WHAT ROLE SHOULD FUEL CHOICE AND NATURAL GAS PLAY IN MEETING THE ENERGY NEEDS OF THE PACIFIC NORTHWEST?

HEARING

BEFORE THE

SUBCOMMITTEE ON REGULATION, BUSINESS OPPORTUNITIES, AND TECHNOLOGY

OF THE

COMMITTEE ON SMALL BUSINESS HOUSE OF REPRESENTATIVES

ONE HUNDRED THIRD CONGRESS

FIRST SESSION

PORTLAND OR, JUNE 3, 1993

Printed for the use of the Committee on Small Business

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WHAT ROLE SHOULD FUEL CHOICE AND NATURAL GAS PLAY IN MEETING THE ENERGY NEEDS OF THE PACIFIC NORTHWEST?

THURSDAY, JUNE 3, 1993

House of Representatives,
Subcommittee on Regulation, Business
Opportunities, and Technology,
Committee on Small Business,
Washington, DC.

The subcommittee met, pursuant to notice, at 10 a.m., at the Portland Metro Council Chambers, Portland, OR, Hon. Ron Wyden (chairman of the subcommittee) presiding.

Chairman Wyden. The Small Business Subcommittee on Regulation, Business Opportunities, and Technology will come to order.

Today, the Small Business Subcommittee on Regulation continues the inquiry begun more than 3 years ago into how natural gas might be used to help increase cost-effective, energy-efficient fuel choices for the Northwest. What this issue is all about is empowering consumers and businesses to have the flexibility to choose the most available source of energy for the lowest cost. As a result, it entails promotion of conservation, ensuring that precious energy resources are conserved for wiser use.

I am of the view that in this time of extraordinary economic change for our region when power sources like Trojan are no longer available, when river water that has traditionally gone for hydropower development is needed for our fish runs, it is absolutely essential that our region not pass up, as it has so often in the past, any source of fuel that is cost and energy efficient and environmentally responsible. When faced with the challenges of our collective energy future, we simply cannot afford the luxury of passing up energy sources such as the direct application of natural gas in meeting the region's energy needs.

I think what would be helpful is a brief history of this issue. It has been one which the subcommittee has pursued for more than 3 years. In 1990, I concluded that the Bonneville Power Administration, which historically has had the obligation to sell electricity, needed to expand that historic mandate.

I was concerned that our region's dependence on hydropower wouldn't be sufficient to meet needs as varied as keeping or contracting more family wage jobs and rebuilding our declining fish runs.

I urged the Bonneville Power Administration more than 3 years ago to set a new course for our energy future that would promote the development of every single environmentally responsible and cost- and fuel-efficient energy source, be it electricity or anything else.

Our subcommittee specifically requested that the administrator at that time at Bonneville, Jim Jura, adopt a fuel choice or incentive program that would allow expanded use of natural gas where its use would meet the test of fuel and cost effectiveness and environmental responsibility. Consumers would be able to choose this power source if negative impacts on nonparticipating utilities were minimized, and where it was clear that the direct application of natural gas would have clear benefits for the region.

This project was established in November 1990. There was, as many predicted, great opposition to this program, and this program was eliminated early in 1992.

I felt that the elimination of the fuel choice program was a mistake. I continued to work with the current administrator of Bonneville, Randy Hardy, on the development of a new fuel choice program. Mr. Hardy has worked consistently and cooperatively with the subcommittee, and, in October 1992, Bonneville agreed to spend $3 million to support fuel choice pilot projects with natural gas. The agency stated at that time it would also pursue changes in the manufactured housing program to create opportunities for the expanded use of natural gas.

I am of the view that the need for an aggressive, comprehensive fuel choice program for our region is even greater now than when the subcommittee began this fight. With the extraordinary economic changes that I touched on, and the very significant possibility of rate hikes in the days to come, it is clear that we must pursue every opportunity to save costs and promote expanded fuel choice for the future.

For that reason, we are going to ask Mr. Hardy to begin today's hearing by briefing the subcommittee on the accomplishments of Bonneville's current fuel choice program and discussing what new steps might be taken at this time to accelerate further development of responsible fuel choice.

[Chairman Wyden's statement may be found in the appendix.]

Chairman WYDEN. Before we hear from Mr. Hardy, the Chair wishes to enter into the record a new subcommittee survey of Northwest utilities that addresses their growing trend toward using natural gas combustion turbines.

[The survey may be found in the appendix.]

Chairman WYDEN. Of the 10 major utilities that the subcommittee surveyed, 3 were currently using natural gas combustion turbines and all 10 indicated to the subcommittee that they were considering the use of natural gas combustion turbines to meet future energy demands.

The survey found, among other things, that the Bonneville Power Administration is contracting to build Tenaska Washington II, a natural gas combustion turbine capable of producing 240 average megawatts. Bonneville is also reviewing contracts for the construction of several optional natural gas combustion turbines.

Portland General Electric is planning to derive up to 400 to 500 average megawatts of electricity from natural gas combustion turbines in the future. They have forecasted that between 30 and 40 percent of their future energy generation would come from combustion turbines.

Puget Power estimates that 90 percent of their new energy generating resources will be combustion turbines.

What the subcommittee survey shows is that our region may again be embarking on a course where too many eggs are being put in one energy basket. The prospect that our region will become overly dependent on natural gas combustion turbines, in effect replicating the decision that was made in 1980's, which was to become overly dependent on nuclear power, is a mistake that I think we should endeavor not to make again and one that warrants great care and great debate within the region.

Certainly, natural gas combustion turbines can play a very constructive role in meeting the region's energy needs, but it has to be noted that even the most advanced such turbine is less than 50-percent efficient. These turbines are no match for the 90-percent efficient natural gas water heater or the natural gas furnace. Studies indicate that using natural gas directly for residential space and water heating is capable of saving the region between 200 and 1,200 average megawatts of power in 1 year.

Certainly, the direct application or end use of natural gas appears to be vastly preferable to burning natural gas at a plant to make electricity that is then sold to heat our homes. This is the time for genuine boldness in the region's energy policy and planning. We ought to move ahead aggressively with natural gas where it is cost and fuel efficient, but with less dependence on combustion turbines. We have to step up our emphasis on conservation and the development of efficient renewable resources.

We ought to move more aggressively to tap opportunities to use Canadian gas, as we know that Alberta and British Columbia have enormous supplies.

Most importantly, the Chair believes that it is high time for the Bonneville Power Administration to adopt a tiered-rate structure that would encourage utility customers to save energy by choosing natural gas or conservation. This type of rate structure would actually save our region precious dollars by reducing demand and the need to buy replacement power, as it would encourage wiser use of scare resources and protection of the environment.

Innovative ideas such as a tiered-rate structure would also help to lower Bonneville's new resource costs.

We are also going to be exploring a number of other options today. The subcommittee has received a substantial amount of information about the possibility of Bonneville allowing utility customers who opt for natural gas or conservation the chance to resell the energy that they save.

The Chair is of the view that if such a resale created a profit and was done only through Bonneville, in effect using Bonneville as a broker, there is a possibility that such a transaction would be in the region's interest.

We also intend to discuss today the Super Good Cents Conservation Program. We are also going to focus on the progress of the natural gas utilities in meeting the region's various conservation building codes.

The time is ripe for more creative energy policies and our witnesses who are assembled today have a considerable amount of expertise, along with positive and innovative ideas to consider. Throughout the region, our citizens ought to have access to the best source of energy rather than just the sources that are available now.

Bonneville is in a position to lead the effort to consummate this new agenda, and we will continue to vigorously prod the agency and the various other public and private participants toward that end.

We want to welcome Mr. Hardy to our subcommittee. He has worked very closely with the subcommittee on these issues. I want to thank him for his cooperation. Mr. Hardy, I think you know that it has always been the practice of this subcommittee to swear all witnesses who come before the subcommittee.

Do you have any objection to being sworn as a witness?

Mr. HARDY. No, Mr. Chairman.

[Witness sworn.]

Chairman WYDEN. We welcome you and again appreciate your input. You may be ahead of me on the technological capability of the mikes over there, and I want to make sure I have got yours on.

Mr. HARDY. I think mine is on.

Chairman WYDEN. Why don't you address the principal points that are important to you and Bonneville on the subject, and we'll make your prepared remarks a part of the record in their entirety.

TESTIMONY OF RANDALL W. HARDY, ADMINISTRATOR, BONNEVILLE POWER ADMINISTRATION, U.S. DEPARTMENT OF ENERGY

Mr. HARDY. Thank you, Mr. Chairman and thank you for inviting me to testify on behalf of Bonneville's fuel choice programs today.

Before I get into my prepared remarks, I guess I would like to respond to the challenge that you put down to us at the very end of your opening remarks on tiered rates.

This is an area where we intend to move ahead on, just as you have suggested. I think you well know that, based on the discussions that we have had over the last year and a half, that represents something of a change of attitude on my part personally and on Bonneville's part as an agency. I should say I came to this job after 7 years of managing Seattle City Light, which is, I believe, the only public utility in this region with a tiered-rate structure, so it wasn't out of any philosophical differences but at the wholesale level that tiered rates do present some unique equity and revenue stability questions, and, at least initially, I was cautious about moving in that direction because of those legitimate equity and revenue stability issues.

I have become convinced, however, over the last 6 months or so, that we do need to move in this direction. A couple of reasons for that, most of them having to do with our changed circumstances, the rate increase, and the problems that we find ourselves confronted with now.

We believe that moving to a tiered-rate structure will both help encourage further fuel switching—we already think the market is doing a reasonably good job, but if it isn't we think a tiered-rate structure will certainly pick up any residual fuel switching that hasn't occurred.

It will also send the right resource development signals to our customers. Rather than paying the cost of our melded rate, they'll see the avoided cost that we are seeing when we acquire new generating resources, and we think that will help them to make more efficient resource decisions on their own, that is, whether they buy additional load growth from us or they build their own resources to meet those needs.

Finally, it will enable us to acquire the same amount of conservation, the 660 megawatts over the next 10 years, which is the Power Council's goal, but do that much more cheaply than relying strictly on program incentives. What we need is a mixture of price signals through tiered rates and program incentives to achieve the 660 megawatt conservation goal. Rather than paying 80 or 90 percent of measured cost and spending $3 billion to acquire that conservation resource over the next 10 years, we can pay considerably less than that through the Bonneville rate and, with a tiered-rate structure, accomplish the same goal.

We plan to move ahead on this expeditiously. Thanks to the initiative of the Northwest Conservation Act Coalition and some of our customers in the rate case settlement discussions, we have achieved a settlement on how to proceed on this issue coming out of the rate case discussions. That settlement will enable us to start moving ahead later this year to develop an actual methodology for implementing tiered rates and then to subsequently incorporate that into either a special rate case or the 1995 rate case.

I should emphasize that this is not a study. We are not asking whether we are doing this. We are assuming we will do it, and we are essentially seeking to develop a methodology as to how we do this. That doesn't say that there can't be a show-stopper that would come up, but we don't think there is, and we think the challenge before us now is not that we've crossed the threshold of whether to do this, but the challenge is how to design it in a way that will be most equitable to all the various parties affected by our rates and achieve the maximum benefits in terms of conservation acquisition and fuel switching potential.

That being said, I would like to review some of the past history of how did we get to where we are, and the changes that we have had down the road, which you have been an active participant and encourager in up until really the present day.

As you cited, in 1990 in our resource program we basically made a decision to leave this decision to individual retail utilities. You challenged us on that, and we moved in our 1992 draft resource program to still rely after doing a couple of data collecting pilot projects, but to still basically rely on individual utilities in the marketplace.

We did then and still think there is about 200 megawatts worth of fuel switching potential that is available beyond what the market at a melded, blended, wholesale rate would give us, but, at that point, we did not opt for further pilot programs. You again challenged us to go further and to do better. As a result of that, in the final 1992 resource program, we committed to three things:

First, to do a series of additional pilot projects, which we now have under negotiation with three different utilities, the utility customers, and gas company customers;

Second, to review our conservation programs, not all but those that might be unintentionally encouraging load building for specifically the Super Good Cents Program, and we now have that review under way. The results of it should be available later this month for that program as well as in subsequent months for the residential weatherization program, manufactured housing program, water heating program.

Finally, we committed, third, to explore providing a gas-fired option for the manufactured housing program, where we had strictly had that as an electric-only program.

Overlaying all of this in the specific issue of fuel choice and the commitments we made as a result of your prodding in the final 1992 resource program was the whole issue of our competitiveness. That's been highlighted by the dramatic run-up in our projected rate increase as a result of the drought, but that is really a symptom of a more fundamental, underlying series of problems that we have to deal with.

Certainly, for the last 13 or 14 years in this region, we have tried to be all things to all people. The customers call it the "punch bowl." Bonneville is the punch bowl with every customer and other interest group with their straws, and he or she who has the biggest straw and sucks the hardest and the fastest gets the mostest. We simply cannot continue in that vein, and we have undertaken to change, to be a more market-oriented, results-oriented, cost-conscious kind of organization.

That involves two principal things: First, is getting ourselves much more efficient. That is part of what the cuts in Super Good Cents are a small part of. Second, is unbundling our services. Right now we provide one product. It is kind of vanilla PF power, and we load all of our costs onto that PF rate. We need to be much more strategic about how we market our services, shaping, storage, load factoring, other services which we are uniquely qualified to provide which are kind of provided now as an afterthought, not marketed intelligently, and for which we do not collect full value.

The final part of the competitiveness projects is changes in our rate structure, both tiered rates of the type we have mentioned already, and eliminating some of the subsidies that exist in our rate structure or at least taking a hard look at those—irrigation discount, low-density discount, variable rate for the DSI's—to eliminate or minimize the number of cross-subsidies that we currently have in our rate structure.

Another important part of our competitiveness is our long-term resource acquisition strategy. We think tiered rates will move us in that direction both in terms of improving the efficiency of our conservation programs and encouraging more retail fuel switching to natural gas or natural gas as a fuel choice beyond what the market does not now dictate, but we also think that generating resources are needed and that combustion turbines and/or gas-fired cogeneration resources play an important role in that future.

I would agree with you that there are limits to the degree to which we want to acquire gas resources. Right now we don't have any, so I feel comfortable in saying that acquiring some is probably a prudent move.

Our resource acquisition goal is to acquire the most cost-effective resources, period, with all environmental costs internalized as part of that cost consideration. Based on the Northwest Power Planning Council's plan and the amount of conservation that they project, conservation alone will not meet the 1,500 megawatts of new resource need that we have over the next 10 years. Some generating resources are necessary even if you count the 200 megawatts of fuel switching potential that is out there beyond the market, so we believe we need to acquire new generating resources. We have selected the Tenaska project. The project that you referenced is the best of those initial resources as a result of the competitive bid process.

In addition to it being the most cost effective in an absolute sense, it is a unique resource in the way that it integrates with the hydrosystem. It is what we would term a hydrofirming resource. That is, we can displace it with surplus hydro up to 50 percent of the time so it actually increases the efficiency of our overall hydrosystem substantially above the 50-percent figure that you mentioned as the maximum figure because of the way it works with the hydrosystem. We are not planning to run this resource as a baseload plant. We are planning to run it as a displaceable resource and utilize that flexibility to maximize the overall efficiency.

It also brings us unique benefits in terms of diversifying our risk. I would fully agree with you that one of the lessons that we learned in the 1970's and 1980's with the WPPS plants was that quite apart from the construction problems, the cost overruns, and everything else, what we learned with the single nuclear plant that we have, that having 1,100 megawatts in a single shaft is a highly risky proposition. The advantage that CT's give you is you have to get that same 1,100 megawatts of capacity. You probably have four or five different resources so that if one of them fails, the consequence of that failure, and going down for some prolonged period of time, is a lot less than if you have it tied up in a single central station resource.

In conclusion, I would just say that we see natural gas playing a very important role in our future, in the region's future, both at the retail level and the wholesale level. We are moving in the retail level in the three areas I mentioned—tiered rates, the Super Good Cents review, and the other review of our programs—to make sure they are not encouraging load-building, and the three pilot projects, two in Washington State and one here in Oregon, that we made as a result of our 1992 final resource program.

We are also moving in a wholesale level with the acquisition of the Tenaska project and acquiring options on other projects which will in all likelihood be gas fired.

We think the result will be cost effective, balanced, and environmentally responsible energy for the future, for Bonneville, and for the region.

With that, Mr. Chairman, I would be happy to answer any questions.

[Mr. Hardy's statement may be found in the appendix.]

Chairman WYDEN. Mr. Hardy, we thank you. That was very helpful, and, as I said, we have appreciated all the cooperation you have shown us.

It seems to me your message on tiered-rate structure is unquestionably a positive one. People can take out of here that Bonneville is breaking new ground, that, in effect, you are saying it's time for a tiered-rate structure so that we can set it in place. Then we get down to the nuts and bolts of actually how do you do it and what the timetable is?

Let me see if I have the big picture straight. You're going to try and do the methodology this year, 1993, and then, presumably if all goes well, you could see this coming up in the rate case next year?

Mr. HARDY. It's a little different. We think it will take about 9 months to a year so we are talking about a July 1, 1993, to July 1, 1994, methodology development process, given the complexity of the equity issues that I have alluded to before and lots of the other issues that interplay with this—billing credits, resource development incentives. I mean this affects a whole range of our activities.

Our target is July 1, 1994, to have a methodology developed that says this is how it is to be done. At that point, we then have to get the formal sanction of a rate case. It has to be a rate-related process so that we get the legal support to be able to implement this, and we anticipate, at least based on what we know now and knowing that we will uncover a lot of other issues, going through a special 7–i process, special rate case process from July 1994 to the end of 1994, and in which case that, if it becomes a done deal, we simply drop it into the 1995 rate case. It is already settled. There have already been all the legal arguments, and it just gets implemented along with all the other issues.

If I can do it sooner than that with the 7–i process, I probably will. If I can't, it will simply go into the 1995 rate case, but I am not anticipating any argument over it because that will already have taken place, and we'll be well on our way to implementing it. People relative to the decisions that they will make, relative to fuel choice decisions, or acquiring their own resources, will be planning on the basis that come October 1, 1995, that goes into effect once we have the methodology developed, so I think it will have the appropriate end effect we hope it will have much earlier than any 1995 implementation date if we ultimately have to wait that long.

Chairman WYDEN. Did you say October 1, 1995 or—I mean if you go July 1, 1993, to July 1994, couldn't businesses and residences, in effect, be operating under the tiered-rate structure January 1, 1995?

Mr. HARDY. Potentially. What I have to assess is whether I can do that in a special 7–i rate process. It gets hooked up with ultimately that has to go back to the Federal Energy Regulatory Commission for review. They potentially open up other issues. Whether we can do that and keep it narrow is the basic challenge there. If we can, we will move in that timeframe. If we can't, it will simply be dropped in as a done deal in the 1995 rate case and that's our game plan right now.

Chairman WYDEN. Do you need any legislative changes? Are there any matters that the delegation needs to pursue that will, in effect, strengthen your hand and allow you to pursue this just as expeditiously as possible?

Mr. HARDY. I am not aware of any such need at the present time, Mr. Chairman. However, I won't hesitate to come to you and other members of the delegation if we require such legislation, but I am pretty confident that we have the authority within the Northwest Power Act and our other statutes to implement this kind of a rate structure and that is within our own discretion.

Chairman WYDEN. Let us move on to some other areas you heard me reference in my opening statement. I am concerned about the possibility that we are going the route of the 1970's by putting all the eggs in one basket, meaning the natural gas combustion turbine option seeming to pick up such increased interest and extensive commitments.

In December, Bonneville announced that they were beginning negotiations on 10 options. All but one of the options included gas-fired generation, either combustion turbines or cogeneration. I think you also heard me say I certainly support some role for the combustion turbines, but I think it would be helpful if you could set out for the region how Bonneville and your work can ensure that the region doesn't, in effect, stack the deck as we did in the 1970's and 1980's with nuclear on the combustion turbine, and that we have a balanced program and not one that over-invests in one area.

Mr. HARDY. I'll certainly be happy to try. Let me describe some process checks and balances, and let me describe some what I regard as substantive checks and balances that will prevent that.

In a process sense, we are working closely with the Northwest Power Planning Council. In fact, the resources that we acquire, most of these resources would be above 50 megawatts, which is the threshold for the Council to have to make a formal, what is called 6-c determination, that is, that that resource—and the Tenaska Project is going through this process right now before the Council; you have Councilman Duncan on your program later today to talk about that—the Council ultimately has to find that project consistent with its regional plan. I think there is a clear check.

We also, every 6 months in our resource planning process, are checking back to see what are our loads, what resources do we have in the pool, what's prudent to go ahead with, and we are continually reviewing and updating those kinds of changes, so it is a continual planning process, and check-back process, and working closely with the Power Council with a requirement that they find those resources that we acquire consistent with their plan, I think, provides some assurance that we will not go overboard in the gas acquisition area for turbines.

Now relative to acquiring turbines, we have in terms of how we go about that, we have a number of things that we can do to minimize the risks which are undeniably there. I mean you may get away from thermal plant risks and those kinds of risks but you have got gas supply and price risks at the wholesale level. You can diversify those by virtue of where you locate the turbines, which pipelines you hook up to, the nature of the gas to contracts that you have, whether they are hydrofirmers or not. I mean the fact that we can displace Tenaska with surplus hydro insulates us to a significant degree against supply and price risk.

All of these projects that we would anticipate—this is the case with Tenaska and we would anticipate this being the case with other projects—that we would have oil-fired backup generation in case we had a cold weather snap, and we wanted to run a particular turbine, and gas was not available or its price was prohibitively high, that we have at least a 1- or 2-week oil storage capability to generate on an emergency basis there.

I think the sum total of what we are looking at of those kinds of things, where you locate them, the operating characteristics that you associate with them enables us to diversify our risk.

At some point, and I am not sure precisely where that point is, you'd probably say that's enough gas-fired resource as a proportion of your overall resource portfolio. Right now we are at zero, so I am not terribly worried about that.

I guess I would say, and this is purely a guess on my part, once we get up to the 15- to 20-percent range in terms of resource portfolio, and it is at that point we probably want to think before we would go any further in terms of what our risk is so we have balance between our hydrogeneration potential, our remaining nuclear plant, the conservation activities that we are engaging in, and the turbine, gas-fired turbine, or cogeneration facilities.

I think that makes for a balanced portfolio, and it's just like dealing in the stock market, to the degree you have balance you have diversified your risk, and to the degree you have decreased the size of the resources and spread them in different pipelines. It diversifies your risk and I guess the lesson that I have carried away from the WPPS experience in the 1970's and 1980's is that I am, and I think most utility executives are, very risk-averse people these days, and I am highly motivated to minimize my risk and diversify it. I frankly see turbines and the way they integrate with the hydrosystem in their proper place as a good tool to do that.

Chairman WYDEN. On the Super Good Cents Program, the electrical utilities, I want to make sure I have understood this. Are you advocating specific changes in Super Good Cents today that you all are going to pursue?

Mr. HARDY. Yes; we will be formally announcing this in the next day or two. We have completed the preliminary review of our Super Good Cents Program. We have found that, in fact, 1 percent roughly of all single family homes where there potentially was some load building impact, albeit unintentional, so the percentage isn't high, but, in fact, that has a fairly significant effect on the overall cost effectiveness of the Super Good Cents Program if you take out that amount of unintentional load creation.

As a result of that we will be announcing today or tomorrow probably a 25- to 30-percent cut in our Super Good Cents budget. That will involve cutting advertising and administrative overhead, but it will also involve reducing incentives in that program so that we don't have overly generous incentives that cross the line between making things efficient electrically and encouraging unintentional load building.

Like I say, we'll be announcing that—I guess I am announcing it now. We'll have something out in the next day or two on it, but that's as a specific result of the initiatives that we undertook in the 1992 resource program as a result of your urging, and I think we reached a conclusion that there was some legitimacy to the concerns that we heard expressed by some of our utility customers.

You have Les Bryan of Washington Water & Power on later today who I believe will probably speak to those. In fact, some of those concerns were legitimate. We're going to try to correct for that. We still think Super Good Cents, in a slimmed down, trimmed down fashion, is a viable program, but we do need to reduce the incentives, particularly in zones 2 and 3 to eliminate any inadvertent load building, and if we need to go further, we will. We haven't ruled out that possibility of even moving to eliminating the program altogether in areas where gas is available, but this is the first step, and I think it is a pretty significant one.

Chairman WYDEN. You are going to announce it obviously formally, but if you could, take me another step further on the incentives issue because we are going to be kicking that around all today. I think it is very welcome in terms of the cuts in the advertising as well. I do hear an awful lot of flack from citizens about that—when we are talking about a rate hike and the like. They look at those budgets and say PR ought to go, and I think that is welcome news.

In terms of zone 2, you talked about zones 2 and 3 for the first kind of focus in terms of changing the incentives. What does that actually mean to people who use this program, if you could talk a little bit more on the incentives.

Mr. HARDY. Zone 2 is Eastern Washington and Eastern Oregon. It's immediately east of the Cascades. Zone 3 is essentially Western Montana and parts of Idaho. They are climate zones where you have different levels of insulation that meet different cost-effectiveness tests considering that the temperatures are colder. Those are the two zones where you have the principal problem. I'm not sure what we are doing exactly in zone 1. There may be some cuts there as well, and I haven't reviewed the details of that but the basic idea is to reduce the level.

We provide quite generous incentives—$2,000 to $3,000 a house—sometimes, and when you combine those with incentives in other programs, for instance heat pumps and some other programs, you can get what amounts to as an incentive or a subsidy as some would call it of $3,000 to $4,000 a house to encourage you to get your home more efficient, but if you are in an area where gas is available, that may encourage you, particularly if you are a builder, to build a whole subdivision that is electrically heated rather than gas heated. Well, that is a problem.

Like I say, we found that occurring in less than 1 percent of the overall single family home starts region-wide. That was still enough to fairly substantially affect the cost effectiveness of our overall Super Good Cents Program, so our first step here is to cut that incentive by 20 to 25 percent and still provide some incentive to get those homes built efficiently if they are going to be built electric but not provide such a generous incentive that we affect the basic fuel choice decision and cause a home that otherwise might have gone gas to go electric. If it does go electric, at least we will assure hopefully that it will be built in the most efficient way possible, and that is what this effort is an attempt to do.

Chairman WYDEN. Let us turn next to the Manufactured Housing Program. As you know, this has been an area that the subcommittee has had a great interest in, and I think there is considerable frustration in the region about trying to get the gas option into the program, again, not as a mandate, not as something that is preferred, but as an option, as a choice. What had been the obstacles, and what is left to do to really nail this down, get it in there, and make it part of a comprehensive choice program?

Mr. HARDY. Well, as was announced in the 1992 final resource program, we worked hard to try to develop a gas option. I offered to basically handle all the administrative costs for whether it was Northwest Natural——

Chairman WYDEN. You offered that to the utility?

Mr. HARDY. Yes; to the gas utilities—if you want to come participate in this program, you put up the incentive money. I mean we were paying typically $2,500 a manufactured home on the electric side to get those homes built as efficiently as possible, and we're already administering that program with the individual manufactured homebuilders and the electric utilities. For a fairly modest additional incremental cost, we could offer that same option to any of the gas utilities for them to offer an incentive.

I was not willing to offer a financial incentive for them to build their home more efficiently. That's their job. I didn't try to tell them what the incentive was. I didn't say it had to be $2,500 like ours, and, based on the statistics that we got from NGU and Northwest Natural and others, it appeared quite likely that a lower incentive, maybe $300, $400, or $500, would be the maximum cost-effective level that they could use, but at least it would be something.

I think the thing that ultimately frustrated our ability to do this on a voluntary basis was the imminent prospect of new HUD standards that would make manufactured homes more efficient which will go into effect later this year, and I think—although you have got Northwest Natural, and I don't know if you have the Oregon PUC on, which was also part of the discussions, and the Power Council later this year—the conclusion that people came to was with the new HUD standards that we're going to require that the homes be built to a higher efficiency level, it simply didn't become an economic proposition for the gas company to put up any incentive money.

It's still probably economic for us to continue to run the program on the electric side, albeit perhaps with a different incentive level. I think that is good news in essence that we are going to get more efficient homes by virtue of HUD standards and regulation rather than having to offer incentives through electric rates or otherwise to do that, but it was my understanding that the prospect of that change in HUD efficiency standards basically rendered it noncost effective for the gas companies to think about participating in a gas-fired option.

Chairman WYDEN. Let me ask you also, and we appreciate having you here because it allows us to kind of open this with sort of an overview, what your sense is on what we should be asking other players to do, particularly the Power Planning Council and the State DOE's in the region, to try to promote fuel choice?

For example, my understanding is when a homeowner switches from an electric water heater to a gas one, the Council doesn't consider that conserving electricity, is that correct?

Mr. HARDY. I believe that is correct. I mean it's based on the definition of the conservation in the regional act that talks about increases in efficiency in the legislative history associated with that, in that, fairly narrow context, but that is the working definition that we have, and I think it is the working definition that the Power Council has, that does not constitute conservation per se.

That doesn't say there aren't some abilities to get at that issue, and that is what we have been struggling with, but we don't have quite as clear legislative authority as we do to fund insulation improvements and other conservation measures.

Chairman WYDEN. What else can we do to get the Council going on that particular issue, short of legislation? I think we in the delegation know the peril of having the act on the floor of the United States Congress.

Mr. HARDY. I really think we are headed, Mr. Chairman, in the right direction here. I think that's been in large part responsive to the urging that you have consistently given us at Bonneville but also others in the region. I really think that the opportunity here is in the tiered-rates area, and the Council needs to play a role with us as well as with the customers in that area.

I think that is the most productive area for us to work hard at designing a rate structure that sends the right price signals but also provides some predictability and some stability so people can plan on that, and then the Council can take that and incorporate the savings that we anticipate, both as a result of conservation measures and as a result of initial fuel switching, and put that into our load forecasts or into our resource supply forecast, whether we call it conservation or we call it something else.

I have already told you that I am quite confident we have the legal ability to implement tiered rates, and I really think that is the best potential solution to this problem. We need the Council's active participation. I talked with Angus at some length about these issues, as well as other Council members, and, at least my impression, almost unanimously from Council members, is they are very supportive of our moving in this direction. I think we have considerable customer sentiment to move in this direction, although some trepidation given that there are potential winners and losers when you start making major changes to your rate structure.

I think that is the forum where with everybody's participation, the customers, Council, NCAC, the various PUC's, and energy offices where we can do something that will really make a difference here and whether that additional fuel switching potential will be on the current market is 200 megawatts or 1,200 megawatts or some number in between, a properly designed tiered-rate structure should get that potential and solve that problem.

Chairman WYDEN. What about the State DOE's? My sense is that the State DOE's, the State Department of Energy offices in the region, have also been slow to get at this issue? You always get the sense that they too were a little bit concerned about offending somebody, and that everybody within the State was a competing energy concern, and that they have been sort of slow getting to this.

What can be done at the State Department of Energy?

Mr. HARDY. Well, I am hesitant to second guess State-related responsibilities. While we have relationships with the State energy offices and State PUC's, we principally relate to the States through the Power Planning Council, staff, and the members.

I guess beyond the tiered rates kind of issue, I guess the other thought that I would offer is that, whether it is the Council or the State energy offices or the PUC's, there are other regulatory issues that can be pursued more aggressively—codes, aligning station policies as they affect the gas companies in particular. All of those are issues that have a very fundamental and important effect on fuel choice policy.

Again, the PUC's and the gas companies, is there a financial ability or should there be to offer incentives on the gas side for manufactured housing even beyond the HUD standards? I don't know, but that is an issue really that the regulators and Northwest Natural or Washington Natural or other companies should address rather than just assuming the answer to that question is no.

I think that the problem we have had too often is people just say, well, that is done, the code's passed, let's go work on the next problem, and we have suffered from the lack of consistent focus and concentration on those issues.

Chairman WYDEN. Let me just ask you a couple of other questions. I appreciate your patience.

What about this matter of Bonneville allowing individual customers, who decided they wanted to go this route, to sell at a profit, using Bonneville to broker the amount of electric energy they saved through fuel choice or conservation?

Is this something that you all are looking at and warrants consideration?

Mr. HARDY. We have looked at it. We have looked at it at the wholesale level and what's called conservation transfers in an aggregate sense. I must say I think it presents some significant problems at the retail level.

First of all, based on the cursory look we have done to date, I do not believe I have the statutory authority to enter into those kinds of arrangements by virtue of the way the Power Act is written and the way our power sales contracts obligate us to meet the firm power requirements of our customers. I think we're prevented from doing something that allows them to arbitrage that power.

Quite apart from the legal argument, I frankly am worried about cream skimming. I think, while it seems like it might provide a benefit, if I were a utility, I know what I would do. I would go in and do the minimal number of most cost-effective conservation members so I could make the maximum profit to keep my rates down, and that means that I go in, and I do a little insulation, weather stripping, and caulking, and I wouldn't do the windows, and I wouldn't do the other stuff that you need to do, because that is the more expensive stuff, and I wouldn't earn as much of a margin on that.

I am concerned that would encourage the cream skimming dynamic that I think would outweigh any potential benefit, even if we did have the statutory authority to do it.

Chairman WYDEN. It's my understanding that British Columbia has agreed to allow gas utilities to enter into long-term natural gas contracts. Does the agency anticipate a continued British Columbian export policy that would help us in terms of assuring stable access to gas and reasonable prices?

Mr. HARDY. I think so. I mean I think clearly there are some uncertainties associated with the Canadian export policy, both in the gas side and the electricity side, and there are examples of things that have occurred in the past in the early 1970's, as well as more recently with Alberta and the California PUC, that are a problem.

I guess what I would say relative to resources that Bonneville would acquire, and I am not trying to generalize this to a gas-fired resource that Puget or Pacific or somebody else might acquire, but relative to gas-fired resources that Bonneville might acquire, which would be dependent upon contracts or contractual relationships in BC, I am relatively comfortable with that.

The reason I am comfortable is we have a whole set of interdependent relationships with BC Hydro and indirectly with the BC Government. We do day-to-day transactions, not just under the Canadian treaty, for a whole variety of things. We trade power back and forth. In the cold snap in January, we both helped each other out. They have helped us out more recently in meeting some of our salmon problems, and I would describe us as kind of mutually interdependent.

I think that has a self-regulating effect on the behavior of both entities to the extent that if somebody tries to do something untoward with a gas contract that supplies one of our turbines, given that you have got this interdependent relationship on the electricity side, and it's all regulated by the Government, I'm quite confident that they would be putting so much at risk there, should they choose to do it, that they will be very circumspect about doing anything, and I don't think they are motivated to do that anyway.

You have, at least in the form of the current Government, a Government that I think is moving toward basically a proexport policy, and so for all those reasons I think we have a situation relative to Bonneville's relationship with BC Hydro and the BC government generally that will be self-regulating and will protect us against any supply or price uncertainties associated with our gas supply in BC.

Chairman WYDEN. How are the gas people doing in meeting the conservation codes? I mean overall, how would you rate their performance in terms of meeting the conservation building codes and the conservation standards the region wants to obtain?

Mr. HARDY. Fair. Not great. OK. Not as good as us, I don't think, for the electric utilities, but, again, they have a different set of resource dynamics, and I don't want to sit up here in judgment about the resource choices that they have. They generally can develop gas and to serve new load a lot more cheaply on a percentage cost basis than we can develop electrical generation, so there are legitimate economic arguments for there being a lesser code level, and then, at least in Washington State, in fact, what we have is a dual code.

I would like to see them at the same level that, frankly, the electric's are. I think that, as a fuel line playing field, is the way to go, but I recognize that there are legitimate resource economic arguments that could argue differently and, in fact, States have made different choices.

Chairman WYDEN. Let me wrap up with one question that I think for me puts it in a way that maybe people at home can understand.

Break out for me, for homeowners served by BPA-supplied utilities, what is the break-out in terms of how they heat their homes today?

What part are gas? What part are other sources?

Mr. HARDY. Oh, gosh, I'd have to answer that one for the record, Mr. Congressman. I don't have the figures right at my fingertips, and, rather than making some guesses at that, I would rather provide it for the record.

Chairman WYDEN. Would it be fair to say that if you could get 20 to 30 percent of the people now going with traditional electric on gas that our region could save hundreds of millions of dollars?

Mr. HARDY. Yes; it is fair to say that we could save a significant amount of money, and, in fact, our projection is that, at least relative to the existing water heat load and a lot of the space heat load, will, in fact, happen. We have accounted for that in our load forecasts.

Back to the point that I made earlier relative to our resource program, we think the market over the next 10 to 20 years will, in fact, accomplish all but 200 megawatts of that kind of fuel switching potential. That will clearly save the region a significant amount of money, and the additional 200 megawatts, if we can accomplish that through tiered rates, whether it is 200, 400, or some other number, I think will result in more cost-effective choices for the region, and it is precisely for that reason as well as others that we are pursuing the two tiered-rates alternative.

