected to the north with British Columbia and Alberta.

We are fortunate in that the Northwest has a winter peaking-load complementary to the summer-peaking load of the system to which we are closely interconnected in the south. And so we find power flowing south in the summer to supply air conditioners, and north in the winter to supply lighting and resistance heating in the Northwest. As you'll see as I talk about a few of these issues, the complementary loads are important in determining how we look at the future of our system.

One thing that George asked me to talk about is hydropower firming, because of possible applications of midsize, high efficiency, low capital-cost combustion turbines.

The situation is this: because of the huge proportion of hydropower supplying our system, we are an energy-limited region. A hydro power plant is designed for maximum flow, which you only rarely get. And so there's plenty of capacity. However, because the energy is determined by the amount of precipitation and the timing of the spring runoff, energy becomes a limiting factor.

Second, the energy output of the hydropower system in the Northwest can vary from 12,000 average MW in a dry year, to as much as 20,000 average MW in a good water year, which is a wet year with lots of snow that stays up in the mountains until late in the season.

Now when we have an abundance of hydro power, thermal plants get displaced. Because we're interconnected with the Southwest, those plants aren't only in the Northwest, they're in the Southwest as well.

Historically, what we've seen in the Northwest is displacement of coal-fired power plants that are supplied by rail-hauled coal. These plants tend to have higher variable operating costs and are the local candidates for economic displacement.

We also have one older combined-cycle plant that historically has gotten displaced a fair amount. It's a bit more competitive now than it used to be because of declining natural gas prices. But still we see it being displaced when we have particularly good hydro years.

The other plants that get displaced, we think, are gas boilers in California. When we have a lot of hydro power in the northwest in a good year, a lot of that power goes south. What we think gets shut down here are the less efficient gas-fired power plants.

So what does this have to do with high efficiency, small, compact, low capital cost combustion turbines? It has to do with the future of the gas boilers displaced by Northwest hydro power. Those gas boilers are aging. They'll become affected increasingly by the requirements to reduce nitrogen oxide production, and at some point repowering or retirement will probably be necessary.

When replacing these plants, it must be realized that there will be some years in which there's going to be an abundance of hydro power and the demand for those plants would not be there.

In drier water years, there will be a need for those plants, and they might be dispatched. This will not be a daily peak type of dispatch, but more of a seasonal dispatch where the plants are operated from periods of several weeks to several months, and then shut down when total load, both north and south, declines in the spring time.

We have looked at the seasonal performance of the power market on the West Coast. This study was done about a year ago, but the conclusions still seem to be valid.

This graph depicts the power prices by month for on and off peak periods. Prices range in the high teens for most of the year except in July and August. During peak periods in July and August, we see higher prices that may range as high as 35 mills.

Now, what's driving those July and August peaks is the southwestern air conditioning load. There is no comparable peak price period for the Northwest winter load. The reason for that is that we have a system with lots of surplus capacity, and we're able to meet our daily peaks using the hydropower system. So we don't need to draw on thermal sources, which is what's driving that summer time peaking price.

Looking out several years, we see some change in the nature of the market. We see a slight overall increase for most of the year from the high teens that represent the current situation to perhaps the low twenties, which would represent a situation with somewhat increasing gas prices, and perhaps some additional costs resulting from additional air pollution control requirements in the southwest. This also reflects some effects from increasing load, although our load growth is pretty low, and perhaps retirements. The summer peak period broadens out to include September and the peak prices get quite a bit higher.

Now this is only a model. The price estimates are cost-based, and don't reflect some of the supply-demand interaction that you see in real life. They also don't reflect weather-related events and equipment or failure events that might also create short-term peaks not only in the summertime, but in the wintertime as well. We saw that happening, for example, last summer when we had some major transmission failures.

But what this study suggests is that if you were to build to sell into this market, the opportunities for making money are restricted to fairly short periods of time in which prices are in the range that one can build a new power plant and expect to make some return on it. So, in order to sell into this market, you must have low cost capacity and operational flexibility because these peaks are summer-time air-conditioning peaks that happen for only several hours a day.

Moving on to another topic — fish recovery and its effect on Northwest hydro power. At one time, the Columbia River was the largest source of salmon in the world, with runs estimated to be as much as 16 million fish per year. It was a major piece of the economy. Those runs have been severely depleted. They're down in the range of a million or so per year now. There have been tremendous efforts made over the past 10 to 12 years to try to restore those runs, with not a whole lot of success, but people are continuing to try.

There are many elements to the recovery effort, but there are three elements that bear fairly directly on the way the hydro power system is operated. One part of the strategy is to restructure the flows within the Columbia River to more closely approximate the natural flows that occurred before the hydro electric system was built on the river.

At one time, the river flow peaked in the spring. That's when the snow is melting, and that's when the big spring freshets used to roar down the Columbia River and sweep the juvenile salmon out to the ocean. When the hydro power system was built, it was built to serve a winter-peak electrical load. So it was designed to shift water to the winter months when we experienced an electrical peak.

As we speak, the river is operated in accordance with the Biological Opinion of the National Marine Fishery Service. The Biological Opinion calls for shifting water to the springtime months of the year to more closely simulate natural river flows. This reduces the amount of winter base-load generation that's available in drier years. That generation is still available in wetter years because there's more than enough water to meet the needs of the Biological Opinion. But in drier years, there isn't enough water to both meet fish flow needs as well as provide winter time generation, so that water is held back, reducing winter-time generation.

There is a fair probability that there might be further shifts in the future if current efforts are not successful in recovering salmon populations.

A second component of the fish recovery strategy is "spill." Water is sent over the dams rather than through the turbines to flush the fish over the dams rather than through the turbines where they tend to be traumatized and injured. Spill reduces the overall output of the hydro system. Not only does it shift flow from winter to spring, but it reduces electric generation because the water does not go through the turbines.

A third component of the fish recovery strategy is reducing the reservoir cross sectional area during the periods of downstream migration. This is being done at the present time by "drawdown." Reservoirs are drawn down to a lower level than originally designed for. This decreases the cross section of the reservoir and increases current velocity. The idea is to sweep the juvenile salmon through more quickly, reducing the travel time to the sea, thereby reducing their mortality.

But drawdown also reduces the ability to manipulate the flow of the river, and may reduce the ability for winter peak load following.

And there are more dramatic drawdowns being considered. More than one proposal involves breaching some of the dams to return reservoirs to natural river conditions, which is, I suppose, the ultimate in drawdowns.

The implication in terms of generation is reduction in base-load capability of the system. But, I don't think that offers an opportunity for the kind of generation that we're talking about here. Rather, it probably will offer the opportunity for additional development of very high efficiency gas-fired combined-cycle units. A unit that can supply our wintertime base load in the Northwest can also supply summer base load in the Southwest. It can be run year around with a relatively high capacity factor. That's a natural situation for a high efficiency, moderate capital cost combined-cycle plant.

If we see further reduction in the ability to meet winter peak loads and load following capability because of these fish recovery requirements, that might open up an opportunity for something more along the lines of the kind of generation that we've been talking about here today.

George also asked me to talk a little bit about the renewables situation in the Northwest. We have in theory, at least, a fair amount of renewable potential of all sorts. But the ones that would be of interest for the kinds of turbines that we're talking about here today would seem to be what I would call intermittent renewables. In addition to hydro power, these would be wind and solar.

I don't think we're going to see much solar development in the Northwest even if we get an aggressive green-power marketing operation going and even if we get mandated expenditures on some renewables development, as is being discussed in some of the restructuring proposals.

Though the solar resource is not poor in some areas of the Northwest, it may make more sense to develop solar generation in the prime resource areas of Nevada and move the power to the Northwest in the winter.

We might see some development of wind power within 10 to 15 years, when its costs are projected to be similar to those of a combined-cycle unit. This might present an opportunity for a compatible, flexible, gas-fired generation that would operate when the wind isn't blowing. We have storm-driven wind systems. The wind blows violently for several days and then goes away for several days as one Pacific storm after another comes through the region. That would seem to be the kind of wind resource where a backup in the form of an operationally flexible, low capital-cost turbine might be useful.

There are proposals for a renewables development fund that would accompany restructuring efforts in the northwest. It's been proposed that this fund amount to about $35 million a year. If this were all spent on wind, which is unlikely, it would bring into service about 90 to 100 MW of wind capacity per year after the year 2000. And then maybe further out, like about 2010 or so, we might see the point where wind could compete on its own, and there might be more extensive development.

Finally, just a few words on industrial cogen. The predominant industrial cogen in the Northwest is in the pulp and paper and lumber and wood products industries. These industries have been declining for a number of years. I think we're down to the level that probably will survive until such time that the forests begin to recover. And then perhaps in 30 years, we might actually see some expansion of the industry once we have some recovery of the forest resources.

The greatest cogeneration potential is in the pulp and paper industry. There are about 20 operations in the Northwest. But because most of the ones that probably will continue to operate have recently upgraded with fluidized bed boilers or with small aeroderivative turbines, I don't see a lot of opportunity in that industry, though there may be the occasional upgrade occurring over the years.

Presentation by

Niels Laursen

ELKRAFT

My presentation will describe a power plant concept that will be used for our new power plant to be built in the eastern part of Denmark.

This power plant will go into operation in the year 2000, and it will integrate a coal-fired plant and the natural-gas-fired advanced gas turbine. The plant will have a total capacity of approximately 500 MW.

Before I present the concept to you, I would like to summarize the conditions for power generation in Denmark, as I think this will give you a better background for understanding why we are proposing this multi-fuel concept, as we call it.

Denmark has high tension lines. Electrically, Denmark is, in fact, two countries without connection. The western part of Denmark is connected to Norway and Sweden and also Germany, and the eastern part, which I represent, is connected to Sweden and Germany.

The power companies are organized in two groups. The western power companies are in a group called ELSAM, and the eastern power companies are in a group called ELKRAFT.

For the time being, the increase in electricity consumption in Denmark is very low. It's roughly one percent per year. This is partly because of demand-side management and integrated resource planning. So the need for new power plants comes from retirement of old units and from extension of the district heating systems, especially in the Copenhagen area.

Our fleet of power plants is getting older, and between the years of 2000 and 2010, a considerable number of units will have to be replaced by new ones. The older units are not equipped with efficient fuel gas cleaning systems. Their electrical efficiency is relatively low, and some of them are located far away from cities with district heating systems. So, therefore, repowering or refurbishment is not so attractive.

Traditionally, power generation in Denmark has been based on imported fuels, fossil fuels, mainly coal for economical reasons. We have no possibilities for hydro power. We have no nuclear power because of a parliament decision made in the mid-70's that nuclear power shall not be part of the energy policy, so we are, in fact, left with fossil fuels and renewables.

And for the time being, more than 85 percent of the power generation is based on coal, which we don't have, so we are talking about imported fuel. We import the coal from all over the world. That means very different qualities, so we always require our plants to be able to burn different coal qualities.

And for the last 10 years, new power plants have been highly efficient, super-critical coal-fired plants for cogeneration of electricity and district heating. Combined heat and power production helps us to increase the efficiency of the power generation system, and thereby reduce CO_2 and other emissions.

On a yearly basis, the energy efficiency of the Danish power generation system is more than 56 percent, when including the supplied heat for our district heating. This figure is going to increase in the future because of the extension on the district heating systems and because of the installation of more efficient power plants that will allow us to reduce power production on condensing units. But this dominant role of coal as fuel is going to change in the near future for a number of reasons.

Denmark now has its own natural gas resources in the North Sea. They are not big, but they are there. And a big national transmission and distribution system for gas has been established. For the time being, the power companies in Denmark are under powerful political pressure to use natural gas for power generation, partly to support the state-owned gas company which has a monopoly, and partly to reduce the CO_2 and SO_2 emissions.

The Danish Parliament has decided that CO_2 emissions shall be reduced by 20 percent in the year 2005 compared to the emissions in 1988. And this goes for all energy use in Denmark. And as it looks like the transportation sector has very big difficulties in achieving any reduction, the reduction requirement to the power generation system is probably going to be 35 to 40 percent.

Also the requirements for reduction of sulfur dioxide emissions are expected to be quite severe because of international agreements.

So, for these reasons, it's most likely that the main fuels for future power generation in Denmark will be changed from coal to a mix of coal and natural gas.

Up to now, our main effort has been to support the advancement of the coal-fired power plant. All our power plants are situated at sea, so that means that we have direct sea water cooling through all our plants, which again means that we can build such plants with an electrical efficiency of 48 percent net efficiency based on the lower heating value.

As mentioned before, we will have to use more natural gas for power generation in Denmark. And the traditional way would be to install combined-cycle plants in parallel to the existing coal-fired plants.

That would mean that you would foresee a system of power plants, part of them coal-fired with an efficiency of maybe 48 percent, and in parallel to those combined-cycle plants, natural gas fired with efficiencies from 55 to 58 today and maybe increasing to around 60 percent in the near future.

We are not so fond of combined-cycle plants because they are totally dependent on the gas turbine. If the gas turbine fails, you lose all your plant. Also, such a combined-cycle plant includes a steam turbine that is rather small, at least compared to the steam turbine that we use for our coal fire plants, and that means it's rather expensive, and it doesn't reach the high efficiencies that we reach with the big steam turbine. Also, the only possible back up fuel for this combined cycle plant would be expensive distillate oil.

Another possibility is that we could have a simultaneous use of gas and coal by combining our super-critical coal-fired plant with a gas turbine that is used as a feedwater heater for the steam plant.

This combination of gas turbines and steam plants can be made in several ways, but this feedwater combination is the most simple way to combine gas turbines and steam turbines or steam plants.

When you use the gas turbine as feedwater heater for the steam plant, you will reduce the extraction of steam from the steam plant, and in this way, the steam plant will act as bottom cycle for the gas turbine. And this bottom cycle, is very effective and efficient.

If we define the efficiency of the gas that we fire in such a plant in the gas turbine this way, that is, the output out of the total plant minus the energy fired for the coal and divided by the energy in the gas, then you will see that you can achieve a very high gas efficiency in such a combined plant

We have tried to take a number of different gas turbines and use them as a feedwater heater for this mentioned steam plant to see what gas efficiencies would be achieved. The coal plant itself is at 48 percent. If we use the LM 6000 aeroderivative gas turbine as a feedwater heater for such a plant, we would get a gas efficiency of around 55 to 56 percent. And roughly the same efficiency would result if we use an industrial gas turbine of the F technology kind. If we had the intercooled gas turbine, we would reach an efficiency of 59 to 60 percent with such a combination.

The total plant efficiency, of course, will depend on how much gas turbine capacity you would add to the steam plant.

So what is the reason for achieving such high gas efficiencies when using gas turbines as feedwater heaters? The reason is that the temperature difference between the feedwater and the exhaust gas from the gas turbine is much lower than when you are using extraction steam. Another reason, of course, is that you have a very efficient steam turbine as bottoming cycle.

The integral gas turbine that we have used for this exercise is what we have called an average, based on work in the CAGT project. Such a machine, of course, can also be used for repowering of existing machines. It's exactly the same concept as for a new plant. And whether it is going to be successful or not depends, of course, on the steam turbine that is available.

We have tried to combine this machine with two existing plants, the first one being a 250-MW unit from 1968. And we found that with the ICAD machine and calculating the same way as before, we could reach a gas efficiency of 56 percent.

This coal-fired unit is rather small in the low pressure part so that means that you have to reduce the output on the coal fired plant to accept one ICAD for this plant.

We also tried to use this machine in combination with a coal-fired power plant from 1981. This is a 640-MW machine, and here we reach a gas efficiency calculated the same way of 57.5 percent.

So we see possible applications, as well in combination with new plants, as in combination with existing plants in our system.

The conclusions from this is that, if you have a power generation system where you want to use coal as well as natural gas as fuel in the system, it's a better idea to use this concept with coal-fired steam plants, and especially aeroderivative gas turbines as feedwater heaters, than having several plants using coal, for instance, steam plants and combined cycle plants.

Thank you very much.

Presentation by

James E. McCallum
Georgia Power Company

I'll be speaking about the need to incorporate the end users' value system into the gas turbine design process. This subject that I'm talking about was written up in the *Global Gas Turbine News* by Bob Richwine, one of our better engineers at Southern Company. He had to have surgery on his knee so he wasn't able to make the presentation. So you all bear with me, and I'll try to represent him the best I can.

One thing that we're looking at in gas turbine design is, of course, the application that you're using the gas turbine for. And the worldwide movement toward more competitive market-based systems of power pricing has led electric utilities and independent power developers to change their method of making technology and manufacturer choice to a more fully integrated business influences these choices. This, in turn, causes the gas turbine suppliers to rethink the process they use in designing, developing, and marketing their product.

Most of you know that, in the past, most gas turbines was pretty much standard design and there wasn't much consideration given other than to just build a gas turbine. And if you needed an 80-MW gas turbine, what was available is what was available.

In the past, it was also not much concern of the utility to try to get a gas turbine design for a specific application. So the main emphasis was placed on making sure that you designed a prudent risk-adverse gas turbine that would get the approval of the public service commission or a public utility commission in order to make sure the utility could build this facility and charge the standard rate of return.

But the market of today, or where it's headed, is going to be profit driven, meaning that you have to take more risks and manage your risks.

The past price of the electricity was driven by the cost, which was prudent cost, that was approved by the commission plus profit that was mandated by the commission, which usually was in the neighborhood of 12 to 14 percent in our area. Risk was avoided. So you really weren't concerned about risk. You would try to design the risk out of the picture.

Future profits are going to drive the market now. So profit is going to equal the price, and the price is going to be driven by the market minus the cost — the cost of building a new plant, the cost of producing electricity, all those things associated with building, owning, and operating a power plant. You have to identify those costs and quantify and manage your risks.

The total costs need to be considered, of course, including initial cost, and O&M cost — meaning variable cost, fixed cost, capital cost, and major maintenance cost. And then, performance cost was also added into this, and at the end, you'd have your total cost and then the profit from there.

Some of the items that are included in performance cost include availability, start reliability cost, running reliability cost, and efficiency cost. All these items, if you want a real efficient unit, are going to cost you.

Along with the market price assessment, all costs must be included in the plant's portfolio when the user chooses its best equipment option. For different applications — base load, cycle, or peaking duties — there will be a different monetary relationship between each of these various costs and performance factors.

For peaking applications, some of the most important items that you would look at are low initial cost, low operating and maintenance (O&M) costs, and high start-up reliability. And maybe some of the least important things to you would be high availability, high running reliability, and high efficiency.

Of course this does not always apply for every application, but this is a general scenario of how this selection process works when you start planning peaking power.

For base-load application, you would have just the opposite. You would want high availability, high run reliability, and high efficiency. The least important to you may be high start reliability, because the unit is going to be started up. Theoretically, you would hope you start the unit up once a year and run it 8,000 hours and then shut it down for maintenance.

All those folks that work with gas turbines know that's not always true. You will get a few starts during the year even though it's a base-load unit.

Low initial cost is not as important as it was with a peaking application. But, of course, when you install a combined-cycle application for base load, you all know that the cost is not as great as installing a coal-fired or nuclear facility.

Low O&M cost is not an important item anymore, per se, but a 200-MW combined-cycle plant may be staffed with 21 to 26 people, where a peaking application may only have 5 or 6 on the staff.

High availability might be classified as of medium importance for a cycling unit, say a cycling unit that comes on every day and runs 12 hours a day, then shuts down, and is put in hot standby for the next day. But high start reliability for a cycling application is just as important as in a peaking application — because you have to start it up every day. So when you plan to build and own and operate this plant, you also have to plan for that unit to have very high start reliability.

A cycling application that is eventually going to progress into a base-load application, though, is a different picture. You would have to maybe shift the initial design to the base-load characteristics of what you're looking for in that unit.

There is a wide variation in the cost of unavailability. On the Southern system, you could experience as much as $8,768 per 100 MW of unavailability costs. In California, for example, those costs would be a lot higher. For off peak season, of course, the dollar amount really goes down — to $211.

The actual relationship among the factors that we were talking about a minute ago depends on their importance in the specific application. For example, for a plant site where fuel is relatively cheap, the value of efficiency is not as important as a value of efficiency in a location where you don't have the availability of reasonably priced gas.

Another example may be if you had an offshore platform where the interruption of generation would have an overwhelmingly large financial consequences because of reduced oil production. You really have to look at the relative importance of engine characteristics to design the plant or have the plant designed to the application.

In order to achieve a competitive advantage in the market, a gas turbine designer should qualify these factors in monetary terms according to customer specific value systems and incorporate them into the design and tradeoff process.

Early and frequent dialogue between the designer and end user is vital is order to develop an optimum product enabling the user to be a winner in an aggressive competitive environment.

Thank you.

Presentation by

David R. McCue
CNG Energy Services Corporation

I'm going to give a power marketer's perspective on some of the things that we've been talking about this morning, specifically on future generation development. A lot of things that I'm going to say have already been covered, and I'm not going to repeat them. But I would like to focus in on a few things that I think are especially of interest to this group.

First, my bottom-line message is that the prospect of deregulation holds great promise for future generation development. David Rohy this morning gave a good overview of AB 1890. I'm going to be talking on a couple of the details of that in California, which I think has a bearing on what's going to happen in the future.

The three main messages that I'd like to get across are that, number one, with deregulation, the meaning or significance of excess capacity for the purposes of the generation expansion business doesn't apply anymore. When full deregulation occurs, it will mean that all generation sources, new and existing, are going to be theoretically on an even footing to compete with one another.

The second point is that generation costs are going to be recovered in a whole different way than they have before. Specifically, in the power pool and through the pool bidding process, whether your unit runs or not depends on whether it's above or below the market clearing price at the time. That's going to create a different generation pattern than the strict classical economic dispatch.

The third area is that the units are going to be operated in a different manner.

So we do not have to worry so much about an excess generation capacity, number one; number two, costs are going to be recovered differently either through the power pool process or through bilateral transactions; and, third, the units are going to be operated and called to operate in a more robust environment.

Another area in which deregulation profoundly affects all of us that are in the generation business has to do with risk management. As many of you are aware, NYMEX established an electricity contract that started trading about a year ago. One wonders why it takes so long for this to happen. When, all of a sudden, did electricity become a commodity instead of a service?

Primarily, it comes down to the fact that risk management took on a whole new meaning for power suppliers, particularly utilities. In the past, utilities had the perfect hedge. Most of them could pass along any increases or decreases in fuel costs to their customers, by law and through Public Utility Commission (PUC) approval. They didn't really have to worry about risk management or about price.

The new transactions that we're seeing on the wholesale market and what is going to occur on the retail side, are transactions in which most, if not all, of the price risk is borne by the supplier.

So when the NYMEX electricity contract came along about a year ago, the idea was that now the supplier is going to have to have better and more sophisticated ways to manage its price risks. When they quote a particular price to a customer, then that price has got to be met, and it's got to be delivered no matter what.

Reliability, in financial let terms, now translates into liquidated damages, which means that if you don't supply or if you don't produce, then you have to make it up in dollars to your customer.

Over the past year or so, I've been involved with the WSPP operating committee in looking at standardized physical products. Those products are similar to NYMEX in that they have certain defined characteristics, but, in essence, their target is for physical power delivery rather than for financial risk management.

This leads into what types of power products the market is demanding. We are still working primarily in a wholesale market, but what we're seeing now and as we gear up for 1998 in California, are many more Requests for Proposals (RFPs) and proposals to buy power from load aggregators. These load aggregators, which are really retail loads, are asking for products that are very similar in nature to what the wholesale market is demanding. That comes down to pricing choices.

In other words, not only is the risk or most of the risk still on the provider to guarantee a price, but the customers typically want pricing choices. They may want a fixed price. They may want a risk managed variable price in which they're guaranteed a floor and a ceiling. They may want an index-type price with a floor and a ceiling. We're also looking at a pretty active electricity options market now. All of which, again, is associated with controlling risk.

Some of the other speakers this morning have talked about ancillary services — load regulation, load shaping, voltage control, reserves — all those things are now being unbundled, separated out from the basic power as a commodity, and are being priced separately.

We talked a lot about renewables and green power. Certainly in the work that we're doing, we see preference and emphasis given to green power in many requests for proposals. We also need to specify how much of our offering involves renewables.

Again, it comes down to reliability. If you're not 100 percent reliable, you must say how reliable you are, and most of the time, you must make up the difference at your cost.

The NYMEX contract is kind of a funny animal because, for example, one NYMEX contract is for 736 MW at a delivery rate of 2 MW. And it's delivered over the 16 peak hours per month.

Well, in any given month, you may or may not have exactly 736 MW hours of energy over those 16 peak hours. It is not so much a physical product as it is a risk management tool. In any case, one of the main attributes of new products is that they do have to start and stop very quickly.

One of the other standard products that we've looked at in the WSPP has involved four-hour blocks. So you may, if you have a generator that is deemed capable and responsible for generating that type of standard product, have to start and stop it every four hours.

The products and the machines that produce them are going to have to be robust, high efficiency, capital cost competitive, high availability, and have minimum start up and standby costs with rapid cycling characteristics and load regulating capability.

We heard quite a bit about the combined energy market that's rapidly evolving. CNG has been highly involved in this in two facets — gas tolling, and what we call reverse gas tolling.

In gas tolling, the idea is that we will rent someone's generator, bring the gas to it, and then take title to the electric power at the bus bar or some other delivery point. The idea is that if the spread is positive, in other words if the energy value of the electricity exceeds the energy value in dollars of the gas, then we will arbitrage that difference to make money in the market.

Reverse gas tolling, contrary to what it sounds like, is not where you pump power into the generator and gas comes out the other end. It's really a way in which you, because of a negative spread, sell the gas rather than using it to generate electricity, because it just makes economic sense.

So, for example, we've had customers who have gas contracts, and the deal that we've made is that we take the gas and we sell it, and in exchange for that, we give them electricity plus cash — basically the same electricity they would have had they used their contracted gas to generate in their own facilities.

The WSPP is looking for anywhere from a 1.5 to 2 percent annual load growth over the next ten years.

We've talked quite a bit about the outlook for retirements and divestiture. Speaking very conservatively, there's certainly at least 1,600 MW of fossil-fired generation that could be retired today simply because it doesn't come near being competitive.

Also, after the nukes are paid off, we're looking at 5,000 MW or so that could be retired after they're paid off. So very conservatively, we're looking at 6,500 to even 7,000 MW that could be retired over the next five years.

In terms of hydro electric capacity reductions in the West, the Colorado River authority has gone through a study in which they have essentially down-rated the capacity of that system that they feel is environmentally compatible. In marketing this power, there may not be near the capacity available that there had been before.

Obviously environmental compatibility is driving much of these retirements as well as economic compatibility, and clearly system reliability is a key factor here.

In the forecasting that we've done, we see three factors as driving the economic viability for new generation projects. One is hydro electric conditions. Those of us who have been involved in the power market over the last two or three years have seen what we think are rock bottom prices in the West, and that's very largely due to the very high over abundance of hydro. That appears to going to be continuing at least through this year.

However, over the long run, we expect hydro availability to average out so that what you're left with is the cost of fuel, and if we're looking at natural gas, then the lower the cost of natural gas, and at the same time the speed at which the market deregulates, are going to drive the profitability of new projects.

In a power pool-type model such as in California, then, as stranded costs are paid off and as we get through the CTC payoff time-frame, gradually we will reach a point where essentially all generation costs have to be recovered through the open market, be it through the pool or through bilateral contracts or contracts with load aggregators.

Once the bulk of the stranded costs are paid off, we're left with a situation where the remaining cost competitive units are still on line, and still have an additional amount of costs over and above what's been traditionally recovered from ratepayers that have to be paid off.

What we're seeing is that there is a bump up in bulk power, you might say commodity pricing, because now the only means for recovery is through this open competition.

What does the future hold? None of us knows, obviously. We appear to be in a trend where we're going from many regulated utility companies down to a smaller number of unregulated energy service companies. Obviously, new generation is going to be required. Deregulation, in general, seems to hold great promise for that success.

Thank you.

Presentation by
Robert Reed
U.S. Generating Company

Thank you for the opportunity to speak to you today. Although I have some nice slides and some interesting remarks, I thought, based on lunch time conversation, one thing I would like to accomplish here is to try to answer a general question, something like: If this is the greatest thing since sliced bread, how come it isn't happening?

U.S. Generating Company is a partnership between Pacific Gas and Electric and Bechtel. Although we have generation projects and we're hoping to develop projects and we have some offices spread around the United States, what we're trying to become is a company that's in power marketing as well as generation, as well as in the gas business. We're trying to become a competitive energy supplier.

The old Genco, the regulated power industry that we're all familiar with, has a structure where in recent years, competitive IPPs and integrated electric utility companies tried to generate all the power and sell it to retail customers. A few customers were large enough to do their own generation..

The new generation company or Genco is operating in a different industry. It's an electric power industry where you have generators, market aggregators, pools, T&Ds, retail customers, and again some self-generation people who are large enough to impact their own destiny.

One of the things that our power marketing people believe exists in the current situation is that the generation business speaks a different language from that of the customers. The customers are talking about no outages, 100 percent reliability, and we in the generation business are still talking about capacity, megawatt hours, and these types of things. And in between, there's some entity that's talking about VARs and VAR support and strange concepts like that.

So in a way, we see the market currently as one where there's a disconnect between power generation and the customers. This is going to change, of course, and then we're going to see market companies filling this void. They're going to come into play to be instrumental in driving where this industry goes and what it evolves to.

And in the market company, we see a generation business that is transformed from kind of unit specifications to be aggregated into portfolios, and then we are going to be trading blocks of power as well as customized products, and all of this is going to interact with the energy market.

Now what I think is very interesting is this 25-by-5-by-16 concept. I don't know how many of you out there are aware of what this terminology is, but this is what is being traded today in the market. It's 25-MW blocks, five days a week, 16 hours a day. This is the fundamental incremental capacity increment that is being traded, and this is what the marketing companies want. This is what they need to have to do their business.

And so four of these blocks, you know, can make an intercooled aeroderivative product pretty attractive if you put four blocks together.

And you might ask, well, what happens if US Gen sells to CNG one of these blocks? Well, CNG then has to go out and sell this 25 MW to a disaggregated group of customers, like a three-megawatt business that needs three megawatts and some other business that needs two and somebody else that needs five, and then they've got to split it up over the time interval to get their profit back from buying this 25-MW block from US Gen.

So with that going on, we describe a new millennium electric industry that in cartoon form, at least, has happy customers at the top of this pyramid smiling because they're getting low prices, and they're getting satisfied by marketeers who are out beating on their door to give them the products that they need.

And the generators are probably happy because they have these marketeers to sell to. And even the gas companies are probably happy because they're selling to the generators. And if it all goes around in a circle and everybody's happy, why it's a place we'd like to be.

Now if we take a more classic look at the structure of the electric power industry, which we have to do to figure out where this is going in the future in terms of some real numbers, we find that the industry is still highly fragmented, meaning that there are a tremendous number of entities selling power, and that each of those entities has a very small market share.

This is quite unlike airlines and some other businesses, the gas business and whatever. It's significantly different in terms of the fragmentation, the diversity, and where the power is coming from and the entities that are handling it. Deregulation is going to be different than some of the other deregulations we've seen.

And if we look at the largest segment of the electric power industry, we're going to look at the generation segment. What we're here today to talk about is where these generators come into the electric power industry. They come into the generation segment.

There is a lot of competition for financing and a lot of competition for marketing opportunities.

There is a distortion in the wholesale market today in pricing. The reason for that is that the marginal costs are what is prevalent in the price of electricity right now, and we don't believe that the costs that are out there reflect the actual cost of generation in terms of the book values of those assets and in terms of operating and owning those assets. But they are marginal costs, and we view that as a distortion of the free market.

There's a visible sign of competition in terms of rapid growth of marketers, and we see merchant plants being announced every day, which is another sign that there's tremendous competition in front of us.

I've drawn on two primary sources of information for this talk: one is the Cambridge Energy Associates recent report called *Power Trends 1996-1997*, and the other is the Research Data Resource International (RDRI) studies.

The chart suggests that the gaps between the current spot prices, the current combined cycle electric prices, and the industrial prices are the keys to where progress is going to be made in new generation and in satisfying the market. We can see that in some areas the industrial markets are going to be attacked quite vigorously because the rates are high. You can also see that we are not able to build much in the way of new capacity with combined cycles with the current technology that's on hand.

So this reinforces the statement that we need something better in terms of gas turbine technology if we're going to get closer to those spot market prices. Either that or we're going to wait indefinitely until the spot market prices move up beyond what the prices are that we can generate at.

In a traditional sense, there has not been much electric sales growth. It's been kind of sporadic, but right now if you leave off the end of that chart at 1995, you see you're growing at only a few percent a year. We can't count on growth to create our business.

If we split it up by segments, we can see there's growth in residential, commercial, and industrial, but not great growth in any one segment. So, again, growth does not provide the key that we're looking for and where to do our business.

If we look at peak power changes over a ten-year period from about 1985 to 1995 by regions, we can see that in some regions, there is significant growth for peak power. And in those regions, there is, or there will be, many peak installations put in the ground in the near term. You can watch for those regions to grow in terms of their peaking capability. That is a real market.

The studies that I'm using, the Cambridge Energy Associates and the RDRI, say that what we can expect is that the long-term trends will continue. The trends we see today are going to go forward for some time. They don't say how long. And these trends include continuing average price declines, investor owned utilities shrinking in number, and that the electric use in growth is going to continue to be tightly coupled.

If we think new capacity is going to be needed, then we have to look pretty carefully at where this can be put in place, because most regions currently have excess capacity. Looking at reserve margins, there is reason to believe that the reserve margins are going to be changing, and that they're generally going to be decreasing because of the factors that are shown here — retirements, peak demand growth, new generation sources, and transfer of transmission capability will probably limit reserve margin changes.

Looking at the RDRI study projections for the year 2000 and 2005, you can see that some areas are different than others, which is going to provide one of the strategic clues as to where the power business is going to change.

By 2005, you can see that we're going to have more lower reserve margins in a significant part of the country. In California, they estimate it moving from about 10 to 15 percent down to something like 5 to 10 percent over that time period.

These types of projections point to the fact that what we already know that there's going to be some pretty good markets out there after the year 2000, but they're not big, widespread margins. They're going to be niche markets or limited applications.

Cambridge Energy Research Associates came to an interesting conclusion, that these technologies are the ones that will drive changes in the future electric market in the long term. And we're kind of focused on number four at this workshop. Not exactly, but their take on the small-scale combined-cycle system, if you read the text of their report says, what's needed is a small power plant with greater than 50 percent efficiency. And they say much greater than 50 percent efficiency.

So that lines up exactly with what we're here today to discuss, and the reason I show this is that an independent research company analyzing the market came to the same conclusion. Although they call it combined cycle, it really is a high efficiency, small-scale gas-fired plant, that they indicate will be one of the key factors out in the future.

