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BRIEFING ON ELECTRICITY FORECAST FROM

ENERGY INFORMATION ADMINISTRATION

(EIA) ANNUAL ENERGY OUTLOOK - PUBLIC MEETING

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Nuclear Regulatory Commission

One White Flint North

Rockville, Maryland

Thursday, June 1, 1995

The Commission met in open session, pursuant to notice, at 10:00 a.m., Ivan Selin, Chairman, presiding.

COMMISSIONERS PRESENT:

IVAN SELIN, Chairman of the Commission

KENNETH C. ROGERS, Commissioner

E. GAIL de PLANQUE, Commissioner

SHIRLEY A. JACKSON, Commissioner

STAFF AND PRESENTERS SEATED AT THE COMMISSION TABLE:

JOHN HOYLE, Secretary of the Commission

KAREN CYR, General Counsel

MARY J. HUTZLER, Director, Office of Integrated Analysis and Forecasting, EIA

SCOTT B. SITZER, Director, Energy Supply and Conversion Division, EIA

ROBERT T. EYNON, Chief, Nuclear and Electricity Analysis Branch, EIA

JAMES HEWLETT, Economist, Nuclear and Electricity Analysis Branch, EIA

J. ALAN BEAMON, Economist, Nuclear and Electricity Analysis Branch, EIA

P R O C E E D I N G S

[10:00 a.m.]

CHAIRMAN SELIN: Good morning, ladies and gentlemen.

I don't know how many of your clients say this to you, but for us you are kind of a reality check. It's really very nice to have you come in and address us as we get wrapped up in the details of the safety regulation of the nuclear industry and our own guesses as to where nuclear is going, where electricity is going in general. It's very beneficial for us to sit back at least once a year and try to listen and understand the overall context in which the industry we regulate has to operate.

So, we're very pleased to have you come and brief us on electricity supply and demand forecasts through the year 2010. Obviously these forecasts are going to be affected by a large number of progress, the overall economic growth, world oil prices, energy management conservation and particularly what happens to the world of competition in the electricity generating business.

Nuclear is a little over 20 percent of the total amount. There are no new orders for nuclear power going on. The prospects are for a number of the current nuclear plants to close down as they face a more difficult competitive environment. On the other hand, the performance of the existing plants continuously improves and so these factors somewhat trade off one against the other. We also have some other issues which can have a dominating effect. For instance, what the Congress does with the spent fuel program or high-level waste program. So, as we try to understand these different qualitative pieces, it's very good to have your quantitative estimates and particularly to understand where your analysis tells us the sensitivities to a number of these factors that might happen. So, we're just looking forward to this presentation.

Commissioners?

Ms. Hutzler?

MS. HUTZLER: Thank you very much for your kind words and good morning.

The Energy Information Administration appreciates the opportunity to brief you, Chairman Selin and Commissioners de Planque, Rogers and Jackson, on our electricity forecast and the Annual Energy Outlook.

I'd like to start with a few highlights about our forecasts that are different this year from last year's forecast that we briefed you in June of last year. First, we have lower fossil fuel prices. The reason for this deals mainly with improved technology but in some cases differences in reserve estimates. We'll be telling you more about this later, but essentially in 2010 you'll see that our oil prices are about 17 percent lower, our coal prices are about 28 percent lower, and our natural gas prices are about 5 percent lower, and this does impact the price of electricity.

In our industrial sector, we see a greater shift to less energy intensive industries and that is another feature of this forecast. We have incorporated the Climate Change Action Plan, which is supposed to stabilize carbon emissions at 1990 levels. You will see based on the fact that funding has not been received for this program that the impact we see is very marginal.

Finally, we've added additional policy analysis or sensitivity cases to this year's forecast and we will be mentioning two to you today. One on varying nuclear retirements and another one for high demand for electricity. I would like to remind you that we do assume that utilities are regulated in these forecasts and at the end I'll summarize some of the work we've been doing on deregulation.

[Slide]

MS. HUTZLER: If you take a look at the briefing agenda, we will start with major assumptions in electricity demand and Scott Sitzer, who is Director of the Energy Supply and Conversion Division, will present those. I will return to talk about the national electricity supply and uncertainties and then Bob Eynon, who heads up our Nuclear and Electricity Analysis Branch, will talk about the regional picture for electricity.

Scott?

MR. SITZER: Okay. Thank you very much.

I'm also very glad to be here in order to brief you on our major assumptions for the Annual Energy Outlook and our electricity demand forecast.

If I could go ahead and have the first slide, please, Dave.

[Slide]

MR. SITZER: Basically the way we do our projections, we take a number of assumptions and we turn them into a projection using our national energy modeling system. Two of the major assumptions that we need in the model are what will be happening to world oil prices and what will be happening to the U.S. macroeconomy.

The first picture here shows what we see as being the world oil price projections through 2010. As Mary stated a moment ago, we are lower for the AEO '95 than we were in the AEO '94. By 2010 we're looking at prices on the order of about $24.00 a barrel in 1993 dollars in the AEO '95 compared to about $26.00 in AEO '94. Primarily what's happening is that between 1993 and 2010 we see a considerable increase in OPEC capacity. 1993 production by OPEC was about 27 million barrels a day and we're looking at a need for about 47 million barrels a day by the year 2010. In order to extract that kind of increased capacity, we do see prices going up, but we don't see them going up as much as they have in the past because we're a bit more optimistic about OPEC's ability to add that capacity and to extract that production at somewhat lower prices.

CHAIRMAN SELIN: You know, the management of the Department of Energy, when they talk about the future, usually talk about some kind of an oil crisis that's going to hit the United States in the next five to ten years. This doesn't reflect it. Is that a judgment that that's not right or is this more of an econometric projection?

MR. SITZER: It is in part an econometric projection, but we also made the assumption that we would not see disruptions, as far as a base case was concerned, between now and the year 2010. If there were disruptions, these would look obviously a lot different. We don't make any assumption about disruptions occurring in our base case.

COMMISSIONER ROGERS: I just had a question. The '95 versus '94 predictions, prices are lower. If you look back in your earlier history of predicting prices, how often have they been lower? Have they been always lower? Do they always come out lower than you predicted? If it's something sort of like that, does that give you a little question about this long-term rise that you're predicting here?

MR. SITZER: You're right about the pattern. We have tended to be lower, at least in the last several years, each time than we were in the previous AEO. We have looked quite hard at what we're saying about projections. If you look back in the late '70s and early '80s, we were talking about prices a lot higher than they turned out to be.

Basically since 1986, when there was a considerable price decline, and OPEC's overall market power began to erode, we have seen lower prices. I think we've been pretty good in the past four or five AEOs. But on the other hand, I think our view of at what price they're going to be able to increase their capacity has been lowered.

CHAIRMAN SELIN: Your model just assumes no OPEC for all intents and purposes. In other words, it assumes economic strife price, not deliberate withholding of supply from the market.

MR. SITZER: The model looks at what the historical ratio has been between prices and available capacity. We're looking at something called moderate growths in consumption. But by far the greatest increase in capacity over the next 15 years is seen in OPEC. We don't see it in the rest of the world particularly. If anything, there is some decline. Certainly in the United States there's decline and only very modest increases in some other parts of the world. So, OPEC is still the swing supplier.

They do have that kind of a role to play.

CHAIRMAN SELIN: I didn't put my question -- you're not assuming that OPEC withholds -- your model assumes OPEC does not withhold supply in order to get the price up, either because they don't want to or because they can't. It's just a set of countries that are producing at an economic rate.

MS. HUTZLER: Because of the uncertainty in forecasting price, we do incorporate two other cases in our report which have lower and higher prices. One of them is a low price case that reaches $15.00 in 2010. So, that's a case that many people believe is plausible. We do show a slightly increasing case to $24.00, as Scott was referring to, for our reference this year.

MR. SITZER: Okay. If we can move on to the next slide.

[Slide]

MR. SITZER: As I said, world oil prices are primarily an assumption as far as our integrated modeling is concerned. They're done with an off-line analysis. The next slide shows natural gas prices. What we're showing here again by 2010, a slightly lower price at the well head than in AEO '94. We're looking at prices at about $3.35 per thousand cubic feet in 1993 dollars by the time we get to 2010. That's about $.20 per thousand cubic feet lower than we said in AEO '94. Once again, what we're looking at here is a slightly more optimistic view of technology improvement and the ability of natural gas producers to turn gas resources into reserves and of their ability to extract gas.

If you look at the curve, you'll see that basically we're lower in the AEO '95 than in last year's forecast until about the mid-2000s, at which time prices are fairly close to what they were last year, but again finishing out somewhat lower than in AEO '94.

CHAIRMAN SELIN: I just can't reconcile those two curves. Today's price is hugely lower than had been predicted for today and so is next year's and so is the years after that. But once you get out to about 2003, the history seems to be irrelevant and the two curves almost coincide.

MR. SITZER: What we're seeing as we go out to the next decade is a combination of increased demand, particularly by utilities, because we do think that gas is going to be an important source of demand for increased generation. As we see that increased demand, we're seeing some notion that reserves are going to be in somewhat limited supply. In order to extract those reserves, we're going to have to see somewhat higher prices for producers.

CHAIRMAN SELIN: So it's really not tied to the short-term projection in price?

MR. SITZER: No, not particularly. We do try to look at the short-term price so that we get a reality check. But our view is that by the time we get out to the next decade, there are going to need to be some increases in price in order to extract those reserves.

[Slide]

MR. SITZER: Looking at the next slide, coal prices and they show an even more dramatic decrease compared to AEO '94. Prices are going up at about three-tenths of a percent per year on an annual growth rate. Essentially the story here is that we've looked at our productivity assumptions and we have found that in order to be more consistent with what's been happening in recent years, in particular with increased penetration of long wall mining and the increasing improved labor productivity. We've raised our productivity assumptions. So, we're looking at the coal prices to be relatively flat between now and the year 2010.

CHAIRMAN SELIN: Your demand projections have not changed?

MR. SITZER: Demand projections are a little bit lower.

CHAIRMAN SELIN: They are a little lower?

MR. SITZER: And particularly coal exports are a little bit lower because we've seen coal exports really drop in the short-term. We've taken a second look at that --

CHAIRMAN SELIN: Because there's so much competition?

MR. SITZER: A lot of competition. There was a strike in 1993. There hasn't been total recovery in terms of our penetration in world markets with that strike and there is a lot of world competition for coal. Plus we're not sure that the demand is going to be as high as we previously thought in places like Western Europe where there are opportunities for gas to penetrate what coal has seen in the past.

COMMISSIONER ROGERS: Why don't those two curves agree in 1993?

MR. SITZER: In last year's forecast we did not have 1993 data. We had to project 1993 in AEO '94.

COMMISSIONER ROGERS: Okay. Good enough.

MR. SITZER: Which is another reason we've lowered the curve in part.

Next slide, please.

[Slide]

MR. SITZER: Is electricity prices and electricity prices are determined by growth in capital costs, having to do with capacity increases, and by operating and maintenance costs and by fuel costs. One of the biggest inputs in terms of fuel is coal. So, if coal is relatively stable, that's going to have a big impact on electricity prices. We have lowered electricity prices slightly from AEO '94 and that's a reflection in part of what we did with coal. We also see capital costs not rising as fast as they did last year. With demand being down, the additional capacity isn't needed and Mary will be talking more about that when she talks about electricity supply.

Next slide.

[Slide]

MR. SITZER: The second major assumption that we make in the AEO is on the U.S. macroeconomy. Our primary driver here is gross domestic product. As this slide shows, in the base case, which is the green lines on the colored slide and the dark lines in the black and white handout, while we're showing growth in the 1990s and in the next decade, that growth is slower than it's been since 1960. The primary reason here is that we see somewhat of a lower labor force participation rate growth than we did in the 1960s, '70s and '80s. Immigration is expected to be down somewhat. Domestic population growth is slowing down. The combination of labor force participation rate and productivity improvements is what gives you your overall economic growth. What we're looking at is economic growth in the 1990s of about 2.4 percent and in the next decade about 2.2 percent for an overall 2.3 percent growth rate over the next 15 or 20 years.

Next slide.

[Slide]

MR. SITZER: This slide shows you basically the same thing. It's a line graph and, as you can see, economic growth in the 1970s was at 2.8 percent. I'm sorry. Yes, between 1970 and 1980. Between 1980 and 1990, about 2.6 percent, slowing to 2.2 percent in our forecast horizon. We do have two scenarios, two alternative scenarios for economic growth. In the high economic growth rate we're looking at 2.7 percent during the forecast period, and the low economic growth rate, 1.8 percent, and these reflect differing assumptions about labor force participation and about growth and productivity.

Next slide.

[Slide]

MR. SITZER: This slide plots four important variables from 1970 through the forecast period. The top line, at least on the forecast horizon, is gross domestic product. The main message of this slide is that we see primary energy consumption moving somewhat away from the growth in gross domestic product. In the 1970s and 1980s, primary energy consumption basically was catching up with economic growth. We had more penetration of electricity. We had somewhat more room for increased demand for energy.

But what we're seeing in the 1990s is something of a decoupling of that as we get more efficient in terms of our energy consumption, as prices grow somewhat in terms of compared to overall inflation and we see energy consumption being perhaps more tied to population growth than we do to gross domestic product over the next 15 years.

CHAIRMAN SELIN: It's sort of implicit in the next curve, but what's the growth rate for electricity compared to energy? Electricity grows a little faster than total energy, doesn't it?

MR. SITZER: I think it's a little bit less.

MR. BEAMON: It grows slightly faster in the energy, but much less than GDP.

MR. SITZER: The other thing is to look at the carbon on this graph. Carbon emissions from energy tend to follow primary energy consumption and that's generally been true both in the historical and in the forecasted period.

COMMISSIONER ROGERS: This is a very interesting result, I think, compared to past history. It's almost a given that the GDP and energy consumption just went together. For whatever reason, they seem to be tracking each other for so long. It comes as a great surprise to see this widening gap. If you look at the gap, that gap can't continue to grow between them. Somehow that gap itself has got to stabilize, one would think. Is there anything in the model that allows for that or is that just something that will evolve in the future?

MR. SITZER: I think one of the things that's happening over this forecast period is the incorporation of efficiency standards from the Energy Policy Act of 1992 and also continuing efficiency improvements from the National Appliance Energy Conservation Act of 1987. The other thing that's happening is that the energy intensive industries are growing less rapidly than the non-energy intensive industries in the forecast period and that tends to lower industrial energy consumption relative to GDP.

COMMISSIONER ROGERS: Those trends are somehow or other going to stabilize at some point, one would think. You can't get something for nothing forever.

MR. BEAMON: They will and in our demand models which have a stock turnover representation, they're going to capture that eventually. Now when you replace a refrigerator, you're taking a really inefficient and replacing it with an efficient. Fifteen years out from now, you're going to be replacing one that was put in today and the gap is not nearly as big and it's going to have to narrow at some point over time.

COMMISSIONER ROGERS: Right.

MR. BEAMON: I imagine that it will.

COMMISSIONER ROGERS: It's just too early to see it in this --

MR. BEAMON: Most products have what, a 15 year life time or so? You're not going to see it in this.

MR. SITZER: We're just at the cusp of that changeover.

COMMISSIONER ROGERS: Yes.

[Slide]

MR. SITZER: And as the next graph shows, comparison of electricity sales and economic growth rates, something of the same story but just looking at electricity alone. Again, a significant difference between the 1970s and the forecast period and in the 1970s we were continuing to see increased penetration of electric appliances, in particular air conditioning. As we move out into the future, we're looking at if not saturation, very high penetration of electricity appliances. Again, this issue of non-energy intensive industry beginning to dominate the traditional energy intensive industries.

Next slide.

[Slide]

MR. SITZER: This slide gives you an idea of the comparison of delivered energy prices between 1993 and 2010. The picture in your handout isn't quite right. We've corrected it on the screen. Basically oil prices are increasing fastest between 1993 and 2010 at a rate of one and a half percent per year with natural gas prices being relatively similar, although you do see a big difference, as you mentioned before, in the post 2000 period where natural gas prices are beginning to catch up as demand increases. Oil prices have the feature of increasing somewhat more rapidly to 2000 and then slowing down in terms of their growth. But the story of this picture is that natural gas and oil prices do continue to grow above the rate of inflation with electricity and coal prices being much closer to the rate of inflation between now and 2010.

CHAIRMAN SELIN: The electricity is so close to coal that it's not even explicable. Just because coal generates 55 percent or what have you electricity, it has to be that the efficiency of the natural gas producers has increased considerably. So that even though the gas prices are going up, the thermal efficiency, I guess, of the plants is assumed to increase continuously.

MR. SITZER: Thermal efficiency will increase as we increase our capacity of new gas burning plants.

CHAIRMAN SELIN: By 2010, what share of electricity is coming from gas?

MR. BEAMON: Eighteen percent.

CHAIRMAN SELIN: Eighteen percent.

MR. BEAMON: Another issue is that the capacity is not growing as fast as demand slightly, so that your capital component of the price also offsets a little bit of the fuel price increase.

CHAIRMAN SELIN: With gas the cap is so small, relatively speaking. So, as fuel prices go up, the cost for fuel per kilowatt hour just can't be going up anywhere nearly as fast as the fuel price. That's interesting.

So, going to the next step, the new turbines, the combined cycle turbines, they promise 60 percent thermal efficiency. I guess it takes 10 or 15 years for these to replace the clunkers.

MR. BEAMON: You've also got to recognize the 60 percent is your --

CHAIRMAN SELIN: The next plant.

MR. BEAMON: It's also your perfect number. We have a big issue with whether you actually operate them in actual operation anywhere near those kind of numbers. The current ones, they're talking 55 percent, which would imply heat rates around 7,000 or so, 6,500, 7,000, but we're not seeing any operate below about 7,200, 7,500. Those are the best ones that are actually operating. So, it implies that when they're actually put in operation, a little bit of cycling and all, that they don't quite get to those kind of numbers. We can't assume those numbers in operating it.

CHAIRMAN SELIN: So, it's not just it takes a long time for the new ones to replace the old ones, but amazing as it may be, the claims might not get seen carried out. That's really fascinating. It basically says electricity is tied to coal no matter what else happens in the economy.

MR. SITZER: Okay. The next slide.

[Slide]

MR. SITZER: This compares growth rates in electricity sales both historically and with our three cases. Again we're seeing a considerable lowering in terms of demand for electricity and forecast period. Growth was above four percent in the 1970s, as I mentioned before, with increased penetration as seen for appliances, moderated to just under three percent in the 1980s and we're looking at about one and a half percent in terms of the base case in the forecast period from 1993 to 2010 with a spread between .8 and 1.4 percent depending on your assumptions about economic growth.

CHAIRMAN SELIN: But they're all much lower than the actual growth of today, not just the historical. Maybe I'm making too much of this chart, but it seems that you've got a much steeper curve going through the current year than you do for even the high curve. Is that right.

MR. SITZER: That's correct. That's correct. We're looking very closely at the short-term and what it implies about the longer term.

[Slide]

The next slide show electricity sales by sector and by the year 2010 we're looking at approximately a third of electricity sales being devoted to the residential sector, about 30 percent to the commercial sector, about 36 percent to the industrial sector and a very small percentage to the transportation sector as alternative fueled vehicles become important, in part spurred by the Energy Policy Act of 1992.

CHAIRMAN SELIN: So, what does this say? Is the relative growth more in the commercial sector than --

MR. SITZER: I'm not sure.

Do we have the historical years on there?

MR. BEAMON: The relative growth is highest in the industrial sector. It's growing faster than the other sectors.

CHAIRMAN SELIN: A slightly different question. If you talk about -- is that right?

MR. BEAMON: I think in the reference case, industrial is drawn at about 1.4 percent. Residential and commercial are both right around 1. One of them is .9 and one of them is 1. I can't remember which one.

MS. HUTZLER: Residential is .9 and commercial is one percent. Industrial is 1.4 percent. It grows the fastest.

MR. SITZER: That's from 1993 and this graph does go back to 1980. So, that might be a bit misleading.

CHAIRMAN SELIN: Does that suggest that there will be continued applications for electricity in the industrial sector where today some other energy form is used? Is there just increased demand of the electricity intensive industries?

MR. BEAMON: It's both. It's improved applications and the electricity intensive ones are the ones that are seen as showing the strongest growth.

MR. SITZER: That completes the section on electricity sales.

CHAIRMAN SELIN: There's a general question I'd like to ask you. Normally, once you get past the J curve, as the price goes down and this term would be price and not energy per dollar, as electricity efficiency improves or the amount of electricity it takes do a given industrial job decreases, in the short-term you would see the pressing demand. In the longer term there would be more and more applications that would use electricity that today might use direct steam. Does your model take account of that? In other words, if you look out far enough, do you get increased demand from electricity because of electricity efficiency?

MR. BEAMON: I'm not as familiar with the industrial model area.