Chairman WYDEN. I think I would like that for the record, because a few years ago my understanding was that Bonneville had looked at some analyses that would suggest that if 20 to 30 percent of the people, the homeowners, in the region Bonneville supplied, homeowners who were, in effect, heating through Bonneville's supplied utilities, were to shift to gas, that we would save several hundred millions of dollars.

I would like that for the record and you have indicated that you thought generally that was the case so why don't we flesh that out.

Mr. HARDY. I think directionally that is correct, but I would like to take a closer look. I think that the number that has been tossed around is $800 million based on one study.

I guess I would point out that was a pretty preliminary theoretical study that looked at a region-wide number as opposed to the Bonneville customers that you posit the question. I think the actual number is considerably less than that, but it is still significant, and I guess the point I am trying to make, Mr. Chairman, is I don't think it is particularly fruitful to debate the precise number, whether it is 200, 300, or 400. The fact is that the 1,500 megawatts that we need to acquire, I don't think under any reasonable scenario can be met solely by conservation and fuel switching.

You need some additional generation, and you need a mix and balance of those, and, ultimately, if we have questions about how much, that's why we have the Northwest Power Planning Council. They are the ones basically that pursuant to their energy plan get involved and make those decisions and that is as it should be. That was, I think, the Congress' assumption when they passed the Northwest Power Act.

Chairman WYDEN. Well, you have been helpful, and suffice it to say that your day did not lack for challenges. You are clearly faced with a whole set of issues on your platter that are of enormous concern to our citizens.

For many of them, like the weather, you can't exactly divine easy solutions, but we want to work very closely with you on this matter of fuel choice because I think this is one of the few areas that is attainable, that is capable of producing actual savings for our region and for our citizens, while at the same time encouraging sensible conservation practices and practices that discourage global warming, have other benefits. The fact that you were willing to come today and talk about how we are going to have a tiered-rate structure—we can talk about some of the specifics on how it is going to be done but we're going to have it—that there are going to be changes in programs like the Super Good Cents Program and other changes is welcome news.

We'll be working closely with you on this issue and others.

Mr. HARDY. Well, thank you, Mr. Chairman, and thank you for your continued attention and support and gentle and sometimes not so gentle prodding to get us to move in that direction, and I think that's been helpful to me personally, and it's been helpful to us as an agency to get to a better set of public policy results on this issue.

Chairman WYDEN. We will be persistent on this subject, and I think you have shown that you are willing to break some new ground, and certainly that is what our region needs, and we appreciate it.

Mr. HARDY. Thank you, Mr. Chairman.

Chairman WYDEN. Thank you. Let us go next to our panel. If we shoot at this rate, we're going to be here till breakfast tomorrow. We'll try to speed things up.

We welcome Jim Lazar, consulting economist, Northwest Conservation Act Coalition; Byron Courts, chief engineer of Melvin Mark Properties.

Gentlemen, I am going to ask you if you would to try to stay to about 5 minutes or so in your prepared remarks, and then we'll be able to have some questions and throw it open to some other matters.

Do either of you have any objection to being sworn as a witness? If you would, please, rise and raise your right hand.

[Witnesses sworn.]

Chairman WYDEN. Why don't we begin first with you, Mr. Lazar? I guess you came down from Seattle today?

Mr. LAZAR. From Olympia.

Chairman WYDEN. Olympia. Welcome. I have known of your good work in this area for many years.

We have used documents that you have prepared, written, and worked on in our work, and we welcome you and appreciate the good work you are doing.

TESTIMONY OF JIM LAZAR, CONSULTING ECONOMIST, ON BEHALF OF NORTHWEST CONSERVATION ACT COALITION

Mr. LAZAR. Thank you, Congressman Wyden. My name is Jim Lazar. I am here——

Chairman WYDEN. Hold on a second here. We've got to make this whiz-bang system work.

Mr. LAZAR. Am I hot yet?

Chairman WYDEN. You are now in the communications age.

Mr. LAZAR. OK. I am here on behalf of the Northwest Conservation Act Coalition, which is a four-State association of environmental groups, public interest groups, and progressive utilities which works on regional issues and has since the passage of the Northwest Conservation Act in December 1980.

As a consultant to utilities, utility associations, and State and Federal agencies, I have done approximately a dozen studies on the potential for fuel conversion and the savings that could be achieved through changes in rate design that would encourage more efficient use of electricity.

One of my studies showed that about 1,500 average megawatts of fuel conversion was available at prices cheaper than gas-fired electric generation. Some of that has been achieved in the 3 years since I did that study. Some of it will be achieved in response to market forces, and a great deal of it will not be achieved unless utilities, including Bonneville, change the way they do business.

The savings from achieving all of that conversion potential would be on the order of $100 to $250 million per year. Now the Northwest already has over 2,000 megawatts of gas-fired generation and more than another 1,000 megawatts is currently in negotiations. This is not a new resource for us. It's one that we have had for quite awhile.

The study looking at fuel conversion cost effectiveness is not simple. The total cost of serving a load with electricity must be compared with the total cost of serving it with gas. It's not just production costs but also transmission costs, distribution costs, and if you are adding gas customers, meter reading and billing costs.

There are many obstacles. There are technical obstacles such as appliance types and houses that weren't built with a chimney.

There are economic obstacles which are quite substantial. Line extensions must be built for gas systems. Electric utility rate designs encourage consumption rather than consideration of economic alternatives such as conservation and natural gas, and perhaps Mr. Hardy's comments on competitiveness need a little bit of response.

Bonneville is not a business. Bonneville does not operate in a competitive marketplace. The utility business is not a market. As an economist and one who has taught economics, the characteristics of a market where you expect efficient results from competition are goods are perfectly substitutable. That is not true for gas versus electricity. Consumers have perfect information about the marketplace. There is free entry and exit from the marketplace. No consumer or producer is large enough to affect the market, to have market power, and capital is fungible; it will move to wherever the highest return is.

None of those characteristics are present in the electric utility industry, and we should not expect an efficient allocation of resources from competitive activity. There is a proper role for involvement and intervention in that market.

There are also political obstacles. Public power has been resistant to efficient fuel choice. BPA has in the past and some of the investor-owned utilities have in the past.

In Bonneville's 1991 competitive solicitation, for example, Bonneville rejected conservation proposals that were more cost effective than gas-fired resource. Bonneville has obstructed and refused to negotiate with those conservation suppliers who made cost-effective proposals such as CESCO.

Bonneville refused in that competitive solicitation to even consider fuel switching but Bonneville is pursuing a contract with the Tenaska Project in Pierce County, Washington, a gas-fired electric generating project. The political obstacles are not small.

There are environmental benefits to fuel substitution. My testimony and one of my studies shows about 20 percent savings on CO_2 from direct application of gas compared with use of combined cycle generation after considering any benefits from hydrofirming. That is from using nonfirm hydro in wet years.

So, what can Bonneville do?

I'll name some things.

First, pursue fuel conversions before gas-fired generation.

Second, reform its rates. They are beginning to make progress in that regard.

Third, allow billing credits for fuel substitution. There is nothing in the act that prevents them from doing so.

Fourth, restructure the low-density discount. Mr. Hardy spoke to that.

Fifth, restructure the conservation programs. Mr. Hardy is, I think, making some progress in that regard.

Sixth, provide funding to offset capital cost of fuel conversion where it is necessary and cost effective for the electric system.

Next, what can the Power Planning Council do?

First, the Power Planning Council can reject the proposed Tenaska II project. Tenaska II is a conventional gas-fired generating resource. It is a lowest priority resource under the act.

Second, the Council can adopt rate design model conservation standards for the public utilities and the other utility customers for Bonneville.

Third, the Council can quantify the potential savings from fuel switching.

Fourth, the Council can quantify the peak demand savings from fuel switching. That is something that is becoming more and more important, particularly on this side of the mountains.

Here are some things that you and the Congress can do.

First, you can define fuel choice as a resource under the Regional Power Act.

Second, you can preserve the House-passed approach to the President's energy tax that treats hydroelectric resources as though they are thermal resources.

Third, you can implement the 1980 Building Energy Performance Standards for New Construction, a building code that was developed by the U.S. Department of Energy in 1980 and has never taken effect.

Fourth, you can amend the Public Utility Regulatory Policies Act and the Clean Air Act to define fuel switching as a resource.

The final area, what can the gas industry do? They certainly have a role here.

First, they need to ensure that appliances that are installed are efficient and cost effective.

Second, they need to secure long-term gas contracts. One of the biggest fears people have in moving to gas is erratic prices and possible large price increases.

Third, they need to review their line extension policies to ensure that they provide line extensions to all customers who should be entitled to them, but don't go extending lines unnecessarily at great expense into rural areas where it is not cost effective.

In conclusion, Bonneville has sufficient resources to serve its priority firm loads for the next 10 to 15 years without any acquisition of gas-fired resources. The only reason Bonneville would need any generating resources would be to serve its nonpriority loads, that is, the direct service industries and any load put on them for large new loads. To my knowledge the only potential need is to serve the direct service industries.

If new resources are needed, the act says conservation first, renewable resources second, resources of high-fuel conversion efficiency third, and conventional generating resources last. I think that fuel conversion falls most appropriately into the third category, a resource of high-fuel conversion efficiency, and Bonneville should not be proceeding with generating resources using natural gas until it has exhausted the priority resource stack.

Thank you very much.

[Mr. Lazar's statement may be found in the appendix.]

Chairman WYDEN. Mr. Lazar, thank you. I'll have some questions in just a moment.

Mr. Courts, welcome. I know of your long-standing interest in this.

Mr. COURTS. Yes; thank you for your consideration of my statements today.

TESTIMONY OF BYRON COURTS, CHIEF ENGINEER, MELVIN MARK PROPERTIES

Mr. COURTS. Basically, if you could go through my pamphlet, I have updated one thing here.

This is a case study of our particular buildings in our business, and exactly what has happened over the years, and how we've responded to this particular issue.

Under cost options, basically, this is an attempt to explain briefly and at a very easy-to-understand level how rates are charged for the two utilities in a commercial sector.

Gas, I guess most people know, is charged by the quantity. Electricity is charged by the quantity plus the peak load.

As we go through here, the second study is an old paper that we wrote for a gas seminar we attended which deals with boiler conversion. The boiler conversion was at the Crown Plaza. It was an electric boiler, and we did change it to natural gas.

The pertinent parts in that are section 5, which shows the actual payback calculations of 3.5 years for a $45,000 investment total.

You go on through to section 6. It shows the actual true performance of the installation and that was a 2-year, 2-month payback on that investment, the point being that on this particular scale of installation the gas was a better economic choice for our company at that point.

The financial data is in the next two pages, and there is a cumulative savings graph behind that for this particular project.

The last one shown here is the Robert Duncan Plaza, and, if you look in your pamphlet, the earlier information I gave you showed the letter which was the calculated savings. Then through working with some of my friends at Northwest Natural Gas, they volunteered to do an actual performance payback differential, and that is what you have in the bound copy.

It shows you the actual performance as far as this particular graph, which is probably the most interesting to you. It shows the actual gas consumption as a line, and the electricity for kilowatt hours equalled as the same line, and then the top part is the demand penalty payment.

The interesting part here for people who may not be consumers and cost-oriented is that besides the kilowatt hour differential between energy costs, there is also a considerable peak load consideration when you are looking at the financial values of these things. The data further is explained in the back of that.

The conclusions that I have reached through working with these different problems as far as direct application has been that larger systems obviously seem to pay back at the present rates and schedules, and we pursued that through all of our properties and applied it where we can.

Smaller systems, and I used the electrical demand load range of 75 to 100 kW and lower, would need financial assistance of some sort in order to get those done as far as being a cost-effective investment for a building owner or an individual.

We have looked into that in several of our buildings with smaller systems from 24 to 100 kW and the turnover of the investment value is not there without some assistance, so I guess my main plea would be that area be done to further your goals in fuel switching.

Thank you very much.

[Mr. Courts' statement, with attachments, may be found in the appendix.]

Chairman WYDEN. Very helpful.

Let me begin by asking you gentlemen what you thought of the principal changes that Mr. Hardy suggested today, that he is going to move to a tiered-rate structure, and that there are going to be changes in the Super Good Cents Program.

Mr. Lazar.

Mr. LAZAR. I think that Mr. Hardy gave some very encouraging remarks this morning that Bonneville is finally moving on some of these issues.

The Power Planning Council called for Bonneville and public utilities to take a more progressive attitude toward rates about a decade ago. NCAC called for that in our model plan published in 1982. One way of looking at it is it took 11 years to get here. Another way of looking at it is Randy, I think, is moving very quickly now to implement some of these changes.

NCAC was the party that proposed moving to tiered rates in this year's Bonneville rate case. We agreed to delay that to the schedule that Mr. Hardy has discussed in order to perfect the mechanism.

I am optimistic that it will occur within the 2 year timeframe that Mr. Hardy set forth. I hope it can be done by the end of 1994.

Mr. COURTS. Yes; I was very encouraged. We have been involved in energy conservation electrical measures in several buildings downtown through PP&L and PG&E, and have had some success with those programs in these major office buildings they work in.

I would like to see more of that done, and besides my professional interest in that as far as my role at my company, I think it's a very important thing to pursue for our region as a citizen.

Chairman WYDEN. I think there is some confusion on one point and maybe you two can enlighten the subcommittee on this.

I am confused as to whether or not Bonneville is currently utilizing the billing credit program as it relates to gas.

Mr. Lazar, is that correct?

Mr. LAZAR. Bonneville does not currently allow billing credits for fuel substitution. Billing credits could be used under the current legislation for fuel substitution through Bonneville's allowance of billing credits for retail rate designs that encourage conservation or renewable resources.

Bonneville believes it would require a redefinition of conservation as a resource to apply billing credits more broadly directly to compensate the costs of fuel switching programs, but there is a mechanism available to Bonneville that NCAC encouraged Bonneville to utilize a decade ago and a year ago, and we have seen no motion on that yet.

Chairman WYDEN. Do you want to add anything to that, Mr. Courts?

Mr. COURTS. Yes; I would actually.

In our conservation program with PG&E at the Robert Duncan Plaza, we studied a large number of conservation measures but were not able to look at the question of the changing of this hot water system to gas within that program because of the way the structure was set up.

The reason this project got done was that we pursued it on our own with Northwest Natural Gas.

Chairman WYDEN. That's helpful. I mean some of this is semantics and some of it is actual dollars and cents, and, as I understand it, what you both are saying is that Bonneville, in effect, doesn't apply billing credits to the fuel choice programs. That seems to be an important concern, and we are going to follow that up.

One last question. Obviously we have to make sure, as we go into this, that the subcommittee and the Congress are sensitive to the electrics and their customers' needs.

What can be done in the view of you gentlemen to ensure that we blast ahead in terms of fuel choice while at the same time being sensitive to the needs of the electrics and their customers?

Mr. Lazar.

Mr. LAZAR. Well, I mentioned a couple of things in my testimony. I think that defining fuel choice as a resource for the purpose of both PURPA and the Clean Air Act will enable the electric utilities to obtain, for example, sulfur bank credits for pursuing fuel choice. I think that will be one thing that will be attractive to them.

I think that the tiered-rates mechanism will make fuel choice programs more attractive to the publicly owned utilities.

I think perhaps the energy tax is another thing that will make it more attractive to the publicly owned utilities.

But I think the most important thing that could be done would be to change the definition in the act of what resources are what so that fuel choice programs would be clearly and unambiguously available for Bonneville funding. With Bonneville funding, I think the public utilities will be more willing to move ahead with fuel choice programs than without it.

Chairman WYDEN. Mr. Courts.

Mr. COURTS. I would like to see the fuel choice programs be funded through an Oregon energy tax credit program similar to some of the other things that we have been able to do in the commercial sector. I think that would be extremely helpful for new construction and also retrofit.

Chairman WYDEN. What was your reaction to Mr. Hardy's policy changes that he was announcing on the Super Good Cents Program?

Mr. Lazar.

Mr. LAZAR. Overdue.

Mr. COURTS. I don't think that I can address that, myself.

Chairman WYDEN. OK. Gentlemen, you have been patient, and we'll be anxious to follow up on some of these issues and continue to work with Bonneville and the other participants in this debate. Thanks for all your cooperation.

Mr. LAZAR. Thank you for your pursuit of this issue.

Mr. COURTS. Thank you.

Chairman WYDEN. I appreciate it.

Next, we have Angus Duncan, Oregon's representative on the Northwest Power Planning Council and Ms. Christine Ervin, director, Oregon Department of Energy.

I think we're asking for all kinds of bold action in the energy field today. Why don't we be bold and also call up our next panel. Mr. William K. Drummond, manager, Public Power Council; Mr. Paul Hathaway, senior vice president, Northwest Natural Gas; and W. Lester Bryan, senior vice president, Rates and Resources, Washington Water Power.

If you three gentlemen will come over, we'll have all our testimony here and then take questions.

Mr. DUNCAN. While they're coming up, Christine's budget is being held hostage down in Salem, and I would be more than agreeable to letting her go first if that comports with your notion of how you want this to progress.

Chairman WYDEN. Any economizing suggestion is very welcome. That makes a lot of sense, so let us do it just that way. Get us some name tags for these gentlemen.

It is a practice of this subcommittee to swear all the witnesses in common. Do any of you have any objection to being sworn as a witness?

[No response.]

Chairman WYDEN. Please rise and raise your right hand.

[Witnesses sworn.]

Chairman WYDEN. Ms. Ervin, why don't you go ahead and proceed if you can take 5 minutes or so, and since your budget is on the line, we'll try and offer you the questions right after your testimony and let you get back down I-5.

Ms. ERVIN. Certainly, I appreciate that.

TESTIMONY OF CHRISTINE ERVIN, DIRECTOR, OREGON DEPARTMENT OF ENERGY

Ms. ERVIN. Good morning. For the record, I am Christine Ervin, Director of the Oregon Department of Energy. I was asked to address two specific questions of yours today. First, what is the State's role in fuel choice programs? Second, what methods of regulation can be used to promote the direct application of natural gas to homes, businesses, and industry?

By way of background, I should say that two State agencies in Oregon play a role in shaping fuel choice programs. My department, as you are aware, is the central State, planning, and policy department for energy. We also run financial and technical assistance programs, represent the State in the Hanford Waste Reservation issues, and site and regulate energy facilities in the State. We work, also, very closely with the Oregon Public Utility Commission, the PUC, which is responsible for rate regulation not only for the privately owned electric and gas utilities, but certain telephone and water utilities and elements of the State's transportation system.

For a number of years, my agency and the PUC studiously followed a fuel-neutral policy in our programs. In 1990, we worked together, our staffs, my agency, and the PUC, to assess the potential for fuel switching, if you will. We conducted a comprehensive study of the long-run economic and environmental cost of using electricity versus natural gas for space and water heat that's in the residential sector only. Our joint study did find that in specific circumstances it indeed was cost effective to substitute gas for electricity.

Based on those study findings, the PUC adopted a new policy in October 1991 to encourage cost-effective fuel switching and to require the utilities to address the potential of fuel switching in their individual least cost plans.

I attach to my testimony a copy of that policy, the summary page, but in short, the PUC policy would allow gas or electric utilities to recover the cost of appropriate fuel-switching programs so long as they were economic, they promoted energy efficiency and were cost effective to customers of both of the utilities involved. As I mentioned before, those determinations would be made on a case-by-case basis in the individual utility plans.

Now, since October 1991, all three of the electric utilities have presented updated least cost plans to the PUC. They have specifically addressed the feasibility of fuel switching programs, and none of those utilities have come forward with a fuel-choice program, for several reasons, we believe.

First of all, there remains some questions on the assumptions—the data used to gauge the scale of cost-effective, fuel-switching potential. We've heard that, earlier this morning, not only in terms of State estimates and regional estimates, we don't have a good consensus as to what the potential is. My staff and those of the PUC, I should mention, do not necessarily agree with the utility assessments of how much potential exists. To that end the PUC has ordered the utilities, PGE and Pacific, to hire consultants to conduct an independent study of the potential, and that should be done some time within this year.

Chairman WYDEN. To make sure I understand that point because it strikes me as a departure in terms of State policy. What you're saying, in effect, is that now, when an individual utility presents a least-cost plan, if they haven't addressed the fuel choice issue specifically, you're prepared to go out and hire and also tell them to go out and hire an independent consultant and actually do an assessment in that fashion?

Ms. ERVIN. Well, that's essentially what we're doing right now. We basically have been talking about—and disagreeing in some cases—various assumptions used in that assessment. There certainly are a lot of areas of agreement, too, but in this case in the last round of least-cost plans, there's enough uncertainty regarding the estimates used that the PUC determined that it would be useful for us to cooperate in an outside study. That's what we're doing.

Chairman WYDEN. Is this the first time you've done that with respect to fuel choice?

Ms. ERVIN. In a study like this, I believe that is true. Now, the previous study was a joint PUC/ODO staff analysis.

One of the other reasons why we haven't seen fuel choice programs presented, I would think, is because we do agree that the rate of conversion that's taking place in the national market is significant, and it should be an important consideration in deciding whether or not new programs are needed. We are also concerned that programs could lead to the free-rider problem given the healthy rate of conversion we're seeing in the market. Essentially, we could spend some considerable program costs that would subsidize conversions that would take place in any case. But let me hasten to say that does not mean that the State is watching the fuel-switching area. We are moving forward. The PUC and my department, for example, have jointly worked to assure that electric utilities do not actively promote electric space and water heat. Some utility programs have, in fact, been modified already to take that promotional element out of their program.

In that vein—and we've talked about it this morning as well—we have encouraged Bonneville to remove the promotional elements of its long-term Super Good Cents Program. I was encouraged to hear Mr. Hardy's comments today.

The PUC has also moved to decouple electric sales from profits with the strong support of my agency and the Power Council. We strongly encourage that. My agency strongly encourages the move toward tiered rates in the Bonneville system. Fundamentally, as a department, we would first address the basic price and market barriers to programs, and that certainly is the price structure.

Let me address just very quickly then the potential from our perspective for fuel switching in Oregon. We believe, in the State, that there's about 110 average megawatts of cost-effective fuel switching in the residential sector. We have not placed any estimates in the business and commercial center. We know that there is some potential. We think it's somewhat less. We also feel that the concept of fuel switching is somewhat less appropriate for the industrial sector because the manufacturing processes are going to dominate decisions of a fuel choice there.

The 110 average megawatts, by the way, amounts to about 45 percent of the electricity used in Eugene today to give you a feel for what we're talking about here.

Future actions—I will only spend just the final minute on that. In light of these various factors that I've mentioned, we believe that we need to move forward. We believe some caution is appropriate. Several steps are needed. We need to continue requiring analysis of fuel switching in the utility least cost plans. Agencies like mine need to continue reviewing them; we need to continue modifying the utility programs including Bonneville to limit those features that explicitly promote electricity over natural gas; we need to undertake a detailed assessment of the potential on the commercial sector. The Power Council is acting in that regard. We need to have a coordinated study of the commercial sector. We need to continue moving toward price reform through decoupling and tiered rates. Finally, we need to conduct pilot programs. In the State of Oregon, the Water Power Natural Gas utility in the Medford region is designing a program now. We've been working with them on that, and we understand it will be operational by the end of the year. I think what we learn from that program will be helpful in designing other programs in the State.

Thank you.

[Ms. Ervin's statement, with, attachment, may be found in the appendix.]

Chairman WYDEN. Tell me more about what you're doing with decoupling and how that relates to this exercise involved in fuel choice and expanding choices for our region where it's in the public interest?

Ms. ERVIN. Well, my agency has essentially——

Chairman WYDEN. Your agency in concert with the State PUC?

Ms. ERVIN. With the PUC.

Chairman WYDEN. Right.

Ms. ERVIN. Our staff did an analysis of the potential and the merits of decoupling. The PUC has directed the utilities to come forward with decoupling proposals, and, as you well know, basically what we're looking at here is that under the current system when utilities sell more electricity the stockholders keep the net revenue and decoupling will simply remove that incentive to promote, in this case electric, water, and space heat over what could be a more cost-effective fuel in a number of circumstances. It's similar to the tiered-rate analogy removing that price incentive to be fuel neutral at the least.

Chairman WYDEN. Let me let you get out the door by asking you, what do you think of the proposals that Mr. Hardy is making today of two-tiered-rate structures, changes in Super Good Sense, and efforts to get the manufactured housing program on track?

Ms. ERVIN. Music to my ears. We're very encouraged about the tiered-rate proposal. That's a very, very strong move, and we've supported that for some time. I need to learn more details about the Super Good Sense Program, but from what I heard today, that is encouraging.

Chairman WYDEN. We thank you. Why don't you go off and pursue the budget. Thanks for your help.

Ms. ERVIN. Thank you very much.

Chairman WYDEN. You are excused.

Chairman WYDEN. Mr. Duncan, welcome, and thank you for all the help and cooperation you've shown to me and to the subcommittee on this over a lot of years. We'll put your prepared statement in to the record, so just fire away.

TESTIMONY OF ANGUS DUNCAN, COUNCILMEMBER, NORTHWEST POWER PLANNING COUNCIL

Mr. DUNCAN. OK. Mr. Chairman, it's always nice to get a helping hand out of DC.

My name is Angus Duncan. I'm one of Oregon's representatives to the Northwest Power Planning Council, and, Mr. Chairman, I'm submitting for your record, a copy of the Council's draft issue paper on Natural Gas Supply and Pricing and some additional documentation which I hope is useful to you and to the subcommittee.

[The information may be found in the appendix.]

Mr. DUNCAN. I need to preface my remarks by indicating that I'm speaking for myself today and not for the full council since there was not the opportunity to circulate my remarks to my colleagues and get their approval for them.

Mr. Chairman, as much as we would like, we would welcome at least one proposition in energy policy areas that would be one dimensional and self-evident. The search will go on. This probably isn't the issue, the question of proper allocation of gas and electricity heating loads, but good analysis ought to yield good working conclusions and ought to yield some actions we can take based on those conclusions, and I would like to offer today three such conclusions that have been based on council analysis regarding the appropriate allocation of gas to loads and then to address some issues that are impeding progress toward that proper allocation.

The first point is, I think to echo to some extent Administrator Hardy's remarks, that gas has value to the Pacific Northwest both for generation of electricity and for direct applications. Gas combustion turbines, preferably gas-fired cogeneration with substantial thermal capture can certainly add to the diversity of the electrical system which is now predominantly hydro and coal based. It can also diminish the diversity value of the system if it ends up crowding out other resources of value to the region including those that have been referenced in the council's plan; direct application of gas is certainly one of those. Conservation could end up being crowded by combustion turbines. So, in an even more real way, could our progress toward renewable resource development. Under some analyses, gas-fired generation could constitute 50 percent or more of the new resource toward load growth in the region. If that were the case, that would be, I think, regrettable.

The review that the council will shortly undertake is going to be an opportunity, I think, to review both the benefits of gas-fired generation and potential risks associated with overreaching in that area. Most of the council's analysis so far on gas costs and supply trends would tend to reinforce the movement toward gas-fired electrical generation if that's all we looked at because we're looking at relatively low, relatively flat-price escalation curves out into the indefinite future, substantial new supplies of gas coming on, particularly in Canada, and relatively low costs for relatively long-term contracts. If that's all we looked at we'd probably be out building nothing but combustion turbines, and that would be unfortunate because there are always instances that don't show up in the trend lines once you extend them out. Who would have guessed, say 3 or 4 years ago, that the Northwest aluminum manufacturers would be pressed by world aluminum prices that had been depressed by the dumping of aluminum capacity out of the former Soviet Union because the former Soviet Union collapsed. That's the kind of thing that just doesn't show up on trend lines, but is exactly the kind of risk that we need to plan and to assure ourselves in the insulation from.

Direct application, value of gas should not be an ideological issue. It should be a function of technology, of loads, of climate, of investment horizons, While I am a strong supporter of moving more toward direct application of gas because I think there are substantial technical and cost-effective opportunities, I don't want direct application of gas to be crowding out appropriate heat pump applications. I don't want it to be crowding out appropriate applications of solar water hearing, and there is always the potential, once you anoint a resource that has a divine right to build load, that you end up getting some negative feedback as well as the values you were trying to reach.

So, all in all, what the council has concluded on doing with Bonneville cooperation, with industry participation, with gas and electric both, is undertaking joint gas, electric consultations and planning. We've had a task force operating for about the last year now with participation from all of those folks. We have one issue paper out, and the research is well on its way toward a specific issue paper regarding fuel substitution and the analytic underpinnings of that. We may well end up with some, at least, approximation of integrated gas, electric planning in the Pacific Northwest if it appears to be of value to the region acknowledged by the gas and electric utilities for the States and consumers.

The second point, markets do work to allocate loads. Sometimes they work slowly, sometimes they work imperfectly, and when they do so they can impose costs that are unnecessary and avoidable. Some of our analysis suggests, for example, that in public power areas in the Pacific Northwest the electric penetration rate for space heat is something like 60 percent. In the region overall it's somewhere around 48 percent. In California it's close. Where the electric rates are about double what they are here, it's down around 20 percent. Those are not accidents, those are marketshares that end up driven by prices that appear in the market.

In Oregon, new single-family gas penetration rates doubled since the late 1970's from 25 to about 55 percent in investor-owned utility territory. The penetration rate is probably closer to 70 percent. That's because gas is available there and that's because until recently investor-owned electric rates were higher than most public utility rates. Those markets work, but what we find, also, is that the penetration rates are much lower and market shifts are much slower in new multifamily and manufactured housing and in conversion of existing residential space and water heating use. So, those are the areas that we want to try to concentrate in.

Third conclusion, most of the analysis that we have done and that we have seen in the region suggests that there is substantial cost-effective fuel conversion that can take place. The numbers vary from 300 to 400 average megawatts in Bonneville territory to 800,000/1,200 average megawatts region wide depending on whether you look at a realizable penetration rate or an overall cost-effective penetration rate. There's a lot, in any event, that would be cost effective to the electric utility industry to seek and to cooperate with the gas industry on.

So, if it makes sense, why isn't this conversion happening? Why isn't it happening faster? What actions would accelerate conversion. Let me suggest four or five of these. One of the problems is that conversion is not always cost effective to consumers. There are a lot of different price signals out there in the marketplace and cost-effective standards. There's the impact of first cost to consumers, there's the annual operating cost, life-cycle costs which may or may not be perceived by a consumer. There is the utility incremental cost of new power or new gas supply, and then there's a larger societal cost. What we need to do to advance conversion in dealing with this problem is to try to address, in particular, the first cost, impact of conversion on consumers to try to substitute utilities, incremental costs of new generation for the consumers' average electrical cost and tiered retail rates which have not been discussed so far today and would be, I think, a significant advance in this direction.

Second, electric gas, and gas utilities both still see profits from load growth. They still compete for marketshare except in areas where the utility serves both fuels. You'll hear from Washington Water Power shortly. We've discussed it with Pacific Gas and Electric and other utilities, and, generally, there's a much more rational allocation of load to fuel where the utility sells both fuels. That's probably not going to happen here in the Northwest, but certainly the decoupling exercises that we have under way with Portland General, and Pacific, and which is already in existence in the Peugeot service territory are major steps in the direction of changing the rate of return signals that an electric utility sees. we hope, ultimately, that a gas utility sees so that the incentive will not be there to build load. That proposition was an integral part of the council's 1991 plan and so was the proposition of tiered wholesale rates for the Bonneville Power Administration.

Right now, public utilities still lose marginal revenue to the extent that they support fuel switching. To accelerate appropriate gas conversions in those areas, Bonneville's progress toward tiered wholesale rates is an enormously important step, one which we've been working with Bonneville on for years now, and which we also applaud as others have done. The next step for Bonneville and public utilities is to address the issue retail rates in publicly served areas as well.

Electricity is available pretty much everywhere with distribution costs that are rate based. Gas is optional and conversion costs vary with the availability of gas, whether it's already in the house, whether it's in the street outside the house, or whether it requires a mainline extension with the costs of that. The regulatory bodies and gas utilities need to deal with both more liberal rate basing of main extension costs and, frankly, more risk taking by the gas utilities to get to that load and to serve it. To the extent it can be accomplished, more common trench installations and new developments to lower the overall cost of extending that gas service to being in front of a new house.

A final point here, electric utilities, fewer switch backs of heating load. If gas prices and supply shocks occur in the future, some of that conversion cost effectiveness right now is being lost because the system savings that you could achieve from smaller substations, smaller lines, smaller transformers, and so on are being lost. The electric utility has to prepare against the potential for a gas-heated house being switched back to electrical service which can happen virtually overnight. The way you deal with that, I'm convinced, is by building the kinds of barriers that discourage switch backs by insulating those consumers from price instability with the highest possible efficiency gas appliances and the most weatherized structures. It is absolutely essential that gas-heated homes and gas-heated hot water operate at the highest possible efficiency if we are going to encourage electric utilities to support this kind of conversion policy.

So, my conclusions are: There is substantial societal, regional, and utility value to be had from accelerating the shift of appropriate residential heating loads and commercial heating loads from electricity to gas. The council sees significant gas-fired generation being installed over the next 20 years. It could have the negative effect of crowding out conversions and other appropriate resources, but it doesn't need to. It's not clear that the market will accomplish optimum conversion if we don't address some of the barriers listed with some of the tools that I have suggested here today. We are beginning to address those, we applaud Bonneville's movement, and we applaud the initial activities of the electric utilities and the gas utility in this State toward reducing or eliminating some of those barriers. Finally, in any event, gas does not and should not inherit this load as an act of manifest destiny. They should not inherit it at the expense of electrical energy efficiency in homes and appliances. The electric utilities need to cooperate, and the gas utilities need to earn their market share by offering both consumers and electric utilities the full value of conversion by providing the region with the least cost, the least wasteful, and the most efficient means of heating homes and water.

Thank you, Mr. Chairman.

Chairman WYDEN. Mr. Duncan, very helpful as always, taking us in the tiered department one step further than we've been before with the retail rates and other interesting proposals. I'll have some questions in a moment.

Mr. DUNCAN. Good.

Chairman WYDEN. Why don't we just proceed with the rest of our panelists? Mr. Hathaway, we welcome you and thank you for your cooperation and interest. Why don't you proceed? Let me see if I can talk our three remaining panelists into trying to stick to around 5 minutes or so in their prepared remarks. I know we all have a biological compulsion to read all our statements to each other. I'll put everybody's statement in its entirety into the record, and if you could take 5 minutes or so and highlight your major concerns, that would be helpful.

Mr. Hathaway, please proceed.

TESTIMONY OF PAUL L. HATHAWAY, SENIOR VICE PRESIDENT, NORTHWEST NATURAL GAS CO.

Mr. HATHAWAY. Thank you very much, Mr. Chairman.

I'm Paul Hathaway, senior vice president of Northwest Natural Gas. In keeping with your wishes, I will depart from the prepared text and give you 5 minutes or less of summary and perhaps a couple of comments that aren't in the prepared text in view of what we have heard earlier.

I very much appreciate the chance to testify before the subcommittee and also want to comment how much I appreciate what you and the subcommittee have been doing over these last several years in bringing the issue of fuel efficiency or fuel choice, and you have studiously avoided, up to this point, fuel switching.

Chairman WYDEN. It doesn't exist. That word doesn't exist.

Mr. HATHAWAY. I rather like your fuel efficiency myself. I wanted to speak for just a moment on the gas industry generally. We've heard about, and honed in on, the rifle-shot issue of fuel choice, but maybe to back up for a moment or two and talk about what the gas industry is in the Northwest and what it means. It's a very significant part of the total energy used in the region, something on the order of 35 to 36 percent, perhaps, in supplying the energy needs excluding transportation fuels. The benefits are pretty obvious of what natural gas is; it's a very clean fuel, it's economic, it's very abundant, and I think you'll hear from others, or read in their prepared testimony, about the issue of gas supply which, in my view really isn't an issue at this point.

The studies that have been recognized nationwide indicate that there are ample gas supplies to last us certainly for the next 60 years or the official estimates of the proven and probable reserves and another 150 to 200 years of, harder to get out and less economic, but nonetheless, available natural gas resources that—call it nonconventional for lack of a better word—that the energy can be moved is certainly a well-known fact. They are about a million miles of natural gas pipelines across the country that can carry the resource from any of the producing areas to virtually any of the market areas where it's used.

Natural gas is an environmentally friendly fuel. It's the best fuel that we have as a burning fuel, in that regard, that's available on an economic basis. That being said gives it some credence for using natural gas where it is most efficient, and where it is most economic and brings the issue of fuel choice right up front. Why hasn't it happened in this region, I think, is a result of the history of the region, partly the culture of the energy providers of the region, and perhaps partly a legal question as was touched on earlier.

The history question says that we've been dominated by low-cost hydropower since hydropower became a fact in the Pacific Northwest, and, as a result of that, there is a very large saturation of electric use for virtually every job that's done in residential, commercial, and industrial energy use.