Now, to give you my personal observations and conclusions as to where this flexible midsized gas turbine could fit into our business. It could fit easily into new peaking applications. In fact, we have applications today, several 100-MW applications, that if we had a high efficiency midsized machine, we would be permitting that instead of something else.

Industrial replacements is going to be a big market. Because when we visit our potential industrial customers or would-be customers, we see aging, inefficient, old, small gas turbines that are ripe for replacement. And these are high polluters, low efficiency, but they're paid for. And if something came along that was cost effective and highly efficient, it could start to back out a lot of GE frame 5's and such type equipment that's out there right now.

And right now, the only way we can probably back out these small engines is with larger advanced technology products that leave us tremendous risk in terms of merchant power. If we had something smaller, it would be a better fit.

In a previous conference in Washington D.C. several months back, we addressed the repowering applications for this technology, and as several speakers brought up today, there are definitely repowering applications. We tried to fit an LM 6000 into one of our new coal plants in Florida and tried to integrate the power cycles in order to sell some additional power, or actually to try to provide some power for our power marketers in that market. We weren't really successful in the economics, because the power price has to be fairly low to take that risk of investment. And the LM 6000 just didn't quite get us there in terms of heat rate.

And that's because gas prices are not cheap in Florida, and because we're backing out a little bit of coal when we put that heat into the feedwater heating system.

I believe if we had this advanced efficient midsized turbine in that study, it would have been enough to probably get us just into a marketable power price range. So I believe it can work. And I believe in this case it would have worked if it was available.

And finally we are looking at high-efficiency capacity additions in a number of places, including New England, in Florida, in the South, I should say, and potentially in California. And right now, the biggest, most advanced technology turbines are the most feasible for these applications. But if there were smaller high-efficient capacity increments that we could rely on, we would probably be using some of those as well.

So in conclusion I would say there is a market right now for this equipment. And so why don't we just do it.

Presentation by

Eric G. Rorstrom

Northeast Utilities System

Even though Northeast Utilities, at 6,000-MW load, is large enough to consider by itself, I feel that we should be looking at New England as a region, as an entity that has similar needs but a much greater volume. Therefore, what you'll be hearing from me is probably more symbolic of all of New England rather than just Northeast Utilities itself.

The New England Power Pool as an entity is known as NEPOOL. There are many utilities included in NEPOOL. Northeast Utilities happens to be the largest utility within the NEPOOL group. NEPOOL as an organization has a 25,000-MW capacity. NEPOOL has a peak load of about 20,000 MW and an annual energy of 115,000 gigawatt-hours. Northeast Utilities (NU) represents approximately 31 percent of both the peak load and annual energy.

Base-load generation plants represent 48 percent of the NEPOOL generating mix, and we're heavy nuclear in New England. Not as heavy today as we would like to be, but we'll go beyond that. The greatest lump of our base-load capacity, 50 percent of it, is nuclear, with 22 percent coal. Right now only four percent is in utility-owned combined cycle. Twenty three percent of our base load is supplied by non-utility generators that have must-run contracts. Even though we don't need all that capacity in the base load, that's where they are. And about half of the non-utility generation in NEPOOL is in combined cycle capacity.

Intermediate load generation represents about 22 percent of NEPOOL capacity. Ninety percent of the intermediate generation capacity plants are oil- and gas-fueled steam units that you have heard about in prior presentations. These units were built in the late 50's through to the late 60's. They were originally designed for base-load coal. They're now burning oil and gas. The size range for these units is 100 to 300 MW.

These units are generally in good condition, but as time moves on, the impact of increased environmental restrictions on these units could make it difficult to maintain their current level of economic generation. Right now they are economic. We have spent a lot of money to make them cycle, but they still have the problem of long start-up times.

The peaking-load generation in the NEPOOL system runs about 30 percent of the installed capacity. Thirty eight percent of the peaking capacity is oil-fired steam units. The majority of these units are 400-MW steam-cycling units built in the early 70's. These units were installed when we didn't think oil was going to be very expensive, so they don't even have air heaters installed. Most of these units have very low capacity factors, but they're nice to have there when you need them, like last summer. Twenty percent of the peaking generation is made up of combustion turbines that were all installed in the crash right after the 1965 Northeast blackout. Most of Northeast Utilities units are the Pratt Whitney aeroderivatives, the FT4s. Forty-two percent of the NEPOOL peaking generation is made up of hydro-electric generation. That status may change because of increased environmental restrictions. Right now, we pond the hydro plants during off peak hours and run them during peak hours. We have two large pumped storage plants in New England, but most hydro-electric plants operate with ponding. Environmental regulations may force these to run almost at base-load, or run of river, so to speak. The environmental reasoning is to reduce fluctuation in water level to prevent bank erosion. Thus, the long term utilization of this resource for load following may be limited.

I believe that the first opportunities for the midsize high efficiency engine is for intermediate load duty. I came to this conclusion after heavily working on the other side, that is base-load duty. As I developed these slides, the market became obvious. It's amazing to see the synergism with what we've heard from other folks here already today.

We see the characteristics of this flexible midsize machine, which generally we think of as the ICAD, as being ideal for filling this intermediate load, with low energy costs and moderate capital costs.

One of the realities we determined when we started developing site requirements for a FMGT machine at a new site is that space is a premium. And anybody who's been through New England knows there aren't that many places you can build a power plant. Even though most of the new units might be installed at existing sites, power density makes a big difference in being able to put that capacity right where you need it.

Short lead times — we heard a little bit about the miracle at Devon earlier today. It was 45 days from the time we said to Stewart & Stevenson we want these machines and the first unit started generating. The FMGT should be capable of short lead times, not as short as 45 days, but short.

Another important feature is the ideal size for meeting capacity. Today, no one wants to buy large plants. One reason is that you may not get your money back right away. And adding 100 to 200 MW at a time, as you grow, is a nice way to plan your system. This is true even if you're talking about a system as large as New England.

As I see the New England market, and I think the other folks in New England will agree with me, the greatest opportunity will come after the year 2000 as capacity needs increase in both replacement from the environmental issues and just plain from needing more capacity. After the year 2000, the marker will start to grow at a rather significant rate.

Another important opportunity is the feedwater heater repowering that we've heard about. Nils Laursen will probably get to it in a little more detail than I have. We have several units within New England and within the Northeast utility system where there could be significant synergism between the particular steam unit and the ICAD. This synergism will produce an increase in performance over the separate operation of either machine. It is possible that some units that are now intermediate duty could be moved towards the base-load duty. This is the direction I was looking when I first began investigating the ICAD for NU. This application could actually improve cycling by warming up the feedwater going to the drum before firing up the boiler.

There is an improved environmental impact from feedwater heater repowering. Since the boiler will not be fired as much, there will be lower emissions. Two of the units in the NU system that are candidates for feedwater heater repowering are very high NOx producers. These units are cyclone-fired once-through units. With these units, the NOx production is significantly reduced when the firing rate is reduced. There are also some opposed wall-fired units in New England that could benefit the same way. But while feedwater heater repowering is a good market, I don't see it as being as big as the stand-alone intermediate-load market in New England.

The intermediate-load plants in New England operate from 8 to 14 hours, five days a week. Some of the intermediate units operate at base-load, during periods when the large base units are out for maintenance. Some of these units may run around the clock for a while, but for the most part, they operate 8 to 14 hours a day. So that's a performance criterion for the FMGT in intermediate duty. Generally, our intermediate units are not required to start up twice a day.

It will be important to have a minimum staff. I don't think a machine as sophisticated as the ICAD can operate without any staff, but as long as we site them at sites where there already is a staff, we may not have to add any more.

The next item is minimal impact of ambient temperature. Our planners say that for every four combined-cycle plants they would add for the winter peak, they have to add a fifth one in order to meet the summer peak. This requirement is the result of degradation of output with ambient temperature. They have asked, "What can you do to minimize the impact of ambient temperature in these new machines you folks looking at?" I have known from talking with some of the developers, that you can modify the design criterion of the intercooled engine so it has less of an impact from ambient temperature.

Certainly the short start-up time is important. That's what's hurting us with the existing steam intermediate units. The station has to get a call to start warming up a unit at two o'clock in the morning in order to make a seven o'clock start up time. Some of the units require even longer time than that.

And even though New England gets a lot of rain, over 50 inches of water a year, we're very careful of what we do with our water. Therefore, a minimal requirement for makeup water is important.

Time to perform maintenance is an important criteria. A lot of us in New England are used to the old FT4s. We can change out an engine in a day if necessary. We had a maintenance need for one of the LM 6000's, and it was back in service within a week. The aeroderivatives are easy to get at, to open up, as opposed to a frame machine that would be more involved.

This last item, that is NOx emissions at the lowest achievable emissions rate (LAER), we came across as we were permitting these LM 6000s. New installations in some parts of New England are required to meet LAER for NOx. That's nine parts per million in New England. NU was able to get offsets from operating units at the site so we did not have to meet LAER with the new units. So the issue of the SCR for the FMGT has become an issue that we have to consider.

The requirements for the design for feedwater heating repowering are equivalent to intermediate duty design. With the exception that the FMGT will be operating base-loaded, 24 hours per day. It will be important to have dual-fuel capability. The gas supply folks do have a lot of gas to sell in the summer, but they don't in the wintertime, and so we need to have ability to run another fuel.

Another item is the minimal requirement for additional water. Here, adding an SCR on the heat recovery steam generator that's making the feedwater heating water would not be as much of as a cost impact as it might be on a simple cycle. But it's certainly something that will have to be considered.

In summary, a high-efficiency midsized combustion turbine will prove a desirable tool for generation planners in New England. The opportunities and applications are in two areas. The intermediate duty is a stand alone unit, and feedwater heating repowering.

Thank you.

Presentation by

Dan Whitney

Sacramento Municipal Utility District

Good afternoon and welcome to the SMUD service area. SMUD is the Sacramento Municipal Utility District. We are the local service provider, and we are eagerly looking forward to moving into the competitive age in restructured utilities.

The lights that we're enjoying here this morning are being powered by quite a variety of resources. SMUD has a very diverse resource mix that we are pleased to announce presently has some 50 percent renewables. That's primarily based upon about a 700-MW hydro electric system that we have trying to work toward meeting something like a 2,500 MW peak load.

We are a summer peaking utility, and that creates a lot of problems for us here on the West Coast because so is everyone else. And what we have done to try to provide the resources is to develop other resources, such as the combined-cycle cogeneration plants, of which we are completing the construction of the third unit, which will bring us up to about 450 MW.

We've got geothermal; we've got quite a bit of photovoltaic; we've got a number of power contracts. And, of course, like everybody else, we're going to be out there in the market taking our chances.

But, significantly, one of the things I can point out to you is that SMUD today is already enjoying the benefits of the midsized turbine program. We're doing it a little bit archaically because we've got these three 100- to 150-MW combined-cycle cogeneration plants, but they are doing just exactly what I think we are here to talk about today. That is, they are providing us power plants that are efficient, cost effective, dispatchable, and able to work aggressively in this new restructured market.

That's what we're really here for, and with my work in advanced gas turbine programs, we're trying to figure out a way to do it at even still lower costs and more effectively than what we are at this point able to do.

One of the frustrations that I have as I listen this morning is that we all seem to be somewhat in agreement about these kinds of machines and the reasons why they should be used. But maybe when you go home and talk to your planners, you'll find out you get a different read.

Because even in a utility like SMUD, which we think is fairly progressive and moving forward in these areas, we have a tremendous amount of reluctance on the part of our planners to admit to some of the things that we are talking about here today.

And that means we've got to do some work in terms of studies and analysis to bring together all the different elements that are necessary to create real projects, in order for these planners to deal with them.

Even as sophisticated as things are in the planning business, we still worry about things like base load and bus-bar cost when we determine which power plants get built and which ones don't.

And I think the message is coming across here this morning is that's not the whole question, or, rather, the whole answer.

What I'm hearing this morning is that there's a tremendous amount of uncertainty. And those of us who build power plants certainly recognize that, and the question is then: How are we going to deal with some of these uncertainties and risks?

These risks are the things that impede the development of the new technologies and make it difficult for us to sell them both in our own service areas, to the regulators, and most importantly, to this coming new market.

As we go into this restructuring, there are a lot of things that are going to have to change. And if we are attempting to be perceptive, we can find already what those major messages are out there. It's all guess work. There's no question about it. But I think there are some certainties in the uncertainty that will help us deal with it.

With respect to risks and the other side of risks, which are the rewards, we can look at these things that we know and try to understand how to come to grips with them.

It's clear to me that investments are going to be very risky. We heard this morning that instead of an 80/20 debt/equity ratio, we're probably going to go to 50/50, and some projects won't even do that well.

That's really a problem, particularly for people coming out of the utility business where we have been rewarded to make big capital investments. That isn't going to happen anymore. And it's extremely difficult for those trying to plan for a utility system to deal with.

What it means is that the new investor is going to be an independent power producer, or something like that — a merchant plant. We probably don't have a good name for it at this point, but there is going to have to be some major shift in the way that generation is done.

California has effectively said, divest yourselves of all of your existing thermal generation and just buy from the market. It remains to be seen how that's actually going to be implemented, but in a few minutes I hope to talk about some of the underlying issues, and maybe some of the their consequences.

Now we've got the question of the rewards, and who is going to receive the rewards. Well, if you're an electric utility, the reward you want to receive is that you stay in business, that you have customers, and that's certainly going to mean that you're going to have to produce electricity at a low price.

The very pragmatic question is, how do you do that? Well, you've got to have something better than the other guy in order to be successful. Things like developing brand names, being able to package your power so that it is greener than your neighbors, so that it's more efficient, more environmentally benign. Those are all things that are going to have a new assessed value as we go into this new market.

There are some strategies that we can develop for how to reduce these kinds of risks. One of them is don't accept them. Let the other guy do it. We'll just take our chances, and we're going to then pay the price in the market and buy power from the grid.

As I outlined to you a moment ago, SMUD is basically taking a portion of that strategy. We think that in diversifying our risks, one of the risks we are willing to accept is the risk of the marketplace, at least for a share of our power. We're going to, therefore, be willing to go out and pay the spot market price and hope that the price is agreeably low.

One of the arguments that we have been using at SMUD for why we should continue to support R&D, in respect to advanced turbines for example, when we tell ourselves and others that we're not going to own new generation any longer, is simply that if we invest in the R&D to have a high-efficiency low-cost turbine available, then whoever we're buying our power from will hopefully be using that machine. And it will be on the margin, and it will be setting the price. So that's why SMUD is still supporting R&D with these kinds of technologies.

This lends itself in a risk-mitigating technique to specialists in generation focusing on the ownership and operation of power plants. And this was hard for us to swallow.

When we were doing the nuclear plant, we had about one and a half persons employed on site for every megawatt of generation. And now we've turned that around. In our new plants we're getting 10 MW per person, and in some cases considerably better than that. That's a huge reduction in costs. It takes that kind of reduction, though, to be competitive in this new marketplace.

Of course, if you can reduce the cost of generation in the first place by reducing its capital cost, that's a good incentive. But there are two parts to that. One of them is the old fashioned dollars per kilowatt that planners can deal with, and the other one is total number of dollars at risk. There is a relationship between those two, and you have to consider both of them. I am not sure that all new projects get assessed in that way.

The final part of it is that it's really important that you maximize the production of energy from this new plant that you're going to build. In other words, you need to have a high capacity factor. That then, gives us the question of, how do we get that and what does it really mean to us?

So given these kinds of constraints and issues with respect to risks, the question is why should we not just go ahead and continue to build large combined-cycle plants? Because as you look around, particularly in the West, you see that's happening. Some very large base-load combined-cycle, highly efficient plants are being built. But it doesn't really answer the question, because it seems like the market should be telling us to build something else.

We need to be a little bit perceptive about who and what is really causing this new kind of power plant to be built. The answer that I've come up with is that they're being built not by utilities, but by independents. They are built by independents who are, in fact, are out doing what I consider to be cherry picking. They're going out and finding discrete markets, discrete customers able to accept that power, giving them a relatively long-term contract, meeting some of the conventional financing schemes, and then justifying the plant on that basis.

They are also going to be in there with a highly efficient plant that they can base load, and then sell into this new market at a maximum margin.

So there is a demand and a need for this kind of facility, but I would suggest that maybe it's a limited need. And, furthermore, as those new plants come on, what do they do? They push the rest of the existing plant base up the load curve and make it much more inefficient. And, of course, that broadens the margin, which might be good if you had the low-cost plant.

So I'd like to show you a diagram that I've made. Our planners don't like my diagram. The reason they don't like this diagram is that it's not expressed in cents per kilowatt hour. Instead, I'm an engineer so I expressed it in terms of Btus per kilowatt hour.

This is the typical yearly average market price that we are forecasting for electricity. SMUD paid a lot of money to some very high priced consultants to develop this curve. This curve represents the Western United States market. You can develop a similar curve for every market in the country or around the world.

And what it shows is not unexpected, that you pay more at some seasons of the year than others. But that's not the message of this chart. The message is that the heat rate in some of those market periods drops down to 8,000 Btus per kilowatt hour. Now, that's the average heat rate during that period of time, during that month. That means that at least half of the time, the heat rate's going to be lower than that and some of the time, it's going to be higher.

Well, this curve is a compilation of thermal hydro nuclear and fossil, so it's got a lot of things forcing it to move. But if you take this and then try to do the economics on a new project, you'll find out there are not very many power plants that are going to be financeable.

And what we heard from the finance community this morning is that they are going to be looking at these kinds of things. And this puts a tremendous challenge before those of us who recognize the need for new power.

The other thing that is happening was mentioned by David Rohy this morning — that there's some 16,000 MW of fossil generation that's for sale in California. I think it's going to be shut down. The reason is that it has heat rates in the 12, 13, 14,000 range. Even though the plant is depreciated, tell me how many hours you're going to run a power plant if it's got a 14,000 heat rate? You can't afford to even maintain it as a peaker.

So there is a tremendous demand coming to put in place new high-efficiency low-capital-cost plants. And ideally, those plants should be able to run year round and do a good job. If we bring them in at high enough efficiency, they can, in fact, do that.

The crux of my presentation to you this morning is that we have got to come up with a power plant technology in simple cycle that's at least as good as we have been assuming for the intercooled aeroderivative. It takes that kind of a plant to work in this kind of a market.

There is no frame machine available in the gas turbine world that will work successfully as a new plant in this market. It takes something as good as 45 percent efficiency in the simple cycle, something with a dollar cost in the very low $200 range, with the whole plant cost being about $350 installed.

And we've taken a look at it. Those kinds of machines can be built around these kinds of aeroderivative technologies. But SMUD has already demonstrated that we need the 100 to 150 MW class. That's what's financeable. That's what we can construct.

We're hoping that this midsize effort will, in fact, give us this even-better machine, which is a machine itself that's in simple cycle and able to give us these combined-cycle-type performance that allows it to run in this environment, and to do so, at the same time, in these smaller sizes.

That's the message that I have from what we have learned. We're very excited to be working with all of you on developing this type of a technology so that we can bring home the machines.

There's a huge market out there if we can do it, and it's certainly for the good of the people paying the bill because it will be a much lower cost of power than any other way that they could get it. Thank you.

Breakout Session Introduction

Premise for Working Group Questions

The premise to be discussed at this workshop is that a worthwhile development program, supported by DOE and the California Energy Commission, would:

- Develop a product that fits in the size range not covered by the ATS Program.
- Be designed to serve a market for mid-range capacity, say 500 to 5,000 hours per year. To do this, the product needs to be more efficient than a simple cycle and needs to have a cost in $/kW closer to that of a large simple cycle than a combined cycle.
- Be designed to have rapid start capability, say cold start to full load in less than 5 minutes, and be able to take many full-load start-stop cycles without a significant reduction in useful life.
- Be designed to enable the economical partial repowering of existing steam plants so they can be more competitive without investing in a full-plant repowering project.

The worldwide market will be large enough to justify the program, provided public funds help mitigate the development risk.

During the panel discussions, breakout sessions, and general discussion that follow, we will examine this premise and determine whether we believe that this program or some modification of it would be a sensible basis for going forward.

Working Group Questions

Group 1: Domestic and International Markets

Facilitator: George Hay, California Advanced Gas Turbine

1. If the flexible, midsize gas turbine is developed, what is the likely market in mid-range power applications, say 500 to 5,000 hours per year, assuming a cost per kW slightly higher than that of a large simple cycle and an efficiency in the mid to high 40 percentage of the lower heating value (LHV)
2. What are the potential worldwide market niches for this technology? What is the size of each of these niches as a function of date? What are the product cost goals for each of these niches?

3. How might the flexible, midsize gas turbine (FMGT) be utilized as a distributed generation resource? What cost savings might be realized (deferred T&D upgrades, voltage support, power quality, etc.)?

4. What are the products that would compete in the markets with midsize turbines? What is the impact?

5. Many aging natural-gas-fired fossil-steam units in the U.S. are used for cycling and peaking power at less than 5 to 50 percent capacity factors; these will be 30 to 50 years old in the year 2000 time frame and will need environmental upgrades, e.g., 20,000 MW in California and a similar number in New England. What types of gas turbine systems will replace these steam units?

6. What will be the requirements of merchant plants with respect to trade-offs on first-costs, risks, efficiency, insurability, financability, etc.?

7. Will quick cold-start times and multiple starts and stops per day be more favored as power pools and gas markets become more dynamic?

8. How will new gas turbine projects fit into a portfolio of emerging energy service companies that are marketing power and natural gas? Will distributed gas turbines in the 30 to 150 MW range become a focal point for arbitrating between electricity and gas and regional markets? What gas turbine product attributes are needed?

9. The current trend is marketing power directly to wholesale (local distribution companies, municipalities, etc.) and retail (wheeling and customer aggregation). Who will be the retail and wholesale customers for electric and gas marketers in the future, and how will new gas turbines fit into service strategies?

10. Low efficiency and low first-cost simple-cycle gas turbines are traditionally used for peaking purposes. However, costs can be as high as $0.30/kWh as a result of low asset utilization of the gas turbine and the associated new electric transmission and distribution requirements. Would higher efficiency FMGTs, which achieve higher levels of asset utilization, be a more economical approach?

11. Operating cycling steam units have high fixed operating costs and efficiencies in the 30 to 40 percent range and set the standard for dispatch. What is the value in terms of increased asset utilization for FMGTs to realize 40 to 45 percent of capital cost and efficiency?

12. Does feedwater preheating of large coal steam units in the U.S. represent a significant market opportunity for simple-cycle, high-efficiency, intermediate-load turbines, and the natural gas industry? Can 60-percent efficiencies be obtained with dramatically lower costs than available using combined cycle approaches?

13. Do the above issues need further investigation on the value and markets for flexible gas turbines?

14. What market needs are not currently being met because of technological shortfalls in commercially available gas-turbine systems? What would be the value of having each of these needs met?

15. In the case of ICADs, if an SCR is used to obtain single digit NOx emissions, which would allow increased firing temperature, the efficiency, first-cost in $/kW, and exhaust temperature available for retrofitting steam plants are improved. Are SCRs acceptable if they produce the best economic choice?

Group 2: Development and Technology Requirements

Facilitator: William Day, Gas Turbine Association

1. What technologies being developed under the ATS Program can be used in the midsize gas turbine, and what additional developments are required? What technology items are appropriate for a university program following the format of the one in the ATS Program?

2. To what extent would the ability of an FMGT to make a cold start to full power in less than 5 minutes help stabilize power grids in a deregulated environment, and what quantity of 100 to 200 MW units would be required in a typical electric system in order to enhance stability?

3. ICADs have been identified as an option in repowering existing steam plants through feedwater heating, which would improve their competitiveness without scrapping (and would retain the economic value of) large portions of the plant. In a deregulated environment, what is the likely number and type of existing steam plants that would be repowered in this way? How many plants in your system would be candidates for this type of repowering?

4. What are some of the issues related to maintenance, operation, reliability, and cost of FMGT systems that would cause marketability problems? Compare ICAD to other product options in this regard.

5. What is the status of ongoing midsize turbine product development?

6. Are there any R&D barriers that need to be overcome to develop a midsize product? If so, what are they? What type of a program and investment is needed to resolve these barriers? Cost of program?

7. What is the level of commitment of gas turbine vendors to commercialization of midsize products? What are the potential financial, technical, manufacturing, and corporate barriers?

8. In the case of ICADs, if an SCR is used to obtain single digit NOx, this would allow an increased firing temperature, efficiency, first-cost in $/kW, and exhaust temperature

available for retrofitting steam plants. Are SCRs acceptable if they produce the best economic choice?

Group 3: Funding Sources and Cost-Sharing

Facilitator: Jeff Abboud, Gas Turbine Association

1. Who are the potential program participants? To what level should each cost-share? Would private partners consider repayment options to their public partners if needed?

2. What are your recommendations for an action plan to get a program underway or to address product issues?

3. What is the total cost and schedule of the development program required for the midsize gas turbine, assuming an arrangement similar to that of the ATS Program (cost-shared program, multiple contractors initially, narrowing to 1 or 2 demo plants)?

4. How will RD&D be conducted in the future for new generation plants? Will add-on electricity costs like the California AB1890 be viable in other markets, and can a national gas turbine program be constructed on this basis?

5. How could the financial investment community and venture capital be used to leverage buyer, supplier, and government funds? Do aircraft engine lease-financing approaches and buying groups provide models for the power generation sector?

6. Are there market incentive approaches to encouraging use of first-of-kind advanced gas turbine technologies and/or to mitigate risks? Should there be power-pool collaborations on demonstration projects to share risks and benefits amongst participants?

Group 4: Links to Other Programs

Facilitator: Dan Whitney, Sacramento Municipal Utility District

1. Are there programs ongoing or which have taken place that address technology development for midsize, flexible gas turbines?

2. What are some of the technology issues currently being addressed related to midsize flexible gas turbines? Could these efforts be leveraged for a midsize turbine program?

3. Given the size of gas-turbine development costs, should greater international collaboration be encouraged as in the Space, Fusion, and Defense Programs? For example, would EEC involvement in a midsized turbine program make sense?

4. Gas turbines cross cut fuels and application sizes — around which energy programs are historically organized, with the potential implication that gas turbine RD&D might be

underfunded. What can be done to increase cross fertilization between these programs and research communities relative to gas turbines?

5. What considerations should there be in a midsized gas-turbine program relative to renewable energy?

Breakout Session Participants

Group 1: Domestic and International Markets

George Hay - Facilitator

Paul Bautista
Ron Belval
Frank Bevc
Barry Davidson
Victor Der
Chris Hodrien
Dan Kincaid
Dave McCue
Jonathon Rayner
Robert Reed
Eric Rorstrom
George Touchton
Alfonso Wei

Group 2: Development and Technology Requirements

Bill Day - Facilitator

Christophe Bellot
Richard Brent
Charles Cook
Lawrence Golan
Jack Janes
Christopher Lane
Niels Laursen
Matthew Layton
Jim Lyons
James McCallum
Robert Moritz
George Padgett
Carl Paquin
Dale Simbeck
Ron Walecki

Groups 3 and 4: Funding Sources and Cost Sharing; Links to Other Programs

Dan Whitney and Jeff Abboud - Facilitators

Don Anson
Mark Axford
Dan Brdar
Ted Elmer
Bernard Givaudan
Evan Hughes
Jeff King
Dick Maclay
Pete McCluer
James Moll
Graham Reynolds
Jim Roberts
Fred Robson
Arden Walters
Steve Waslo
Doug Westerkemp

Breakout Session Summary

Group 1: Market Opportunities, Timing and Niches

There are opportunities in the U.S. and in the international market, if FMGT technology were available now, especially for feedwater applications. Another opportunity is replacing steam units. The timing of U.S. and replacement markets is strongly tied to deregulation and environmental regulation. The market starts in the 2000 to 2010 time frame and then accelerates.

Requirements

Cost: 20 to 40 percent lower than combined cycle; efficiency of 45 to 50 percent for the simple cycle; need quick start; high residual value; short project lead time; meet NOx requirements; high availability; low O&M/small staff.

Value/Cost Saving: improved efficiency load following; green — lower CO_2 emissions; power electricity cost/intermediate load; dispatchable renewables.

Competition: steam plants continued unit operation; utility can purchase power; large unit cycling; existing intermediate load; reciprocating engines in large power blocks.

Public/Private partnership benefits: availability of funds accelerates availability for replacement market; assess feasibility and benefits of program; demonstrate support and need for program; share costs/benefits - users cannot provided R&D, but orders; manufacturers require evidence of market.

Discussion: **George Touchton** — Importance of rapid start? **Eric Rorstrom** — Just-in-time availability has value; don't burn the fuel till you know need electricity. **Carl Paquin** — how do you define rapid start? **Eric Rorstrom** — it's defined by the power pool at 15 or 30 minutes. Is there a difference between a 5 and 10 minute start? Not yet. The power pool will have to assign value to ancillary services, including availability to start up. Will have to be sold as guarantee — premium is not on the time frame, but on the certainty. **Dan Whitney** — The WSCC time frame is 10 minutes, or there's an economic penalty.

Group 2: Development and Technology Requirements

Technologies

We need to design in the ability to link to renewables. Must pay attention to combustion to assure low emissions for cycling duty. Some ATS results are applicable to FMGT. ATS university program continues research that is applicable to ATS and FMGT; e.g., coatings and ceramics example. Intercooling: need to explore other options, not just water.

It is necessary to set product cost goal and meet it; bring suppliers into the design process.

Quick Start capability

MA PUC allows distributed generation on the feeder to avoid transmission congestion; 10 minutes on line has value, tied to a 15-minute bid cycle.

Repowering

Attractiveness depends on the need for capacity and steam cycle conditions, ability of steam turbine to handle additional output. Utility Data Institute may be a source of info for estimating market size. **Niels Laursen:** Estimated improved 25-percent capacity and 10-percent steam turbine efficiency. **Eric Rorstrom:** An amendment — there are also potential emission offset/credits. **George Touchton** and **Barry Davidson:** The future of super-critical plants may be different than sub-critical.

Maintenance, Reliability and Cost Considerations

Fuel gas supply: cost issues for air/air; availability of water, though the requirements are lower than for combined cycle; influenced by firing power class; influences the choice of fuel, i.e., biomass; another option is ICR; CHAT is too complex; real estate requirements, especially for air to air cooler. Value of high power output on a hot day, since that performance is tied to capacity payments.

Discussion: What considerations should be given to inlet air chilling? No differentiation. **Graham Reynolds:** The ICAD design will be influenced by climate. In an EdF study of injection vs ICAD, ICAD was the winner. As to part-load performance, it was not clear whether or not this was important; it requires analysis/clarification.

Status of Development of FMGT

All three aircraft engine companies like the ICAD, but they need partnerships. Frame engines will also advance.

R&D issues

See Q1. May raise bearing issues related to thrust load.

Premise

Size not covered by ATS; it is a result of aero production (nominal 100 MW); mid-range is 500 to 5,000 hrs/yr.

Discussion: George Touchton: The program should address any interesting cycle, including CHAT.

Level of Commitment/Barriers to Entry

Source of intercoolers at reasonable cost/real estate; may need controls; market acceptance - size and timing; assess through running utility/power marketer models to assess role of FMGT - test purchase and lease assumptions; profitability.

Emissions

Can the turbine be single-digit NOx without SCR? How close is gas composition to pure methane? ELKRAFT: you don't need an SCR in a facility with SCR for coal. Do modeling on SCR and IDBM.

Groups 3 and 4: Funding Sources and Cost Sharing; Links to Other Programs

See the timeline.

Other funding programs and timing: ATS at high level till 2000, then reduction; Combustion 2000 — till 2000, then demo; WR21 — question, need to be aware of interactions; AB 1890 — a prototype for other states, renewables, and RD&D; try to access those funds for FMGT.

Participants: source of funds and support described and prioritized (see attached).

After the lead agency is selected, an advisory panel needs to be formed to deal with anti-trust issues, and who owns the technology output. The money available needs to be in the right place at the right time.

Group 1: Domestic and International Markets

Facilitator: George Hay
California Advance Gas Turbine

1. ***If the flexible, midsize gas turbine is developed, what is the likely market in mid-range power applications, say 500 to 5,000 hours per year, assuming a cost per kW slightly higher than that of a large simple cycle and an efficiency in the mid to high 40 percentage of LHV?***

Total world market: 30 GW per year. 20 sc/10cc – this is potential.

Gas pressure an issue ($1 million cost for 40-MW machine); Allison machines — $200,000 to $300,000; GRI — $70/kW.

Gas supply an issue. Replace oil and gas fired units that were once coal.

Victor Der: What is the impact of a several-year delay?

US Gen: Making choices now on machines that will be installed 1999 and 2000, estimate a couple thousand megawatts/year.

EPRI: Industry will more and more have an investment in available machines that will consume attention and resources.

PG&E: The key item is uncertainty in deregulation.

DOE: Show that there is a decline in opportunity, and we can use this as argument for DOE funding.

CAGT: Replacement market could be accelerated if machines were available.

Utilities will not stay in the generation market through regulated entities.

Northeast Utilities: Machines with better part-load efficiencies will overall burn less fuel than serving the same demand with very large machines.

2. ***What are the potential worldwide market niches for this technology? What is the size of each of these niches as a function of date? What are the product cost goals for each of these niches?***

SFA Pacific: Get some feel for comments.

3. ***How might the Flexible, Midsize Gas Turbine (FMGT) be utilized as a distributed generation resource? What cost savings might be realized (deferred T&D upgrades, voltage support, power quality, etc.)?***

GRI: Distributed generation is a retail market.

CAGT: Put the plant in locally, away from load, and put a transmission line in to bring in power.

US Gen: How does fuel supply match electricity need?

GRI: Site this turbine on a combination of factors, including gas and electricity need. Smaller sizes can be placed at customer site.

PG&E: SMUD ran a 1,000 psi gas line into Sacramento to serve new generation.

GRI: Even very small combustion turbines need a gas compressor, and Capstone type units had problems.

CNG: Transmission lines must be made open to all, so willingness to invest is questionable. Note: CNG contracts include liquidated damages – must buy replacement power if can't supply.

4. ***What are the products that would compete in the markets with midsize turbines? What is the impact?***

SFA Pacific: Reciprocating engines (get facts).

CAGT: STIG technology?

SFA: STIG going into Australia.

GRI, SFA: Recips using cetane injection are increasingly being used. They can burn full diesel fuel as back-up. Availability and part-load are problems, as are maintenance costs. The market is mainly for co-gen because of the utilization of waste heat. Prices are good. Midsize turbines may be perceived as "lower tech" or less exotic and demanding than gas turbines. Purchased power may be the biggest competitor. Frame 6 is a current hot topic – EGT is selling for $8 million while the LM 6000 costs $10 to $12 million.