MR. SITZER: I think there's movement into electricity, in part spurred by that improved efficiency and also in part spurred by the relative price difference between gas and electricity. You have to look at it in a little more detail to see, but I think as we get further out in the forecast we're seeing that switchover.

MS. HUTZLER: Given the 1.1 percent growth in electricity sales, the utility generating sector has a number of ways of meeting that demand growth. One of the first ways is to increase the utilization of existing plants. We assume this year, similar to last year, that the nuclear capacity factor will increase from its existing 71 percent to 74 percent by 2010 and that the coal capacity factor will increase from somewhere in the 50 percent range to 68 percent by 2010. Combined cycle also increases to the 60 --

CHAIRMAN SELIN: That's a huge increase in utilization.

MS. HUTZLER: That's because utilities are not using their coal plants today to the maximum level that they could be and essentially it assumes that they will before they start adding other capacity. We're still working off an increase in the capacity that we have today.

CHAIRMAN SELIN: It's not a technological --

MR. BEAMON: The 68 percent is historically the highest national average that they actually operated at. It's a demand issue. All these plants were built when demand was expected to grow at four and five percent a year, it didn't, and they've got them anyway.

CHAIRMAN SELIN: So, you must be assuming that plants that are not economical at three cents a kilowatt hour will be economical at four and a half or five cents.

MR. BEAMON: No, that there's not enough demand right now to fully utilize them. That's what we're saying, that they will as demand grows and they'll continue to --

CHAIRMAN SELIN: As demand grows, price will grow. As price grows, these marginal plants will be --

MR. BEAMON: Yes.

COMMISSIONER JACKSON: You haven't made any assumptions about environmental constraints.

MR. BEAMON: We have environmental constraints endogenously built into the model with respect to the Clean Air Act and the SO2 emissions standard. So, they will have to -- I mean anybody will have to compensate for any additional SO2 that they put out. They're going to have to pay the allowance.

MR. EYNON: It might be useful to note that the 68 percent represents an upward bound on plants. It's not preordained that capacity will achieve that level, it's simply a matter of the economics and the generation requirements would support plants operating up to 68 percent. There are also plants that currently exist or are currently operating at levels higher than that today and we assume that plants that are achieving greater than 68 percent capacity factor will continue to do so in the future.

MS. HUTZLER: Okay. The combined cycle units, too, though we have limited information currently on them, they're probably operating in the 50 percent range right now and by 2005 they reach the capacity factor of coal plants at 68 percent. That again is an upper limit based on the economics.

Another way to meet the demand for electricity is to extend the lives of existing plants and we do have life extension assumptions built into the model. We extend about 340 gigawatts of capacity of which 248 are coal and 93 gigawatts are oil and gas.

Other areas on the supply side to meet the demand are to import electricity from Canada and Mexico, to increase a reliance on non-utility generators, to institute demand-side management programs, and finally to construct new plants. I'll be talking about these in the next slide.

COMMISSIONER JACKSON: Now, built into any of those, do you have repowering of existing plants built into any of these categories?

MS. HUTZLER: We don't actually look at repowering as a separate issue. We just deal with the life extension issue. It's something that we need to examine in the future.

MR. BEAMON: We do have repowering if it's been reported to us. We do change the plants. They will change their fuel --

MR. EYNON: One of the issues with repowering is that it's very site specific and it's very difficult to deal with in an aggregate model. But as Alan indicated, where utilities have told us they plan to repower, we have included that.

MS. HUTZLER: The next chart shows our retirement assumptions. We're assuming that 53 gigawatts of the existing plants will be retired by 2010. Of these, about 11 gigawatts have been announced by the electric utility industry. Again we're assuming nuclear plants will be retired after their 40 year lives. Again, this is a very general assumption that we've made because we don't have the details of the individual units. We're assuming that the ones that will be life extended versus the ones that will be retired early will compensate for this. We'd like to work on this assumption and if you do have information on it, we'd be happy to work with you before our next Annual Energy Outlook. So, you see the almost 13 gigawatts of nuclear retirements that we're assuming there.

CHAIRMAN SELIN: What's so extraordinary about this chart, there's only 15 and a half coal retirements even though that's more than half of the nominal -- it's about 60 percent of the nominal capacities. So you're assuming people are really going to stretch out their coal plants.

MS. HUTZLER: That is correct, mainly because utilities have only reported about, I think, nine gigawatts of fossil fuel retirements and we do believe that they will -- it is cheaper for them to extend their lives than to build new plants and we do believe that they will do that.

CHAIRMAN SELIN: Whereas gas plants, they just want to let them go and replace them with more efficient turbines.

MS. HUTZLER: Yes. We do believe on the gas side that they'll be adding combined cycle units and turbines rather than extending the steam plants, though we do assume in regions where the generation is fairly high from oil and gas use, say about 10 percent, for instance the northeast, that there will be some life extension there and we do have 93 gigawatts of oil and gas units life extended.

MR. BEAMON: Can I make one comment about the coal? Commonly, there's a lot of old coal plants out there and that you expect them to retire. But one thing that people often forget is that most of these old coal plants are really small. So, when you start talking about in terms of capacity, it doesn't come up that big a deal. In fact, if you do an unadjusted average age for coal plants, they come out in a 27 or 28 year average. But if you adjust that for size, they come down closer to 20, 21, 22. So, while this 15.6 doesn't look like a lot of capacity, it's a lot of units. It's just that they're teeny.

[Slide]

MS. HUTZLER: Okay. Moving on to the next chart, this charts shows our electricity trade with Canada and Mexico. Historically, you can see that we hit a peak in terms of net imports of electricity in about 1987 when I believe it was about 46 billion kilowatt hours. You see the big dip in 1990 and that occurred for two reasons. One was essentially a drought, decreasing the amount of hydroelectric generation, and the other reason were that a number of their coal plants in Canada were down to add scrubbers.

In terms of the future for electricity imports, you'll see that we do see a growth that declines through about 2005 because contracts are expiring and at this point in time we do not know if they'll be renewed. By 2010 we see an increase so that net imports reach 56 billion kilowatt hours and that's because there are new hydroelectric plants that become economic in Canada that are being built.

COMMISSIONER ROGERS: What's the fraction of the import that comes from Mexico or is expected to come from Mexico?

MS. HUTZLER: It's very small, less than one percent.

MR. EYNON: Less than one percent.

MR. BEAMON: Under one percent.

COMMISSIONER JACKSON: Do you consider the other way, that the Mexican economy might expand, that it might be exports?

MS. HUTZLER: We do export some electricity to Mexico right now. We're not really assuming a major increase, we're assuming the Mexican market will stay fairly stable, I believe.

Is that right, Alan?

MR. BEAMON: It's pretty small. As I understand, part of the problem is that not all of the Mexican grid is synchronized with the United States, a very small portion of it right there on the border. So, unless they do some things to deal with that, there's not a lot of room for increasing exports.

COMMISSIONER JACKSON: That's also true for the imports? I mean the grid is the grid.

MR. BEAMON: Right, from Mexico.

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MS. HUTZLER: Moving on to our non-utility story, as you can see from this chart, the share of non-utility generation to total generation increases over time. Of course this was spurred by a number of reasons. First, the Public Utility Regulatory Policy Act of 1978 and then the Energy Policy Act of 1992. By 1990 we reached the numbers we had in 1970 when we saw a good deal of cogeneration in the marketplace. Then we're forecasting that it will reach about 16 percent by 2010.

In terms of the way we look at non-utilities, we believe that their technology characterizations will be the same as the electric utility industry, but we do think that their financial structure will be different, that the cost of equity for non-utility generators will be about one and a half percentage points higher than utilities and the cost of debt, about .75 percent higher, percentage points higher. So, that's a major difference in terms of the penetration levels.

COMMISSIONER JACKSON: You're assuming true non-utilities, independent power producers, not restructured utilities?

MS. HUTZLER: Yes, exactly.

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MS. HUTZLER: The next graph tells our story about electricity generation from gas. Because of gas technologies, advantages of low initial capital costs, high efficiencies and low emissions, we see that gas generation will increase from its current 1993 level of 13 percent to 18 percent by 2010. In terms of the additional gas fired generation, we see it increasing at a 60 percent level over this time period. After 2005, rising natural gas prices begin to make gas-fired plants less economical than coal-fired plants and you'll see in our later story that coal does enter into the marketplace in the 2005 and after period.

[Slide]

MS. HUTZLER: Moving on to demand side management, the numbers that you see in this graph deal with what information electric utilities report directly to the Energy Information Administration. In terms of the cumulative energy savings, in 1990 it represents about .7 percent of demand and that increases to about 2.6 percent of demand by 1998. And, of course, demand side management include weatherization programs, more efficient appliances and industrial efficiency programs. We, in the forecast, see DSM not being a major impact mainly due to the standards in the residential, commercial, industrial sectors that result from the National Appliance Energy Conservation Act of 1987 and the Energy Policy Act of 1992.

COMMISSIONER ROGERS: The '98 figures, do they include any aspects of deregulation?

MS. HUTZLER: No.

COMMISSIONER ROGERS: Is that just a separate issue?

MS. HUTZLER: Separate issue, exactly.

In terms of the annual expenditures that electric utilities are spending on demand side management, you'll see in 1990 it was $1.3 billion and that is to increase to $3.9 billion by 1998. That's a 15 percent annual growth rate.

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MS. HUTZLER: Moving on to the next chart, you'll see our forecast for cumulative additional capacity that is needed to meet demand after we have dealt with non-utilities, imports of electricity, increasing the utilization of existing plants and also dealing with life extension.

As you can see from this chart, turbines and combined cycle units are increasing the fastest in the earlier period of time due to the need for cycling and peaking capacity. Later on in the forecast horizon, and that's after 2005, you'll see the need for base load capacity and therefore coal enters into the picture. Our electricity sales growth rate is about 1.1 percent. In this chart we're adding about 135 gigawatts of capacity, of which

55 are planned by electric utilities. That's about 40 percent of the total.

In terms of the distribution by ownership type, we see about 58 percent being electric utility owned, about 41 percent being non-utility owned, and 12 percent coming from co-generation. In terms of types of capacity, turbines represented about 50 gigawatts, combined cycle about 30, coal about 30, renewables about 20. And nuclear, we're assuming that Watts Bar 1 and 2 both will come on this forecast. We will revise that in our next forecast, looking only at Watts Bar 1. But in this forecast, we have both of them coming on-line.

CHAIRMAN SELIN: The combined cycle role is gas-fired

MS. HUTZLER: Yes.

COMMISSIONER ROGERS: And what's in turbines now?

MS. HUTZLER: The number of turbines we have now?

COMMISSIONER ROGERS: No, I mean what's included in that turbine category. It's not combined cycle.

MR. BEAMON: Just simple cycles.

MS. HUTZLER: Simple cycles.

MR. EYNON: Mostly fired with natural gas.

COMMISSIONER ROGERS: Okay. But they are natural gas.

MS. HUTZLER: Let me just mention here that we've looked at the difference in capacity needs when we charge our assumption in electricity growth rate. We did a high demand case this year where we had demand growing for electricity at an annual rate of 1.9 percent. What we found there is that we would need 261 gigawatts of capacity. So, with a change in the annual growth rate for electricity of .8 percentage points, we get 126 gigawatt static capacity. We tend with higher demand to need more baseload capacity.

COMMISSIONER de PLANQUE: Can you tell us a little bit more about the basis for seeing no need in the nuclear category?

MS. HUTZLER: Because of uncertainties in the nuclear area, it's essentially an exogenous assumption that we're saying that there's no need for new capacity. In next year's forecast, we're going to 2015. We will be competing in on economics. But there still are a lot of uncertainties dealing with cost, disposable waste and all of those issues.

COMMISSIONER de PLANQUE: What are you considering the lead time on construction of a baseload coal plant right now?

MS. HUTZLER: It's about seven or eight years.

MR. BEAMON: Yes, seven years with licensing and all that. We're currently looking at all of those because if you look at recent history, those things have been changing for everybody because everybody recognizes that you're not going to build a plant that takes you seven or eight years to build, not in a deregulated market. You're going to have to change. Some coal plants would come on it in 36 months and non-utilities have brought them on in the last few years.

CHAIRMAN SELIN: Say this again.

MR. BEAMON: I said some coal plants have come on in 36 months. U.S. Gen has brought a couple on that quickly. So, people are making adjustments because the market is going to force them to. So, we're going to have to look at all of these numbers.

COMMISSIONER de PLANQUE: That would indicate that the time interval is not so much dictated by regulation as by the efficiency of construction. What's the difference?

MR. BEAMON: Perhaps if they were built by non-utilities, perhaps they were able to do it outside of some of the regulatory issues. I'm not sure. They're also smaller. Coal plants which were averaging 600 megawatts a decade ago, even for utilities now are down around 400 and non-utilities are brought on in the 250 to 350 range. So, they're all coming down in size and I think they're trying to take advantage of factory construction, doing as much as they can off the site and bringing it in, doing it just like they've done with some of the other types of units.

MR. EYNON: It's clear that the construction time is separate from the licensing and permitting time and for large capital investments, whether they are nuclear plants or coal plants, shrinking that time would make those assets more desirable from an economic standpoint for construction.

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MS. HUTZLER: Okay. The next chart shows the distribution over time of capacity editions by non-utility and utility generators. Essentially in the current decade, 1980 to 1990, we see about 19 percent of the capacity editions being added by non-utility. By the 2000 to 2010 arena, about 76 percent is being added. So, it just shows the changing industry structure.

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MS. HUTZLER: The next chart that you have in your packet I wasn't going to talk about. There's a number of errors within that chart. I mentioned the mean highlight which is that in the high demand case we do have higher additional capacity needs of -- it's really 261 gigawatts. The number on the chart that you have there is incorrect, and the reason for that higher amount of capacity needs.

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MS. HUTZLER: Moving on to the next chart, we see electricity generation by fuel. Here again you'll see that coal remains the dominant fuel in the future and that it's supplying 50 percent of our generation requirements. Gas is becoming the second greatest and surpassing nuclear by 2010, where gas represents 18 percent of total generation. Nuclear is representing 16 percent in the year 2010. We get a slight increase from renewables and a slight increase from oil.

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MS. HUTZLER: The next chart shows our generating capacity from renewable fuels, excluding hydroelectric. The major story here deals with the growth in wind capacity. After 2005, there is a large increase in wind capacity, mainly due to improved technology, higher fossil fuel prices, increased capacity needs from utility generators and also externality costs that we have embedded in a number of the fossil fuel plants based on state regulations. In the earlier years, wind increase is due to state set asides. For instance, California has about one gigawatt of capacity coming on-line. Minnesota, about .4 gigawatts of capacity.

In terms of the other renewables, we don't get as much growth. Geothermal increases by one and a half gigawatts. That's mainly in the west. We do have some growth in MSW because it serves as a source of baseload power and also because it provides a means for disposal of waste. Biomass and solar just make very small contributions.

COMMISSIONER ROGERS: Well, that curve, the wind curve, always excites interest because it is so dramatic and so much in the future. You've got a couple of break points in there that have to come from some assumptions about something happening. I wonder how much of this is really guesswork. What is the foundation for this kind of a dramatic takeoff of wind power?

MS. HUTZLER: Actually a number of things, of course. First of all, we do model technologies, we do represent their capital costs, we do represent their learning over time and how those capital costs will decrease. In terms of wind, we do see substantial learning as you get penetration of that technology within the market. Our numbers are essentially based on the Electric Power Research Institute's technology assessment guide.

The other major reason deals with natural gas prices rising in the post-2005 period. Because of that, we get room for wind to expand in that time period. Now, all of this is helped because of the state set asides. The fact that states are saying that wind technology will be coming on-line and allowing for that gets market penetration that helps it. Without that you'd also see a lower wind penetration in the out years.

COMMISSIONER ROGERS: But if you are talking about a deregulated electricity system where wind has to compete with everything else --

MS. HUTZLER: You're right.

COMMISSIONER ROGERS: -- there are big questions about whether something as dramatic as this is going to --

MR. SITZER: If the set asides go away, this line will be considerably different. We did assume the set asides.

MS. HUTZLER: Right. And I will talk about that a little later and about a deregulated market where we do see set asides going away. But you would not see the same growth in that case.

MR. BEAMON: It looks dramatic. We also need to look at the scale of the chart.

COMMISSIONER ROGERS: Oh, I know.

MS. HUTZLER: Yes. We're seeing -- it's 10 gigawatts by 2010, but it is almost doubling of our current capacity levels.

MR. SITZER: And gas is also allowed to compete as a fuel saver. In other words, it's assumed it can be built without necessarily contributing to the reserve margin and that helps wind at the end as gas prices go up.

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MS. HUTZLER: In your packet, I'd like to take the second chart rather than the next chart that you have first. This chart shows the changing age profile of nuclear units over time. As you can see, the average age of nuclear units is currently less than 20 years, if you take a look at the 1993 bar, and by 2010 most nuclear units will be at least 20 years of age. In a reference case, as I mentioned, we're retiring 12.7 gigawatts of nuclear units. That's total of 17 units.

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MS. HUTZLER: I wanted to set the stage for the next graph where we talk about the operable new nuclear capacity under three different sets of assumptions. In the high nuclear case, we're assuming that only two units would retire by 2010, that there would be essentially five years of additional operation beyond their license expiration date.

COMMISSIONER ROGERS: What do you mean by that? I saw that in your report. Is it five years just to carry you out to 2010? If somebody renews their license, there's no good reason to believe they're only going to renew it for five years, is there?

MS. HUTZLER: We agree. It's just an assumption so that we can take a look at three different sets of cases. If you did it on an individual basis, you'd be looking at it very differently.

COMMISSIONER ROGERS: Yes.

MS. HUTZLER: In the low nuclear case, we're assuming that 52 units would retire and that they would be retired five years before their license expiration date. Essentially what these cases tell us is that we would see coal, combined cycle and turbines replacing the retiring nuclear units. In the low case, low nuclear case, we essentially get approximately one additional quadrillion BTU of oil and natural gas than we did in the reference case and about 35 million metric tons of carbon emissions higher than the reference case numbers, which is about a six percent increase. In the high nuclear case, it's just the opposite in the sense that we see a decrease of fossil fuels but about a half of quadrillion BTU decrease and carbon emissions are reduced by 11 million metric tons. This is to supply some analysis on what a different profile for nuclear units would do.

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MS. HUTZLER: The next chart shows carbon emissions by sector. As I said earlier, we did incorporate the climate change action plan. However, the impact that we saw after we took a look at the funding picture and the impact that our models show of the programs, we get only about a reduction of 12 million metric tons in carbon emissions in the year 2000. So, as you can see from this graph, we're increasing our carbon emissions by about 20 percent from 1990 to 2010. The growth rate is .9 percent and that's similar to the growth rate that we're assuming in population over this time period. The electric utility industry represents one-third of the total carbon emissions in 2010. The largest growth rate, however, is in the transportation sector which has a growth rate of 1.3 percent per year.

There are a lot of uncertainties in this forecast, and of course the most important is restructuring and deregulation and what that would do on the industry. Unfortunately, we have not modeled what deregulation would do.

We have done some sensitivity analysis where we have taken all of the different assumptions in the electric utility modeling effort that we have and we've tried to figure out along with the policy people in the Department of Energy where we think we might see changes. Some of those changes deal with units with lower operating costs should become increasingly more valuable in a competitive environment and as a result we would see them operating more. We looked at an assumption where the capacity factor for coal plants, rather than having a max at 68 percent, would have a max at 75 percent.

Also, we changed our interregional transmission constraints and we increased those by 25 percent. Another assumption we made was that we would retire nuclear units at 35 years of age. Now, again, this is a simplifying assumption to try to deal with the high cost nuclear units. We did not look at them individually. We also took away the set asides for renewables. We made other assumptions dealing with reserve margins in a competitive environment. Utilities would not maintain the high reserve margins they have today, ranging from 15 to 20 percent depending on the regions, that they in fact would be lowered by -- and this again is an assumption -- two percentage points in each region.

We believe that there would be increased risk to build and operate new plants and so we assume that the cost of equity to investor-owned generators would be raised by two percentage points. As a result, the cost of capital would increase by approximately one percentage point, from 9 percent in our reference case to 10 percent in the year 2000.

Another big factor --

CHAIRMAN SELIN: That's really cheap, you know. It's just amazing that people keep putting capital in when industry has got such a low historical return on it, particularly -- well, I guess you haven't really modeled the deregulatory environment.

MS. HUTZLER: No.

CHAIRMAN SELIN: So, the assumption would have to be that return would have to go up but the margin for people that continued to invest if they were in awe of the regulatory production.

MS. HUTZLER: We also assumed that in a deregulated market we would be seeing lower prices for electricity. The reasons why there would be lower prices, first, would be the utility's inability to fully recover the cost of expensive generating plants, i.e. the stranded assets issue. Second, that high priced purchase power contracts, that is take or pay contracts, would probably be renegotiated. Third, that lower overhead expenses would mean that utilities would reengineer and downsize, consolidate and streamline. And fourth, that there would be reduced DSM expenditures in a deregulated environment.

