Energy Northwest Executive Board Review of Nuclear Program

January 23, 2003

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EXECUTIVE SUMMARY

Energy Northwest's Executive Board has concluded a review of the organization's nuclear program, the findings of which are summarized in the following report.

The review examined how nuclear power can fit within the region's energy portfolio to the greatest benefit of the region's ratepayers, and considered a variety of possibilities ranging from the feasibility of finishing a partially completed nuclear plant, to the potential benefits of third-party management or the sale of Columbia Generating Station (Columbia).

The review assessed current operations and examined ways to optimize future expenditures, increase generation, and reduce the cost of Columbia's power without jeopardizing either public and employee safety or the long-term reliability of plant operations. In doing so, the Executive Board recognizes that Energy Northwest, as owner and license holder, is responsible for retaining qualified staff and plant material conditions to support safe nuclear operations, while ensuring full compliance with all state and federal regulations.

The Executive Board initiated the review when a severe energy crisis coincided with the need to make permanent plans for WNP-1 (a terminated nuclear project located adjacent to Columbia), thus prompting the Executive Board to investigate the feasibility of completing the unfinished plant. Three separate teams of consultants (Bechtel Power Corp., R.W. Beck, and Goldschmidt Imeson) retained by the Executive Board to conduct the investigation unequivocally concluded that completing the plant was neither economically nor politically feasible.

In the course of the investigation, however, there were unofficial expressions of interest in the third-party management or purchase of Columbia, which the Executive Board felt due diligence required be explored. Executive Board Chairman John Cockburn then appointed an ad hoc planning committee consisting of members both internal and external to Energy Northwest.

After the ad hoc planning committee completed its work, which included extensive interviews and other research, and after numerous discussions and energetic exchanges of diverse views, the Executive Board concluded there was unlikely to be a net benefit either in third-party management or sale of Columbia, and that either option might lead to increased economic risk to the region's ratepayers. Additionally, Energy Northwest's member utilities overwhelmingly opposed both alternatives.

Using commonly accepted standards of performance, Columbia is a very well-run plant, and there is no reason to instigate a substantial change in either its management or mode of operation. In short, the Executive Board has determined neither to contract out management of, nor to sell, Columbia.

Under its current management and ownership, Columbia is a major asset to public power and the region's ratepayers, providing enough cost-effective, reliable power for half a million homes. It gives Bonneville financial flexibility through its historical bonding capability and flexibility in operating the Federal Columbia River Power System because of its ability to vary output according to water conditions. It adds diversity to the region's power supply, is currently the region's only large generating asset not dependent on weather conditions, does not adversely affect fish or other wildlife, and produces no carbon dioxide or other greenhouse effects.

The Executive Board agrees with Bonneville, however, that it is imperative that the future cost of Columbia's power be kept as low as possible without compromising either safety or the long-term reliability of plant operations. To that end, the Executive Board expects the senior management team to continuously scrutinize Columbia's budget and operations – including benchmarking against other well-run plants – to identify opportunities to optimize expenditures and increase generation, and to ensure that Columbia does not subsidize ventures conducted through Energy/Business Services.

These efforts already are ongoing, and as part of this review, Energy Northwest staff compared Columbia's performance to that of other nuclear plants on the basis of several criteria. Where possible, comparisons were made to other large, single-unit plants as providing the most relevant and therefore enlightening information. Staff also updated the projected cost of operating Columbia for the remainder of Bonneville's current rate period. The results of those comparisons and other data on Columbia's performance are discussed in this report and its appendices.

In addition, the Executive Board retained an independent nuclear industry consultant, Richard Kacich, to assess the reasonableness of the findings, especially regarding costs, and to assess opportunities for improvement. He concluded that the cost comparison methods and metrics selected were reasonable and offered some suggestions for further refinement. And while many of his findings reflected favorably on current operations, he also noted some opportunities for improvement. His findings are attached to the end of this report as Attachment A.

Energy Northwest also is taking steps in the near term to assist Bonneville with its current difficult financial situation, including deferring some large expenditures, absorbing into the current budget an unanticipated $6.6 million in expenses for security enhancements and spent fuel storage, and committing to a $5 million cost reduction in each of the last three years of the current rate period. Also, a commitment was made to reduce cash requirements by $76 million by deferring replacement of condenser tubes and changes in nuclear fuel inventory. Energy Northwest will continue to work with Bonneville to optimize the integrated debt portfolio of both agencies consistent with the best interests of ratepayers.

Finally, Energy Northwest will continue to strive to minimize the disadvantages of a geographically isolated, single-plant operation.

The Executive Board would like to express its appreciation to all who assisted in this extensive examination of Energy Northwest's nuclear program, which we believe will benefit the region's ratepayers and Energy Northwest for years to come.

INTRODUCTION

In the 1970s, Energy Northwest (then known as Washington Public Power Supply System), with the backing of the public power community, embarked upon an ambitious program to construct five nuclear power plants. Three of those plants, WNP-1, WNP-2 (now Columbia Generating Station), and WNP-3, were funded by tax-exempt construction bonds backed by the Bonneville Power Administration (Bonneville). Columbia Generating Station (Columbia) commenced commercial operation in 1984. Construction of WNP-1 and WNP-3 was stopped when they were partially complete, and those projects were terminated in 1994.

Through complex contracting and billing arrangements, participants in the WNP-1, WNP-3, and Columbia projects transferred the anticipated outputs of the plants to Bonneville in exchange for payment of all project costs. Consequently, Bonneville is responsible for guaranteeing payment of all costs, including debt service, associated with those projects and, as owner of the output, has the right to direct the power generated by Columbia.

Energy Northwest, as owner and license holder, operates the plant in the best interest of the region's ratepayers and is responsible for retaining qualified staff and plant material conditions to support safe nuclear operations, while ensuring full compliance with all state and federal regulations.

Over the past 2 years the Executive Board conducted a due-diligence review of Energy Northwest's nuclear program. The review examined the feasibility of completing WNP-1 (approximately 65 percent complete at the time construction ceased), considered other management or ownership alternatives for Columbia, examined the recent and current performance of Columbia relative to other nuclear plants, and sought ways to further improve Columbia's performance.

This report summarizes the results of the review and provides additional detail in the attached appendices.

WNP-1

In March 2001, when an energy crisis coincided with the need to make decisions concerning demolition and site restoration, the Executive Board initiated a study of the feasibility of completing WNP-1. Congressmen Doc Hastings and George Nethercutt encouraged the study. It seemed every potential generating asset should be explored when a severe drought adversely affected the region's hydropower system, and a dysfunctional California electricity market led to historically high electricity prices. In addition, completing WNP-1 would have mitigated some of the disadvantages of operating Columbia as a single, geographically isolated plant.

The feasibility study was initially designed to examine several questions:

- Is completion of WNP-1 technically feasible?
- Is completion of WNP-1 economically and politically feasible?
- What is the long-term need for additional power generation in the Pacific Northwest?
- Is completion of the plant in the best financial interests of Energy Northwest's member utilities?
- Would a decision by the Executive Board to complete the plant be in the overall best interests of the region's ratepayers?

However, as explained below, while the answer to the first question was affirmative, the answer to the second was not, so the remaining questions became moot.

The first step in the study was to retain Bechtel Power Corporation (Bechtel) to prepare a detailed cost-to-complete analysis. Bechtel concluded that it would be technically feasible to finish WNP-1, and that doing so would cost in the range of $2.3 to $3 billion and take approximately 72 months.

Next, R. W. Beck was hired to independently assess Bechtel's methodology, and to examine the economic feasibility of completing the plant when compared to competitive market alternatives. R. W. Beck's report, completed in October 2001, verified that Bechtel's methodology was reasonable and concluded that completing WNP-1 would entail an additional $1.2 billion in financing expenses.

Energy Northwest's senior management team then prepared a supplemental report examining the impact of changing assumptions and variables. The team's report did not fundamentally contradict the findings of Bechtel and R. W. Beck that the total cost to complete WNP-1 would be approximately $4.2 billion including financing expenses.

Finally, in December 2001, the Executive Board retained the consulting firm of Goldschmidt Imeson to review the Bechtel and R. W. Beck reports and meet with industry, regional, and political leaders to discuss the most appropriate use of the WNP-1 site, including whether any nuclear plant operator would be interested in completing WNP-1. Following that, Goldschmidt Imeson was to provide the Executive Board with a recommendation for the site.

After extensive investigation, Goldschmidt Imeson reported there was no interest in completing WNP-1, and that doing so would be neither economically nor politically feasible. Goldschmidt Imeson further reported that any expressions of interest in WNP-1 were contingent upon the plant being coupled with Columbia, and that WNP-1 clearly would be considered a liability, not an asset, in such a transaction.

At the same time, however, Goldschmidt Imeson said several parties had indicated an interest in purchasing Columbia, or managing Columbia as a prelude to purchasing the plant. Goldschmidt Imeson recommended that the Executive Board examine whether such a sale or management contract would be in the best interests of Energy Northwest, Bonneville, and the region.

COLUMBIA GENERATING STATION

Following Goldschmidt Imeson's report to the Executive Board, Chairman John Cockburn appointed an ad hoc planning committee to examine Columbia's long-term value to the region. In addition to four members of the Executive Board and J. V. Parrish, Energy Northwest's Chief Executive Officer, the committee included Steven G. Hickok, Bonneville Deputy Administrator; Nicholas Reynolds, Senior Partner at Winston & Strawn, a law firm with wide nuclear regulatory and industry practice; Diana Goldschmidt, a principal of Goldschmidt Imeson; and John Carter, also of Goldschmidt Imeson and recently retired Vice President of Bechtel Corporation.