GRI: What can people in this room do to make this machine an option in the 2000 to 2002 time frame?

US Gen and NP: No R&D budget and time frame of 2 to 3 years.

EPRI: Will IPPs and former utilities lobby for development of FMGT?

Northeast Utilities: There is a need for perceived end-user benefits to sell the program to his company.

US Gen: If we had an intercooled engine that made 100 MW, perhaps that would be a better way to get to the market than the Frame 6.

EPRI: We are discussing an FMGT – not an aeroderivative exclusively.

FMGT Markets:

Intermediate Load (30 to 150 MW); cost is lower than for a combined-cycle system; 45 to 50% efficiency; cycling at 20- to 40-percent utilization; quick start/load following; feedwater repowering; cogeneration; fuel hybrids/good small combined cycle.

Timing of Market:

National Power: The CEC and DOE see timing and window of opportunity as important.

Northeast Utilities: 2000 will see the next revision of the Clean Air Act.

Will force the retirement of older steam plants.

EPRI: The older steam plant can serve mid-range duty, and will push the window of opportunity further out for the mid-range size.

PG&E: The question is one of economics, not physics.

Northeast Utilities: There is economic benefit of using old sites: you can connect into an existing T&D system, permitting is easier on old site, and you can use existing emissions credits. And, medium size machines can fit into the site more easily.

PG&E: In the west, we have a tremendous supply of base-load power. When we need power, it will need to be dispatchable.

Window of opportunity:

A mix of very small and very large machines or intermediate machines. Need: in 5 years and the doors will start closing 10 years beyond.

US Gen: The market exists right now – will be closed by more competition in the small market (401F, GE 6FA, and Siemens V64.3A).

SFA: Lots of soul-searching in moving to small machines must be done.

BG: Projects are available now, but using frame machines. The window of opportunity is to have them available to market in order to meet older steam plant retirements.

Allison: What do DOE funds do to the competitive picture?

Northeast Utilities: The funds do not wipe out others competitors, but make them compete harder. There is an advantage to public policy to introduce this machine and foster better energy use and more competition.

SFA: If we believe DOE retirement numbers, then the window of opportunity is 2000 to 2010 (and SFA doesn't believe in the numbers).

The opportunity market would be to produce the catastrophic-need product.

Vermont: Around the year 2000, there will be niche transmission constraints.

GRI: If FMGT is not developed, then existing systems will be used.

RR: The window of opportunity begins in 4 years time, because they have a four year development program in planning.

Northeast Utilities: There are two operatives: environmental constraints and market competition. Starting from the year 2000 and going on to 2010, there will be an increasing market if competition forces retirement.

Either existing combined cycle (CC) and simple cycle (SC) will serve the market or FMGT. FMGT will not back up CC systems once installed.

National Power: British Coal contracts make it difficult to displace the mid-merit coal plant. These expire in 1998 and will make displacement somewhat easier.

US picture:

Size (MW)	Capacity (GW)	Average Age (Years)	Capacity Factor
100 or less*	20	40	<25%
100 - 200	60	35	Up to 40%
200 - 300	40	30	Up to 50%

* Non-reheat

GRI: The market does have to do with DOE; CEC funding, but EPA is influential. Will EPA really keep to the 2003 timetable for stricter regulations? If DOE and CEC participate, they must support a program that seems not to be focused on self-interest at the expense of competition. If the FMGT is available in 2003, it will be competitive.

5. ***Many aging natural-gas-fired fossil steam units in the U.S. are used for cycling and peaking power at less than 5 to 50 percent capacity factors; these will be 30 to 50 years old in 2000 time frame and will need environmental up-grades, e.g., 20,000 MW in California and similar a number in New England. What types of gas turbine systems will replace these steam units?***

Answered as part of Question 1.

6. *What will be the requirements of merchant plants relative trade-offs of first costs, risks, efficiency, insurability, financeability, etc.?*

7. *Will quick cold-start times and multiple starts and stops per day be more favored as power pools and gas markets become more dynamic?*

Answered a part of Question 1.

8. *How will new gas turbine projects fit into a portfolio of emerging energy service companies marketing power and natural gas? Will distributed gas turbines in the 30 to 150 MW range become a focal point for arbitrating between electricity and gas and regional markets? What gas turbine product attributes are needed?*

9. *The current trend is marketing power directly to wholesale (local distribution companies, municipalities, etc.) and retail (wheeling and customer aggregation). Who will be the retail and wholesale customer for electric and gas marketers in the future and how will new gas turbines fit into service strategies?*

CNG: Arbitrage opportunities dry up fast as people learn the system.

CNG: The real opportunity for ICAD is in ancillary services, load following, shifting load in time. Municipalities could choose their suppliers. Meter everybody together and then get contract for supply with load following. Joint power agencies (Northern and Southern Ca. School Districts) and irrigation districts have some exemption from transition costs. All loads are not at a 100-percent load factor – FMGT will fill the bill.

10. *Low efficiency and low first-cost simple-cycle gas turbines are traditionally used for peaking purposes. However, costs can be as high as $0.30 per kWh as result of low asset utilization of gas turbine and the associated new electric transmission and distribution requirements. Would higher efficiency FMGTs, which achieve higher levels of asset utilization, be a more economic approach?*

The question is, what is pushed into peaking? Could be your plant, could be competitor.

GRI: Would customers for FMGT pay for the flexibility?

BG: Of course – they would do overall project costs.

PG&E: There's no such thing as rate base.

11. Operating cycling steam units have high fixed operating costs and efficiencies in the 30 to 40 percent range and set the standard for dispatch. What is the value in-term of increased asset utilization for FMGTs to achieve 40 to 45 percent of capital cost and efficiency?

12. Does feedwater preheating of large coal steam units in the U.S. represent a significant market opportunity for high simple-cycle efficiency turbines, intermediate load, and the natural gas industry? Can 60-percent efficiencies be obtained with dramatically lower costs than combined cycles?

13. Do the above issues need further investigations relative the value and markets for flexible gas turbines?

14. What market needs are not currently being met because of technological shortfalls in commercially available gas turbine systems? What would be the value of having each of these needs met?

15. In the case of ICADs, if an SCR is used to obtain single digit NOx emissions, which would allow increased the firing temperature, the efficiency, first cost in $/kW, and exhaust temperature available for retrofitting steam plants are improved. Are SCRs acceptable if they produce the best economic choice?

EPRI: The decision not to apply an SCR will greatly increase development costs.

SFA: You should not compromise performance to avoid SCR. Costs should not be greater than $15/kW.

Cost of NOx control in an SCR system: Northeast Utilities: Costs are very high and costs are high for an SC machine.

EPRI: The technology is near the point where you produce NOx at the firing temperature.

GRI: ammonia on site is a problem.

US Gen: At 4,500 to 6,000 hrs/yr, you can get away with higher NOx. Cooling the exhaust gas to 800 to 900 °F is good for the SCR catalyst.

GRI: IPP projects are more likely to go with an SCR not to delay the project.

SFA: SCR keeps you below 150 tons/yr and saves a year; so time as the value of money pays for SCR.

EPRI: Dry-low NOx systems do not have good load following capability.

Summary

Market Opportunity Timing and Niches (Questions 1,2,3,5,10,14)

Market Timing: The niche market is now.

Repowering (feedwater heating, hot windbox).

Cogeneration: Between 2000 and 2010, a growing market.

Replacing cycling steam plants: in the US, there are 12 GWs greater than 30 years old. The rate of market development is driven by the pace of deregulation and environmental regulation.

Global market: 3 to 4 GW.

Attributes and Requirements for Competitiveness (Questions: 6, 7, 8, 9)

Capital cost (20 – 40% lower than CC).

Quick start/load following.

Short lead times (6 months).

Efficiency at 45 to 50 percent.

Nitrogen oxides: meet available standards.

Other: high residual value; relocatable package; high availability; low O&M.

Value and Cost Saving Benefits and Potential (Questions: 3,11, 12,13,15)

Lower CO_2 than other alternative serving this market.

Greater system reliability.

Manufacturing jobs.

US dominant in this technology.

Energy sufficiency.

Gas/biomass hybrids.

Facilitates Green Resources.

Makes renewable resources dispatchable.

What is the Competition? (Question 4)

Continued unit operation of existing steam turbines.

Environmental.

Purchased power.

Large frame cycling combined cycle.

Existing combustion turbine products.

Reciprocating engines.

Private/Public Partnership

Private cost sharing is available from Operating and equipment manufacturers (OEMs).

User direct cost sharing not available.

Public funding will accelerate the program.

Public funding necessary for product to meet window of opportunity

Group 2: Development and Technology Requirements

Facilitator: William Day

Gas Turbine Association

1. ***What technologies being developed under the ATS Program can be used in the midsize gas turbine, and what additional developments are required? What technology items are appropriate for a university program following the format of the one in the ATS Program?***

Ron Walecki: What is the outcome of a university program? **Larry Golan:** Industry drives the choice of technologies for research, i.e., P&W, GE, Solar, Allison, Parker, Allied, Westinghouse. The center administers programs through 83 universities; 42 universities are under contract. There are some initial barriers at universities. The program seeks cooperation among universities and other participants. There is a summer internship program for 2 years, with 30 participants. A new twist is faculty fellowships, offering support for faculty to go to industry. A typical contract is for 1 to 3 years, with a minimum of 1.5 years. Use the academic calendar, $150,000/yr, and a very competitive review process (1 of 10 is chosen). DOE thru FETC has invested $17 million so far, and companies contribute $25,000/yr. Areas of research include primarily combustion, aerodynamics, and heat transfer, with some emphasis on controls.

Bill Day: Can we use midsize gas turbines to continue university program? What subjects? **Robert Moritz:** two aspects of ATS - aeroderivative high pressure/high efficiency) and low pressure engine have not been discussed yet - what about ICR - ceramic blades, ancillary technologies - low NOx. Test environmental preference by testing alternative fuels and prepare for biomass. ATS research has not shifted like the rest of government to renewables/environment. We would be well advised to find a link to renewables.

Charles Cook: I'd like to offer a clarification on GE's work. The GE work began on a large, single-shaft 480 MW machine, and then GE backed out of aeroderivative studies. GE has the H design, and therefore was not involved in early ATS research. However, GE has been involved in Phase 2 ATS research and in the enabling technology phase. The GE ATS program above has some aspects that are transferable to other turbines; however, some will not make sense at midsize scale. **Bill Day:** Large scale does not have the attributes sought in the midsize program.

Richard Brent: Will the program deal with emissions in relationship to combustion and duty cycle?

Jimmy McCallum: Solar and Allison are already members of the large scale ATS research; what are they looking for that is not already there? **Bill Day:** That is a good question. Are the technologies also applicable to midsize work: materials, cooling, seals, and an area that is not transferable — combustion. University work is very long term; It could help both programs, however.

Should ATS continue R&D that helps midsize and other sizes?

Richard Brent: Is this information for the public record? Answer: yes, for funded proposals (note: long-term results), maybe ATS+, unfunded proposals are proprietary to ERC. **Larry Golan:** Substantial leveraging is possible: 37 states, 200+ professors/students.

Ron Walecki: The focus is on demonstrated technologies, not developed. Ceramics is an example. **Bill Day:** Note the need for refinement beyond the demonstration level; e.g., some agreement on the importance of materials.

Charles Cook: Re: the life cycle of design, there is a need to get to the end of research in particular areas. For example, in materials, we need to stop and make a commercial decision. We are already past that point in ATS; this may be of interest for midsize

George Padgett: You can't unload stuff on traditional customers (e.g., ICR), and you need to factor this (customer/market) into the choice of technologies. **Carl Paquin:** If risk isn't there, will the vendor take action? **Richard Brent:** Most want to be in the first or second wave, after Solar determines that the product is robust enough. Solar has a customer conference every 3 years to introduce customers to technologies.

Larry Golan: ERC will shut down; the organization is already funding the request for 1998, and will start planning for how to shut down effectively, given university research timing and a shutdown in the 2000/2001 time frame.

George Padgett: There is some value, even if DOE pulls out — as a recruiting example, could continue research at a lower level.

Jimmy McCallum: Lots of countries have emission requirements: Pakistan/World Bank example. **Richard Brent:** if you can't site it, you can't sell it. Here's a problem: you don't get rid of dirty technologies because the others aren't clean enough.

2. ***To What extent would the ability of an FMGT to make a cold start to full power in less than 5 minutes help stabilize power grids in a deregulated environment, and what quantity of 100 to 200 MW units would be required in a typical electric system in order to enhance stability?***

Jimmy McCallum: Who will be controlling the peaking power, the value set by the transmission system?

Richard Brent: The MA ruling is: distributed generation can be owned by the utility if such generation is related to transmission congestion on feeders. Do you need dual dispatchability? The retail service company will almost have to be the one to seek the dual benefit. Does utility get to rate-base the machine?

How do you convince anyone to hold spinning reserve, keep the plant on standby, even if standby is brief?

Larry Golan: Start-up time is not considered by the ATS program. Do other ATS goals (emissions, cost, etc.) apply?

Richard Brent: What are the goals? To meet ATS conditions. **Jimmy McCallum:** No, ATS is not peaking.

Bill Day: What is quick start-up worth? **Jimmy McCallum:** something.

Charles Cook: There is a market out there, for example, malls back-up as proxy for value.

There was broad agreement on the need for quick start.

Do you need quick start at 100 MW or more, or is that amount more predictable? Some say no, some see the need in an open-access environment. **Bill Day:** The increment may be unspecified.

Is quick-start capability consistent with cycling ability? **Niels Laursen:** Isn't quick-start capability consistent with lower cost of start? Even if so, it does not replace spinning reserve.

3. ***ICADs have been identified as an option in repowering existing steam plants through feedwater heating, which would improve their competitiveness without scrapping (and retain the economic value of) large portions of the plant. In a deregulated environment, what is the likely number and type of existing steam plants that would be repowered in this way? How many plants in your system would be candidates for this type of repowering?***

Bill Day: Incremental improvements would be by feedwater preheating.

Jim Lyons: In Southern Company, the best repowering is to redo all but the steam facility, but this depends on what is needed. Southern Company needs capacity.

Bill Day: The desired improvement is in efficiency, not capacity. We need better information on feedwater-related capacity impacts, which varies with the steam cycle, and the ability of a steam turbine to accept power.

Richard Brent: Utility Data Institute/McGraw Hill can give data on the likely number of plants for the U.S.

Niels Laursen: There are 10 candidate units in Denmark, each between 300 and 400 MW, and each using about 2 turbine units, resulting in additional output, most of this in turbine capacity. Denmark will not keep older facilities, but will update newer facilities. **Bill Day:** will this be true in U.S.? What are the steam cycle benefits: **Niels Laursen:** Approximately 10 percent.

Participant: There is a reduction in beneficial recuperative heating.

Charles Cook: The supercritical plants in Denmark are not similar to those in the U.S. This statement was supported by Richard Brent and others.

Bill Day: What about windbox repowering? **Jim Lyons:** exhaust temperatures require expensive metallurgy, and thus, this is the least likely repowering type to be cost-effective. Feedwater preheating is the best application.

4. What are some of the issues related to maintenance, operations, reliability, and cost of FMGT systems that would cause marketability problems? Compare ICAD to other product options in this regard.

Richard Brent: Issues include fuel-gas supply for high pressure application, which drives down reliability; and is the intercooler closed loop? **Bill Day:** This depends on customer preference and availability of water.

George Padgett: Heat sink will vary.

A cost issue is air to air. Another issue is the option for evaporative cooling or heat recovery (heating/cooling). **Jim Lyons:** there is less water/kWh than in a combined cycle system.

Bill Day: Is the CHAT option too complex? **George Padgett:** The Russian option has too many complicated features. **Richard Brent:** There is a cost problem associated with the real estate required, especially for interceding equipment.

Discussion ensued on the promise of the Catalytica process. **Bob Moritz** offered the chain cycle, but noted that it has surge margin impacts.

Jim Lyons: Utilities value the ability-to-power argument during peak load (33 to 500 hrs/yr) instead of simple cycle CTs, the ability to increase output by 5 percent.

Charles Cook: The GE option in Tampa: power augmenting is a standard GE upgrade, a combination of NOx control, and power augmentation. **George Padgett:** Do many have enough water for this? GE has standard 5 percent of flow.

Christophe Bellot: EdF reviewed steam injection, and prefers ICAD in terms of modification of plant. Steam injection makes sense for small machines, but not large machines, compared to ICAD that is.

5. ***What is the status of ongoing midsize turbine product development?***

Bill Day: ICAD has been studied by all three manufacturers. All liked it, but will require partnerships to pursue for any modifications/additions.

Bob Moritz: ICAD looks good, but is expensive, and support will be required.

Bill Day and **Charles Cook:** We are not speaking for Evindale, but GE will not undertake ICAD without support; GE will continue through evaluation process to upgrade the 6FA.

George Padgett: The frame-type turbine is not from the aircraft? **Bill Day:** yes, and this includes Solar.

Bob Moritz: We are talking without specs; see the chart for review. A 100-MW engine will be regarded as the big engine of the future.

Little emphasis was placed on part-load heat rate, a second round discussion of the basis for this or not showed that analysis/clarification are required. ICAD does help on hot-day performance, valuable because this is basis for value calculations.

6. ***Are there any R&D barriers needed to be overcome to develop a midsize product? If so, what are they? What type of a program and investment is needed to resolve these barriers? Cost of program?***

Bill Day: Is there anything here not addressed in question 1?

Bob Moritz: The dimensions of small relative to power handled, and therefore the bearings are difficult (thrust load). **Participant:** Spend time on specifications. **Jim Lyons:** Add the target electric price; a suggestion — 10 percent less than competing alternatives to be consistent with other DOE programs. **Charles Cook:** Also add environment, performance, and permittability. **Participant:** Add the time between overhauls as a measure; the market expects 20,000 to 25,000 hours. **Jimmy McCallum:** We prefer higher than 25,000 hours. Also add enabling the partial repowering of existing steam plants through feedwater preheating.

7. ***What is the level of commitment of gas turbine vendors to commercialization of midsize products? What are the potential financial, technical, manufacturing, and corporate barriers?***

Bill Day: This is like the Q5 on turbine vendor commitment. **Larry Golan:** what is the estimated cost? **Richard Brent:** this is a hurdle for RD&D funding. Manufacturing barriers include problems with intercoolers. Is this beyond the core competency of turbine manufacturers? And how is the cost of time required treated? Include the influence of economies of the turbine.

Bob Moritz: There are two choices: LM with the intercooler integrated, or off-engine air to air intercooling. This is not challenge in itself ,but there are engine impacts, a need to emphasize cost effectiveness. There is also a control issue.

Barrier to entry = market uncertainty and market acceptance. Less interesting combined cycle alternative; the pressure ratio is too high.

Jim Lyons: Feed what is known about the machine into utility models. **Carl Paquin:** add power marketer models. **Richard Brent:** Add run on base, intermediate, and peaking basis options. We need to incorporate the price of low-price gas as a driver of baseload operation.

Financeability was also an issue.

8. ***In the case of ICADs, if an SCR is used to obtain single digit NOx, this would allow increased firing temperature, efficiency, first-cost in $/kW, and exhaust temperature available for retrofitting steam plants. Are SCRs acceptable if they produce the best economic choice?***

Bill Day: 9ppm drives low-temperature operation.

Participant: We should consider that SCR allows the burning of fuels other than natural gas, which would be difficult in a dry, low-NOx system.

Richard Brent: watch the degrading of SCR through poisoning of the catalyst. **Bob Moritz:** are there solid wastes?

Charles Cook: An update on Catalytica tests — they are incomplete but positive.

Bill Day: Is there a requirement to hit 9ppm without an SCR, as was the case in the ATS program? No one knew of one.

Carl Paquin: The market may prefer dry, low-NOx or another alternative to SCR, and may be willing to pay the premium.

Bob Moritz: Can an SCR be operated remotely? **Richard Brent** and **Charles Cook:** Yes, as a passive system.

Niels Laursen: SCR is not an issue in Denmark; SCR is already in a coal-fired plant.

Carl Paquin: An SCR is an adder to plant cost; some estimate 10 percent, but this varies with the size of the plant.

Richard Brent: Check emission costs against utility, IPP, power market models.

Charles Cook: Add — the biggest aeroderivative (likely midsize); set the product price goal at the outset. Consider multiple cost bases — first, busbar, maintenance. Same point for emissions — consider design issues early in relation to cost. Compare with the potential for downstream design decisions.

Carl Paquin: What are the key cost drivers? **Charles Cook:** Integration of effort, communication, for example with the vendor.

Allison notes that more and more cost barriers are the materials, not the manufacturing. This is less of a problem with ICAD, because the core does not change. **George Padgett:** Cost reduction activities are hard to do unless done the first time and involve the manufacturer/supplier in the design process.

General concern was voiced by the group: Will this initiative take dollars from the ATS program, and the consensus was that it had better not!

Group 3: Funding Sources and Cost Sharing

Facilitator: Jeff Abboud

Gas Turbine Association

Summary of program concepts and products development: define the concepts, the technology demonstrations, the research — both technical and market components, budgeting the cost of entire development program, the commercialization potential, legislative goals. Determine the technical/economic feasibility, do a sensitivity study, assess the market, define the barriers, define the mission and vision statement, and advocacy/lobby. Barriers may be institutional, economic, and environmental. Define the risk and technical competition — these are barriers. Define the timeline, determine alliances (DOE, municipalities, states, etc.). Commercial industry should do the evolutionary things; revolutionary things should be done by alliances of shared interests and everybody participates collectively. Maybe there are benefits in talking about how we can bring alliances together to develop such a machine, define stakeholders for alliances.

Links to other programs — what are the complementary programs? Defense applications (ARPA, DARPA, DOE), Combustion 2000 — looking at aeroderivative, ATS, high performance power systems, WR 21 (DOD program) to develop an engine that would be efficient at part load/ or a combined-cycle program called racer eventually died; an award was made to WEC for an intercooled recuperator. The net result is where the military can afford it, there is a big capital cost. The military has intercooled technology and recuperator technology that is subject to tight review and scrutiny every year; this began in 1992. IHPPTET (F1/41 engines) at high temperatures for F4 engine-integrated high performance turbine technology; NASA has propulsion turbine programs.

When are these programs to be completed? ATS in 2001. Combustion 2000 — Phase 2 goes to the year 2000; the demo is 2005 (at $12 million/year). WR21-end of the technical design phase, which includes running an engine in 1999. The U.S Navy hopes to identify a ship and an engine to go into the ship — but it will be about 2001 before it actually goes into the ship as they are learning that intercooling is not as easy as thought. The California 1890 bill at a total of $500 million for 5 years, $246 million for 5 years. GRI/EPRI have enabling work in catalytic combustion. It now makes a difference as to what you want your engine to look like.

The design of the FMGT has to have advantages: low cost, existing engine core, has to be low dollars for electrical cost, no mechanical costs. As an option in the design process, should consider alternative generation forms — the average engine size sold has been 80 MW with fuel flexibility (e.g., how much alkali can you withstand?). The engine could be limited to natural gas and still capture a good portion of the market. Develop a product for the mass market and modify for the niche markets. The development needs to start with natural gas initially and then look at alternate sources of fuel. Intercoolers are not optimum for every environment. Encourage international thinking and include governmental groups and motivate their interests.

1. ***Who would be potential program participants? to what level should each cost-share? Would private partners consider repayment options to their public partners if needed?***

Engine manufacturers-10; DOE/CEC 1890 programs/-10; EPRI/GRI are potential participants-8; Utility organizations-6; States R&D-7; International government support/develop international markets-8; Industrial manufacturers/Department of agriculture-5; Department of Commerce/DOD-2,5; Universities-5; National labs-5; CAGT/GTA other associations-8; Packagers-8; End-users/Merchant Generators/onsite power-10; Customers-10; Insurers/financial community-6; Environmentalists-7; White House-8; EPA/regulators-8.

Repayment options will have to be included in the program for both the CEC and the DOE.

2. ***What are your recommendations for an action plan to get a program underway or to address product issues?***

Perform a programmatic research development announcement to determine the situation in with the market timing and manufacturing.

Include national benefits/market or impact and have international market impact.

Develop a commercialization/enabling technology development.

CEC/other states funding starts to develop a concept plan in 1998.

DOE potentially puts forth enabling technology development funds in the 1999 to 2000 time frame.

Who will be the lead agency? CEC/DOE/Governors Office Collaboration. During the review process, an advisory panel could be used to determine who is the lead agency and determine who could be leveraged for funding.

CAGT will perform an updated market study, which will be performed in parallel with the Phase 1 study.

Phase 2 would include component development and a full-scale component validation assessment; this would take 24 to 30 months. Phase 2 would be initiated around June of 1999.

3. ***What is the total cost and schedule of development program required for the midsize gas turbine, assuming an arrangement similar to that of the ATS Program (cost-shared program, multiple contractors initially, narrowing to 1 or 2 demo plants)?***

1997-1998: Phase 1 feasibility study/market study with CAGT.

Mid-1999: Initiate cost-shared manufacture/CEC/DOE and others effort to complete conceptual design/technical development of enabling technologies and unique component development.

Phase 2 would run from 1999-2001.

Phase 3 would be awarded after Phase 2 in 2001. Continuation into Phase 3 would be determined in the year 2002. The first engine would be ready to test around 2001-2002 time frame with testing completed around 2003.

Total cost for program will not be defined until after the initial concept phase determines the total funding need. The program will be cost-shared by CEC-States-DOE manufacturers. Initially, the CEC will provide funding for Phase 1 to determine the feasibility of the program. The manufacturers will cost-share after Phase 1 to perform enabling technologies. DOE may begin cost-sharing after Phase 1 is completed. The lead agency will oversee the structure of the program. Phase 1 could potentially cost up to $5 million. Phase 2 could cost up to $50 million. Phase 3 could cost up to $100 million per vendor.

4. ***How will RD&D be conducted in future for new generation? Will add-on electricity costs like the California AB 1890 be viable in other markets, and can a national gas turbine program be constructed on this basis?***

CEC and DOE could support R&D with universities and vendors. CEC has a special funding mechanisms dealing specifically with R&D. DOE historically has looked at applied research with universities/labs as a means to perform applied research.

5. ***How could financial investment community and venture capital be used to leverage buyer, supplier, and government funds? Do aircraft engine lease financing approaches and buying groups provide models for the power generation sector?***

6. ***Are there market incentive approaches to encouraging use of first-of-kind advanced gas turbine technologies and/or to mitigate risks? Should there be power-pool collaborations on demonstration projects to share risks and benefits amongst participants?***

Group 4: Links to Other Programs

Facilitator: Dan Whitney

Sacramento Municipal Utility District

1. ***Are there programs ongoing or which have taken place that address technology development for midsize, flexible gas turbines?***

Links to other programs: What are the complementary programs? Defense applications (ARPA, DARPA, DOE), Combustion 2000 — looking at aeroderivative, ATS, high performance power systems, WR 21 (DOD program) to develop an engine that would be efficient at part load/ or a combined-cycle program called racer eventually died; an award was made to WEC for an intercooled recuperator. The net result is where the military can afford it, there is a big capital cost. The military has intercooled technology and recuperator technology that is subject to tight review and scrutiny every year; this began in 1992. IHPPTET (F1/41 engines) at high temperatures for F4 engine-integrated high performance turbine technology; NASA has propulsion turbine programs.

When are these programs to be completed: ATS in 2001. Combustion 2000 — Phase 2 goes to the year 2000; the demo is 2005 (at $12 million/year). WR21-end of the technical design phase, which includes running an engine in 1999. The U.S Navy hopes to identify a ship and an engine to go into the ship — but it will be about 2001 before it actually goes into the ship as they are learning that intercooling is not as easy as thought. The California 1890 bill at a total of $500 million for 5 years, $246 million for 5 years. GRI/EPRI have enabling work in catalytic combustion. It now makes a difference as to what you want your engine to look like.

Midi would be a block and is a primary competitor; think of other partners.

2. ***What are some of the technology issues currently being addressed which are related to midsize flexible gas turbines? Could these efforts be leveraged for a midsize turbine program?***

Currently, there is utilization of dual fuel capability. A 100-MW system would be too large to accept only biomass systems. Hybrid fuel systems would be more feasible than those solely fueled on biomass; we should look at hybrid systems. Free markets are going to change — you could use cycling of the turbine to utilize FMGT as a load-following capability or backup for wind for example. Utilities used to provide support for renewable resources. With the deregulated industry, aggregated power suppliers will be needed to manage flexible power suppliers to serve customers. The question is, how and who will be the aggregators? FMGT may provide the alternative option to simple cycle gas turbines that need to be replaced. Information should be provided to federal government on hybridization schemes so that this can be input into their planning process.

3. ***Given the size of gas-turbine development costs, should greater international collaboration be encouraged as in the Space, Fusion, and Defense programs? For example, would EEC involvement in a Midsized Turbine Program make sense?***

Collaboration financially may cause issues with U.S. funding sources. Collaboration without funding encourages U.S. funding sources. It's an alternative, perhaps, for developing the market potential.

4. ***Gas turbines cross cut fuels and application sizes — around which energy programs are historically organized, with the potential implication that gas turbine RD&D might be underfunded. What can be done to increase cross fertilization between these programs and research communities relative to gas turbines?***

Look at various topping cycles or bottoming cycles to bring federal/state funding sources together. Utilization of WR21 with solar tower, and blending it in with recuperation. Use the wind flow to drive the intercooler. Bottoming cycle applications such as biomass drying or the utilization of waste heat may be appropriate. Federal bills exist to develop new renewable applications, but this is not fully defined.

5. ***What considerations should there be in a midsized gas turbine program relative to renewable energy?***

Blend the biogas with the natural gas stream of natural-gas midsize turbines. Use the natural gas to sweeten the biogas; then, it would be able to generate 100 MW of power. There may still be some impurity issues that need to be resolved. Regional landfills may be a potential for this type of turbine — the 25-MW size of new regional landfills could use this type of turbine for bending with natural gas. IGCC is proposed for use of biomass gasification.

There's a lot of interest in improving biomass gas utilization. If we can make the machine to handle biomass gases, this will improve the opportunities to use the funding available from the renewable pathways. We will need to qualify this engine to utilize biomass, and we need to address the fuel composition for blending of gases for combustion systems, landfill, and biomass, which is variable depending on which landfill/biomass source exists.

The midsize turbine and how the renewables for California will benefit from midsize turbine applications should be included in the legislation.

We need to better publicize the opportunities to blend renewables with fossil fuels as hybrid systems. Prorate the blending related to renewables funding program.