What we did in trying to figure out how this would change revenues was we took a look at the long-run marginal cost of service for generation being the levelized cost of a new natural gas fired combined cycle plant operating at a 60 percent capacity factor in each region. Then we compared, based on data, what the costs were against that cost and we estimated what the stranded assets would be. We actually found that the lost revenues would be somewhere around $30 to $35 billion per year. We also assumed that the fixed general and administration expenses would be lowered by 20 percent in each region and those were the two major assumptions we made to take a look at lower electricity prices.

Essentially, we also made another assumption and that is rather than using the demand models that we operate, we assumed that the demand elasticity with respect to price would be minus .3 for this particular exercise. Essentially, that resulted in an increase in electricity demand of about six percent in 1995. The major differences in this particular scenario from what we've told you about in our reference case is that there would be less nuclear and less renewables. We have an increased use of fossil fuels and therefore we'd have higher carbon emissions. We also took a look at a phase-out in that electricity price. There are believers who believe that by 2010, because of depreciation, that these stranded assets would essentially not affect price, so that price would be nearer the normal 2010 levels that we were predicting. So, essentially, that would have no impact on demand in the out years, where in the case of the stranded assets not being phased out, it would have an impact and we'd see electricity prices lower in 2010 by about one cent per kilowatt hour.

As I said, this isn't really representing a deregulated market in its entirety, it's just taking a look at some assumptions that we think would impact this particular area. Other uncertainties within the reference case deal with demand growth. We can envision different worlds depending on appliance standards, stock turnover and that kind of thing. So, demand could be growing at different rates than we have predicted in the reference case. There is also a lot of uncertainty in gas and coal prices and whether they would be fairly constant or they would increase at the rates that you see them in our reference case.

Technological development is also a major uncertainty. Obviously that effects efficiencies and also the amount of pollutants that you might see. Also, the climate change action plan has a big impact. If, in fact, rather than the involuntary program we see more stringent standards being implemented to meet stabilization of carbon emissions, that would really impact the electric utility industry.

Finally, the impact of efficiency standards can make a difference in DSM programs and what utilities do there.

We will move on to the regional forecast, unless you have any other national questions.

COMMISSIONER ROGERS: Well, you mentioned that interregional transmission constraints -- you mentioned the topping and I wasn't clear which way that was going to go and where it was coming from and what the effect is in your model.

MS. HUTZLER: Okay. We allowed additional interregional transfers in the deregulated case and essentially we have bounds on the amount that's allowed now and we increase those bounds by 25 percent.

COMMISSIONER ROGERS: It sounded like you were increasing.

MS. HUTZLER: The other way.

COMMISSIONER ROGERS: I think you said increasing the constraints, but maybe not.

The thing is the $30 billion number for stranded assets, how does that compare with other estimates that other people have made?

MR. BEAMON: As you know, they're all over the board. But what we tried to do was we tried to figure out what a marginal clearing price would be in the market by using a combined cycle at 60 percent and then look and compare that utility by utility to their embedded cost. And then using their current demand, we could figure out what revenues they wouldn't be able to recover and that's where we got the $30 billion. We also go on the order of 10 or 12 billion utilities that are going to be in a good situation too, whose current prices, embedded prices is substantially below what the market might be.

So, I think one of the biggest differences when you see all the wide range of numbers is how they treat, whether they go unit by unit and only count the guys that are negative or whether they do utility by utility or region by region and count the fact that some of them, there's going to be some companies that are going to be in a good situation. They're going to be able to make a higher price and I think that's where you get the big range in asset and differences. Other than that, I don't think that our numbers are all that much different.

It's real difficult to translate it back into physical assets. We haven't tried to do that and we've taken the approach that FERC has laid out recently about using a stranded revenue more than a physical asset approach.

MS. HUTZLER: Okay, Bob.

MR. EYNON: I'd like to talk for a few minutes about the regional forecast. As you may recall, the national results that we have here are predicated on representing individual NERC regions and subregions. So, we have a total of 13 regions that make up the national forecast. I'd like to maybe focus on a handful of those in terms of their interest, particularly from a nuclear perspective or from the standpoint of the anticipated growth rates for electricity.

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MR. EYNON: The first chart shows you New York as a region. New York is of particular interest because it is one that is more dependent on oil and gas capacity than the nation as a whole. It also has a large share of its generation which is from nuclear power. Over our forecast horizon, we see growth in New York lagging the rest of the nation, growing at about .5 of one percent versus the nation of 1.1 percent. At the same time, we have a couple of nuclear plants that are retiring. Nine Mile Point 1 and I believe it's Ginna are both retiring in 2009 and that has an impact on our forecast in 2010.

If you look at this chart in terms of the composition of electricity that will be provided in 2010, we see that although utilities are increasing generation internally, we also see a healthy chunk of generation which is going to come from non-utility sources. New York is also of interest because it is somewhat dependent on power from outside the country, principally from Canada or exclusively from Canada as far as imports are concerned. We see 4 billion kilowatt hours of additional power coming from Canada.

In terms of the increased generation in New York, we expect that both the contribution from utilities and non-utilities will be coming from a combination of renewables and existing oil-fired steam plants. So, the existing stock of plants will be used more intensively and we expect renewables to make up the offset from nuclear retirements and a slight reduction in coal also reflects retirements. The composition of the renewables includes both increased conventional hydroelectric as well as small amounts of biomass, MSW, which is municipal solid waste, and a small amount of wind.

If we turn to the next chart, we have a similar story for New England, again an area where sales growth is expected to be rather modest, well below the national average. In this case, most of the additional generation is expected to come from non-utilities. Utilities are not expected to increase their contribution to meeting total demand virtually not at all. Here we have nuclear retirements that include Haddam Neck, Maine Yankee and Millstone 1. So, the nuclear share of generation declines more precipitously than even in New York.

To make up for this loss of nuclear capacity we have increased generation from natural gas, mostly from non-utility sources, increased use of oil in steam plants that are utility owned, as well as additional renewables. The same mix of renewable sources are included in New England. We have hydroelectric poundage, hydroelectric MSW, biomass and wind.

Flipping to the next chart, we go from the eastern part of the country to the west. If we take a look at the northwest, an area where we expect growth to be above that of the national average, growing at 1.3 percent a year compared with the national growth of 1.1 percent. We see that an appreciable part of the new generation will come from utility sources with a small but real increase in non-utility sources.

Natural gas plays an important role in this region, growing for both utility and non-utility generation in both combined cycle and turbines. We have a modest reduction in nuclear because of the retirement in 1993 of Trojan. Renewable sources are increasing. Most of those renewables in this case are hydroelectric. Increased use of the in-place hydroelectric sources as well as the geothermal contribution.

Moving down the coast a little bit to California, we have retirements here of Diablo Canyon 1 and 2 close to the end of our forecast horizon. By the way, that's the chart after the one in your packet. We see here where utilities actually contribute less to meeting their demands in 2010 than they provided in 1993. The additional demands are being met by non-utility sources as well as increases in imports. The offset for Diablo Canyon is increased coal generation from both utility and non-utility sources as well as decreased gas generation. The decreases in gas generation in California here represents declines in inefficient steam plants rather than increases we see in gas consumption that occur in other regions because of increased turbines and combined cycle plants. So, existing gas steam plants are used less intensively than they are today.

The renewables contribution in this region is composed of geothermal sources as well as smaller amounts of biomass, increases in solar and in wind, again relatively modest compared with the natural gas increases.

The final region I'd like to talk about is the Mid-Atlantic Coordinating Council. If you flip down in your charts, it's the third one, I believe, in your handout.

[Slide]

MR. EYNON: In this region we have an appreciable retirement of nuclear plants and we have nuclear share declines. Although coal continues to support the region, we have an increase in gas consumption, gas share both from utility and non-utility sources, and slight increases in the renewables. As with the other regions, utilities are building less capital intensive projects and planning to meet demand other than adding more baseload capacity from either coal or nuclear.

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MR. EYNON: If you would turn to the next to the last chart in your packet, it provides us with some information on what we might expect to see beyond 2010. It takes a look at the retirements of nuclear capacity that we would project in 2010 as well as --

CHAIRMAN SELIN: This is just 40 year life, I assume?

MR. EYNON: Yes, the same assumption of 40 year life limits, 40 years where we have both life extension as well as premature retirements. If we assume an average life of 40 years, we see here that there are a number of regions where a significant amount of capacity will be retired, particularly in the time period after 2010. Until 2010, as we indicated, there are perhaps a little less than 13 gigawatts retiring, but we have an appreciable amount of capacity, something like 39 gigawatts of capacity total that would be retired by 2015.

CHAIRMAN SELIN: This is a precise but incorrect chart. The best predictor of retirement, I think, is going to be projection of price and operating cost rather than periods of investment. With the license renewal rule, there's nothing magic about 40 years. Plants will close down sooner and it will go beyond that.

MR. EYNON: This represents essentially a mechanical exercise that's saying on average if plants operate at 40 years, what can we expect the nuclear contribution to be in the post-2010 period? Where we see about 13 gigawatts of capacity retiring by 2010, we have a total of 39 gigawatts that would be unavailable to certain needs in 2015.

CHAIRMAN SELIN: A big benefit to us in your analysis is not this part but it's everything else which has -- I mean since nuclear is such a small share in most of these regions, a little more, a little less nuclear capacity is not going to drive the price very much. So, we can just take the price projections and the demand projections as given, sort of independent of what happens to the nuclear plants and then take a look at the plants and say, "Which of these plants would be competitive in the environments that you predicted?" That would give us probably the best single insight that we could get about likely retirement.

MR. EYNON: That's correct. Generally that does characterize the nation. If you flip to the next chart, though, it does provide us some information on how nuclear contribution is important to particular regions.

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MR. EYNON: If we look at this chart on the darker lines that are shown, we can see that in four of the regions of the nation, fully two-thirds to 100 percent of the nuclear capacity would be retired by 2015 under the assumption of a 40 year average life. For these particular regions then, nuclear is an important issue and the replacement of that power would have to be addressed in that time frame.

CHAIRMAN SELIN: My point is a little different. In places where nuclear is above say 20 or 25 percent of the mix, what happens to nuclear plants would affect the supply and the price. The rest of the country, we could just take the supply and prices fixed from your projections and then see which plants would be tenable without having to do the feedback and say, "Well, if these plants close, what's that going to do to the price?" So, that's very helpful, extremely helpful.

MR. EYNON: That concludes the discussion of the regional forecasts.

CHAIRMAN SELIN: What are you going to do next year with the deregulation? You had some qualitative comments, but what do you propose to do in the actual analysis of both assuming different amounts of deregulation or conversely doing your projection and say what would that tell you in terms of the opportunity for deregulation?

MS. HUTZLER: Well, first of all, our hope next year is to extend the forecast to 2015 since we're coming so close to only a 15 year horizon right now. We are not able at this point in time to modify our modeling capability to really restructure the industry for a number of reasons. One is we still don't know how that's going to happen. So, at this point in time, we're just looking at various sensitivity analysis off our reference case and we hope to take a look at certain parameters, some of which I spoke to you about today, and include some of that in our Annual Energy Outlook.

At this point in time, we don't know yet, based on resources, whether we'll be able to accomplish that or not, but that's our first step. Hopefully in the next couple of years we'll be able to figure out how our restructured market might work and be able to start modeling that.

MR. EYNON: Some of the scenario analysis that we're doing will give us an indicator of which parameters are most important in affecting our forecast. For example, the cost of capital assumption or perhaps a treatment of stranded assets will be the big ticket items that our model responds to. We would orient our analysis to capture uncertainties in those parameters.

CHAIRMAN SELIN: The second thing, last year you had an interesting chart which compared your projections with everybody else's projections. Do you still have that?

MS. HUTZLER: Yes, we have it in our Annual Energy Outlook. Essentially, we're showing less demand for electricity than other forecasters are. That's the major difference. I would say in terms of the split of capacity types, we're probably fairly similar, but we do have less demand.

CHAIRMAN SELIN: And more generally the price for these different fuels, not for electricity but the price, the energy prices, how do you compare with the other --

MS. HUTZLER: Other forecasters right now are also reducing their fossil fuel prices and some have come out since our publication with vastly different fossil fuel prices, lower gas prices, and, in fact, declining coal prices from today's levels. So, there are some interesting forecasts out there. We're also going to be reviewing those again for next year. So, you may, in fact, see lower prices from us as well, but we haven't done that analysis yet.

CHAIRMAN SELIN: Commissioner Rogers asked how the projections have looked compared to what has actually shown up. The one thing that's been true is gas prices have always been lower than everybody's projections for them. I don't know why.

MS. HUTZLER: There are some people who now believe that gas will be a commodity and should be priced as a commodity rather than as dealing with the resource base as we represent it. So, there are vastly different issues being discussed now than --

CHAIRMAN SELIN: It's just the curve and they figured for given prices people will find the gas. That's interesting.

Commissioner Rogers?

COMMISSIONER ROGERS: No. I just thought it was a very interesting and excellent presentation. Thank you.

CHAIRMAN SELIN: Commissioner de Planque?

COMMISSIONER de PLANQUE: With respect to the increases that you project in international imports, should I assume that your projections are consistent with the available capacity projected by the Canadians, for example?

MR. EYNON: We've done essentially an economic analysis of the projects that have been proposed in Canada and the forecast that we have provided essentially are driven by a combination of both economy sales and firm power sales. The sales post-2000 represent the development of some projects in Canada which would be competitive given the costs that we have to develop those projects. In the post-2000 time frame when capacity is needed, particularly in those regions such as New England and New York, it becomes economic to develop those projects.

COMMISSIONER de PLANQUE: But is that consistent with the Canadian electricity need, that this capacity will be available for export?

MR. EYNON: We assumed that the development of those projects at least initially would be dedicated to provide power to the United States. We have not really specifically addressed the growth of electricity in Canada. We've essentially made an independent decision. We do not have a North American model that represents the needs of both Canada and the United States.

COMMISSIONER ROGERS: They have a big over capacity right now.

MR. EYNON: That's true.

COMMISSIONER de PLANQUE: Okay. Thank you.

CHAIRMAN SELIN: Commissioner Jackson?

Thank you very much. It's very interesting. It's always nice to see you. It's very helpful. If you make a major shift to commodity base, that will be really very, very interesting.

MS. HUTZLER: I don't see us doing that in the near future, but we are going to start examining that issue looking at workshops and talking to experts who purport that particular type methodology.

CHAIRMAN SELIN: I really don't think your gas price is right. It's just not possible for the gas to be so much cheaper now than we thought it would be and yet go out ten years and see no impact on the long-term projected price. If you thought there was a given supply, actually the price would go up because it would be drawing down the gas faster. But it doesn't seem right.

Thank you very much.

[Whereupon, at 11:25 a.m., the meeting was concluded.]

CERTIFICATE

This is to certify that the attached description of a meeting of the U.S. Nuclear Regulatory Commission entitled:

TITLE OF MEETING: BRIEFING ON ELECTRICITY FORECAST FROM ENERGY INFORMATION (EIA) ADMINISTRATION ANNUAL ENERGY OUTLOOK - PUBLIC MEETING

PLACE OF MEETING: Rockville, Maryland

DATE OF MEETING: Thursday, June 1, 1995

was held as herein appears, is a true and accurate record of the meeting, and that this is the original transcript thereof taken stenographically by me, thereafter reduced to typewriting by me or under the direction of the court reporting company

Transcriber: Carol Lynch

Reporter: Peter Lynch

Electricity Supply and Demand Through 2010

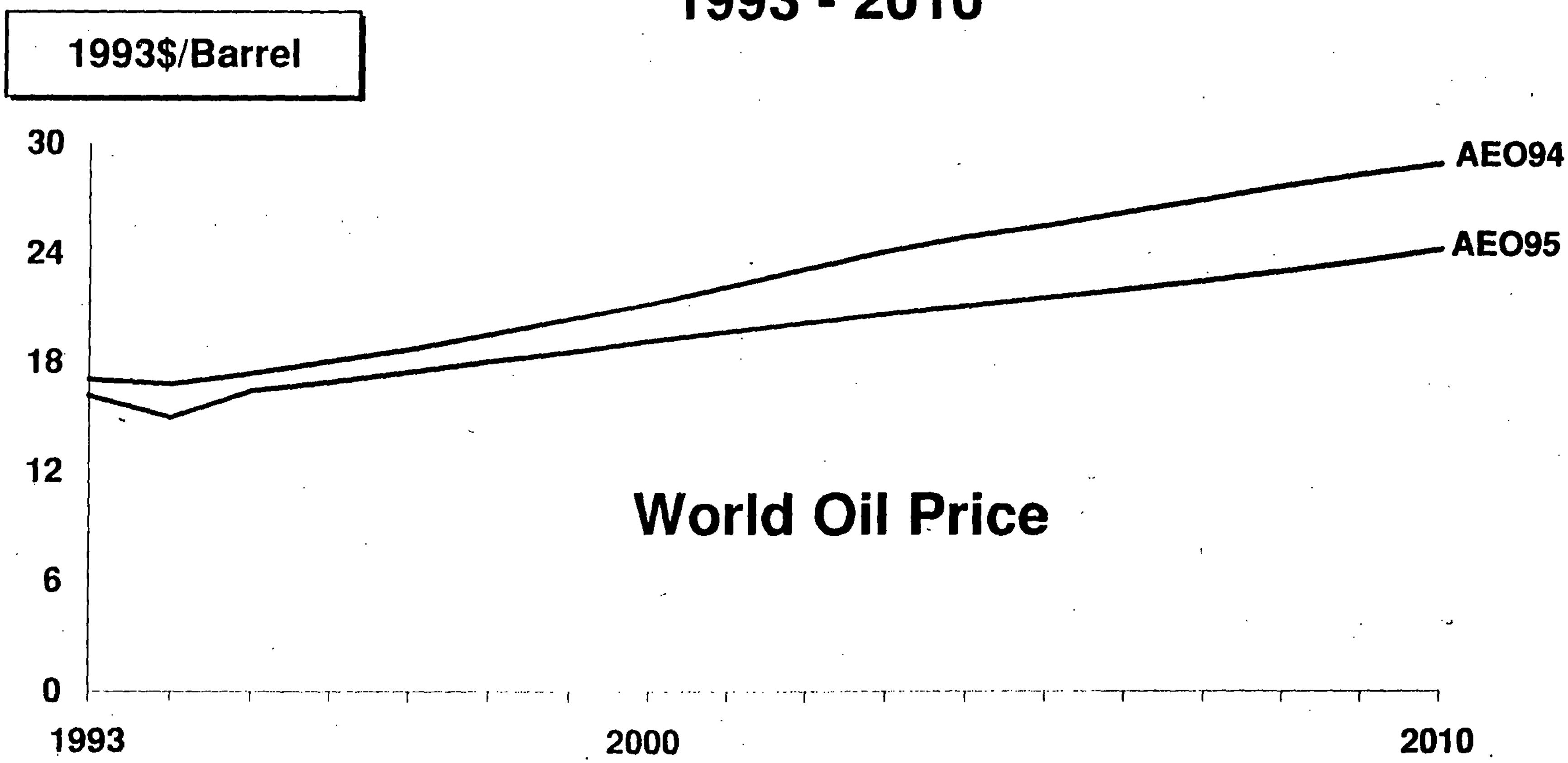
Presented to the

Nuclear Regulatory Commission
June 1, 1995

Briefing Agenda

- Major Assumptions
- National Electricity Supply
- Regional Electricity Review
- Uncertainties