Natural gas has only recently become more economic in most places than electricity. We remain with a relatively low saturation, again, on an order of about 35 percent in the heating, the water heating and the traditional heating type uses for natural gas. In many ways in my view, that's a blessing for the region because it says that there is out there an amount of energy that can be shifted that can reduce the demand on an already over-taxed electric system effectively, cost effectively, and efficiently, and it can be done relatively rapidly as well. It's an existing resource that we're talking about.

An example of what is available, we'll use our own system to be specific, we have about 100,000 residential customers who use natural gas for space heating, but who heat their water electrically. If you use a figure that's fairly common, maybe about .5 kilowatts per water heater. It works out overall to a potential peak load of about 140 megawatts just roughly speaking. The numbers aren't precise, obviously, because uses will vary, but it's in the ballpark. That's a large amount of power generation requirement that is in homes that are already served by natural gas.

The least cost to convert the water heating load, if you figure $500 per unit for a total subsidy—and I don't believe that you need a total subsidy to induce a large amount of them to be shifted from electricity to natural gas, but if you use that, it winds up figuring out at around $350 or so dollars per kilowatt of installed generating capacity. Compare that with what it costs to buy the combustion turbine or other type of powerplant to provide that capacity, it's probably a half to a third of the cost of installing new power generation. Those are the economics that are fairly persuasive to me.

Apart from the fact that the efficiency of CT's at best is in the low 40 percent overall and the CT installed to meet that 140 megawatt load would burn more than twice as much natural gas compared to using it directly. So, when we talk about conservation from fuel choice, we're talking about, not only conserving electric demand, but also conserving the natural gas resource that ultimately is used either way to do that heating job. That's the issue that has been a very strong part of our discussions over the last several years. What to do about it? Well, we're working at it, and, as Randy Hardy testified, Bonneville has worked at it and is beginning to come around to some notion, at least, to promote this. My concern about that is the speed at which it's being done. I'm not sanguine enough to believe that we're going to be able to cover the electric needs by first doing all the fuel switching you can and second doing all of the high efficiency cogeneration and then doing CT's. They're all going to happen at once. But my problem is, as soon as there are enough CT's or cogenerators built, that there will be interest lost in the third and the most efficient and most cost-effective means of providing power, and that is fuel choice shifting from electricity to natural gas use. That's my concern.

I'm delighted to see the progress that's being made. We, ourselves, are working with three utilities in putting together some fuel switching programs and other programs which I think are equally important which have been touched on, things like joint trenching to reduce the cost of installing all utility facilities. Other joint efforts that we can undertake together as utilities: We're working with Eugene Water and Electric Board, Clark PUD; and we have an excellent project going with Portland General Electric where we'll share pipeline capacity with them to the benefit of both utilities' customers in reducing the costs of bringing gas in for our customers and for the customers of what are CT's on the Portland General system. So, there are a lot of ways that we work together. I feel a very strong need to urge Bonneville to be more proactive. I was a little dismayed at the 1995 date that Randy mentioned for beginning as tiered-rates programs. That may be too little and too late to do a maximum amount of good.

Our suggestion, too, is that the Super Good Sense type programs really should be eliminated. I disagree with his figure on how much that swings the market. We just did a little study in one particular area of one subdivision, and the effect of fuel choice for heating was 60 percent influenced by the Super Good Sense subsidy just in that one subdivision that we took a look at. That's a far cry from 1 percent electing to go with electric heating rather than natural gas when offered both.

The most important thing, I think, is to encourage Bonneville, the gas utilities, and the electric utilities to work together to plan the use of the resource in the most integrated way possible. We've been trying for the last several years. We have worked with the Power Council, and we have worked with Bonneville, but, as yet, we have not reached that era of continuous, really joint, resource planning that we should.

[Mr. Hathaway's statement, with attachments, may be found in the appendix.]

Chairman Wyden. Very helpful. Thank you.

Mr. Drummond.

TESTIMONY OF WILLIAM K. DRUMMOND, MANAGER, PUBLIC POWER COUNCIL

Mr. DRUMMOND. Thank you, Mr. Chairman. It's a pleasure to be here this morning. I'll dispense with reading my remarks as well and just highlight the three points that I want to touch upon and then get on to some other issues raised by some of the other witnesses.

First, as has been pointed out, there are a variety of issues that surround the question of fuel choice and what we believe needs to be addressed before a policy on fuel choice is actually implemented. Some of those questions have been raised today. Clearly, one of the concerns that the electric utilities have is the issue of take back or switchback, as it were. If a utility were to encourage the use of natural gas, the price of natural gas skyrockets, as happened in the early 1970's. What is the obligation then of the electric utility to go back and serve those customers if they change back? Questions about how high any sort of a financial encouragement ought to be when we have significant amounts and there is some dispute about whether it's 95 percent of new electric homes—excuse me, the new housing market going to gas where gas is available or just exactly what that figure is, but certainly it's very, very high.

The second point is we support the Bonneville Program, and that is a significant switch from where we were several years ago. There was a point in time when we did not support any look at fuel choice, as it were, particularly any sort of a subsidization by Bonneville, but we do support the program as outlined by Bonneville. We think it will help to answer some of the important questions that have been raised by this issue.

Third is the question of regional diversity. The public utilities that I represent go across the region. They are a very, very diverse group in both size and in the nature of their service territories. One of the utilities, in fact, is even a dual fuel utility in the State of Washington that serves both gas and electricity. The point is that we believe that this ought to be a local utility issue that they're in the best position to make the decision as to what is right for their customers particularly on behalf of the public utilities, they're all represented by electric boards, and they have to stand for election over a given term just as you do and, consequently, are very, very responsive to their members. So, we believe that it is a local utility issue.

I guess with that, let me move to a couple of the points that have been raised by some of the other speakers. First, on the issue of tiered rates, Mr. Hathaway mentioned some concern about the speed with which tiered rates might be implemented. Let me suggest that while we have some questions about tiered rates again and how they would be implemented, we're not opposed to tiered rates. Bonneville has a very real potential, as you're well aware, of rate increases over the next 3 years that could total 50 percent between a rate increase this year that will be at least 15 percent, the possibility of an interim rate adjustment in 1994, 1995 rate increase of at least 10 percent, an energy tax as you are well aware, and we appreciate your support in fighting that energy tax in its application to hydroelectric power. If it were to go as the house passed version had gone, it would be 12 percent. The repayment acceleration proposals that even the speakers supported would have added another 4 percent. The point is, Bonneville's rates are going up, and they're going up significantly.

Whether or not a tiered-rate mechanism is absolutely necessary to encourage people to become more efficient, perhaps even pursue other sorts of conservation and generation alternatives, is an open question. We believe, clearly, Randy has given the signals that Bonneville is going to go forward, and so we're going to be preparing our own tiered-rates proposal in this effort.

I would suggest that there are some other questions that haven't quite been addressed yet, one of which is allowing public utilities to become local distribution companies for natural gas. Mr. Duncan pointed to the issue of trying to combine fuels and, as Mr. Bryan here, is becoming dual fuel utilities. That's certainly one alternative that I know several utilities are interested in, and I think that's one thing that could be pursued.

Second, I think that it might be useful in future hearings to get the view point of PG&E and Pacific Power and Light. Certainly, in the State of Oregon, they serve over half of the customers here, and it might be useful to get their view point as well.

Finally, we as electric utilities have benefited from having the Power Planning Council in the region. Some of my colleagues within Public Power would disagree with that viewpoint, but I'm firmly convinced of it. The Power Council shows us the cost of not planning as a single utility, not that that actually may be the future that we pursue, but they show us the cost of not doing it, and I think that same principle could be applied to the gas utilities as well as electric utilities. So, my suggestion is that might be another alternative to pursue to see whether or not the Power Planning Council purview could be applied to the gas companies as well, and we could plan as a regional energy entity.

Thank you.

[Mr. Drummond's statement may be found in the appendix.]

Chairman WYDEN. Very, very helpful. Thank you. I'll have some questions in a minute.

Mr. Bryan, welcome.

TESTIMONY OF W. LESTER BRYAN, SENIOR VICE PRESIDENT, RATES AND RESOURCES, WASHINGTON WATER POWER CO.

Mr. BRYAN. Good morning, Mr. Chairman. On behalf of the Washington Water Power Co., we thank you for the opportunity to testify before this committee on the important questions of fuel efficiency and the effective use of natural gas in the region. I hope that my comments will be viewed by you and your committee as the beginning of a success story that was spread across the region.

The Washington Water Power Co. is headquartered in Spokane, Washington. We provide both natural gas and electrical service to Eastern Washington and Northern Idaho. We also provide natural gas service to portions of Southern Oregon and the South Lake Tahoe area in Northern California.

About 3 years ago, when we started looking at our long-term resource plan because we were approaching load resource balance, we saw gas-fired generation in our energy plan. As we looked further, we decided that something made better sense than constructing base-load, gas-fired generation and that was first seeing if we could figure out how we could get our customers, who heated their homes electrically and heated their water electrically, to convert to natural gas. About a year ago, the Idaho Commission and the Washington Commission approved a demand-side management program, a fuel efficiency piece, so this conversion effort could take place. We started that effort last May. Since last May, over 5,700 residential customers have opted for this program. We estimate that we have saved about 7.5 average megawatts. Now, when we talk about regional need, that's not a lot, but that's about a 1-year load growth from my company on the electrical side.

We expect by 1995 to save 29 average megawatts, and, over the next 20 years, our total resource package will add about 212 megawatts to our system and 81 megawatts of that 212, about 40 percent, will come from our fuel efficiency program. So, we see this as a substantial piece and the major foundation upon which our long-term resource plan is built.

I'd like to talk a little bit about the costs and what we're experiencing as far as costs. We have an avoided costs for our demand-side management programs of about 6.8 cents a kilowatt hour. We are bringing in our fuel efficiency savings at 2.5 cents a kilowatt hour. We estimate, over the life of these programs, that our fuel efficiency program will be somewhere between 3 and 3½ cents. I know of no other utility in the United States that is looking at resource additions at this low of a cost.

In addition, our customers benefit. Even with their contribution to lost margin on the electric side which is part of the program, our customers will save almost $300 a year for the first 60 months that they're under this program, and after that we're estimating their annual savings to be $500 a year. So, it's a win for the electric customer and a win for the customer who converts. It's also a win for my company because it allows us to maintain our position as one of the lowest cost energy suppliers in the region. Of course, being a combination company, it's easy for us to supply a total energy package to our customers, and we want to supply that at the lowest total cost to our customers.

Very quickly on barriers; obviously, any time you institute a program like this, the electric side of the business has to come out whole. If it doesn't, they won't support it. We have been very fortunate to have both the Idaho Commission and the Washington Commission to work with us to see how our program is doing, and they have supported that, and we have a collaborative process going on with the Idaho Commission staff and the Washington Commission staff so that we can continue this program long term.

The Northwest is resource short, and it's time for us to get after business. My side of the company is the electrical side of the house. I came out of the power supply side. We came very close this past year in the spring of having to implement the first step of a failing plant. Reservoirs will be down this year as we enter into the next operating year. We've got to get after resource additions. I can see no better resource that the region ought to go after than the direct application of natural gas. Thank you.

[Mr. Bryan's statement may be found in the appendix.]

Chairman WYDEN. Very good. Very helpful. All of you have been very good. I think we'll go back to you, Mr. Duncan, and have you start us again. You noted that you were testifying today on behalf of yourself, really on behalf of Oregon, on these issues. When do you think the Council will take a final position on fuel choice, and what do you expect the official Power Planning Council position to be on fuel choice?

Mr. DUNCAN. Well, I always hesitate to prognosticate on behalf of my colleagues because they'll pay me back for it, but the Council has pretty much made the decision to move into the area of trying to recognize the offsets and the benefits of gas and electricity serving loads that originally we focused on only for electrical purposes. Now, whether that ends up in joint planning, integrated gas/electric resource planning, that's certainly where I think it would make the most sense to end up. There is more reluctance on the part of some of my colleagues to move boldly into this area, but, effectively, we are doing so with the gas supply advisory committee which frankly is a major change, not just for the Council, but also for the gas industry which 6 or 8 years ago was filing suit to basically ask the council to stay to hell out of gas issues. So, I think there has been a major advance on the part of both the utility industries involved and the council that is really headed in this direction.

We have posited exactly the kinds of joint planning benefits that Mr. Hathaway made reference to when he observed that Northwest Gas and PGE were collaborating in a joint pipeline. There is certainly concern that the electric and the gas companies and direct gas customers could end up competing in a destructive way, but equally, there's an enormous potential for them to cooperate in a way that keeps, especially, front-end capital costs of supply down by spreading them around.

Chairman WYDEN. Let me, before you've finished, note again that this subcommittee is very, very sensitive to the concerns of electric and their customers on this. We anticipate asking them for their ideas and suggestions on these and related issues in the days ahead. We appreciate your sensitivity on these issues. The idea in this region is not to leave anybody behind. If you leave anybody behind, then you don't really look for sensible, long-term policies in this area. All you do is end up having people make demands for a bunch of coal-fired plants and lots of things that are much more expensive and are a significant environmental problem. So, your point is well taken.

Mr. DUNCAN. There are certainly significant opportunity costs, though, to our not collaborating. I think, generally, the parties in the region are recognizing that. The Council also will probably, sometime this summer, put out an issue paper specifically on the question of fuel conversions, what the data are, and what the conclusions are we ought to draw from those data. So, I think that the Council is moving progressively toward recognizing de facto that this is a resource. It doesn't necessarily have to be called conservation. It's not conservation, but it is a resource, and we can certainly deal with it as a council in that way.

Chairman WYDEN. The market seemed to be working in terms of promoting fuel choice in the household arena. That's what we've been discussing today, talking about markets, talking about households, and, clearly, we're making progress.

Mr. DUNCAN. In the new single-family household market.

Chairman WYDEN. Right. But we have not been talking much about markets, gas, and fuel choices that relate to appliances and other areas where energy is a substantial policy question. How do you think the markets are working in terms of promoting fuel choice as it relates to appliances?

Mr. DUNCAN. Well, pretty dismally, so far. I mean, that is in part because those kinds of gas-fired appliances are not widely available, and it's brand-new to most consumers, and consumers tend to be fairly conservative when they look at something brand-new like that. But certainly when we look at fuel conversions and proper allocation of direct application gas we ought to, and we intend to look at that with respect to appliances, not just space and water heating. There is some real promise, particularly in the area of, for example, gas-fired dryers and some other appliances as well where there is a substantial amount of heat applied.

Chairman WYDEN. We'll start with you specifically, Mr. Duncan. What role would you like to see a decoupling play in this whole debate about fuel choice?

Mr. DUNCAN. One of the reasons that we put the proposition of decoupling for investor-owned utilities in the Council's plan 2 years ago—the principal reason was to try to focus on short-term profits for load building as a disincentive to conservation. But one of the side benefits it has is it also tends to make fuel choice a more rational one for an electric utility. That is to say, if an electric utility is serving a house, it doesn't necessarily have to serve the space or water heating in order to earn its elaborate return from the PUC, and so it can start to look at fuel conversion, not as a threat to its market share and a threat to its short-term profits, but rather as either a subject of indifference and neutrality or arguably a resource of benefit to the electric utility if it allows them to displace new electric resource they would otherwise have to acquire. If it looks more cost effective at that point, and that impulse to protect market share becomes less of a factor or no factor at all.

I would add that I expect the Oregon PUC to address the question of decoupling to the gas companies that serve Oregon as well as it has now addressed those. The electric utilities, both PGE and Pacific Power have now submitted decoupling proposals, mechanisms to the PUC. Both of those mechanisms have been developed as a broad collaborative effort with customers, with environmental and public interest groups, with Bonneville, with Council, and the State, and I sat on both of those collaboratives. I'm very pleased with the consequences of them.

We've had a couple of discussions so far with Northwest Gas about the application and decoupling principles to the gas system as well. That's still preliminary, but I'm hopeful that will come to fruit as well.

Chairman WYDEN. Very helpful. We have more questions if the hour went late and you can stay, we may still need to come back to you.

Mr. Hathaway, Mr. Hardy, when I asked him about the track record of gas utilities on conservation, expressed some concern, and I think at the same time wanted to give you an opportunity to comment as well. This was not to set off a holy war or anything like that, but how would you assess your performance in terms of meeting the various kinds of energy codes in the region, and what do you all plan to do in the days ahead to encourage conservation?

Mr. HATHAWAY. Thank you for the opportunity. I'll give you an answer from a couple of different directions. First, our company has been in the conservation business for at least the last 15 years. That's as long as I've been with them, and I guess we have weatherized and done weatherization inspections in over 100,000 of our customers' homes. We have financed about $78 million worth of conservation in all of those homes, and I think we have promoted adherence to the conservation codes where the issue is where they are cost effective for our customers, in virtually every case. We're as conservation conscious as anyone, so I don't give us the fair rating that Randy did.

The issue comes about in the variation of the price between gas and electricity which has a direct impact upon what is cost-effective conservation to a gas customer as compared to what is cost-effective conservation for an electric customer. The dollar savings that are realized in weatherizing an electrically heated home are going to be a lot more, allowing a greater degree of conservation expenditure in that home as compared with a gas home where the cost savings per therm of gas are much less. That's been the issue. I think, as it has turned out in Oregon, certainly, our codes are as strong as any in the country, and we fully support them in all of our efforts.

Chairman WYDEN. That's something we're going to have to return to. It's probably late in the day to pursue this any more, but I think that on both the conservation codes and the next area that I'm interested in, the MAP Program, we're going to have to somehow get an accommodation if we're really going to make some progress. If we're really going to have a comprehensive fuel choice program in our region, we're going to have to have Bonneville saying gas folks are making the progress on conservation, and making the progress on MAP, and then they meet you halfway. I guess I'd be interested in your thoughts on what it's going to take to get the MAP Program going. I mean, Bonneville—Mr. Hardy comes and says, shoot, we offered to do the administrative side of it, what more is it going to take for these people? Why won't they get on with the show. I guess the question really is, are you all going to create your own MAP Program to compete with Bonneville's MAP Program or just how are we going to again have everybody meet halfway and get on with really making gas an option in MAP?

Mr. HATHAWAY. It's a similar issue there, and you heard it earlier in the testimony that what is cost effective in a manufactured home would be on the order of a few hundred dollars of a subsidy compared with the $2,500 subsidy that is the electric MAP Program. We have not pushed as hard on the MAP Program because it's a marginal market for us in many cases. The homes are smaller, the use is less, and the cost to provide service is really cost effective where you have, for example, a manufactured home development where they're close together and where the cost of the infrastructure is less. For the single unit it becomes a difficult issue for us.

The effect of the MAP Program as we have seen it in Oregon, I think there are about 18 different manufacturers that have signed onto the program, and the effect has been that natural gas is just about at a zero penetration in that market, even where the developers of manufactured home parks and developments have come to us and said, we want natural gas. The manufacturers will not deliver natural gas homes to them. We've had one individual who said, well, we'll buy the electric MAP home, put it in our lot, and then we'll convert the heating and water heating to natural gas. I don't know whether it was illegal or not by the Oregon Department of Energy who administers the program. So, even that can't be done. So, the effect of MAP is pretty severe. Again, it hasn't been at the top of our issue list because it's a marginal market.

Chairman WYDEN. Well, I don't know. We may take you all and Bonneville up to Camp David or something and work this conservation and MAP issue out, because I think both of them are important, and we'll want to pursue it.

Let me just ask one other question for you all on decoupling. The investor-owned utilities are looking at this regulatory procedure to encourage their customers to conserve and, at the request of the PUC both PGE and Pacific, now are looking at decoupling mechanisms. Is this something that the gas side would be willing to look at, too, the decoupling mechanism?

Mr. HATHAWAY. I think as Mr. Duncan said, we are discussing decoupling both with the Council and with the Oregon Public Utilities Commission. A private company like ours, or as most of the gas companies in the region are, has some inherent reservations about a decoupling of their traditional way of doing business in a competitive, market-oriented society. That's going to be an issue that has to be overcome. There is some concern, I think, residual to the first decoupling efforts that Peugeot Power and Light went through where I gather, if I understand right, the program was put into place for a year and then the rate increases that came about as a result of it were so high that they have had to reconsider it. I don't have all of the detail on that, but it's a concern to us. Nonetheless, if it is a way that is seen in the public interest to encourage conservation of resources, certainly we're going to be looking with it and working out a way to make it acceptable to our owners as well as to our customers.

Chairman WYDEN. I think that's helpful and obviously on this and virtually everything else in this area, the devil is in the details. But I think that we're going to have to continue to try to keep this kind of focus of getting beyond the turf and having the largest array of choices so that customers out there can go with what's good in terms of dollars, efficiency, and environmental responsibility. If the investor-owned utilities are looking at this, I think we want to get everybody else out there on the track looking at it, and I urge you full speed ahead in these discussions with Mr. Duncan and your other associates, so that we can keep this kind of balance as we push fuel choice.

Again, I'd ask you more questions, but I'm going to get out the door after we let Mr. Drummond and Mr. Bryan get into this a little bit.

Mr. Drummond, I guess it's encouraging to me that it sounds like the comfort level of your folks, utilities and customers, has gone up a little bit in terms of these ideas, now that you all are seeing that people like me aren't demons and aren't going to be pushing subsidies and all the rest. I want to assure you that the words "fuel switching" doesn't exist at this subcommittee nor does the word "subsidy" exist, because if we're going to keep everybody at the table and moving toward an integrated approach that has the largest array of choices, if I have anything to say about it, we're not going to have subsidies, and will get everybody in a position where when they've got the choices in front of the table, they know the Government and the policymakers have done their best to say "you've really got a free choice and not a choice that's stacked because somebody had a little more clout." I gather you all have a slight increase in your comfort level in terms of how we're going at it. Is that a fair summary of where we are?

Mr. DRUMMOND. It is, particularly as we begin to get results back from Bonneville's effort on doing a series of pilot projects on fuel switching. I think that will answer a lot of the questions that have been inhibiting us from moving forward on it.

Chairman WYDEN. Now, if the fuel-choice program is essentially decided at the local level, where I think there is obviously substantial interest, and again it takes us away from big decisions, subsidies, centralized policymaking, and the like, do you think the acquisition of generating resources such as natural gas turbines ought to also be decided locally?

Mr. DRUMMOND. Definitely. The public utilities involved in resource acquisition are interested in looking at alternatives and that involves the vast majority of them in the region. Do it with open eyes. The experience in the 1970's and early 1980's, in terms of resource acquisition, was not a very pleasant one for public utilities. A lot of people lost their jobs. A lot of managers, or excuse me, a lot of commissioners and directors were thrown out of office over both the Washington Public Power Supply System and some other resource ventures as well. So, people go into it very, very cautiously, and there's no way that a public utility manager or a board could possibly go into it without the full knowledge and consent of the people who they represent and the people who they serve. The have to get elected every couple of years and that's a real strong incentive to do what those folks want.

Chairman WYDEN. You have to explain the BTU tax, too, just like the Congress people felt, giving a filibuster here, just passing on that. One of my colleagues in the Congress was back home for the town meetings and things like that. Mr. Duncan knows that I have these when we come home and people come and share their views. He came back from Washington and told the story about one of his constituents coming up to him and saying, Congressman, this is outrageous, I don't even own a BTU——

[Laughter.]

Chairman WYDEN [CONTINUING]. Why are you people making me pay taxes. The Mrs. doesn't own a BTU either.

No, you all are much in the same position as those of us trying to come up with a plausible case on the BTU's, and I hear you on that.

On the matter of some of the associated expenses for setting up fuel choice programs, things like pipeline extensions and some of these installation costs, again, we're going to have to figure out how to do it, and whatever we do, spread it fairly and equally so that people don't feel they're taking a special hit, and that some other fuel source becomes competitively advantaged in the process. What are your thoughts on how that task ought to be undertaken say with Bonneville, the public? How do we get into the process of allocating those costs fairly?

Mr. DRUMMOND. That's going to be a very, very difficult issue. One of the things that we found encouraging about Bonneville's program is that it does involve a contribution from Bonneville from the gas company and from the consumer, and I think that in any program you're going to want to have those sorts of contributions. How that actually gets allocated out as to the capital costs involved, that's something that's going to have to be worked out. I don't have a good answer for you.

Chairman WYDEN. Interesting idea. Would you then say, and maybe I'm just kind of picking up on your idea, that you would feel fairly comfortable about putting Bonneville in charge, at least initially, maybe subject to some sort of input later down the road, of trying to make the initial apportionment decision?

Mr. DRUMMOND. Well, they're going to, as part of this pilot program, anyway. As I said, one of the things that enticed us about the pilot program was that one, it had the three different groups——

Chairman WYDEN. Can I interrupt you again?

Mr. DRUMMOND. Sure.

Chairman WYDEN. Because this is a good point. My understanding is they're going to do it for the pilot program, but that's not policy for Bonneville at large yet with respect to gas choice, is it?

Mr. DRUMMOND. Their only policy right now, at least with respect to fuel choices, is the pilot program.

Chairman WYDEN. I interrupted you. I think you're making a good point. You'd like to see how this apportionment process works in the pilot projects, and I think that that's a very valid idea. I'm saying that I think the point you made of having Bonneville, in effect, try to orchestrate the apportionment of costs makes a lot of sense. We will follow up on it.

Mr. Drummond, anything else you want to add?

Mr. DRUMMOND. No; I don't think so. Thank you.

Chairman WYDEN. All right. Let us go to your sidekick.

Mr. DRUMMOND. May I real quickly?

Chairman WYDEN. Sure.

Mr. DRUMMOND. Just on the manufactured housing program, because that's gotten a lot of discussion today. From the electric utility side, and I had staff who were involved in those negotiations from the beginning, there are about 11,000 manufactured homes that are built annually in the region. About 90 percent of those are all electric. We viewed the manufactured housing program as a win/win situation. It was a win for the Electric Utility and for

Bonneville, and it encouraged conservation and got fuel efficient or certainly electrical efficient manufactured homes out there in the region, and it was also a win for the consumers because they saved about $300 a year on their electrical bill from buying one of these homes. So, that's why we thought it was a real good idea. I would agree it's important to try to get that other 10 percent that ends up or does not end up being electrically heated through water heating. But I think that the program overall is still a good one.

Chairman WYDEN. I don't think that's being debated. I think that the question is what more can we do at a time when we're in the throes of everything from fish to rate hikes to economic change and the like, so rest assured, nobody is saying the manufactured housing program isn't useful.

Mr. Bryan, are you all involved in a rate case now with respect to natural gas?

Mr. BRYAN. Yes.

Chairman WYDEN. What is the situation there?

Mr. BRYAN. Well, the rate increase that we asked for in Washington was approved, and the rate case in Idaho has been deferred for a later date because we had an intervener, and they were both tracker increases, tracking the costs of the transportation of gas.

Chairman WYDEN. How is this likely to affect your customers? You have to make some judgments obviously.

Mr. BRYAN. Yes.

Chairman WYDEN. How much? How it might come out?

Mr. BRYAN. We had about 100 letters in the State of Washington from Washington customers that went to the Commission. Those letters were from people who had participated in our fuel efficiency program and ones that were in the cue. Obviously, we're concerned how they feel about this. We're working hard to develop information to get it out to them. We have already sent letters to those who participated in the program showing them the economics of their decision, and we're continuing to intensify our public communication process.

Chairman WYDEN. What's your sense about conversions from electric space heating to gas space heating? The implications in terms of costs and what you all have looked at?

Mr. BRYAN. Our program is based on a total resource cost so we have to build the cost of gas into the level of incentives that we provide. Our avoided cost is dropping, and we are in the course of making a mid-term adjustment. We will probably be reducing our incentive payments in order to encourage our customers to make the switch. But our natural gas prices are about 40 percent of our electric prices. That's pretty much the case with the customers who border our system, the REA's and the co-ops. Our electric rates are very similar, so from a customer standpoint, it's really in their best interest to use natural gas as the heating fuel of choice.

Chairman WYDEN. How has fuel choice reduced your peak load?

Mr. BRYAN. Our energy load so far, as I indicated earlier, has dropped about 7.5 megawatts. We haven't converted that to peak, but I would estimate that probably somewhere in the range of 10 to 15 megawatts.

Chairman WYDEN. That is 10 to 15?

Mr. BRYAN. Yes; that's just since last May.

Chairman WYDEN. OK. Anything else you wanted to add, Mr. Bryan?

Mr. BRYAN. I might just add a couple of comments, one on the tiered rates. My company supports tiered rates. We have been discussing that issue within the region for the last couple of years. I believe that tiered rates will facilitate the development and acquisition of resources where they should take place, and that's at the utility and not at BPA. I think the utility would be much more effective, and it will have lower cost resource developed in the region. I think two-tiered rates will be a positive in getting resources on line at the lowest cost.

With respect to the Super Good Sense adjustments that Mr. Hardy talked about, my company is very much in support of those changes. Although we haven't seen the details, and I guess time will tell when we do see the details, we believe there has been misuse of the Super Good Sense of moneys, and I have given testimony before the Regional Power Council relative to that misuse, and so, hopefully, those changes will eliminate that.

I don't have a lot of details on this, but I was told by my people that there are also economic development moneys coming from the Federal Government that are being utilized to exclude natural gas as a fuel of choice by the REA's and the co-ops.

Chairman WYDEN. We will follow that up.

Mr. Bryan, Mr. Drummond, Mr. Hathaway, and Mr. Duncan, an excellent panel, and I will tell you that I take considerable satisfaction in how far we've come in 3½ to 4 years since we've been banging away on it. Mr. Drummond is smiling. We had a few spirited conversations when this whole issue began, and I think we made a lot of headway. We are going to continue in this vein that I think is encouraging, and that we've heard today. We'll just keep everybody at the table and continue to look at ways in which we can, in effect, take energy policy and energy planning up to the next level and continue to keep in mind that every step along the way, that if you're not fair to people, almost undoubtedly it's going to cause extra cost to the region, economic dislocation, and set back the effort that I think all of you have committed to, which is to set a new energy course that gets all the options on the table, but assures that nobody is unfairly advantaged at the same time.

We thank you for your cooperation, and I'll follow up on a number of these matters very quickly. Unless you all have anything further to add, we'll adjourn at this time.

[No response.]

Chairman WYDEN. You are excused and the subcommittee is adjourned.

[Whereupon, at 12:50 p.m., the subcommittee was adjourned, subject to the call of the Chair.]

APPENDIX

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HEALTH AND LONG-TERM CARE
SUBCOMMITTEE

CO-CHAIRMAN
FORESTRY 2000 TASK FORCE

STATEMENT OF CONGRESSMAN RON WYDEN
FUEL CHOICE HEARING

Today, the Small Business Subcommittee on Regulation continues the inquiry begun more than 3 years ago into how natural gas might be used to help increase cost-effective, energy-efficient fuel choices for the Pacific Northwest.

This discussion is about empowering consumers by giving them the flexibility to choose lowest cost, most available sources of electrical power. As a result, we must encourage utilities to develop and promote conservation. Precious energy resources would be conserved for wiser use.

I am concerned that unless changes are made, our current energy plans will result in significant wastage of our finite natural gas stocks.

The need for a comprehensive fuel choice program in the Northwest is even greater now than when the Subcommittee first turned its attention to this issue. Our region is in the throes of massive economic change, power sources like Trojan are no longer available, river water that has usually gone to hydropower development is needed for our fish runs, and to meet these new demands the Bonneville Power Administration projects that significant rate increases will be necessary.

When faced with the challenges of our collective, energy future, our region cannot afford to overlook the important role of resources such as natural gas, in meeting the region's energy needs. We are here today to explore whether the use of natural gas combustion turbines should be our first choice for energy generation, or whether natural gas should be conserved for a more cost-efficient use.

A brief history of this debate may be helpful. Early in 1990, the Chair concluded that the historic role of the Bonneville Power Administration -- which has been to sell electricity -- should be expanded. I was concerned then that our region's historic dependence on hydropower would not be sufficient to meet needs as varied as keeping and attracting family wage jobs, and re-building our declining fish runs. In correspondence and meetings with the Bonneville Power Administration, I urged them to set a new course that would promote the development of all environmentally responsible and cost- and fuel-efficient energy sources -- be they electricity or any other resource.

My Subcommittee specifically requested that then Bonneville Power Administrator, Jim Jura, adopt a fuel choice, or incentive program that would allow expanded use of natural gas where its use would meet a three pronged test of cost-effectiveness, fuel-efficiency, and environmental responsibility focusing on service territories with rapid growth. Customers would be able to choose this power source, based on issues of cost and availability. The program also required that negative impacts on non-participating utilities be minimized and that natural gas projects have clear benefits for the region. This program was established in November of 1990.

In the face of strong opposition, this program was eliminated by Bonneville Power early in 1992. Believing that the elimination of fuel choice programs was a mistake, the Chair continued to work with current BPA Administrator, Randy Hardy, on the development of new fuel choice programs. In October of 1992, BPA agreed to spend $3 million to support fuel choice pilot projects with natural gas and stated that the agency would initiate changes in the manufactured housing program to create opportunities for the expanded use natural gas.

The need for a comprehensive fuel choice program in the Northwest is even greater now than when the Subcommittee first turned its attention to this issue. Our region is in the throes of massive economic change, power sources like Trojan are no longer available, river water that has usually gone to hydropower development is needed for our fish runs, and to meet these new demands the Bonneville Power Administration projects that significant rate increases will be necessary.

Therefore, we will begin today's hearing by asking Randy Hardy to brief the Subcommittee on the accomplishments of BPA's current fuel choice program and discuss what new steps might be taken at this time to accelerate further the development of fuel choices for our region.

Before the Subcommittee hears from Mr. Hardy, the Chair wishes to enter into the record a new Subcommittee survey of Northwest utilities, and their use of natural gas combustion turbines. Of the ten major utilities we surveyed, three were currently using natural gas combustion turbines, and all ten were considering the use of natural gas combustion turbines to meet future energy demands.

The survey found:

- The Bonneville Power Administration is contracting to build Tenaska Washington II, a natural gas combustion turbine capable of producing 240 average megawatts (aMW). The Bonneville Power Administration is also reviewing contracts for the construction of several, optional, natural gas combustion turbines.

• Portland General Electric, is planning to derive up to 400 to 500 aMW of electricity from natural combustion turbines in the future. They have forecasted that approximately 31%-41% of their future energy generation will come from combustion turbines.

• Puget Power expects that 90% of their new energy generating resources will be combustion turbines. Puget power presently has contracts for the construction of four new combustion turbines.

These findings suggest that our region may be putting too many eggs in the natural gas combustion turbine basket. In the 1980's, many of our energy woes stemmed from a decision to become overly reliant on nuclear power. It is important that the N.W. not make the same mistake again.

Natural gas combustion turbines can certainly play a constructive role in meeting the region's energy needs, but even the most advanced such turbine is less than 50% efficient. Certainly these turbines are no match for the 90%-efficient natural gas water heater or natural gas furnace. Studies indicate that using natural gas directly for residential space and water heating is capable of saving the Northwest between 200 and 1,200 aMW of power in one year. The direct application or end use of natural gas appears to be vastly preferable to burning natural gas at a plant to make electricity that is then sold to heat homes.

This is the time for boldness in Northwest energy policy and planning. We must move ahead aggressively with natural gas, albeit with less dependence on combustion turbines. We must step up our emphasis on fuel choice conservation and the development of renewable resources. We must endeavor to tap opportunities to use Canadian gas, as Alberta and British Columbia have enormous supplies.

Most importantly, the Chair believes the Bonneville Power Administration should move quickly to adopt a tiered rate structure that would encourage utility customers to save energy by choosing natural gas or conservation. This type of rate structure would save our region money by reducing demand and the need to buy replacement power, as it encourages wiser use of scarce resources and protection of the environment. Innovative ideas such as a tiered rate structure will also help to lower BPA's new resource costs.

There are other options that should be examined today. The Chair is interested in exploring the possibility of BPA allowing utility customers who opt for natural gas or conservation the chance to re-sell the amount of energy they save. If such a re-sale created a profit and was done only through BPA, such a transaction might be in the region's interest. We will also discuss today how the "Super Good Cents" conservation programs of electric utilities might be improved, and the progress of the natural gas utilities in meeting the region's various conservation building codes.

The time is ripe for more creative energy policies and our witnesses today have many positive, and innovative ideas to consider. Throughout the Northwest our citizens should have access to the best source of energy rather than just the sources that are available now. BPA must lead the effort to consummate this agenda, and this Subcommittee intends to continue to vigorously prod for such an energy future.

A SURVEY CONDUCTED BY THE SUBCOMMITTEE ON REGULATION REGARDING THE USE OF NATURAL GAS COMBUSTION TURBINES, BY UTILITIES IN THE PACIFIC NORTHWEST.