Abbreviations and Acronyms

ARPA	(U.S. Department of Defense) Advanced Research Projects Agency
ATS	Advanced Turbine Systems
BG	British Gas
CAGT	California Advanced Gas Turbine
CC	combined cycle
CCGT	combined-cycle gas turbine
CEC	California Energy Commission
CHAT	cascaded humidified advanced turbine
CTC	combustion turbine combined-cycle
DARPA	(U.S. Department of) Defense Advanced Research Projects Agency
DG	distributed generation
DOD	(U.S.) Department of Defense
DOE	(U.S.) Department of Energy
EdF	Electricité de France
EPA	(U.S.) Environmental Protection Agency
EPRI	Electric Power Research Institute
FCC	Federal Commerce Commission
FERC	Future Energy Resources Corporation (also FERCO)
FETC	Federal Energy Technology Center
FMGT	flexible, midsize gas turbine
GRI	Gas Research Institute
GTA	Gas Turbine Association
GTCC	gas turbine combined-cycle
HAT	humid air turbine
HT	high temperature
ICAD	intercooled aeroderivative
ICR	intercooled recuperating
IPP	independent power producer
ISO	independent system operator
LAER	lowest achievable emissions rate
LHV	lower heating value
LT	low temperature
NEPOOL	New England Power Pool
NOx	nitrogen oxides
NP	National Power
NREL	National Renewable Energy Laboratory

NU	Northeast Utilities
O&M	operating and maintenance (costs)
OCGT	open-cycle gas turbine
OEM	operating and equipment manufacturers
PG&E	Pacific Gas and Electric
PUC	Public Utility Commission
PURPA	Public Utility Regulatory Policy Act
R&D	research and development
RD&D	research, development, and demonstration
RDRI	Research Data Resource International
RR	Rolls Royce
SC	simple cycle
SCR	selective catalytic reduction
SFA	SFA Pacific, Inc.
SMUD	Sacramento Municipal Utility District
STIG	steam turbine integrated gas
T&D	transmission and distribution
UK	United Kingdom
US Gen	U.S. Generating Company

Participants List

Jeffrey S. Abboud
Gas Turbine Association
1600 Wilson Boulevard, Suite 901
Arlington, VA 22209 USA
Ph: 703-524-7616; Fax: 703-812-8743

Don Anson
Battelle
405 King Avenue
Columbus, OH 43901 USA
Ph: 614-424-5823; Fax: 614-424-3321

Mark Axford
Stewart & Stevenson
2727 North Loop West, P.O. Box 1637
Houston, TX 77008 USA
Ph: 713-868-7650; Fax: 713-868-7697

Paul Bautista
Gas Research Institute
8600 W Bryn Mawr Ave.
Chicago, IL 60631 USA
Ph: 773-399-5460; Fax: 773-399-8170
E-mail: pbautist@gri.org

Christophe Bellot
Electricité de France
6 quai Watier
Chatou 78400 FRANCE
Ph: 33-1-3037-7712

Ron Belval
City of Burlington
585 Pine Street
Burlington, VT 05401 USA
Ph: 802-658-0300; Fax: 802-865-7400

Frank Bevc
Westinghouse
4400 Alfaya Trail
Orlando, FL 32826 USA
Ph: 407-281-3393; Fax: 407-281-5014
E-mail: bevc.f.p.@wec.com

Daniel Brdar
Federal Energy Technology Center
P.O. Box 880
Morgantown, WV 26505 USA
Ph: 304-285-4666; Fax: 304-285-4292
E-mail: RBRDAR@FETC.DOE.GOV

Richard Brent
Solar Turbines
P.O. Box 85376
San Diego, CA 92186 USA
Ph: 619-544-5663; Fax: 619-544-5263

Arthur Cohn
Electric Power Research Institute
3412 Hillview Ave.
Palo Alto, CA 94304 USA
Ph: 415-855-2525; Fax: 415-855-8759
E-mail: ACOHN@EPRI.COM

Charles Cook
GE Power Systems
1 River Road, 53-425
Schenectady, NY 12345 USA
Ph: 518-385-9421; Fax: 518-385-4314
E-mail: cookch@pssch.ps.ge.com

Barry Davidson
National Power PLC
Windhill Business Park
Swindon, Wilts SN5 6PB UNITED KINGDOM
Ph: 44-1793-896260; Fax: 44-1793-896386
E-mail: Barry.Davidson@research.natpower.co.uk

William Day
Pratt & Whitney
400 Main Street, M/S 165-22
East Hartford, CT 06001 USA
Ph: 860-565-0086
E-mail: dayw@pweh.com

Victor Der
U.S. Department of Energy
19901 Germantown Road
Germantown, MD 20874-1290 USA
Ph: 301-903-2700; Fax: 301-903-2713
E-mail: victor.der@hq.doe.gov

Ted Elmer
Seattle City Light
700 5th Avenue
Seattle, WA 98104-5031
Ph: 206-386-4518

Bernard Givaudan
Electricité de France
12-14 avenue Dutrievoz
69628 Villeurbanne, Cedex FRANCE
Ph: 04-72-82-76-96

Lawrence Golan
South Carolina Energy R&D Center
386-2 College Avenue
Clemson, SC 29634 USA
Ph: 864-656-2267; Fax: 864-656-0142
E-mail: glawren@clemson.edu

David Hatfield
California Energy Commission
1516-9th Street, MS-43, Box 944295
Sacramento, CA 94244-2950 USA
Ph: 916-654-4500; Fax: 916-653-6010
E-mail: fomts@pacbell.net

George Hay III
California Advanced Gas Turbine, LLC
42 Sunrise Lane
Lafayette, CA 94549 USA
Ph: 510-988-9792; Fax: 510-988-0402
E-mail: geohay3@aol.com

Chris Hodrien
British Gas PLC - Gas Research & Tech.Ctr
Ashby Road, Loughborough
Leicestershire LE11 3GR UNITED KINGDOM
Ph: 44-0-1509-282000; Fax: 44-0-1509-28231
E-mail: chris.hodrien@bggrc.co.uk

Evan E. Hughes
Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, CA 94304
Ph: 415-855-2179; Fax: 415-855-8501
E-mail: ehughes@epri.com

Jack Janes
California Energy Commission
1516-9th Street, MS-43, Box 944295
Sacramento, CA 94244-2950 USA
Ph: 916-654-4613; Fax: 916-653-6010
E-mail: jjanes@energy.state.ca.us

Mary Johannis
California Energy Commission
1516-9th Street, MS-43, Box 944295
Sacramento, CA 94244-2950 USA
Ph: 916-654-4611; Fax: 916-653-6010
E-mail: mjohanni@energy.state.ca.us

Dan Kincaid
Gas Research Institute
8600 W Bryn Mawr Ave.
Chicago, IL 60631 USA
Ph: 773-399-8338; Fax: 773-399-8170
E-mail: dkincaid@gri.org

Jeff King
Pacific Northwest Power Planning Council
Portland, OR 97204 USA
Ph: 503-222-5161; Fax: 503-795-3370
E-mail: jking@NWPPC.org

Christopher Lane
Generation Equipment Services Company
13624 E. Nelson Ave.
City of Industry, CA 91746 USA
Ph: 818-855-1429; Fax: 818-855-1428
E-mail: cklaner@aol.com

Niels Laursen
ELKRAFT
5, Lautruphoj
2750 Ballerup, Copenhagen DENMARK
Ph: 4544660022; Fax: 4544656104

Abbie Layne
Federal Energy Technology Center
3610 Collins Ferry Road
Morgantown, WV 26505 USA
Ph: 304-285-4603; Fax: 304-285-4469
E-mail: ALAYNE@FETC.DOE.GOV

Matthew Layton
California Energy Commission
1516-9th Street, MS-43, Box 944295
Sacramento, CA 94244-2950 USA
Ph: 916-654-3868; Fax: 916-654-3882
E-mail: mlayton@energy.state.ca.us

Jim Lyons
Southern Company Services
P.O. Box 2625, Bin B237
Birmingham, AL 35202-2625 USA
Ph: 205-992-6526; Fax: 205-992-0361
E-mail: james.w.lyons@scsnet.com

Dick Maclay
Pacific Gas and Electric
77 Beale Street
San Francisco, CA 94177 USA
Ph: 415-973-1670; Fax: 415-973-9062
E-mail: wrm8@pge.com

James E. McCallum
Georgia Power Company
333 Piedmont Ave NE, Bin 10160
Atlanta, GA 30308 USA
Ph: 404-526-7006; Fax: 404-526-7723
E-mail: Jimmy.E.McCallum@gpc.com

Pete McCluer
Consultant
P.O. Box 650
Mt. Aukum, CA 95656 USA
Ph: 916-610-0022; Fax: 916-620-4623

Katie McCormack
California Advanced Gas Turbine, LLC
1530 Meadow Lane
Burlingame, CA 94010-3351 USA
Ph: 415-692-5254; Fax: 415-692-2081
E-mail: Katiemc@igc.org

David R. McCue
CNG Energy Services Corporation
1001 SW Fifth Ave., Suite 17501
Portland, OR 97204 USA
Ph: 503-323-9138; Fax: 503-323-7344
E-mail: David_R_McCue@ESC.CNG.COM

James Moll
Moll Associates
450 San Antonio Road, Suite 19
Palo Alto, CA 94306 USA
Ph: 415-494-2850; Fax: 415-494-6125

Robert Moritz
Allison Engine Co.
P.O. Box 420
Indianapolis, IN 46206 USA
Ph: 317-230-3614; Fax: 317-230-3691

Robert Nicholson
Global Project Finance, Department 5051
Bank of America
555 California Street, 12th Floor
San Francisco, CA 94104 USA

George Padgett
Caterpillar
2200 Pacific Highway
San Diego, CA 92186 USA
Ph: 619-544-5708; Fax: 619-544-2682

Carl Paquin
Pacific Gas and Electric
2303 Camino Ramon, Suite 200
San Ramon, CA 94563 USA
Ph: 510-866-5766; Fax: 510-866-5909
E-mail: cdp@pge.com

Jonathon Rayner
Rolls-Royce
Ansty
Coventry CV7 7JR UNITED KINGDOM
Ph: 44-1203-623101; Fax: 44-1203-623250

Robert Reed
U.S. Generating Company
7500 Old Georgetown Road
Bethesda, MD 20814 USA
Ph: 301-718-6972; Fax: 301-718-6917
E-mail: rreed@usgen.com

Graham Reynolds
Rolls-Royce
Ansty
Coventry CV3 6EL UNITED KINGDOM
Ph: 011-44-1203-623200; Fax: 01-411-1203-623250

Jim Roberts
Rolls-Royce
Ansty
Coventry CV7 9JR UNITED KINGDOM

Fred Robson
KraftWork Systems, Inc.
P.O. Box 115
Amston, CT 06231 USA
Ph: 806-228-9212; Fax: 806-228-1066
E-mail: FROBSON@AOL.COM

David Rohy
California Energy Commission
1516-9th Street, MS-43, Box 944295
Sacramento, CA 94244-2950 USA
Fax: 916-653-6010
E-mail: drohy@energy.state.ca.us

Eric G. Rorstrom
Northeast Utilities System
Box 270
Hartford, CT 06141-0270 USA
Ph: 860-665-5825; Fax: 860-665-5771
E-mail: rorsteg@nu.com

Dale Simbeck
SFA Pacific, Inc.
444 Castro Street, Suite 920
Mountain View, CA 94041 USA
Ph: 415-969-8876; Fax: 415-969-1317

Valentino Tiangco
California Energy Commission
1516-9th Street, MS-43, Box 944295
Sacramento, CA 94244-2950 USA
Ph: 916-654-4664; Fax: 916-653-6010
E-mail: Valen@ns.net

George Touchton
Electric Power Research Institute
3412 Hillview Ave.
Palo Alto, CA 94304 USA
Ph: 415-855-8935; Fax: 415-855-8759
E-mail: gtouchto@epri.com

Ron Walecki
Allied Signal Ceramics
252 W. 190th Street
Torrance, CA 90504 USA
Ph: 301-512-5916; Fax: 310-512-5901
E-mail: RON.WALECKI@ALLIED SIGNAL.COM

David Walls
Arthur D. Little
Acorn Park
Cambridge, MA 02140-2390 USA
Ph: 617-498-5000

Arden Walters
Advanced Energy Research
13114 Bayfield Dr.
Austin, TX 78727-3320 USA
Ph: 512-252-2144; Fax: 512-252-2228
E-mail: waltersab@aol.com

Stephen Waslo
U.S. Department of Energy
9800 S. Cass Ave.
Argonne, IL 60439 USA
Ph: 630-252-2143; Fax: 630-252-8649
E-mail: stephen.waslo@CH.DOC.GOV

Alfonso Wei
Allison Engine Company
2441 Production Drive, Suite 200
Indianapolis, IN 46241 USA
Ph: 317-230-3984; Fax: 317-230-3509
E-mail: ACWei@AEC572.AGT.GMEDS.COM

Douglas Westerkamp
General Electric
1 Neuman Way
Cincinnati, OH 45215 USA
Ph: 513-552-5574; Fax: 513-552-5001

Daniel Whitney
Sacramento Municipal Utility District
6201 S Street
Sacramento, CA 94244 USA
Ph: 916-732-5351; Fax: 916-732-6423
E-mail: dwhite@SMUD.org

John Wills
Rolls-Royce
11911 Freedom Drive
Reston, VA 22090 USA
Ph: 703-318-9008; Fax: 703-318-9009
E-mail: Wills @RRReston.attmail.com

Appendix

The Appendix consists of the best available versions of eight presentations. Text, graphics, or photos that were not readable were omitted. These presentations are included in the same order as the transcribed speeches.

A PERSPECTIVE ON FMGT & CHANGING ELECTRIC MARKETS

George A. Hay III
President
CAGT, LLC
42 Sunrise Lane
Lafayette, CA 94549

P:510-988-9792
F: 510-988-0402
E-mail: geohay3@aol.com

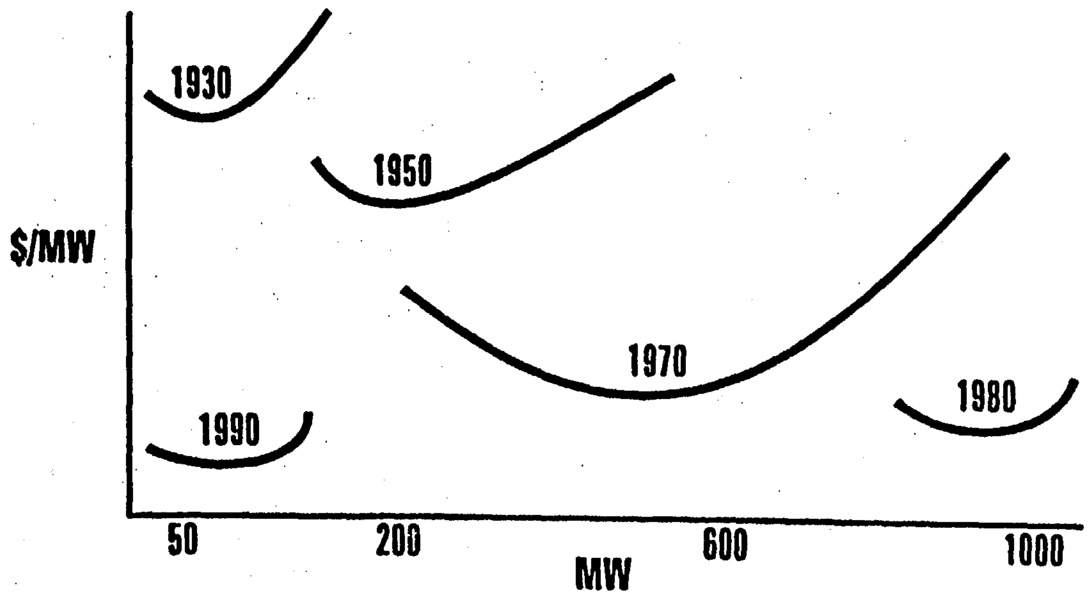
Gas Turbines Driving Industry Restructuring

- Economic Shift from Coal and Nuclear Steam to Gas Turbines and Natural Gas has Helped Drive Restructuring

- Trade-off Economies of Scale and Flexibility
  - Bayless Article Suggests 100 MW Size

- Steam Plant Fleet Legacy
  - Coal Units Increased Capacity Factor
  - Obsolesce of Gas Steam Cycling Units?

Figure 1
Optimal Plant Size
Per-MW Cost Curves (1930-90)

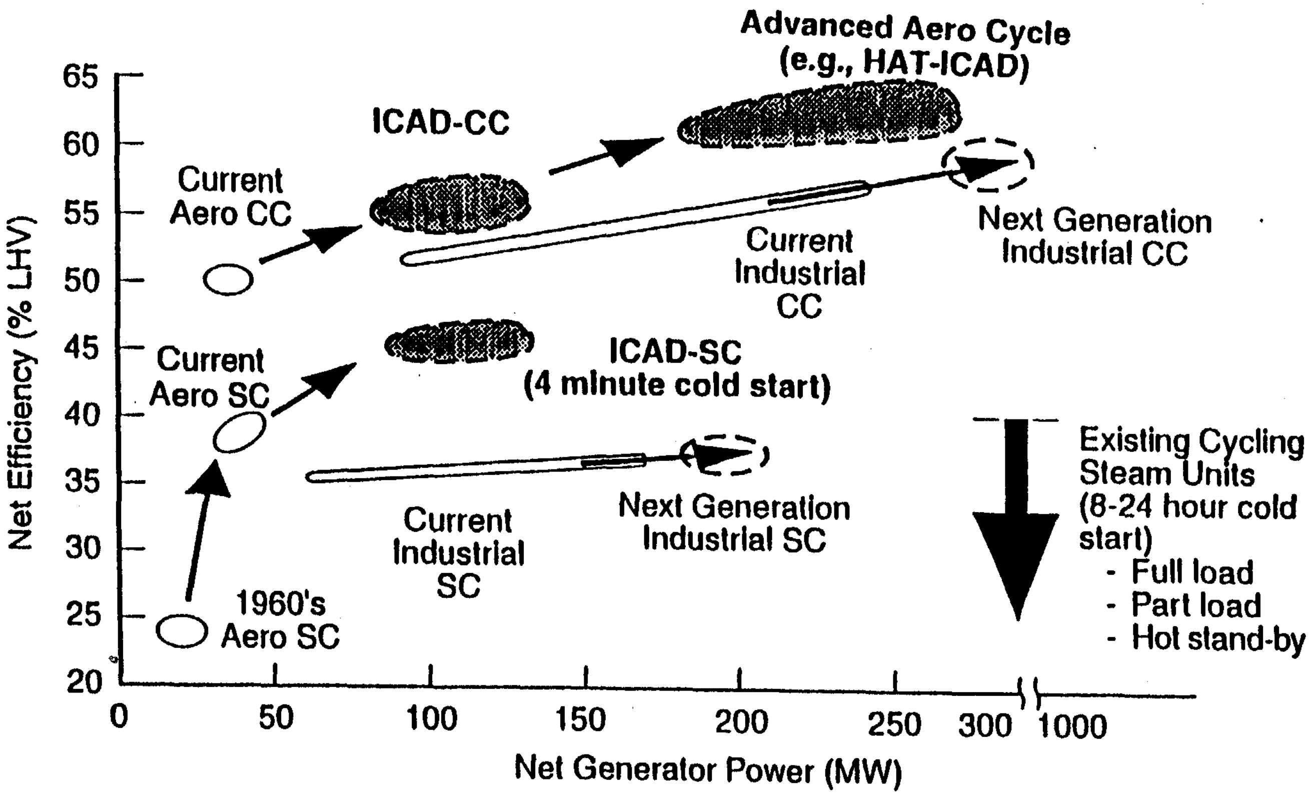


CAGT Program Overview

- Initiated by CEC & CA Utilities as Repowering Collaborative
  - Target Replacement of 20,000 MW Aging Steam Units
  - 2000-2010 Time Frame
  - Collaboration Grew into International "Buyer" Group

- $5+M Study Identified "Flexible" 100 MW+ ICAD Gas Turbine
  - 20-40% Lower Cost than Combined Cycles
  - 45-50% Efficiency without Heat Recovery
  - Superior Intermediate Load & Repowering Option

ICAD Gas Turbine Represents Flexibility New Intermediate Load Product Class



ICAD = Intercooled Aeroderivative

SC = Simple Cycle

CC = Combined Cycle

HAT = Humid Air Turbine

Figure 5

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Intercooled Aeroderivative (ICAD) Gas Turbine Attractive Over a Wide Range of Capacity Factors

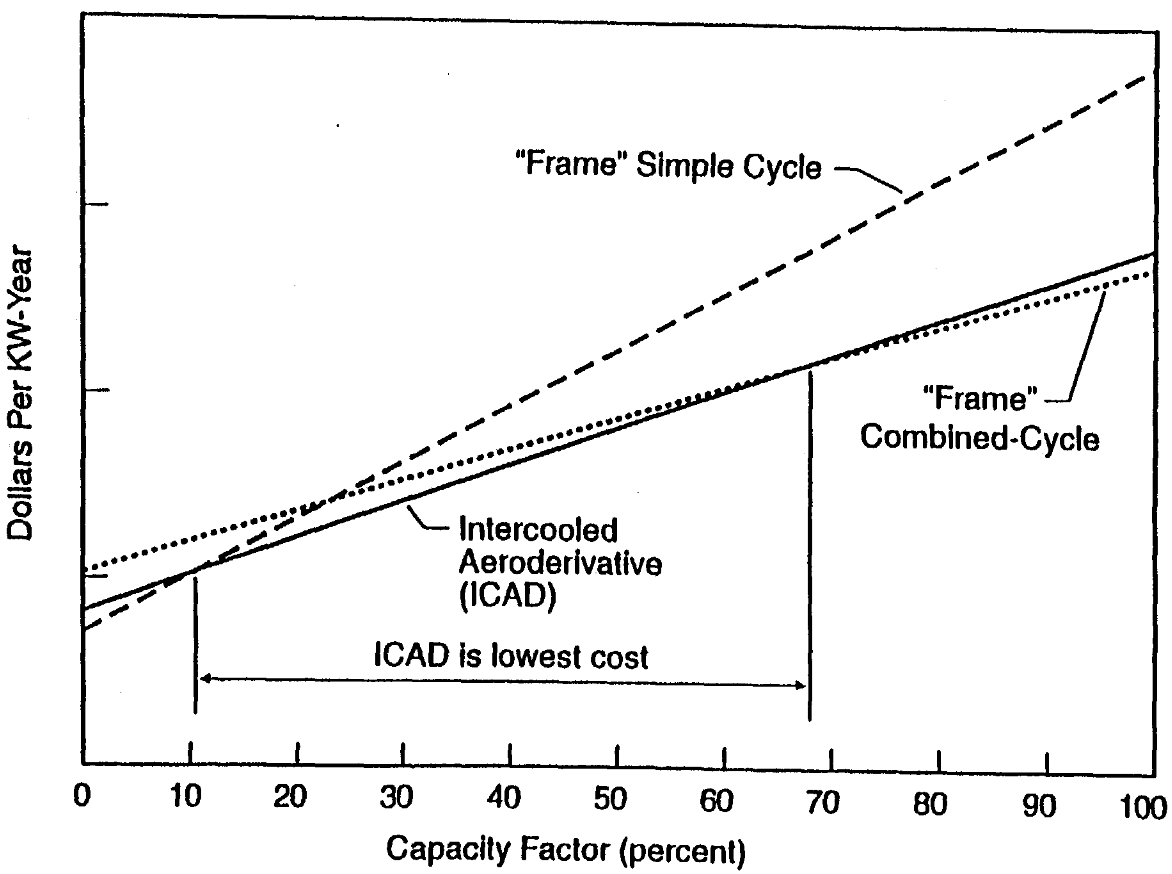
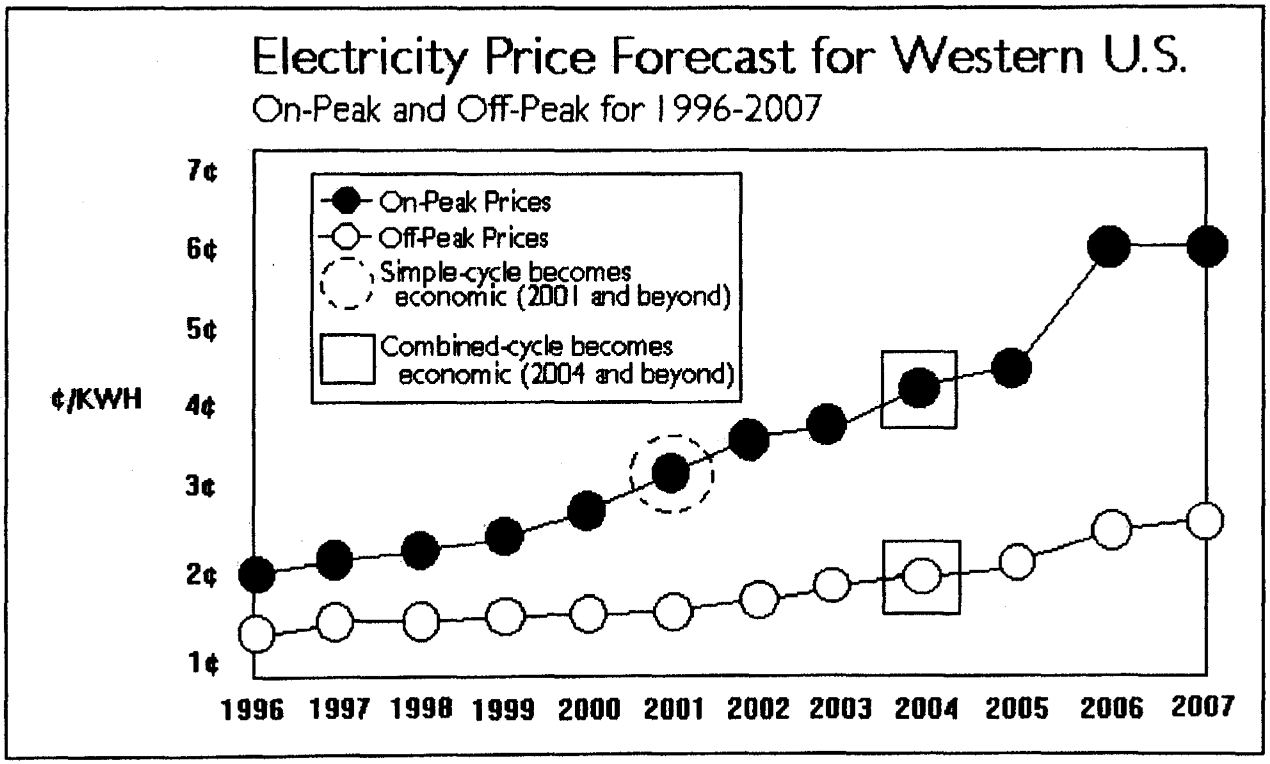


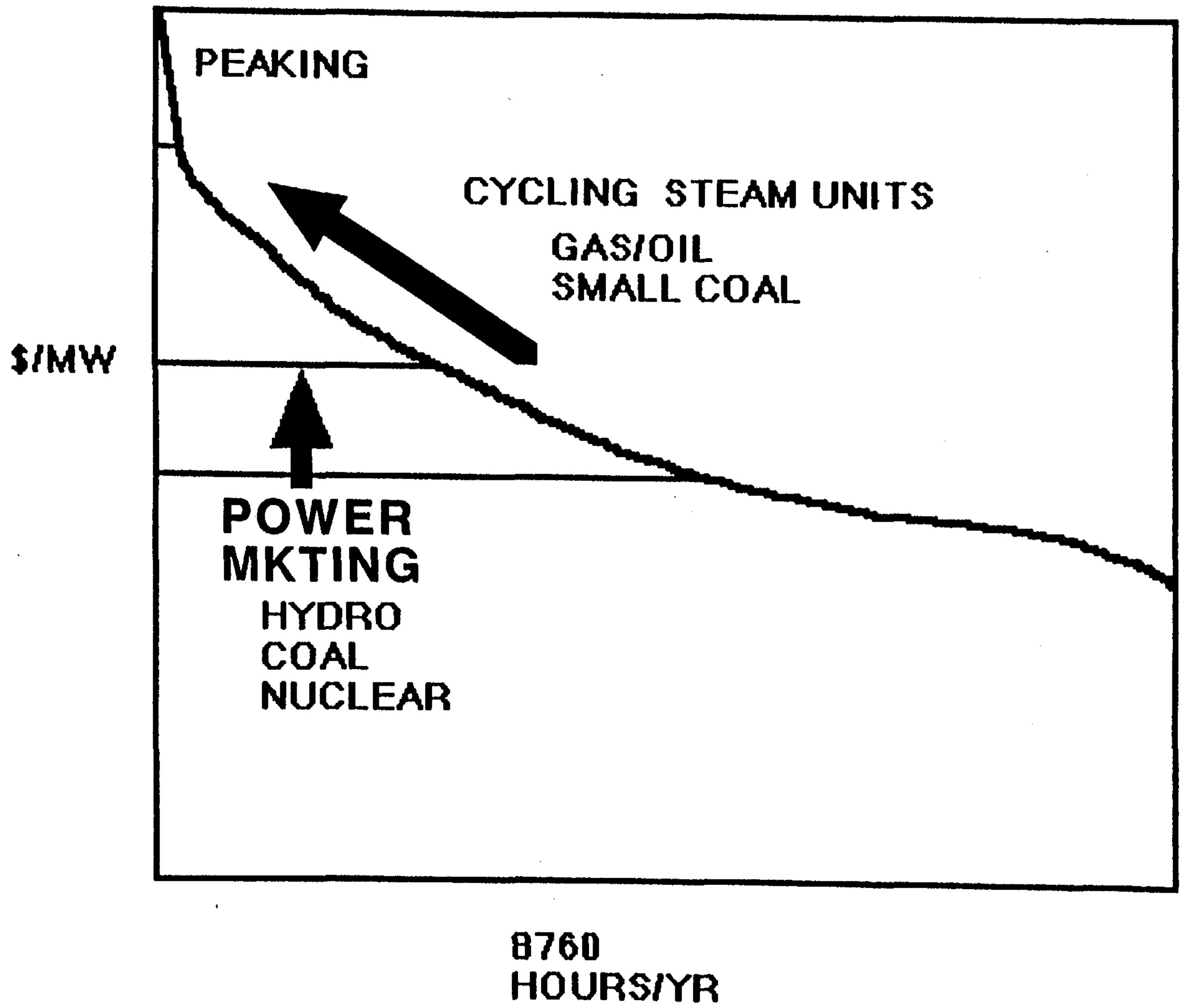
Figure 9

US Market Drivers for FMGT

- Coal and hydro will handle baseload market needs
- Load Growth
  - Dropping Electric Prices and Strong Economy
  - Pushing Reserve Margins and Reliability Concerns
  - "Just in Time Capacity" Favors Factory Packaging
  - Higher Value for Peaking/Intermediate Power
- Huge 2000-2010 Replacement Market for Cycling Natural Gas Fired Steam Units
- Market Risk of Merchant Plant
  - Favor Lower First Cost Over Efficiency
  - Favorable Economics Under Many Scenarios
  - Salvage Value (High Sunk Cost of Heat Recovery)
- Emerging Energy Service Company Strategies
  - Distributed Firming of Regional Wholesale Power
  - Emerging "Aggregated Customers" e.g., municipalities
  - Guarantee Reliability of Service
  - Arbitraging between Electric and Gas/Regional Markets


Electricity Price Forecast for Western U.S.
On-Peak and Off-Peak for 1996-2007
¢/KWH
7¢
6¢
5¢
4¢
3¢
2¢
1¢
On-Peak Prices
Off-Peak Prices
Simple-cycle becomes economic (2001 and beyond)
Combined-cycle becomes economic (2004 and beyond)
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007

LOW MARGINAL COST EXCESS REGIONAL POWER WILL LOWER CAPACITY FACTOR OF OIL/GAS AND SMALL COAL STEAM UNITS USED FOR CYCLING, E.G., CA AND NE



WILL ENVIRONMENTAL UPGRADES AND HIGH FIXED COSTS ACCELERATE RETIREMENT OF THESE UNITS?

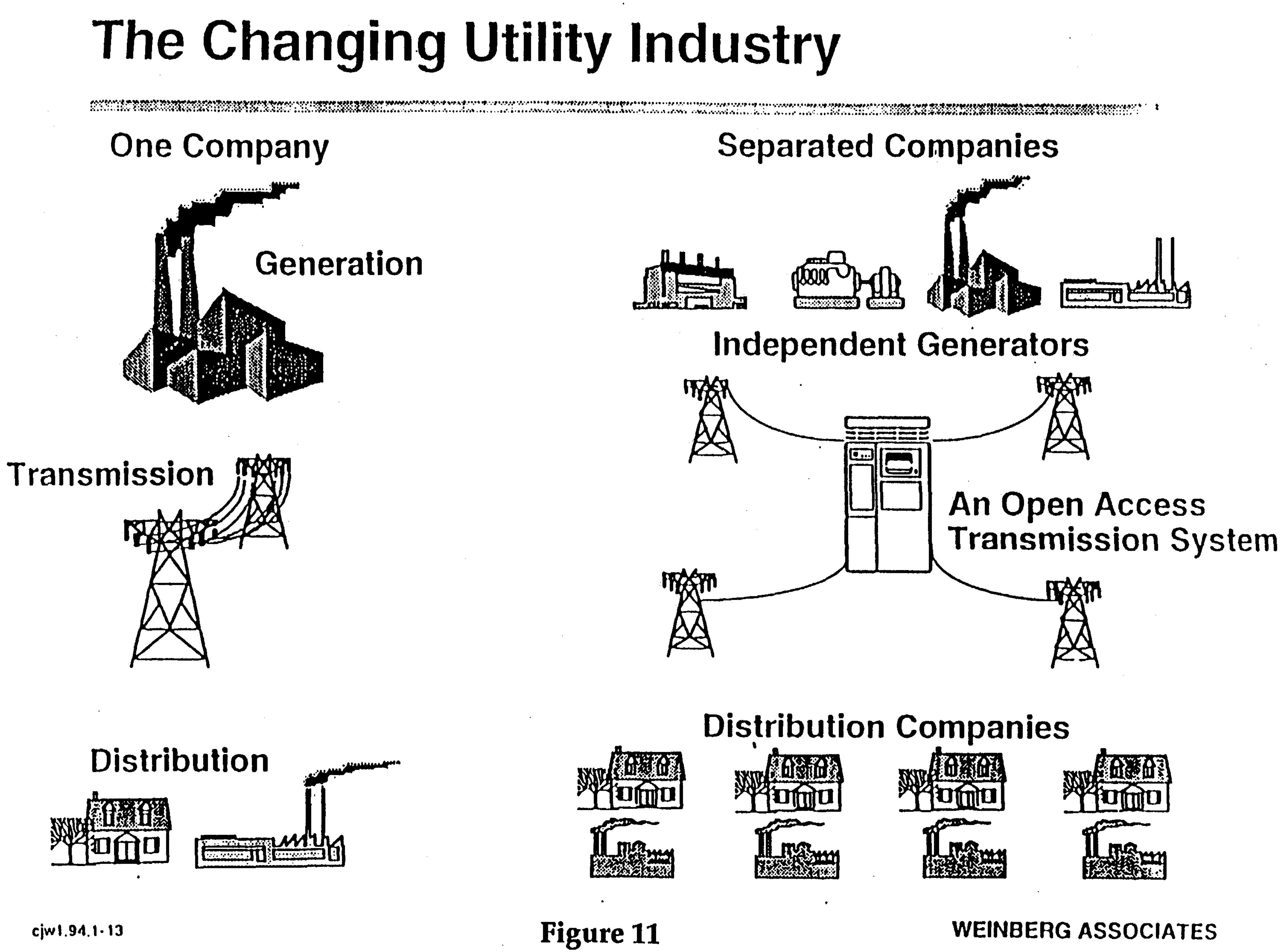

The Changing Utility Industry
One Company
Generation
Transmission
Distribution
Separated Companies
Independent Generators
An Open Access
Transmission System
Distribution Companies
cjw1.94.1-13
WEINBERG ASSOCIATES

Figure 11

Gas Turbines System Paradigm for Integrating Merchant Services

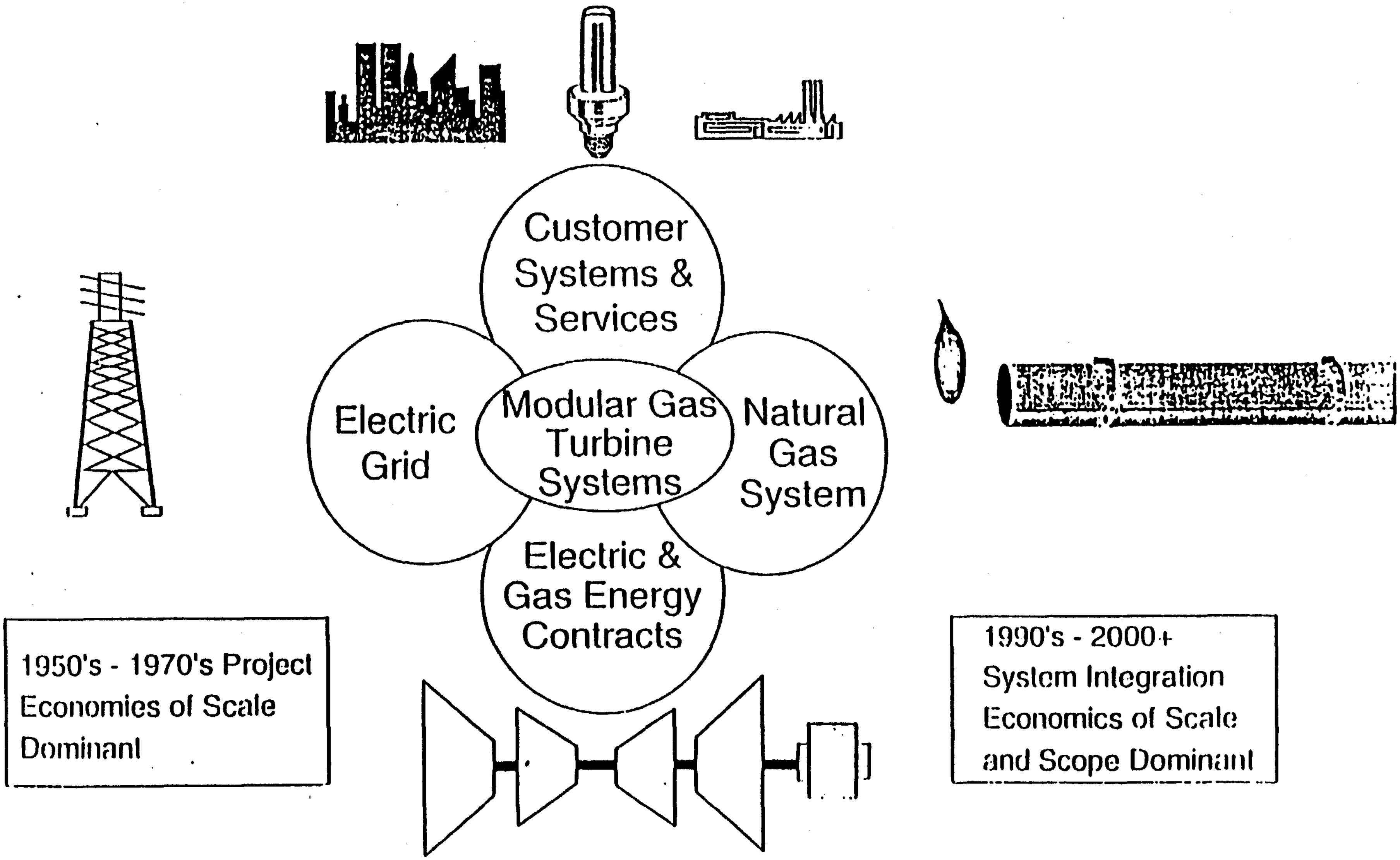


Figure 12

Need for DOE and CEC Support

- FMGT /ICAD Could Have Major Impact in 2000+ Time Frame
    - Lowering Costs and Improving Value/Reliability of Electricity
    - Enabling New Innovations in Applications and Energy Services, e.g., Large Distributed Gen, Hybrid Fuel Concepts and Arbitraging
- Strong and Broad Consensus of Future Users and Suppliers
- Commercialization Barriers
    - Large Development Costs ($100M+)
    - Short-run Drying up of Investment in New Generation
    - Market Uncertainty and Dropping Gas Turbine Prices
    - Dropping of Utility RD&D for New Generation
    - RD&D Not Priority for IPP or Energy Services Co.
    - Gap in DOE ATS Program
- CA CURC Recommended Mid-sized Turbine Program to DOE in 1993
    - Market Has Changed Dramatically Since DOE ATS Define
    - Appropriate Time to Consider Phasing in New Program
    - Potential to Catalyze International Collaboration for US Turbines

Changing Electric Markets

California Energy Commission

sponsored

Flexible, Midsize Gas Turbine Program Planning Workshop

March 4-5, 1997

Sacramento, CA

D.R. Simbeck

Vice President Technology

SFA Pacific, Inc.