Fuel Price Projections
AEO94 and AEO95 Compared
1993 - 2010



Fuel Price Projections
AEO94 and AEO95 Compared
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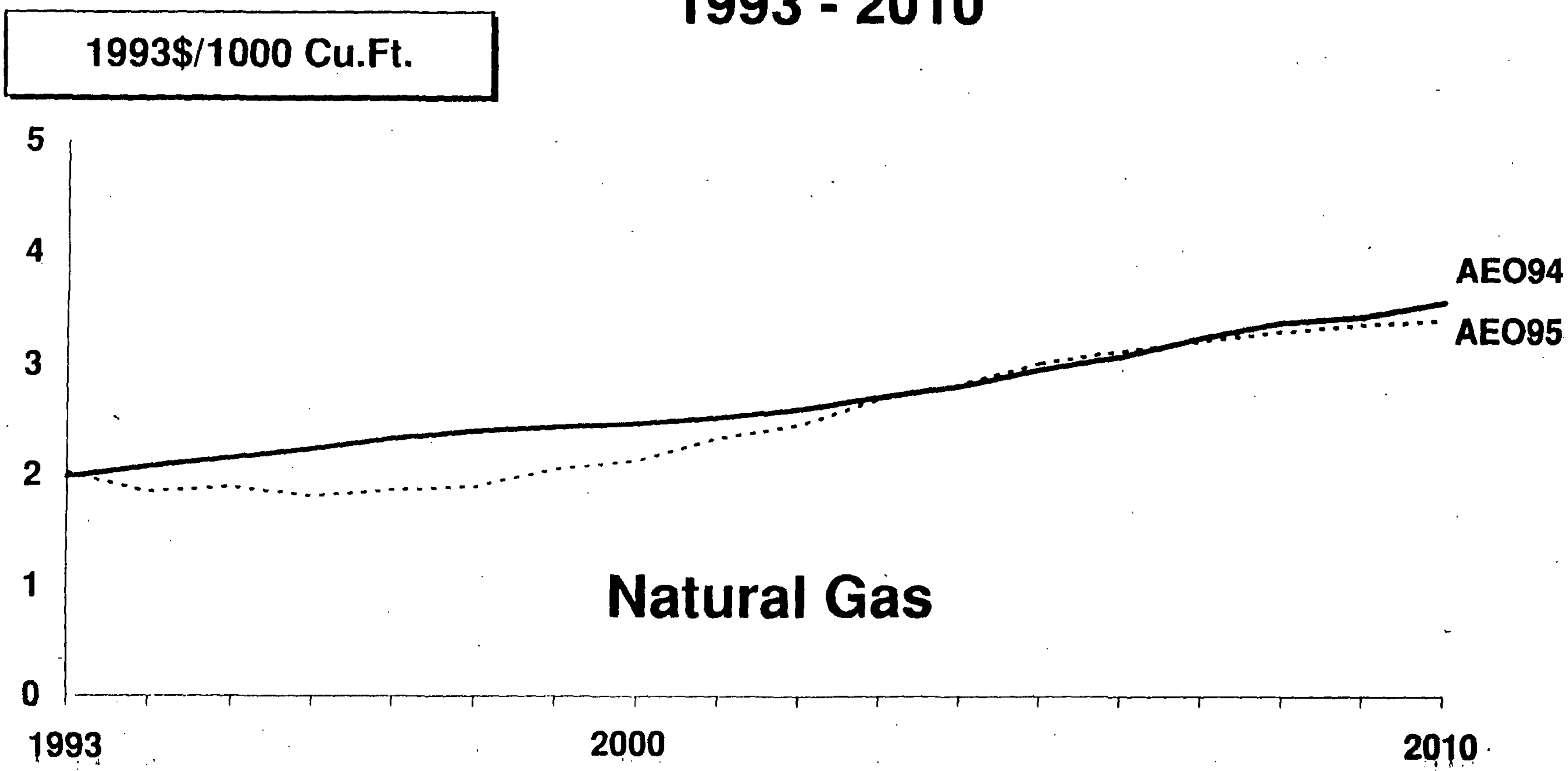

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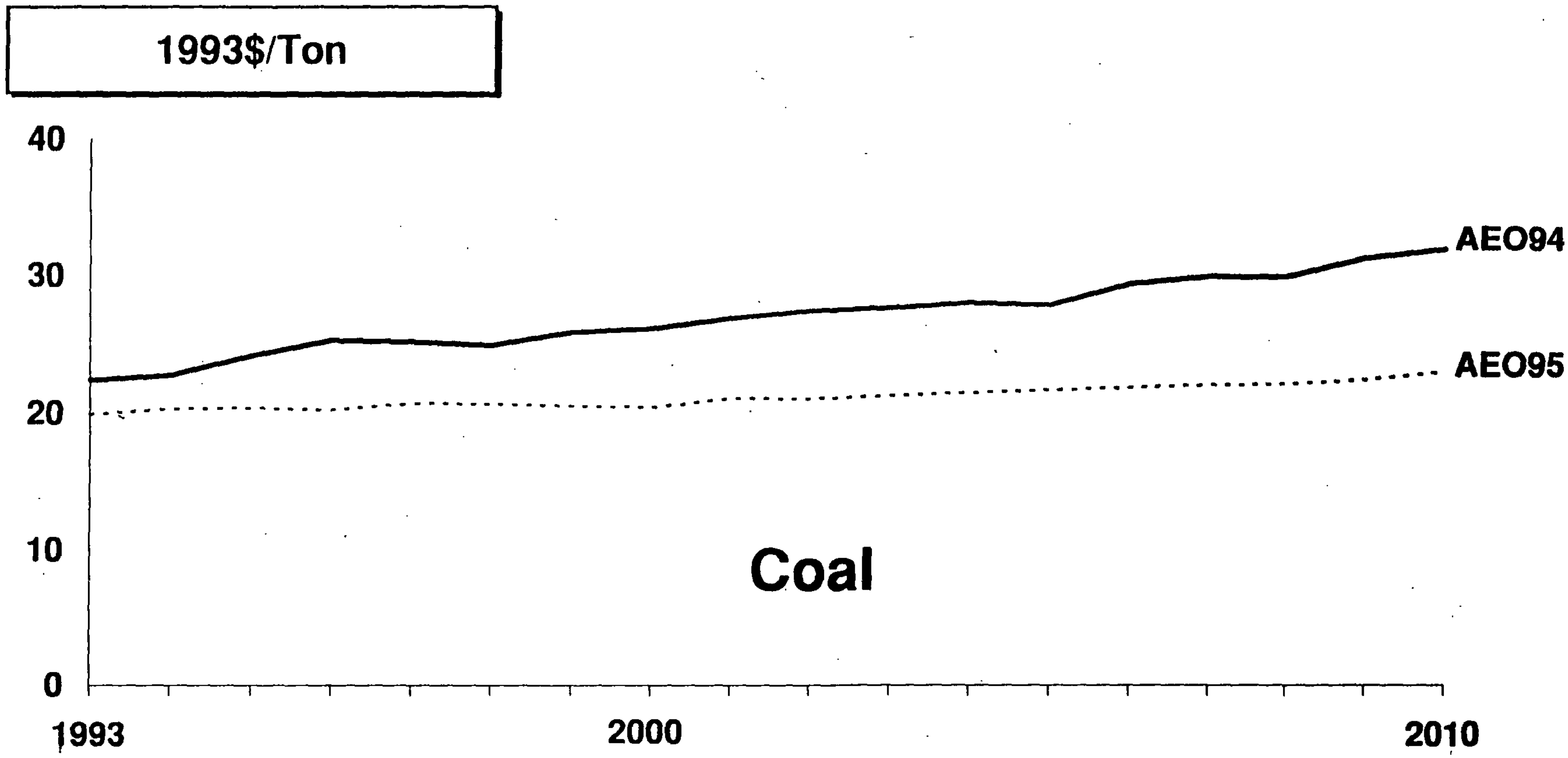

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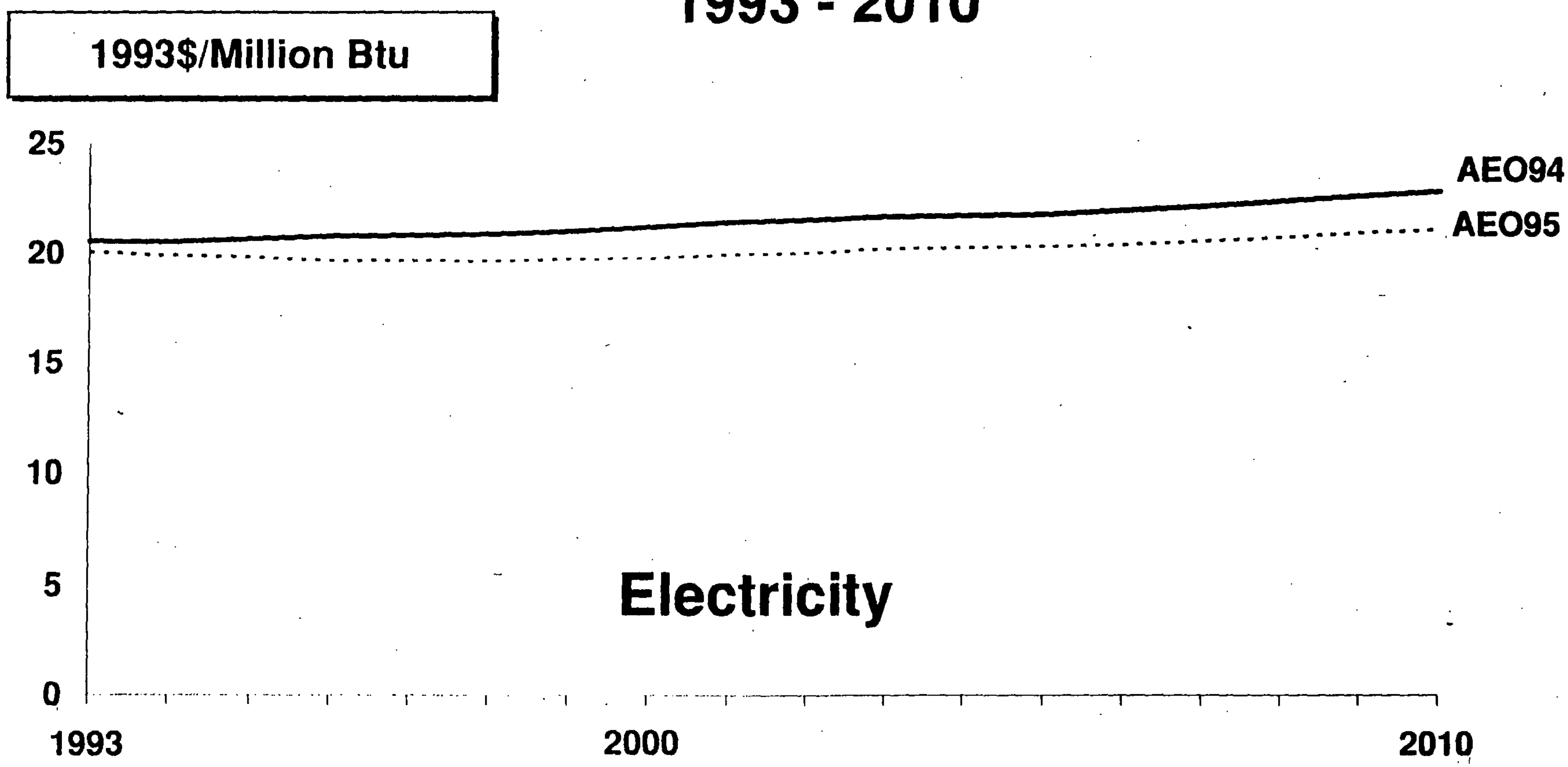
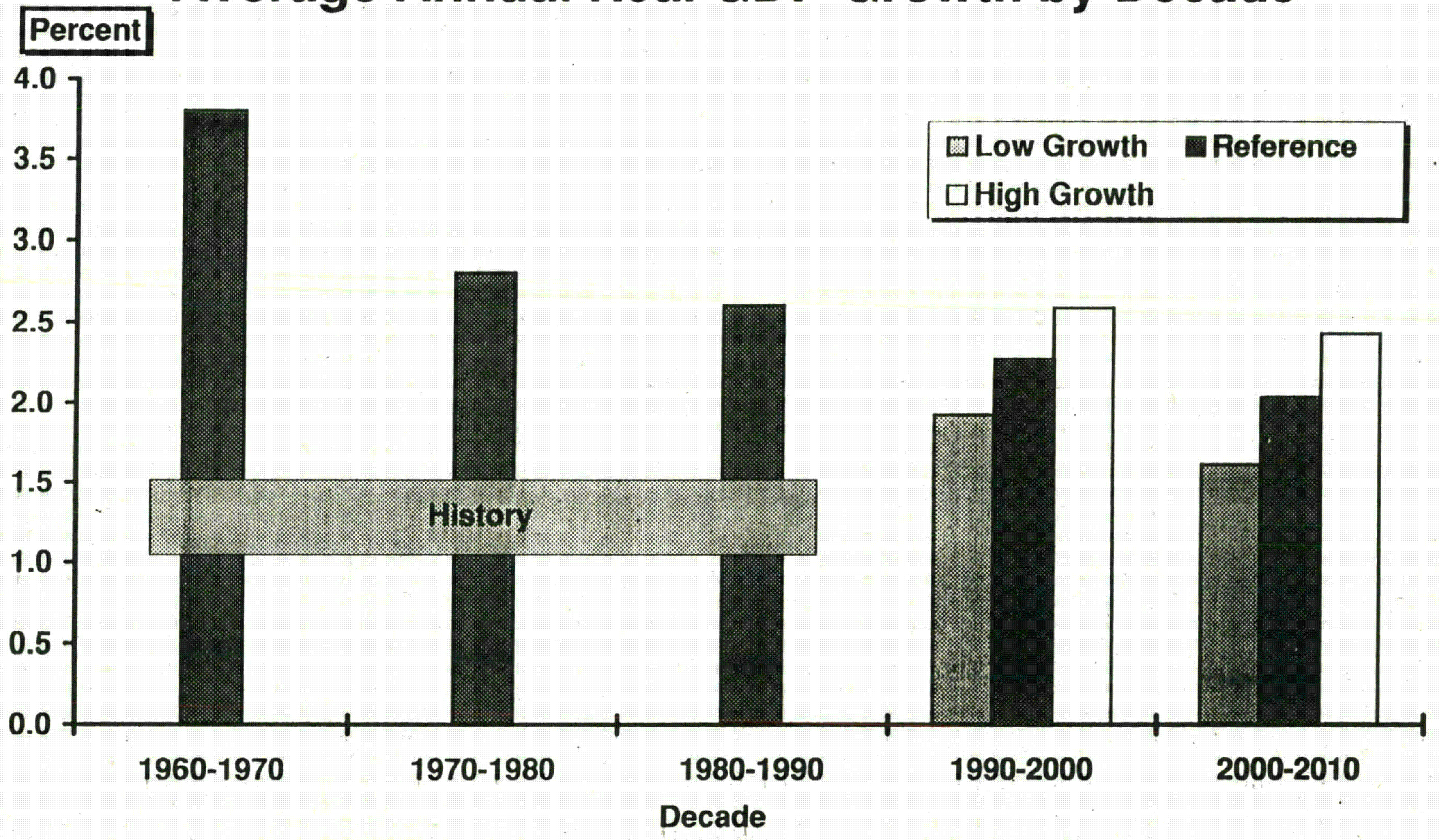


Average Annual Real GDP Growth by Decade



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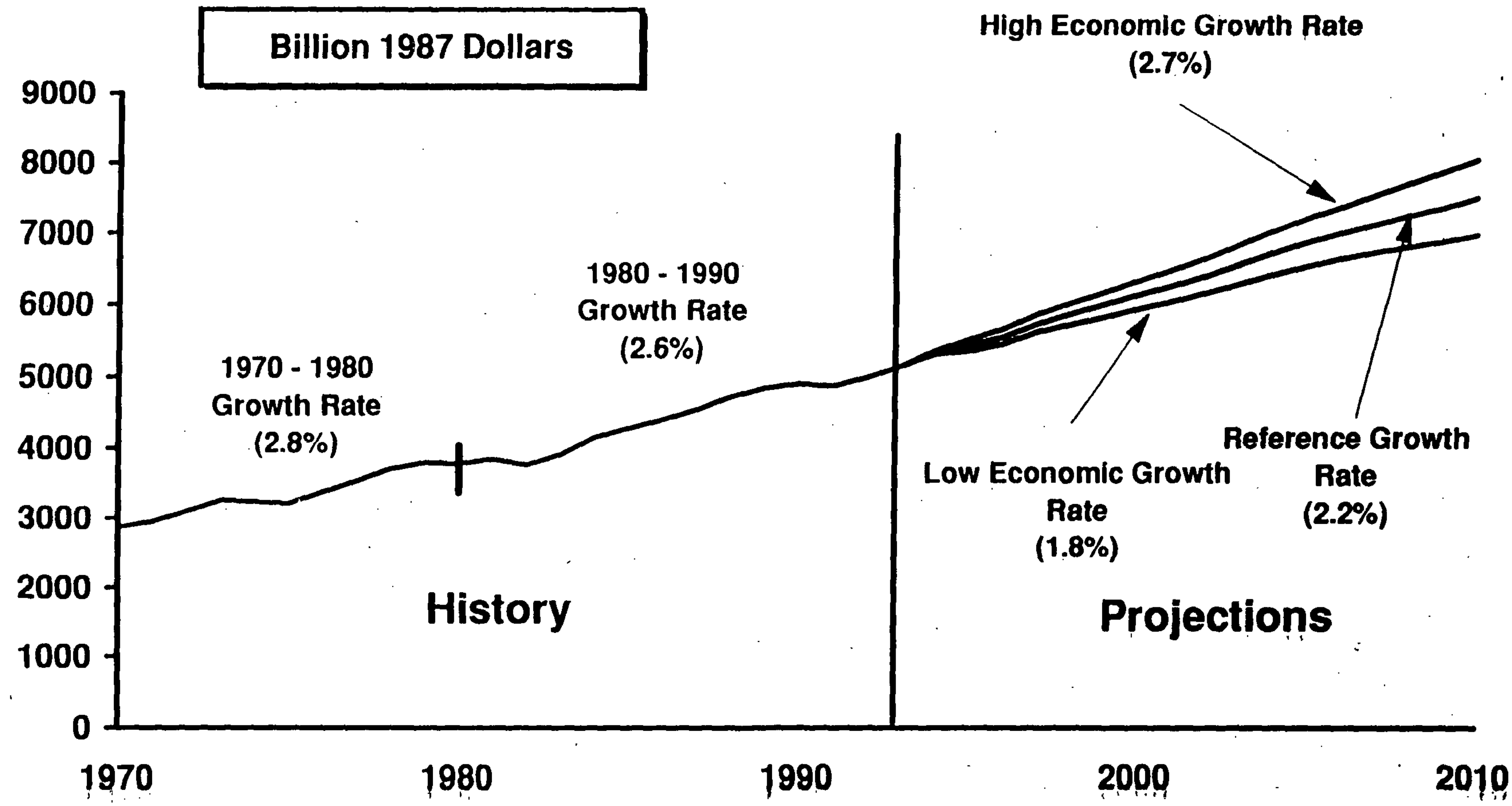
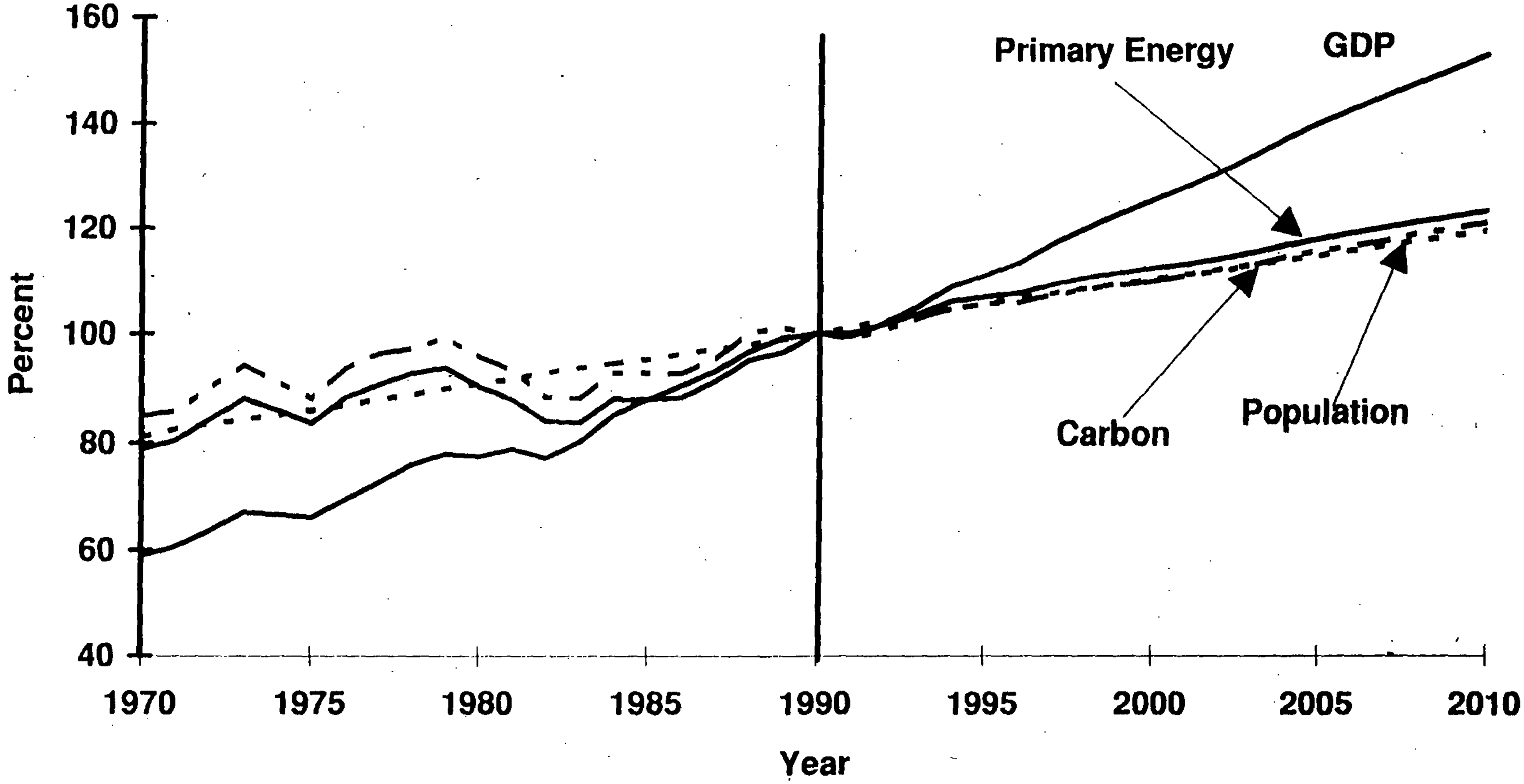
U.S. Gross Domestic Product
1970 - 2010