A survey of ten major electric utilities in the Pacific Northwest has found that of the ten utilities, three are currently using natural gas combustion turbines, and all ten are considering the use of natural gas combustion turbines to meet future energy demands.

Those surveyed are:

1. Bonneville Power Administration
2. Portland General Electric
3. Snohomish Public Utility District
4. Clark County Public Utility District
5. Pacific Corp.
6. Puget Power
7. Washington Water Power
8. Mason County Public Utility District #3
9. Seattle City Light
10. Tacoma Public Utilities

Bonneville Power Adminstration

Bonneville Power Administration is contracting to construct the Tenaska Washington II, combined-cycle natural gas combustion turbine project, in Pierce County, Washington. The Tenaska Washington II project is expected to produce 240 aMW, a significant portion of their energy load.

Portland General Electric

Portland General Electric receives 17% of their electric energy from combustion turbines. They are expecting to use cogeneration and combustion turbines to supply 31%-41% of their future energy demands.

Snohomish County Public Utility District

Snohomish County Public Utility District does not receive any of its power from natural gas combustion turbines. They are considering the use of natural gas combustion turbines to meet future energy demands.

Clark County Public Utility District

Presently, Clark County Public Utility District receives most of their power from the Bonneville Power Administration, and none from natural gas combustion turbines. They are considering a proposal for a natural gas combustion turbine which is expected to meet 100-150 aMW of their future energy demands.

Pacific Corp.

Pacific Corp. is currently operating one gas turbine in Utah. However, it is difficult to determine exactly how much power is used in the region. Pacific Corp. will be buying electricity from California Edison, to meet Oregon winter peaking capacity, for the next ten years. Most of this power is generated by natural gas combustion turbines. Pacific Corp. has also indicated that they are considering further use of natural gas combustion turbines to meet future energy demands.

Puget Power

Puget Power currently operates seven natural gas combustion turbines. They have recently contracted for the construction of four new natural gas combustion turbine plants. Puget Power has estimated that 90% of their future energy production resources will be natural gas combustion turbines.

Washington Water Power

Washington Water Power operates one combustion turbine, and is planning to construct two more natural combustion turbines capable of producing approximately 160 aMW.

Mason County Public Utility District #3

The Mason County Public Utility District #3 is considering the construction of a cogenerative natural gas combustion turbine which has the potential to meet approximately 75% of their future energy load.

Seattle City Light

Seattle City Light is not currently using natural gas combustion turbines. They are planning to construct one natural gas combustion turbine in the next ten years. It is expected that this turbine will meet 30 aMW of their future energy demands.

Tacoma Public Utilities

Tacoma Public Utilities is considering several natural gas combustion turbine projects, to be used to meet future energy demands. It is expected that such projects could potentially meet up to 15% of their future energy demands.

STATEMENT OF RANDALL W HARDY

BONNEVILLE POWER ADMINISTRATION

UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE SUBCOMMITTEE ON

REGULATION, BUSINESS OPPORTUNITIES, AND TECHNOLOGY

HOUSE COMMITTEE ON SMALL BUSINESS

JUNE 3, 1993

Statement of Randall W. Hardy, Administrator
Bonneville Power Administration
June 3, 1993

Chairman Wyden, I am Randy Hardy, Administrator of the Bonneville Power Administration (Bonneville) It is a pleasure to appear before the House Subcommittee on Regulation, Business Opportunities, and Technology.

Today, I come prepared to discuss how fuel choice can play an important role in the Northwest and in Bonneville's future as a supplier of electrical power. In my remarks today, I will use the terms fuel choice and fuel-switching interchangeably to refer to the decision builders and consumers face in selecting what form of energy to use for particular end uses. I will first briefly discuss the fuel choice activities we have pursued over the past two years, and the activities we expect to pursue in the future. I will then discuss a longer-term program to improve Bonneville's competitiveness and how fuel choice will fit into the picture.

Fuel Choice in Bonneville's Resource Programs

As part of its 1990 Resource Program, Bonneville published a study of global warming noting, among other things, that under certain conditions and for some consumers, substituting natural gas for electric space or water heating held the potential to reduce energy costs for customers and ratepayers and provide environmental benefits. However, Bonneville concluded in the 1990 Resource Program that decisions to encourage fuel-switching should be left to local utilities because many regional utilities said the decision should be left up to them. We included no actions in support of fuel-switching to natural gas or alternative fuels in the 1990 Resource Program

In response to our 1990 Resource Program, you encouraged Bonneville to work with the natural gas industry and its utility customers to foster policies that support "the use of the most environmentally responsible and cost and fuel efficient energy source--be it electricity or natural gas--" You emphasized the importance of developing a "high efficiency path" for providing space and water heating in the region, and expressed a belief that any programs to encourage fuel-switching should be voluntary, should focus primarily on higher load growth utility service territories, and should minimize any negative effects on non-participating utilities

Then and now, we concur in these principles. We have proceeded to work with our utility customers and others to identify policies consistent with these principles.

Specifically, in the spring of 1991, we convened a group of our customer utilities to explore the effects of consumer fuel choice on their business interests. We, among others, also developed estimates of the potential for cost-effective fuel-switching available in the region, beyond that expected to be delivered by market forces alone.

In our Draft 1992 Resource Program, we found that market forces would be able to deliver all but 200 megawatts of cost-effective fuel-switching, in our service territory. We also concluded that actions by Bonneville or retail electric utilities might not be appropriate in capturing the benefits of this additional fuel-switching. Recognizing this, we proposed to review the effects of existing programs and policies on fuel-choice. We decided not to embark on any programs to encourage fuel-switching.

When commenting on the Draft 1992 Resource Program, you and others reiterated the importance of encouraging the use of the most environmentally-sound and cost and fuel efficient energy sources to meet ratepayer needs You stated that the policies and actions we had proposed were inadequate, and asked that we incorporate a voluntary fuel choice program in our Final 1992 Resource Program

In response to your comments and the comments of others arguing for a more active approach to fuel choice, we expanded our commitments In our Final 1992 Resource Program, we agreed to pursue three activities

First, we would review existing programs and policies for unintended or undesirable fuel choice effects and revise our programs where such effects were found Revisions would be developed and discussed with our customers and the public before being implemented By the way, early indications are that one soon to be completed review suggests that the Super Good Cents Program in some instances hampers fuel choice. We expect to revise our long-term Super Good Cents Program by the end of fiscal year 1993

Second, Bonneville would provide financial assistance for customer-initiated projects that would demonstrate potential benefits from fuel-switching and provide information to guide additional fuel choice policies. To date we have received three proposals for these demonstrations.

Third, we would work with regional natural gas utilities, manufactures, and others to develop a fuel choice (natural gas) option in our Manufactured Housing Acquisition Program

In addition, we recognized the need to continue to develop information on fuel choice and when appropriate, support and participate in others' fuel choice efforts. We also would develop additional policy options and recommendations for our 1994 Resource Program

Given the cost pressures now facing Bonneville and a need to improve our long-term competitiveness, it is all the more important to better integrate natural gas, for both direct use and generation, into Bonneville's and the region's energy planning

Competitiveness

Natural gas and fuel choice each have a role in our long-term program to improve our competitiveness. We are initiating actions which will reforge our competitive edge. Our plan is to become more market-driven, customer and ratepayer focused, cost-conscious, and results-oriented. While recognizing our unique social responsibilities to the ratepayers in the Northwest, we will apply sound business principles to good government.

To achieve this, we are first looking at ways to become more efficient. We will seek out greater efficiencies by improving existing processes and programs and look to obtain added value from new products and services. Also, we will eliminate unneeded activities.

Bonneville is developing a corporate marketing plan that will identify our different markets and develop product and pricing strategies for these markets. We will move to "unbundle" our power products and transmission services. Our goal is to provide greater variety and more customized services to match customers' needs to the markets they serve. Possibilities will include fuel choice related activities, different types of transmission products, load-shaping, storage, and transmission and integration services. Bonneville also will examine and consider multiple rates for multiple products--concepts such as tiered rates will be explored as well Everything will be on the table.

Natural Gas Use for Direct Use and Electricity Generation

Cost and efficient use of natural gas are two important components of energy services for Northwest consumers and will be important considerations as Bonneville works to provide energy products By this, we mean efficient use of natural gas for direct use in homes and buildings and for electrical generation. These two are not in any way mutually exclusive We believe the region needs both First, I will describe our efforts oriented at the direct use of gas Then I'd like to briefly outline how gas generation fits into our plans

As I described earlier, Bonneville committed in its 1992 Resource Program to three near-term actions review our existing programs; support for customer-initiated projects, and work toward a gas option in the Manufactured Housing Acquisition Program

We are presently reviewing some of our existing programs for unintended fuel choice effects. Our long-term Super Good Cents Program review will be the first completed Results from reviews of our other programs where fuel choice is a potential issue are as follows: Manufactured Housing Acquisition Program in July 1993; Residential Water Heat in August 1993, Residential Weatherization in September 1993; and Energy Smart Design commercial buildings efficiency in October 1993

We are today proceeding in discussions with three of our customers, two utilities and a direct service industry, on customer-initiated fuel switching projects. Two of these projects involve the direct burning of natural gas as a substitute for electricity The third project is a study of the financial and economic effects of retrofitting electric space and water heat on a specific utility and its consumers We expect to have agreements signed on at least one of these projects by late June, 1993, and signed agreements for the other two by August, 1993

We will continue to work with representatives from the Northwest Natural Gas Company, the Association of Northwest Gas Utilities, the Oregon Public Utility Commission, and the Northwest Power Planning Council to explore a gas option for the Manufactured Housing Acquisition Program Our work to date indicates that the proposed new HUD standards for manufactured home efficiency will capture most of the additional efficiency that is cost-effective for gas consumers We stand ready to provide administrative support under our MAP program for gas utility and PUC programs to promote more efficient gas heated manufactured housing.

We are also continuing to promote and participate in constructive dialogue between the gas and electric industries and other interested parties. We are participating in the Northwest Power Planning Council's Natural Gas Advisory Committee, Washington Natural Gas Company's Least Cost Plan Technical Advisory Committee, and the Pacific Northwest Gas/Electric Industry Integration Task Force Later this summer, I am also planning to meet with the CEOs of the region's gas utilities and pipelines to share information and perspectives and discuss the issues.

Bonneville, like a number of electric utilities across the nation, believes that high-efficiency, natural gas-fueled electrical generation is an important component of a prudent resource mix. Natural gas-fired combustion turbines (CTs) are a cost-effective, highly reliable and environmentally attractive source of additional electrical generation We are committed to acquiring all cost-effective conservation resources; however, we also must pursue generating resources and resource options to provide the region's consumers with reliable, least-cost energy services. BPA does not currently have enough firm power to meet expected loads. Conservation alone will not close the gap of the region's energy needs. CTs are one of the cost effective generating resource additions we will need in order to meet our customers firm energy requirements

CTs are important in our resource plans for several reasons First, they are cost-effective. A broad range of analysts, forecasters, and planners believe that both the near- and long-term outlook for gas prices and availability are favorable. And, new CTs are very efficient and reliable due in part to their extensive use and continued development world-wide.

CTs are especially cost effective to Bonneville because they complement our existing hydroelectric dominated generation portfolio. Under normal water conditions, the hydrosystem has significant amounts of nonfirm power that can be used to displace CTs. The first few CTs added to the Bonneville system (we have none today) are especially attractive because of the way they integrate into and complement our existing system.

Also, CTs have short lead times, low initial costs and are available in relatively small increments as compared to other resources. Our commitment to this resource is likewise incremental This means that we can and will continually reassess the merits of adding CT generation as our needs and options evolve. This makes CTs especially valuable given the significant load growth and hydro system risks and uncertainties facing Bonneville.

Presently, under our 1991 competitive solicitation, we are moving forward to acquire the output from one CT, Tenaska Washington II (Tenaska). If acquired, Tenaska will provide up to 240 average megawatts of firm energy. We are also currently evaluating CTs and other resources as part of our Resource Contingency Program. Under this program, we will secure options that shorten resource lead times should we later elect to exercise the option to develop a given resource. After acquiring Tenaska, less than three percent of BPA's firm energy will be supplied by gas-fueled resources.

As an update on the Tenaska acquisition process, we issued a draft Record of Decision to acquire the output of Tenaska on April 28, 1993. We expect to have issued the final

Record of Decision on May 28, 1993 If we find the proposed acquisition consistent with the Northwest Power Planning Council's Regional Plan, then the Council will have 60 days to make their finding of consistency of the proposed acquisition with the Plan

Finally, new CTs are environmentally attractive when compared to other generation options Using current emission control technologies, CTs are able to operate with low emissions of nitrogen oxides and negligible sulfur oxides and particulate emissions. Emissions of carbon dioxide remain a concern, but are still much less than for other fossil fuels. CTs do not present fish and wildlife habitat problems sometimes associated with new hydro development. Indeed, their operational flexibility increases our ability to use the existing hydrosystem to meet fish habitat and flow requirements.

Conclusion

Mr. Chairman, we share your position that natural gas and fuel choice can play a major role in the new Bonneville and in meeting the region's future energy needs. We appreciate your interest in these critical issues and will continue to work closely with you, the region, our customers, and other parties to address a long-term strategy to remain competitive in the changing Northwest energy markets.

This concludes my statement, I would be pleased to address your questions.

NORTHWEST CONSERVATION ACT COALITION
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Comments of Jim Lazar, Consulting Economist
On Behalf of the Northwest Conservation Act Coalition
Subcommittee on Regulation, Business Opportunities, and Technology
Committee on Small Business
Direct Application of Gas versus Electric Generation
Portland, Oregon June 3, 1993

My name is Jim Lazar, and I am a consulting economist based in Olympia, Washington. My practice focuses on energy efficiency and utility ratemaking. My clients include public utilities, state and federal agencies, and industrial trade associations. For much of the past twelve years, I have been involved, in one way or another, in regional energy policy making. I was a founding board member of the Northwest Conservation Act Coalition (NCAC).

In 1982, I prepared a report for the National Marine Fisheries Service which recommended, among other things, that conversion of electric heating loads to natural gas would enhance the ability of regional hydroelectric system managers to provide sufficient spring and summer flows to facilitate fish migration. Since that time, I have prepared at least ten separate studies or analyses relating to the fuel choice issue. These include:

- 1987: Review of Pacific Power electric rate design for Washington Public Counsel;
- 1989: Review of Puget Power promotional water heater program for Washington Public Counsel;
- 1989: Analysis of fuel choice options for Snohomish PUD;
- 1990: Direct Application versus Hydrofirming study for Association of Northwest Gas Utilities;
- 1990: Quantification of fuel switching potential for Association of Northwest Gas Utilities;
- 1990: Development of cooperative water heater switching program with Washington Natural Gas Company for Snohomish PUD
- 1991: Participation in BPA Puget Sound Electric Reliability Project for Northwest Conservation Act Coalition;
- 1992: Analysis of Washington Water Power "Fuel Efficiency" program for Washington Public Counsel;
- 1993: Examination of Washington Natural Gas utility line extension policy for Washington Public Counsel;
- 1993: Examination of rate design and connection charge alternatives to encourage gas fuel choice on Puget Power for Washington Public Counsel.

My analyses have produced one common and consistent result. Where the existing natural gas distribution system is near a residence, conversion from electric resistance space and water heat to natural gas is usually cost-effective. The total cost-effective conversion potential in the region is as much as 1500 average megawatts of energy savings, and up to six thousand megawatts of peak capacity savings. My findings are consistent with those from other studies by other consultants, including Delta Pacific, Pacific Energy, and the Washington State Energy Office.

These figures are much larger than those reported by the Bonneville Power Administration. The differences are really not a dispute over the potential. BPA includes some of these conversions expected to result from price and consumer preference in its forecast; my analyses and the other studies are of technical potential and do not separate out the amount expected to occur without market intervention. BPA excludes any savings from homes with zonal space heat; the others do not. BPA includes only the potential in the service territories of its requirements customers; the other studies include the service territories of generating public utilities and investor-owned utilities. We really do not have any disagreement on how many homes are electrically heated, or on how many of them can be economically reached by gas lines.

Measuring the cost-effectiveness of fuel conversions is not simple. The proper comparison is between the total cost of serving the end-use with gas, versus the total cost of serving that end-use with electricity. BPA and other regional utilities are acquiring new electric generating resources using natural gas as fuel. In a thermodynamic sense, the issue is whether to burn gas at 40% - 50% efficiency in new combined-cycle power plants, or whether to burn it at 60% - 90% efficiency in direct space and water heating applications. In an economic sense, however, it is a more complex issue. The total cost of gas service includes securing new gas supplies, adding gas transmission and distribution capacity, installing service connections, meters, and regulators, and installing and maintaining gas appliances. Under conditions of growing loads, the total cost of continuing to serve the same loads with electricity <u>also</u> includes the cost of new generating resources plus transmission and distribution upgrades. If the <u>total</u> cost of serving loads with gas is lower than the <u>total</u> cost of serving the same loads with new electric resources, then sound public policy dictates that gas should be used.

Since the marginal cost of new gas resources is lower than the marginal cost of new electricity resources, there are cost-effective opportunities for conversions to natural gas. However, since the cost of gas distribution system expansions is not small, there are many possible opportunities which are <u>not</u> cost-effective. The primary situations where conversion is not cost-effective is where the home is a considerable distance -- over 1000 feet -- from a gas distribution main, in smaller dwelling units where the load to be served is small, and in better insulated newer units where the load to be served is small.

The savings are considerable. The average cost of fuel conversions is about 20% - 40% (1-2 cents/kwh) lower than the average of new electrical resources. At the maximum economic and technical potential of 1500 average megawatts, the savings would equal $100 - $250 million per year for the region.

OBSTACLES TO COST-EFFECTIVE FUEL CHOICE

There are many obstacles to cost-effective fuel choice. Some are technical, some economic, and some political.

The technical obstacles are the least burdensome. Gas appliances are now made which can be vented without a chimney. They cost a bit more than conventional appliances. Gas utilities have limited capital resources, and limited construction resources. In recent years, with booming construction, these have been directed primarily at the new construction market.

The primary economic obstacles involve inefficient pricing of electricity. The electric utility industry is price controlled from generating plant to meter, with prices based on historical "embedded" cost principles. Gas production is now completely unregulated. While electric rates are generally well below marginal costs, gas rates are very close to marginal cost.

BPA is proposing to buy power from new gas-fired resources, such as the proposed Tenaska generating project. BPA presently sells power at wholesale at a flat, melded rate, rather than one which reflects the high incremental cost of new resources.

Public utilities follow that lead, pricing power at rates far below the cost of new resources. The typical retail rate for a public utility in the Northwest is about 4 cents/kwh, about half of the cost of production, transmission, and distribution for a new electric generating resource. While the public utilities will tell you that they base their rates on the "cost of service," there are many ways of measuring cost of service, and they generally choose methods based on average, historical costs, rather than on new resource costs.

Private utilities in the Northwest generally have more progressive pricing policies, imposed on them by state regulation. All of the major investor-owned utilities in the region have inverted retail rates, with end-block rates for usage over 1000 kwh/month around 5-7 cents/kwh, a level which makes gas conversions very cost-effective. Most of the conversion activity seen to date has been in the service territories of investor-owned electric utilities.

The political obstacles are relatively simple. Many electric utilities do not want to give up market share. They do not want to concede customers to the gas utilities. It seems surprising that consumer-owned utilities would take actions contrary to the interest of consumers, but they do. The reason is partly economic -- BPA's flat, melded rate design; it is partly political -- a sense that the gas utilities are competitors in the market, rather than colleagues in the energy services field.

ENVIRONMENTAL IMPACTS

My 1990 report to the Association of Northwest Gas Utilities compared the carbon dioxide produced by direct application of gas to space and water heating loads to the use of electric generation to serve these loads. Depending on whether the electricity is produced in cogeneration applications of conventional combined-cycle generation, and on whether the alternative generation is gas-fired or coal-fired, the environmental benefits of direct application range from modest to dramatic:

Lbs./year of CO_2 To Provide Space/Water Heating to One Home

Direct Application of Natural Gas:	7,080
High-Efficiency Cogeneration:	7,682
Combined Cycle Generation:	8,563
Coal Generation:	14,948

The construction of renewable resources will not affect the environmental impact of conversion of electric space and water heat to gas, since the incremental fuel for the west coast will remain a fossil-fired resource. If the Northwest were to develop sufficient wind, geothermal, and solar resources to serve all load growth, we would still be in a position to export power to California and displace fossil-fuel generating plants.

WHAT CAN BPA DO?

The Bonneville Power Administration is in a position to encourage more efficient fuel choice, where it is economic, in many ways. To date, BPA has been timid. One concern is that fuel conversions may not be a "resource" under the Pacific Northwest Electric Power Planning and Conservation Act. I believe that there are many things which BPA can do immediately, under its existing authorities, to encourage more efficient fuel choice:

1) **PURSUE FUEL CONVERSIONS BEFORE GAS-FIRED GENERATION:** BPA is currently aggressively pursuing acquisition of gas-fired generating resources from Bingen Lumber and from Tenaska II. These are less efficient and less economic than fuel conversions, and should be given lower priority.

2) **RATE DESIGN:** A decade ago, NCAC and NPPC urged BPA to implement tiered wholesale rate designs which encourage customer utilities not to place demands on BPA unless the incremental power is valued at the cost of new generation. BPA has just begun efforts in this direction.

3) **BILLING CREDITS:** BPA is required to offer billing credits to utilities which implement retail rate designs which encourage conservation and the installation of renewable resources. These same rate designs may also encourage direct application of natural gas. BPA has refused to pay billing credits for savings which result from rate design induced fuel switching.

4) **RESTRUCTURE LOW-DENSITY DISCOUNT:** BPA offers a "low-density" discount to rural utilities. This was intended by the Act to offset the high distribution costs of rural utilities. BPA does so by discounting the kilowatt-hours it sells to these utilities. The result is that these utilities --

which often serve some urbanized areas with gas service -- have lower rates per kilowatt-hour than the utilities serving the urban centers. If BPA instead provided a direct credit against distribution costs, but priced the electricity at an economic price, these utilities would have lower distribution charges, but higher energy charges, and fuel conversions would be more cost-effective.

5) **RESTRUCTURE CONSERVATION PROGRAMS:** BPA's new construction program, Super Good Cents, provides cash incentives for builders to choose superinsulated electrically heated homes over gas heat. That program should be terminated, restricted to areas where gas is not available, or the incentives should be fuel-blind. BPA's customer utilities often require customers taking advantage of retrofit weatherization financing to agree not to convert to gas. This makes no sense. NCAC called for fuel-blind incentive program in 1982; to date, BPA has operated conservation programs as load-retention mechanisms. If it is worth paying a customer $2000 to reduce their heating load on the electric system by 30%, through weatherization, why discourage that customer from reducing their heating load by 100% for the same price?

6) **PROVIDE FUNDING TO OFFSET CAPITAL COSTS OF FUEL CONVERSIONS WHERE IT IS COST-EFFECTIVE TO THE ELECTRIC SYSTEM:** BPA pays for conservation measures and generating resources out of rates, but does not contribute towards fuel conversions of any kind. BPA and its customer utilities should provide funding up to the level of avoided transmission and distribution capacity costs to facilitate extension of gas service. Subject to a strict Total Resource Cost test, BPA should provide funding for fuel conversions up to the level of net savings to the region from fuel substitution.

WHAT CAN THE NORTHWEST POWER PLANNING COUNCIL DO?

The authority of the Northwest Power Planning Council (NPPC) is limited, but several steps could be taken to encourage efficiency in general, and fuel choice efficiency in particular.

1) **REJECT THE PROPOSED TENASKA II PROJECT:** The proposed gas-fired generating plant in the Tacoma area is less economic and less thermodynamically efficient than direct application of gas. The potential for cost-effective fuel conversions (even by BPA's assessment) is greater than the potential output of Tenaska. The project should be rejected.

2) **ADOPT RATE DESIGN MODEL CONSERVATION STANDARDS:** A decade ago, NPPC agreed to delay implementation of retail rate design model conservation standards, based on a promise by the public utilities int he region to aggressively pursue energy conservation. The public utilities have not delivered, and the reasons for adopting rate design standards are stronger than ever today.

3) **QUANTIFY THE POTENTIAL SAVINGS FROM FUEL SWITCHING:** The Council is currently studying fuel choice, and the Council is uniquely suited to quantifying the potential savings from conversion of existing homes to gas, and directing new construction to gas. My study for ANGU remains the only study to date which attempted to identify where in the NPPC resource stack fuel conversions would fall.

4) **QUANTIFY THE PEAK DEMAND SAVINGS FROM FUEL SWITCHING:** The NPPC has not yet attempted to quantify peak demand savings of any of the demand-side energy resources they have evaluated. Peak savings are increasing valuable in the Pacific Northwest, and should be quantified.

WHAT CAN THE CONGRESS DO?

There are a few steps which could be taken by the Congress to encourage cost-effective fuel choice in the Pacific Northwest:

1) **DEFINE FUEL CHOICE AS A RESOURCE:** The Act could be amended or otherwise clarified to specifically identify direct application of natural gas as a "resource of high fuel conversion efficiency." This could logically be done by simply removing the word "generating" from the description of Category 3 resources. Direct application of gas should not be considered "conservation" or a "renewable resource" as Priority 1 and Priority 2 of the Act define them.

2) **PRESERVE THE HOUSE-PASSED APPROACH TO THE ENERGY TAX:** The House-passed BTU tax assesses hydropower at the average value of new electric generating resources. This was a compromise below the level originally proposed by the President. Several Northwest utilities have advocated having the BTU tax applied at a lower rate to hydropower. Without entering the debate over whether the non-thermal, renewable nature of hydropower justifies special tax treatment, the effect of special treatment for hydropower would be to discourage economic fuel choice. This is because more than half the electricity in the region is hydro, and favorable treatment will hold down the regional cost of electricity, but all gas will be subjected to the BTU tax. If hydropower is not taxed at the same rate as thermal generation, the effect will be to increase the price of natural gas space and water heat relative to gas space and water heat.

3) **IMPLEMENT THE 1980 BUILDING ENERGY PERFORMANCE STANDARDS (BEPS):** In the 1978 National Energy Act, the Congress directed the Department of Energy to implement a nationwide efficiency code for new construction. The standards were developed in 1980, but never implemented. The BEPS properly recognized that direct application of gas was a more efficient way to heat buildings than electric heat. The building codes for all four northwest states are weaker than the 1980 BEPS for new electrically-heated construction.

4) **AMEND PURPA AND THE CLEAN AIR ACT TO DEFINE FUEL SWITCHING AS A RESOURCE:** Under PURPA, electric utilities are required to purchase cost-effective resources provided by other parties. By defining fuel conversions as a resource eligible for avoided cost or competitive bid pricing under PURPA, and a resource eligible for the sulphur-bank credits provided by the Clean Air Act, the Congress could encourage and require electric utilities to consider fuel conversions along with generating resources.

WHAT CAN THE GAS INDUSTRY DO?

It would be inappropriate to place the entire burden of a more efficient fuel choice strategy on the electric utility industry. The gas industry also has a considerable role to play. The role of the gas industry should be to ensure stable supplies, predictable pricing, and efficient use of its product.

1) **ENSURE THAT APPLIANCES INSTALLED ARE EFFICIENT AND COST-EFFECTIVE:** Fuel conversion means installing new appliances, and gas appliances last a long time. Attention should be given to ensure that furnaces and water heaters are efficient. It is possible to "oversell" efficiency, however -- 90+ efficient furnaces are very cost-effective in large, single-family homes in Missoula, but the cost premium over 85% efficient units may not be justified in small homes in Eugene.

2) **SECURE LONG-TERM GAS CONTRACTS:** One obstacle to conversion is uncertainty about long-run costs for natural gas. By securing long-term contracts, gas utilities can stabilize the price of gas.

3) **REVIEW LINE EXTENSION POLICIES:** Gas line extension policies need to be reviewed to ensure that customers are allowed utility-financed line extensions whenever it is cost-effective. Gas utilities should receive contributions from the electric system associated with the capacity that fuel conversions free up on the electric system.

CONCLUSION

The potential regional savings from more efficient fuel choice are significant. Unless BPA, the region's public utilities, the Power Planning Council, and the gas utilities work together, a tremendous opportunity may be lost. The potential savings -- $100 million to $200 million per year -- will help to strengthen the regional economy. It's time for the territoriality of electric utilities -- and the negativism toward conservation of gas utilities -- to give way to a new era of cooperation and economic savings.

NORTHWEST POWER PLANNING COUNCIL
1991 PLAN RESOURCE PORTFOLIO

Expanded to Include Direct Application of Gas

Available Resource	High Forecas Megawatts	Levelized Nominal Cost	Levelized Real Cost	Resource Category
Conservation Voltage Regulation	100	1.4	0.7	Conservation
Hydro Efficiency Improvements	110	2.2	1.1	Renewable
Industrial 1	491	2.6	1.3	Conservation
Water Heat	472	3.5	1.8	Conservation
Water Heater Conversions - Gas In House	**198**	**3.6**	**1.9**	**Gas Direct**
New Commercial Model Conservation Standards	647	3.7	1.9	Conservation
Irrigation	43	4.6	2.3	Conservation
Commercial Renovations and Remodel	144	4.6	2.3	Conservation
Small Hydro 1	90	5	2.5	Renewable
Transmission & Distribution Efficiency Improvements	200	5.1	2.6	Conservation
Industrial 2	308	5.3	2.7	Conservation
Space/Water Heat Conversions - On Gas Main	**357**	**5.4**	**2.8**	**Gas Direct**
Existing Commercial	859	5.4	2.7	Conservation
New Single-Fam Res Model Conservation Standards	213	5.6	2.8	Conservation
Space/Water Heat Conversions - Near Gas Main	**893**	**5.9**	**3.0**	**Gas Direct**
Multifamily Residential Weatherization	57	6.3	3.2	Conservation
Single-Family Residential Weatherization	124	6.4	3.2	Conservation
New Manufactured Housing	131	6.5	3.3	Conservation
Hydrofirming (Combines-Cycle 1)	1070	6.6	3.3	High Efficiency
Hydrofirming (Combined-Cycle 2)	1430	6.6	3.3	High Efficiency
New Multifamilly Res Model Conservation Standards	20	6.7	3.4	Conservation
WNP-3	868	7.3	3.7	Thermal
Thermal Plant Efficiency Improvements	56	7.4	3.7	High Efficiency
Cogeneration 1 (Biomass Fueled)	480	7.5	3.8	Renewable
Cogeneration 2	57	7.6	3.9	High Efficiency
New Residential Lighting	63	7.9	4	Conservation
Hot Water Heat Pumps	136	8	4.1	Conservation
Municipal Solid Waste	30	8.1	4.1	Renewable
WNP-1	818	8.1	4.1	Thermal
Small Hydro 2	100	8.2	4.2	Renewable
Existing Residential Lighting	26	8.8	4.5	Conservation
Cogeneration 3	1130	10.3	5.3	High Efficiency
Wind 1	29	10.5	5.3	Renewable
Geothermal	350	10.7	5.4	Renewable
Eastern Montana Coal Gasificaation	1704	10.7	5.5	Thermal
Small Hydro 3	130	11.1	5.6	Renewable
Eastern Washington Coal Gasification	745	11.3	5.7	Thermal
Cogeneration 4	540	11.3	5.7	High Efficiency
Expensive Conservation	412	11.4	5.8	Conservation
Eastern Oregon Coal Gasification	745	11.5	5.8	Thermal
Western Wash/Oregon Coal Gasification	750	11.7	5.9	Thermal
Nevada Coal Gasification	716	12.2	6.2	Thermal
Wind 2	376	12.3	6.3	Renewable
Small Hydro 4	90	13.7	6.9	Renewable
Biomass	90	14.5	7.4	Renewable
Wind 3	253	15.7	8	Renewable
Solar Thermal	480	16	8	Renewable
Ocean Wave Power	N/A	16	8	Renewable
Solar Photovoltaics - On-site Applications	N/A	30	15	Renewable

Testimony For:

**Subcommittee on Regulation,
Business Opportunities, and Technology**

June 1993

Submitted By:

Byron Courts
Chief Engineer
MELVIN MARK PROPERTIES
111 SW Columbia, Suite 1380
Portland, OR 97201

My personal involvement with natural gas is in commercial office building application and specifically space heating and domestic water heating.

Melvin Mark Companies manage, maintain and develop property in the Portland area consisting of 21 buildings totally 1,933,297 square feet directly controlled by our operations department.

My direct concerns are in Mechanical and HVAC areas. Gas is used for space heating in approximately 65% of our buildings and for domestic hot water in approximately 70%.

Cost of Operation:

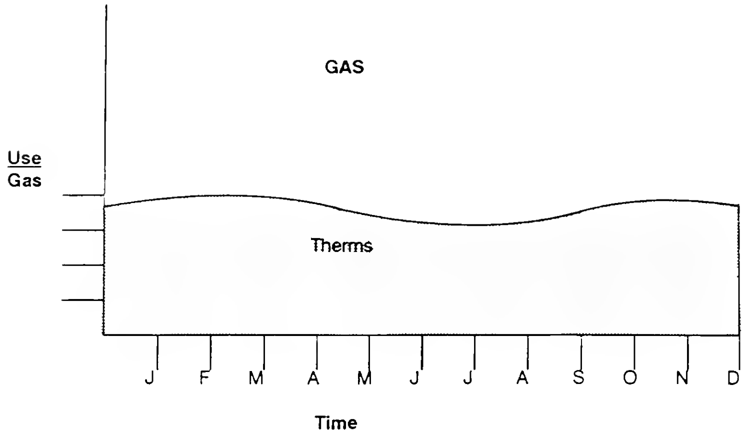
Three examples of rate structures and their effect on our decision making are submitted.

- The first is a graphic comparison of costing between electric and gas with schedule 32 and 4 respectively used for this comparison.

- The second is a paper written in 1986 titled "Office Building Boiler Conversion to Gas: A Case Study. This is an example of removal of an electric space heating boiler and installation of a gas system in its place. Sections 5 page 3 and sections 6 page 5 illustrate along with the savings graph the operating cost advantage of gas over electric for this project.

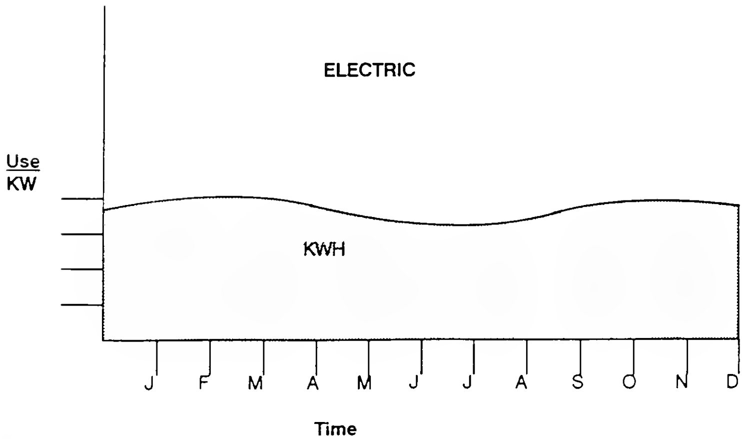
- The last is an example of a new building the Robert Duncan Plaza which was completed in September of 1991. This example applies to domestic hot water use. Besides the normal water uses of an office building, there are also showers, photo processing areas and a day care center that increase the water heater sizing.

Gas and electric graphic comparison of cost and rate schedules over one (1) year



Total yearly cost is equal to the total area of the graph or

Therms total X Cost per therm = Total cost



Total yearly cost is = to the total area of the graph and KW peak for each month or

KWH total + KW peaks for each month X Costs = Total cost

OFFICE BUILDING BOILER CONVERSION TO GAS: A CASE STUDY

Presented: "Energy for the 80's and Beyond"
April 17, 1986
Red Lion Jantzen Beach
Portland, Oregon

By: David Zier
Byron Courts
Melvin Mark Properties
111 S.W. Columbia
Portland, Oregon 97201

PREAMBLE

Melvin Mark Properties is one of Portland's oldest and largest real estate firms. We own and manage over a million square feet of office space in fourteen buildings. Our scope of activity includes building development, management, brokerage and general contracting.

We attempt to stay abreast of current trends in property management and have spent millions in renovations and upgrading of building systems over the last several years.

Our operating philosophy is that we try to deliver the best space at the best price to our tenants.

OFFICE BUILDING CONVERSION TO NATURAL GAS
A CASE STUDY

Section 1. - Building History

In 1970 the Crown Plaza was constructed for Melvin Mark Properties. Architects were Zimmer Gunsul and Frasca. The two buildings occupied two blocks in downtown Portland, consisting of 13 floors of office space and seven floors of parking. Approximately 250,000 square feet of office and retail space, with parking for 800 cars.

The Crown Plaza was, and continues to be a modern and successful class I office complex, competing for tenants with newer but not necessarily better buildings for the ever changing large office and retail leasing market.