Mountain View, CA

Phone (415) 969-8876

Fax (415) 969-1317

Overview of presentation

SFA Pacific's background

Overview of the many changes in US electric markets

Overview of the many changes in worldwide electric markets

- Market shifts from US & Europe to Asia Pacific
- Deregulation
- Environmental
- Technology
- Cogeneration
- Politics of electric markets
- Future power generation favors combustion turbines
- Advanced combustion turbine programs

Summary

Background of SFA Pacific

Basis of name: founded in 1980 as Synthetic Fuels Associates & do extensive work in the Asia-Pacific

Perform technical, economic and market assessments for the major energy companies

Principal work is in power generation and heavy oil upgrading

Niche is objective outside opinion before companies make major investments

Have no vested interest in technologies or project development

Overview of the many changes in US electric markets

The golden age of larger central steam power plants

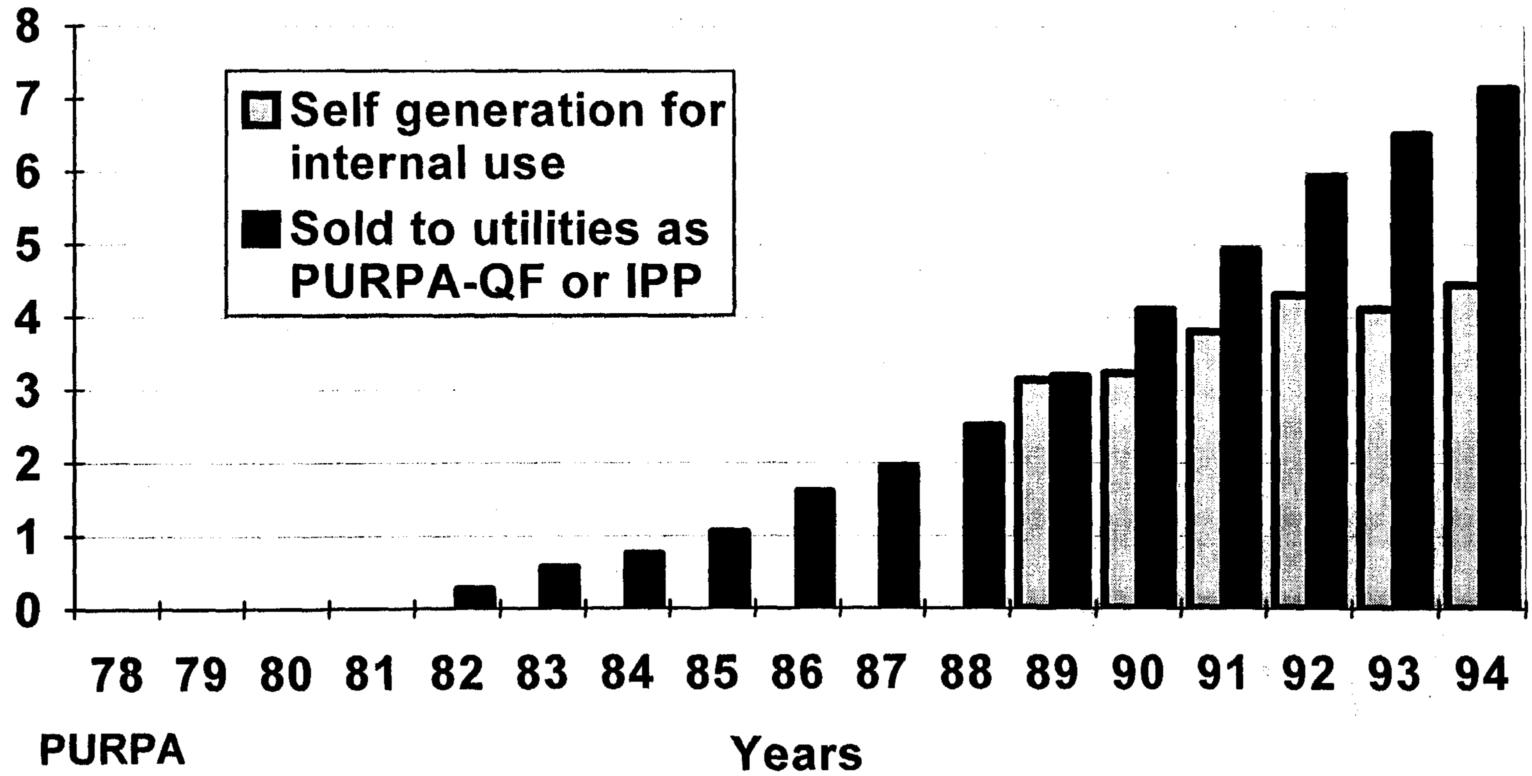
- 1960s to early 1970s (7%/yr load growth)
- Each new boiler was larger (lower unit cost) & more efficient than the last (older units reduced to cycling use)

Events of 1970s changed things forever

- Clean Air Act of 1970; massive building of large nuclear & "grandfathered" coal units to avoid FGD
- Oil shocks of 1973 & 1979; no load growth (thereby large reserve margins) & higher fuel costs
- Three Mile Island; end of nuclear option due to costs
- Deregulation & competition (PURPA then IPP)
- Stranded assets & lower pricing to avoid "death spiral"

Non-Utility Generated (NUG) power in the US as percent of utility generation

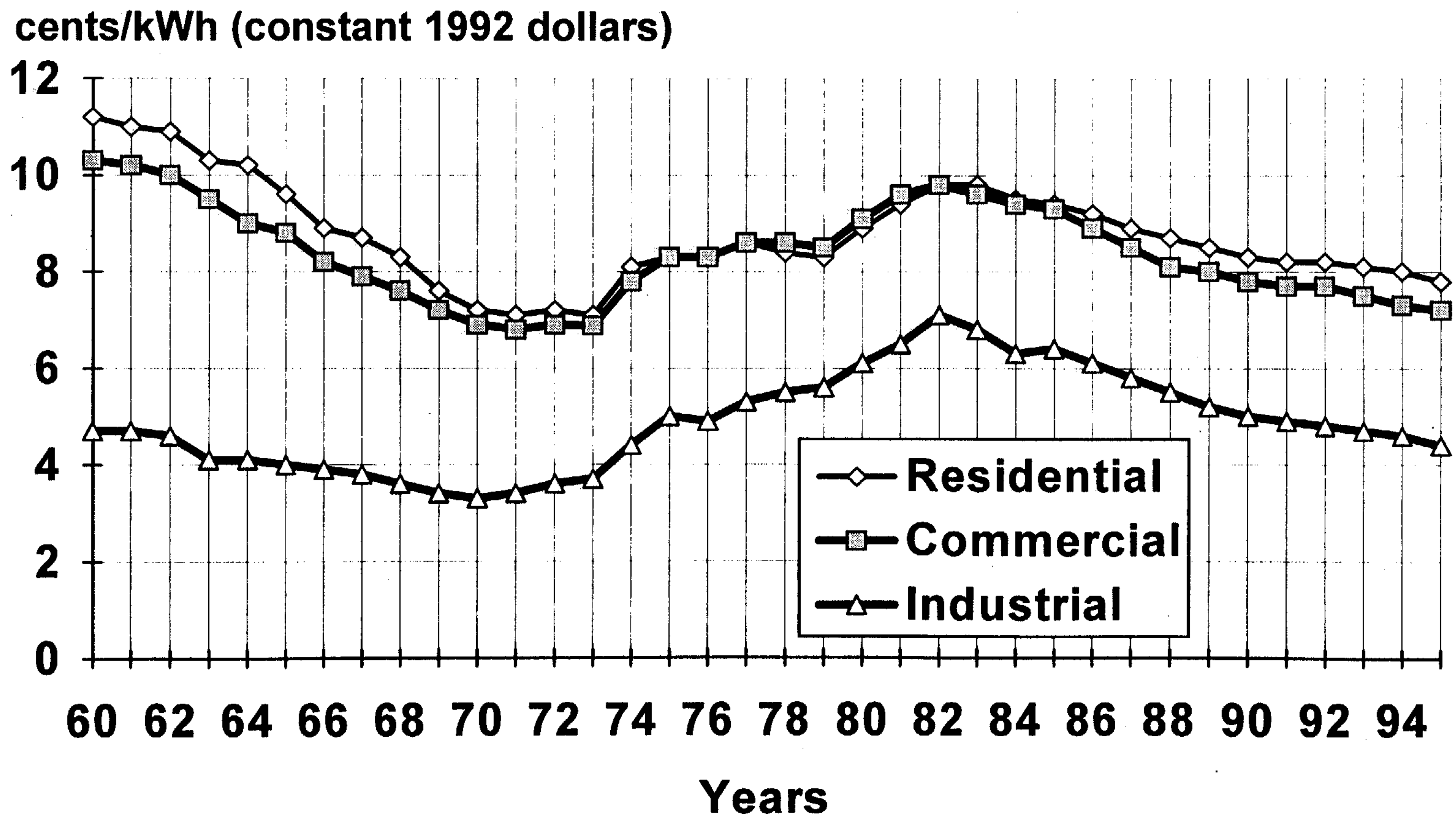
real beginning of competition was after 1982 via PURPA



Source: SFA Pacific from DOE/EIA data

US retail electricity prices 1960-1994 in constant dollars

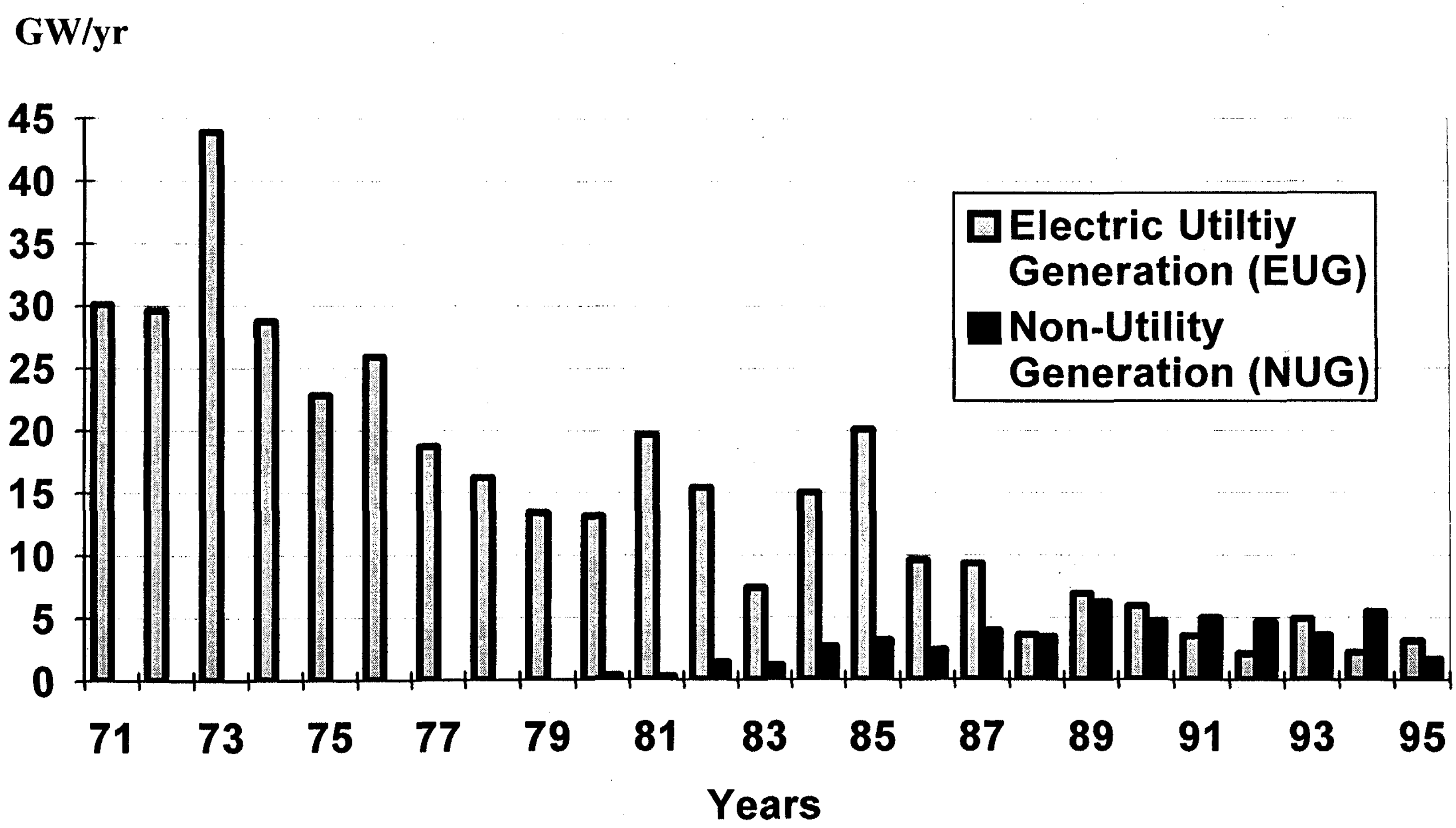
after 1982 shows why competition is good & will stay
capital charges, not fuel mix & price, dominate electricity price



Source: SFA Pacific from DOE/EIA data

SFA Pacific, Inc.

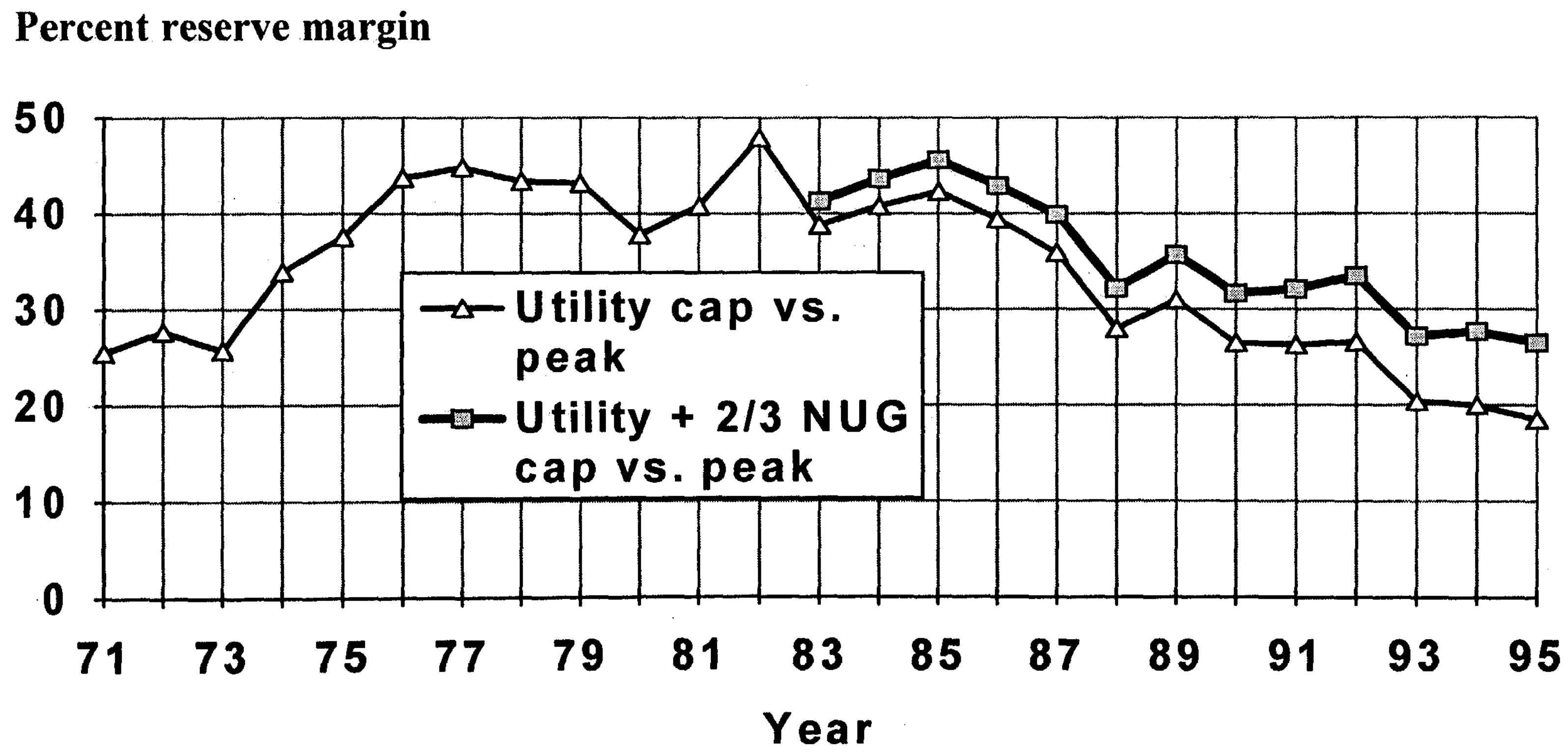
US electric generation capacity additions for the last 25 years



Source: SFA Pacific from EIA and EEI data

US power plant reserve margin including NUG capacity sold to the grid

Reserve margin = (summer rated capacity - peak)/peak
Historically require about 10-15% for high system availability



Source: SFA Pacific from EIA , EEI & NERC data

Current changes in US electric markets

Regulated utilities

- Avoid new capacity & old plant retirements
- Put power plant building expertise in IPP subsidiary
- Quietly & quickly paying off stranded assets

NUG & utility IPP

- Easy days are over
  - No more "PURPA machines"
  - Too many competitors (buyer's market), thereby not making much money on new projects
- Redirecting marketing efforts to Asia-Pacific

Market shifts from US & Europe to Asia-Pacific

High growth rates due to large growth rates in both energy per unit GDP and energy use per capita

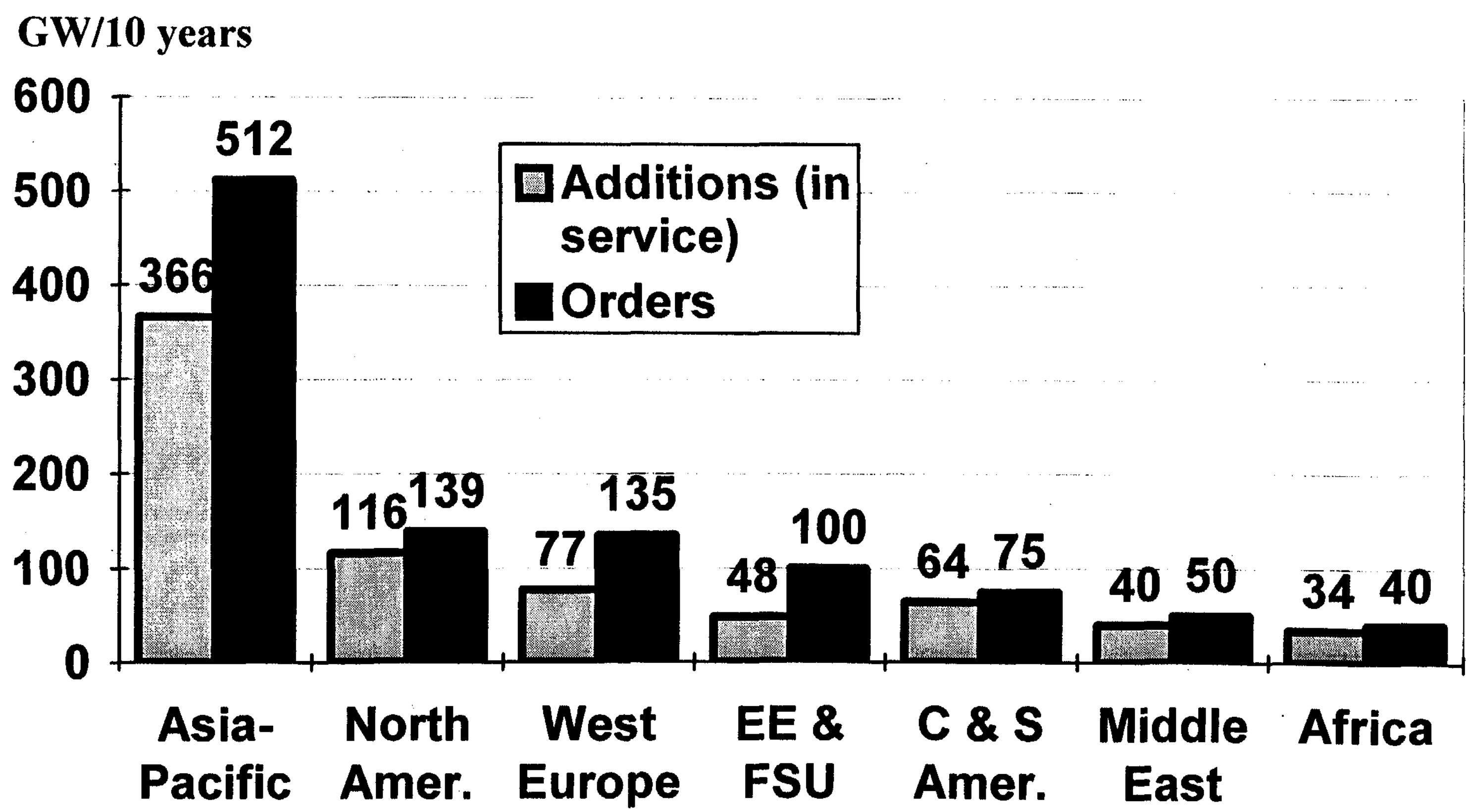
Large and growing population with fast-rising standard of living from low starting points

Principal power need is still mostly baseload

Energy shortages limiting economic growth and thereby making power plant development top priority

Limited domestic gas & oil favors the technologies regulated utilities like best; large, capital-intensive: coal, hydro & nuclear central power plants

Worldwide power plant projections additions & orders 1997-2006



Source: SFA Pacific

Deregulation

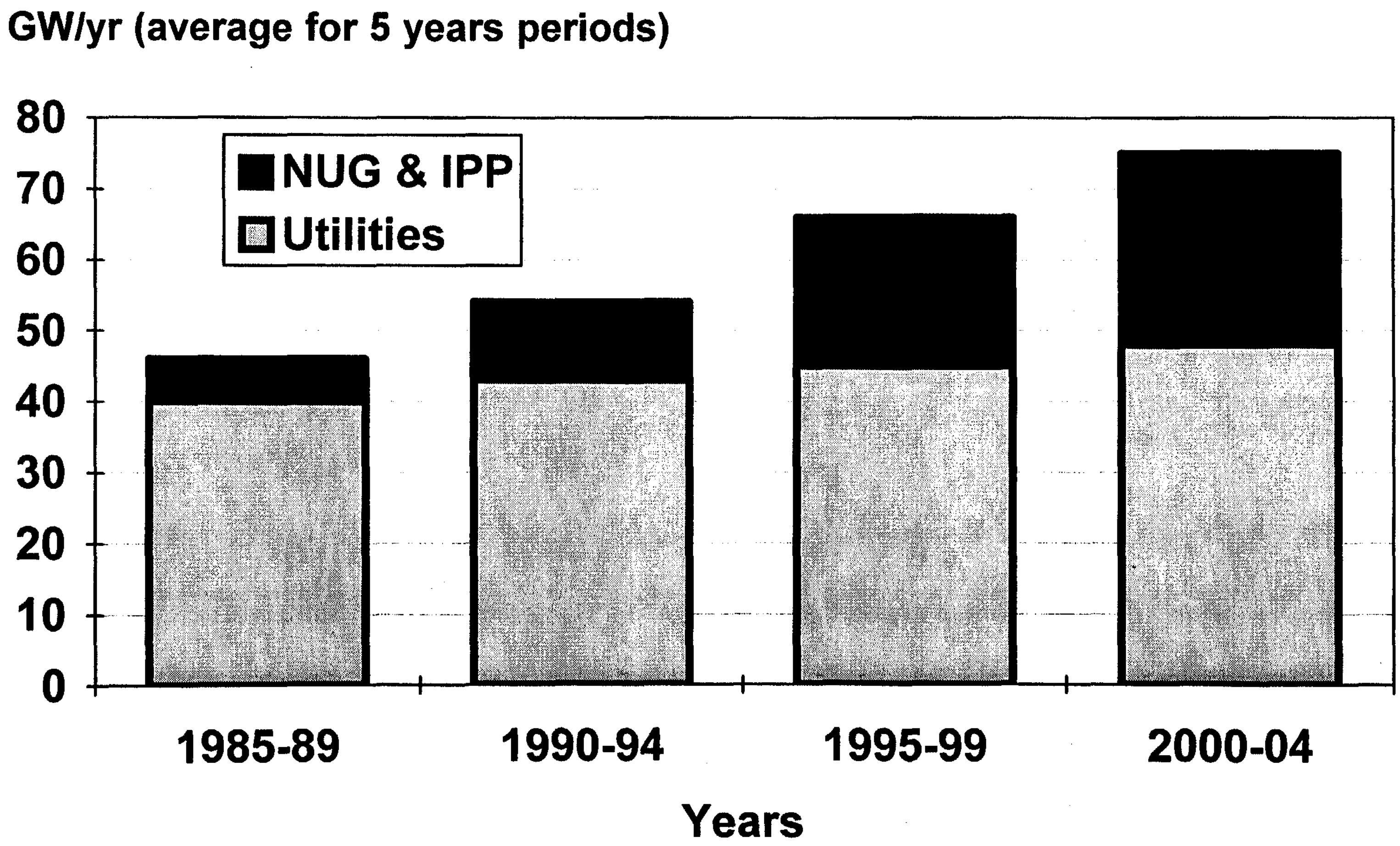
It is here to stay thanks to the following:

- Clear technical, economic, environmental & efficiency success
- Advantages for local governments to raise capital by reselling partially paid-off facilities & then blame IPP for any associated increase in power costs (ie: Australia)
- Allows the true potential of much higher efficiency cogeneration to develop

Happening in much of Asia-Pacific due to power shortages & need for external capital to meet power demand

Is even happening in Japan due to high domestic electric prices & efficiency advantages of allowing effective cogen

Worldwide change in fossil-fueled power plant orders by customer



Source: SFA Pacific from Siemens data

Deregulation (cont.)

Deregulation favors:

- Lower capital cost technologies (oil & gas) even with the risk of imported fuels with uncertain long-term energy prices & supplies
- Smaller units that assure high utilization & less risk
- Cogeneration at high power to heat ratio
- Baseload with minimal dispatch limits (unless attractive capacity payments)

Traditional electric utilities favor:

- High capital cost technologies (coal, hydro & nuclear) to avoid fuel supply & price uncertainty
- Large central power plants with less concern about utilization and dispatch

Environmental

Environmental "overkill" is generally out of favor due to politics of strong economy & job growth

Emissions trading and "bubble" concept greatly reduce costs due to "$/ton removed" thinking

Global climate change issue

- Impact of CO2 & any global climate changes are unclear
- Never-the-less, the concerns help efforts to promote renewables & nuclear energy options
- China controls world CO2; key issue is energy policy reform (to encourage improved efficiency & cogeneration), <u>not</u> technology or control

Technology

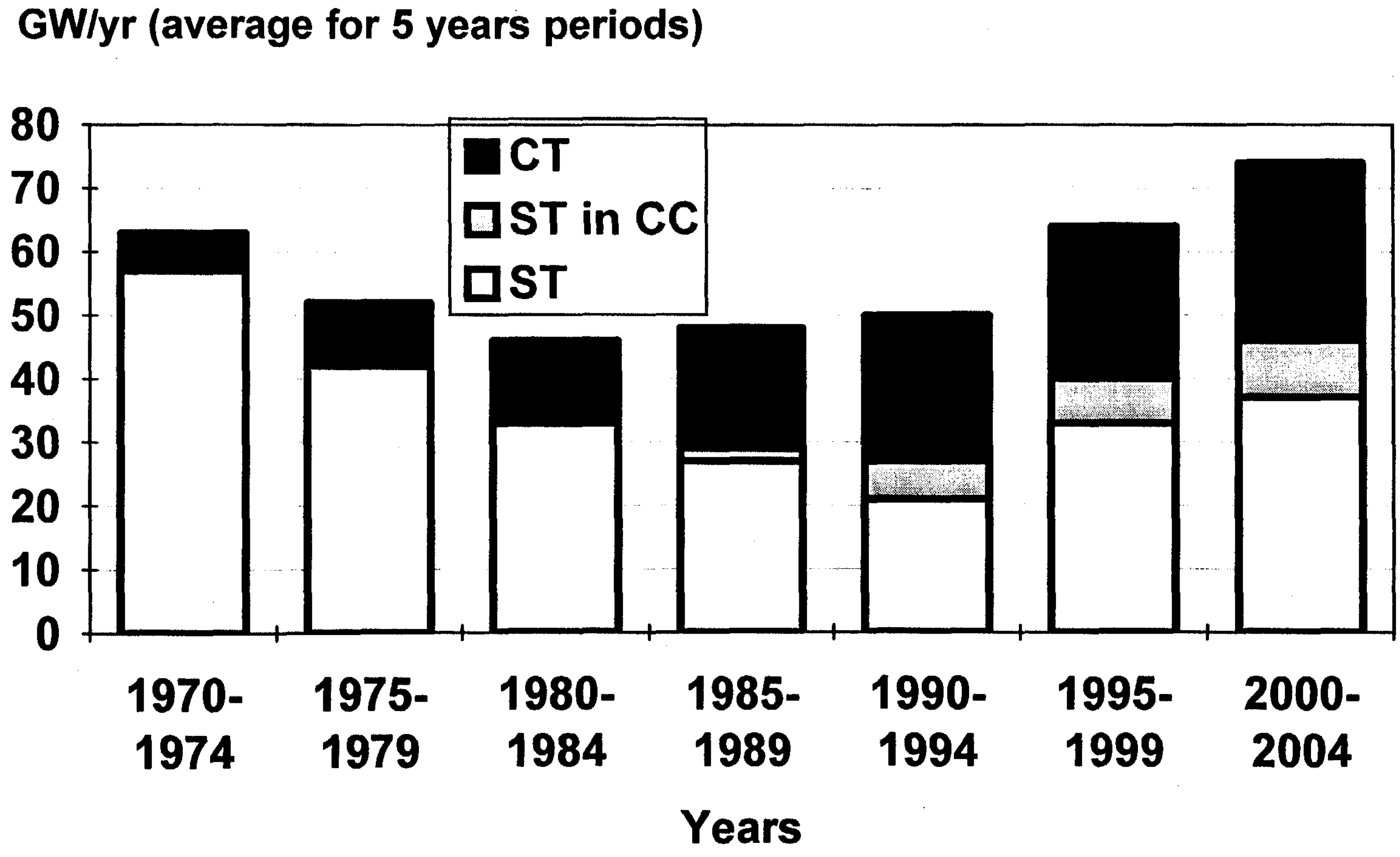
Combustion turbines (CT) now dominate (except China) due first to deregulation and second to improved gas price/supply, low capital, high efficiency & low emissions

Big move of market from ST to CT has created strong vendor competition that continues to improve CT cost/performance

CT for the following applications:

- Peaking regardless of fuel costs
- New cycling capacity at moderate fuel costs
- New baseload at moderate fuel costs
- Cogeneration at even high fuel costs

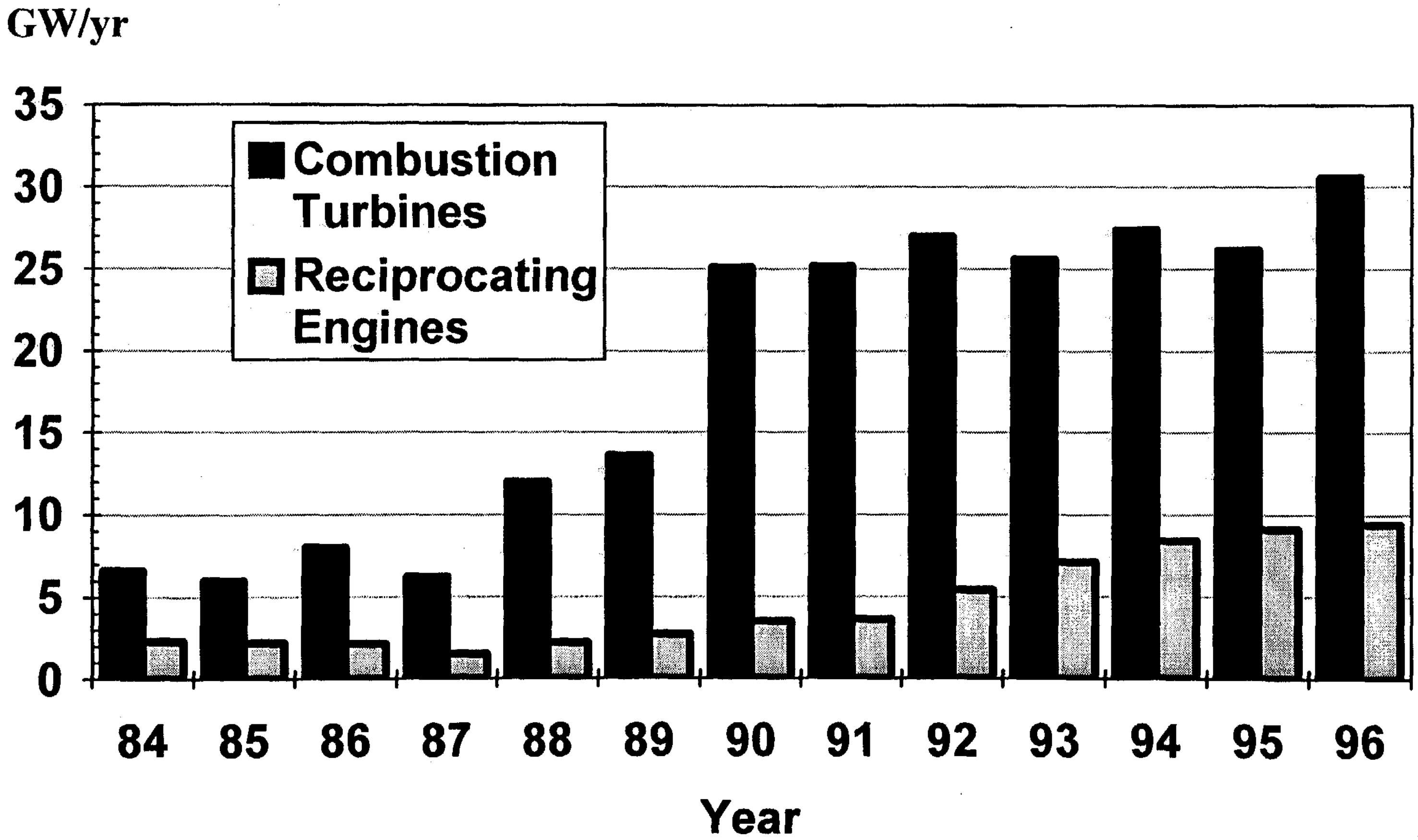
Worldwide fossil-fueled power plant orders for combustion & steam turbines



Source: SFA Pacific from Siemens data

SFA Pacific, Inc.