It should be noted that creation of the ad hoc planning committee was in no way due to misgivings about the current operations of Columbia, but rather the result of the Executive Board's obligation to exercise due diligence in acting in the best interests of the region's ratepayers. In 2000, Columbia earned an excellent performance rating (INPO 1) from the Institute for Nuclear Power Operations, which evaluates nuclear plants on the basis of safety as well as management systems and controls. At the time, out of 65 nuclear plant sites operating in the nation, only 26 had the INPO 1 rating and only eight of those were single-unit plants.

Agreeing that any final course of action for Columbia would have to be acceptable to Bonneville, the public power community, and political leaders, the committee divided its task into four parts:

- Developing a matrix of interests and values
- Developing a "most efficient operation" proposal
- Developing a request for preliminary expressions of interest to be sent to parties interested in managing or purchasing Columbia
- Conducting a survey of single-plant owners to determine how the owners operate

The committee later substituted "learning about the experiences of owners with plants under third-party management" for "developing a request for preliminary expressions of interest."

The committee believed the matrix would be particularly important if a major change in the management or ownership of Columbia were contemplated. Such a change would potentially and significantly impact how plant output is coordinated with hydro system operations (including consequential impacts on environmental concerns such as fish), the plant's long-term future as part of the region's generating resources, labor, and a wide variety of other matters.

However, results from the survey of single-plant owners and research on the experience of owners with plants under third-party management suggested that while there was no guarantee that third-party management or sale of Columbia would benefit the region, there was considerable potential risk associated with either option. In addition, the complicated contracting, billing, and financing arrangements made an outright sale unwieldy and unlikely. For those reasons, the matrix was never fully developed.

A. Third-Party Management

Contractors are profit-oriented and focus on the terms and conditions of their contracts, which typically are structured to reward improvements in plant performance, such as increased production or reduced operational costs.

Short-term performance goals may be inconsistent with the long-term interests of Columbia and the region, as planning for sustained plant reliability may require a more conservative approach to operations and maintenance than would a more short-term concern. For example, an incentive to achieve short-term operating goals may encourage the deferral of maintenance activities that are better performed sooner rather than later for long-term reliability. The current experience at the Davis-Besse plant illustrates the extreme result when proper maintenance practices are not followed. Columbia's operating license does not expire until December 2023, and could be extended until 2043. Consequently, strategic, long-term planning is much more important than tactical, short-term enhancements in performance.

Initially the ad hoc planning committee, and later the Executive Board, called upon Mr. Reynolds for information about third-party management of nuclear plants. Based on nuclear industry experience, Mr. Reynolds believes the term of a management contract would likely be three to five years. Industry experience suggests the contractor would replace most if not all of Energy Northwest's senior management with its own personnel. At the end of the contract term, Energy Northwest would have to renegotiate the contract or recruit a new contractor, and would be bargaining from a position of substantially reduced leverage and with limited options.

The only entity whose principal business is managing nuclear plants it does not own is Nuclear Management Company (NMC). Any other contractor probably would be unwilling to provide its best personnel to Columbia at the expense of the contractor's own plants. (In any event, Goldschmidt Imeson reported finding no interest on the part of any other entity in managing Columbia except as a prelude to purchase.)

Mr. Reynolds noted there is an acute shortage of qualified, high-caliber nuclear plant managers, and the situation is not expected to ease anytime in the foreseeable future. If the current senior management team at Columbia were replaced, it would be extremely difficult for Energy Northwest to re-staff those ranks should Energy Northwest be unhappy with the contractor's performance or the terms of a proposed renewal contract, and be unable to secure a new third-party manager. In other words, a decision to replace Columbia's management could well be irreversible.

Data is limited and findings inconclusive regarding how well plants perform under NMC's management. The performance of two poorly-performing plants improved when NMC took over management. However, the performance of a third plant, whose prior performance had been relatively good, did not appear to improve. This suggests that while poorly performing plants may improve under NMC's management, well-performing plants such as Columbia are unlikely to improve significantly.

B. Other Single-Plant Owners

Goldschmidt Imeson interviewed seven single-plant owners, each of which claimed to have undergone an extensive strategic planning process as part of the decision to maintain its single-plant status, and each of which described unique and generally substantial business reasons for the decision. Those reasons included financial, operational, and competitive factors.

To mitigate the disadvantages of being a single-plant operation, several plants reported participating in the Utilities Service Alliance (USA), whose eight members can share costs for spare parts, security investigations and a variety of other expenses. One company helped create the STAR Alliance, another cooperative arrangement among nuclear plant owners. Another company explored creating a nuclear plant pool with a single operating company, which never reached fruition. Finally, another plant, geographically distant from USA plants, reported creating an informal alliance with adjacent investor-owned utilities to reduce costs in warehousing, spare parts, audits, and personnel.

Energy Northwest is a member of USA, and of the Boiling Water Reactors Owners' Group, which provides opportunities to share costs and information with all other boiling water reactor owners, both nationally and internationally. Energy Northwest also initiated a two-year effort to form a service company with Omaha Public Power District, which owns the Fort Calhoun nuclear plant. Those efforts were ultimately unsuccessful.

C. Benchmarking/Most Efficient Operation

Based on the above information, the Executive Board decided to no longer explore the options of either third-party management or sale of Columbia, and instead to focus on making the operation of Columbia the most efficient possible. This is defined as continuing good management practices measured by favorable comparison with consistently high performing single-unit plants. Any increased efficiency must be accomplished without jeopardizing the long-term safe and reliable operation of Columbia.

Optimizing costs and increasing generation so that Columbia's cost of power is reduced poses significant challenges. As a geographically isolated, single-plant operation, many of the cost-spreading and operational synergies of multi-plant operations simply are unavailable.

One means of identifying ways to improve Columbia's performance is to scrutinize how well the plant is currently performing relative to other plants, and how that performance has changed over time.

The nuclear power industry is one of the most closely regulated and examined in the world. A tremendous amount of data on the performance of nuclear plants is available, although accurate comparisons between plants are difficult due to the many variables in plant design, modes of operation, and data reporting.

With these caveats in mind, Energy Northwest staff compared Columbia's performance to that of other plants using data available through a number of sources, including the Institute for Nuclear

Power Operations (INPO), World Association for Nuclear Operations (WANO), EUCG (formerly Electric Utility Cost Group), Federal Energy Regulatory Commission (FERC), Nuclear Energy Institute (NEI), and Boiling Water Reactors Owners' Group (BWROG).

Staff examined Columbia's cost of power, staffing levels, generation, radiation dose rate, and environmental stewardship as measured by liquid discharges. In addition, staff used in-house and regional data to examine circumstances unique to Columbia – specifically, power-level changes made at Bonneville's behest, and the impact of Energy Northwest's Energy/Business Services group (formerly Resource Development) on Columbia's costs.

The Executive Board retained an independent nuclear industry consultant, Richard Kacich of Janus Management Associates, to review staff's findings and make suggestions for improvements. Mr. Kacich is the Director of Special Projects at Northeast Utilities where, among other responsibilities, he is involved in the oversight of the various nuclear facilities in which Northeast has an ownership interest. As part of his review, the Executive Board asked him to assess the reasonableness of the cost of Columbia and other comparisons in his report.

He concluded the cost comparison methods and metrics selected were reasonable and offered some suggestions for further refinement. And, while, many of his findings reflected favorably on current operations, he also noted some opportunities for improvement. His findings are attached to the end of this report as Attachment A.

The findings of the Executive Board are briefly summarized below, with more detail provided in the appendices.

1. *Cost of Power.* Columbia's cost of power is comparable to that of other single-unit plants, and is nearly the lowest when compared to plants managed by NMC. (FERC, INPO. See Appendix A.)

2. *Staffing.* Columbia's total staffing – including direct, indirect or allocated, and full-time contractors on long-term projects – appears to be somewhat high. The primary reasons are that Columbia is a single unit that is not part of a fleet, and consequently supports most of Energy Northwest's general and administrative costs. (EUCG, NEI. See Appendix B and Attachment A.)

3. *Generation.* Columbia's overall generation is increasing as the plant's capability factor, unplanned capability loss factor, and unplanned automatic scram factor are improving. Of all boiling water reactors in the United States, Columbia's capability factor is now at or above the median, its unplanned capability loss factor is at the median, and its unplanned automatic scram factor has reached the top quartile. (WANO. See Appendix C.)

4. *Generating Flexibility.* Columbia is the only nuclear plant in the nation that regularly adjusts its output in response to market conditions or for environmental purposes. The value of this generating flexibility is difficult to quantify other than by the value of lost generation, but it assists Bonneville in operating the Federal Columbia River Power System in a manner consistent with Biological Opinion requirements for certain species of migrating salmon. (See Appendix D.)

5. *Radiation Exposure.* Columbia's recorded radiation exposure is the fifth best in the nation among boiling water reactors, and is third best for the 12 months ending June 30, 2002. (BWROG. See Appendix E.)

6. *Environmental Stewardship.* Columbia has had no radioactive liquid discharges since 1998. It was one of only seven nuclear plants in the nation to have no radioactive liquid discharges in 1999, and one of eight plants in 2001, the most recent year for which industry data is available. (INPO. See Appendix F.)

7. *Energy/Business Services.* Each Energy/Business Services project receives a full allocation of overhead costs based on audited accounting practices. An analysis by Energy Northwest and Bonneville indicated a resulting benefit of $7.5 million to Columbia over the past five years by new projects absorbing a portion of the fixed overhead costs. (See Appendix G.)

In December 2002, management received a multi-dimensional benchmarking report for Columbia on nuclear plant cost and production prepared for Bonneville by J. Lewis & Associates. It is currently being reviewed by management and will be reviewed with the Executive Board in the near future.