Section 2. - HVAC - General Description

The Crown Plaza was a fully designed system by Chet Timmer and Associates. Plans and specs were completed in 1969. Timmer's concepts were at the front line of systems being used nationally at that time. The system is a variable air volume variable air temperature system with induction boxes for zone control. Four vane axial fans in the basement mechanical room supply tempered air to two air delivery systems that divide the building into two vertical zones, north and south. Separate sets of dampers for each air delivery system control discharge air temperature by mixing return air and outside air to economize on air temperatures delivered to the tenant areas. Induction boxes further temper supply air by inducing ceiling return air into the air stream. This air is then delivered to the tenant area at whatever temperature is desired by the room thermostat, 58° to 78°. Air is returned through the common ceiling plenum system and drawn back to the basement mechanical room by two return air fans.

The boiler system's purpose is to control heat loss at the perimeter of the building. Fin tube radiators are installed full length on each floor throughout the building. Hot water is pumped in four zones, north, south, east and west to the radiators and controlled through the use of three way mixing valves. Each face of the building has its own control system and reset schedule based on outside air and solar temperature. Each loop is designed to make up the amount of heat being lost at the building perimeter so that the variable air volume variable air temperature system described earlier can operate within its range.

Section 3. - Boiler Design

An electric boiler rated at 1530 KW was chosen for the original installation. Some of the reasons for this decision would be - an all electric building in 1969 was a selling point. Basement location gas or oil venting would be a problem, and lower relative power costs for electricity. The 1530 KW load was divided into 20 steps, each step had four 480 volt three phase 19 KW elements. These were run by an individual contactor per step. Each step had approximately 76.5 KW. The steps were controlled by a series of pneumatic and electro-mechanical relays. The water temperature would be reset from outside air temperature. The water temperature would further be reset for each zone. Some of the problems that occurred with this system were - relatively heavy maintenance, new contactors were needed every two years, loose connections in the boiler needed to be checked regularly, and control adjustments were frequently needed. Because of the state of control design at that time, the reset schedule would not follow the building heat loss curve. It was the best of the electro-mechanical options at that time, but would not stay accurate. Adjustments would be needed whenever the weather conditions would change.

Section 4. - Decision to Change

In late 1982, after trying several ways to upgrade the existing system with only moderate success, Byron found that the boiler had derated itself over night. One of the major wiring harnesses inside the boiler itself had grounded. 480 volt three phase current fuses at 1500 amps at the main disconnect. The short continued to burn through the 25% of the contactor leads. An immediate 25% savings in operating costs Byron and his crew patched things together and had the boiler up to 75% by that afternoon. We ran the rest of the winter at 75% of capacity. Luckily we had mild weather and it was not necessary to add the lost capacity.

The following spring of 1983 we were involved in an energy audit program with Peterson Engineering Company and at the same time trying to decide whether to spend the dollars for the boiler repair, $8,000 or to go to a completely new boiler system. We commissioned Peterson Engineering to study the question and advise us of the most economical and most reliable course of action.

From our figures and from simple logic, gas was thought to be the best solution. The main thing being you do not pay an energy demand charge for gas, such as you do for electricity.

Section 5. - Construction

Peterson's study confirmed our opinion, and they were hired to do a full design spec with plans in February of '83. In April bidding began. The original investment estimate was for $45,000 with a 3.5 year payback. Out of 5 major contractors, Interstate Mechanical was awarded the contract for $49,710, $3,200 of which were controls adds that we had asked for.

Peterson's design consisted of a two boiler scheme. Each boiler consists of three separate units that would be brought on in sequence of boiler one-unit one two then three. Boiler two unit four five then six. This allows the system to fire in proportion to building load and not over or under shoot the building needs.

Net output per unit is 834.8 MBTU's. Hydrotherm boilers were chosen for the job, and a Dorthem multi-temp RS8 outdoor reset controller was used for control. This operates on a new reset schedule 65° outside air and above-off; 20° outside air - 150° water; 10° outside air and below-160° water. A draft inducer fan was needed and would start on a call for the fourth boiler unit. From one to three the stack would gravity flow and from four to six, power venting would be needed. Pumps and automatic valves were installed for positive flow through each boiler and ran in conjunction with the firing order. Discharge temperature gauges and indicator lights for all units were added to existing operator's control panel.

Construction was completed in October of '83, and our first heating season with our new heating system began. No technical problems occurred, and all systems operated as planned. The reset schedules needed to be increased by 5° for better tenant comfort.

Repairs needed for the units for the last three years consisted of one gas valve, value approximately $65.

Section 6. - Savings History

Comparisons are from gas to electric and are converted by btu's Gas boiler btu's to KWH, with adjustment for boiler efficiencies, kilowatt hours peak load or KW were calculated by using average boiler KW per month from 1979 to 1982.

First year calculating totals a savings of $19,256.

Second year $25,433.

Third year, $30,835.

Total savings to date - $75,524.

Actual cost of the system - Total cost to Interstate Mechanical $49,710. Additional costs for an electrician from Christenson Electric, plus repairs and new starters for the new pump basis, $4,650. This was a total of $54,360. Savings amounts crossed over the line of expenditures in January of '86, or in two years, two months. A graph provided with the literature shows the dollar expenditures on the left to the winter months of heating at the bottom edge. The three years of winter heating are shown. '83-84, 84-85, 85-86. Also a sheet showing the monthly savings amount is included.

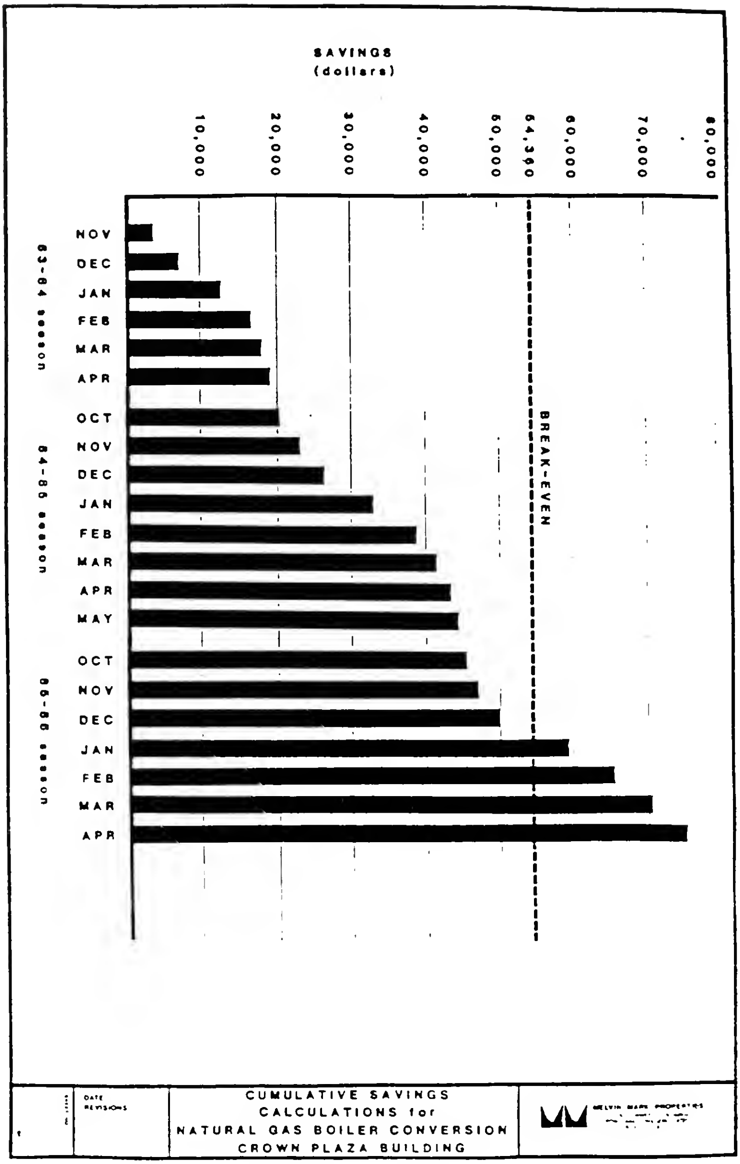
Some of the other benefits besides the dollars saved by the system have been better control and tenant comfort, ease of operation and lastly reliability.

Thanks to Gary Shull, Ken Meeker and Bill Anderson of Northwest Natural Gas, and for their help in this project. They have also been of great assistance in our six boiler retrofits in our older downtown buildings. Melvin Mark Properties appreciates your help and assistance and professionalism in dealing with energy management problems that face all of us in todays ever changing commercial market.

Savings Calculations for Natural Gas Boiler at Crown Plaza Building

	Heating Months	Kilowatt Hrs. Dollars Saved	Kilowatt Dollars Saved	Total	Running Total
1983-1984	October	159	979	1,138	
	November	544	1,560	2,104	3,242
	December	1,397	1,773	3,170	6,412
	January	2,982	3,100	6,082	12,494
	February	1,263	2,722	3,988	16,479
	March	333	1,165	1,498	17,977
	April	367	912	1,279	19,256
1984-1985	October	1,011	979	1,080	20,336
	November	1,245	1,560	2,805	23,141
	December	1,656	1,774	3,430	26,571
	January	3,586	3,101	6,687	33,258
	February	3,416	2,722	6,138	39,396
	March	1,074	1,165	2,239	41,635
	April	880	909	1,789	43,424
	May	356	909	1,265	44,689
1985-1986	October	9	1,003	1,012	45,701
	November	187	1,395	1,582	47,283
	December	2,399	1,878	4,277	51,560
	January	5,223	2,672	7,895	59,455 *
	February	2,803	3,579	6,382	65,837
	March	3,431	1,345	4,776	70,613
	April	3,908	1,003	4,911	75,524
		37,319	38,205	75,524	

* Boiler Construction Cost $54,360


SAVINGS
(dollars)
10,000
20,000
30,000
40,000
50,000
54,390
60,000
70,000
80,000
83-84 season
NOV
DEC
JAN
FEB
MAR
APR
84-85 season
OCT
NOV
DEC
JAN
FEB
MAR
APR
MAY
85-86 season
OCT
NOV
DEC
JAN
FEB
MAR
APR
BREAK-EVEN
DATE
REVISIONS
CUMULATIVE SAVINGS
CALCULATIONS for
NATURAL GAS BOILER CONVERSION
CROWN PLAZA BUILDING

ROBERT DUNCAN PLAZA

Domestic: **Hot Water Heating System**

Choices for the cost of insulation and run costs for both electric and gas were compared for this domestic hot water heating system. The calculations showed that gas would cost less to operate and pay back the increased initial costs for the high efficiency gas system in approximately 3.5 years.

The fuel cost difference between gas and electric alone reflected only a 11.5 year pay back. When the KW peck load cost for electric were included, the total pay back came down to 3.5 years.

Please refer to Kenneth Meeker's letter with enclosures to Byron Courts dated May 28, 1993.

NORTHWEST NATURAL GAS COMPANY

ONE PACIFIC SQUARE
220 N.W. SECOND AVENUE PORTLAND, OREGON 97209

Mr. Byron Courts
Chief Engineeer
Melvin Mark Companies
111 SW Columbia Suite 1380
Portland, Oregon 97201

May 28, 1993

Re: Robert Duncan Plaza

Dear Mr. Courts

The existing gas consumption and cost for water heating needs of the Robert Duncan Plaza have been compared with electric energy costs. The results are enclosed as a bar and line graph and in the spreadsheet which shows details and gives assumptions used.

Electric water heating costs would have been about **three times greater** than the gas costs have been; even with a conservative estimate for electric demand, had electricity been used.

The cost for natural gas during the past year has been $1,487 or $124 per month. If the water heating had been electric, the cost would have been about $386 per month ($4,627 annually). Without a demand charge the energy cost would approximate $207 per month, or 2/3 more than natural gas.

Note that if natural gas had been used in a combustion turbine to generate the electricity for this water heating, about 6,400 therms would have been consumed, 2.2 times the gas used directly in the water heater. The price ratio of the two energies reflects the value and propriety of using the gas directly in the building.

I hope this provides the information you need at this time. Please let me know if we may be of any assistance.

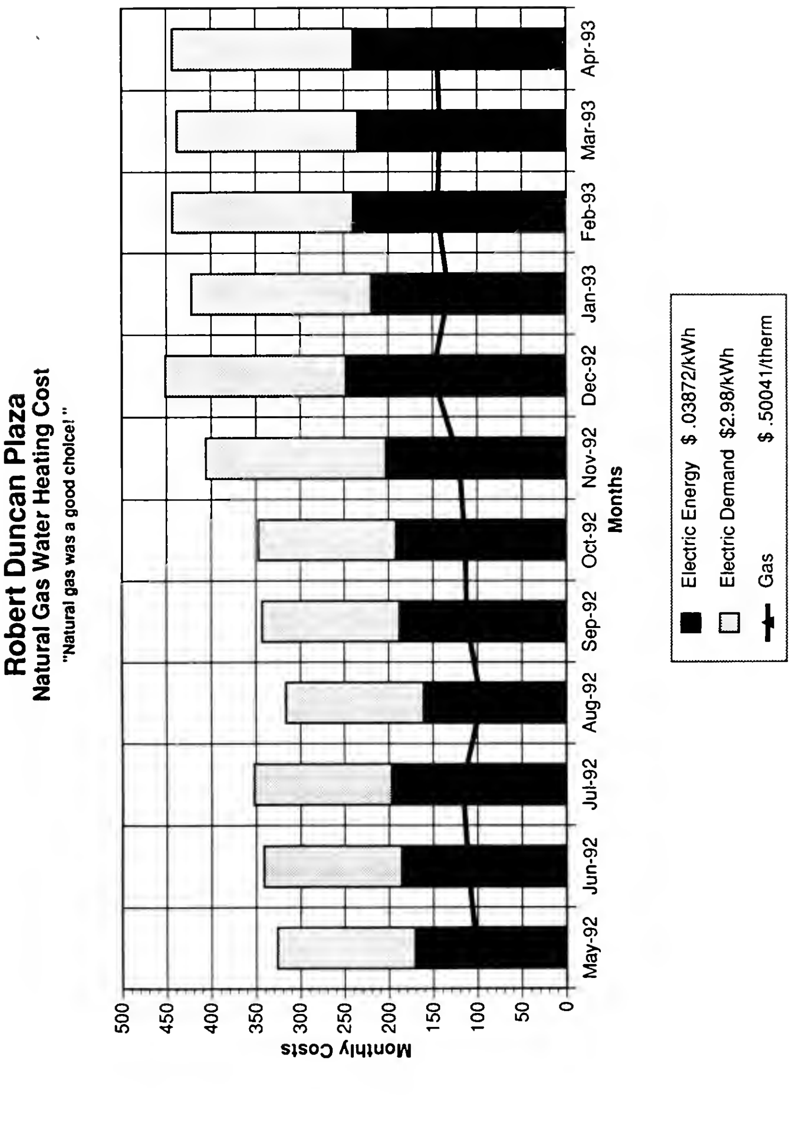
Sincerely,

Ken Meeker

Kenneth D. Meeker
Customer Services Division

enclosures (2)

cc: Paul Hathaway
Bill Anderson



Robert Duncan Plaza
Natural Gas Water Heating Cost
"Natural gas was a good choice! "
Monthly Costs
500
450
400
350
300
250
200
150
100
50
0
May-92
Jun-92
Jul-92
Aug-92
Sep-92
Oct-92
Nov-92
Dec-92
Jan-93
Feb-93
Mar-93
Apr-93
Months
Electric Energy $ .03872/kWh
Electric Demand $2.98/kWh
Gas $ .50041/therm

FOR ROBERT DUCAN PLAZA 333 S W First Avenue, Portland, Oregon May 27, 1993
Requested by Byron Courts, Melvin Mark Companies

Water Heating Cost Saving That Resulted From Installing Gas Water Heating Instead of Electric

Month	Gas use (therms)	Gas cost R 5.3($)	Equivalent electric (kW-hr)	Energy cost ($)	Demand cost 60kW($)	Total elec cost ($)
May 92	201	$102	4,425	171	155	$326
June	219	111	4,809	186	155	341
July	231	117	5,084	197	155	352
Aug	189	96	4,161	161	155	316
Sept	221	112	4,851	188	155	343
Oct	225	114	4,946	192	155	346
Nov	239	121	5,243	203	203	406
Dec	292	150	6,416	248	203	451
Jan 93	258	132	5,660	219	203	422
Feb	282	145	6,199	240	203	443
Mar	277	142	6,080	235	203	438
Apr	282	145	6,199	240	203	443
Total	2,915	$1,487	64,073	$2,481	$2,146	$4,627
Monthly av	243	$124	5,339	$207	$179	$386
						0 0722

GAS SAVINGS CALCULATIONS, with explanatory notes

If the water heating requirements of the Robert Duncan Plaza had been met with electric energy instead of natural gas, the cost would have been greater as shown. (Gas efficiency at point of use is 75%, electric is assumed to be 100%)

Monthly average gas use (therms, from history above) — 243 per month

Convert gas units to heat units: — 24,290,833 Btu's/mo.
(multiply therms x 100,000 Btu's/therm)

Calculate electric energy equivalent — 5,339 kW-hrs/mo.
(divide gas input by 3,412 Btu's/kW-hr and multiply result by 75%)

Calculate electric energy cost: — $207 per month
The marginal energy cost for PGE rate schedule 32 is $ 03872/ kW-hr

Calculate electric demand cost — $179 per month
The history of gas use shows about one-third of the gas consumption originally anticipated The power demand of an electric water heater would also have been reduced, 60 kW demand is assumed in these calculations (Original plans would have required a 264 kW machine)

Calculate total monthly electric cost (Add power and demand cost — $386 per month

Monthly saving with gas (Pro-forma electric minus present gas) — $262 per month

Annual saving with gas — $3,140 annually

Percentage saving with gas — 68%

KDM
Northwest Natural Gas Co GASEL3A

Conclusion:

On larger installations of 75 to 100 KW or more, gas has definite run cost advantages over electric. This is true for either domestic hot water or hot water heating plants.

First costs for gas are higher than electric which can be absorbed by run costs over a 3 to 5 year estimated time period.

Both examples given are buildings that were built by our company and will be managed by our company for the long term, at least 10 to 20 years. Because of this, we take the long term approach to investment in energy programs. Other builders, owners and operators may look on these situations with a different perspective. Initial cost incentives may be needed to lower the pay back period to match their financial and contractual agreements.

Smaller systems below 100 KW will need financial incentives to decrease first costs. The ratio of savings to investment will be less with this group.

I would hope that your committee would consider studying the ratio of size to pay back and the relative incentives needed for these smaller users.

Thank you for this opportunity to be heard on this important energy use issue.

Respectively submitted by,

Byron Courts

Assessment of Fuel Choice Programs in Oregon

Testimony of Christine Ervin, Director
Oregon Department of Energy

For the U.S. House Small Business Committee
Subcommittee on Regulation Business Opportunities and Technology
Portland, Oregon
June 3, 1993

I have been asked to address two specific questions for you today:

- What is the state's role in fuel choice programs? and

- What methods of regulation can be used to promote the direct application of natural gas to homes, businesses, and industry in the Northwest?

My testimony will also cover Oregon's current policy on residential electricity vs. natural gas use; the potential for cost-effective conversions to gas; and our assessment of what needs to happen now.

State's Role and Position on Fuel Choice Programs

Two state agencies play a direct role in shaping fuel choice programs in Oregon. My Department is responsible for overall energy policy and planning in the state. In addition, we run financial and technical assistance programs, represent the state in Hanford Waste Reservation issues, and site and regulate energy facilities in the state. We work closely with the Oregon Public Utility Commission (PUC) which is responsible for regulating the rates of privately-owned electric and gas companies, certain telephone and water utilities, and elements of the state's transportation system.

In 1990, the Department of Energy and the PUC launched a comprehensive study on the long-run economic and environmental costs of using electricity vs. natural gas for space and water heat. Our joint study found that in specific circumstances it was cost-effective to substitute natural gas for electricity to heat homes and water.

Based on the study findings, the PUC adopted a new policy in October 1991 to encourage cost-effective fuel-switching. I have attached a copy of the Commission's policy. In short, the PUC policy would allow gas or electric utilities to recover costs of appropriate fuel-switching programs so long as they were: economical, promoted energy efficiency, and cost-effective to customers of both affected utilities. Those determinations would also be based on a case-by-case basis as presented in the individual least-cost plans of the utilities.

Since then, all three electric utilities have presented updated least cost plans to the PUC which specifically address the feasibility of fuel-switching programs. None have come forward with a fuel-choice program for several reasons.

First, there still remain questions regarding the data and analysis used to assess fuel switching potential. My staff and those of the PUC do not necessarily agree with the most recent utility assessments. To that end, the Commission has ordered PGE and Pacific to hire consultants to conduct independent assessments of the potential.

Second, we do agree with the utilities that the current pace of conversion from electricity to gas is significant and should be an important consideration in deciding whether or not new programs are needed. Natural gas utilities estimate that about 5,600 homes converted to gas space heat in 1992--many of which were electric. In addition, about 7,800 homes have converted from electric to gas water heat. Today, natural gas space heating systems are installed in more than 300,000 of the new single family homes built in Oregon.

We are all concerned that fuel-switching programs could lead to a free-rider problem given the healthy rate of conversion we're already seeing in the market. In other words, program costs could be used to subsidize conversions that would already have occurred on their own.

That is not to say, however, that the state is not moving forward. The PUC and my Department have jointly worked to assure that electric utilities do not actively promote electric space and water heat. Utility programs have been modified to remove certain promotional elements. In that vein, we have also encouraged BPA to remove promotional elements of its Long Term Super Good Cents programs.

The PUC has also moved to decouple electric sales from profits with the strong support of my agency and the Oregon members of the Northwest Power Planning Council. Currently, when utilities sell more electricity, their stockholders keep the net revenue. Decoupling will remove this incentive to promote electric water and space heating at the exclusion of what could be a more cost-effective fuel. PGE has submitted a decoupling proposal for all customers. Pacific Power has indicated that it will voluntarily implement decoupling for its residential customers. The PUC will act on these proposals in the next rate case for each utility.

The Potential for Fuel Switching in Oregon

Overall, the Department of Energy believes that there is about 110 average megawatts of cost-effective fuel-switching in the residential sector. That's about 45 percent of the electricity used in Eugene today. The potential is in two prime areas:

- Replacing worn out electric water heaters in homes that have natural gas space. We estimate that there are about 150,000 to 200,000 such homes.

- Replacing electric furnaces in homes with natural gas space heaters. We estimate there about 50,000 to 75,000 such homes in Oregon.

We believe there is little potential for increased use of gas in the new home market. Zonal resistance electric space heat is the cost-effective choice for small houses and apartments. Where houses are being built with gas, the older practice of putting in electric water heat is extremely rare.

We have not estimated fuel switching potential in the commercial and industrial sectors. There is likely to be some potential but it is extremely difficult to estimate. In addition, the concept of cost-effective fuel switching is really not applicable to industry. In that sector, the choice of fuel has less to do with efficiency than with the fuel's impact on product quality and integration with the rest of the industrial process.

Future Actions

In light of the various factors mentioned above, most strongly the market trends already in place, we believe caution is warranted in actively promoting or mandating new fuel switching programs. We are sensitive to the reality that policies that seem sensible today can have unanticipated negative effects in the long run. Promotion of wood heat is a good example.

But several steps are still warranted from my agencies point of view:

- Continue requiring analyses in utility least cost plans;

- Continue to modify BPA and utility conservation programs to limit features that explicitly promote electricity over natural gas;

- Continue to implement decoupling of electricity sales from profits;

- Finally, conduct pilot programs that will help us all learn more about the potential of fuel-switching programs. In Oregon, we have been working with the Water Power Natural Gas utility in the Medford region to develop such a pilot. It will be operational by the end of the year. What we learn from that program will help us evaluate the potential for other utility programs.

Thank you.

Oregon

PUBLIC
UTILITY
COMMISSION

October 1, 1991

To Natural Gas and Electric Utilities
Regulated by the Public Utility Commission

On September 3, 1991, the staffs of the Commission and the Department of Energy jointly presented a report entitled "ODOE/OPUC Fuel Switching Analysis: Observations and Policy Implications." A copy of the report is enclosed.

In addition to written comments received, the Commission elicited at its September 3 public meeting reactions to the report. Most comments were favorably disposed to the observations and findings in the report.

In the report and at the public meeting, the ODOE/OPUC staffs recommended five issues for evaluation when fuel switching programs are filed. The staffs suggest that the utility sponsoring a fuel switching program demonstrate that:

- The program is clearly economical in terms of a resource cost comparison between the electric and natural gas utility.
- Cost-effective fuel switching is not being pursued rapidly enough.
- Existing customers of the utility promoting fuel switching also benefit.
- The program is designed to encourage participation only for those customers for whom fuel switching is cost effective.
- Energy efficiency programs are aggressively pursued as a part of any fuel switching program.

The Commission accepts the above recommendations and the report as constructive toward enhancing the efficient use of energy. Moreover, we wish to expand on the report by advising Oregon's natural gas and electric utilities of the following observations:

Barbara Roberts
Governor

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October 1, 1991
Page Two

- We encourage reasonable fuel switching program proposals by any utility--natural gas or electric--which demonstrates that such programs are in the public interest, promote energy efficiency, and are cost effective to customers of both affected utilities.

- Utilities may file joint programs if it appears that such programs will enhance the effectiveness of appropriate fuel switching activities.

- Proposals will be assessed on a case-by-case basis, as indicated in the staff report.

- Financial issues, such as transfer of weatherization loans and lost revenue recovery, will likewise be assessed when programs are filed. If appropriate, utilities may propose methods to minimize financial disincentives they face in implementing programs. Utilities sponsoring programs may suggest financial incentives, if incentives appear necessary to induce the utility to aggressively pursue reasonable programs. In addition, financial mechanisms should not generally be applicable to fuel switching activities that are occurring without a fuel switching program.

- At the Commission's public meeting on September 17, 1991, the Commission, based upon a recommendation of its staff, opened a docket to consider assessment of external environmental costs as they relate to energy usage pertinent to regulation of utilities in Oregon. When credible estimates of these costs are developed, they should be considered in evaluating fuel switching proposals.

We understand that the parties are currently engaged in an effort to develop consistent energy modeling techniques for assessing issues such as fuel switching. We urge that these efforts conclude expeditiously to enable appropriate program proposals to proceed.

We commend all participating parties on the work involved and invite proposals regarding this matter at the earliest practical date.

Myron B. Katz
Chairman

Ron Eachus
Commissioner

Joan H. Smith
Commissioner

dg/gr/1930HH-2

Enclosure

cc: Fuel Switching Advisory Group

TESTIMONY OF PAUL L. HATHAWAY
SENIOR VICE PRESIDENT
NORTHWEST NATURAL GAS COMPANY

BEFORE THE
UNITED STATES HOUSE OF REPRESENTATIVES

COMMITTEE ON SMALL BUSINESS

SUBCOMMITTEE ON REGULATION, BUSINESS OPPORTUNITIES AND TECHNOLOGY

THURSDAY, JUNE 3, 1993

It is an honor to be asked to testify before this Committee on the subject of the regulation of energy in the Pacific Northwest.

Our natural gas industry in this part of the world represents a very significant portion of the total energy used in our region. Since natural gas was brought into the region in 1956, our industry has grown to serve more than a million customers, 130,000 businesses, and 5,000 industries. Our customers in the region use over 3 billion therms yearly, or the equivalent of nearly 10,900 average megawatts of power. Natural gas use in the region is growing at an extremely rapid rate, faster than any other part of the country. Our growth rate is 5% to 6% per year.

Natural gas is emerging as the energy resource of choice for the 1990's, as has been acknowledged by the Clinton administration. Natural gas is plentiful in North America; it's economic and it's very clean environmentally. It is interesting to note that the pipeline transportation system that carries natural gas to market is already in place. More than a million miles of pipeline exists that can carry natural gas from any producing point to any market point in the country. The reserves of natural gas in the United States and other parts of North America are enormous. The U.S. Department of Energy estimates that we have a 60-year supply of conventional reserves, sufficient to supply us at present and projected use rates. We also have another 150 to 200 years of unconventional reserves. Those are reserves that require technology and are more costly to recover, but none the less are very much available. So the natural gas supply issue is really not an issue, at least for the next century or so. There is more than enough natural gas to last this country from the present time into the energy era that we look for in the not-too-distant future when the true renewables will be the primary sources of energy as opposed to the fossil fuels of today.

What is important to our region now is that natural gas be integrated into the total energy planning of the region. Because of the Pacific Northwest's long history of domination by low-cost hydroelectric power, natural gas has been virtually ignored as a major energy resource, until now. The seemingly endless hydroelectric resources of the Columbia River do have limits and we have now reached the limits of that resource. To meet our increasing electric demands we must now turn to other means of power generation. As we look at the options possible to do this the list becomes very short, particularly the list of potential electric generating resources for the near term, the next 10 years or so. Very quickly we discover that new nuclear power plants are highly unlikely to be built or completed, coal-fired power plants are costly to build, and very time consuming in their construction, and are a cause of great environmental concern. We reach the conclusion inevitably that the electric power resources that are easiest of access, lowest cost to build and quickest in time of construction are those fueled by natural gas. Typically, these are cogeneration plants sited at large industries and combustion turbine central station generating plants built by electric utilities or independent power producers. It's apparent from this that natural gas is going to be a key player in the future electric as well as the future natural gas energy requirements of the region.

Because of this, it's time for us to be integrating natural gas into the region's total energy planning process. To this point there has been very little joint natural gas and electric planning. We have made efforts in our industry to work together with the Northwest Power Planning Council (NPPC), but so far there has been relatively little contact except for an occasional meeting to discuss the possibilities of the use of natural gas. We've also met several times with the Bonneville Power Administration (BPA) in an effort to integrate natural gas into

BPA's activities but, thus far, there has been no true integrated energy resource planning that has come to fruition.

Because of the projected large-scale use of natural gas as power plant fuel in the resource plans of the generating electric utilities of the region, we have great concern about the efficiency of the use of natural gas in these power plants. The key issue that this subcommittee is investigating is the question of fuel efficiency; whether it is more efficient to use natural gas directly in homes, business and industries or to use natural gas to generate electricity in combustion turbines. I have included two charts which are entitled Total Energy Trajectories that illustrate the efficiencies of the direct use of natural gas vs. combined cycle combustion turbine electric generation. One chart deals with the overall efficiency of residential space heating by direct use of natural gas compared with natural gas-fired electric generation and the other deals with water heating. As you can see, principally because of the relatively low efficiency of the combined cycle turbine, the direct use of natural gas is far more efficient than the indirect use of natural gas to generate power.

In a way, our long history of domination by low-cost hydropower is a blessing to the region in helping to meet its current and projected demands for new energy as the region grows. Because electricity has dominated the energy scene here for so long, the market saturation of natural gas in the region is very low, something on the order of 35%. This means that there is a large amount of electric space heating and water heating in the region. Much of that electric space and water heating is located in homes and businesses that are near or already served by natural gas. The potential for shifting these existing electric space and water heating customers to natural gas represents a very large electric generation savings by reducing demand on the electric systems of the region. There have been half a dozen different studies that have looked at the magnitude of this potential. The conclusion that we reach is that somewhere between 1,000 and 1,600 average megawatts of electric generating capacity could be saved by shifting residential space and water heating customers from electricity to natural gas. This is a resource that is available very readily. It's an existing resource. On our own system at Northwest Natural Gas we have about 100,000 customers who already use natural gas for space heating but who use electricity for water heating. To convert those water heating customers to natural gas would be relatively inexpensive and could be done relatively rapidly. Those 100,000 water heaters represent an average demand of .56 kilowatts each and total about 140 megawatts at peak use. If those customers were completely reimbursed for their cost of conversion to natural gas, the total cost to do the job would be about $50 million. $50 million to serve a 140 megawatt peak is about $354 per kilowatt of installed generating capacity. That's about 1/2 to 1/3 of the cost of building a combustion turbine power plant to serve that load. In addition, the power plant that would serve that electric load would operate at an efficiency of about 40% and would burn more than twice as much natural gas as compared to sending that natural gas directly to the homes for water heater service. That's what fuel switching is about. That's what the direct use of natural gas in homes means for customers' cost reduction, for reducing electric demand in the region, and for reducing the total use of the raw material of energy, natural gas, in the region. If we agree that shifting space heating and water heating loads from electricity to natural gas is a good thing and a proper thing to do, then what are the constraints against doing it? Why haven't we done this already? The answer lies partly in our history, partly in our culture, and partly in BPA's interpretation of the law. Our history says that we are predominately in an electricity-dominated region and that it's hard for us to change our basic heating and water heating source. That's understandable. The culture built up around the BPA is that we are an electricity marketing organization and that's what we do best and it's hard to shift that kind of thinking as well. When BPA first even barely mentioned the possibility of fuel switching, its electric utility customers were very disturbed and let BPA know in no uncertain terms that this was not a good thing to do. If a part of their load were shifted from electricity to natural gas there would be a reduction in their revenues and it would cause potential rate increases for their customers. That certainly is an understandable reaction and it's a question that needs to be answered - how do we deal with the revenue impact of the resources that have been shifted?

In the past, BPA has taken the position that the Northwest Power Act does not give BPA or the NPPC authority to consider natural gas as a permissible conservation resource for reducing electric power consumption. More recently, BPA and NPPC have been advised by their attorneys that the Council can make "nonbinding" recommendations to BPA's customers on the use of natural gas and/or fuel switching to reduce electric consumption. However, advisory efforts to date have not been particularly productive. This legal position taken by BPA and NPPC, although certainly arguable considering the language of the statues in question, makes natural gas a "second rate" electricity conservation resource in the region.

One interesting approach to the problem of reduced electric revenues from conservation or fuel switching is already being tried by some public utilities. That is, they will continue to purchase electric power from BPA, but will resell to other entities the power that is saved through conservation or fuel-switching efforts on their own systems. This offsets their revenue losses for reduced demand. Another method of making up revenues lost due to conservation or fuel switching would be to shift BPA's conservation incentive payments to the serving electric utilities. In this way programs such as Super Good Cents would be focused on the amount of energy actually conserved or fuel-switched by the electric utilities who would then be reimbursed by BPA from the Super Good Cents funds.

If we do decide that the direct use of natural gas, i.e. fuel switching, is a means of conserving electric energy and conserving the natural gas resource, we should look very carefully at conservation and the means that we've been using to achieve it. All of the utilities in the Northwest, natural gas and electric, have had active conservation programs for many years. In our own case, my company has done more than 100,000 weatherization audits of homes, and has financed $78,000,000 in conservation measures. But some of the BPA conservation programs that have been operating for the last few years have had just the opposite effect of that intended. The Super Good Cents Program, for example, was designed to encourage home builders and individuals to build dwellings to a higher building code standard and thus conserve energy for heating. What has happened, in fact, is that the subsidies given to home builders and home buyers under the Super Good Cents Program have encouraged, and in some cases, forced those builders to heat the home electrically and to foster electric water heating. This has removed the choice of natural gas for the builders or homeowners who want to obtain the Super Good Cents subsidy. This type of program is, in fact, obsolete since the state building codes have now been improved almost to the point where they are equivalent with the Super Good Cents standards. It is our strong feeling that programs like this should be eliminated. They are a deterrent to conservation, and they adversely influence home builders and home buyers toward additional electric heating rather than giving that home builder or buyer the opportunity to use natural gas for these purposes. The millions of dollars spent on these subsidies to home builders could be far better applied in encouraging electric heating and water heating consumer to shift those uses to natural gas.

The whole issue of fuel choice, fuel switching, or the direct use of natural gas is really an issue of total energy resource management for the region. There is an urgent need for natural gas and electric utilities together to plan the use of their respective energies. This will assure that the markets that each utility serves represent the most efficient uses of each energy form. Fuel choice will result in conserving all forms of energy for the region as well as reducing the cost of electric power generation by being able to push back the time when new, expensive natural gas combustion turbines will need to be built. The Oregon Public Utility Commission recognized the benefits of fuel switching in October 1991 when they found that fuel switching "...appears to be cost effective over a broad range of energy usage levels."