Worldwide power plant orders for combustion turbines & reciprocating engines



Source: SFA Pacific from *Diesel & Gas Turbine Worldwide*

Change in cogen market from PURPA machines to true cogen

There is still large potential for additional cogen in the US once: new or replacement industrial boilers are needed, energy prices increase & new baseload power capacity in needed

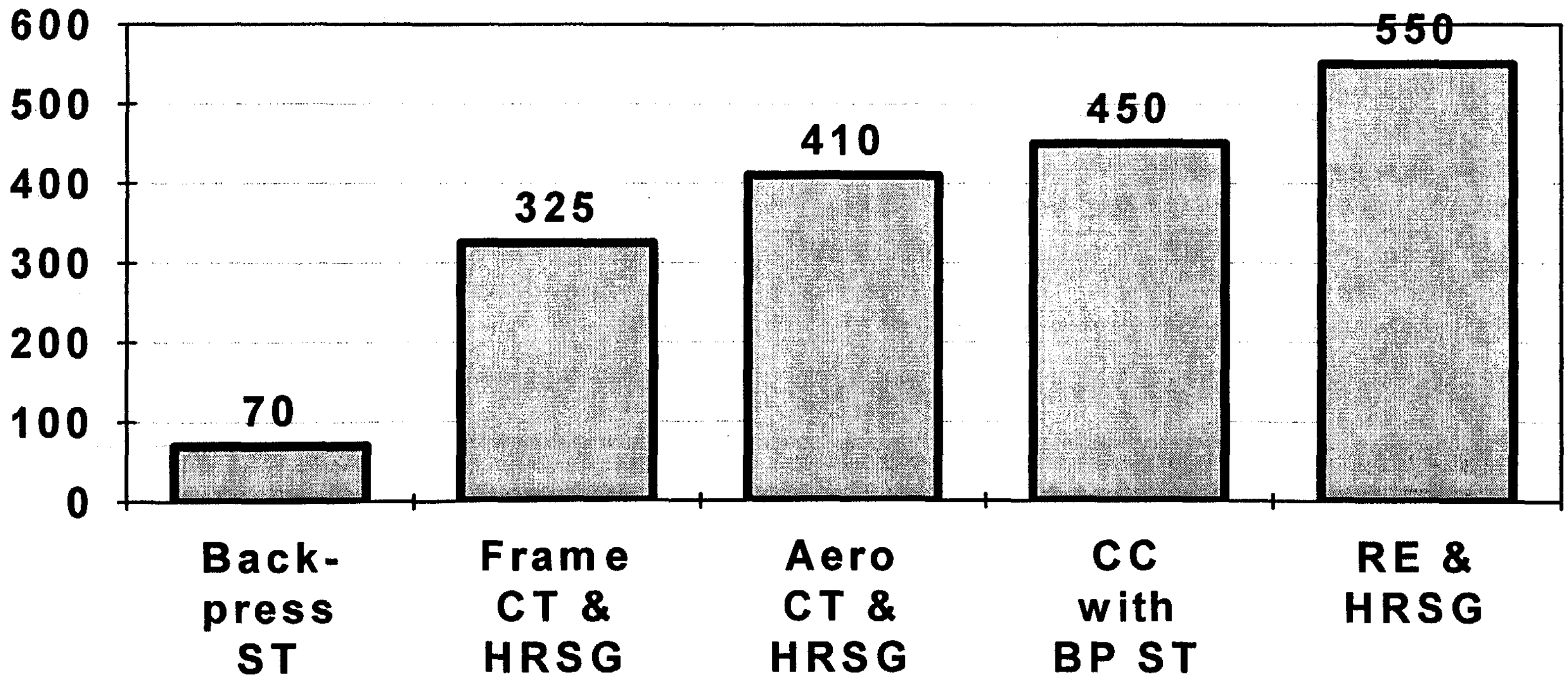
Dutch cogen experience shows there is more true cogen potential than believed

The Japanese Gas Association 1991 Industrial Repowering Analysis showed the large potential (17.5 GW) & attractive efficiency (16%) gain in overall Japan power generation

Technologies with both high power to cogen heat ratio and favorable unit costs at smaller scale will have advantages

Cogeneration clearly favors combustion turbines & reciprocating engines over steam turbines

For a given heat host 5-8 times more power with CT/RE vs ST



Source: SFA Pacific from GE & Wartsila data

Politics of electric markets

True power costs (including capital charges) are high at low dispatch

NUGs want baseload with the cycling/peaking left to the utilities

Utilities want time-of-day rates for NUG power while true power cost by each utility unit (including capital charges) are not segregated

True cogeneration is unfavorable to traditional regulated utilities

- Cogen can be the highest efficiency & lowest cost baseload
- Cogen clearly favors smaller baseload natural gas fired CT over large steam (nuclear or coal) central power plants

Rational governments will let effective cogen develop as long as it is lowers electricity prices & does not cause over-capacity of existing utility baseload units (avoid the US PURPA mistakes)

Global climate politics ultimately favors the major efficiency advantages of cogen & deregulation as this is has fundamental $/ton CO_2 avoided cost advantages over nuclear or renewables

Future power generation favors CT

CTs are clearly favored over traditional steam systems due to:

- Deregulation, cogeneration & uncertain markets
- Improved price/supplies of natural gas
- Economic, environmental & efficiency advantages (the 3 “E”)

Future CT application could favor intercooled aeroderivatives

- Ideal for utility cycling needs (great part-load performance)
- Great flexibility due to weight & size that allows for “just-in-time” additions plus high availability of 24-hour replacements
- Ideal for industrial cogen at <u>any</u> power/heat ratio (i.e., “designer” cogen)
- Great format for development of a reheat CT that should be better Than ABB reheat CT

Advanced combustion turbine programs

US DOE Advanced Turbines System (ATS) Program

- Plan 200-300 MWe G/H heavy duty CT demo of West. or GE
- Plan 5-15 MWe light industrial CT demo of Allison or Solar
- Designs have become more conservative as government co-funding of demo gets smaller & politics of selection gets hotter

Collaborative Advanced Gas Turbine (CAGT) Research Program

- Plan 75-110 MWe intercooled aeroderivative CT demo
- This type & size CT matches the changing electric markets
- CAGT members & technology attributes create vendor interest
- Demo could be in CA due to CEC interest & deregulation law with funding for advanced systems
- Offers strategic flexibility for the uncertain future of deregulation

Summary

Many opportunities in electric markets

- Short-term confusion due to excess capacity, wheeling, deregulation delays, cheap gas and too many IPP promoters
- However long-term is clear, winners are the lowest cost generators

Key issues

- Amount, type and location of new capacity needs
- Time-of-day power pricing & costs (including capital charges)
- Dominance of combustion turbines due to economic, environmental & efficiency advantages

Advanced intercooled aeroderivatives combustion turbines have many potential advantages for this changing electric market

In January, 1995 Arthur D. Little completed a worldwide market analysis for a 120 MW, intercooled, aeroderivative (ICAD) gas turbine product for CAGT and EPRI.

- Arthur D. Little was retained to conduct a market analysis and provide guidance to their market entry and commercialization strategy.
- Focus on traditional market applications:
  - Peak, intermediate and baseload, greenfield applications,
  - Combined cycle repowering,
  - Industrial cogeneration, and
  - Utility and IPP ownership.
- Analysis based on accepted regulatory practices,
  - but since that time, there have been many changes.
- The following presentation reviews the results of our previous study and discusses the implications of worldwide regulatory and market changes.

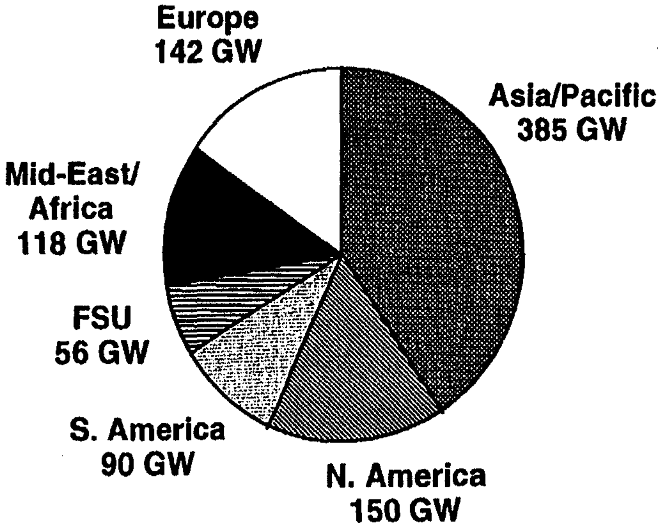
Based on the 1995 analysis, the ICAD market has the potential to approach 40 units per year within ten years of introduction, with the majority in simple cycle configurations.

- North America and Asia/Pacific appear to be the most attractive regions.
  - 13 units/year in North America by 2008, as a result of the competitive economics of gas/gas turbines.
  - 9 units/year in Asia Pacific by 2008, driven by growing gas market
- Up to 35 units/year by 2008 in intermediate load applications (600–4,000 hours/year) using a simple cycle configuration.
- In combined cycle, ICAD technology appears less attractive with likely sales of 5 units/year by 2008.
  - ICAD GTCC does not have an economic advantage over conventional GTCC

We had assumed that the first commercial products would be available in 1999.

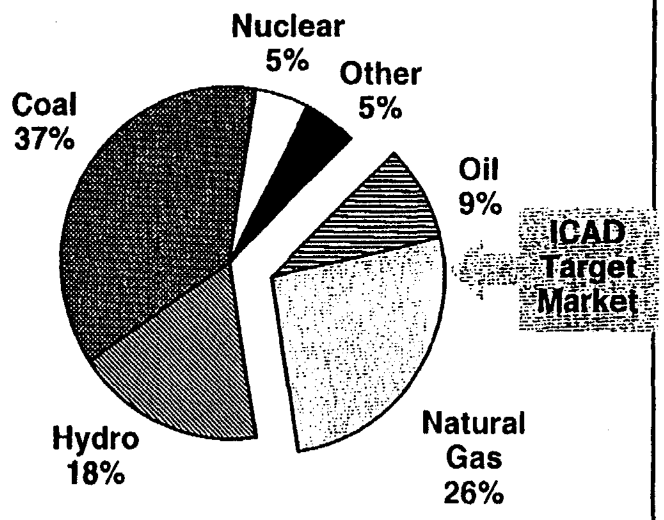
Worldwide power generation capacity additions are expected to be 90–100 GW per year during the 1999–2008 time period.

Worldwide Power Generation Market 1999–2008



Total: *940 GW*

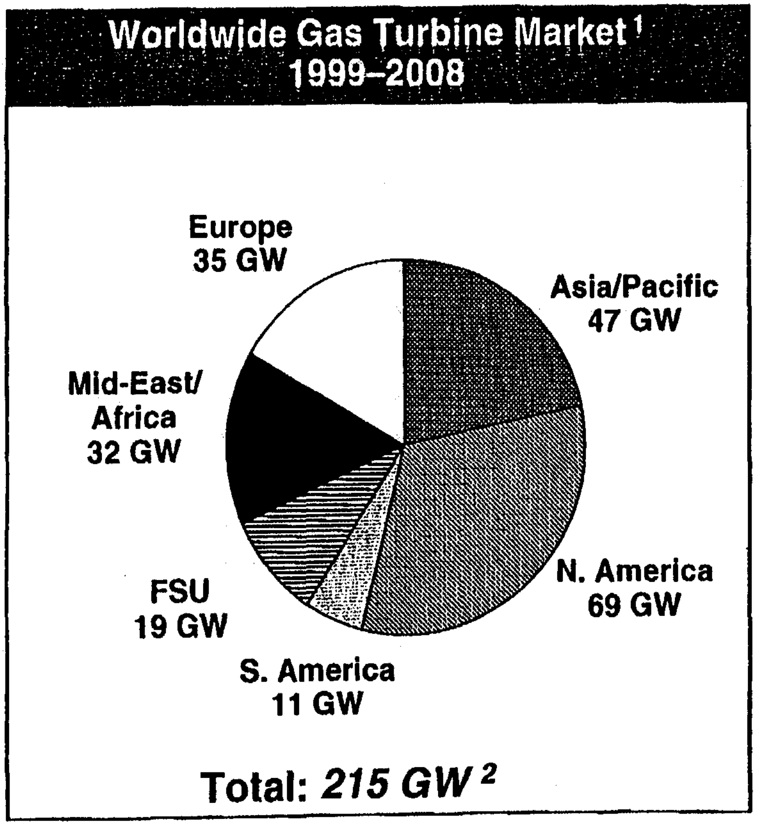
Fuel Mix for Capacity Additions 1999–2008

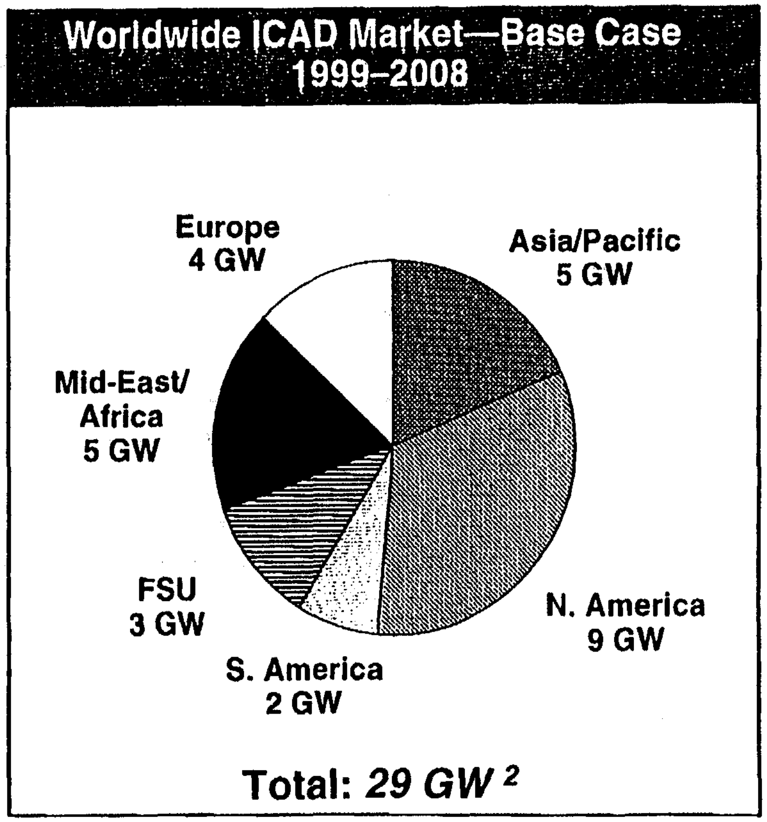


Total: *940 GW*

The core ICAD market will be a portion of the oil and gas fueled market, which is likely to be approximately 30 GW per year.

We concluded the ICAD has the potential to obtain up to 15% of the large industrial and utility gas turbine market over the 10 year period.

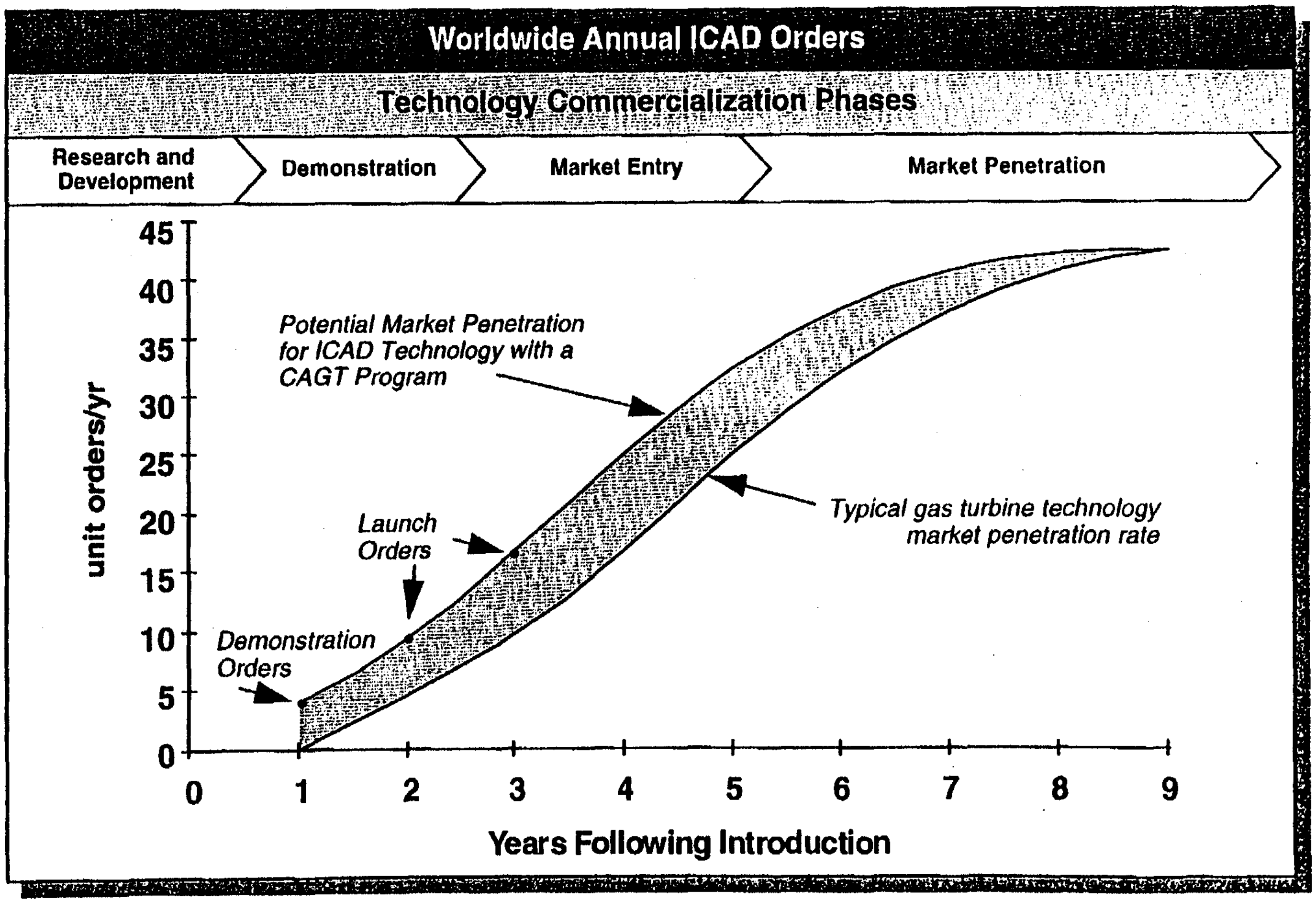




1 Estimated market for plants requiring more than 60 MW
2 Includes GT and GTCC (GT and steam turbine) capacity additions.

This assumes a typical market penetration rate over the timeframe.

Creating a multi-unit launch order via a mechanism like CAGT has the potential to accelerate ICAD market penetration by 2–3 years during the critical period of market entry.



Based on historical data on market acceptance, market penetration by the ICAD would otherwise be expected to take 7–9 years.

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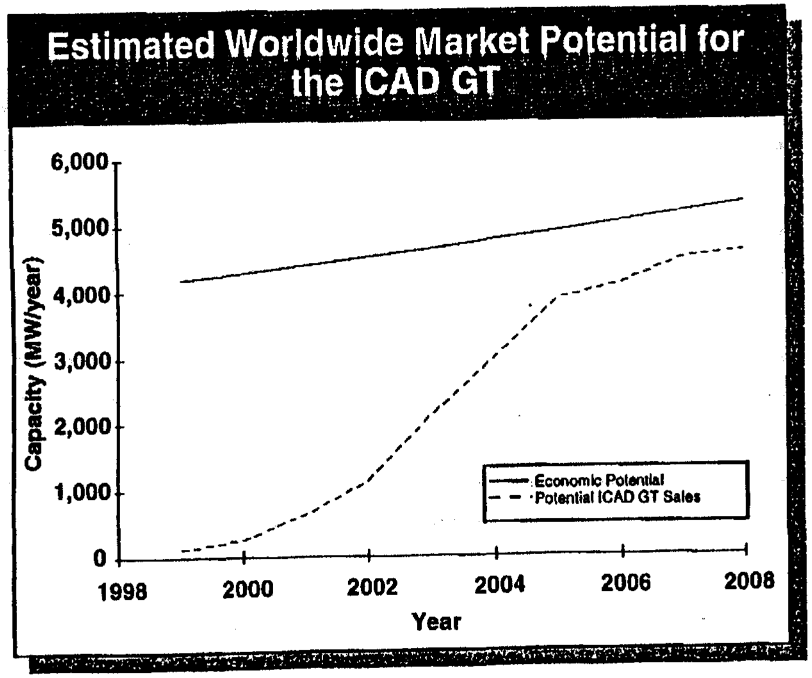
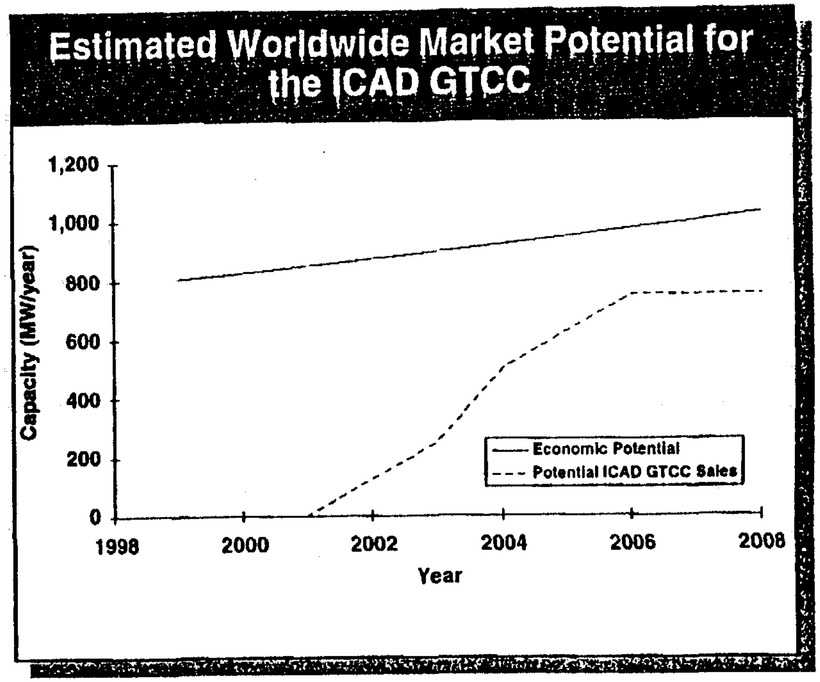
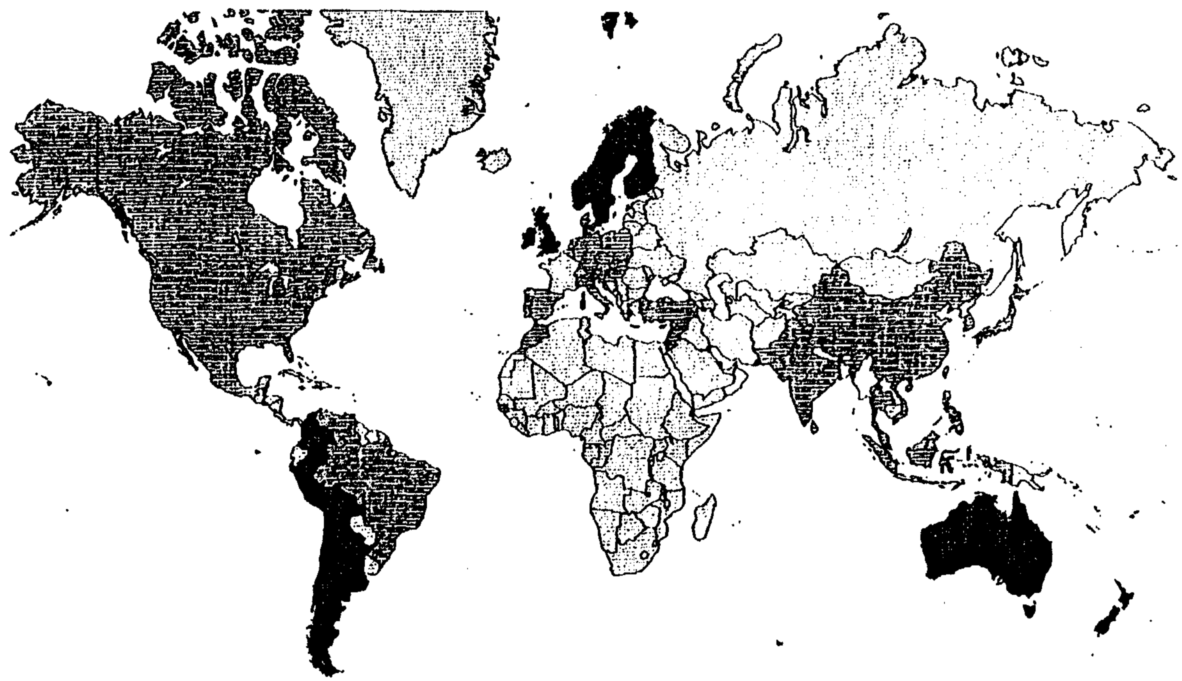
At the baseline installed cost, a market of approximately 4,500–5000 MW/year appears achievable with at least 80% in simple cycle unit sales.





This market penetration scenario assumes a traditional market introduction and commercialization process involving a limited number of initial customers and applications.

Since 1995 the pace of change in the global power industry has increased rapidly with many privatizations, deregulation and widespread use of competitive bidding.

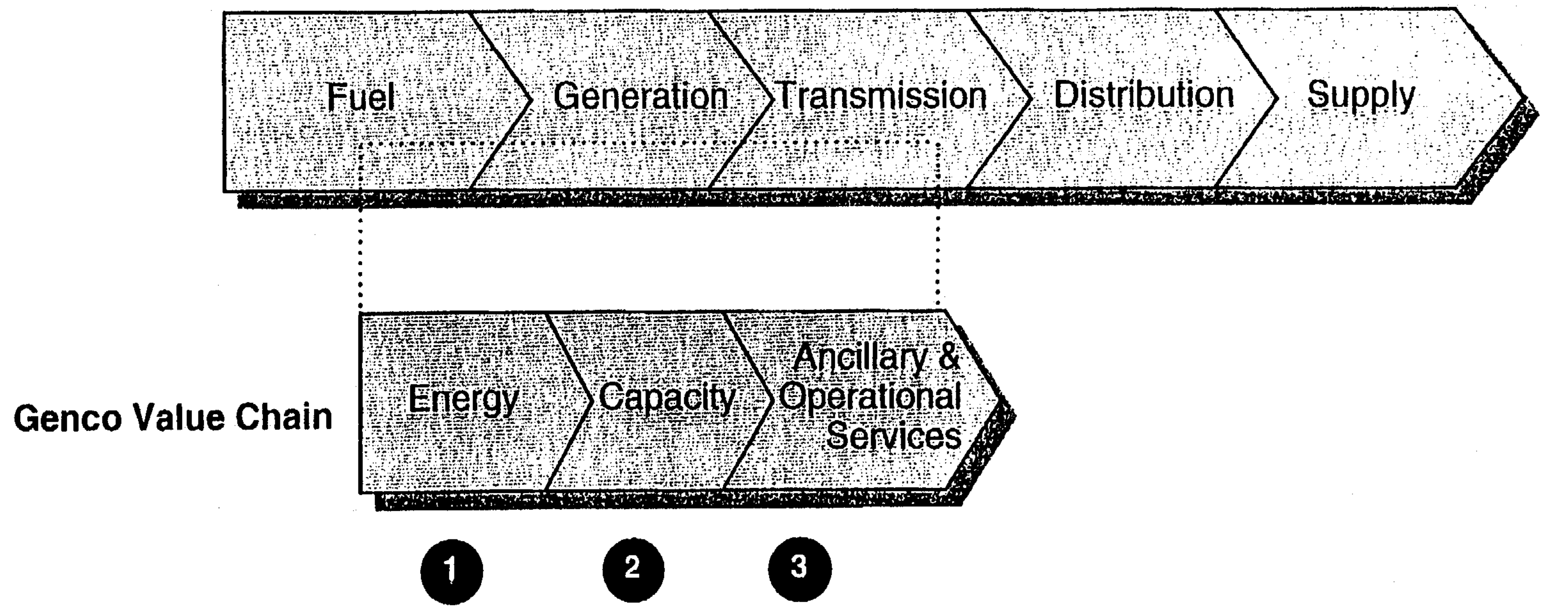


- Monopoly Markets, National Utilities
- Competitive Bid
- Pool/Merchant

The end-state of this change appears to be pooled or merchant power markets with an emphasis on risk management in most segments of the electricity value chain.

In a pooled power market a Genco (company involved only in generation) adds value through three principal activities in the electricity supply industry value chain...

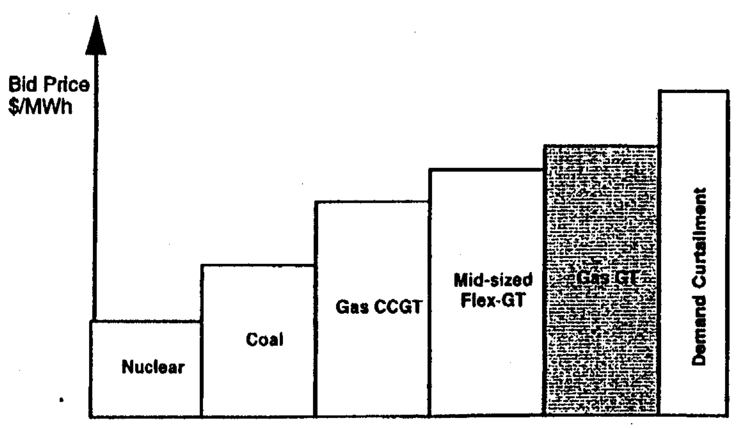
Electricity Supply Industry Value Chain



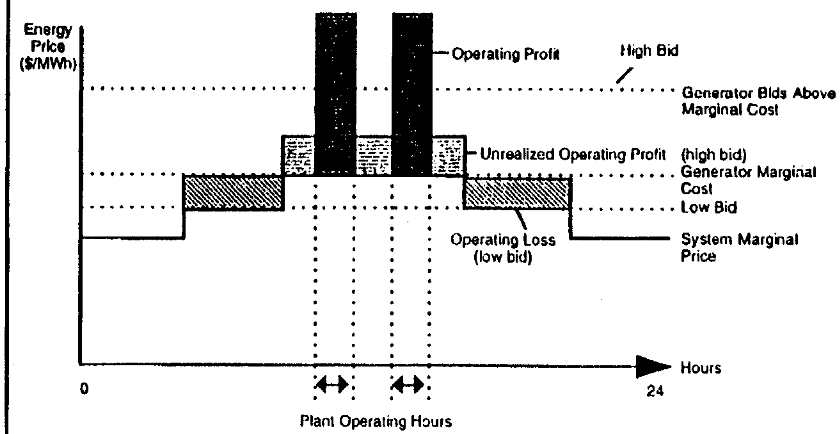
...and through three main Genco services the Genco is able to influence the value of each section of the chain.

Potential for profitable operation of intermediate and peak capacity plants is resulting in a significant increase in new GTCC additions in the U.K.