D. <u>Action</u>

Looking forward, by continuing to increase generation and optimizing expenditures, the cost of power generated by Columbia will be reduced. Improving the performance of projects in the Energy/Business Services group will provide money for new projects, which in turn will assume a portion of Columbia's administrative overhead and further drive down the cost of Columbia's output.

Bonneville asked Energy Northwest to review Columbia's current budget and long-range forecast to find ways to reduce costs and cash requirements in Bonneville's current rate period. As described below, Energy Northwest has taken immediate steps to help ameliorate Bonneville's current financial situation and will continue to try to identify further opportunities to assist Bonneville in the current and future rate periods. In addition, Energy Northwest will continue to work with Bonneville to benefit ratepayers by managing the combined debt of Energy Northwest and Bonneville.

1. *Generation.* Historically, Columbia was refueled annually, only recently moving to a 24-month refueling schedule that will reduce the number of future refueling outages by one-half. In addition, initiatives are under way to shorten both planned and forced outage lengths, and to reduce other power losses.

a. <u>Refueling outages.</u> Refueling outages are scheduled in the late spring, when river flows are usually high and Bonneville usually has the least need for Columbia's output. Consequently, the length of time it takes to refuel Columbia has tended to matter less in high-water than low-water years. Due to the extensive planning required for a refueling outage, it is not feasible to adjust outage plans based on continually changing water flow conditions.

Staff is currently determining what would be necessary to reduce the length of refueling outages. The target is to complete the refueling outage in less than 25 days. One step would be to perform more on-line maintenance to reduce the amount of work that must be accomplished during an outage. Another step is to conduct maintenance work on emergency diesel generators at some time other than during a refueling outage. Staff also is studying the experience of plant operators that conduct short and efficient refueling outages, using the information gathered to plan and execute future outages at Columbia.

Plans are well under way for the 2003 refueling outage, and there is every reason to believe it will be completed on schedule and within budget. After the outage, as with other outages, staff will thoroughly review outage performance to identify areas for potential improvement.

b. <u>Forced outages and power losses.</u> Increasing Columbia's reliability will reduce both the occurrence and duration of unplanned outages. Energy Northwest currently has a program under way to improve equipment reliability and optimize preventive maintenance. This program, along with continuing efforts to improve the ongoing monitoring of the plant's performance, should help maintain the trend of fewer forced outages and reduce the number of occasions in which Columbia's output must be decreased due to mechanical issues.

Should a forced outage occur, staff uses pre-developed forced-outage schedules to minimize the length of the outage, and uses the outage as an opportunity to do off-line maintenance and make improvements to enhance future reliability.

c. <u>Power uprates.</u> Management investigated the feasibility of increasing Columbia's generating capacity (an "uprate") by approximately 15 percent through various mechanical improvements, but concluded the estimated cost did not justify the investment at this time. Management will continue to evaluate opportunities to increase Columbia's productivity in small increments using cost/benefit analyses as the primary evaluation tool.

Regardless of whether there are future uprates, as a result of the initiatives to reduce and shorten outages and power losses, Columbia's output should be higher than in previous outage years, and should set plant generation records in non-outage years.   Projected generation levels through fiscal year 2006 are in the Adjusted Long-Range Forecast table below.

2. Expenditures. After reviewing projected costs and generation in the Long-Range Forecast for Columbia, Energy Northwest's senior management concluded an additional $5 million per year could be removed from the forecast of future costs through fiscal year 2006. This conclusion was based on management's judgment of acceptable operating risk. But, to achieve the reduction, Energy Northwest will most likely need to defer/forego some capital improvements to Columbia, and examine the feasibility of either deferring or canceling some currently planned programs. Each of these decisions will require risk management and analysis. No decision will be made that might jeopardize public safety, or the long-term reliability of the plant. Estimates will be reviewed each year based on updated operational and industry data. Also, estimates may change due to unforeseen plant conditions or regulatory requirements.

The table below shows the current forecast, adjustments and the resulting forecast.

Adjusted Long Range Forecast – Columbia Generating Station
($ in millions)

	FY03*	FY04	FY05	FY06
Operations & Maintenance	$130.6	$135.8	$141.2	$146.9
Outage and Major Maintenance	50.2	7.1	56.8	3.9
Capital	17.6	10.2	52.8	9.0
Fuel	35.4	41.3	40.6	45.3
Total Costs**	$233.8	$194.4	$291.4	$205.1
Adjustments				
Condenser Tubes#			-37.8	
Further Reduction#		-5.2	-5.4	-5.6
Fuel Amortization Changes#		1.3	-3.3	-3.1
Adjusted Total	$233.8	$190.5	$244.9	$196.4
Generation (gigawatt hours)				
Plan	8574	9605	8240	9679
New projection	8574	9637	8347	9610
Cost-of-Power ($ per MWH)				
Plan	27.3	20.2	35.4	21.2
Adjusted	27.3	19.8	29.3	20.4

* current budget year
** excludes interest expense and decommissioning contributions
# escalation added to reductions

Escalation reflects increased future costs of labor, materials, and services. Four percent (4%) was chosen as a planning number based on consideration that a major portion of Columbia's cost subject to escalation is comprised of labor, both direct and through contractors. Considerations for choosing a 4% rate are the shortage of trained nuclear workers, large increases in medical costs and the competitive market for workers in the local area due to major new Hanford environmental restoration projects. In September 2002, a well-known human resource consulting company projected base salaries for utilities will increase by 4% in 2003.

The changed generation projections are based on current assumptions of Columbia's capacity factor and outage length. Fiscal years 2003 and 2005 costs are higher because they include refueling outages. In fiscal year 2005 the higher cost-of-power is due to cost escalation and lower generation. The planned refueling outage is longer than normal because it includes extensive reactor vessel inspections.

As for the current plan, in August 2002, CEO J. V. Parrish sent a letter to Bonneville committing to cash deferrals of $76 million. This is to be accomplished by reducing the fuel inventory by $41 million and by deferring replacement of condenser tubes. Management has determined the level of increased financial and reliability risks represented by these deferrals is acceptable. Bonneville must approve Columbia's Fuel Management Plan, which will be submitted in March 2003. Management also committed to absorbing, in the current budget, an unanticipated

$6.6 million in expenses for security enhancements and Independent Spent Fuel Storage Installation. Management has said this will be achieved through aggressive reductions in expenses and by capturing budget under-runs as they occur.

Since a large part of Columbia's costs are related to staff, to better understand its staffing situation for both nuclear and non-nuclear positions, during this fiscal year Energy Northwest will conduct a benchmarking study in which Bonneville will participate. The findings will be reported to the Executive Board.

It is important for Energy Northwest to continue all efforts to mitigate the disadvantages of being a single-plant operation, such as by attempting to increase the benefits of membership in USA, being alert to any opportunity for additional and potentially helpful alliances with other nuclear plant operators, and by making the Energy/Business Services group as successful as possible.

This past summer, J. V. Parrish retained David J. Carey, a management consultant with extensive experience in banking, manufacturing, distribution, and service businesses, to assess the strategy, management, staffing, and effectiveness of Energy/Business Services. While his report was quite positive overall, Mr. Carey made numerous recommendations for improvement, and identified several existing projects with high immediate potential for success that he suggested be given top priority in the short term. Energy/Business Services is in the process of implementing many of Mr. Carey's recommendations. As noted earlier, it is anticipated that as the individual projects within the group grow and new projects are added, they will assume an additional portion of the overhead currently borne by Columbia. In addition, increasing the breadth and diversity of group projects has the potential to help Columbia attract and retain qualified employees.

In efforts to control costs and increase generation, it is imperative that there be a proper balance between those objectives and the maintenance of long-term safe and reliable operation of the plant. Energy Northwest will ensure that budget reductions will not have a negative impact on nuclear safety or a safety conscious work environment. Quarterly performance indicators and benchmarking data will continue to be reviewed.

3. ***Debt Optimization.*** Energy Northwest will continue to work closely with Bonneville in debt management to accomplish cost-effective refinancing, optimize outstanding debt, issue additional variable-rate debt, and finance capital projects.

In 2002, $707 million in bonds were issued to reduce interest costs and restructure the net-billed debt into Bonneville's total debt obligation. Additionally, $35 million in taxable short-term notes were issued specifically for the Independent Spent Fuel Storage Installation. In April 2002, the Executive Board passed a resolution authorizing Energy Northwest to request a private Internal Revenue Service (IRS) ruling to allow up to $191 million in tax-exempt bonds to be issued for capital projects. If the IRS grants approval, the $35 million in taxable financing will be replaced by issuing tax-exempt bonds, leaving a balance of $156 million of tax-exempt financing for capital projects.

CONCLUSION

Columbia will remain a geographically isolated, single-plant operation for the foreseeable future, as WNP-1 will never be completed. The disadvantages and potential risks in retaining a third-party manager or selling the plant outweigh speculative benefits. Columbia is an invaluable asset to the region, both in terms of helping Bonneville meet its load and in providing flexibility to Bonneville in managing the Federal Columbia River Power System.

While Columbia's performance has improved substantially since the early 1990s, all opportunities for cost optimization and increased generation must be identified and vigorously pursued, to the extent they are consistent with the safe and reliable long-term operation of the plant. Successful, diversified Energy/Business Services projects also will benefit Columbia and, consequently, ratepayers. The Executive Board will continue to work closely with management and Bonneville in pursuit of these goals.

This report concludes the Executive Board's review of Energy Northwest's nuclear program. Energy Northwest remains committed to being a valuable member of the public power community, and to continuing the safe operation of Columbia for the long-term benefit of the ratepayers of the region.