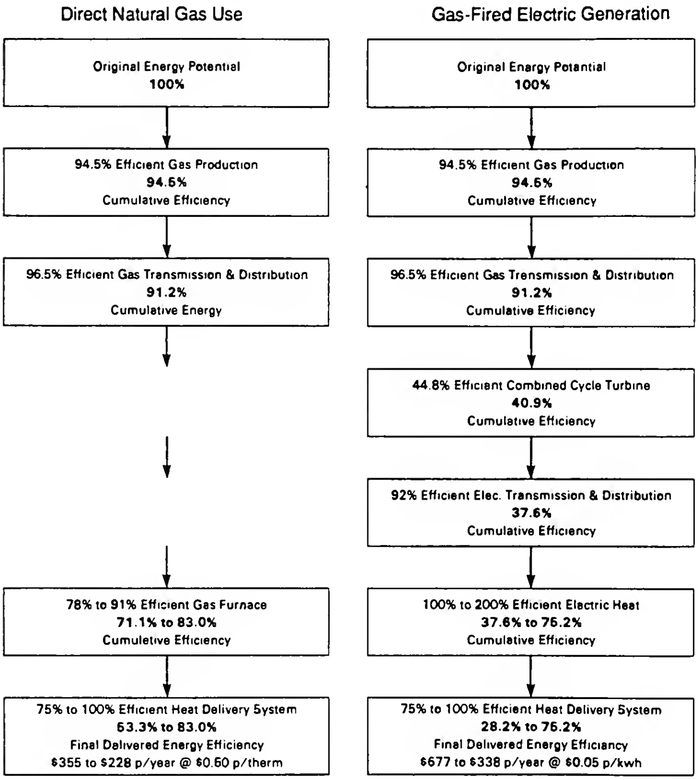
There are already good examples where natural gas and utilities are beginning to work together to integrate their energy use and planning. Washington Natural Gas Company and Snohomish PUD have had a very successful fuel switching pilot program. Washington Water Power, a combined natural gas and electric utility, has an ongoing fuel switching program that is extremely successful. Northwest Natural Gas Company is working together with Eugene Water and Electric Board and the Clark Public Utilities of Vancouver, Washington to put together not only fuel switching programs but also other joint operational programs that will help reduce costs for all energy consumers. We have also entered into a joint gas transportation agreement with Portland General Electric to mitigate the impact of the Trojan nuclear plant shutdown. More of these efforts need to be undertaken in the region so that the full potential of fuel switching and conservation can be realized.

It is our very strong recommendation to the Committee that it undertake several different efforts. First, the BPA should be requested to become proactive in encouraging and providing incentives for fuel switching wherever it is economic or feasible on systems served by BPA. Second, the obsolete conservation programs that are inhibiting the use of natural gas, where natural gas is more efficient, should be eliminated immediately. These would include such programs as Super Good Cents. Third, the BPA and the natural gas utilities should be working together in planning not only fuel switching programs but also other uses of natural gas, including the potential for sharing pipeline capacity as new natural gas-powered electric generation is brought on to the various electric systems. We owe it to the consumers of the Pacific Northwest to conserve all forms of energy, to work together to reduce the wasteful use of energy wherever possible, and to keep our energy supplies economic in the market place.

Thank you very much for this opportunity to testify.

Direct Use of Gas (Continued)

Total Energy Trajectory[1]
Direct Natural Gas Use vs. Combined Cycle Combustion Turbine Electric Generation
Residential Space Heating[2]

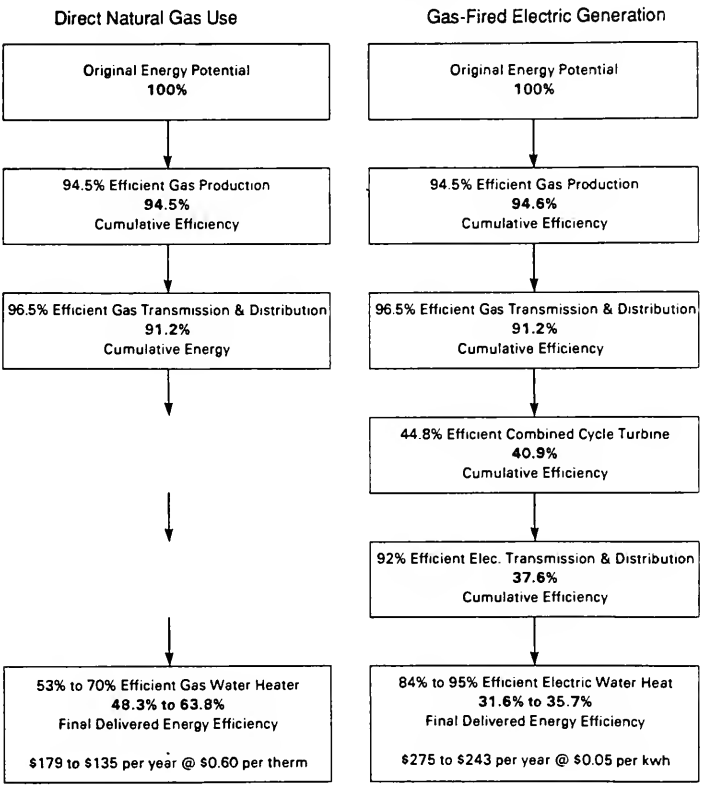


[1]Total Energy Trajectory includes the total energy required to extract, process and convert a basic energy resource and deliver the resulting energy to the customer's meter. It also includes energy used by appliances on the customer's side of the meter to create useful energy such as heat and to distribute it within the house. Since appliance efficiencies vary, the final delivered efficiencies and annual costs are given as a range.

[2]Based on a typical residential space heat load of 35 million Btus per year.

Direct Use of Gas (Continued)

Total Energy Trajectory[1]
Direct Natural Gas Use vs. Combined Cycle Combustion Turbine Electric Generation
Residential Water Heating[2]



[1]Total Energy Trajectory includes the total energy required to extract, process and convert a basic energy resource and deliver the resulting energy to the customer's meter. It also includes energy used by appliances on the customer's side of the meter to create useful energy such as heat and to distribute it within the house. Since appliance efficiencies vary, the final delivered efficiencies and annual costs are given as a range.

[2]65 to 74 gallon first hour rating and 16 million Btu per year water heat load.

Testimony of
William K. Drummond
for the
Public Power Council
before the
House of Representatives Committee on Small Business
Subcommittee on Regulation, Business Opportunities, and Technology

Good morning. My name is William K. Drummond. I am the manager of the Public Power Council, an association of 114 municipal, public and peoples utility districts, and rural electric cooperatives in the Pacific Northwest. All of our members rely on the Bonneville Power Administration either in full or in part for their supply of electric power and wheeling services. Our members provided half of Bonneville's revenues in 1992. I want to thank you for with the opportunity to address the issue of application of natural gas as an energy resource in the Northwest.

For the past two years the topic of fuel choice has been the subject of much discussion in the Northwest. The origin of this debate has been the need for new electric generating resources in the region after a decade of energy surplus. Natural gas, because of its availability, moderate environmental impacts and current low price has been the fuel most often proposed for new generating resources. The question of whether that fuel could be more efficiently used to displace electric end-uses such as water and space heating has arisen in this context.

I would like to make three points this morning. First, there are a variety of issues that need to be addressed before a regional policy on fuel choice is implemented. Second, we support the Bonneville pilot program aimed at improving our knowledge about the fuel

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choice issue and determining if our efforts will be successful at influencing the regional energy markets. Finally, because of regional diversity, we believe that fuel choice is best addressed at the local utility level.

While it is technically correct that direct use of natural gas for space and water heating is more efficient than using the gas in a combustion turbine to produce electricity, there is more to the public policy debate than technical analysis. In fact, even the technical analysis is not entirely clear because combustion turbines would be displaced by nonfirm hydroelectric energy. The decision to encourage the use of natural gas as a substitute for electric end-uses is also a complex business decision.

Many questions surround the implementation of a regional fuel switching policy. To what extent are measures beyond current market price signals necessary? Current signals have encouraged 95% of the new housing market to choose natural gas over electricity to serve household heating needs. Given this level of gas utilization, one wonders what additional steps would be effective.

Other questions arise if you then make the decision to proceed with a regional fuel choice policy. What is the appropriate level of contributions from the three parties involved; the electric utility, the gas utility and the customer? Should the transaction be viewed as a deferral of the need to purchase new generating resources by the electric utility or the transfer of a revenue stream to the gas utility? Given that customers are already responding to the price differentials between natural gas and electricity, what is the likelihood that electric utilities would be paying for a consumer decision that would have occurred anyway? What is the correct incentive to pay if all you are achieving is the acceleration of a market trend? What prevents consumers from reversing their decision and returning to the electric utility when the price of natural gas escalates? These questions put the fuel choice issue in a broader and more comprehensive perspective.

My second point is that while public power has raised many questions about a policy regarding fuel choice, we are not opposed to efforts to answer those questions. We fully support the Bonneville fuel choice policy as outlined in the 1992 Resource Program. We support the evaluation of existing programs to determine whether any of the existing policies, regulations, procedures or conservation program incentives provide mixed or contradictory price signals with regard to fuel choice. We also support the notion of assistance for customer-initiated pilot projects. An important element for eligibility for assistance is the requirement that all parties participate in the funding of the program either through direct financial or in-kind contributions. This insures that the electric and gas utilities as well as the "switching" consumer have all contributed to an effort that stands to benefit them all.

My third point deals with regional diversity. The member utilities of the Public Power Council represent a diverse set of business viewpoints and operating environments. Some of our members are located where natural gas is not even available. Others are in direct competition with natural gas or dual-fuel utilities. One of our members is actually a dual-fuel utility itself. Many find themselves in extremely competitive environments with no access to bulk power suppliers other than Bonneville. Despite this diversity, public power has spoken with a united voice regarding a regional fuel choice policy. We continue

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to believe that fuel choice issues are best addressed at the local level. The limited availability of natural gas on a regional basis itself speaks for a policy that is local in its focus and implementation.

In summary, there are many questions regarding the use of natural gas but we are committed to the evaluation of fuel switching as a resource option.

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W. Lester Bryan
Senior Vice President, Rates and Resources
Washington Water Power Company

Washington Water Power Company is headquartered in Spokane, Washington and serves electricity and natural gas in eastern Washington and northern Idaho and serves natural gas to portions of southern Oregon and the South Lake Tahoe area in northern California.

Water Power's electric to gas conversion program is referred to as a fuel efficiency program. Washington Water Power, as well as other utilities in the region and non-utility generators, are likely to rely on gas-fired turbines for future supply-side resources. In the Northwest Power Planning Council's forecast, the next firm resources following DSM are combustion turbines. However, even without factoring transmission and distribution losses, gas turbine generation is typically about 40% efficient. In contrast with this relatively inefficient use of natural gas, the direct use of gas for water and space heating results in 50% to 90% efficiency. Therefore, significant energy efficiency savings are gained by the direct use of natural gas for water heating, space heating, and process needs as compared to the use of natural gas-fired combustion turbines.

Washington Water Power is currently offering a fuel efficiency program to customers in it's Washington and Idaho jurisdictions to switch from electric space and water heating equipment to natural gas equipment. The program is offered regardless of whether Water Power serves the natural gas. (i.e. Cascade Natural Gas serves the Othello, Washington area.) In the state of Washington, the company currently provides a grant amount of up to $2700 for a combination space and water heat change-out. The customer pays any costs above the $2700 plus 60 monthly payments of $19 per month which covers the lost margin associated with the reduced electric usage.

I have three topics that I would like to address in my comments. They cover the <u>savings and cost effectiveness</u> of fuel efficiency (electric to natural gas conversions) as a demand side resource program, <u>barriers</u> for utilities looking at fuel efficiency programs, and <u>concerns associated with the regional role of natural gas in resource development</u>.

W. Lester Bryan
Senior Vice President, Rates and Resources
Washington Water Power Company

Savings & Cost-Effectiveness:

Over 5,700 residential customers have participated in the company's fuel efficiency program between May 1992 and March 1993. Approximately half of these customers already had natural gas space heating, but converted their water heater through the program. An estimated 7.5 aMW (65 million kWh) have been saved on an annualized basis as a result. Through 1995, the company has plans to acquire 29 aMW (254 million kWh) of this fuel efficiency resource. In it's 1993 Electric Integrated Resource Plan, Water Power projects acquiring resources totaling 212 aMW through the year 2011, including a mix of both supply and demand-side resources. Sixty-four percent of these resources (136 aMW) is expected to come from demand side programs, including 81 aMW of fuel efficiency.

Because electric space and water heating loads have a relatively low load factor, there are also significant capacity benefits associated with the conversion program, which are assured by the physical removal of the electric equipment.

Through the fuel efficiency program, the electric side of the company acquires a very cost-effective electric demand-side resource. Program costs are running approximately 2.5¢/kWh compared to an electric avoided cost of 6.85¢/kWh (latest revised avoided cost including demand side resource related credits and 1.84¢/kWh for capacity credit). Therefore, this fuel efficiency program is a good buy for the non-participating electric customers as well. Rates for all electric customers are also kept lower because of the lost margin payments made by participating customers.

Customers converting electric space and water heat to natural gas, as of March 1993, are saving an estimated 17,700 kWh per year of electricity. At approximately 5.3¢/kWh, these customers average electric bills are reduced by $942. Based on Water Power's current natural gas rates in the state of Washington, the annual gas bill would be approximately $404, resulting in annual bill savings of $538/year. Even after the lost margin payment of $228/year ($19 for 12 months), the annual bill savings are $310/year. In addition, the customer receives new heating equipment.

W. Lester Bryan
Senior Vice President, Rates and Resources
Washington Water Power Company

Barriers:

There are three principle barriers to implementation of fuel efficiency or any other energy efficiency type DSM programs. Those barriers are:

1) Recovery of all costs, including carrying costs associated with the company's investment.
2) Lost electric margins associated with the reduced electric sales.
3) Time lag between when the costs are incurred and when they are recovered in rates.

Washington Water Power has addressed each of these barriers with it's regulatory commissions in Washington and Idaho. Specific accounting treatment has been made available to defer all costs until a general rate case including accumulated lost margin. This covers both the cost recovery and time lag issues. Lost sales margins are deferred, including carrying costs, until the next general rate case for the traditional energy efficiency demand side management programs. The lost margin is billed to participating customers in the fuel-efficiency program.

Water Power recognizes and appreciates the support provided by both Washington and Idaho commissions in being open to different approaches and to addressing these key barrier issues.

W. Lester Bryan
Senior Vice President, Rates and Resources
Washington Water Power Company

Concerns associated with the regional role of natural gas in resource development:

First, I want to clarify that over our planning horizon, Washington Water Power will be acquiring both supply and demand side resources. Supply side resources will likely include hydro redevelopment projects, power purchases and natural gas fired combustion turbines. Direct use of natural gas will at the same time be encouraged as part of our overall demand side resource acquisition programs. We plan to acquire a balanced mix of both supply and demand side resources throughout the planning horizon.

I would like to characterize concerns over regional resource acquisition issues in the form of recommendations that would support efficient and cost-effective use of natural gas.

- Regional policies should support direct application of natural gas. Within the region, BPA's policies are key. The BPA could provide more specific encouragement of direct use of natural gas by assisting wholesale customers with funding for measures as might be appropriate depending on the price signal included in BPA's wholesale rates.

- Water Power will work together with BPA and other utilities in the region to assist in development of regional policies that will be creative and will encourage the direct application of natural gas.

- In the development of these policies, it will be important that they are designed such that electric utilities do not suffer as a result.

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March 12, 1993

To Interested Parties:

Attached is draft issue paper #93-4 on Natural Gas Supply and Price. This is the first of a series of issue papers relating to natural gas and its role in the Council's regional electric power plan. The paper describes the dramatic changes that have taken place in the natural gas market since the Council's 1991 Northwest Conservation and Electric Power Plan was developed. The implications of these changes have altered the outlook for natural gas supply and price.

The forecasts of natural gas prices and supplies form the basis for further assessment of the role of natural gas in the Council's power plan. The results of recent utility resource bidding and integrated resource planning reflect that natural gas-fired generation or cogeneration has become very attractive to utilities in the region. Planned acquisitions of gas-fired resources by utilities substantially exceed the amounts included in the Council's 1991 plan.

The Council intends to reassess the role of natural gas in meeting the region's electricity needs during the next several months. Issues addressed will include the total energy advantages of using gas directly for space and water heating, new information on the costs of gas-fired resources as well as renewable resources, and a strategic assessment of the most cost-effective role for gas in the region's electric energy future.

The Council welcomes your comments on this paper. It is important that a wide range of views be considered in setting the basic assumptions about gas prices and supplies. Close of comment on this paper is April 16, 1993. The Council will hear public comment on this paper at its April 13-15 meeting in Pendleton, Oregon.

Sincerely,

Steve Crow, Director
Public Affairs Division

enclosure

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DRAFT

STAFF ISSUE PAPER 93-4

NATURAL GAS SUPPLY AND PRICE

March 12, 1993

Summary

Dramatic changes have taken place in the natural gas market since the 1991 plan was developed. These changes have altered the outlook for natural gas supply and prices. There are significant implications not only for gas prices, but also for the conditions under which gas is likely to be supplied to electricity generators.

There is a strong consensus that supplies of natural gas available to the Pacific Northwest are adequate for the life of proposed gas-fired resources. The rapidly progressing deregulation of the natural gas supply and pipeline system is providing the incentive needed for the market to respond efficiently to changes in demand for natural gas deliveries. Recent activities confirm that pipeline capacity will be expanded as necessary to transport supplies to expanding natural gas markets. Nevertheless, the cyclical volatility that characterizes commodity markets is likely to remain.

Expected future average prices for natural gas for electricity generation are lower than those contained in the Council's 1991 plan. However, the emerging natural gas market is such that electricity generators are not likely to pay "average" prices for natural gas. Rather a wide variety of packages of natural gas supply, pipeline transportation capacity, balancing services, price guarantees, gas storage access, and backup fuel arrangements will be employed to help control price and supply risks. Such arrangements have the potential to mitigate price volatility in the natural gas commodity market.

Introduction

Since the adoption of the 1991 power plan, significant developments have occurred in natural gas markets. The most visible change has been the continued weakness in prices and reductions in nearly all organizations' forecasts of future gas prices. But less visible and more significant is the aggressive shift towards a less regulated, more competitive industry structure. This is reflected in active spot and futures markets for the gas commodity. These developments are dramatically altering the way in which natural gas is purchased and transported, and may affect the attractiveness of natural gas as an electricity generation resource.

The Council approached this topic with a status report entitled, "The Implications of the Current Gas Price Outlook for Conservation Targets" which was done in October 1992. That paper addressed the most urgent question from the Council's perspective. That is; Is the Council's primary action plan priority, acquiring at least 1500 average megawatts of efficiency resources by 2000, compromised by lower gas price forecasts. Although just a preliminary analysis, the findings strongly supported continued aggressive action toward the conservation goals. However, many implications of changing natural gas markets for the Council's plan were not addressed in the status report. The Council directed the staff to undertake a study that would evaluate more comprehensively the robustness of its plan in the face of changing natural gas markets.

This issue paper is the first product of that study of natural gas markets and their effect on the Council's plan. It describes the nature of the changes in the gas markets, the adequacy of gas supplies, and establishes a range of gas price forecasts to use in further study of the role of natural gas in the plan. Following this issue paper will be papers on the following:

- Fuel choice issues and policy options.
- Supply and cost of electricity resource alternatives.
- Role of natural gas in the plan's resource portfolio.

Call the Council if you would like to be included on a mailing list for the natural gas study. The study will extend through the summer of 1993 and, depending on the findings, could lead to an amendment to the Council's plan.

Changes in Natural Gas Markets

Regulatory: There were numerous changes in laws and regulations applying to the natural gas industry in the last ten years. The full effect of these changes has just become more apparent in the last few years as the necessary elements for a functioning market have been added. The changes were set in place by the natural gas shortages that developed during the 1970s. It became apparent to many at that time that natural gas regulations were preventing the supply and demand adjustments that were necessary for a reliable natural gas system.

The Natural Gas Policy Act of 1978 began the decontrol of the wellhead price of natural gas. Federal Energy Regulatory Commission orders 436 and 500, in 1985 and 1987 respectively, began the process of opening up natural gas pipelines for use by other parties, this is called open access. Restrictions on the use of gas by electric utilities that were included in the Powerplant and Industrial Fuel Use Act were repealed. In 1989 the Natural Gas Wellhead Decontrol Act called for the completion of decontrol of natural gas prices at the wellhead by January 1993. Signaling the beginnings of a real natural gas commodity market, the New York Mercantile Exchange began trading natural gas futures on April 3, 1990.

The latest and perhaps most pervasive change came with Federal Energy Regulatory Commission order 636 issued in April 1992. Order 636 fundamentally changes the way that natural gas is purchased and transported. In the past, natural gas pipelines served the function of securing gas supplies at the wellhead, transporting it to local distribution companies, balancing supplies and demands, and providing storage services to help meet seasonal gas demands. Local gas distribution companies simply relied on the pipelines to deliver gas to the city gate. Order 636 essentially does away with this merchant function, and pipelines become providers of separate services in each of these areas. This change is called unbundling services. The burden of securing gas supplies, acquiring space to move it on the pipeline, balancing supply and demand, and contracting for and utilizing storage now fall on the local distribution companies and individual customers who are large enough and sophisticated enough to make such arrangements for themselves. This is a huge change for local distribution companies. At the same time, it opens up opportunities for new service providers that specialize in providing gas supply, transportation management, and related services.

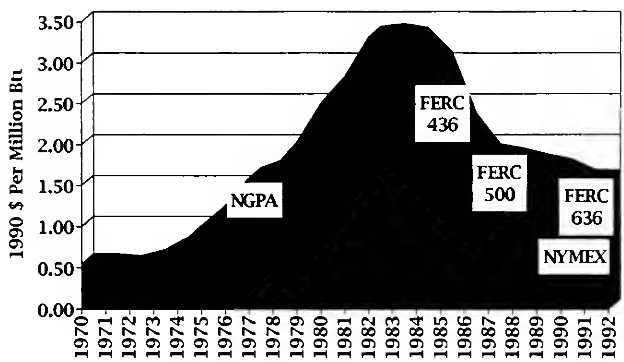
Order 636 also included several changes that were intended to give the incentive for utilizing pipeline capacity effectively. For example, by requiring that most of firm pipeline transportation costs be paid through a capacity charge, which does not change with the actual amount of gas used, low capacity factor gas users are heavily penalized. Since local distribution companies are typically low capacity factor gas users because of their large commercial and residential weather-sensitive demands, this provision creates a special challenge for them. Of importance to the electricity system, is that the use of gas-fired combustion turbines for firming the hydroelectric system or for providing peak period capacity would also be low load factor gas uses. In effect, whereas the Council assumed in the 1991 plan that most of the natural gas costs could be saved when turbines were backed down by secondary hydroelectricity, under 636 the transportation cost component of gas costs may be largely a fixed cost.

Order 636 is likely to have a significant effect on the increased reliance on spot market purchases and interruptible transportation that have characterized the market since open access was required by Federal Energy Regulatory Commission order 500. Interruptible pipeline transportation seems destined to be largely replaced by a market for releasing unneeded firm pipeline capacity. The development of such a market is an important part of order 636.

Taken together, these regulatory and policy changes have set the stage for a more efficient and competitive natural gas market. This should largely eliminate the deliverability shortages that plagued the gas industry during the 1970s. Free movement of price to help bring markets into equilibrium will likely result in some increased price volatility in spot and futures markets. Some of this volatility has been evident during the past year.

Declining Prices: Between 1983 and 1987 natural gas prices fell from $3.28 to $1.87 in real 1990 dollars at the wellhead, a 43 percent drop. Figure 1 illustrates the historical patterns of real natural gas prices from 1970 to 1992. (The 1992 figure is only an estimate.) The decrease was widely described to be a result of a temporary surplus of natural gas deliverability, the so called gas bubble. As a result, most forecasts of gas prices assumed that the rapid escalation of real gas prices experienced during the 1970s would resume soon.

Figure 1
Natural Gas Wellhead Prices



However, natural gas prices have remained low. The extended weakness is now described as the result of a gas "sausage" instead of a gas bubble. During the last two years, forecasts of natural gas price escalation have been decreasing as gas market deregulation makes the 1970s look more like the abnormal pattern than recent years. Analysts are increasingly recognizing the role that regulation played in the shortages and price escalation of the 1970s, and also the ability of the gas markets, when freed, to respond to changing prices.

It is still widely believed that natural gas prices currently are too low to encourage the development of new gas supply to meet growing demand. This conclusion is supported by data on exploration and drilling. The total number of completed gas wells in 1991 was the lowest since 1972. Between 1981 and 1991 gas well completions dropped from 19.7 thousand wells to 6.2 thousand wells. Further, behind these trends, the reduction has occurred entirely in the exploratory well area. Wells that develop known supply resources have held up well, but the more risky exploration has fallen dramatically.[1] Due to these views, most forecasts still call for real growth in natural gas prices in the future, although the forecast rates of price increase have decreased substantially over the years since the 1991 Council's plan was developed.

Since natural gas markets are continental, the above trends have affected the Pacific Northwest. Gas price declines in the Northwest have been even more dramatic than the rest of the country. This is probably due to Canadian gas pricing policies during the 1970s that raised prices in this region more than the rest of the country. In addition, Western Canada, where this region gets much of its gas supply, has had substantial quantities of gas available at low cost and with limited capacity. to transport it to other markets. This has stimulated price declines in the Northwest.

Gas Use Patterns: Declining prices, excess supplies, and deregulation resulted in some changes in the patterns of gas use over the last several years. Total natural gas consumption in the nation peaked in 1973 at about 22 trillion cubic feet. Since then it has decreased substantially reaching a low of nearly 16 trillion cubic feet in 1986.[2] Most of the decrease occurred in the industrial and electric utility sectors where significant fuel switching capability exists.

The Pacific Northwest has also shared in the declining use of natural gas although perhaps to a lesser extent because the region was not affected by declining electric utility use of gas. This is because this region used almost no gas for electricity generation until 1989 when extremely attractive gas prices resulted in some use of the region's gas-fired generation plants. Significant increases in regional gas use in 1987 through 1990 have brought the region much closer to

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[1]Natural Gas Trends: North America 1992, Cambridge Energy Research Associates, 1992, Table 5, P. 24
[2]Source: Energy Information Administration, Monthly Energy Review.

historical peak gas use than is true for the nation as a whole, although the region remains below those historical peaks by about 6 percent.[3]

The manner in which industrial gas users acquire their supplies of natural gas has shown a significant change in the past several years. There has been increasing reliance on interruptible gas transportation and spot market supplies. This has been made attractive by low gas prices and by the availability of surplus gas supplies and transportation capacity which made interruptible gas essentially firm. Taking advantage of this situation was made possible by the opening up of gas pipelines for transport of gas not owned by pipelines. This was a result of Federal Energy Regulatory Commission order 500 in 1987. Large industrial gas users typically now contract directly with gas suppliers for natural gas and use pipelines and local distribution companies as common carriers to transport the gas to their plants.

The extent of this change is dramatic. In 1986, between 80 and 90 percent of industrial gas in the Northwest was purchased directly from the local distribution company . By 1991 the share of industrial gas deliveries that were purchased from local distribution companies had declined to 44 percent in Washington, 19 percent in Oregon, and less than 1 percent in Idaho.[4] The future of such sales is highly uncertain under order 636.

A side effect of the growth of the direct gas purchasing trend in the industrial and, to a lesser extent, the commercial sector was to deprive analysts of a reliable source of information about the prices being paid for natural gas. This is because gas price information is reported by local distribution companies. Before 1986 this source covered nearly all industrial gas sales, but since then it has become relevant to only a small portion of gas sales. As a result, it has been very difficult to track the recent reductions in natural gas prices paid by industry.

Adequacy of Natural Gas Supplies

A significant concern for utility planners when considering increased use of natural gas to generate electricity has been whether there is an adequate supply of natural gas for the foreseeable future. Adequacy of supply of course depends on the demand and the price. If gas supplies were available, but only at a price considered noncompetitive with alternative sources of energy, that would not likely be considered an adequate supply.

Pinning down estimates of the supply of natural gas is not straightforward. This is partly because the relevant value is not the amount of gas in the ground, but rather, the amount of gas that will be brought to the market at various prices. Bringing gas to the market is a long process, from a geologist's theory to exploration, to proving, to producing and marketing. The most common measure

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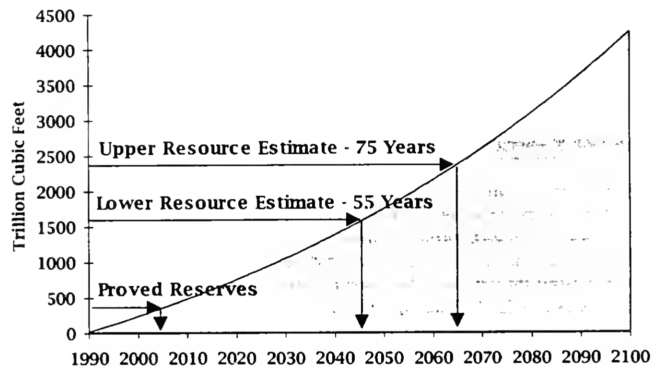
[3]Source: Energy Information Administration, State Energy Data Report, May 1992.
[4]Source: Energy Information Administration, Natural Gas Monthly.

of natural gas supply is probably "proved reserves". Proved reserves is the amount of gas that is known to be available to produce on relatively short notice. The costly preliminary work of geologic evaluation and exploratory drilling has already been done. However, proved reserves are not a good estimate of the total amount of natural gas resources that may be available in the future. For example, proved reserves in North America are estimated to be about 340 trillion cubic feet while ultimately recoverable gas resource estimates range from 1,500 to 2,300 trillion cubic feet.[5] These numbers compare to current North American consumption of about 21 trillion cubic feet per year.

The adequacy of these supplies partly depends on the growth in demand for natural gas. Nationwide forecasts of the growth of natural gas demand average about 1 percent a year, with most of the growth coming in the industrial and electric utility sector. If a 1 percent a year growth in demand is sustained, then proved reserves would last about a dozen years, but ultimately recoverable resources would last between 50 and 75 years. This is illustrated in Figure 2.

Figure 2
Cumulative Production and Resource Estimates



[5] Source: Based on a survey of estimates from several sources including, U. S. Department of Energy, American Gas Association, Potential Gas Committee, National Petroleum Council, Enron Corp., and the U.S. Energy Information Administration.

These calculations are clearly only illustrative. In the real world, supplies and demand will both respond to changes in price. Supplies will not remain stationary as exploration and recovery technologies develop, and demand will not continue to grow at 1 percent until all natural gas is used up. As prices rise, less natural gas will be demanded as other alternatives begin to compete. These alternatives include efficiency of use and substitution of other energy sources such as oil, coal, renewable resources, or imported liquefied natural gas. Any of these alternatives can limit the growth of natural gas use and prices in the future.

Natural gas is primarily a continental market. Pipelines are built to transport gas from supply areas to points of use, and with progressing deregulation the transportation system is likely to become more efficient in serving the markets. Currently, about 60 percent of U.S. marketed production of natural gas comes from the Gulf Coast and Texas area. Although Canadian gas is an important source in the Northwest, it accounts for only about 7 percent of U.S. gas supplies. Nearly all Canadian gas comes from Alberta and British Columbia.

In the U.S., the share of production from the Gulf Coast and Texas is expected to gradually decline as production from the Rocky Mountain area and Appalachia grow. Nevertheless, projected supplies are expected to continue to be dominated by conventional supplies from the lower-48 states. However, conventional supplies will be supplemented by some unconventional supplies such as coal bed methane, coal gasification, Devonian shale gas, tight sands gas, and liquefied natural gas (LNG) imports at existing terminals.

Pacific Northwest gas use is served primarily from gas wells in British Columbia, Alberta, and the U.S. Rocky Mountains. Two major pipelines serve the region. Service to firm gas markets has primarily been provided by the Northwest Pipeline Corporation. Northwest pipeline takes gas from the north from Westcoast Pipeline in British Columbia and connects to the Rocky Mountain and San Juan Basin areas in Wyoming and Utah. The other pipeline running through the Northwest is owned by the Pacific Gas Transmission Company. It accesses gas supplies from Alberta at the Canadian border. The Pacific Gas Transmission pipeline exists primarily to carry Alberta gas to California, but does interconnect with Northwest Pipeline at Stanfield Oregon so that Alberta gas can be delivered from the Northwest Pipeline system. Recently, Pacific Gas Transmission has announced interest in expanding capacity to serve Pacific Northwest markets. Two projects have been announced to extend the Pacific Gas Transmission system across the Cascade Mountains to serve customers in Western Oregon.

The Pacific Northwest has historically benefited from the fact that gas supplies in Alberta and the Northern Rockies greatly exceeded the capacity of pipelines to deliver the gas to markets. The region's access to these supply areas helped keep gas prices low. Significant pipeline expansion projects have begun to reduce the region's advantage. The Kern River pipeline began operation in 1992 carrying Rocky Mountain gas to California and had an immediate effect on Northwest gas prices. Pacific Gas Transmission is also expanding its pipeline to increase the capacity to move Alberta gas to California.

The weight of the evidence available seems to indicate that supplies of natural gas are likely to adequate for the life of proposed power plants. The issue of likely prices and emerging issues of gas delivery under deregulated conditions are addressed further below. In addition, a number of challenges arising from increased use of gas for electricity generation will be briefly discussed in the next section.

Growing Reliance on Natural Gas for Electricity Generation

Natural gas is increasingly becoming the fuel of choice for planned new electricity generation. This is a trend throughout the United States. In 1990 natural gas was the fuel for over half of planned electric utility capacity additions through the year 2000.[6] This trend is also reflected in the Northwest Power Planning Council's plan for the Pacific Northwest and to an even greater extent in the plans of individual utilities in the region. The response to regional bids for electricity resources has been dominated by gas-fired proposals.

Growing reliance on natural gas for electricity generation raises several issues. These include questions about the adequacy of natural gas supplies and the uncertainty about future prices which this issue paper discusses. However, it also raises questions about the growing interrelationship between natural gas and electricity markets. These are questions for a broader analysis that will follow this issue paper. The Council will need to decide how it should best interact with the natural gas industry to coordinate or cooperate in energy planning for the region.

The growing reliance on natural gas in electric utility planning stands in dramatic contrast to recent trends. As shown in Figure 3, the role of natural gas in electricity generation in the United States has been declining for two decades or more. In 1973, the year of the OPEC oil embargo, 18 percent of electricity was generated from natural gas. This share has now dropped to less than 10 percent. Reductions in gas and oil use for electricity generation were made up largely by increases in coal-fired and nuclear generation, as is illustrated in Figure 4.

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[6]Electric Power Research Institute, Natural Gas for Electricity Generation: The Challenge of Gas and Electric Industry Coordination, Sept. 1992 (EPRI TR-1-1239), pp. s-2 and s-3.

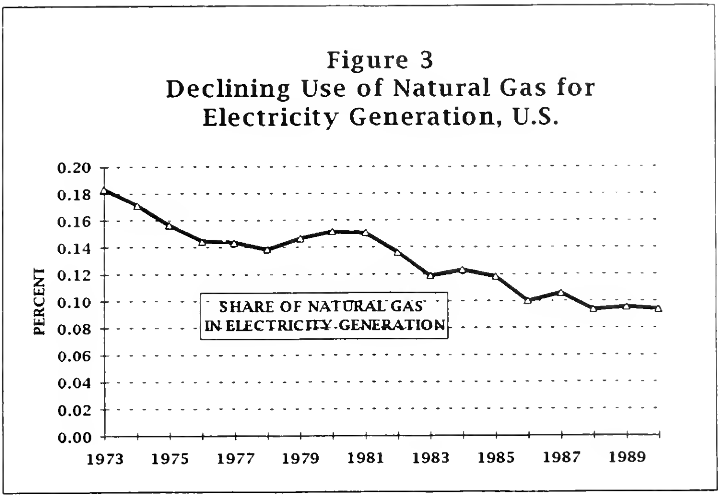
Figure 3
Declining Use of Natural Gas for Electricity Generation, U.S.
PERCENT
0.20
0.18
0.16
0.14
0.12
0.10
0.08
0.06
0.04
0.02
0.00
SHARE OF NATURAL GAS IN ELECTRICITY GENERATION
1973
1975
1977
1979
1981
1983
1985
1987
1989

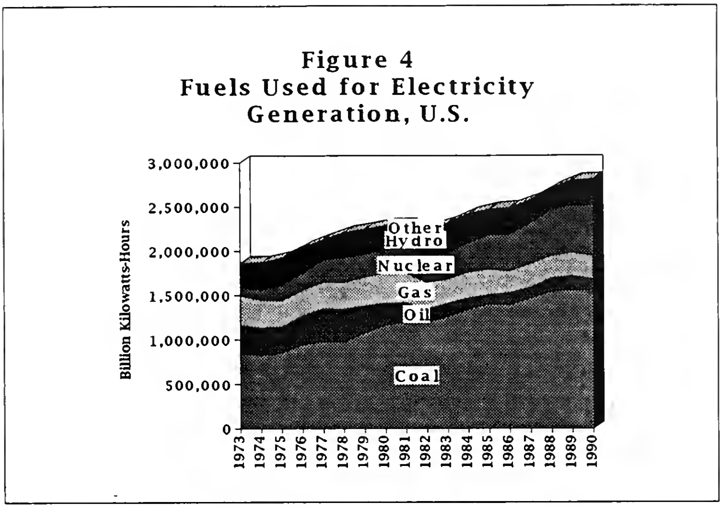
Figure 4
Fuels Used for Electricity Generation, U.S.
Billion Kilowatts-Hours
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
Other
Hydro
Nuclear
Gas
Oil
Coal
1973
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986
1987
1988
1989
1990

The historically decreasing role of natural gas for electricity generation was due to the rapid escalation of gas prices during the 1970s and early 1980s, deliverability problems in the 1970's that caused serious concerns about the reliability of natural gas supplies, and the Powerplant and Industrial Fuel Use Act prohibition of new baseload gas-fired electricity generation. The Canadian government also took a hand in controlling export prices of Canadian natural gas during this time. These factors affected all markets for natural gas, resulting in a 3 trillion cubic feet per year decrease in gas consumption between 1973 and 1990.