Ranking of Bid Prices

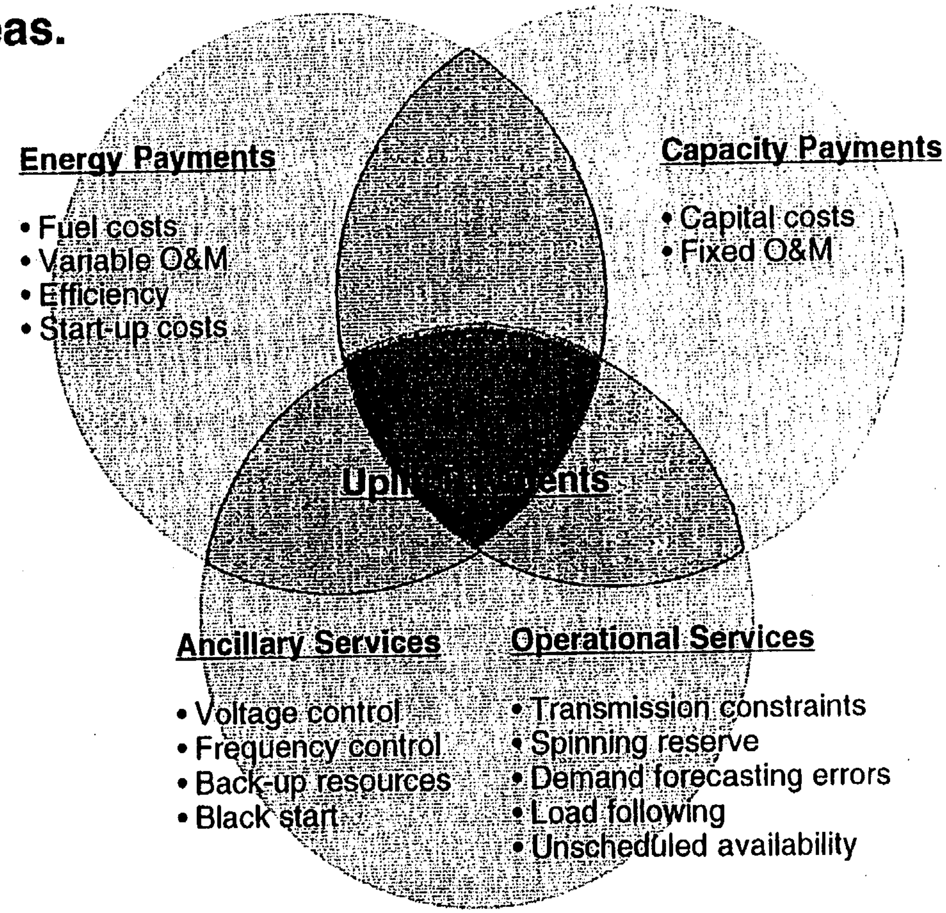


Operating Profit



In these competitive markets it is becoming evident that there is room for new competition, even though there are no real capacity constraints in the U.K.

In order for technology to provide competitive advantage to owners it will need to add value, or provide cost advantage in all three GENCO service areas.



These market mechanisms should provide significant upside potential to the markets for technologies such as mid-sized, flexible gas turbines that can add value in all three segments.

Many of the changes occurring in the world have the potential to create technology needs that mid-sized, flexible gas turbines could meet.

Opportunity	Technology Need
Pool/Merchant Markets	• Capacity to capture market share • Extract "hidden" value
New LNG Markets	• "Bridging" capacity to establish market – 2000 MW needed to support LNG infrastructure
"Tolling" Facilities	• Technology to support gas/electricity "convergence" – Plant becomes a processing station
Stranded Gas Development	• Capacity that balances efficiency, size, portability, and service issues

These changes could easily increase the market potential for the ICAD and similar technologies.

Technology decisions in many non-traditional markets are strongly influenced by "non-economic" product attributes which may favor the ICAD or other mid-sized, flexible gas turbine products.

- Project developers are beginning to understand many of the non-economic attributes of aeroderivative technology.
  - Product attributes such as compact size, high availability, mobility, serviceability and maintainability are highly valued in many emerging applications.
- Deregulation may lead to increased demand for technologies like the ICAD that offer increased project flexibility.
  - Increased project flexibility may result from lower capital cost, shorter delivery cycles, portability or unique O&M features that minimize downtime.
  - Alternative financing techniques and project structures may be able to take advantage of the flexibility attributes.
  - Business products involving leasing, operation and service contracts, and BOT schemes are likely to become more important in the future.
  - New entrants into the power generation market (e.g., oil and gas companies, E&C firms, and arbitrage and trading companies) may be more willing to accept and exploit new technology features.
- Integration of intermediate load gas turbine capacity with the gas supply system may take some time to evolve.
  - Gas supply strategies will need to incorporate more short-term storage, back-up fuel supplies, and diverse supply portfolios, to minimize pipeline capacity charges.

Future of Intercooled Aeroderivatives in the EDF Generation System

Christophe Bellot
Electricité de France, R&D Division

EDF in Figures:

28,970,000 clients
423.8 billion kWh generated
Installed capacity: 98,100 MW
118,074 employees
183.6 billion Francs in sales
61.7 billion kWh exported

Present Situation of the EDF Generation System:

- High availability of nuclear plants
- Overcapacity in fossil-fueled plants
- Except for unexpected events:
  - no need for peaking units in the short term
  - no need for additional mid-range load units
  - new mid-range power plants are deferred until the retirement of existing fossil-fired units

Additional Advantages of SC Intercooled AEROs:

- Higher operational flexibility
- Easy siting (reduced cold-source requirement)
- Suitable for urban areas (compactness)
- Reduced O&M costs
- Short erection time

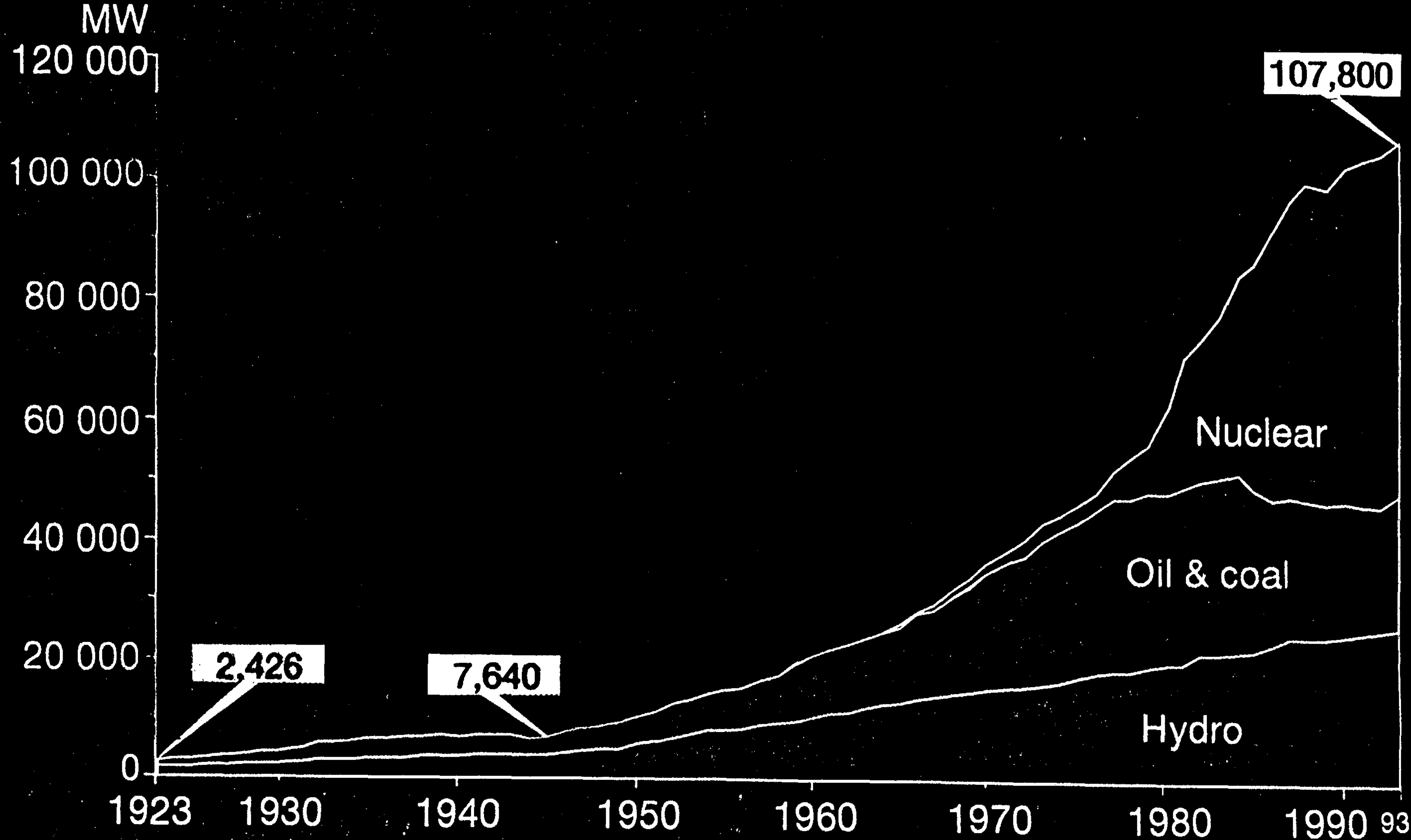
Storage Requirements:

- In France, natural gas (NG) is 90-percent imported.
- The NG production/transportation system is capitalistic: therefore, there is low flexibility on annual gas deliveries.
- Gas is supplied continuously, but is not used regularly throughout the year: therefore, modulation storage is necessary.

Future EDF NG-Fueled Power Stations

- Due to the present overcapacity in power, new mid-range power units will only appear after 2010.
- The existing storage capacity usable for mid-range power-plant supply is limited (9 TWh).
- On this basis, 2 to 3 GW (elec) could be fueled.
- Additional electric capacity would require new storage, which is costly and time-consuming to develop.
- The optimum annual operating hours range from 3,000 to 5,000 hours/year.
- SC Intercooled Aeroderivatives seem to be better suited than conventional combined cycles.

INSTALLED CAPACITY IN FRANCE



EDF Source : Résultats Techniques d'Exploitation 1993

Electricité de France ©DE/Délégation à la Communication - 18.03.94

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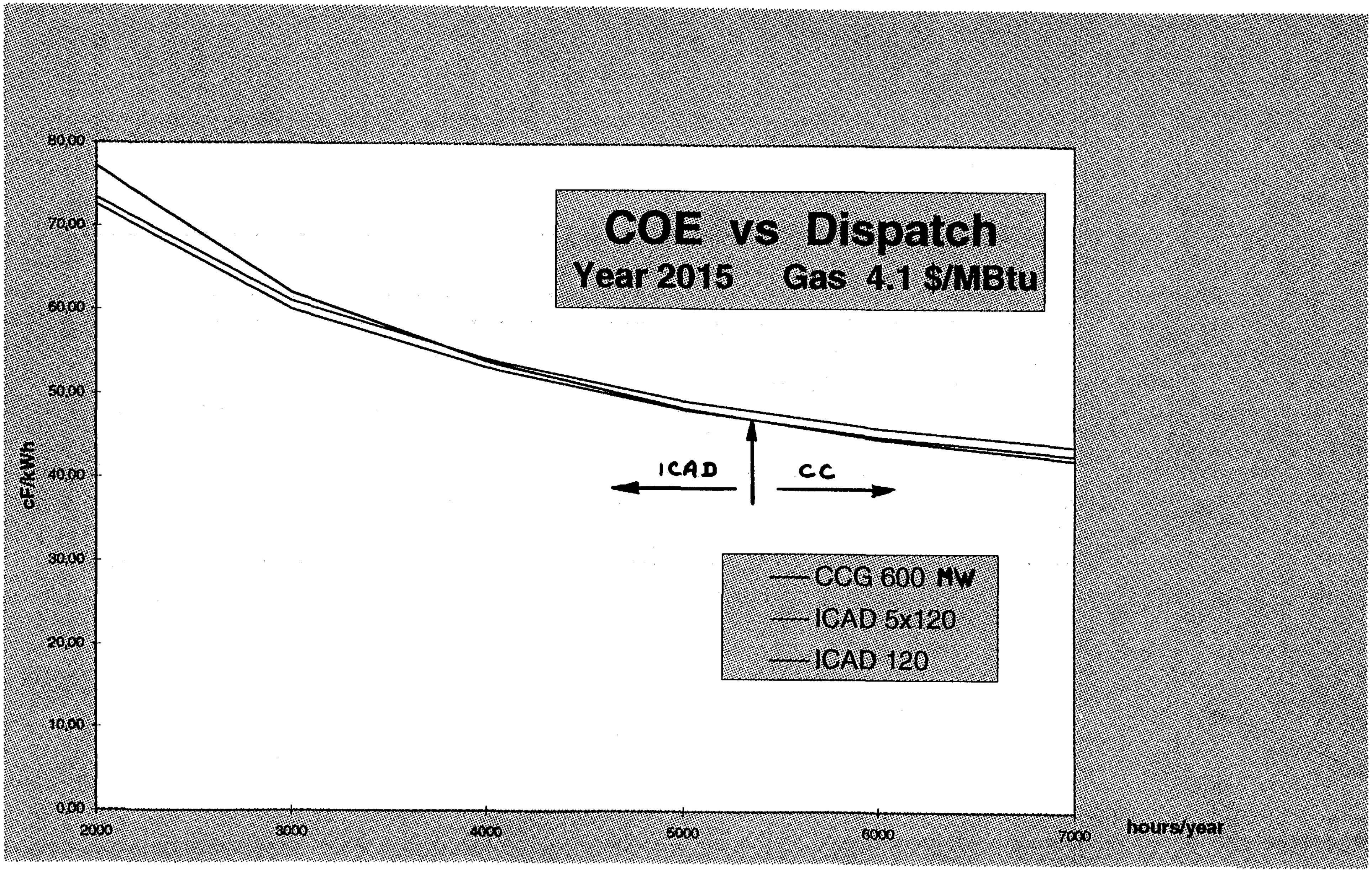
COE vs Dispatch
Year 2015 Gas 4.1 $/MBtu
cF/kWh
80,00
70,00
60,00
50,00
40,00
30,00
20,00
10,00
0,00
2000
3000
4000
5000
6000
7000
hours/year
ICAD
CC
CCG 600 MW
ICAD 5x120
ICAD 120

A MULTI-FUEL HIGH EFFICIENT POWER PLANT CONCEPT

Niels Laursen
ELKRAFT Power Company
DK-2750 Ballerup

ABSTRACT

The paper describes the power plant concept, on which a new power plant to be built in the eastern part of Denmark is based. The power plant is planned for commercial operation in late 2000. It will integrate a coal fired ultra super critical steam plant and a natural gas fired advanced gas turbine and have a maximum capacity of approx. 520 MW. The gas turbine is used for heating the condensate and boiler feed water, but operation without the gas turbine is also possible. The electrical efficiency of the coal fired plant without operation of the gas turbine will be in excess of 48%.

Dependant of the type of gas turbine available the efficiency of the natural gas used in this plant can surpass that of the most efficient combined cycle plant, especially when using high efficient aeroderivative gas turbines with relatively low exhaust gas temperatures.

In a power generation system using both coal and natural gas as a fuel, the concept presented here looks very attractive compared to separate plants for coal and gas firing respectively.

The concept can also be an interesting alternative when considering repowering of existing steam power plants. However, the attainable efficiency of the natural gas will in this case probably be somewhat below the efficiency attained in a plant designed for the presented concept.

The increasing use of natural gas in the Danish power generation system is not primarily motivated by economy, but more by a national commitment to drastically reduce the CO_2 and SO_2 emissions.

INTRODUCTION

This paper describes the power plant concept, on which a new power plant to be built in the eastern part of Denmark is based. The power plant is planned for commercial operation late 2000. It will integrate a coal fired ultra super critical steam plant and a natural gas fired advanced gas turbine and have a maximum capacity of approx. 520 MW.

Before presenting the concept I would like to summarize the conditions for power generation in Denmark, as I think, that would give you a better background for understanding, why we are proposing the multi-fuel concept. Although conditions in Denmark might differ from conditions elswhere we think, that this concept could be of interest for power producers in other countries.

DANISH CONDITIONS

The Danish power generation system consists of two groups of power plants, which due to geography are not interconnected. West to the Great Belt, six power companies have formed the common company called ELSAM, while east of the Great Belt two power companies have formed the common company called ELKRAFT. I represent ELKRAFT, and the two companies retaining ELKRAFT are the City of Copenhagen and SK Power Company.

Denmark has some 5.2 million inhabitants, and the yearly electricity consumption is about 30 TWh, corresponding to 5,800 kWh per capita.

The installed capacity amounts to approx. 9,000 MW, of which 4,000 MW is located in the eastern part of Denmark. Most of this capacity consists of coal fired power plants, located inside or in close proximity to the bigger cities. This way district heating may be supplied to the cities.

Although the western and eastern systems are not connected, both systems operate at 50 Hz.

For the time being the increase in electricity consumption is low in general in Denmark, and in the eastern part the increase is practically zero. This is partly due to demand side management and integrated ressource planning. The need for new power plants comes from retirement of old units and from extension of the district heating systems, especially in the Copenhagen area.

Our fleet of power plants is getting older, and between year 2000 and 2010 a considerable number of units will have to be replaced by new ones. The older units are not equipped with efficient flue gas cleaning systems, their electrical efficiency is relatively low, and several of them are located far away from cities with district heating systems. Therefore repowering or refurbishment is not attractive.

Traditionally power generation in Denmark has been based on imported fossil fuels, mainly coal for economical reasons. Today coal accounts for about 80% of the energy used for power production, the coal being imported from all over the world. For the last ten years new power plants have been highly efficient super critical coal fired plants for cogeneration of electricity and district heating.

Combined heat and power production helps to increase the efficiency of the power generation system and thereby reduce CO_2 and other emissions. On a yearly basis the energy efficiency of the Danish power generation system is more than 56% when including the supplied heat for district heating. And this figure will increase in the future, due to extension of the district heating systems, and due to installation of more efficient power plants, that will allow us to reduce power production on existing condensing units.

NEW CONDITIONS

The situation, I have just described, is going to change in the near future for a number of reasons.

Denmark has now its own natural gas resources in the North Sea, and a big national transmission and distribution system for the gas has been established.

In Denmark the power companies are under powerful political pressure to use natural gas for power generation, partly to support the state owned gas company, partly to reduce CO_2 and SO_2 emissions.

The Danish parliament has decided, that CO_2 emissions shall be reduced by 20% in 2005 compared to the emissions in 1988; this is a consequence of the Toronto-agreement. The requirements for reduction of sulphurdioxid emissions are also expected to be quite severe, due to international agreements. For these reasons it is most likely, that the main fuels for future power generation in Denmark will be changed from coal alone to a mix of coal and natural gas.

I trust, that I have given you a picture of the situation for power generation in Denmark and will now turn to our concept for new power plants.

COAL FIRED PLANTS

Up until now our main effort has been to support the advancement of the pulverized coal fired power plant. With direct sea water cooling resulting in condensor pressures around 0.02-0.025 bar such plants may now be built with an electrical efficiency of 48% based on lower heating value of fuel.

The typical parameters for such a power plant will be 300 bar (4300psi) and 580°C (1075 °F) for the high pressure live steam, and reheat to 600°C (1110 °F). The condensate and feed water train will typically comprise 10 stages providing an end feed water temperature of about 310°C (590°F). These parameters would result in a net efficiency of 48% based on lower heating value of fuel. Guarantee fuel will typically be Polish coal with a lower heating value of 24.7 MJ/kg, ash content 13.1% and sulphur 0.9%.

SEPARATE GAS FIRED AND COAL FIRED PLANTS

As mentioned before we will use more natural gas for power generation in Denmark. To do this the traditional way would be to build combined cycle plants. Using available gas turbines you could achieve a plant efficiency of 55%, maybe increasing to 58-60% using next generation of industrial gas turbines. The natural gas supplied from the North Sea typically has a lower heating value of 48.3 MJ/kg, a methane content of 81.3% and a content of higher hydrocarbons of 16.6%.

This way you would have a system comprising some coal fired plants and some gas fired plants, which are completely separated.

We think the conventional natural gas fired combined cycle plant has a number of drawbacks. It lacks fuel flexibility, as the only back up fuel would be expensive distillate oil, and the plant is totally dependant on the gas turbine, as no part of the plant may operate, if the gas turbine fails.

The combined cycle steam turbine is normally rather small and relatively expensive and it has low efficiency compared to the steam turbines we use for our supercritical coal fired plants. Using the future intercooled aeroderivative gas turbine with high simple cycle efficiency and rather low exhaust temperature and flow in combined cycle would augment this trend.

MULTIFUEL PLANTS

Another possibility for simultaneous use of coal and gas is to combine the modern coal fired power plant with a gas turbine. This can be done in several ways, but the simplest one is probably to use the gas turbine exhaust gas for heating the condensate and feed water of the steam plant.

Using the exhaust gas from the gas turbine for feed water heating will substitute extraction steam from the steam turbine. Therefore the steam turbine will act as a bottoming cycle for the gas turbine, that is for the steam, that is not being extracted from the steam turbine. This bottoming cycle is characterized as a multi-pressure stage type using a large highly efficient steam turbine.

The efficiency of the natural gas may be calculated as follows:

$$\eta_{GAS} = \frac{E_{ST} + E_{GT} - \eta_{COAL} \cdot Q_{COAL}}{Q_{GAS}}$$

where

E_{ST} = electricity production from the steam turbine
E_{GT} = electricity production from the gas turbine
η_{COAL} = efficiency of the steam plant without gas turbine
Q_{COAL} = the energy of the coal comsumption of the steam plant
Q_{GAS} = the energy of the gas consumption of the gas turbine

Dependant on the characteristics of the gas turbines very high efficiences of the fired natural gas can be reached.

What are the reasons for that?

Let me explain the thermodynamics of the feed water train for the steam turbine. It is important to remember, that the feed water heaters are condensers, therefore most of the energy in the extracted steam will be transferred to the feed water at the saturation temperature corresponding to the steam pressure in the preheater. This means, that preheating of the feed water certainly adds to the overall efficiency of the steam turbine, but when using extracted steam, this process is accompanied by considerable thermodynamic losses.

Accordingly there is a considerable difference between the temperature of the steam in the turbine and the temperature, at which it condenses in the feed water heater. This applies to all extraction points.

If we preheat the feed water using the exhaust gas from the gas turbine, the temperature difference will be much smaller. Consequently by substituting superheated steam extracted from the steam turbine with exhaust gas from the gas turbine we get a more efficient thermodynamic process.

This is also true for the steam not extracted from the two first extraction points, as it will return to the boiler to be superheated. This will call for additional fuel consumption of the boiler, but fuel used for reheat in the boiler is converted with a higher efficiency than the fuel used to generate live steam.

It should also be remembered, that the output from the "bottom cycle" comes as incremental output from a large high efficient steam turbine-generator, which in itself is more efficient than a smaller bottoming steam turbine.

The efficiency figures, which may be obtained by the proposed concept, depend on the characteristics of the gas turbine, that is used for condensate and feed water heating.

The steam turbine included in this concept has a size of approx. 375 MW. The steam parameters are as mentioned earlier.

As a coal fired the plant it will have an efficiency of 48% based on lower heating value. If we add an LM 6000 gas turbine as partial feed water heater the efficiency of the natural gas will be approx. 56%. Using a gas turbine with F-technology data we may obtain roughly the same gas efficiency of the natural gas.

Using an intercooled aeroderivative gas turbine (ICAD) with characteristics of the CAGT-project the efficiency of the natural gas will be approx. 60%, yielding a higher gas efficiency than any available combined cycle plant. It should also be noted, that the higher the gas turbine simple cycle efficiency, the more gas turbine capacity can be added to the same steam turbine capacity. The efficiency figures refer to identical feed water end temperature.

The data used for the intercooled aeroderivative gas turbine shows a high simple cycle efficiency coupled with a moderate exhaust temperature, which fits well with the needs for feed water preheating, where only moderate temperatures are needed.

However the exhaust temperature is still so high that it is possible to increase the efficiency of the natural gas even further by applying a slightly more complex process. The hottest exhaust gas from the gas turbine could be used for partial reheat of the steam from the steam turbine or increased preheating of the combustion air for the coal fired boiler. So far we have not considered such a concept.

Instead we have studied the consequences of allowing a higher feed water end temperature for the boiler when operating the gas turbine. With the gas turbine it is very easy to increase the feed water end temperature, in contrast to using extraction steam, as it is a very delicate matter to provide steam extraction from the high pressure steam turbine. Some turbine manufacturers are opposed to making extraction from the high pressure turbine, others will only provide one extraction point on their high pressure turbine.

If the gas turbine is allowed to increase feed water end temperature by 20°C or 36°F, the efficiency of the natural gas will increase by 1% point, while the temperature of the most stressed tubes in the boiler furnace will only increase by 2-3°C or 4-5°F.

REPOWERING WITH GAS TURBINES

The concept, that I have just described, can of course also be used for repowering of existing plants. In principle any thermal power plant, that includes a feed water train, can have a gas turbine added on for partial or total feed water preheating. Such a plant will have very high flexibility, as the steam plant can operate without the gas turbine, if its original feed water train is maintained, and it can also relatively easy be arranged, that the gas turbine can be operated without the steam turbine in operation if so desired. When the steam turbine is operating, the gas turbine can be switched on and of like an open cycle machine, but with the important difference, that when the gas turbine is operating, its efficiency will be very high. The installation cost of a gas turbine as feed water preheater on an existing site is low, and no extra personel will be needed at the site. An interesting situation could be a power plant, which comprises an old 120-150MW unit and one or more younger steam units. A feed water preheater gas turbine could possibly use the 120-150 MW unit's generator and high voltage installations and could act as feed water preheater for one or more of the younger and more efficient steam units.

The gas efficiency, you can obtain by repowering existing fossil fired power plants with gas turbines as feed water heaters, will depend very much of the specific steam turbine and boiler plant as well as of the size and type of gas turbine. The steam plant must have a certain capacity to be able to absorb all the exhaust heat from the gas turbine through feed water preheating. Its generator shall allow for increased output, and the steam turbine must be able to consume the increased steam flow, which may be a problem especially in the LP-part.The turbine should have a feed water train and thus a boiler designed for high feed water end temperature.

This applies best to relatively new steam turbines of a few hundred MW capacity and upwards, as the increase in capacity, steam flow, etc. is relatively small for such units. But the gas efficiency will in most cases be somewhat lower than attainable in a new power plant designed for the concept. However, when studying possibilities for repowering of existing units with feed water preheater gas turbines, it should be checked if the boiler could accept higher feed water tempe-ratures compared to feed water preheating by bleed steam. If so this will contribute to an even higher gas efficiency.

If the steam plant has limitations in the low pressure part or in generator output you always have the possibility of derating the boiler, but this will normally affect the gas efficiency in a negative way.

To give an idea of which gas efficiencies can be obtained by repowering different steam plants with gas turbines as feed water preheaters, we have chosen a number of characteristic steam units in our generating system and equipped each of them with an aeroderivative gas turbine with data corresponding to the "average" ICAD gas turbine from the CAGT-project. The gas efficiencies have been calculated as well for unchanged feed water end temperature as for a 20 C increased feed water temperature.

I would guess, that the steam data for the selected plants are representative for many steam plants built in the period 1965 to 1990. The obtainable gas efficiencies are very good, also compared to combined cycle plants, which are more expensive and less flexible in operation.

Industrial or heavy duty gas turbines can also be used as feed water preheaters. Since these machines normally are optimized for combined cycles, they have unnecessary high exhaust temperature for feed water preheating. These machines will also suffer more from frequent start and stop as will the lighter aeroderivatives, which for airplane application are designed for frequent start and stop and rapid load pickup.

CONCLUSION

Our conclusion is, that if you have a power generation system, where you want to use as well coal as natural gas, the most efficient and also the cheapest and most flexible concept would be the combination of a super critical pulverized coal fired steam power plant and a highly efficient aeroderivative gas turbine used as feed water heater for the steam turbine. This concept provides an efficiency of the natural gas of up to 60% for a new plant, and at the same time a flexible and very cost-effective plant. The same is true for repowering of existing steam power plants, although the attainable gas efficiency in most cases will be somewhat lower.

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Danish Energy Policy:

√ More use of Natural Gas
√ Reductionof CO_2 Emissions
√ Reduction of SO_2 Emissions

Power Generation in Denmark

Population:	5.2 million
Electricity Consumption:	30 TWh/year or 5,800 kWh per capita
Installed Capacity:	West - 5,000 MW
	East - 4,000 MW
	Total - 9,000 MW
Frequency:	50 Hz
Increase in Consumption:	1% per year

New Plants to Replace Old Plants for:
higher efficiency, lower emissions (CO_2, SO_2, NOx), supply of district heating.

No hydropower, due to geography.
No nuclear power, due to Parliament decision.
Fossil-fired power plants.
More than 85% of power generation based on imported coal.
High efficiency coal-fired plants.
Combined heat and power.

Data for Supercritical Coal-Fired Plant:

√	Steam Pressure:	300 bar - 4,300 psi
√	Steam Temperature:	580 °C - 1,075 °F
√	Reheat Temperature:	600 °C - 1,100 °F
√	Feed-Water Temperature:	310 °C - 590 °F
√	Feed-Water Train:	10 stages
√	Electric Efficiency:	48% LHV

Use of Gas and Coal:

- √ Separate Gas-Fired and Coal-Fired Units

√	Supercritical Coal Plant:	48% Efficiency
√	Combined-Cycle Plant:	55-60% Efficiency

Combined Gas- and Coal-Fired Plant:

(Gas Turbine as Feedwater Heater)

√	Coal Plant Efficiency:	~ 48%
√	Gas Efficiency:	~ 55-56% with LM 6000
√	Gas Efficiency:	~ 55-56% with F-Technology
√	Gas Efficiency:	~ 59-60% with ICAD
√	Plant Efficiency:	~ 50-53% depending on Gas Turbine type and capacity

Gas Turbine Average ICAD

Basis:	
Gross Power	128 MW
Gross Efficiency	47%
Basis	ISO-conditions
Assumptions:	
Inlet Pressure Loss	0.01 bar
Outlet Pressure Loss	0.025 bar
Natural Gas Supply Pressure	60 bar
Use Values:	
Gross Power	126 MW
Gross Efficiency (LHV)	46.4%
Exhaust Flow	218 kg/s (481 lbs/s)
Exhaust Temperature	470 °C (878 °F)
Intercooler	32 MW

Repowering With Gas Turbines as Feed-Water Heaters Dependent on:

- √ Steam Turbine Capacity
- √ Generator Capacity
- √ Size of LP-Turbines
- √ Feed-Water Train
- √ Feed-Water End Temperature

Asnaes Unit 4

Year of Commissioning:	1968
Plant:	Pulverized Coal-Fired
HP-Steam Parameters:	540 °C; 177 bar (1,004 °F; 2,567 psi)
IP-Steam Parameters:	540 °C; 42 bar (1,004 °F; 609 psi)
Feed-Water Temperature:	258 °C (496 °F)
Net Power:	264 MW
Net Efficiency:	41.0%
Repowering Unit:	1 x ICAD (126 MW)
Parameter:	Seawater Cooled Intercooler
Net Power (Total):	380 MW
Net Efficiency (Total, LHV):	46.0%
Gas to Power Utilization (LHV):	56.0%
Gain in Efficiency Acc. to Basis:	-
Extra Power:	116 MW

Asnaes Unit 5

Year of Commissioning:	1981
Plant:	Pulverized Coal-Fired
HP-Steam Parameters:	540 °C; 177 bar (1,004 °F; 2,567 psi)
IP-Steam Parameters:	540 °C; 47 bar (1,004 °F; 681 psi)
Feed-Water Temperature:	262 °C (504 °F)
Net Power:	639 MW
Net Efficiency:	40.5%
Repowering Unit:	1 x ICAD (126 MW)
Parameter:	Seawater Cooled Intercooler
Net Power (Total):	791 MW
Net Efficiency (Total, LHV):	43.0%
Gas to Power Utilization (LHV):	57.5%
Gain in Efficiency Acc. to Basis:	-
Extra Power:	152 MW

Efficiency of Natural Gas

$$\eta_{GAS} = \frac{E_{ST} + E_{GT} - \eta_{COAL} \cdot Q_{COAL}}{Q_{GAS}}$$

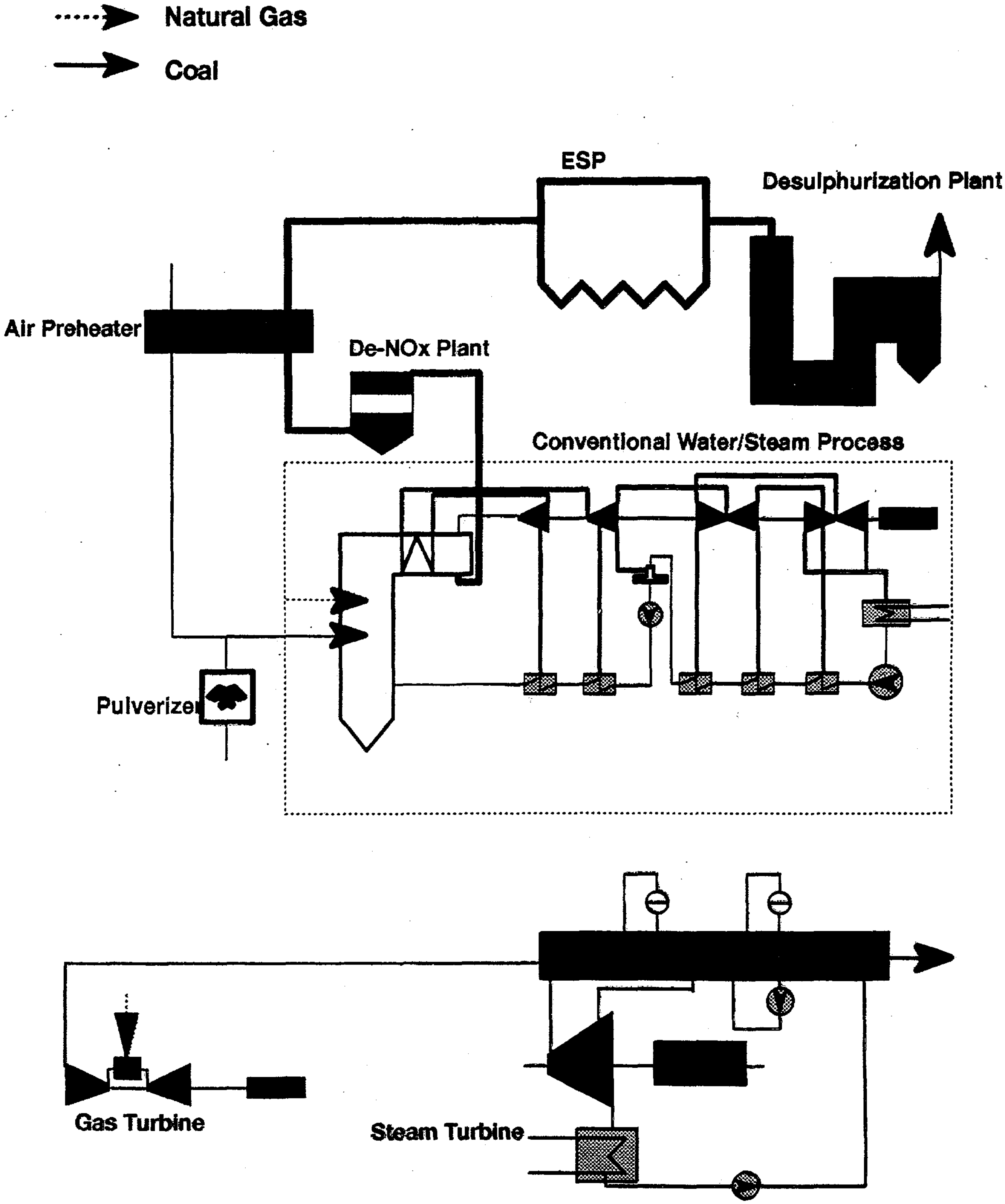
Where:

E_{ST}	=	Electricity production from the steam turbine
E_{GT}	=	Electricity production from the gas turbine
η_{COAL}	=	Efficiency of the steam plant without gas turbine
Q_{COAL}	=	The energy of the coal consumption of the steam plant
Q_{GAS}	=	The energy of the gas consumption of the gas turbine

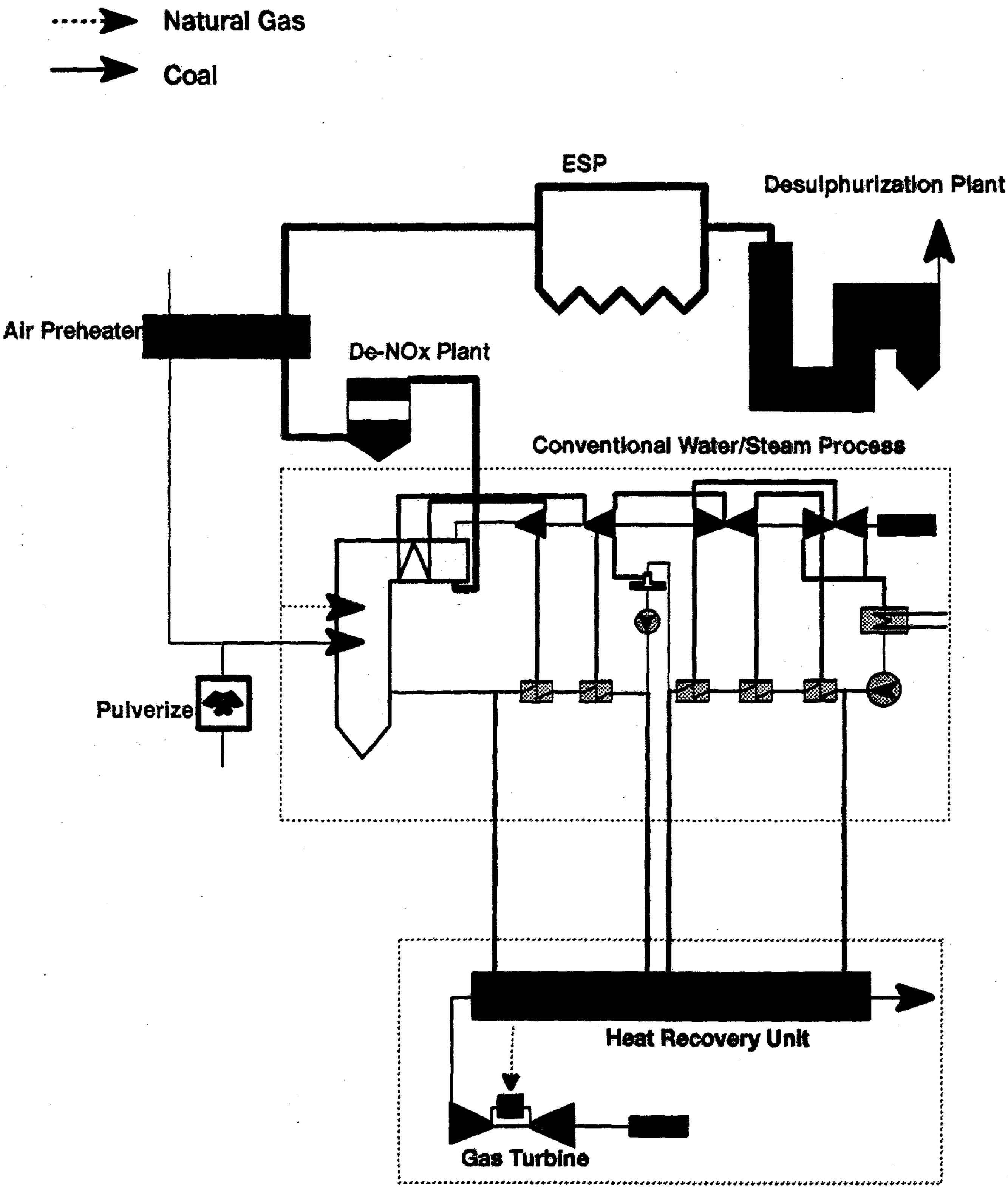
Conclusion:

The combination of a supercritical coal-fired plant and gas turbines — especially intercooled aeroderivatives — as feed-water preheaters for the coal-fired plant is a cost-effective and flexible concept, offering gas efficiencies comparable to or higher than the most efficient combined-cycle plants.