Adopted by the Executive Board on January 23, 2003

John Cockburn, Chairman
Retired Bank Executive
Seattle, Washington

Dan Gunkel, Vice Chairman
Klickitat County PUD Commissioner
Goldendale, Washington

Sid Morrison, Secretary
Retired Executive
Zillah, Washington

Vera Claussen, Assistant Secretary
Grant County PUD Commissioner
Ephrata, Washington

Margaret Allen
Attorney
Olympia, Washington

Darrel Bunch
Okanogan County PUD Commissioner
Okanogan, Washington

Tom Casey
Grays Harbor County PUD Commissioner
Aberdeen, Washington

Ted Coates
Retired Utility Executive
Tacoma, Washington

Larry Kenney
Retired Organized Labor Executive
Seattle, Washington

Amy Solomon
Foundation Program Officer
Seattle, Washington

Roger Sparks
Kittitas County PUD Commissioner
Ellensburg, Washington

Appendix A
Cost of Power

"Cost of power" is the industry standard for comparing the production costs of various electrical generating plants and is generally expressed in dollars per megawatt-hour (MWH). To calculate the cost of power, cost is divided by net generation. Columbia, like most other nuclear utilities, uses two sources for obtaining cost data – FERC (Federal Energy Regulatory Commission) and the EUCG (formerly Electric Utility Cost Group), an industry group. The EUCG data also contains staffing information.

Both sets of data are imperfect and therefore must be used with caution. For example, some utilities do not report staff costs when a support activity is performed at a location other than the plant site. At Columbia, all staff are located at the plant site and consequently reported.

Numerous factors affect the cost of power. For example, refueling outages increase maintenance costs and lost generation, so the time between refueling outages has a major impact on the cost of power. Until recently, Columbia was on a 12-month refueling cycle so the plant would be off line during the spring runoff when hydropower was plentiful. Based on multiple reasons, including a desire to reduce the cost of power and the need to maintain spring outages, Columbia has transitioned to a 24-month refueling cycle. The first full 24-month cycle will be completed with the Spring 2003 refueling outage. An 18-month cycle is generally recognized as most efficient and is most common, and multi-year averages often are used in cost-of-power studies to account for the effect of refueling outages.

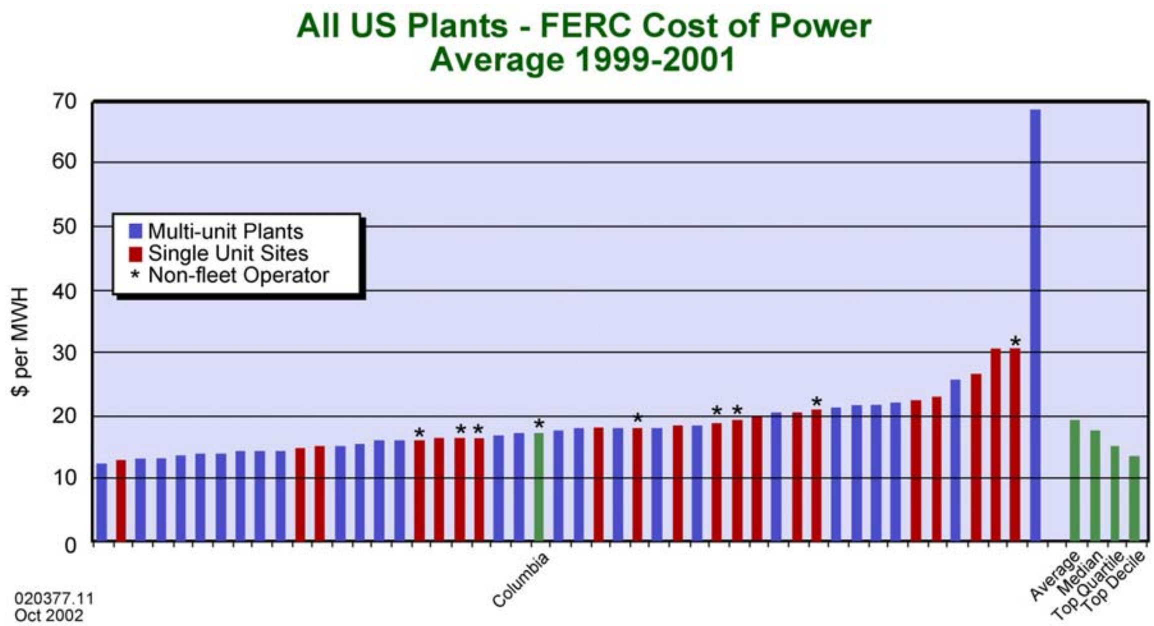
The number of generating units at a particular site also has a large impact on the cost of power. At multi-unit sites, many activities need be performed only once for all units or can be performed using shared resources, resulting in significant efficiencies. Entities operating plants at more than one site also can benefit from shared resources. Plants with these cost advantages are referred to as "fleet" plants. Columbia is a geographically isolated, single-unit plant that is not part of a fleet. Most cost-comparison studies identify this operational factor and select appropriate plants for comparison.

Management's focus at a given time affects the cost of power. Spending on a range of projects and programs varies according to financial conditions of the entity, the market value of the power and other factors. For example, beginning in the mid-1990s, cost containment was the primary focus for Columbia. Recently, as the effects of the West Coast energy crisis drove up the value of the station's output, management's focus shifted to plant reliability resulting in some increased costs. Activities that increase reliability are reducing maintenance backlogs, increasing preventive maintenance, replacing obsolete equipment, maintaining regulatory margin, replacing retiring employees early and increasing the pool of licensed operators.

Cost of Power – FERC

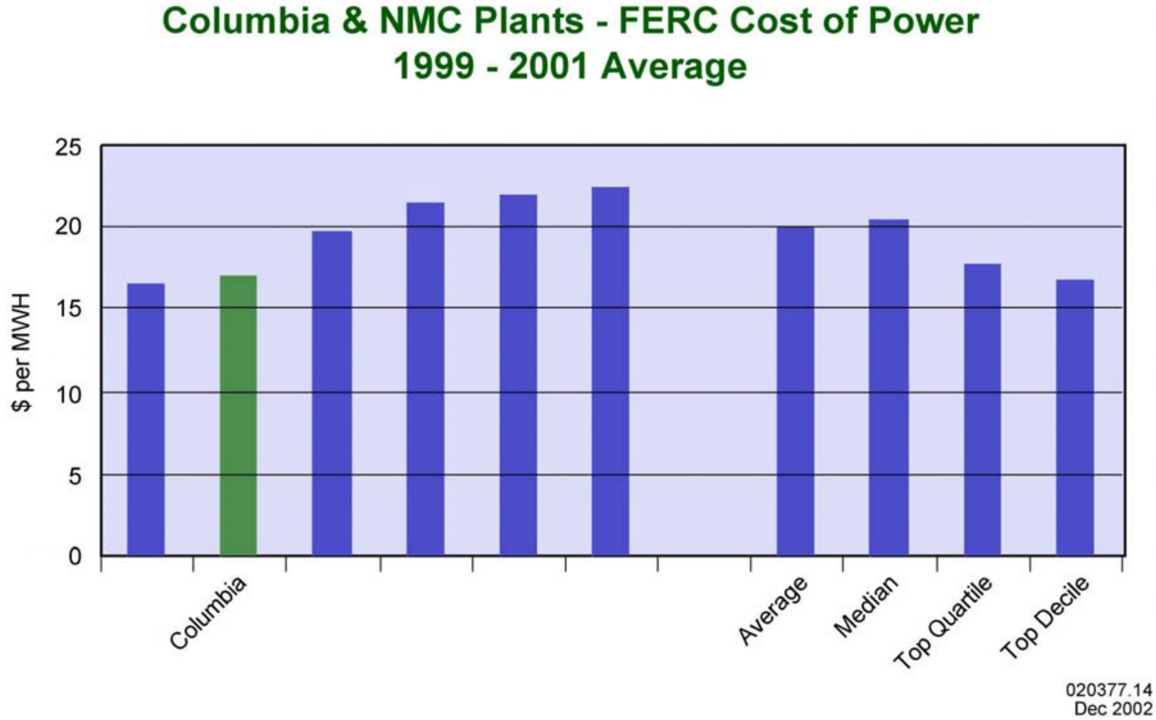
Annually every electric utility is required to report plant costs to FERC in a standard format. For utilities not regulated by FERC, a similar requirement is met through the EIA-412 report. This data is the only publicly available data for comparing the costs of electricity generating stations, and thus is extensively used by the electrical industry. When using FERC data to measure performance, the focus is most often on production costs, which includes operations, maintenance and fuel. Excluded from production costs are administrative and general, capital, depreciation, decommissioning and interest expense.

The chart below shows FERC cost-of-power data for 48 commercial nuclear power plants, identifying single-unit plants and those not operating as part of a fleet. Data has been averaged over three years to mitigate the non-annual refueling outage impact. Only plants submitting FERC or EIA-412 data for the time period are included.



This chart shows the average cost of power from individual plants in the U.S. commercial reactor fleet from 1999 through 2001. Columbia is near the median. (Source: FERC, INPO)

The Goldschmidt Imeson report suggested one option for cost savings was to consider retaining a third party to manage Columbia. Nuclear Management Company (NMC) is the only company in the United States engaged in managing plants it does not intend to purchase. The following chart compares the cost of power from Columbia and plants managed by NMC.