If utility plans and most forecasts are right, the outlook for gas as an electricity generation fuel has been dramatically reversed. There are a number of reasons for the renewed attractiveness of natural gas for electricity generation. Most of these were discussed above but are summarized again here. The price of natural gas has fallen over the past several years to very low levels. For a regional example, city gate prices in Washington have fallen to nearly one third of their 1984 levels . In addition, many restrictions of the Power Plant and Industrial Fuel Use Act have been lifted, clearing the way for utilities to take advantage of the lower gas prices. Finally, it is now widely understood that the natural gas deliverability problems during the 1970s were due to the perverse incentive effects of natural gas regulation. Several steps have been taken to deregulate gas supplies beginning in 1978 with the Natural Gas Policy Act and continuing in the form of several Federal Energy Regulatory Commission orders. These actions to free up the natural gas markets have improved the ability of the industry to respond to changing demands and thus removed some of the reliability concerns about natural gas deliverability.

In addition to these reversals of historical conditions, there have been substantial improvements in gas generating technology since the mid-1970s. Driven by research and development in the aircraft industry, the efficiency and reliability of utility-scale combustion turbine power plants have greatly improved. Combustion turbines were considered a relatively high maintenance and unreliable technology as late as the mid-1980s. Emission controls for gas combustion turbines have been greatly improved. Moreover, gas-fired power plants do not seem to be affected by the public antipathy that characterizes other types of power plants.

The attractiveness of natural gas goes well beyond price and removal of regulatory barriers, however. Natural gas generation has characteristics that blend well with some of the most important planning considerations facing electric utilities today. A recognition of the future's uncertainty is becoming an inherent part of utility planning, and dealing with the risk created by an uncertain future requires the flexibility provided by characteristics such as smaller unit sizes and shorter lead times for bringing capacity additions on line. Combustion turbines have these characteristics and are, thus, well suited to addressing planning risk due to uncertain demand growth. The flexibility of natural gas fired generation is considered to be especially valuable in the Pacific Northwest because of its potential for complementing the region's hydroelectric system. Natural gas also has significant environmental advantages over many of the traditional fuels for electricity generation, and environmental considerations have become very important in utility planning.

Increased use of natural gas for electricity generation will create substantial challenges to improve the coordination between electric utilities and the gas industry. This is especially true in the Northwest where there has been little coordination required in the past and the system planning and operations of the two industries are so different. Electric utilities in the Pacific Northwest have traditionally planned for meeting average annual energy constraints, while relying on surplus hydroelectric capacity to meet loads in peak periods. Natural gas utilities, in contrast, plan for meeting peak day requirements. These are generally met by use of natural gas storage withdrawals and interrupting customers that have alternative fuel capability. These different patterns offer possible opportunities as well as problems, that will require more coordination as gas use becomes more prevalent in the region's electricity generation. A discussion of these coordination problems is beyond the scope of this paper. A good discussion of these issues has been done by the Electric Power Research Institute.[7]

The regional plans for natural gas-fired generation would increase significantly the total amount of gas consumed in the Northwest. Current natural gas consumption in the region is about 300 billion cubic feet per year. Under expected conditions, the Council's 1991 plan called for the addition of 1,850 average megawatts of gas-fired generation by 2010. Assuming that the combustion turbines are operated to firm hydroelectricity and that the cogeneration operates most of the time, these plants would add about 60 billion cubic feet per year to regional gas demand, an increase equal to 20 percent of current consumption. If combustion turbines were run as base load resources, instead of hydro-firming resources, it could increase gas use in the region by one third of current use. The combined plans of individual Northwest utilities for gas-fired generation include about 5000 megawatts of combustion turbines which would clearly have an even larger effect on gas demand.

Natural Gas Prices

Natural gas prices play two important roles in the Council's planning. First, since natural gas is an alternative fuel for many end uses of electricity, gas prices are an important determinant of electricity demand. Second, the cost effectiveness of gas-fired electricity generation depends on the cost of gas to electric utility generating plants, and the portion of that cost which is fixed, that is has to be paid even when the plants are not operated. Therefore it is necessary to forecast retail natural gas prices for the residential, commercial, industrial, and electric utility users.

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[7]EPRI (TR-101239), op. cit.

The objective is to estimate the average delivered cost of natural gas to these various users. When natural gas was mostly delivered by local distribution companies who bought gas delivered to their system from the natural gas pipelines, estimation of average gas prices was not too much of an abstraction. Local distribution companies reported their total gas sales and revenues to the Energy Information Administration. Total revenues divided by total sales was a good measure of average gas costs in each sector. This approach is still valid for residential and commercial customers, but far less so for large industrial and utility customers. One reason, discussed above, is that the reporting system no longer catches the large industrial customers that purchase their gas directly from suppliers and use pipelines and local distribution companies as common carriers to deliver the gas. Their average costs are unknown.

In the deregulated future, gas is less likely to be priced on a delivered basis. Instead gas costs are likely to include separate components for the gas itself, transportation, storage and balancing services, and other differences reflecting the quality, reliability, and delivery conditions of the gas. These various services may not even be provided by the same entities as the market is likely to create new businesses specializing in specific aspects of gas services.

Diverse alternatives for gas supplies and services will help the gas users deal with expected price volatility. For example, long-term gas supply and transportation capacity may be contracted for under a variety of service qualities and cost guarantees. By utilizing a mix of contracts, users can help mitigate the gas supply and price risks just as is commonly done in many other markets.

It is not possible to model this market diversity. The objective of the forecasts presented here is to speculate about the average cost of natural gas in the future with the understanding that a diverse market is at work and actual prices will vary with the quality of supply, services, and price guarantees.

Forecasting begins with assumptions about the average wellhead price of natural gas for the U.S. market. This price is then adjusted to reflect the various costs of delivering the gas to regional end users. Historical adjustments can be observed directly for residential, commercial, and industrial customers of local distribution companies. However, for industrial and electric utility customers who contract directly with producers for their gas supply, the adjustments must be estimated based on pipeline transportation costs and regional wellhead price differences. Regional price differences are important because, although the markets for natural gas are continental, regional wellhead price differentials exist due to availability of adequate pipeline capacity to reach gas markets, cost and quality of natural gas reserves, and differences in the costs of moving a region's gas supplies to major market competition centers. It is expected that the Pacific Northwest will continue to enjoy lower gas prices than many regions due to our proximity to abundant Canadian gas supplies.

Wellhead Price Forecasts: Wellhead prices are a traditional measure of gas prices. Wellhead price is actually a misnomer because it includes "...charges fo natural gas plant liquids subsequently removed from the gas, gathering and compression charges, and State production, severance, and/or similar charges."[8] It is convenient to use as a starting point for regional forecasts because it is a widely used concept and several forecasts of it are readily available. Such forecasts utilize large and detailed models of natural gas markets. Gas supplies are estimated by producing region and utilize geological estimates of gas resources and the costs of expanding reserves and production to meet growing demand. Demands are forecast by consuming region. Costs are incurred to transport gas from producing to consuming regions. Transportation capacity is expanded as needed and costs of the expansion are included in gas prices. These forecasts take into account gas resource supply curves, demand forecasts, and transportation capacity and cost for the continental market to an extent that is not feasible for the Council. By using these forecasts to help define the range of gas price assumptions, we indirectly maintain consistency with the best information and analysis about the future continental gas market. Nevertheless, large uncertainty remains.

Currently, the price of natural gas is being set by gas-on-gas competition. That is, because of excess supplies of gas, different gas producers and supply areas are competing against one another for the limited gas markets. Under such conditions, gas prices are dependent on the costs of producing and transporting gas to consuming markets rather than the cost of competing fuels. As the excess deliverability of natural gas is worked off, the price of gas is expected to rise. The timing of this increase and the size of the increase are highly uncertain, but all forecasts include some degree of price increase as gas supply and demand become more balanced. This is the reason for fairly steep price increases before 2000 and a relative flattening thereafter in most of the forecasts.

Current prices are widely viewed as being below replacement costs of gas supplies. What replacement costs really are and how they will change over time is highly uncertain. However, the future prices of natural gas could be capped by several factors arising from the competitive nature of energy markets. Possible limits to natural gas prices include, residual oil prices (as assumed in the Council's 1991 fuel price forecasting model), coal prices, imported LNG prices, and end-use efficiency measures. Prices for natural gas cannot rise above levels that are competitive with these other energy sources for significant periods of time. In addition, as long as natural gas prices are significantly below the costs of these alternatives the price of the alternatives are likely to be moderated by competition with natural gas.

Some of the key uncertainties regarding future gas prices are listed below:

- The degree to which drilling charges escalate when the industry attempts to bring new supplies on line. There is very little drilling taking place now and competition has reduced the drilling charges to very low levels.

[8]U.S. Energy Information Administration, Natural Gas Monthly, November 1992, p. 151.

- The pace of technology advances in gas exploration and drilling. There have been dramatic improvements in the last few years.

- The effects of environmental regulations on natural gas demand and on the ability of alternative fuels to compete with gas.

- Government incentives for developing non-conventional gas supplies. Such incentives have played a large role in developing coal bed methane supplies.

- The effect of deregulation of natural gas supplies and transportation. Will it lead to more or less volatility of prices? Will it lead to incremental pricing of new pipeline capacity? Will it substantially change the share of gas costs that are fixed and cannot be avoided when gas use declines?

- Canadian export policies. When markets tighten up, is Canada likely to try to control export prices to a larger degree?

- Cost of new interstate pipeline capacity. Most recent expansions utilized existing right of way. Will new right of way be more difficult and expensive to secure?

- Will large users of gas tend to acquire their own gas wells? How would such a trend affect the expected price paid by users?

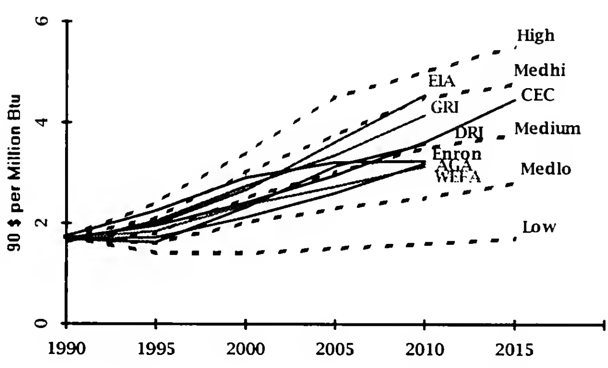
- Are there large new uses of natural gas in the future, such as transportation, that could substantially increase the expected growth of demand?

Much of the uncertainty regarding future gas prices comes down to the degree to which one thinks the current gas market is an aberration . On one side, it could be viewed as a transition from highly regulated markets that has exaggerated gas supplies and severely depressed current prices. On the other side, it could be argued that the higher prices in the past were primarily a result of clumsy regulation and the current prices are more indicative of what should be expected under freer market conditions. There is considerable truth in both arguments and that is why nearly all forecasts call for some near term price increase, but most also have lower long term price escalation compared to forecasts a couple of years ago.

Figure 5 illustrates a number of recent wellhead price forecasts by energy forecasting organizations. Most of these forecasts reflect gas demand growth of between 1.0 and 1.5 percent per year. These wellhead price forecasts cannot be compared to Council assumptions in the 1991 plan because that plan did not explicitly include wellhead price forecasts. A range of proposed wellhead gas price assumptions for the Council's natural gas study is shown in dashed lines. (This range is also shown in Table 1.) The forecasts from other organizations fall roughly within the proposed medium-low to medium-high range. The medium assumption reaches $3.50 per MMBtu in 2010, which is toward the middle of the forecasts by other organizations. Since the medium-low to medium-high assumptions cover the best guess forecasts of several credible organizations, forecasts in that range seem most likely.

The low and high assumptions are intended to explore less likely, but not implausible, futures. The high forecast escalates rapidly until 2005 when it flattens out and grows more slowly. This forecast is very pessimistic about the costs of increased gas supplies and the cost of alternative fuels and technologies. It would also be consistent with a higher forecast of demand growth, which would require more rapid supply expansion. A high growth forecasts could reflect more rapid expansion of natural gas use in automobile, stricter environmental constraints on oil and coal, or the more rapid development gas using technologies. However, as prices near $5.00 even pessimistic forecasts of alternatives will begin to seriously limit natural gas demand and price growth. The low forecast assumes essentially flat real gas prices. Before 1973 natural gas prices had been flat or declining in real terms for many years. A return to that pattern from today's prices implies that gas supplies can be brought on line at lower costs than most energy forecasters think, but many who are involved in the workings of the gas industry on a day-to-day basis see this as a possibility. Such a low forecast could also result from lower than expected growth in gas demand. Figure 6 illustrates the range of wellhead price assumptions in their historical context.

Figure 5
Natural Gas Wellhead Price Forecasts



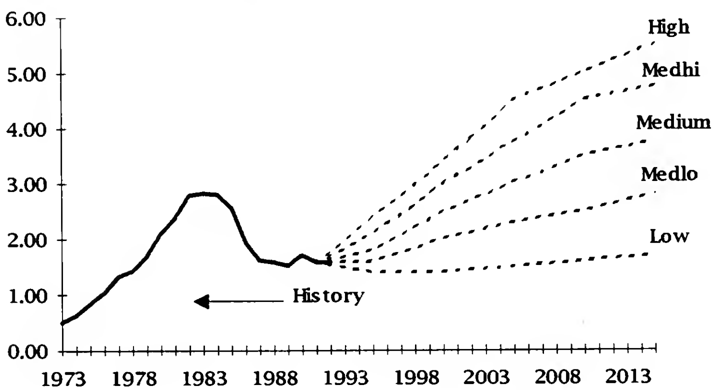
Sources:

AGA - American Gas Association
CEC - California Energy Commission
DRI - Data Resources Inc.
EIA - Energy Information Administration.
GRI - Gas Research Institute
Enron Corp.
WEFA Inc.

TABLE 1
WELLHEAD GAS PRICE FORECAST RANGE
(1990 $ per million Btu)

Year	Low	Medlow	Medium	Medhigh	High
1990	1.71	1.71	1.71	1.71	1.71
2000	1.50	2.00	2.50	3.00	3.40
2010	1.60	2.50	3.50	4.50	5.00
2015	1.70	2.80	3.75	4.75	5.50
Growth Rate (%)					
1990-2015	0.0	2.0	3.2	4.2	4.8

Figure 6
Historical and Forecast Wellhead Price
(1990$ per Million Btus)



End-Use Price Forecasts: End-use prices are estimated by adjusting average U.S. wellhead prices to the retail prices of natural gas delivered to end-users in the Northwest. As discussed above, the adjustment to estimate price for `residential, commercial, and industrial customers of local gas distribution companies is fairly straightforward. Determining gas prices for industrial and electric utility customers who contract directly for their gas supplies is more complicated and much more uncertain, even for historical periods. This section describes how retail prices were determined consistent with wellhead price ranges and then describes the resulting forecasts.

Residential, commercial, and some industrial gas consumers, the so-called core consumers, obtain their gas from local gas distribution companies. The average price they pay is reported and data is available about those prices. The required adjustments for historical years are simply the difference between reported retail rates and average U.S. wellhead prices. Since the retail rates are reported at the regional (actually state) level, this difference implicitly includes any differences between wellhead prices in supply areas that primarily serve the Pacific Northwest and the average U.S. wellhead price. The forecasts of these core customer adjustments were provided by Bonneville Power Administration, and were based on forecasts by the Gas Research Institute. These adjustments decline very slowly in real terms over the forecast period. Similar adjustments for core customers done by the California Energy Commission using the North American Natural Gas Model did not show a significant trend in adjustments for the Northwest. In this draft, we have retained the Gas Research Institute trend. In the future, when demand forecasts need to be revised, the issue of the effect of order 636 on core customer gas costs will need to be examined.

For the industrial users and electric utilities that contract directly with gas suppliers for their gas supplies, historical measures of the adjustment are not available. The reason for the industrial customers was given earlier, there is simply no data collected on the average cost of gas to these consumers. For the utility sector, the reason is different. Although data is reported by utilities about the average cost of gas that they purchase, there has been essentially no gas purchased for electricity generation in the Pacific Northwest historically. In the absence of information about actual retail prices in these sectors, the approach is to build up an estimate of their prices by adding a number of specific components to average US wellhead prices.

These components are of four general types; pipeline costs, local distribution system costs, firm gas supply premiums, and the difference between wellhead prices in regions that supply gas to the Northwest and the average U.S. price. Distinctions are made between firm transportation charges and interruptible transportation charges on both the pipeline and local distribution systems. Pipeline firm transportation costs are further distinguished between rolled-in pricing and incremental pricing. This is done because utility gas use is likely to have to pay incremental transport rates, whereas much of the industrial use will be in existing plants with rolled-in pricing.

Table 2 below illustrates how the various adjustments used in the forecasts are calculated from the components. The year 2000 is used for illustrative purposes. Some of the components vary by scenario and are shown as a range. For example, the regional wellhead price difference is assumed to decline from present levels to between 30 cents per million Btu in the low case and zero in the high case, although the high case value has not quite reached zero by the year 2000. All of these differences are less than recent average wellhead price differences because of growing pipeline capacity to improve the access of traditional Northwest supplies to other markets. Major uncertainties remain about regional price differentials, as well as, how much of the Northwest transportation advantage due to proximity to Canadian gas supplies can actually be captured by Northwest gas users.

Local gas distribution companies firm transportation charges are assumed to range between 15 cents and 30 cents per million Btu based on a variety of opinions from the Council's Natural Gas Advisory Committee.

Incremental pipeline capacity pricing is expected to increase the long-term price of this service by 20 cents per million Btu over the next several years. After that differing assumptions of real growth are used, varying from -0.5 percent a year in the low case up to 1.5 percent in the high case. The variations in these adjustments are consistent with the economic and likely gas demand conditions in the scenarios.

TABLE 2

ADJUSTMENTS FROM WELLHEAD PRICE TO NON-CORE USERS PRICE
(90$/MMBtu)

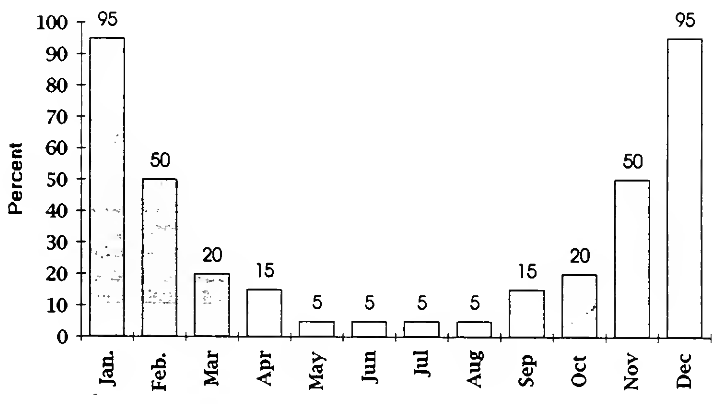
	Industrial		Utility			
Components	Interrupt.	Firm	Interrupt.	Firm	Firm Variable	Firm Fixed
Pipeline:						
Capacity Cost	.25	.30	.25	.50		.50
Commodity Charge	.02	.02	.02	.02	.02	
Local Distribution:	.15	.15 - .30				
Fuel Cost:						
Firm Premium		.25		.25		.25
Regional Difference	-.36 - -.06	-.36 - -.06	-36 - -.06	-.36 - -.06	-.36 - -.06	
TOTAL	.06 - .36	.36 - .81	-.09 - .21	.41 - .71	-.34 - -.04	.75

The two right hand columns split firm utility gas adjustments into two components, fixed and variable. Variable costs will depend on the actual consumption of gas, while fixed costs only depend on the amount of firm pipeline capacity that is contracted for. All firm pipeline transportation capacity is treated as a fixed cost. This means that when a combustion turbine is backed down by secondary hydroelectricity, no recovery of pipeline capacity costs is assumed. Order 636 specified that a market for unneeded pipeline capacity be created. Therefore, it should be possible to recover some of the costs of unused pipeline capacity by releasing it to the market.

Since the value of released capacity is expected to be highly seasonal, these adjustments to gas costs will be modeled on a monthly basis in the Council's decision model, ISAAC. Figure 7 illustrates proposed recovery share assumptions by month. In Spring and Summer capacity releases are expected to have little value, but in the peak Winter season most of the costs may be recoverable. Since this market is not yet functioning, these assumptions are speculative and the Council would welcome comments on appropriate assumptions.

The effect of the capacity release market will be to lower the average cost of gas somewhat below the prices presented in this paper. Since it is likely that turbines will be shut down mainly in spring and early summer when capacity on the pipelines will be most plentiful the savings will probably be small. In addition,

Figure 7
Recoverable Shares of Pipeline Capacity Cost



various contracting strategies are likely to develop to decrease the average gas costs below the forecasts in this paper, which simply assume that firm capacity is utilized to supply gas. Some of the possibilities include a mix of contractual arrangements for gas supply and transportation, capacity sharing arrangements among users with different patterns of use or different flexibility, utilization of gas storage capacity, and use of backup fuels. If the market is allowed to work, an infinite variety of deals will likely be made to achieve a higher overall pipeline capacity utilization. This was the vision of order 636.

For the natural gas study, the most important forecast is electric utility gas prices and industrial gas prices for cogenerators. The main issue is how the revised gas price forecasts will affect the Council's resource portfolio and action plan. In the utility case, the results that actually enter into the resource analysis are the variable and fixed costs of natural gas. The estimates are based on the assumption that natural gas-fired combustion turbines will acquire gas and transportation services on a firm basis. The adjustments described above assume that utilities will pay incremental pipeline costs and a $.25 per million Btu premium for firm gas supplies. The capability has been added to the Council's planning model to model a plant's gas contracts in a variety of ways, from prices that simply follow current market gas prices to fixed prices with escalators. In the portfolio analysis a variety of gas contracts can be assumed to reflect the value of diverse supply conditions.

The cogeneration analysis will use a combination of firm industrial gas prices for small to medium sized plants and the firm utility gas price for the large plants. The difference between industrial firm prices and utility firm prices is that large plants are assumed to avoid the local distribution company costs by connecting directly to pipelines. The Council's estimated capital costs of large plants include the cost of constructing a pipeline spur to the plant. In addition, it is assumed that large plants will have to pay incremental pipeline costs while other industrial cogenerators will get rolled-in treatment.

The series of tables below summarize the forecasts of retail natural gas prices. Although forecasts of wellhead prices increased at rates between 0.0 and 4.8 percent between the low and high forecasts, the retail prices tend to grow at a slower rate. This is because the adjustments from wellhead to retail prices increase less slowly or not at all. The residential and commercial sectors with large and declining real adjustments are the slowest growing. Utility firm prices with small adjustments with some significant growth due to assuming incremental pricing have growth rates similar to the wellhead prices. The appendix contains more detailed summary tables for each scenario and detailed electric utility price forecast tables.

Table 3A

Residential Gas Price Forecasts
(1990 $ per Million Btus)

	Low	Medium Low	Medium	Medium High	High
1990	$5.36	$5.36	$5.36	$5.36	$5.36
1995	5.04	5.24	5.44	5.74	6.04
2000	4.89	5.49	5.99	6.49	6.89
2010	4.80	5.70	6.70	7.70	8.20
2015	4.77	5.87	6.82	7.82	8.57
1990-2015 Growth	-0.5%	0.4%	1.0%	1.5%	1.9%

Table 3B

Commercial Gas Price Forecasts
(1990 $ per Million Btus)

	Low	Medium Low	Medium	Medium High	High
1990	$4.38	$4.38	$4.38	$4.38	$4.38
1995	4.11	4.31	4.51	4.81	5.11
2000	4.00	4.60	5.10	5.60	6.00
2010	4.03	4.93	5.93	6.93	7.43
2015	4.04	5.14	6.09	7.09	7.84
1990-2015 Growth	-0.3%	0.6%	1.3%	1.9%	2.4%

Table 3C

Average Industrial Gas Price Forecasts
(1990 $ per Million Btus)

	Low	Medium Low	Medium	Medium High	High
1990	$2.24	$2.24	$2.24	$2.24	$2.24
1995	1.84	2.06	2.26	2.63	3.00
2000	1.90	2.56	3.06	3.67	4.12
2010	2.13	3.08	4.14	5.20	5.75
2015	2.23	3.38	4.38	5.44	6.25
1990-2015 Growth	-0.0%	1.7%	2.7%	3.6%	4.2%

Table 3D

	Utility Firm Gas Price Forecasts (1990 $ per Million Btus)				
	Low	Medium Low	Medium	Medium High	High
1990	$1.86	$1.86	$1.86	$1.86	$1.86
1995	1.58	1.73	1.93	2.32	2.72
2000	1.81	2.58	3.00	3.66	4.12
2010	2.04	3.04	4.15	5.26	5.86
2015	2.13	3.34	4.41	5.54	6.40
1990-2015 Growth	0.5%	2.4%	3.5%	4.5%	5.1%

Figures 8 and 9 show the change in forecasts from those used in the Council's 1991 plan. Figure 8 shows residential prices. The pattern of difference is similar for the commercial sector and industrial customers that buy their gas from a local distribution company. These price forecasts generally stay within the 1991 plan forecast range, but the range is significantly narrower. The narrowing has all come off of the top of the range as the new high is just below the previous medium-high forecast.

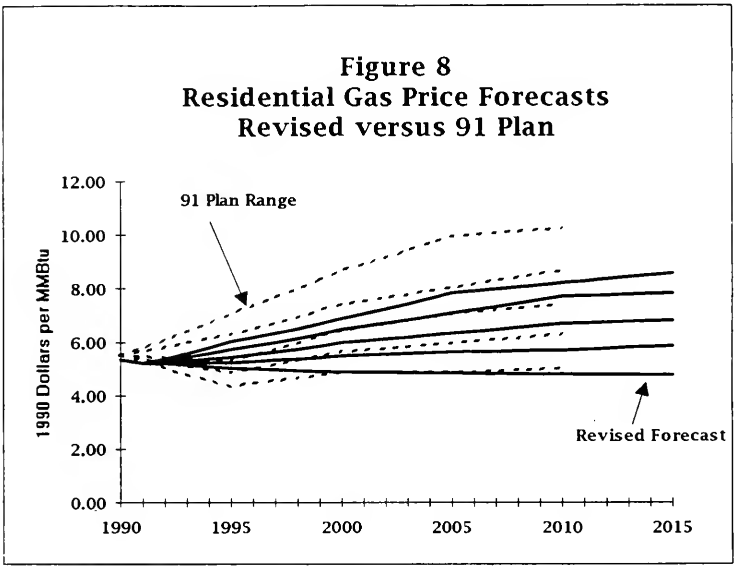
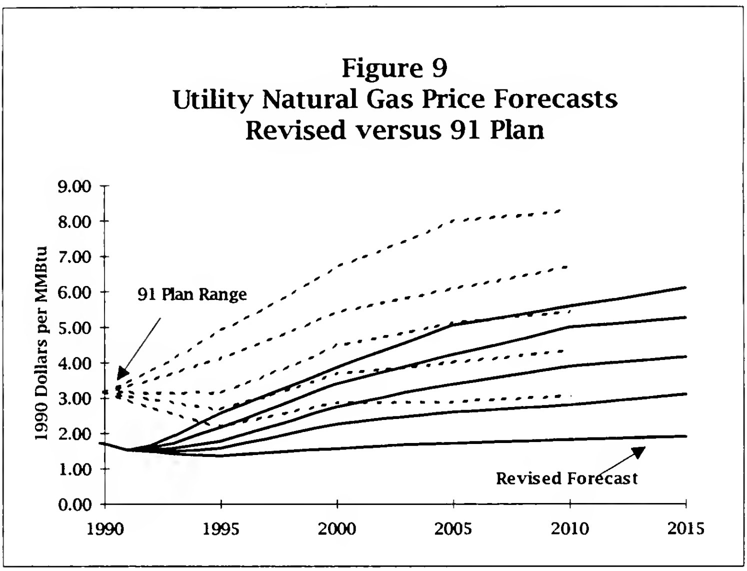


Figure 9 shows a comparison with the 1991 plan forecast for "hybrid" utility gas prices. The hybrid forecast is shown because that was the projection used in the 1991 plan. It is simply the average of the firm and interruptible price forecasts. Although the hybrid concept has been replaced by a firm price with capacity release, it is used here in order to compare to the 1991 plan. The pattern of change shown for hybrid utility gas prices is similar to that for industrial customers that purchase their own gas supplies. The striking difference from the residential sector change is a downward shift of over a dollar starting in 1990. This large shift is a result of estimating prices for these sectors where no historical data was available. This problem with the historical data was discussed earlier. The revised price levels seem to be more consistent with costs being bid to utilities for gas-fired resources and with hearsay about current prices.



Conclusion

Changes in the natural gas industry over the last few years have significantly altered gas markets. The effects of many of these changes are yet to be fully felt. However, it seems clear that past forecasts of gas price escalation are probably too high. The high case forecasts, in particular, have become very unlikely. Further, the previous estimates of current gas prices for large utility and industry users were too high, causing the entire forecast range for those users to be too high.

The proposed forecasts include estimates of fixed and variable fuel cost components in contrast to earlier estimates that treated all gas costs as variable. This change will enable the Council to better assess the value of gas-fired resources to the system since an important component of that value is displaceability

A new range of natural gas price assumptions has been proposed in this issue paper. Although the proposed range is lower and narrower, there is still substantial price uncertainty. The risk posed by that uncertainty needs to be more carefully assessed in the Council's resource planning. This will be addressed in a future issue paper in the Council's natural gas study.

Combined with more favorable gas price outlooks, is an optimistic view of future natural gas supplies. There appear to be adequate gas supplies to serve significant expansions of gas use well beyond the expected life of power plants that will be built over the next several years. However, increased use of gas for generating electricity raises issues of increased coordination between the gas and electric industries. The specific conditions of utility gas use need to be explored in order to begin to better coordinate the planning of gas and electric utilities. The fit between the two industries is likely to significantly affect the cost effectiveness of natural gas in the regional plan.

The forecasts discussed in this paper have not incorporated the effects o: President Clinton's proposal for a Btu tax. The effects of such a tax, if enacted, will be incorporated in the portfolio analysis model. Preliminary analysis of the effects of the tax on electricity from various sources indicates that natural gas would be favored over most traditional sources of electricity. However, non conventional renewable resources would not be taxed under the proposal.

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APPENDIX

			NATURAL GAS FORECAST SUMMARY				
				Low Case			
			(1990$ per MMBtu)				
				Regional Gas Price			California
	World	U. S.	Average				Interr.
	Oil	Wellhead	Industrial	Residential	Commercia	Utility	Utility
Year	Price	Price	Price			Firm	Price
	(90$/Bbl.)						
1980	52.00	2.44	6.18	7.78	7.23	2.59	3.14
1981	51.83	2.77	6.06	7.98	7.30	2.92	3.47
1982	44.12	3.23	6.84	8.66	7.99	3.38	3.93
1983	37.08	3.28	6.34	8.57	7.73	3.43	3.98
1984	35.26	3.25	6.00	8.21	7.42	3.40	3.95
1985	32.00	2.98	5.42	7.75	6.72	3.13	3.68
1986	16.18	2.24	3.96	6.86	5.91	2.39	2.94
1987	20.31	1.87	3.23	6.40	5.28	2.02	2.57
1988	15.78	1.83	2.83	6.25	5.21	1.98	2.53
1989	18.82	1.76	2.52	5.76	4.83	1.91	2.46
1990	21.76	1.71	2.24	5.36	4.38	1.86	2.41
1991	17.92	1.52	2.04	5.22	4.23	1.67	2.22
1992	16.85	1.53	1.97	5.21	4.24	1.63	2.23
1993	15.84	1.49	1.91	5.16	4.20	1.57	2.19
1994	14.89	1.44	1.87	5.09	4.15	1.53	2.18
1995	14.00	1.40	1.84	5.04	4.11	1.51	2.15
1996	14.55	1.40	1.85	5.01	4.09	1.58	2.17
1997	15.13	1.40	1.87	4.98	4.07	1.65	2.18
1998	15.73	1.40	1.87	4.94	4.04	1.72	2.20
1999	16.35	1.40	1.88	4.91	4.02	1.79	2.21
2000	17.00	1.40	1.90	4.89	4.00	1.81	2.22
2001	17.00	1.42	1.93	4.88	4.00	1.84	2.26
2002	17.00	1.44	1.96	4.87	4.00	1.88	2.29
2003	17.00	1.46	1.99	4.86	4.00	1.92	2.32
2004	17.00	1.48	2.01	4.85	4.01	1.94	2.36
2005	17.00	1.50	2.03	4.84	4.01	1.96	2.41
2006	17.20	1.52	2.05	4.83	4.01	1.97	2.46
2007	17.39	1.54	2.07	4.82	4.02	1.99	2.52
2008	17.59	1.56	2.09	4.82	4.03	2.01	2.57
2009	17.80	1.58	2.11	4.81	4.03	2.03	2.63
2010	18.00	1.60	2.13	4.80	4.03	2.04	2.68
2011	18.38	1.62	2.15	4.79	4.03	2.06	2.72
2012	18.77	1.64	2.16	4.79	4.04	2.08	2.77
2013	19.17	1.66	2.18	4.79	4.04	2.10	2.82
2014	19.58	1.68	2.20	4.78	4.04	2.11	2.87
2015	20.00	1.70	2.23	4.77	4.04	2.13	2.90
Growth Rt.							
1900-2015	-0.34%	-0.02%	-0.02%	-0.46%	-0.32%	0.55%	0.74%

PNW Electric Utility Gas Price Forecast Module

Low Case

1990 Dollars/mmbtu

Year	Average Wellhead Price	Interruptible Wellhead To User Markup	Interruptible Burner-tip Gas Price	Firm Wellhead To User Markup	Firm Burner-tip Gas Price	Variable Fuel Cost	Fixed Fuel Cost ($/KW/Yr)
1980	2.44	-0.15	2.29	0.15	2.59	2.04	36.71
1981	2.77	-0.15	2.62	0.15	2.92	2.37	36.71
1982	3.23	-0.15	3.08	0.15	3.38	2.83	36.71
1983	3.28	-0.15	3.13	0.15	3.43	2.88	36.71
1984	3.25	-0.15	3.10	0.15	3.40	2.85	36.71
1985	2.98	-0.15	2.83	0.15	3.13	2.58	36.71
1986	2.24	-0.15	2.09	0.15	2.39	1.84	36.71
1987	1.87	-0.15	1.72	0.15	2.02	1.47	36.71
1988	1.83	-0.15	1.68	0.15	1.98	1.43	36.71
1989	1.76	-0.15	1.61	0.15	1.91	1.36	36.71
1990	1.71	-0.15	1.56	0.15	1.86	1.31	36.71
1991	1.52	-0.15	1.37	0.15	1.67	1.12	36.71
1992	1.53	-0.20	1.33	0.10	1.63	1.08	36.71
1993	1.49	-0.22	1.27	0.08	1.57	1.02	36.71
1994	1.44	-0.21	1.23	0.09	1.53	0.98	36.71
1995	1.40	-0.19	1.21	0.11	1.51	0.96	36.71
1996	1.40	-0.17	1.23	0.18	1.58	0.98	40.05
1997	1.40	-0.15	1.25	0.25	1.65	1.00	43.39
1998	1.40	-0.13	1.27	0.32	1.72	1.02	46.73
1999	1.40	-0.11	1.29	0.39	1.79	1.04	50.06
2000	1.40	-0.09	1.31	0.41	1.81	1.06	49.90
2001	1.42	-0.07	1.35	0.43	1.84	1.10	49.73
2002	1.44	-0.05	1.39	0.44	1.88	1.14	49.57
2003	1.46	-0.03	1.43	0.46	1.92	1.18	49.40
2004	1.48	-0.03	1.45	0.46	1.94	1.20	49.24
2005	1.50	-0.03	1.47	0.46	1.96	1.22	49.07
2006	1.52	-0.03	1.49	0.45	1.97	1.24	48.91
2007	1.54	-0.03	1.51	0.45	1.99	1.26	48.75
2008	1.56	-0.03	1.53	0.45	2.01	1.28	48.59
2009	1.58	-0.03	1.55	0.45	2.03	1.30	48.43
2010	1.60	-0.03	1.57	0.44	2.04	1.32	48.27
2011	1.62	-0.03	1.59	0.44	2.06	1.34	48.12
2012	1.64	-0.03	1.61	0.44	2.08	1.36	47.96
2013	1.66	-0.03	1.63	0.44	2.10	1.38	47.80
2014	1.68	-0.03	1.65	0.43	2.11	1.40	47.65
2015	1.70	-0.03	1.67	0.43	2.13	1.42	47.49
Gr. Rt. 90-15	-0.02%	-6.23%	0.27%	4.32%	0.55%	0.32%	1.03%

Markups are calculated in the MARKUP.XLS spreadsheet.
See embedded cell notes there.