Separate Steam - and Gas Turbine Plants

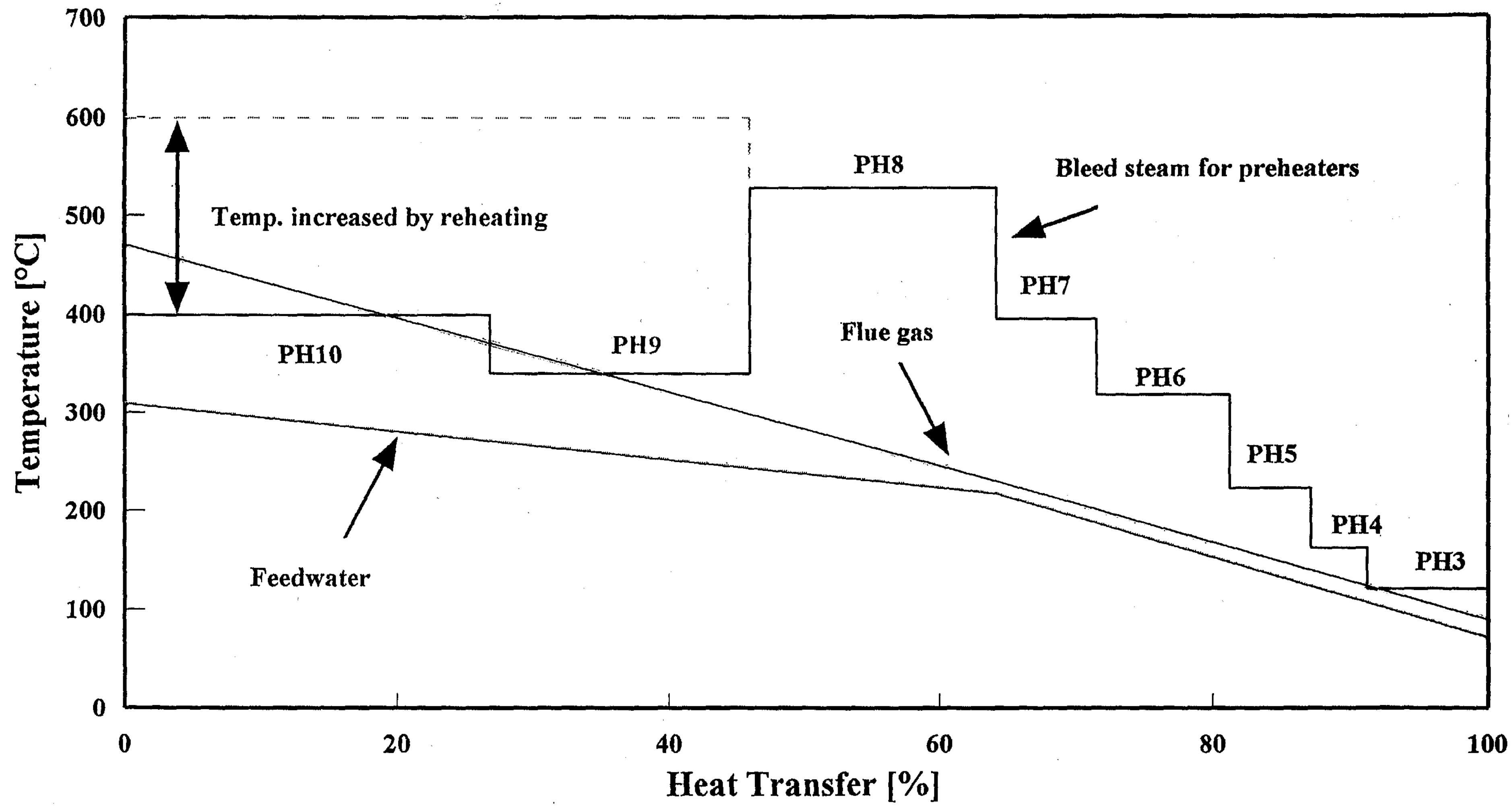


Combined Steam - and Gas Turbine Plant
Partial Feedwater Heating



TEMPERATURE LEVELS

FOR A "8-PRESSURE" HEAT RECOVERY UNIT



Gas Turbine Design Requirements Changing for U.S. Utilities

Jimmy E. McCallum
Georgia Power Company

The worldwide movement toward more competitive, market-based systems of power pricing has led electric utilities and independent power developers to change their methods of making technology and manufacturer choices, and to more fully integrate business influences into these choices. This, in turn, should cause gas turbine suppliers to rethink the process they use in designing, developing, and marketing their products. Engine manufacturers should now incorporate their clients' values into design trade-off options and be prepared to tailor their offerings more effectively to match particular user applications.

As an illustration of the new relationships emerging between gas turbine developers and users, we can look at three different gas turbine powered generating plants being developed in a typical large utility in the United States. The managers of each of these plants face different challenges in trying to meet their goals of reducing the utility's total cost of electricity in a changing competitive environment.

Joe will be the station manager of a generating plant consisting of simple-cycle gas turbine generator sets, used almost exclusively for meeting the company's peak-load requirements. Each gas turbine is expected to operate fewer than 200 hours per year at 4 to 5 hours per start.

Mary's combined-cycle plant will be made up of gas turbine generator sets connected to heat recovery steam generators that power steam turbines and are used for daily cycling duty. The plant will start up each day and run for 12 hours before being shut down each night.

Bill will manage an integrated coal gasification combined-cycle power plant that, because of its thermal efficiency and low fuel cost, will be continuously dispatched at full load, except when it is out of service for maintenance or because of a forced outage.

In the past, the U.S. electric utility industry has been highly regulated, and the same gas turbine design would have been acceptable as the heat source for all three of these plants. Today, as the electric utility industry evolves toward a more market-based system, a different gas turbine design is needed for each. To appreciate this, we need to consider how the changing marketplace affects utility decision making.

Historically, the price an electric utility charged its customers was determined by taking its "prudently incurred cost" and adding a legally mandated return on investment. In other words,

Price = Cost (prudent) + Profit

The primary motivation for the utility's decision maker was whether or not a decision could be defended as "prudent," regardless of the actual effect the decision had on the utility's price of electricity. With no real competition among electric utilities, the rates one utility charged for electricity had little effect on another's decision making. This led to a strong risk-avoidance mindset. (Risk in this context refers to the outcome of an equipment decision that is not absolutely certain.) From a stockholder's perspective, risk-avoidance was the most appropriate criterion to use in making these decisions.

For example, investment in a risky decision that was wildly successful (say a 10 to 1 return) could by law only yield a profit of the "allowable" rate of return (perhaps 12 to 14%), while an unsuccessful investment might be disallowed entirely in a "prudence" review and no return at all permitted. Therefore, from a stockholder's perspective, the maximum return a risky investment decision could possibly yield would be equal to, but no greater than, a "safe" decision, and the return could be less. Because of the laws of probability, over time, a series of "risky" decisions would, therefore, only dilute the utility's maximum return on investment.

Under this strategy, when investing in a new power plant, a U.S. utility would consider its needs and the various manufacturers' offerings in terms of the initial cost, while specifying that certain performance guarantees be demonstrated in relatively short-term tests. Little weight was given to differences in the long-term impact on the utility's electricity cost of such items as maintenance requirements, reliability, efficiency degradation over time, operator training, and other factors. Gas turbine designers, when evaluating design trade-offs, had to consider the evaluation process the utilities would use and develop their products accordingly. Designs thus emphasized low initial cost (achieved in part by developing a standard design for all user applications) and high efficiency (achieved with high inlet temperatures, tight tip clearances on rotating blades, and sophisticated controls and instrumentation systems). This did not necessarily lead to an investment decision that would allow the utility's cost of electricity, but rather one that could be defended as "prudent," because that was the standard industry method of evaluating this.

Consider what is happening now in the U.S. electric power industry. With power producers being able to supply electricity to industrial users (and eventually to commercial and residential users) outside their traditional service territories, end-users have a wider choice of power suppliers and their primary considerations are becoming price and customer service (reliability, quality, etc.). Because of competition, the price of electricity will now be determined by the marketplace.

Therefore, the formula for profit changes for the utility. Profit is now determined by the difference between the cost of electricity and the market-based price:

Profit = Price (market) - Cost

This changes the decision maker's attitude toward risky investments. Higher risks may now lead to higher returns. Instead of avoiding risks, the utility decision maker must identify, quantify, and manage risks to evaluate their cumulative impact on the total cost of electricity.

The engine designer, from now on, must identify all of the new elements that will enter the utility's decision process as well as consider the changing importance of both the old and the new elements. The designer must then transform these elements into usable cost figures. (These elements include all costs and revenues over the life of the project including performance penalties and incentives.) Finally, the designer, instead of designing one generic product for all applications, must develop a series of products for the needs of particular power segments.

We can now reconsider our three plant managers:

Joe's simple-cycle gas turbine plant needs a simple, low-cost design with high start-up and load-carrying reliability. He is less concerned with efficiency (since he won't be producing many MW-hrs per year), but he wants a very low O&M cost.

Mary's combined-cycle daily cycling plant, with its almost constant transient loading condition, calls for a sophisticated instrumentation and controls system with increased emphasis on efficiency. This is balanced against the risk of increased forced outages due to its difficult operating regime. (Industry studies have shown correlations between cycling duty and low reliability coupled with high O&M costs due to fatigue and increased opportunities for mis-operation.) Because the utility values availability for this plant more than for Joe's simple-cycle plant, increased expenditures can be justified for operator and maintenance training, spare parts inventories, condition monitoring and predictive maintenance, outage planning, and other needs.

Bill's integrated coal gasification combined-cycle plant, because of its low fuel cost, will run almost continuously at full-load. The ideal regime for this plant would be to start it up; run it for 8,000+ hours at full-load, if possible; then shut it down for an annual maintenance outage. Bill can be careful during startup to avoid blade-tip rubs, etc., and not worry about transient conditions until it is time to shut down. His primary concerns are efficiency and running reliability, and he can justify more elaborate on-line performance monitoring systems and diagnostic tools that help him minimize his costs during steady-state operating conditions where high reliability can be anticipated. For example, the Southern Company's only base-loaded cogeneration gas turbine plant has averaged 99.15% reliability over the last 25 years (4GTs).

As each of these three plants are being developed, Joe, Mary, Bill, and people with similar experience will be actively involved in the equipment-procurement evaluation process to ensure that the long-term operational effects are properly considered. The utility (or other developer) will select the equipment alternative that yields the lowest cost of electricity. In doing this, the utility will often select manufacturers who are willing to share the risks and rewards of a project either through performance incentives/penalties or, increasingly, as an equity partner in the project. This, in turn, should influence the manufacturer's marketing organization to communicate more fully the future requirements and value systems of their clients (partners) back to their design organizations for use in the early stages of product development. These designers, starting from the customer's perspective, will then be better able to perform the basic trade-off studies necessary to develop products that will be the competitive choice in each plant application ... not just for this utility, but for other utilities around the world with similar requirements.

The following generic table indicates the *relative* importance of several key factors influencing a power producer's gas turbine equipment purchase decision according to its anticipated duty cycle.

Relative Importance of Engine Characteristics by Application

Gas Turbine Engine Characteristics:	**Gas Turbine Plant Applications:**		
	Peaking	**Cycling**	**Base Load**
High Availability	L	M (Day)/L (Night)	H
High Start-Up Reliability	H	H	L
High Running Reliability	L	M	H
High Efficiency	L	M	H
Low Initial Cost	H	M	L
Low O&M Cost	H	M	L

L = Low; M = Medium; H = High

The actual relationships among these factors will depend on their importance in the specific application. For example, a plant sited where fuel is relatively cheap would value efficiency less than a plant located where fuel is expensive. Another example might be for an off-shore oil platform where any interruption in generation could have overwhelmingly large financial consequences due to reduced oil production. The value of availability (due either to planned or unplanned outages) would be much greater than for a similar facility that had a reliable source of back-up power. The important principle here is that these factors must be quantified in monetary terms according to the customer's specific value system in order to provide the optimal design.

Summary

Changes in the basic economic framework of power generation in the United States, fostered by increasing competitive pressures, are dramatically altering the decision-making criteria employed by utilities in equipment selection. These changes are not confined to the United States. As the world continues to evolve to a more global economy, a key factor in any country's economic growth will be the availability of low-cost, reliable power. Efforts to satisfy this need create incentives for cooperation and the formation of partnerships between power producers and equipment manufacturers. The most successful manufacturers, instead of offering a one-configuration-fits-all approach, will take aggressive steps to understand their customers' priorities and values and incorporate them into a range of designs, each one optimal from a user's perspective, to meet the requirements of differing market segments.

✦ During the gas turbine design process, numerous trade-off decisions are made between cost and performance factors.

✦ Increasing competitive, market-based pressures are altering the way the end user evaluates equipment.

CRITERIA FOR TECHNOLOGY CHOICE

<u>PAST</u>	→	<u>FUTURE</u>
Prudent (risk adverse)		Profit (risk managing)

✦ **<u>PAST</u>:**

Price = Cost (Prudent) + Profit (mandated)

↓

<u>*Avoid Risk*</u>

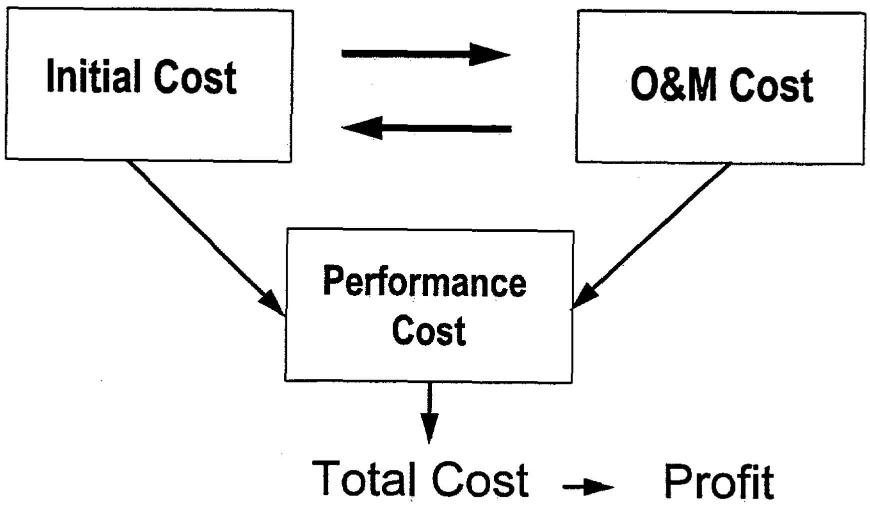
✦ **FUTURE**:

Profit = Price (Market) - Cost (total)

↓

Identify, Quantify, Manage Risk

Total Costs Considered by User



PERFORMANCE COST INCLUDE:

- ✦ Availability Cost
- ✦ Start-up Reliability Cost
- ✦ Running Reliability Cost
- ✦ Efficiency Cost

- ✦ Along with a market price assessment, <u>all</u> cost must be included in the plant's pro-forma when the user chooses its best equipment option.
- ✦ For different applications (baseload, cyclic, peaking duty cycle) there will be different monetary relationships between each of the various cost/performance factors.

RELATIVE IMPORTANCE OF ENGINE CHARACTERISTICS

Application	Most Important	Less Important
Peaking	Low Initial Cost Low O&M Cost High Startup Reliability	High Availability High Running Reliab. High Efficiency
Base Load	High Availability High Running Reliab. High Efficiency	High Start-up Reliab. Low Initial Cost Low O&M Cost

VARIATION IN COST OF UNAVAILABILITY

Cost Per Day Per 100 MW

	Peaking	Cycling	Base Load
Peak Season	$8,768	$14,730	$31,006
Off Peak Season	$211	$3,821	$21,155

- The actual relationships among these factors will depend on their importance in the specific application.

- In order to achieve a competitive advantage in the market a gas turbine designer should quantify these factors in monetary terms according to its customers specific value system and incorporate them into its design trade-off process.

- Early and frequent dialogue between the designer and end users is vital in order to develop an optimal product, enabling the user to be a winner in an increasingly competitive environment.

FLEXIBLE, MIDSIZE GAS TURBINE PROGRAM PLANNING WORKSHOP: SECOND END USERS' PANEL ON MARKET NEEDS

"A POWER MARKETER'S PERSPECTIVE ON FUTURE GENERATION"
presented by David R. McCue, CNG Energy Services Corp.
NOTES TO SLIDES 3/4-5/97

I. How has the prospect of deregulation affected the outlook for generation development?

Deregulation presents unprecedented opportunities for generation development because not only can non-utilities now participate in the generation market, we don't have to wait for the so-called "excess generation capacity problem" to go away -- market forces will take care of it! New market players will now be able to go after the $210 Billion US retail market. The WSCC comprises approximately 153,000 MW of generation, with about 55,000 in the CA-So. NV power area. Between now and 2005, at least 9,120 MW will be added in the WSCC, with 2,520 in CA. However, at least 6500 MW will be retired in CA alone.

In addition, deregulation will change not only how generation costs are recovered but how generators are dispatched and required to perform. Under the power exchange (px) model, each utility's generator bid into the px must recover all its fixed and variable operating costs from the px, with any excess "stranded costs" allowed to be recovered through a Competitive Transition Charge (CTC) in California. At the end of the stranded investment recovery period in 2003, all costs must be recovered through the px. Other parties may sell their power on a bilateral basis outside the px. Generation with costs above market at that point will be retired.

The ISO will take everyone's hourly schedule and dispatch it. Where transmission constraints arise, "congestion" charges will be assessed. Congestion Contracts will allow players to pay ahead for a transmission reservation and avoid congestion charges.

II. How is the power market evolving toward more standardized power products?

One of the results of deregulation is that electric energy is now bought and sold on the NYMEX like other commodities. A NYMEX contract amounts to 736 MWH of energy delivered 16 hours/day over on-peak hours during (approximately) a month. Although the NYMEX is essentially a financial contract, new similarly-structured physical products have started to become standardized, such as "5x16," "6x16," monthly and quarterly on-peak and flat, and "strips."

Unit and system reliability has taken on a new meaning beyond traditional "utility firm," with the addition of liquidated damages contract provisions in the event of failure to deliver. Clearly, future generation must set a new standard for exceptional reliability.

The implication for new generation is not necessarily that we will have to build "NYMEX Contract Generators" but that as the nature of power delivery continues to evolve from that of system economic dispatch to commodity delivery, new generation must have the added flexibility necessary to economically stop and start up again when needed. New units with low start-up, operating, and standby costs will be most competitive.

III. What types of power products is the market demanding?

As the traditional regulated utility "cost-plus" approach is replaced by competitive market pricing, customers have begun demanding pricing options which best suit their tolerance for risk, e.g., fixed price, indexed price (Dow-Jones, NYMEX, Pwr Mkts Week, MW Daily, etc.)

Variable price options also include ceilings and floors, which, from a trading standpoint, are accomplished through financial derivatives.

The commodity portion of power delivery has thus become unbundled from the ancillary services portion, and ancillary services such as load regulation, load shaping, voltage support, metering, and even energy accounting are packaged, priced, and billed separately.

States passing deregulation bills will require and give special credit to green power sources. The California deregulation bill AB 1890 has allocated $540 million to renewables.

Successful new generation projects will have to manage their cost risks in a manner which mirrors the pricing options which the market is demanding.

IV. What are the attributes of the new products?

In the old days, generating units were neatly and scientifically dispatched with other units in or near the utility's service area according to their marginal costs, and run virtually to the end of their physical lives. In the new world, generators will be brought on line as their costs stay at or below the prevailing market clearing price at the time. The clearing price will be set not by a particular utility but by all the other generators in the region which can reasonably compete to serve a given load in a certain location. All the other players will have equal rights to call on the transmission to get to that load, and generators which cease to be price competitive must of economic necessity be retired.

To be successful competitors, new generation projects must be "robust," i.e., they must have all the characteristics necessary to run profitably under a wide variety of market conditions (see slide). Ideally, they can cycle as well as baseload while maintaining very high availability.

V. <u>How does the combined electric and natural gas energy market convergence lend itself to generation development?</u>
Gas tolling and reverse tolling (gas/electricity swaps) are ways of using the most economic source of energy available at any given time -- either to generate or not generate electricity -- depending on your unit heat rate and the relative cost of gas vs. electric energy. This differential is known as the "spark spread." If positive, it means you should use natural gas to generate electricity; if negative, it means you should buy your electricity and sell your gas!

A new or existing generating unit may be a candidate for tolling if it can take advantage of the spark spread as it occurs with minimal advance notice, Unit contingent tolling contracts may be set up on an hourly, daily, monthly, or longer basis. The toller may provide only the unit, and charge a tolling or rental charge, and the tollee may both bring the fuel and take title to the electricity at the generator busbar (or other delivery point).

VI. <u>What is the market outlook for new generation over the next 5-10 years?</u>
Demand and Energy Load growth 1995-2005: NWPP Area: 1.2% and 1.9%; Rocky Mountain Power Area: 1.7% (demand and energy); AZ-NM Area: 1.9% and 2.3%; CA-So. NV Power Area: 1.4% and 2.2%. As noted earlier, the WSCC has over 150,000 MW of generation capability, with 50,000+ MW in CA-So. NV.

Fossil-fired retirements: Obvious candidates are plants which don't come close to recovering their forward-looking costs (fixed plus variable) from the pool: 1,609 MW in CA by 2001.

The CA nukes will be allowed by the CA PUC to accelerate recovery of these investments. Diablo Canyon (2150 MW) is scheduled to be paid off by the end of 2001. San Onofre (also 2150 MW) is scheduled to be paid off by the end of 2003. Edison's 579 MW share of Palo Verde (3800 MW total operated by APS) will be paid off by 2003. It may be assumed that once these investments are fully recovered, these plants will be retired. It may also be assumed that the WNP-2 nuclear power plant (1200 MW) in Washington state would also be retired at the end of 2003.

AB 1890 provides continuing allocation of resources in an amount of 2.5% (or around $300M) of annual retail revenues to be expended in public benefit programs including: (1) Energy Efficiency and DSM; (2) Research, Development, and Demonstration; (3) Renewable Energy Facilities; and (4) Low-income Programs.

In addition, we see many RFPs from both traditional wholesale entities and new load aggregators which give preference to renewable energy resources.

One benefit of the July and August blackouts last summer in the WSCC was that it brought attention back to the importance of physical system reliability. As a result, the WSCC is instituting mandatory reliability standards. The transmission capability at COB was conservatively derated down from 8000 MW (4800 MW on the AC tie and 3200 MW on the DC tie) to 5500 for most of the latter half of 1996 and is likely to settle out in the neighborhood of 6500 MW.

The outlook for future generation: 6500 MW (conservatively) of capacity in California must be replaced over the next 10 years! The WSCC forecasts known generation additions by 2005 in WSCC (total) and the CA-So. NV Power Area of only 9,120 MW and 2,520 MW, respectively. At a growth rate of 1.4% annually in CA, these new additions would accommodate only 3 1/2 years of load growth. In 1995, total summer reserve margins in California fell to as low as 14%.

VII. <u>What are the market cost-drivers for successful new generation projects?</u>
Future market prices in the west will be driven by hydro availability, fuel price, and market restructuring.

Hydro conditions may have a major short-term cash-flow impact, however, over the life of a project, it is assumed that annual hydro surpluses and deficiencies will average out.

Gas is the marginal fuel at COB 40% on average and 20% at PV. Modeling shows new projects reach maximum profitability when gas prices remain low and restructuring is implemented throughout the WSCC more rapidly. Low gas prices allow gas-fired projects to be more competitive with coal-fired units in the long-run, and thus improve overall profitability.

Due to the px system requiring recovery of costs which used to be recovered as fixed costs from captive ratepayers now having to be recovered from the pool, some models now predict a significant rise in bulk power costs as pool-style deregulation proceeds. The market price in CA under a pool therefore increases (20-30%) due to the inclusion of start-up and no-load costs, in addition to the recovery of fixed (operating) costs. Thus, even the market prices in the

Northwest and Arizona increase 2-3 mills/kWh, which is far in excess of inflation.

The Pacific AC Intertie was derated 1000 MW from 4800 MW to 3800 MW following the WSCC summer '96 blackouts. Models show a constraint of 1400 hours/year with the derating, and a decrease of 600 hours constrained at the full rating, however, the change in market prices is negligible.

Merchant plants are assumed to be plants which do not have life-of-project customer contracts. This price analysis assumes such a plant is in fact selling exclusively into the px, or spot market.

VIII. Who will be the new customers?

The California electric retail market is approximately $13.5 Billion! US $210 Billion!! Theoretically, every electric utility customer could become a "new customer" in the deregulated energy marketplace over the next 5-10 years (see slide)!

IX. Who will be the new suppliers?

New generation projects will be driven by market forces, not strictly by the amount of surplus reserves owned by utilities. Many new players will now have the opportunity to become suppliers!

Transmission and distribution may remain regulated entities (with open access required), however transmission ownership concepts may change, and distributed, on-site power sources in the future may reduce or change the nature of distribution systems.

X. What will the future look like?

CNG's studies conservatively show merchant plant viability in the 2002-2004 range. The most efficient and versatile new generation plants will be economic in the earlier years. More customers will again be interested in looking at long-term contracts beginning in the next 3 years!

"Merger mania" may change the industry landscape from many regulated vertically-integrated companies to a few large unregulated generation companies, delivering power to regional open-access transmission systems and local distribution companies.

A Power Marketer's Perspective on Future Generation

David R. McCue
CNG Energy Services Corporation

How has the prospect of deregulation affected the outlook for generation development?

- ★ Wholesale Open Access (FERC 888)
- ★ Retail Open Access (California AB 1890)
- ★ The PX and the Pool Bidding Process (all generation costs to be recovered from the pool)
- ★ The ISO and Transmission Constraints (wheeling costs and congestion pricing)
- ★ Unbundling

How is the power market evolving toward more standardized power products?

- ★ NYMEX Electricity Contract
- ★ WSPP "Umbrella" Agreement
- ★ Standard Physical Power Products
- ★ Liquidated Damages (i.e., reliability)

What types of power products is the market demanding?

- ★ Pricing choices
- ★ Pricing using financial derivatives
- ★ Power plus ancillary services
- ★ "Green" Power
- ★ 100% Reliability

What are the attributes of the new products?

Compatible with a robust energy marketplace; i.e.:

- ★ High efficiency
- ★ Capital cost competitive
- ★ High Availability
- ★ Minimal startup and standby cost
- ★ Rapid cycling characteristics
- ★ Load regulating capability

How does the combined electric and natural gas energy market convergence lend itself to generation development?

- ★ Gas Tolling
- ★ Reverse gas tolling (gas/electricity swaps)

What is the market outlook for new generation over the next 5-10 years?

- ★ Load growth
- ★ Fossil-fired plant divestiture and retirements
- ★ Nuclear plant retirements
- ★ Hydroelectric capacity reductions
- ★ Environmental compatibility
- ★ System Reliability

What are the market cost-drivers for successful new generation projects?

- ★ Future natural gas costs
- ★ Costs to be recovered from sales into power pools (PX)
- ★ Transmission congestion costs (congestion contracts and strategic siting)
- ★ The Merchant Plant concept
- ★ Availability

Who will be the new customers?

- ★ Large industrials
- ★ Load aggregators of smaller commercial and residential loads
- ★ Municipals (utilities and municipal load aggregators)
- ★ Power Pools (PX)

Who will be the new suppliers?

- ★ Energy Service Companies
- ★ IPPs
- ★ Traditional utilities to become "wires" companies -- and get out of the generation business (?)
- ★ Transmission to evolve from private ownership to "open access" to ownership by highest bidder (?)

What will the future look like?

- ★ Many (or few?) unregulated Energy Service Companies serving all retail customers
- ★ Generators strategically sized and sited to match customers' needs

A New England User's View on Requirements for a Midrange Aeroderivative Combustion Turbine

Eric G. Rorstrom
Northeast Utilities System

Background

Northeast Utilities is part of the New England Power Pool (NEPOOL)

NEPOOL Statistics:

- Generating Capacity of 25,000 MW
- Peak Load 21,000
- Annual Energy 115,000 GWH

New England Generating Mix:

Base Load: Provided by Nuclear, Coal & CC
Intermediate (load following): Provided by oil/gas Steam & CC
Peaking: Provided by Peaking Steam, CTs & Hydro

Opportunities for Midsize High Efficiency Combustion Turbine

Stand Alone Installations

Intermediate Load Duty
1. Low energy cost at moderate capital
2. High power density
3. Short lead times allow closer planning
4. Ideal size for meeting capacity additions

Greatest opportunity as need for new capacity occurs (post 2000)

Feedwater Heater Repowering of Large Fossil Steam Units

Reduced energy cost with low incremental capital cost
5. Improved environmental impact of original unit

Retains usefulness of large asset

Criteria for New Design for Intermediate Duty in New England

Operating 8 to 14 hours /day 5 days/week
Operation with minimal permanent staff
Minimal impact of ambient temperature
Dual fuel capability
Short start-up time
High ramp rates
Minimal requirement for water
Modular maintenance with short turn-around time
Emissions for NOx will have to meet LAER

Criteria for New Design for Feedwater Heating Repowering

Operating 24 hours/day
Minimal impact of ambient temperature
Dual fuel capability
Minimal requirement for water
Modular maintenance
Emissions for NOx will have to meet LAER (SCR on HRSG)
High Power Density

Summary

A high efficiency midsized combustion turbine will provide a desirable tool for generation planners in New England.

Opportunities for application are in two areas:

1. Intermediate duty as stand-alone unit
2. Feedwater heater repowering