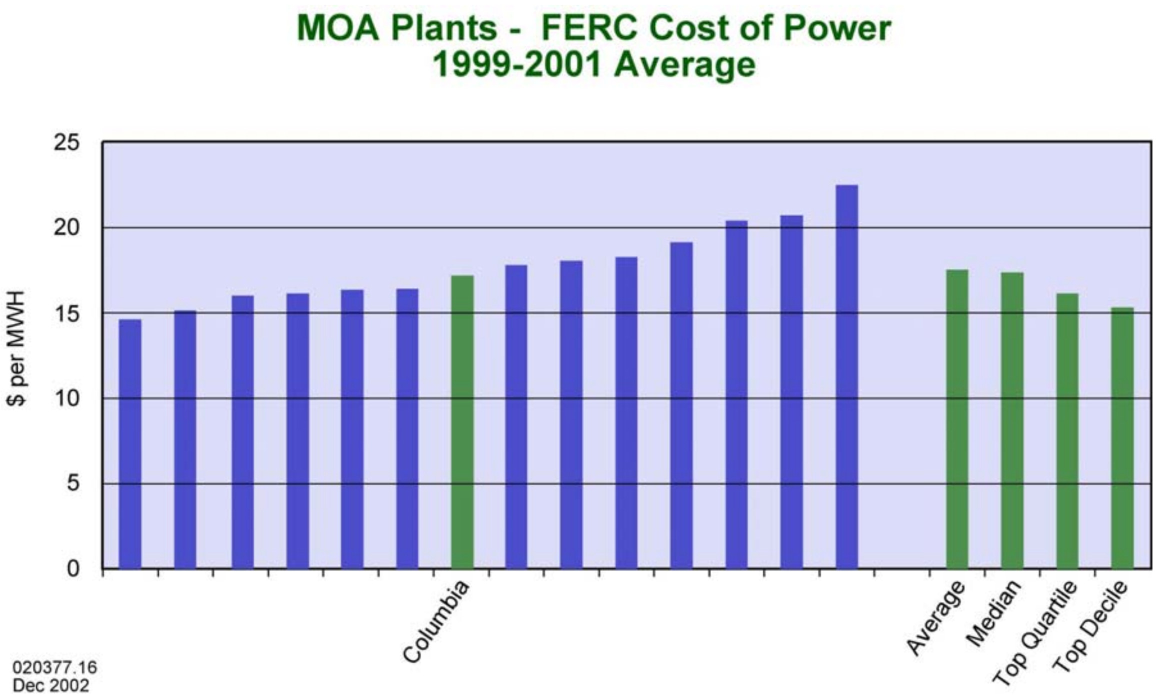


This graph shows the cost of power for Columbia and plants operated by NMC. Not all plants currently operated by NMC are listed here, because they had not been under management by NMC for the entire three-year period. (Source: FERC)

This data does not support the belief that third-party management would reduce the cost of Columbia's power.

In 1999, Bonneville and Energy Northwest identified a group of single-unit plants to use for evaluating Columbia's cost performance. This group was selected to establish benchmark targets for operational incentive payments to Energy Northwest from Bonneville. Included were large, single-unit plants with good generation over the selected years. Excluded were plants that had extended outages or other operational problems. This group of plants is referred to as the Memorandum of Agreement (MOA) plants.

The graph below shows FERC cost-of-power data for the MOA plants. Columbia is near the median.



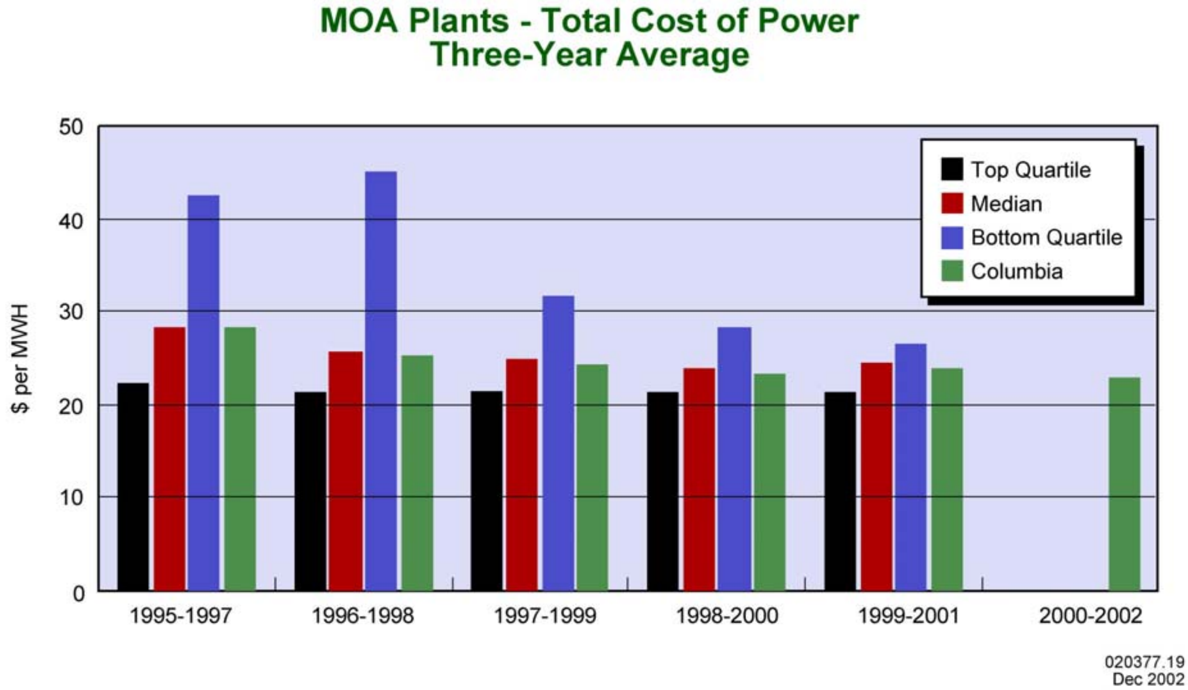
This graph shows the three-year rolling average cost of power for MOA plants selected for comparison by Bonneville and Energy Northwest. (Source: FERC)

Cost of Power – EUCG (Industry Group)

The EUCG Nuclear Committee collects cost and staffing data submitted voluntarily and confidentially. This data is more inclusive than FERC data as it includes production costs (operations, maintenance and fuel) as well as indirect (administrative and general) costs and current-year capital expenditures. Costs for depreciation, interest, decommissioning, and taxes are not included. This grouping of cost data was selected by EUCG as a consistent basis by which to compare nuclear power plant costs. The more traditional total cost of power, which reflects past investments through depreciation and interest expense, is not generally used by the industry for benchmarking studies. Consequently, the “total cost” discussed below is the total based on the EUCG definition.

EUCG data is commonly used to examine production and total costs. Due to inconsistencies in reporting indirect cost and judgments associated with capital investments, production cost data is considered to be the most accurate, and thus a more valid basis for comparison than is total cost. However, since production cost is compared above in graphs using FERC data, total cost is compared below using EUCG data.

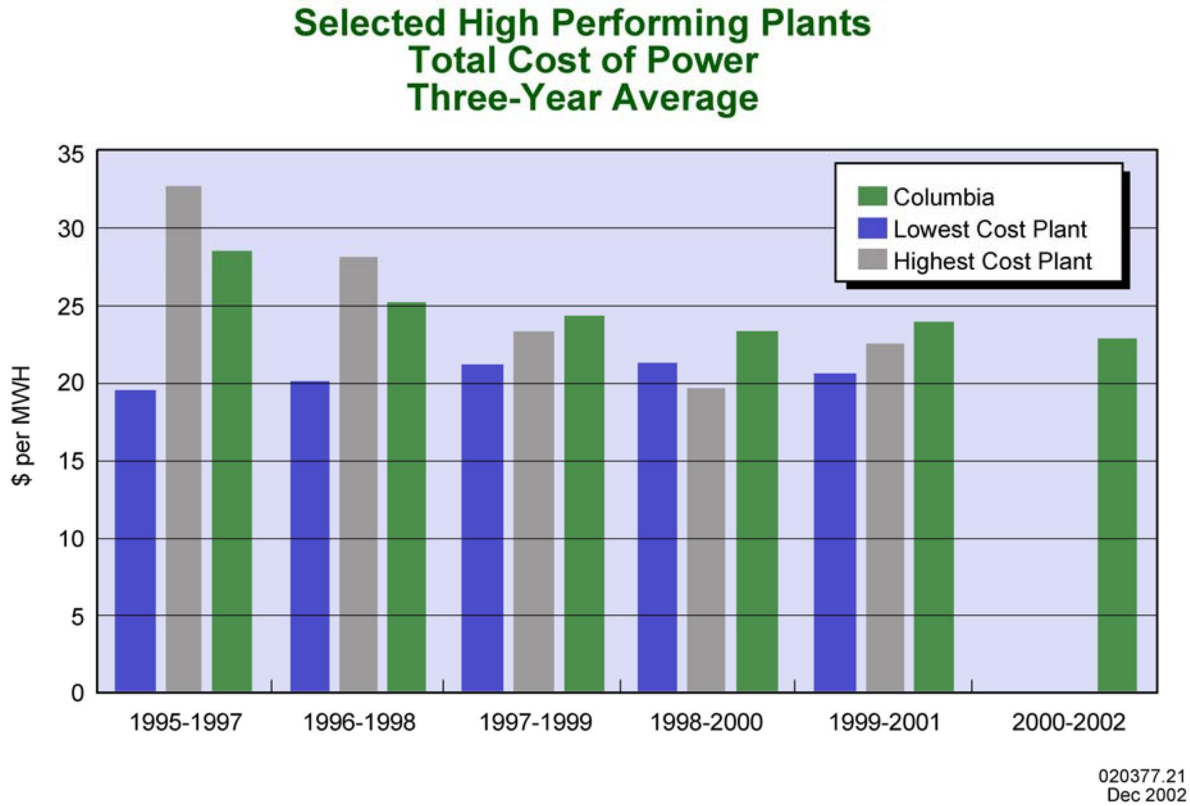
The following graph shows the cost of power from the MOA plants on a EUCG total cost basis. Data is presented by reporting year and shows Columbia compared to the average and top quartile plants for each listed year. Individual utilities also have varying fiscal years. Energy Northwest's fiscal year ends on June 30. Columbia's 2002 data is currently available; however, industry comparison data for 2002 will not be available until spring 2003.