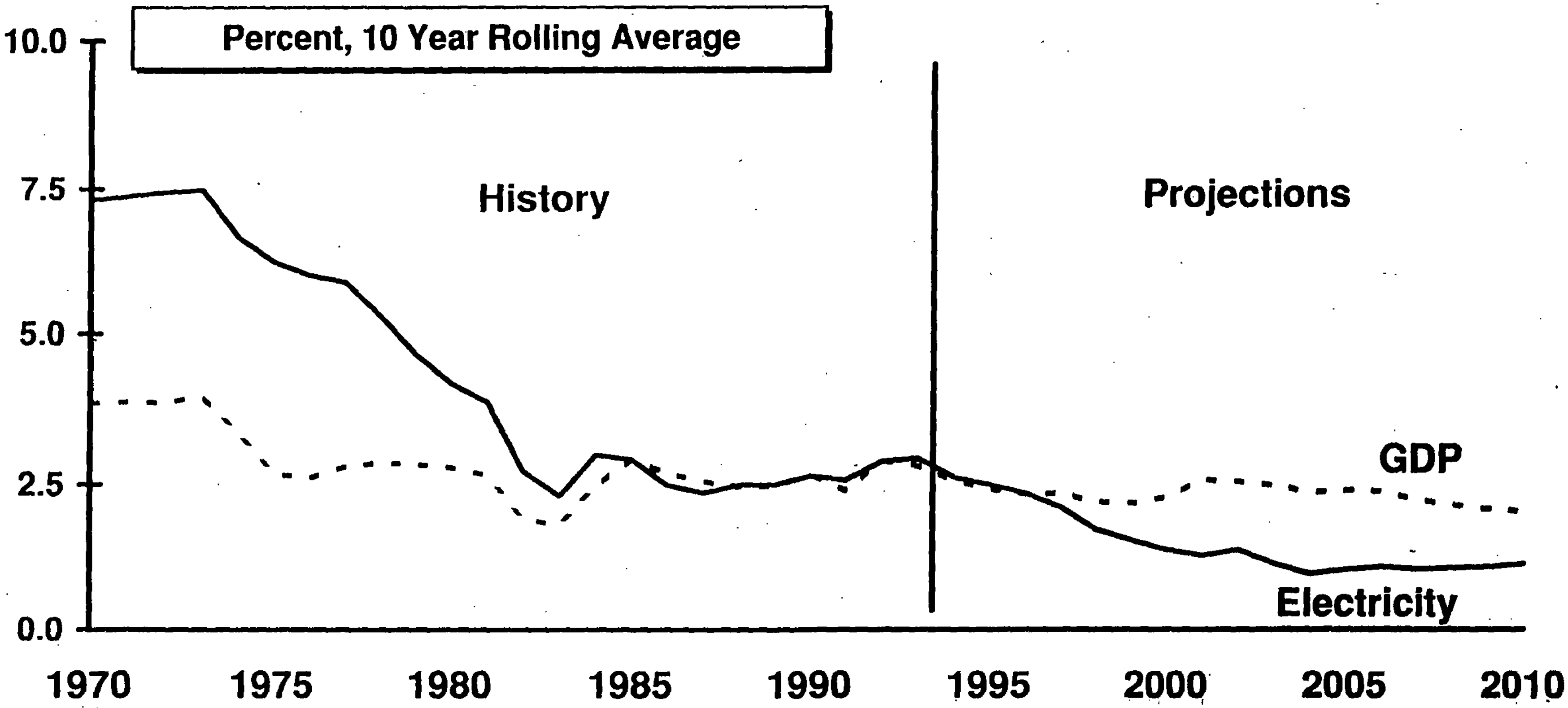


Note: (*.*) indicates average annual growth rate.
Projection growthrates based on 1993 - 2010 projection period

Indices of Economic Growth, Energy Consumption, Population and Carbon Emissions (1990=100)



Electricity Sales and Economic Growth Rates 1970 - 2010



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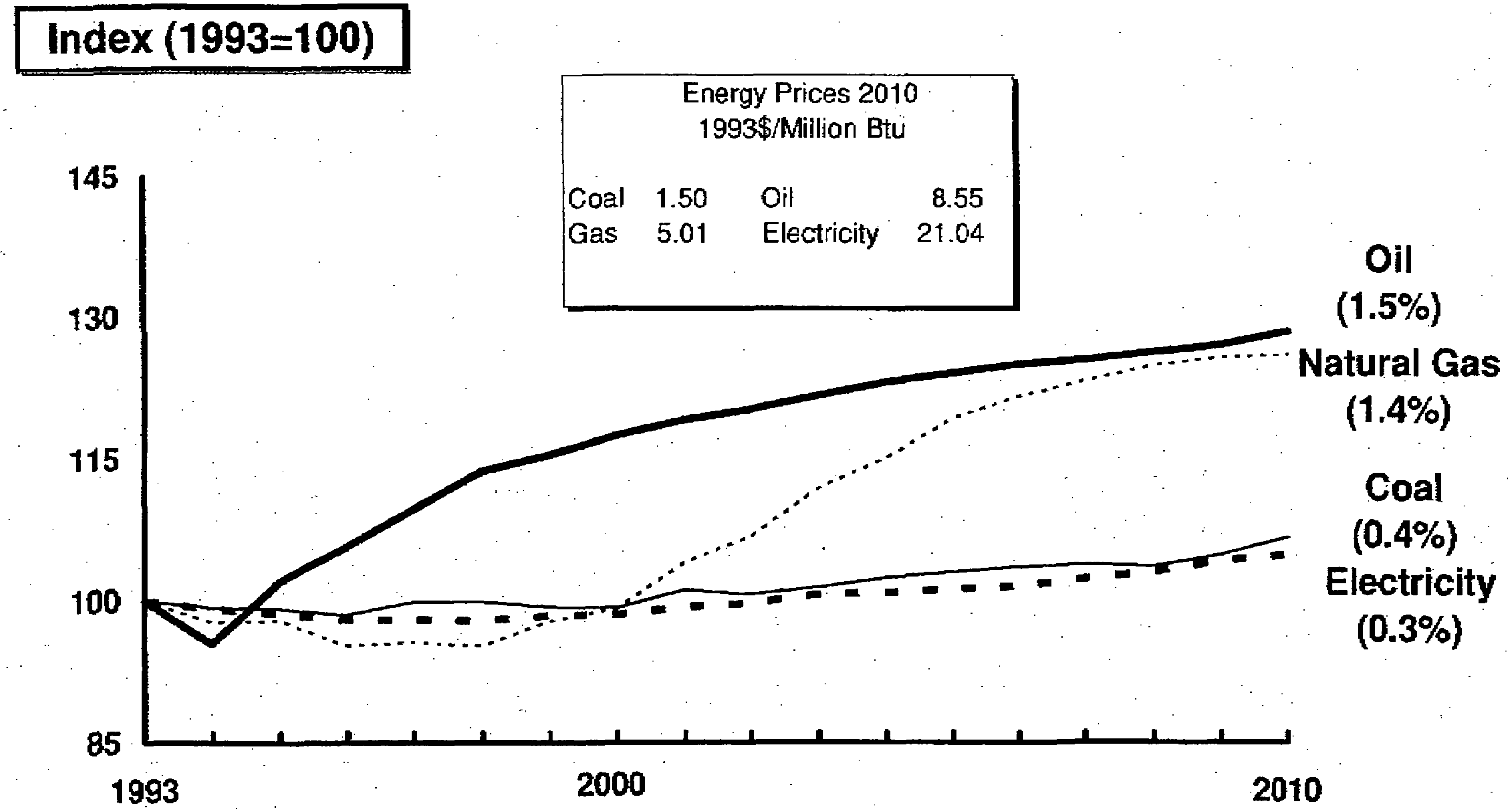
Delivered Energy Prices : Relative Indices
1993 - 2010



Note: (*.*%) = Annual average growthrate, 1993 - 2010

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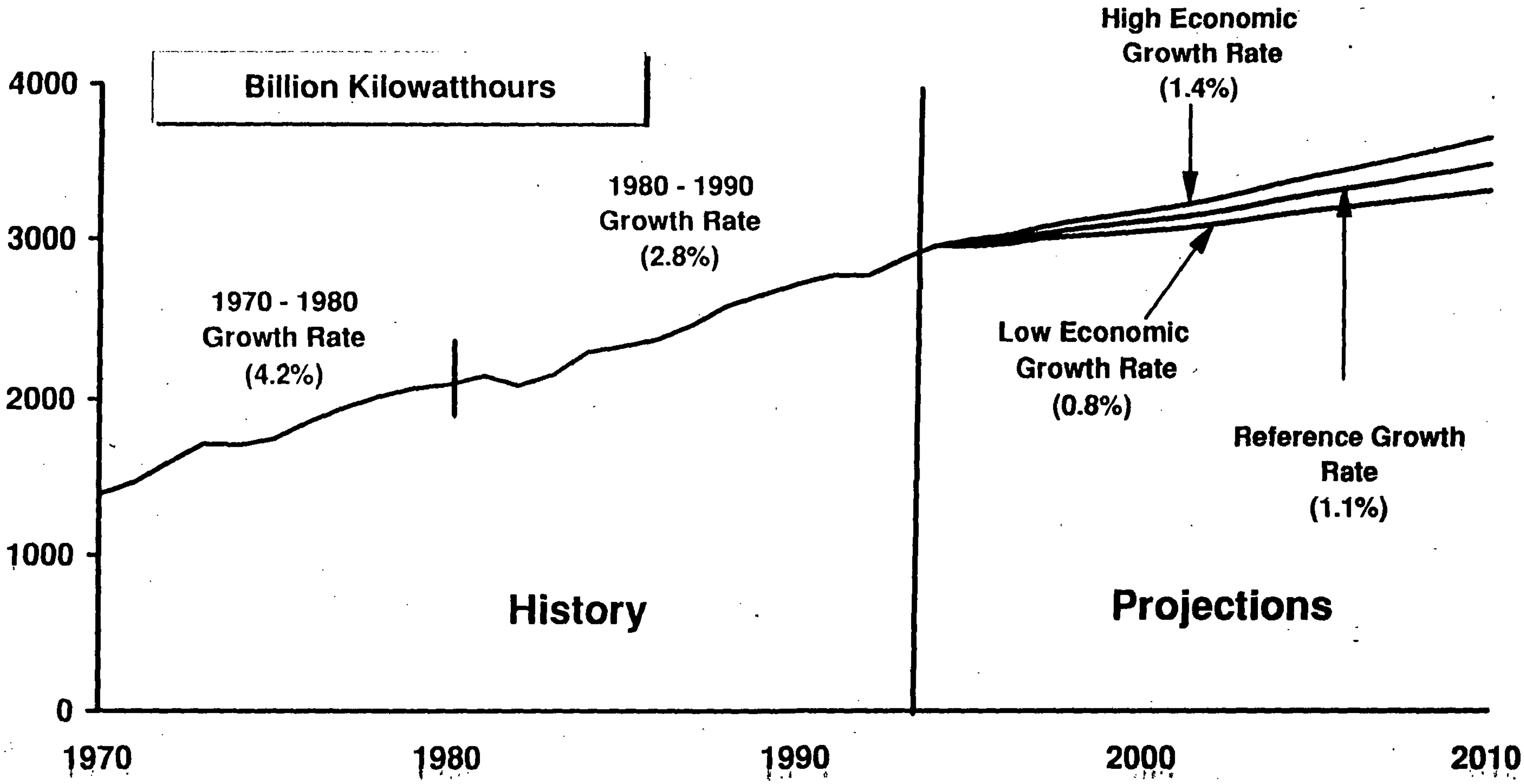
Electricity Sales 1970 - 2010



Note: ( ) = annual electricity sales growth rate

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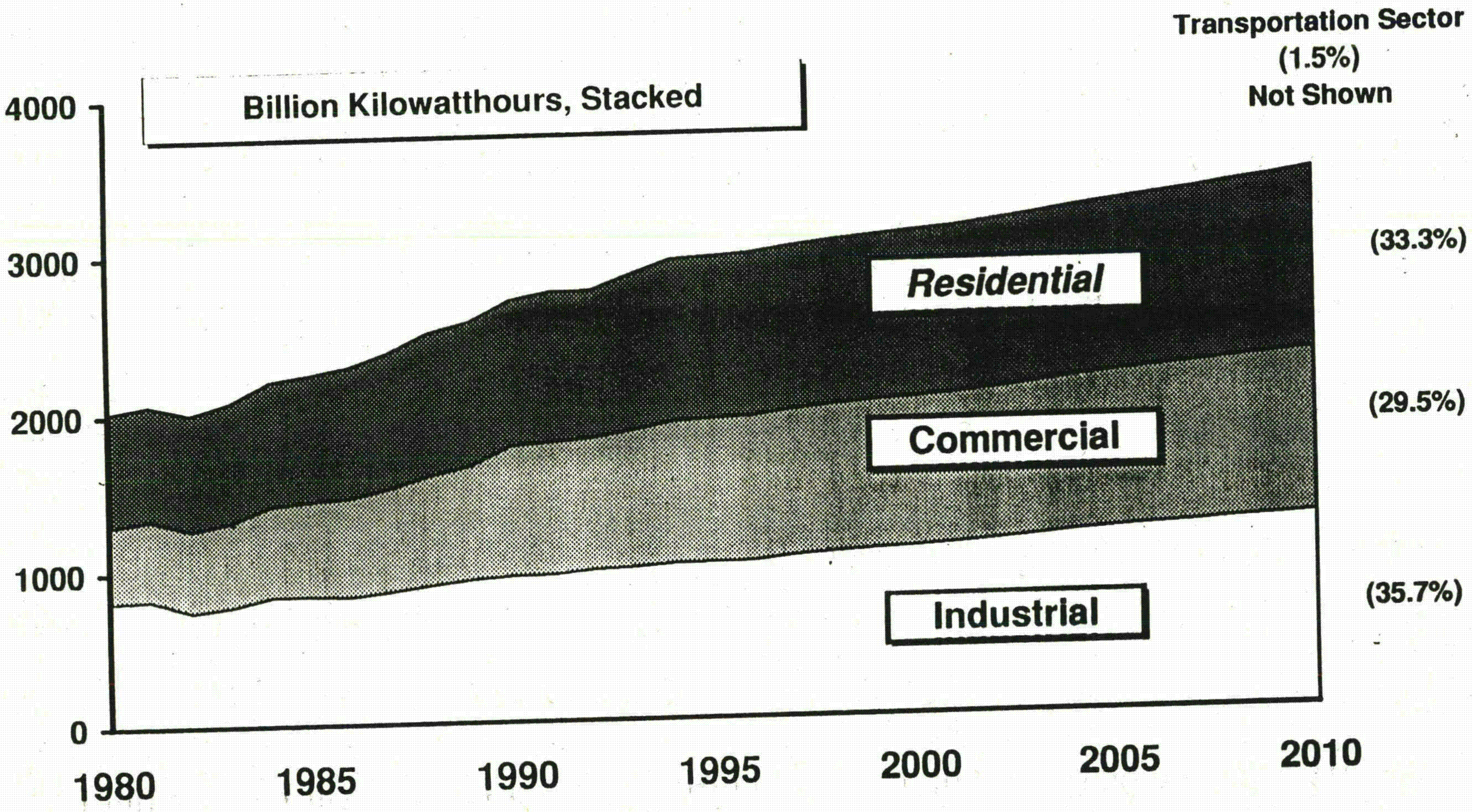
Electricity Sales
1980 - 2010



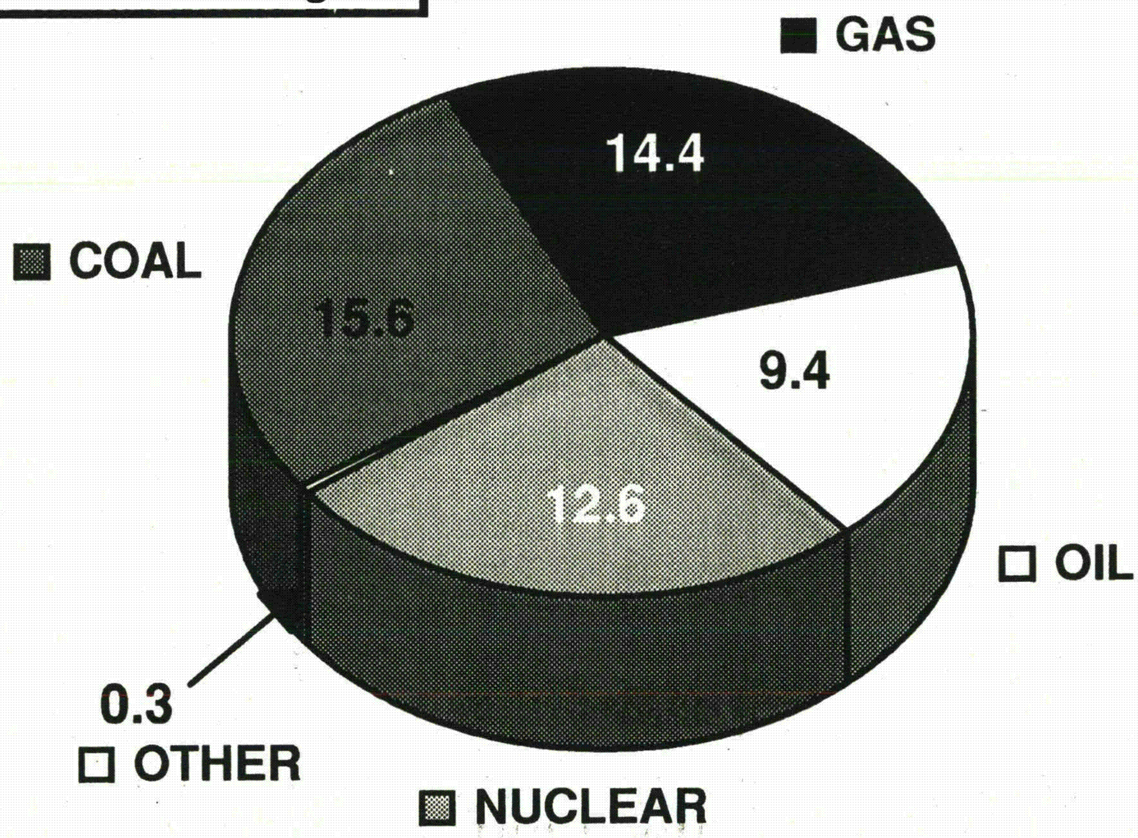
Note: (*.*%) indicates percentage of total sales in year 2010