			NATURAL GAS FORECAST SUMMARY				
			Medium Low Case				
			(1990$ per MMBtu)				
				Regional Gas Price			California
	World	U. S.	Average				Interr.
	Oil	Wellhead	Industrial	Residential	Commercial	Utility	Utility
Year	Price	Price	Price			Firm	Price
	(90$/Bbl.)						
1980	52.00	2.44	6.18	7.78	7.23	2.59	3.14
1981	51.83	2.77	6.06	7.98	7.30	2.92	3.47
1982	44.12	3.23	6.84	8.66	7.99	3.36	3.93
1983	37.08	3.28	6.34	8.57	7.73	3.43	3.98
1984	35.26	3.25	6.00	8.21	7.42	3.40	3.95
1985	32.00	2.98	5.42	7.75	6.72	3.13	3.68
1986	16.18	2.24	3.96	6.86	5.91	2.39	2.94
1987	20.31	1.87	3.23	6.40	5.28	2.02	2.57
1988	15.78	1.83	2.83	6.25	5.21	1.98	2.53
1989	18.82	1.76	2.52	5.76	4.83	1.91	2.46
1990	21.76	1.71	2.24	5.36	4.38	1.86	2.41
1991	17.92	1.52	2.04	5.22	4.23	1.67	2.22
1992	17.69	1.54	1.98	5.22	4.25	1.64	2.24
1993	17.46	1.56	1.98	5.23	4.27	1.64	2.26
1994	17.23	1.58	2.02	5.23	4.29	1.68	2.32
1995	17.00	1.60	2.06	5.24	4.31	1.73	2.35
1996	17.56	1.67	2.16	5.28	4.36	1.89	2.44
1997	18.14	1.75	2.25	5.33	4.42	2.04	2.53
1998	18.74	1.83	2.35	5.37	4.47	2.22	2.62
1999	19.36	1.91	2.46	5.42	4.53	2.38	2.72
2000	20.00	2.00	2.56	5.49	4.60	2.50	2.82
2001	20.57	2.06	2.64	5.52	4.64	2.59	2.89
2002	21.15	2.11	2.70	5.54	4.67	2.65	2.97
2003	21.75	2.17	2.76	5.57	4.71	2.71	3.04
2004	22.37	2.24	2.82	5.61	4.77	2.78	3.12
2005	23.00	2.30	2.88	5.64	4.81	2.84	3.21
2006	23.20	2.34	2.92	5.65	4.83	2.88	3.28
2007	23.39	2.38	2.96	5.66	4.86	2.92	3.36
2008	23.69	2.42	3.00	5.68	4.89	2.96	3.43
2009	23.80	2.46	3.04	5.69	4.91	3.00	3.51
2010	24.00	2.50	3.08	5.70	4.93	3.04	3.58
2011	24.39	2.56	3.14	5.73	4.97	3.10	3.66
2012	24.78	2.62	3.19	5.77	5.02	3.16	3.75
2013	25.18	2.68	3.25	5.81	5.06	3.22	3.84
2014	25.59	2.74	3.31	5.84	5.10	3.28	3.93
2015	26.00	2.80	3.38	5.87	5.14	3.34	4.00
Growth Rt.							
1900-2015	0.71%	1.99%	1.66%	0.37%	0.64%	2.37%	2.05%

PNW Electric Utility Gas Price Forecast Module
Medium Low Case
1990 Dollars/mmbtu

Year	Average Wellhead Price	Interruptible Wellhead To User Markup	Interruptible Burner-tip Gas Price	Firm Wellhead To User Markup	Firm Burner-tip Gas Price	Variable Fuel Cost	Fixed Fuel Cost ($/KW/Yr)
1980	2.44	-0.15	2.29	0.15	2.59	2.04	36.71
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1982	3.23	-0.15	3.08	0.15	3.38	2.83	36.71
1983	3.28	-0.15	3.13	0.15	3.43	2.88	36.71
1984	3.25	-0.15	3.10	0.15	3.40	2.85	36.71
1985	2.98	-0.15	2.83	0.15	3.13	2.58	36.71
1986	2.24	-0.15	2.09	0.15	2.39	1.84	36.71
1987	1.87	-0.15	1.72	0.15	2.02	1.47	36.71
1988	1.83	-0.15	1.68	0.15	1.98	1.43	36.71
1989	1.76	-0.15	1.61	0.15	1.91	1.36	36.71
1990	1.71	-0.15	1.56	0.15	1.86	1.31	36.71
1991	1.52	-0.15	1.37	0.15	1.67	1.12	36.71
1992	1.54	-0.20	1.34	0.10	1.64	1.09	36.71
1993	1.56	-0.22	1.34	0.08	1.64	1.09	36.71
1994	1.58	-0.20	1.38	0.10	1.68	1.13	36.71
1995	1.60	-0.17	1.43	0.13	1.73	1.18	36.71
1996	1.67	-0.13	1.54	0.22	1.89	1.29	40.05
1997	1.75	-0.11	1.64	0.29	2.04	1.39	43.39
1998	1.83	-0.06	1.77	0.39	2.22	1.52	46.73
1999	1.91	-0.03	1.88	0.47	2.38	1.63	50.06
2000	2.00	0.00	2.00	0.50	2.50	1.75	50.06
2001	2.06	0.03	2.09	0.53	2.59	1.84	50.06
2002	2.11	0.04	2.15	0.54	2.65	1.90	50.06
2003	2.17	0.04	2.21	0.54	2.71	1.96	50.06
2004	2.24	0.04	2.28	0.54	2.78	2.03	50.06
2005	2.30	0.04	2.34	0.54	2.84	2.09	50.06
2006	2.34	0.04	2.38	0.54	2.88	2.13	50.06
2007	2.38	0.04	2.42	0.54	2.92	2.17	50.06
2008	2.42	0.04	2.46	0.54	2.96	2.21	50.06
2009	2.46	0.04	2.50	0.54	3.00	2.25	50.06
2010	2.50	0.04	2.54	0.54	3.04	2.29	50.06
2011	2.56	0.04	2.60	0.54	3.10	2.35	50.06
2012	2.62	0.04	2.66	0.54	3.16	2.41	50.06
2013	2.68	0.04	2.72	0.54	3.22	2.47	50.06
2014	2.74	0.04	2.78	0.54	3.28	2.53	50.06
2015	2.80	0.04	2.84	0.54	3.34	2.59	50.06
Gr. Rt. 90-15	1.99%	#NUM!	2.43%	5.26%	2.37%	2.76%	1.25%

Markups are calculated in the MARKUP.XLS spreadsheet.
See embedded cell notes there.

			NATURAL GAS FORECAST SUMMARY				
			Medium Case				
			(1990$ per MMBtu)				
				Regional Gas Price			California
	World	U. S.	Average				Interr.
	Oil	Wellhead	Industrial	Residential	Commercia	Utility	Utility
Year	Price	Price	Price			Firm	Price
	(90$/Bbl.)						
1980	52.00	2.44	6.18	7.78	7.23	2.59	3.14
1981	51.83	2.77	6.06	7.98	7.30	2.92	3.47
1982	44.12	3.23	6.84	8.66	7.99	3.38	3.93
1983	37.08	3.28	6.34	8.57	7.73	3.43	3.98
1984	35.26	3.25	6.00	8.21	7.42	3.40	3.95
1985	32.00	2.98	5.42	7.75	6.72	3.13	3.68
1986	16.18	2.24	3.96	6.86	5.91	2.39	2.94
1987	20.31	1.87	3.23	6.40	5.28	2.02	2.57
1988	15.78	1.83	2.83	6.25	5.21	1.98	2.53
1989	18.82	1.76	2.52	5.76	4.83	1.91	2.46
1990	21.76	1.71	2.24	5.36	4.38	1.86	2.41
1991	17.92	1.52	2.04	5.22	4.23	1.67	2.22
1992	18.19	1.59	2.02	5.27	4.30	1.69	2.29
1993	18.45	1.65	2.08	5.32	4.36	1.73	2.35
1994	18.72	1.73	2.16	5.38	4.44	1.83	2.47
1995	19.00	1.80	2.26	5.44	4.51	1.93	2.55
1996	19.91	1.92	2.41	5.53	4.61	2.14	2.69
1997	20.86	2.05	2.56	5.63	4.72	2.35	2.83
1998	21.86	2.19	2.71	5.73	4.83	2.57	2.99
1999	22.90	2.34	2.89	5.85	4.96	2.81	3.15
2000	24.00	2.50	3.06	5.99	5.10	3.00	3.32
2001	24.75	2.59	3.18	6.05	5.17	3.13	3.43
2002	25.53	2.69	3.30	6.12	5.25	3.27	3.54
2003	26.33	2.79	3.43	6.19	5.33	3.42	3.65
2004	27.15	2.89	3.54	6.26	5.42	3.53	3.77
2005	28.00	3.00	3.64	6.34	5.51	3.64	3.91
2006	28.39	3.09	3.73	6.40	5.58	3.73	4.04
2007	28.78	3.19	3.83	6.47	5.67	3.83	4.17
2008	29.18	3.29	3.93	6.55	5.76	3.93	4.30
2009	29.59	3.39	4.03	6.62	5.84	4.04	4.44
2010	30.00	3.50	4.14	6.70	5.93	4.15	4.58
2011	30.39	3.55	4.19	6.72	5.96	4.20	4.65
2012	30.78	3.60	4.23	6.75	6.00	4.25	4.73
2013	31.18	3.65	4.28	6.78	6.03	4.30	4.81
2014	31.59	3.70	4.33	6.80	6.06	4.36	4.89
2015	32.00	3.75	4.38	6.82	6.09	4.41	4.95
Growth Rt.							
1900-2015	1.55%	3.19%	2.73%	0.97%	1.33%	3.51%	2.92%

PNW Electric Utility Gas Price Forecast Module

Medium Case

1990 Dollars/mmbtu

Year	Average Wellhead Price	Interruptible Wellhead To User Markup	Interruptible Burner-tip Gas Price	Firm Wellhead To User Markup	Firm Burner-tip Gas Price	Variable Fuel Cost	Fixed Fuel Cost ($/KW/Yr)
1980	2.44	-0.15	2.29	0.15	2.59	2.04	36.71
1981	2.77	-0.15	2.62	0.15	2.92	2.37	36.71
1982	3.23	-0.15	3.08	0.15	3.38	2.83	36.71
1983	3.28	-0.15	3.13	0.15	3.43	2.88	36.71
1984	3.25	-0.15	3.10	0.15	3.40	2.85	36.71
1985	2.98	-0.15	2.83	0.15	3.13	2.58	36.71
1986	2.24	-0.15	2.09	0.15	2.39	1.84	36.71
1987	1.87	-0.15	1.72	0.15	2.02	1.47	36.71
1988	1.83	-0.15	1.68	0.15	1.98	1.43	36.71
1989	1.76	-0.15	1.61	0.15	1.91	1.36	36.71
1990	1.71	-0.15	1.56	0.15	1.86	1.31	36.71
1991	1.52	-0.15	1.37	0.15	1.67	1.12	36.71
1992	1.59	-0.20	1.39	0.10	1.69	1.14	36.71
1993	1.65	-0.22	1.43	0.08	1.73	1.18	36.71
1994	1.73	-0.20	1.53	0.10	1.83	1.28	36.71
1995	1.80	-0.17	1.63	0.13	1.93	1.38	36.71
1996	1.92	-0.13	1.79	0.22	2.14	1.54	40.05
1997	2.05	-0.10	1.95	0.30	2.35	1.70	43.39
1998	2.19	-0.07	2.12	0.38	2.57	1.87	46.73
1999	2.34	-0.03	2.31	0.47	2.81	2.06	50.06
2000	2.50	0.00	2.50	0.50	3.00	2.25	50.23
2001	2.59	0.03	2.62	0.54	3.13	2.37	50.40
2002	2.69	0.07	2.76	0.58	3.27	2.51	50.57
2003	2.79	0.12	2.91	0.63	3.42	2.66	50.74
2004	2.89	0.12	3.01	0.63	3.53	2.76	50.91
2005	3.00	0.12	3.12	0.64	3.64	2.87	51.08
2006	3.09	0.12	3.21	0.64	3.73	2.96	51.25
2007	3.19	0.12	3.31	0.64	3.83	3.06	51.42
2008	3.29	0.12	3.41	0.64	3.93	3.16	51.60
2009	3.39	0.12	3.51	0.65	4.04	3.26	51.77
2010	3.50	0.12	3.62	0.65	4.15	3.37	51.95
2011	3.55	0.12	3.67	0.65	4.20	3.42	52.12
2012	3.60	0.12	3.72	0.65	4.25	3.47	52.30
2013	3.65	0.12	3.77	0.66	4.30	3.52	52.48
2014	3.70	0.12	3.82	0.66	4.36	3.57	52.66
2015	3.75	0.12	3.87	0.66	4.41	3.62	52.84
Gr. Rt. 90-15	3.19%	#NUM!	3.70%	6.12%	3.51%	4.16%	1.47%

Markups are calculated in the MAARKUP.XLS spreadsheet.
See embedded cell notes there.

			NATURAL GAS FORECAST SUMMARY				
			Medium High Case				
			(1990$ per MMBtu)				
				Regional Gas Price			California
	World	U. S.	Average				Interr.
	Oil	Wellhead	Industrial	Residential	Commercia	Utility	Utility
Year	Price	Price	Price			Firm	Price
	(90$/Bbl.)						
1980	52.00	2.44	6.18	7.78	7.23	2.59	3.14
1981	51.83	2.77	6.06	7.98	7.30	2.92	3.47
1982	44.12	3.23	6.84	8.66	7.99	3.38	3.93
1983	37.08	3.28	6.34	8.57	7.73	3.43	3.98
1984	35.26	3.25	6.00	8.21	7.42	3.40	3.95
1985	32.00	2.98	5.42	7.75	6.72	3.13	3.68
1986	16.18	2.24	3.96	6.86	5.91	2.39	2.94
1987	20.31	1.87	3.23	6.40	5.28	2.02	2.57
1988	15.78	1.83	2.83	6.25	5.21	1.98	2.53
1989	18.82	1.76	2.52	5.76	4.83	1.91	2.46
1990	21.76	1.71	2.24	5.36	4.38	1.86	2.41
1991	17.92	1.52	2.04	5.22	4.23	1.67	2.22
1992	18.65	1.65	2.08	5.33	4.36	1.75	2.35
1993	19.40	1.79	2.21	5.46	4.50	1.87	2.49
1994	20.18	1.94	2.43	5.59	4.65	2.11	2.68
1995	21.00	2.10	2.63	5.74	4.81	2.32	2.85
1996	22.08	2.26	2.81	5.87	4.95	2.58	3.02
1997	23.22	2.42	3.01	6.00	5.09	2.84	3.20
1998	24.42	2.60	3.22	6.14	5.24	3.12	3.40
1999	25.68	2.79	3.45	6.30	5.41	3.41	3.60
2000	27.00	3.00	3.67	6.49	5.60	3.66	3.82
2001	27.93	3.14	3.82	6.60	5.72	3.82	3.97
2002	28.90	3.28	3.98	6.71	5.84	3.99	4.13
2003	29.90	3.43	4.13	6.83	5.97	4.15	4.30
2004	30.93	3.59	4.29	6.96	6.12	4.31	4.47
2005	32.00	3.75	4.45	7.09	6.26	4.48	4.66
2006	32.58	3.89	4.59	7.20	6.38	4.63	4.83
2007	33.17	4.03	4.73	7.31	6.51	4.78	5.01
2008	33.77	4.18	4.88	7.44	6.65	4.93	5.20
2009	34.38	4.34	5.03	7.57	6.79	5.09	5.39
2010	35.00	4.50	5.20	7.70	6.93	5.26	5.58
2011	35.58	4.55	5.24	7.72	6.96	5.31	5.65
2012	36.17	4.60	5.29	7.75	7.00	5.37	5.73
2013	36.77	4.65	5.34	7.78	7.03	5.42	5.81
2014	37.38	4.70	5.39	7.80	7.06	5.48	5.89
2015	38.00	4.75	5.44	7.82	7.09	5.54	5.95
Growth Rt.							
1900-2015	2.26%	4.17%	3.62%	1.53%	1.95%	4.46%	3.68%

PNW Electric Utility Gas Price Forecast Module

Medium High Case

1990 Dollars/mmbtu

Year	Average Wellhead Price	Interruptible: Wellhead To User Markup	Interruptible: Burner-tip Gas Price	Firm: Wellhead To User Markup	Firm: Burner-tip Gas Price	Variable Fuel Cost	Fixed Fuel Cost ($/KW/Yr)
1980	2.44	-0.15	2.29	0.15	2.59	2.04	36.71
1981	2.77	-0.15	2.62	0.15	2.92	2.37	36.71
1982	3.23	-0.15	3.08	0.15	3.38	2.83	36.71
1983	3.28	-0.15	3.13	0.15	3.43	2.88	36.71
1984	3.25	-0.15	3.10	0.15	3.40	2.85	36.71
1985	2.98	-0.15	2.83	0.15	3.13	2.58	36.71
1986	2.24	-0.15	2.09	0.15	2.39	1.84	36.71
1987	1.87	-0.15	1.72	0.15	2.02	1.47	36.71
1988	1.83	-0.15	1.68	0.15	1.98	1.43	36.71
1989	1.76	-0.15	1.61	0.15	1.91	1.36	36.71
1990	1.71	-0.15	1.56	0.15	1.86	1.31	36.71
1991	1.52	-0.15	1.37	0.15	1.67	1.12	36.71
1992	1.65	-0.20	1.45	0.10	1.75	1.30	36.71
1993	1.79	-0.22	1.57	0.08	1.87	1.32	36.71
1994	1.94	-0.13	1.81	0.17	2.11	1.56	36.71
1995	2.10	-0.08	2.02	0.22	2.32	1.77	36.71
1996	2.26	-0.03	2.23	0.32	2.58	1.98	40.05
1997	2.42	0.02	2.44	0.42	2.84	2.19	43.39
1998	2.60	0.07	2.67	0.52	3.12	2.42	46.74
1999	2.79	0.12	2.91	0.62	3.41	2.66	50.06
2000	3.00	0.15	3.15	0.66	3.66	2.90	50.40
2001	3.14	0.17	3.31	0.68	3.82	3.06	50.75
2002	3.28	0.19	3.47	0.71	3.99	3.22	51.07
2003	3.43	0.20	3.63	0.72	4.15	3.38	51.42
2004	3.59	0.20	3.79	0.73	4.31	3.54	51.77
2005	3.75	0.20	3.95	0.73	4.48	3.70	52.12
2006	3.89	0.20	4.09	0.74	4.63	3.84	52.47
2007	4.03	0.20	4.23	0.74	4.78	3.98	52.83
2008	4.18	0.20	4.38	0.75	4.93	4.13	53.19
2009	4.34	0.20	4.54	0.75	5.09	4.29	53.56
2010	4.50	0.20	4.70	0.76	5.26	4.45	53.92
2011	4.55	0.20	4.75	0.76	5.31	4.50	54.30
2012	4.60	0.20	4.80	0.77	5.37	4.55	54.67
2013	4.65	0.20	4.85	0.77	5.42	4.60	55.05
2014	4.70	0.20	4.90	0.78	5.48	4.65	55.44
2015	4.75	0.20	4.95	0.79	5.54	4.70	55.82
Gr. Rt. 90-15	4.17%	#NUM!	4.73%	6.85%	4.46%	5.24%	1.69%

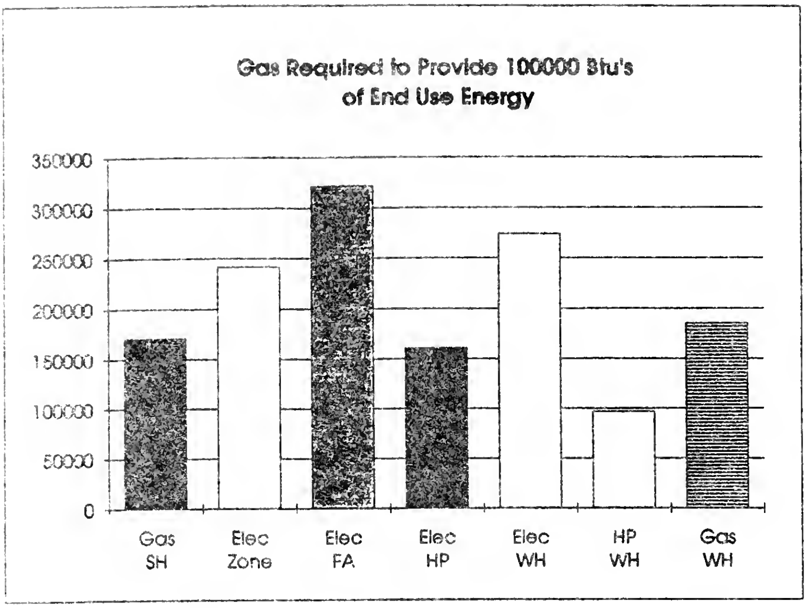
Markups are calculated in the MARKUP.XLS spreadsheet.
See embedded cell notes there.

			NATURAL GAS FORECAST SUMMARY				
			High Case				
			(1990$ per MMBtu)				
				Regional Gas Price			California
	World	U. S.	Average				Interr.
	Oil	Wellhead	Industrial	Residential	Commercia	Utility	Utility
Year	Price	Price	Price			Firm	Price
	(90$/Bbl.)						
1980	52.00	2.44	6.18	7.78	7.23	2.59	3.14
1981	51.83	2.77	6.06	7.98	7.30	2.92	3.47
1982	44.12	3.23	6.84	8.66	7.99	3.38	3.93
1983	37.08	3.28	6.34	8.57	7.73	3.43	3.98
1984	35.26	3.25	6.00	8.21	7.42	3.40	3.95
1985	32.00	2.98	5.42	7.75	6.72	3.13	3.68
1986	16.18	2.24	3.96	6.86	5.91	2.39	2.94
1987	20.31	1.87	3.23	6.40	5.28	2.02	2.57
1988	15.78	1.83	2.83	6.25	5.21	1.98	2.53
1989	18.82	1.76	2.52	5.76	4.83	1.91	2.46
1990	21.76	1.71	2.24	5.36	4.38	1.86	2.41
1991	17.92	1.52	2.04	5.22	4.23	1.67	2.22
1992	19.86	1.70	2.14	5.38	4.41	1.80	2.40
1993	22.00	1.91	2.41	5.58	4.62	2.09	2.61
1994	24.37	2.14	2.70	5.79	4.85	2.41	2.88
1995	27.00	2.40	3.00	6.04	5.11	2.72	3.15
1996	28.44	2.57	3.21	6.18	5.26	2.99	3.34
1997	29.95	2.76	3.42	6.34	5.43	3.28	3.54
1998	31.55	2.96	3.64	6.50	5.60	3.56	3.75
1999	33.23	3.17	3.86	6.68	5.79	3.84	3.98
2000	35.00	3.40	4.12	6.89	6.00	4.12	4.22
2001	35.77	3.60	4.33	7.06	6.18	4.35	4.43
2002	36.55	3.80	4.55	7.23	6.36	4.59	4.65
2003	37.35	4.02	4.78	7.42	6.56	4.82	4.89
2004	38.17	4.25	5.01	7.62	6.78	5.06	5.13
2005	39.00	4.50	5.25	7.84	7.01	5.32	5.41
2006	39.77	4.60	5.35	7.91	7.09	5.42	5.54
2007	40.55	4.69	5.45	7.97	7.17	5.53	5.67
2008	41.35	4.79	5.55	8.05	7.26	5.64	5.81
2009	42.17	4.90	5.64	8.13	7.35	5.75	5.95
2010	43.00	5.00	5.75	8.20	7.43	5.86	6.08
2011	43.96	5.10	5.84	8.27	7.51	5.96	6.20
2012	44.93	5.19	5.94	8.34	7.59	6.07	6.33
2013	45.93	5.29	6.04	8.42	7.67	6.18	6.45
2014	46.96	5.40	6.14	8.50	7.76	6.29	6.59
2015	48.00	5.50	6.25	8.57	7.84	6.40	6.70
Growth Rt.							
1900-2015	3.22%	4.78%	4.19%	1.90%	2.36%	5.07%	4.17%

PNW Electric Utility Gas Price Forecast Module
High Case
1990 Dollars/mmbtu

Year	Average Wellhead Price	Interruptible: Wellhead To User Markup	Interruptible: Burner-tip Gas Price	Firm: Wellhead To User Markup	Firm: Burner-tip Gas Price	Variable Fuel Cost	Fixed Fuel Cost ($/KW/Yr)
1980	2.44	-0.15	2.29	0.15	2.59	2.04	36.71
1981	2.77	-0.15	2.62	0.15	2.92	2.37	36.71
1982	3.23	-0.15	3.08	0.15	3.38	2.83	36.71
1983	3.28	-0.15	3.13	0.15	3.43	2.88	36.71
1984	3.25	-0.15	3.10	0.15	3.40	2.85	36.71
1985	2.98	-0.15	2.83	0.15	3.13	2.58	36.71
1986	2.24	-0.15	2.09	0.15	2.39	1.84	36.71
1987	1.87	-0.15	1.72	0.15	2.02	1.47	36.71
1988	1.83	-0.15	1.68	0.15	1.98	1.43	36.71
1989	1.76	-0.15	1.61	0.15	1.91	1.36	36.71
1990	1.71	-0.15	1.56	0.15	1.86	1.31	36.71
1991	1.52	-0.15	1.37	0.15	1.67	1.12	36.71
1992	1.70	-0.20	1.50	0.10	1.80	1.25	36.71
1993	1.91	-0.12	1.79	0.18	2.09	1.54	36.71
1994	2.14	-0.03	2.11	0.27	2.41	1.86	36.71
1995	2.40	0.02	2.42	0.32	2.72	2.17	36.71
1996	2.57	0.07	2.64	0.42	2.99	2.39	40.05
1997	2.76	0.12	2.88	0.52	3.28	2.63	43.39
1998	2.96	0.15	3.11	0.60	3.56	2.86	46.73
1999	3.17	0.17	3.34	0.67	3.84	3.09	50.06
2000	3.40	0.21	3.61	0.72	4.12	3.36	50.56
2001	3.60	0.24	3.84	0.76	4.35	3.59	51.07
2002	3.80	0.26	4.06	0.78	4.59	3.81	51.59
2003	4.02	0.27	4.29	0.80	4.82	4.04	52.11
2004	4.25	0.27	4.52	0.81	5.06	4.27	52.64
2005	4.50	0.27	4.77	0.82	5.32	4.52	53.18
2006	4.60	0.27	4.87	0.82	5.42	4.62	53.73
2007	4.69	0.27	4.96	0.83	5.53	4.71	54.29
2008	4.79	0.27	5.06	0.84	5.64	4.81	54.85
2009	4.90	0.27	5.17	0.85	5.75	4.92	55.42
2010	5.00	0.27	5.27	0.85	5.86	5.02	56.00
2011	5.10	0.27	5.37	0.87	5.96	5.12	56.59
2012	5.19	0.27	5.46	0.88	6.07	5.21	57.19
2013	5.29	0.27	5.56	0.89	6.18	5.31	57.80
2014	5.40	0.27	5.67	0.90	6.29	5.42	58.42
2015	5.50	0.27	5.77	0.90	6.40	5.52	59.04
Gr. Rt. 90-15	4.78%	#NUM!	5.37%	7.45%	5.07%	5.92%	1.92%

Markups are calculated in the MARKUP.XLS spreadsheet.
See embedded cell notes there.



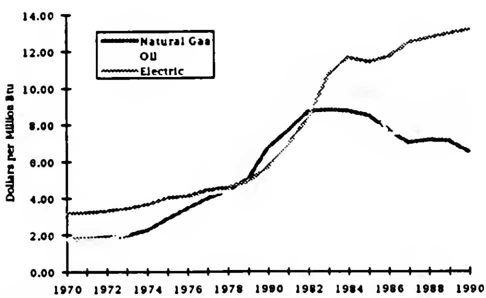
ASSUMPTIONS:

- Gas Furnace Efficiency .78
- Duct Losses .75
- Electric Zone and Furnace Heat Efficiency 1.0
- Heat Pump Efficiency 2.0
- Electric Water Heat Efficiency .88
- Assumes Electricity Generated by Combined
  Cycle Comustion Turbine, Efficiency .45
- Assumes Electricity T&D Losses of 8 Percent
- Heat Pump Water Heater Efficiency 2.5
- Gas Water Heat Efficiency .54

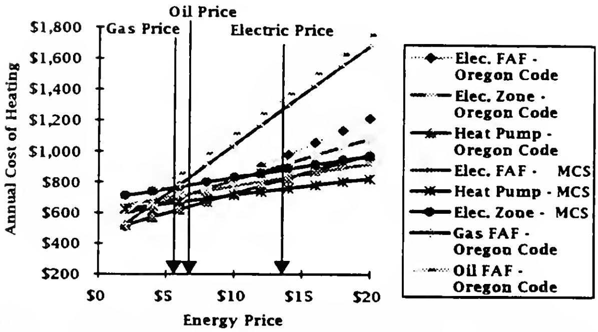
Council Fuel Efficiency Actions

- SRC Study, Sept. 1982
- Staff Issue Paper, Oct. 1982
- 1983 Power Plan
  - Neither encourage nor discourage a consumer's continued use of electricity compared to a nonrenewable fuel.
- Lawsuit (1983)and Legal Opinions (1991)
- 1986 Power Plan
  - BPA monitor programs for fuel choice effects, Council do cost of heating study
- Council Cost of Heating Study, June 1988.
- 1991 Power Plan.
  - Recognize growing interface between gas and electric industries.

Efficiency Adjusted Energy Prices in Washington



Cost of Heating Study



Cost-Effectiveness Analyses

- Council Cost of Heating Study
- Oregon Residential Energy Efficiency Project
- Washington State Energy Office

Fuel Conversion Resource Potential Studies

- SRC Study for Council, 1982
- Jim Lazar for ANGU, 1990
- ODOE, Charlie Stephens, 1991
- BPA, 1991
- WSEO, Dick Beyers, 1992
- Aos & Blackmon, for WNG, 1992
- Aos & Blackmon, for PGE, 1992
- PGE, Thompson and Eustis, 1992

Typical Market Segmentation

For each Housing Type:

Gas in Home — **Elec. WH → Gas WH**

Service Connection Required
- **Elec. WH → Gas WH**
- **Elec. CFA → Gas CFA**
- **Elec. Zone → Gas CFA**

Main Extension Required
- **Elec. WH → Gas WH**
- **Elec. CFA → Gas CFA**
- **Elec. Zone → Gas CFA**

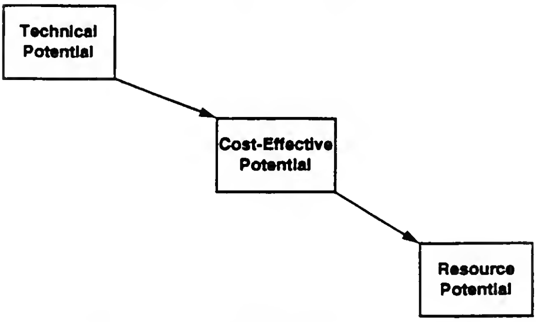
Fuel Conversion Costs

- Capital Costs
  - Furnace or Water Heater
  - Ducting
  - Service Connection
  - Gas Main Extension
  - Electric Distribution Savings
  - Insulation Cost Difference for New Homes

Fuel Conversion Costs

- Operating Costs
  - Fuel Cost (Incremental or Retail)
  - Maintenance
  - Gas Service Costs
  - Electric Fan Load for Zone Replacements
  - Gas Peak Capacity

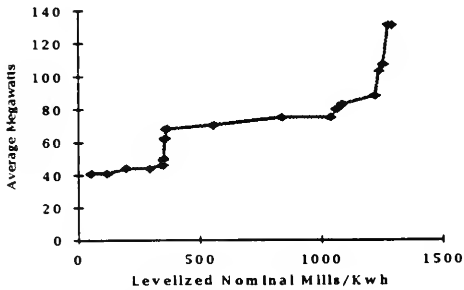
Stages of Fuel Conversion Resource Potential Estimates



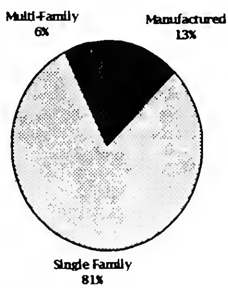
Summary of Fuel Conversion Resource Findings

Study	Technical Potential	Cost-Effective Potential	Resource Potential
Lazar	1448		
Bonneville			385
Beyers	1370	855-1177	460-730
Aos & Blackmon	1483	1038	845

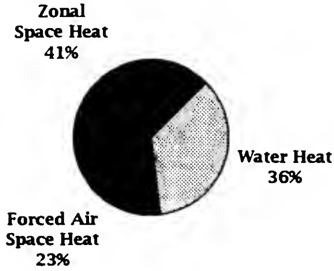
Aos & Blackmon Fuel Conversion Supply Curve



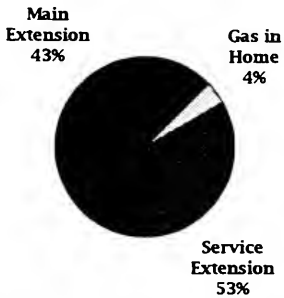
Fuel Conversion Potential by Housing Type



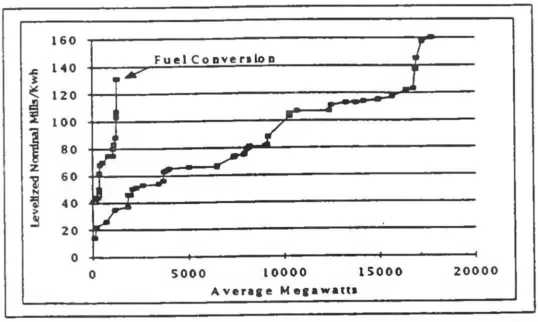
Fuel Conversion Potential by Gas Availability



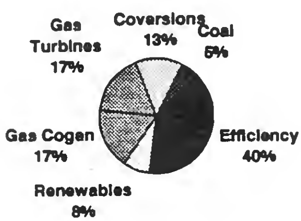
Fuel Conversion Potential by End Use



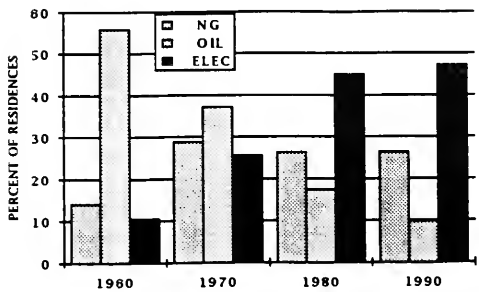
Comparison of Electricity and Fuel Conversion Supply Curves



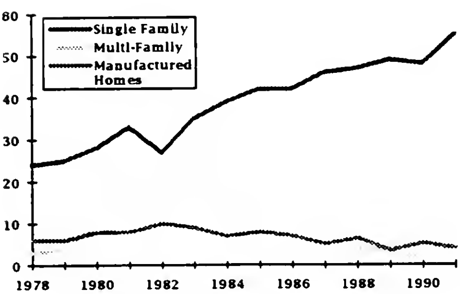
Gas Conversion Potential in Medium Council Plan



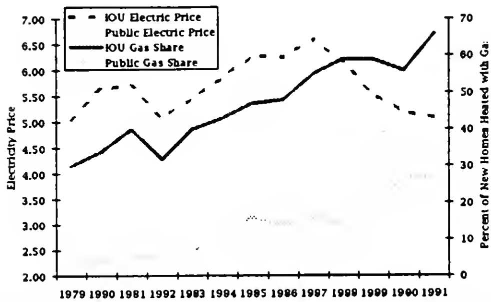
Space Heat Fuel Shares in the Northwest



Gas Space Heat Penetration Rates in Oregon



Electricity Prices and Gas Space Heat Penetration in Oregon



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