This graph shows power costs of the MOA plants for the last seven years on a rolling three-year average. Data for Columbia is shown over eight years. Plants selected for comparison had good performance over the time period. Excluded were plants with very low or no generation and plants with missing cost data. (Source: EUCG)

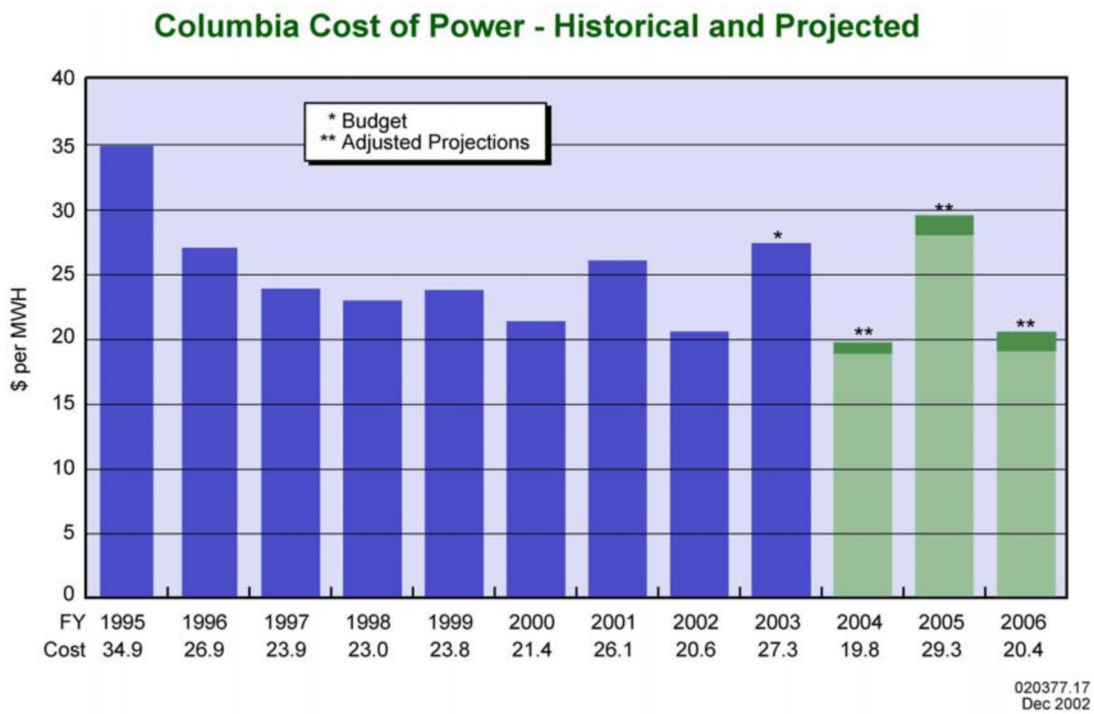
In a cost-comparison study performed in 2002, an Energy Northwest/Bonneville team used EUCG data to compare Columbia with five top performing single-unit plants, a subset of the MOA plants. The plants were selected as the best overall performers having low production costs over the last seven years. Plants with high costs, a combination of alternating low cost and high cost years, or questionable data were eliminated. Those plants with alternating low and high production costs not attributable to refueling outages apparently reduced costs for a short time at the expense of reliability and then later incurred high costs upon investing a significant amount of money to improve reliability. The plants in the "top performing" category appeared to have the right strategy for plant equipment reinvestment that allowed for consistently low operating costs and high plant reliability (measured by high generation over a sustained period of time). Note that three of the five plants used in this comparison are part of multi-plant fleets.

The following chart compares the total cost of power from Columbia to that of the selected high-performing plants.



This chart shows a rolling three-year average of total costs. This includes production, indirect and current-year capital expenditures. Columbia is compared to the lowest and highest cost plants in the selected high performing group of five other plants. (Source: EUCG)

Columbia's historical and projected cost of power using EUCG total-cost basis is depicted below. Projections for future years incorporate cost-reduction endeavors outlined elsewhere in this report. Fiscal years 2001, 2003 and 2005 are years with 24-month refueling outages with costs much higher and generation lower than non-refueling outage years. Prior to fiscal year 2001, Columbia performed annual refueling outages except in fiscal year 1999 when the plant was off line in the spring for a fuel-saving and maintenance outage to help transition to a 24-month refueling cycle.



Cost of power is provided using nominal dollars by fiscal year. Costs include operations, maintenance, A&G and current year capital expenditures. Not included are interest expense, decommissioning contributions or depreciation. Cost projections for 2004-2006 include escalation at 4 percent and depict the escalation amount at the top portion of the stacked block for each year period.

While cost-of-power (comprised of cost and generation) is a very good indicator of performance, there are other factors routinely evaluated by management and the Executive Board which include the NRC performance indicators and findings, INPO performance indicator index, plant performance indicators, leadership in industry groups, independent industry assessments and feedback from oversight groups.

As evidenced by the data, Columbia is a solid performer when the cost of its power is compared to that of all nuclear plants operating in the United States. When compared to the top performing single-unit plants, however, the data shows opportunity for improvement. For future years the challenge will be to be among the top performers in the industry not only in cost but in all areas. Management and the Executive Board have and will continue to monitor all these indicators of performance.

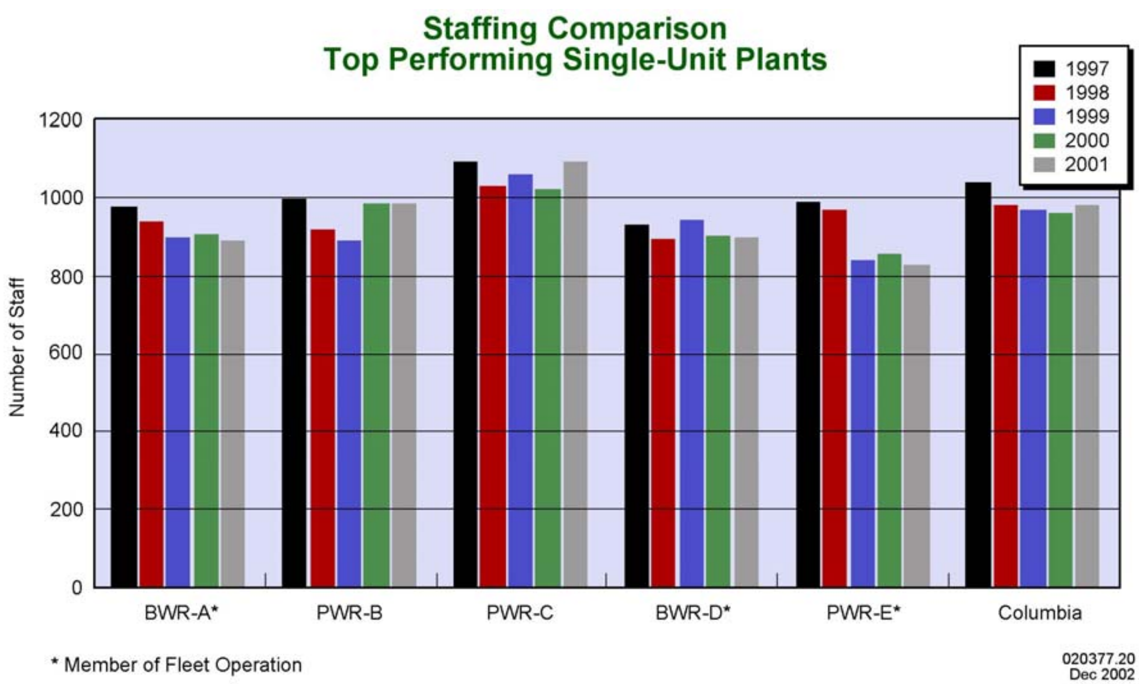
Appendix B
Staffing

Several sources have suggested Columbia's staffing level may be higher than the norm, including Mr. Kacich and Goldschmidt Imeson (whose conclusions were based on interviews with other nuclear plant owners without first-hand experience with Columbia operations).

The source of staffing information used for comparison comes from the EUCG, an industry group. Staffing data can be misleading because reporting is voluntary and because of inconsistencies in how each plant counts people. For example, employees and full-time contractors are to be categorized either as "direct" or "indirect"; some plants have reported numbers only in one category. Only through benchmarking with a specific plant can it be determined if those plants have accounted for all employees and contractors.

Factors to be considered when comparing staffing data include the number of units at a plant site, fleet operation and reactor type. Industry data shows multi-plant sites have significantly lower staffing per installed megawatt. There also are additional staffing advantages for plants which are members of fleet operations and for pressurized water reactors when compared to boiling water reactors.