Meeting the Demand for Electricity

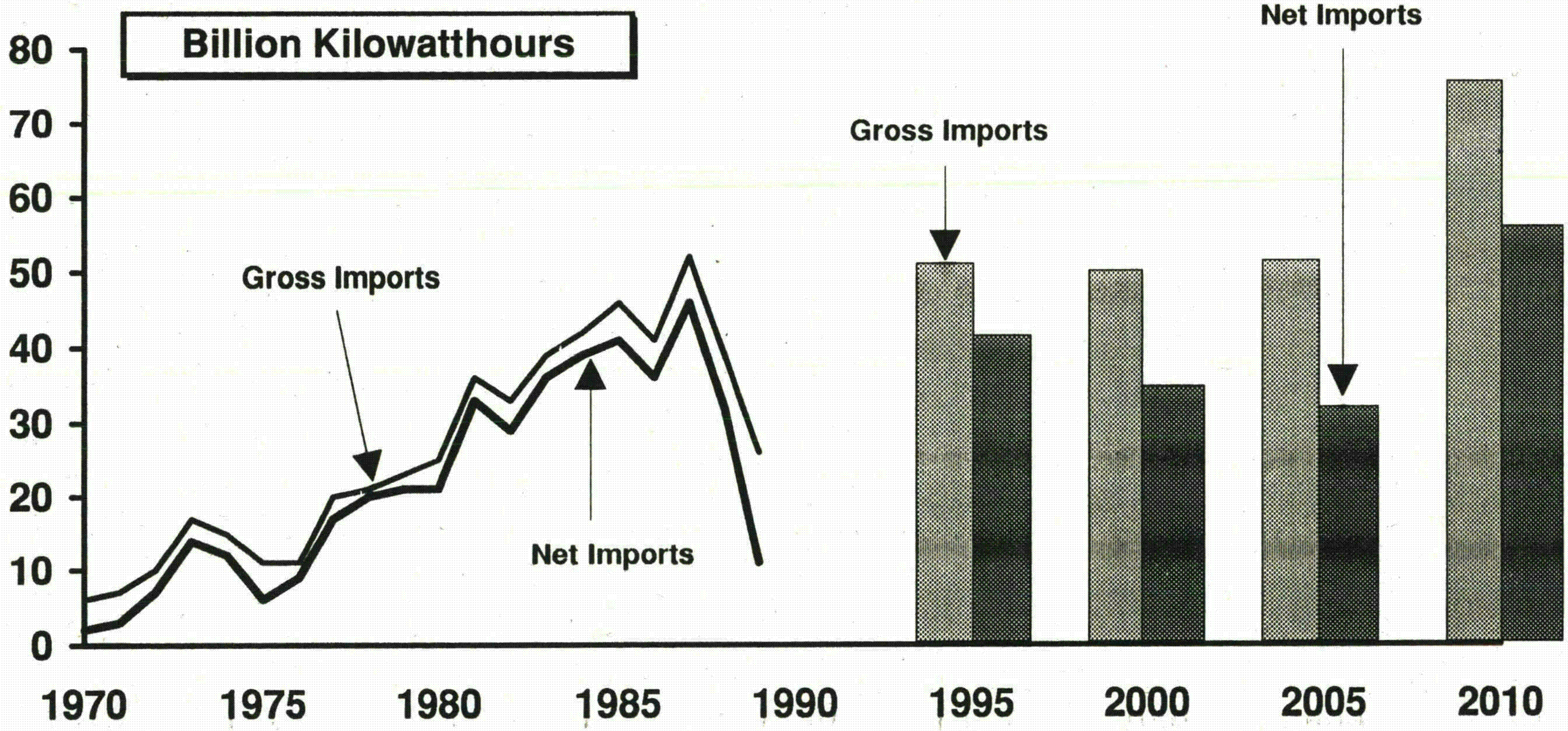
- Increased Utilization of Existing Plants
- Extending the Lives of Existing Plants
- Electricity Imports
- Growing Reliance on Nonutility Generators
- Demand-Side Management
- Constructing New Plants

RETIREMENTS 1993 - 2010

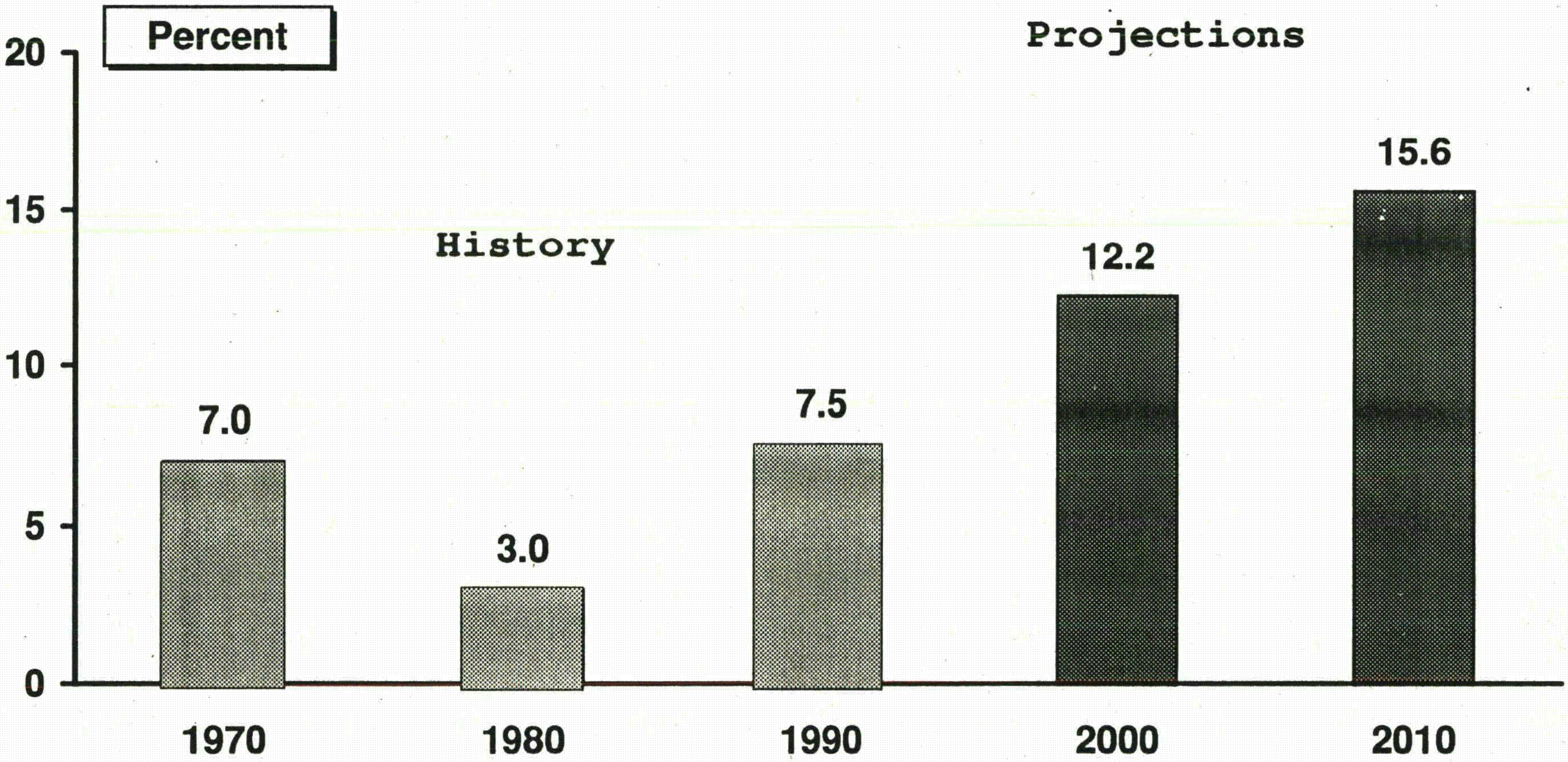
(Gigawatts)
Total Retirements = 52.7 gW



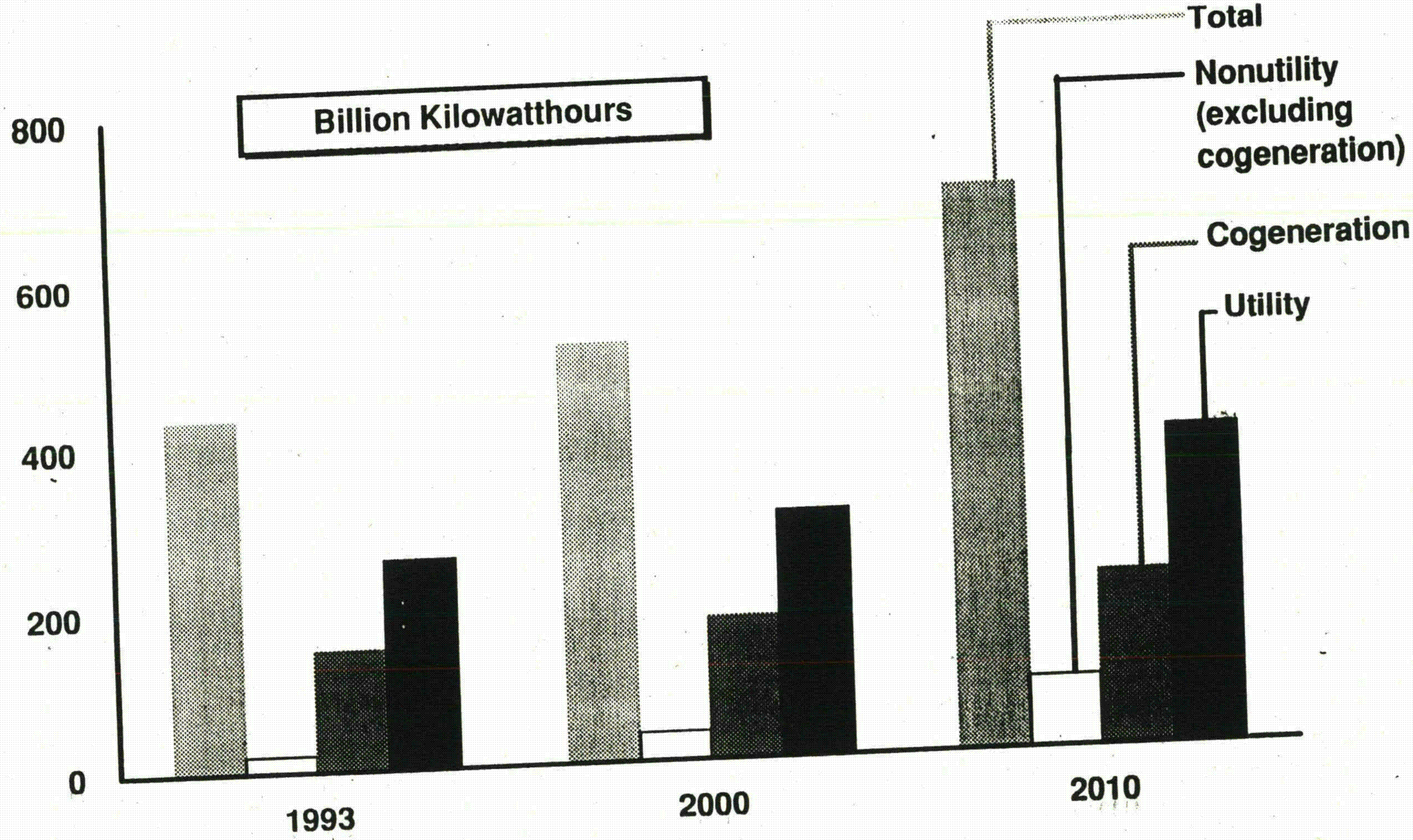
Electricity Trade with Canada and Mexico 1970 - 2010



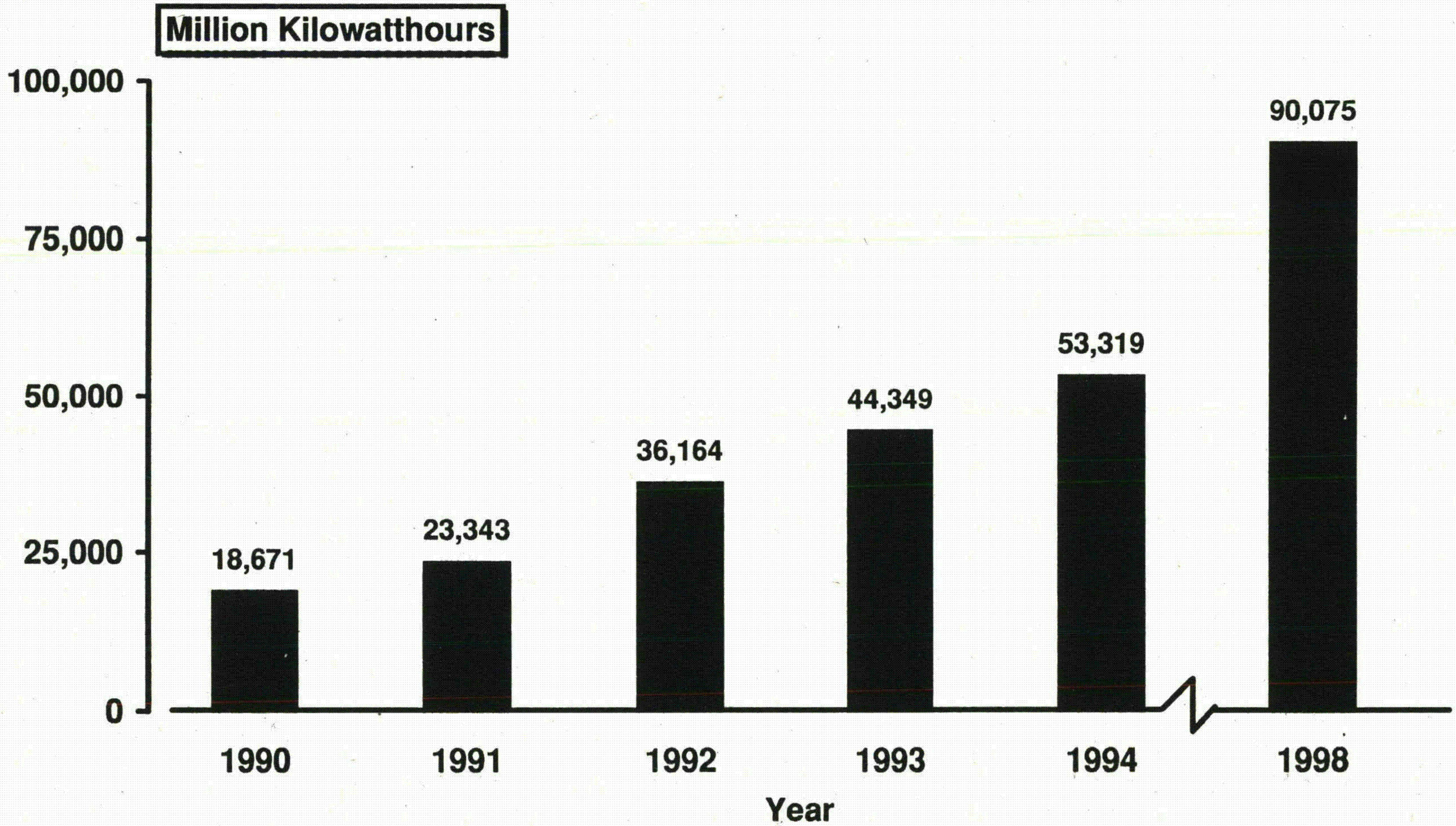
NONUTILITY SHARE OF TOTAL U.S. GENERATION



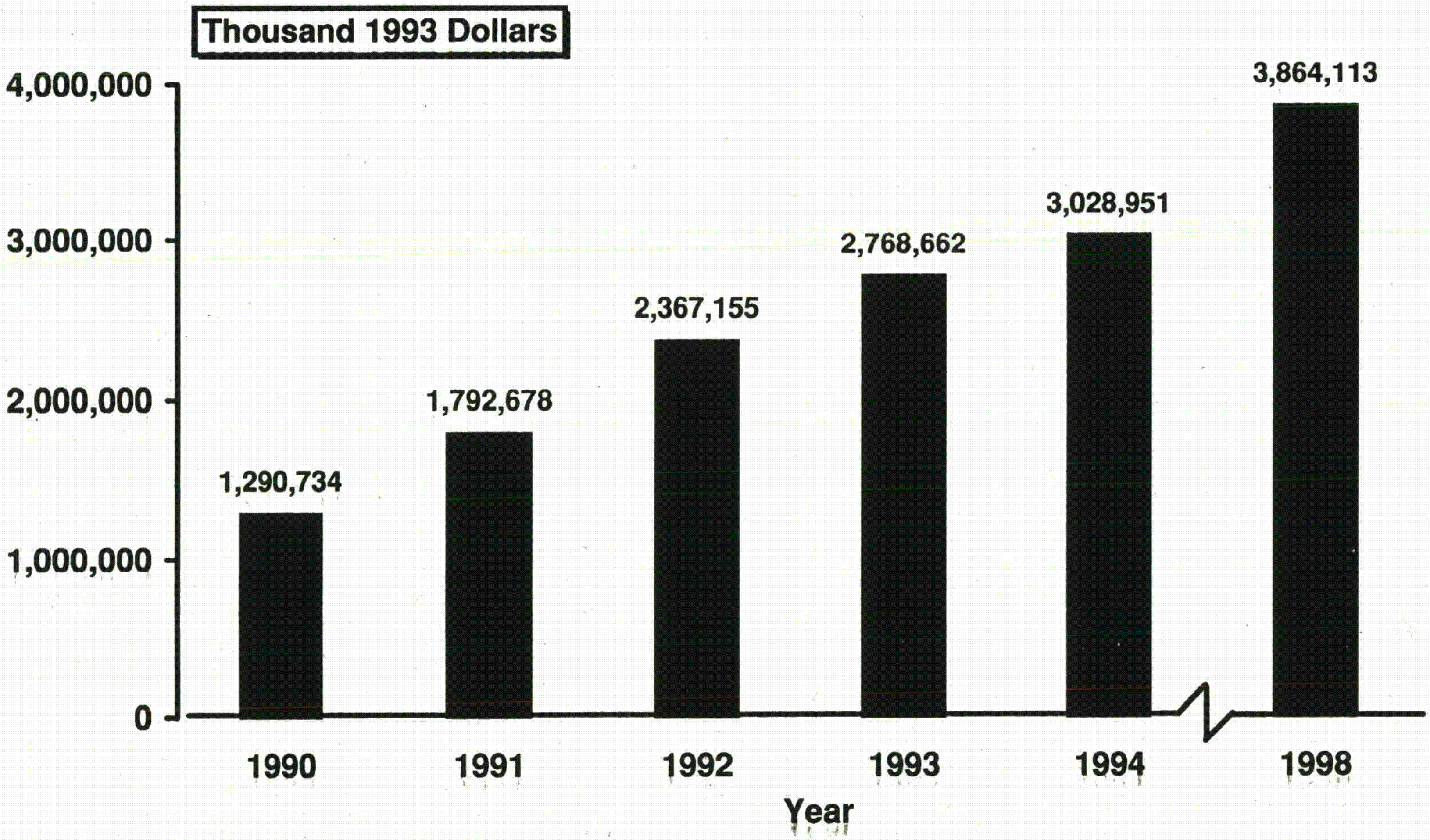
Electricity Generation From Gas 1993, 2000, and 2010