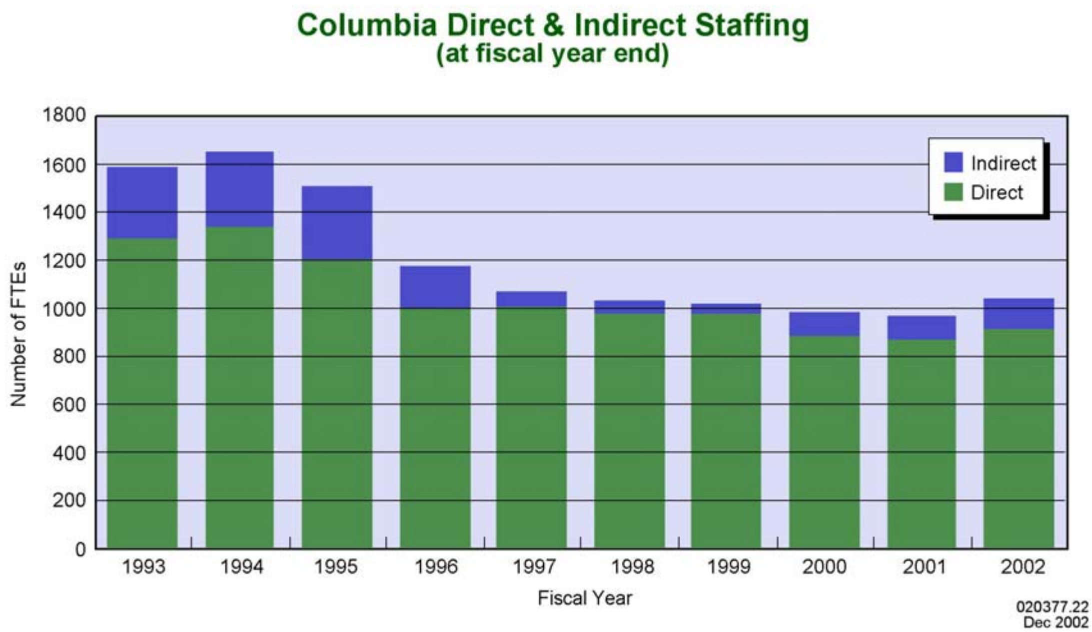
With those caveats in mind, the following chart depicts the best currently available information on how Columbia's total staffing level compares to that of five single-unit plants identified as the best overall single-unit performers with low production costs. It is important to note that three of the five plants are part of multi-plant fleets.



The data includes all employees – direct, indirect or allocated – and long-term contractors on a full-time-equivalent basis averaged over the year. (Source: EUCG)

Columbia is somewhat disadvantaged when comparing total staffing numbers to other single-unit plants. Most plants are part of a larger organization and allocate large portions of their infrastructure to other plants/business lines. Columbia, as a single-unit plant in a relatively small organization, supports over 90 percent of the corporate infrastructure. This percentage should drop with the increasing success of Energy/Business Services projects.

Another view of staffing is derived from historical reports routinely issued to the Executive Board. Following is a graph showing changes in Columbia's total staffing over time, with the subcategories of "direct" (staff assigned directly to Columbia) and "indirect" (including "allocated" - Columbia's apportionment of staff whose functions serve all Energy Northwest activities including the administrative and general activities).



Data derived from the year end reports issued by Energy Northwest to the Executive Board. The definition of direct and indirect changed from year to year. (Source: Staff)

The numbers reflect both full-time and part-time employees. Less than one percent of all Columbia employees are part-time**.** In 1995 significant staff reductions were taken to reduce the cost of power from Columbia. In 2002 plant reliability became a higher priority, resulting in small increases to staffing levels. In 2003 an additional 44 people are budgeted to support the Independent Spent Fuel Storage Installation operation (21 employees), increased security requirements, information systems and other support areas. Future staffing increases may be required due to increased security requirements.

Another important component in comparing staffing numbers is the number of contractors a plant engages. All nuclear plants use a large number of contractors to support outages. Many also use contractors for special projects as well as to supplement regular staff. At Columbia, an estimated 15 to 20 contractors are used to supplement regular staff. Prior to 1995, Columbia depended on a large number (795 at fiscal year end in 1994) of contractors to support outages, special programs, and plant operation. The current practice is to not rely on contractors for routine operations but use them for refueling outages, peak work, and highly specialized tasks.

In his report, Mr. Kacich expressed a belief that modest staff reductions were achievable over the long term without sacrificing safety, but that such reductions should not be an immediate priority since maximizing generation has the potential of yielding much greater improvements in cost performance. He recommended working on process improvements prior to any staff reductions. These include reducing rework rates, optimizing preventive maintenance, identifying ways to simplify processes, requiring fewer organizational “handoffs,” and taking increased advantage of technology. With improved equipment reliability, fewer unanticipated issues, and improved long-range planning, the organization will increase control over its destiny rather than reacting to the challenge of the day. (See Attachment A.)

The workforce in the nuclear industry as a whole is aging. Human Resource projections indicate 145 individuals will be eligible to retire over the next five years, with 50 of the 145 eligible by August 2003. Additionally, military and university programs are producing fewer graduates with nuclear expertise than in earlier decades. To date, management has been successful in attracting high quality employees at Columbia. Diverse opportunities provided by Energy/Business Services, the culture of the organization, and the quality-of-life-in-the-community have helped to retain qualified staff. However, it is likely a single-unit plant will find attracting and retaining qualified staff increasingly difficult over time because a single-unit plant provides fewer opportunities for advancement than does a multi-unit plant operation.

Having sufficient nuclear expertise to operate a plant is not only necessary for efficiency, but more importantly, for public safety as well. Energy Northwest alone, as holder of the Nuclear Regulatory Commission’s license to operate Columbia, is responsible for ensuring adequate staffing with that expertise. Consequently, a “bench” is especially important for a single-unit plant like Columbia (it is better to be over-resourced than under-resourced in nuclear expertise), and may lead to higher staffing numbers than at multi-unit plants and fleet operations that can share staff. With these realizations, some departments (e.g. Engineering) have implemented the practice of hiring replacements in advance of some pending retirements to ensure an individual’s expertise and knowledge are not lost with the retirement.

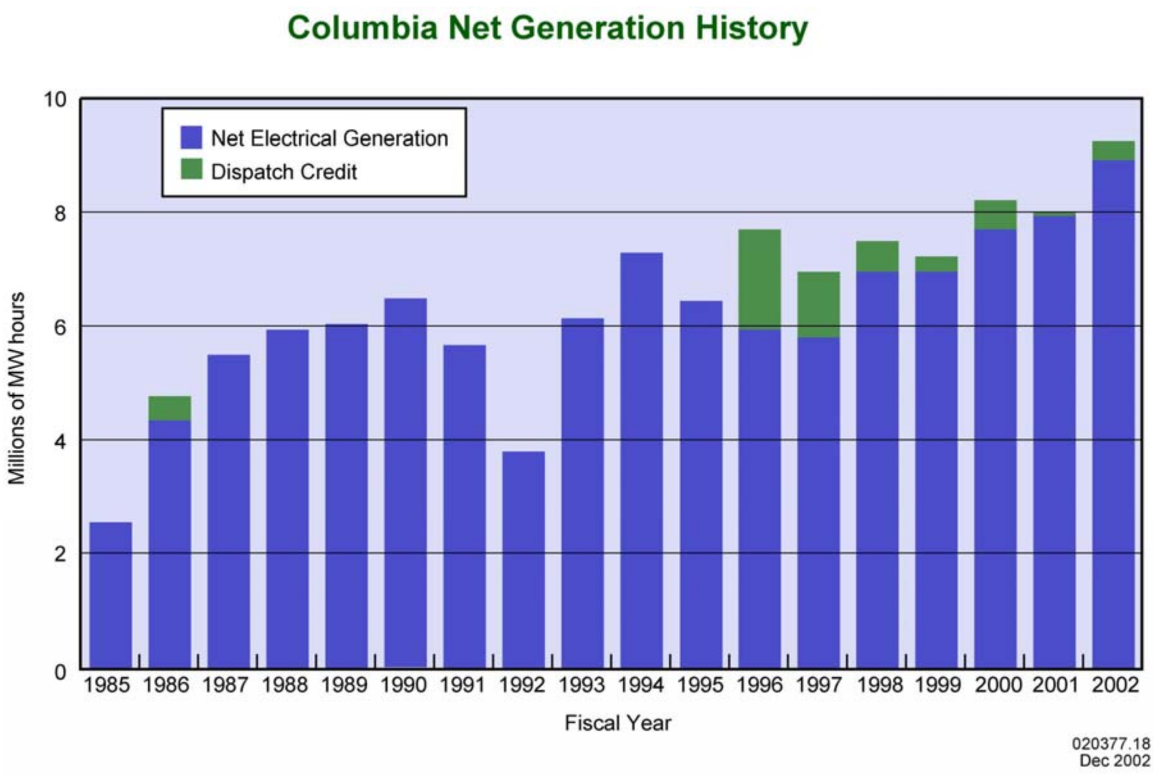
A bench is considerably less important in areas involving less technical expertise, and at this point it is unclear how Columbia compares to other plants in staffing nuclear and non-nuclear positions. Consequently, during this fiscal year Energy Northwest will conduct a benchmarking study in which Bonneville will participate, and will brief the Executive Board on the findings.

Appendix C
Generation

Generation is a key element in keeping the cost of power as low as possible. Regardless of how well costs are otherwise contained, unplanned outages and lengthy planned outages (such as for refueling) increase unit costs.

Historically, Columbia's traditional 12-month refueling cycle helped make the plant's output some of the most expensive in the nation. In addition, the plant was plagued by forced outages and long refueling outages. As the plant became more reliable and moved to a 24-month refueling schedule, the cost of its power descended.