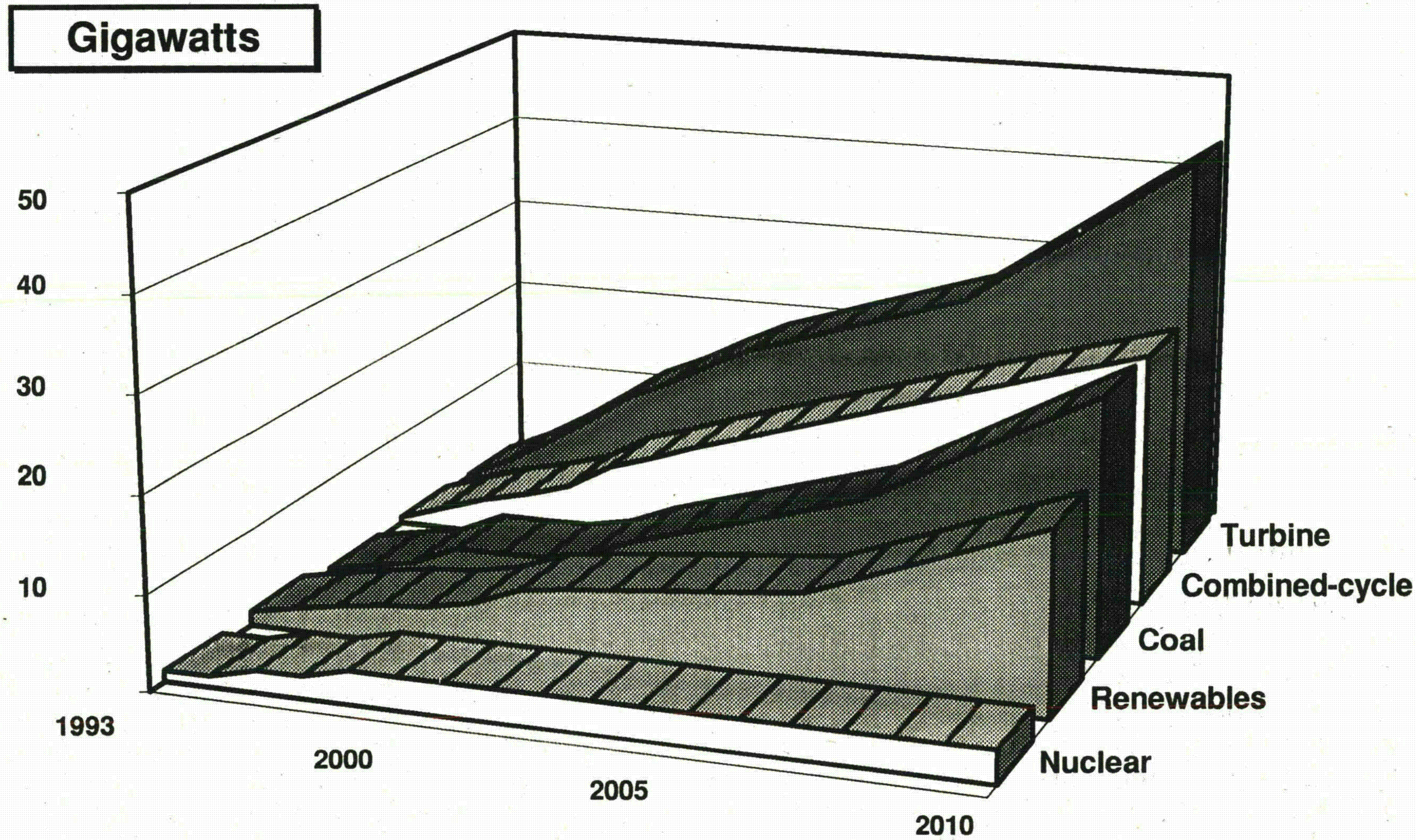
Cumulative DSM Energy Savings



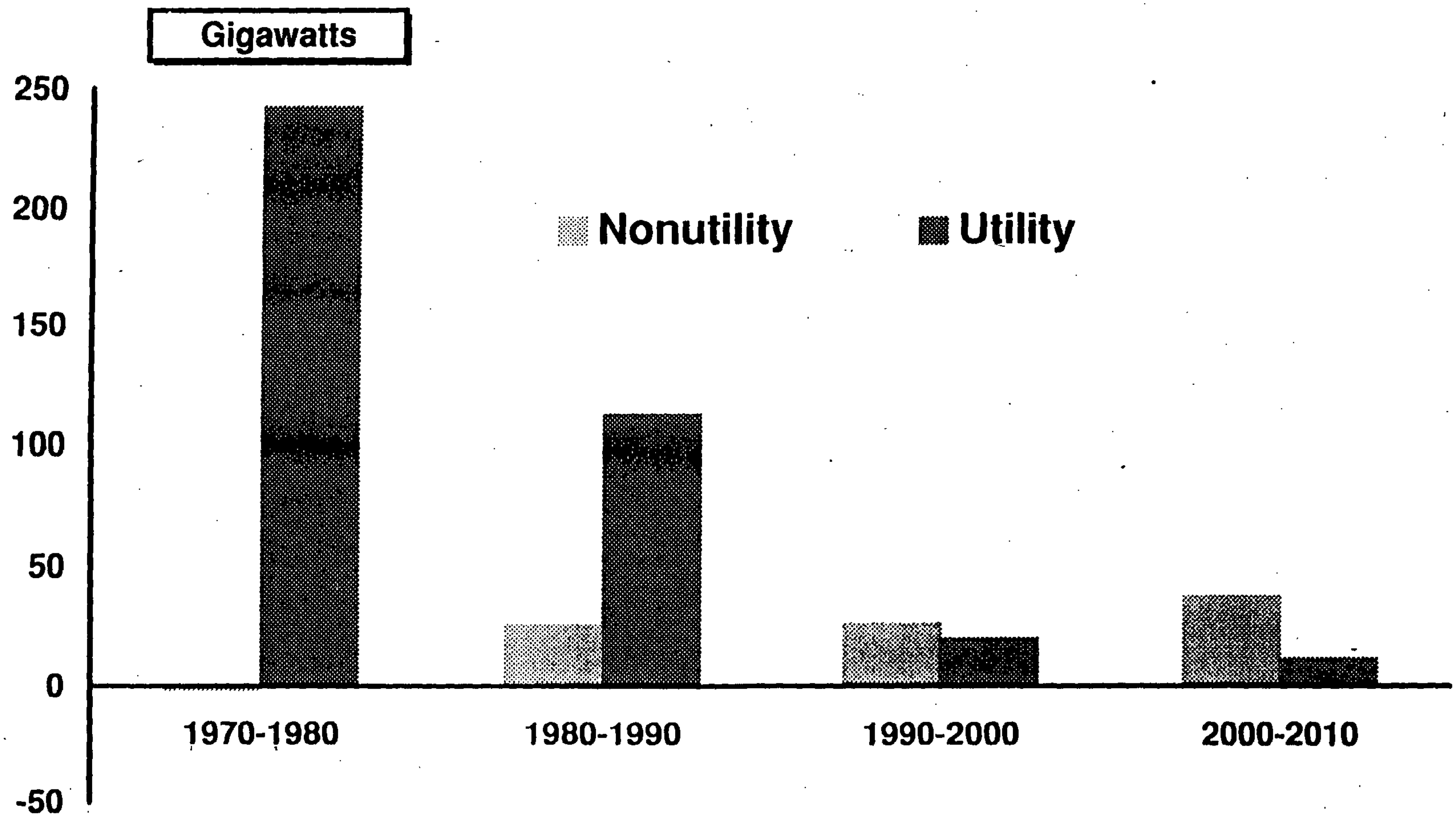
Annual DSM Expenditures



Cumulative Additional Needed Capacity
1993 - 2010



Utility and Nonutility Net Capacity Additions by Decade
1970-2010



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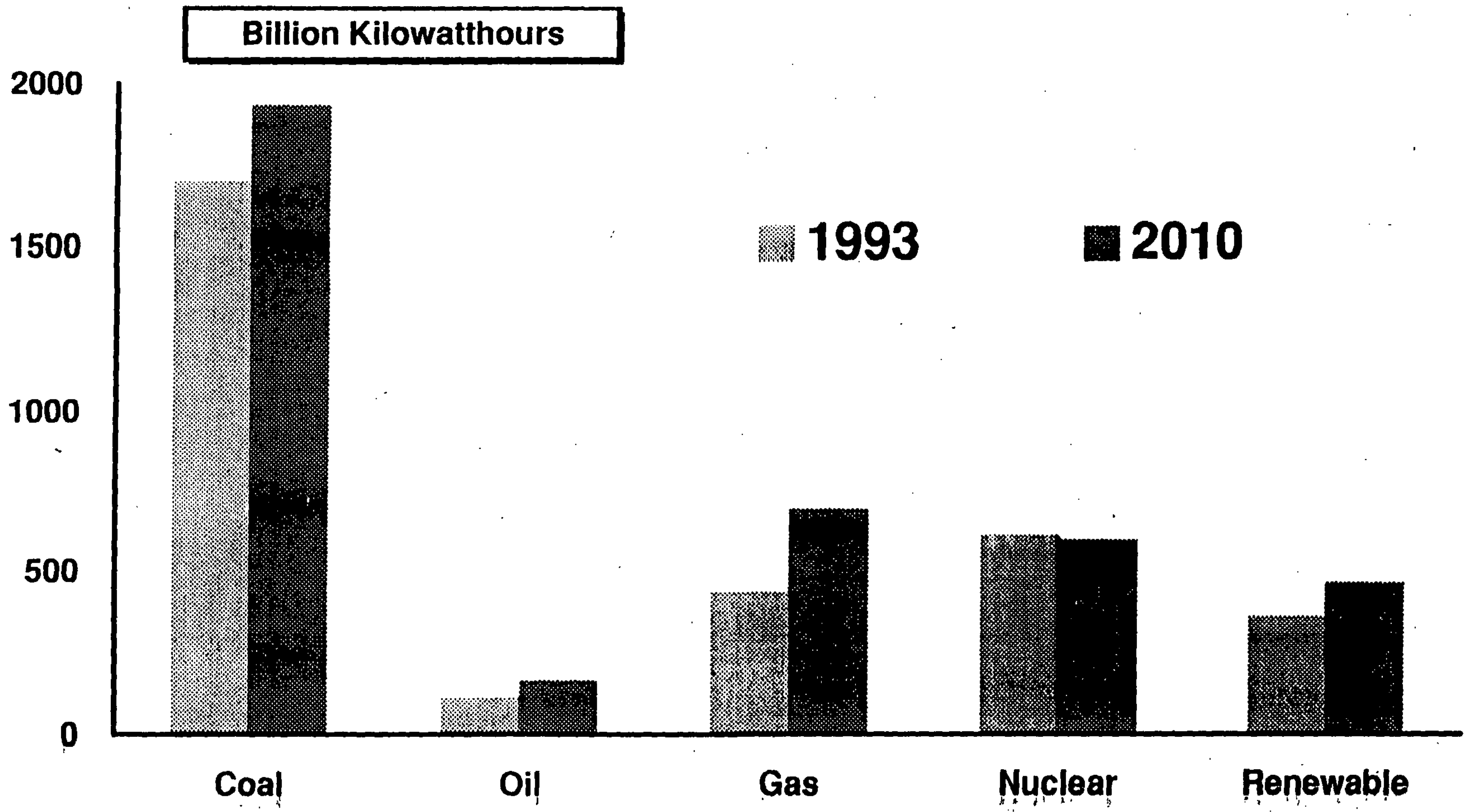
Electricity Generation by Fuel
1993 and 2010



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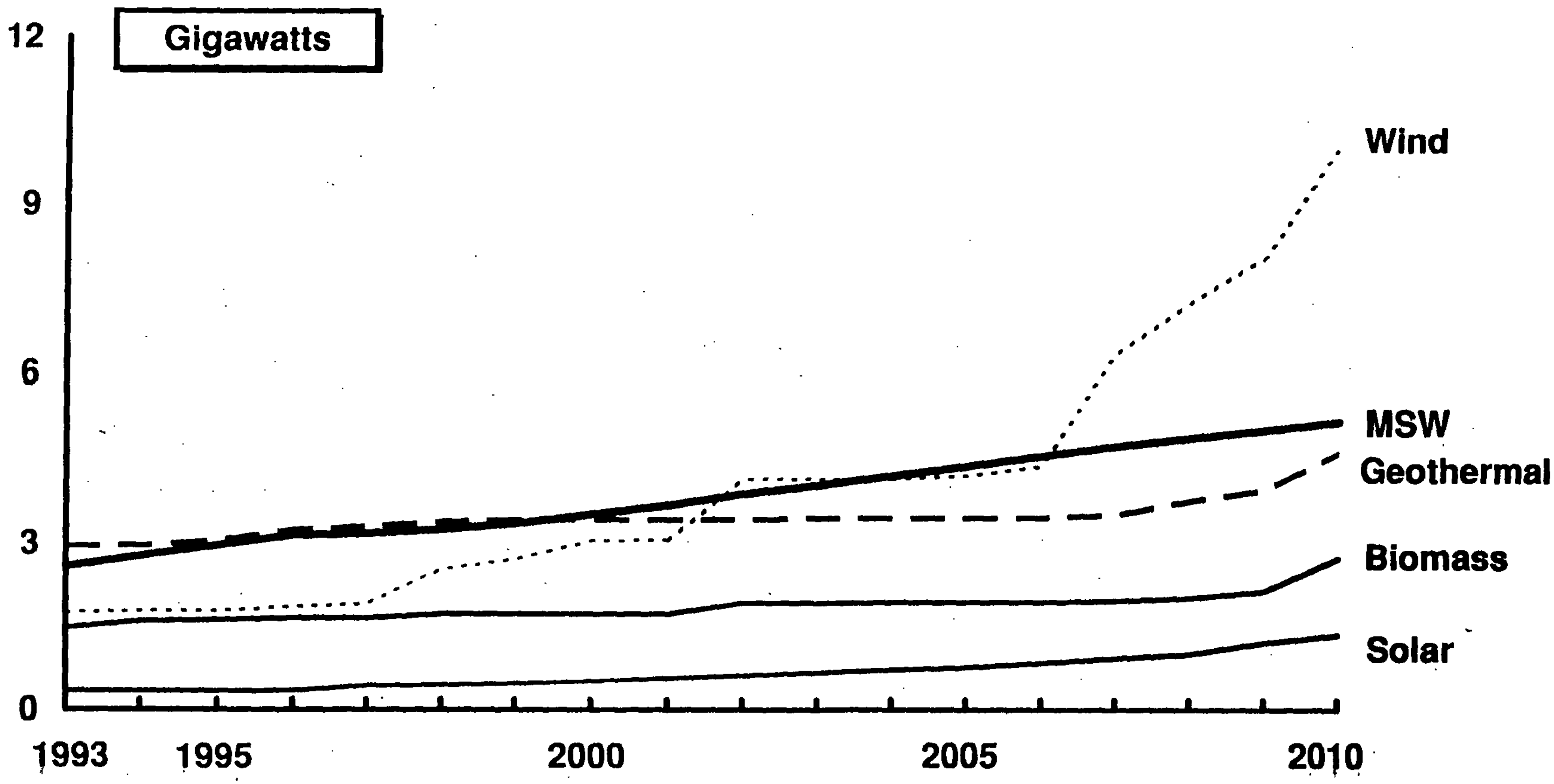
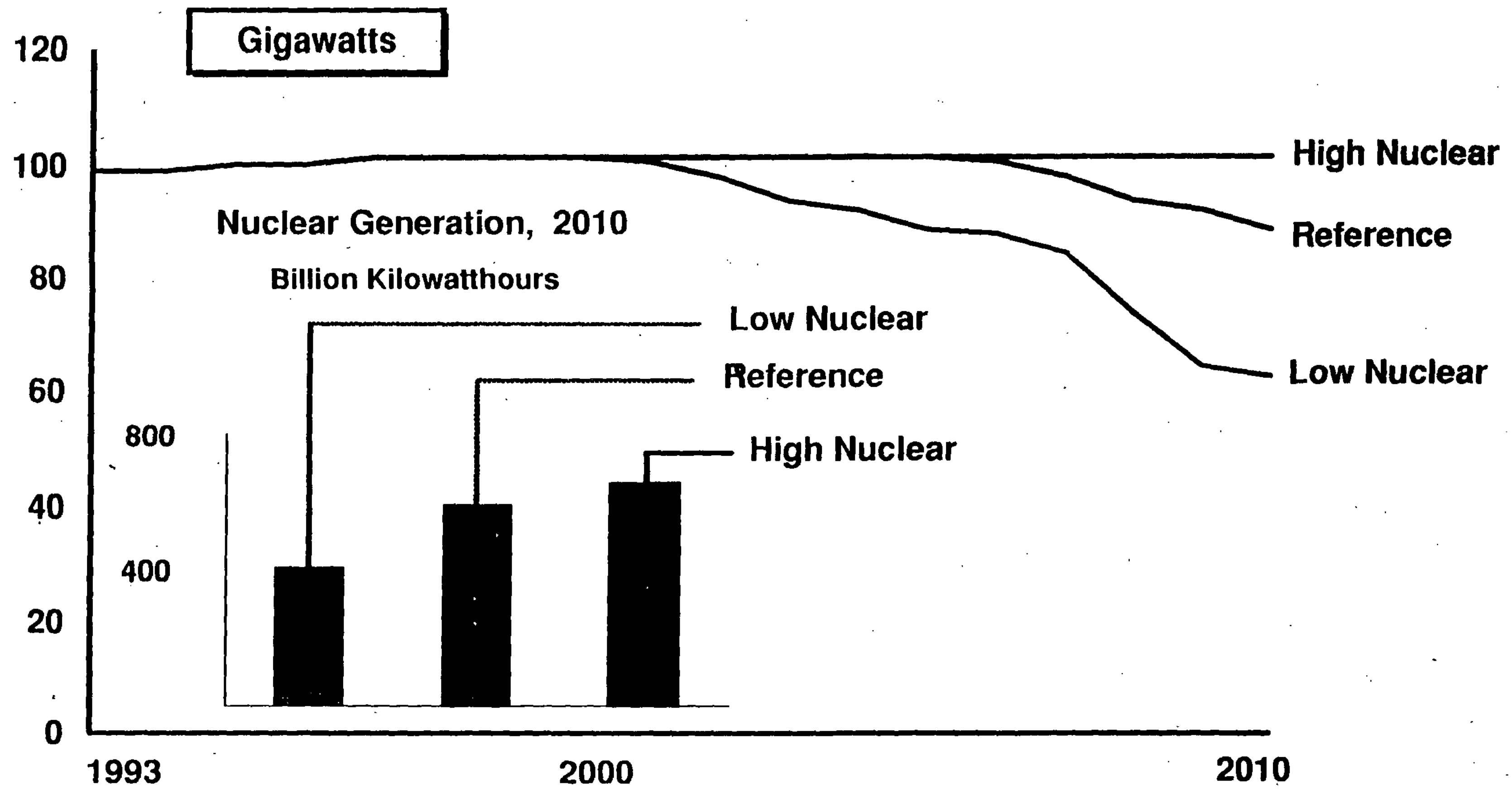
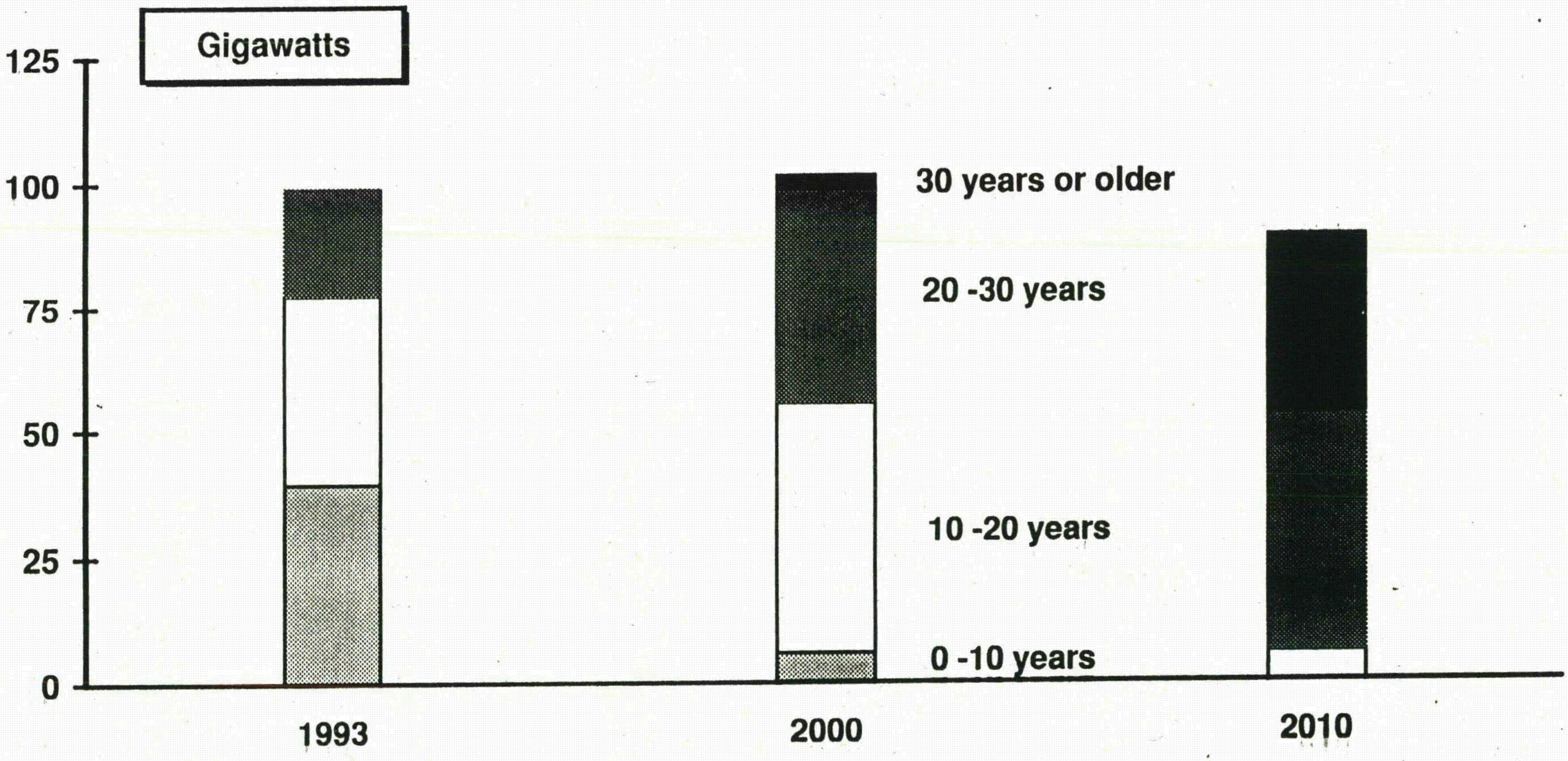
Nonhydroelectric Generating Capacity from Renewable Fuels by Fuel Type 1993 -2010



Operable New Capacity in Three Cases 1993 - 2010



Nuclear Generating Capacity by Age of Reactor Units
1993, 2000, and 2010



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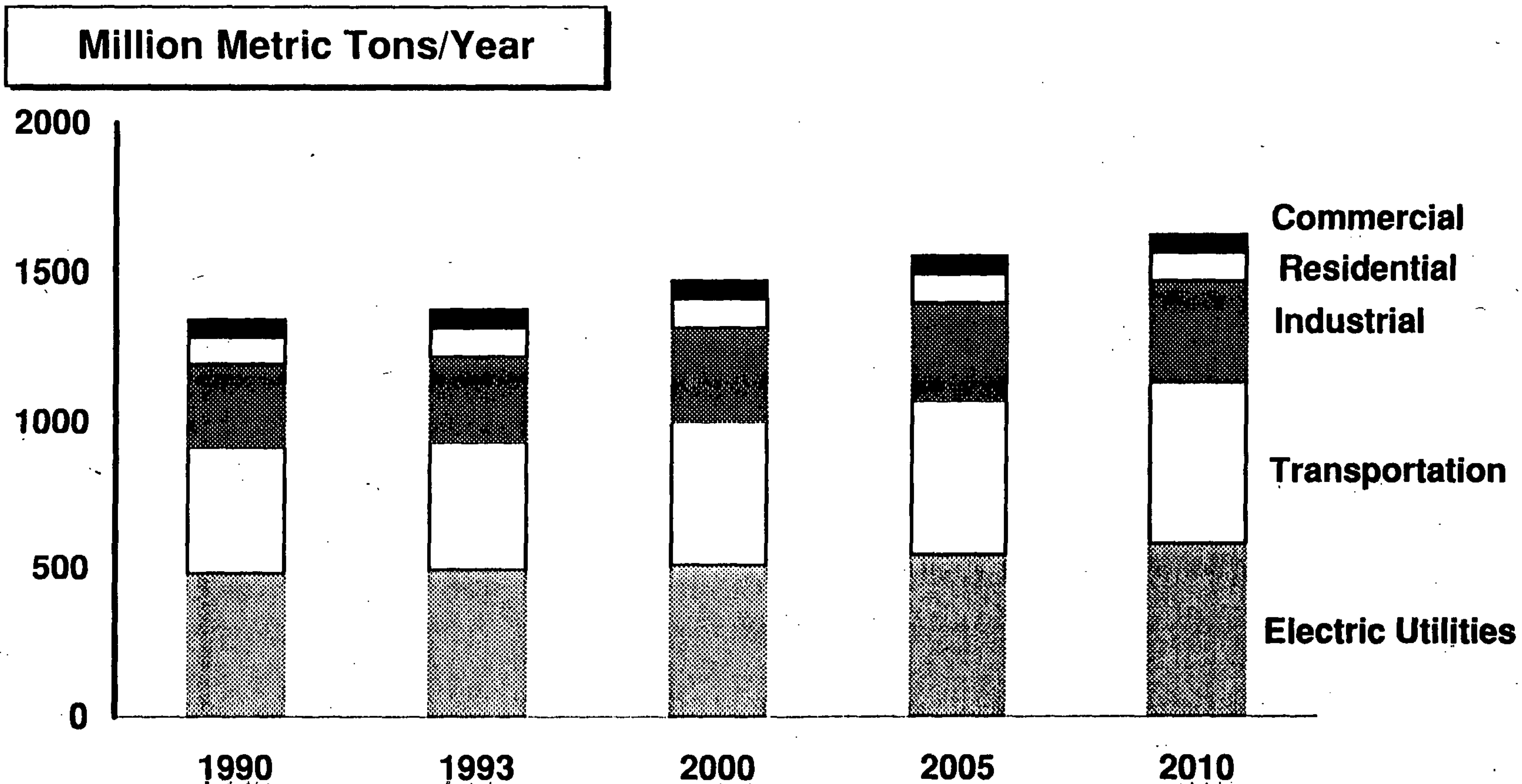
Carbon Emissions By Sector 1990 - 2010



Uncertainties

- Restructuring / Deregulation
- Demand Growth
- Gas / Coal Prices
- Technological Development
- Climate Change Action Plan
- Impact of Efficiency Standards

Energy INFOcard

United States (1993)

PETROLEUM

Production (crude oil, NGPL)(MMbd)	8.6
Net imports (crude oil & refined products)(MMbd)	7.6
Other sources(refinery gain, alcohols, other)(MMbd)	1.0
Consumption (26% of world total) (MMbd)	17.2
Dependence on foreign oil (net imports/consump.)	44%
Recoverable resources (yrs of current production)	23 - 38
Share of US oil consumption for transportation	66%
Drop in real world oil price from 1980 peak	72%

NATURAL GAS

Production(dry gas) (2nd in world to Russia) (tcf)	18.4
Consumption (1/4 of world total) (tcf)	20.3
Consumers: industrial *(incl. lease, plant, pipeline fuel)*	48%,
residential 25%, commercial 14%, electric utilities	13%
Share of consumption from Canadian imports	11%
Recoverable resources (yrs of current production)	26 - 66
Drop in real wellhead gas price from 1983 peak	46%

COAL

Production (2nd in world after China) (million tons)	945
Share produced West of the Mississippi	44%
Share produced from surface mining	56%
Exports as percent of production	8%
Electric utility share of consumption	88%
Productivity: 4.7 tons/miner-hour vs 1.9 tons/m-hr in	1963
Recoverable reserves (yrs of current production)	250+

ELECTRICITY

Utility net generation (trillion kilowatthours) 2.9

Coal 57%, Nuclear 21%, Gas 9, Hydro 9, Oil 3, Other 1%

Nonutility net generation (billion kilowatthours) 314

Gas 54%, Wood & Waste 17%, Coal 16%, Oil 4%, Geothermal 3%, Hydro 4%, Wind 1%, Other 1%

Sales: residential 35%, commercial 28%, industrial 34%

Emissions (million tons)	CO_2--2500	SO_2--16	NO_x--7
Coal fired	*87%*	*96%*	*90%*
Oil & gas fired	*13%*	*4%*	*10%*

Units:

MMbd = million barrels per day; Mcf = thousand cubic feet
tcf = trillion cubic feet; kWh = kilowatthour

Most recent annual data available as of 2/10/95

Source: Energy Information Administration, U.S. Department of Energy.

NUCLEAR

Number of operable generating units	109
Capacity (million kilowatts)	99
Capacity Factor	71% in 1993 vs. 54% in 1983

RENEWABLE ENERGY

Consumption (quadrillion Btu) 6.3

Hydropower 50%, Wood 35%, Waste 8%, Other(ethanol, geothermal, solar, wind) 7%

Renewable share of total energy consumption 7%

TOTAL ENERGY and EFFICIENCY OF USE

*Total Primary Energy Production (quadrillion Btu) 68

Coal 30%, Gas 28%, Oil 25, Nuclear 9, Renewable 8%

*Total Consumption (quadrillion Btu) 87

Coal 22%, Gas 24%, Oil 39, Nuclear 8, Renewable 7%

** Updated to include estimated 3 quads dispersed renewables*

Decline in Energy/GDP ratio since 1973	1.6%/yr
Annual consumption per capita (million Btu)	326
US share of world energy consumption	24%
Number of households (million)	93

Heating fuel: Gas 51%, Electricity 26, Oil 12, Wood 5%

Household vehicle miles/gallon: 1979(14.6) 1991(19.3)

H. vehicle miles traveled (trillions) 1979(1.1) 1991(1.6)

(Total stock of cars and other vehicles in household use)

World (1993)

Primary energy production (quadrillion Btu) 350

Coal 26%, Gas 22%, Oil 39%, Nuclear 6%, Hydro 7%

(Dispersed renewables, primarily firewood, are not included)

Energy-related carbon emissions:	1970	1992
OECD (16% of world population in 1992)	57%	48%
Rest of World	43%	52%

Crude oil production (million bbls/day) 61

US 11%, OPEC 43%, Persian Gulf 28%

Electricity generation (trillion kilowatthours) 12

US 27%, W.Europe 21%, Russia 8, Japan 7, China 6%

Nuclear share of electricity (selected countries):

France 78%, Germany 30%, Japan 28%, UK 27, US 20%

Share of world nuclear electricity generation (5 largest):

US 29%, France 17%, Japan 11, Germany 7, Russia 6%

Recoverable resources (yrs of current production):

Crude Oil: 67, Natural Gas:123, Coal: 230

Btu Equivalents: *1 bbl crude oil: 5.8 million; 1 Mcf gas: 1.03 million; 1 kWh electric: 3.4 thousand; 1 ton coal: ~22 million; 1 gal. gasoline: 125 thousand; 1 cord dry hardwood: 21.5 million;*

For further information, please contact:

National Energy Information Center 202-586-8800

or Internet E-Mail: INFOCTR@EIA.DOE.GOV

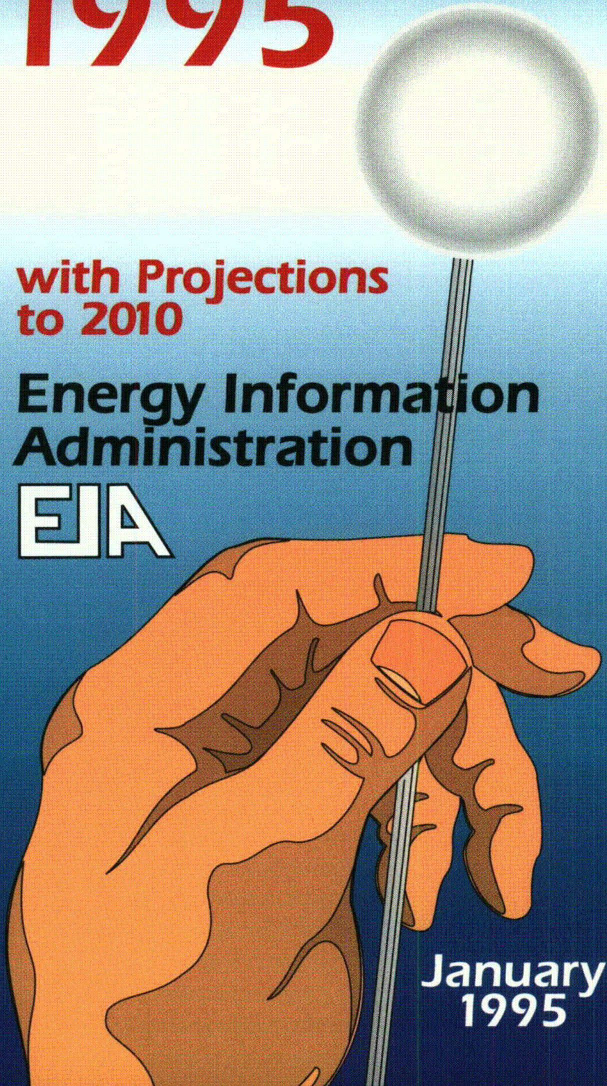
DOE/EIA-0383(95)

Annual Energy Outlook 1995

with Projections to 2010

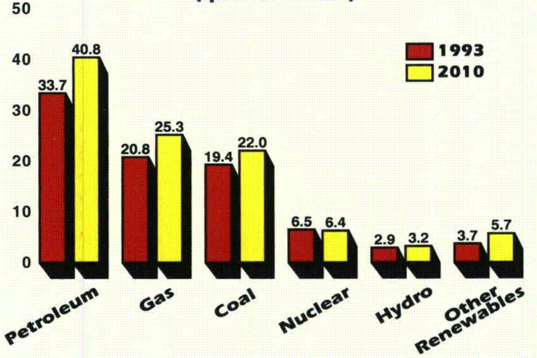
Energy Information Administration

EIA



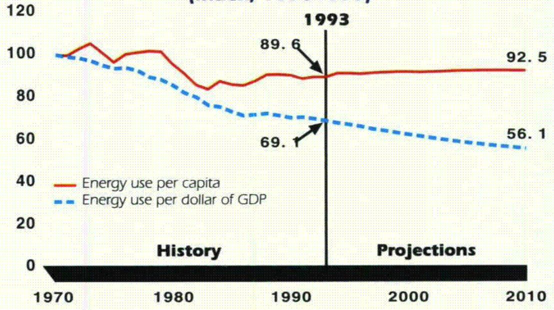
January 1995

Energy Consumption by Source, 1993 and 2010
(quadrillion Btu)



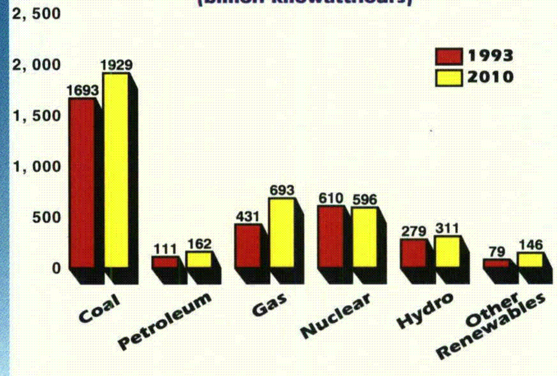
- The transportation sector accounts for two-thirds of petroleum consumption, as future increases in travel offset increased efficiency.
- Natural gas consumption increases due to rapid growth for electricity generation and growth in the industrial sector for cogeneration and other uses.
- Coal consumption for electricity generation accounts for nearly 90 percent of total coal use in 2010.
- Consumption of renewable energy grows rapidly with two-thirds consumed for generation.

Energy Use per Capita and per Dollar of Gross Domestic Product, 1970-2010
(index, 1970=100)



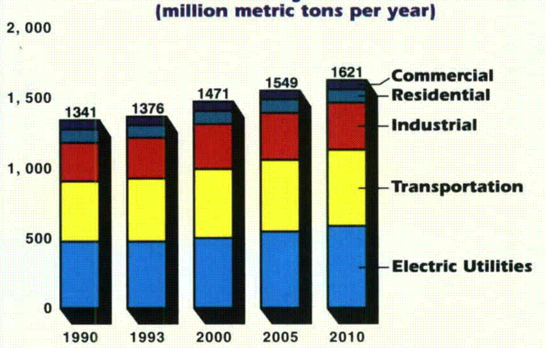
- U.S. energy intensity declined for energy use per capita and per dollar of gross domestic product (GDP) from 1970 to the mid-1980s; however, use per capita increased in the mid-1980s with low energy prices.
- Energy use per capita rises slowly with low energy prices and increasing demands for energy services.
- Energy use per dollar of GDP continues to decline, although at a slower rate than in the 1970s. Low energy prices and growth in energy-intensive industries contribute to the slower decline.

Electricity Generation by Fuel, 1993 and 2010
(billion kilowatthours)



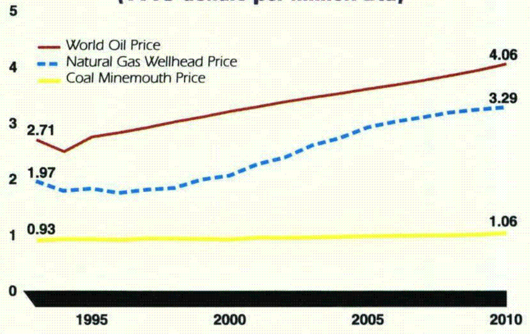
- Coal-fired generators – utility, nonutility, and cogenerators - remain the primary electricity source.
- Gas-fired generators overtake nuclear power as the secondary electricity source, due to relatively low capital costs, high efficiency, and low emissions.
- Nuclear power increases through 2006 primarily because of improved performance of existing units, then it declines as older units are retired.
- Hydropower is the primary renewable generation source; however, wind is the fastest-growing.

Carbon Emissions by Sector, 1990-2010
(million metric tons per year)



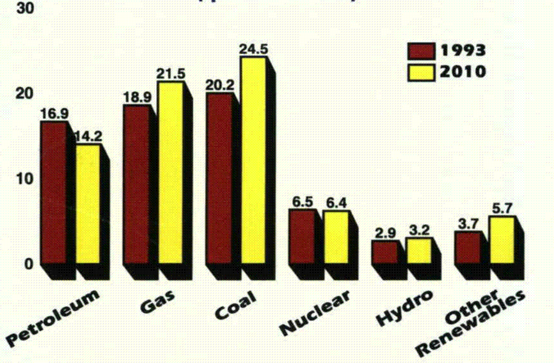
- These projections include the Climate Change Action Plan (CCAP). The goal of CCAP is to stabilize U.S. greenhouse gas emissions in 2000 at 1990 levels. The AEO95 accounts for carbon released by fuel combustion and related activities.
- Electric generators account for over one-third of the carbon emissions because of the use of coal.
- Petroleum is the largest fuel source of carbon emissions, more than 40 percent, from its use in the transportation and industrial sectors.

Fuel Prices, 1993-2010
(1993 dollars per million Btu)



- Oil and natural gas prices increase at lower rates, 2.4 and 3.1 percent per year, respectively, than in the prior forecast. The slower growth rates are due to reassessments of oil production capability in the Organization of Petroleum Exporting Countries and of the impacts of technology improvements on oil and gas production.
- Coal minemouth prices also rise more slowly than in the previous forecast, 0.8 percent per year, because of increasing labor productivity and lower demand.

Energy Production by Source, 1993 and 2010
(quadrillion Btu)



- As U.S. crude oil production declines and demand increases over the forecast period, the share of petroleum consumption met by net imports reaches 59 percent in 2010 compared with 44 percent in 1993, measured in terms of barrels per day.
- Natural gas production increases 0.8 percent per year to partially fill growth in demand, which is also met by increases in imports, primarily from Canada.
- Coal production increases 1.1 percent per year to meet the domestic and foreign demand for coal.

Highlights

	1992	1993	2010				
			Reference	Low Economic Growth	High Economic Growth	Low World Oil Price	High World Oil Price
Primary Production (quadrillion Btu)							
Petroleum	17.55	16.91	14.23	13.75	14.74	10.21	15.97
Natural Gas	18.37	18.90	21.51	20.49	22.57	20.02	21.82
Coal	21.59	20.23	24.51	23.93	25.30	24.28	24.63
Nuclear Power	6.61	6.52	6.36	6.36	6.36	6.36	6.36
Renewable Energy/Other	7.14	7.06	9.25	8.79	9.68	8.94	9.57
Total Primary Production	**71.25**	**69.62**	**75.86**	**73.32**	**78.66**	**69.82**	**78.37**
Net Imports (quadrillion Btu)							
Petroleum (including SPR)	14.99	16.47	26.02	24.73	27.41	33.85	23.24
Natural Gas	1.97	2.17	3.66	3.24	3.91	3.24	3.71
Coal/Other (- indicates export)	-2.27	-1.46	-1.89	-2.16	-1.70	-2.03	-2.06
Total Net Imports	**14.68**	**17.18**	**27.78**	**25.80**	**29.62**	**35.06**	**24.88**
Discrepancy	-0.32	0.46	0.22	0.24	0.21	-0.17	0.28
Consumption (quadrillion Btu)							
Petroleum Products	33.56	33.71	40.82	39.03	42.74	44.20	39.92
Natural Gas	20.15	20.81	25.30	23.86	26.60	23.38	25.66
Coal	18.87	19.43	21.97	21.36	22.83	21.59	22.08
Nuclear Power	6.61	6.52	6.36	6.36	6.36	6.36	6.36
Renewable Energy/Other	6.43	6.80	9.41	8.75	9.95	9.18	9.51
Total Consumption	**85.61**	**87.27**	**103.88**	**99.36**	**108.48**	**104.71**	**103.53**
Prices (1993 dollars)							
World Oil Price (dollars per barrel)	18.70	16.12	24.12	23.29	24.99	14.65	28.99
Domestic Natural Gas at Wellhead (dollars per thousand cubic feet)	1.80	2.02	3.39	3.01	3.74	2.88	3.51
Domestic Coal at Minemouth (dollars per short ton)	21.57	19.85	22.77	22.25	24.13	21.39	23.68
Average Electricity Price (cents per kilowatthour)	7.1	6.8	7.2	6.8	7.5	7.0	7.3
Economic Indicators							
Real Gross Domestic Product (billion 1987 dollars)	4,986	5,136	7,485	6,949	8,028	7,537	7,456
GDP Implicit Price Deflator (index, 1987=1.00)	1.211	1.242	2.074	2.724	1.823	2.062	2.082
Real Disposable Personal Income (billion 1987 dollars)	3,633	3,701	5,140	4,889	5,396	5,180	5,118
Index of Manufacturing Gross Output (index, 1987=1.00)	1.077	1.097	1.598	1.491	1.716	1.609	1.591
Energy Intensity							
(thousand Btu per 1987 dollar of GDP)	17.17	16.99	13.88	14.30	13.51	13.89	13.88

Notes: SPR=Strategic Petroleum Reserve. World Oil Price represents the average refiner acquisition cost for imported crude oil. 1992 and 1993 represent partial historical data, which may be revised in later publications. Production of renewable/other includes renewable sources of energy, liquid hydrogen, methanol, supplemental natural gas, and some inputs to refineries. Net imports of other includes coal coke and electricity. Some of the refinery inputs appear as petroleum product consumption. Consumption of renewable/other includes renewable sources of energy, net coal coke and electricity imports, liquid hydrogen, and methanol.

For Further Information...

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Forrestal Building, Room 1F-048
Washington, DC 20585
202/586-8800

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202/586-1181
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Internet: INFOCTR@EIA.DOE.GOV

Prepared by the Office of Integrated Analysis and Forecasting, Energy Information Administration.