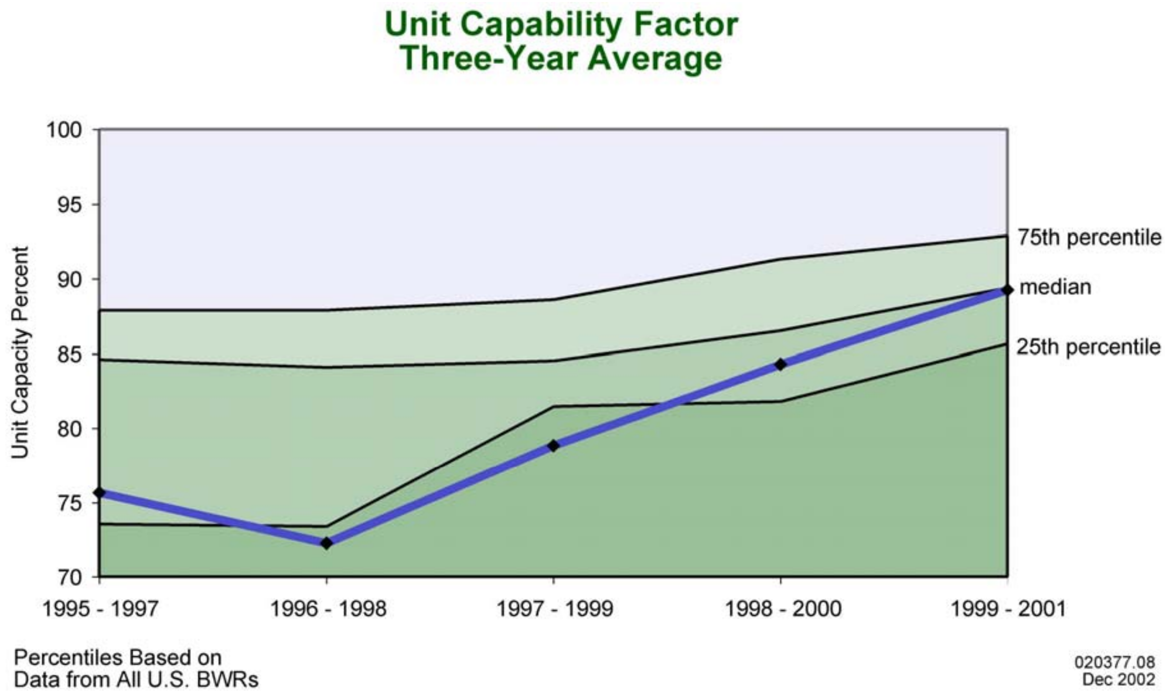
Columbia set a new plant record in fiscal year 2002, generating over 9.2 million megawatt-hours. Below is a graph showing the generation history of Columbia beginning with the first year of commercial operation.



This chart is a year-by-year tally of Columbia's output on a fiscal year basis. "Dispatch credit" credits Columbia for times when it produces less than full generation at Bonneville's request. (Source: Energy Northwest System Engineering)

Unit capability factor indicates the percentage of total generation the plant was capable of producing. This is in comparison to the capacity factor, which indicates the percentage of maximum generation the plant actually produced. Because of the Northwest's unique hydropower system, Bonneville sometimes asks Columbia either to reduce power output or suspend generation when the plant is capable of doing so. (See Appendix D.) Consequently, the capability factor is a more telling measure of Columbia's reliability than is the capacity factor.

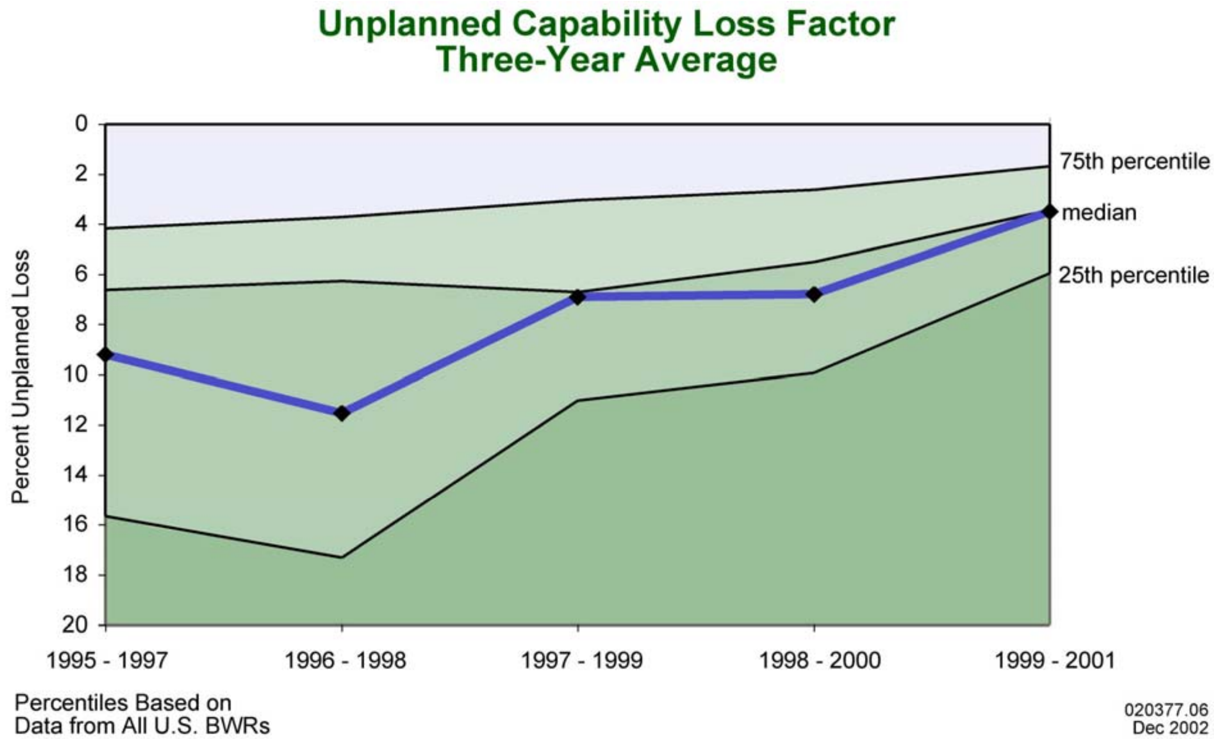
The following chart shows Columbia's capability factor based upon reports from all 34 U.S. boiling water reactors (BWRs).



This chart shows a steady increase in the capability factor of Columbia (indicated by the blue line) when compared to other BWRs. Without counting its record generation during the 2002 fiscal year, and despite substantial outages of previous years, Columbia's capability factor is about at the median. (Source: WANO)

Loss of capability can be unplanned – such as in forced outages – or planned, such as scheduled refueling outages. Unplanned loss of capability may reflect a lack of planning or inadequate maintenance of the plant. The length and number of scheduled outages are determined by managers, and often are designed to ensure reliable operation in the future.

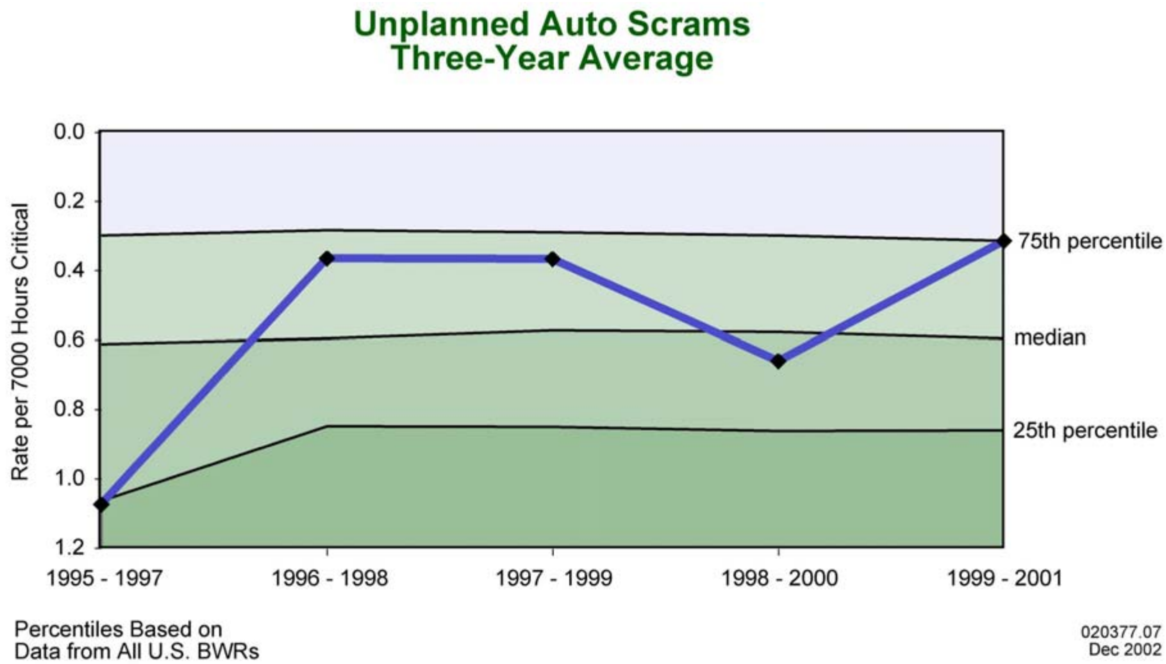
The following chart shows the unplanned capability loss factor of Columbia Generating Station as compared to other BWRs in the nation.



Columbia (indicated by the blue line) currently is at the median of U.S. BWRs for unplanned capability losses, with an improving trend over the past four years. (Source: WANO)

Of all unplanned capability losses, automatic scrams reflect most unfavorably on plant operations as they may represent a failure of operators to predict and maintain the condition of the station. In an automatic scram, monitors inside the plant detect something out of the ordinary and shut the plant down.

The following graph shows Columbia's automatic scram rate compared to other BWRs in the nation.



This chart illustrates that Columbia has now reached the top quartile of U.S. BWRs. (Source: WANO)

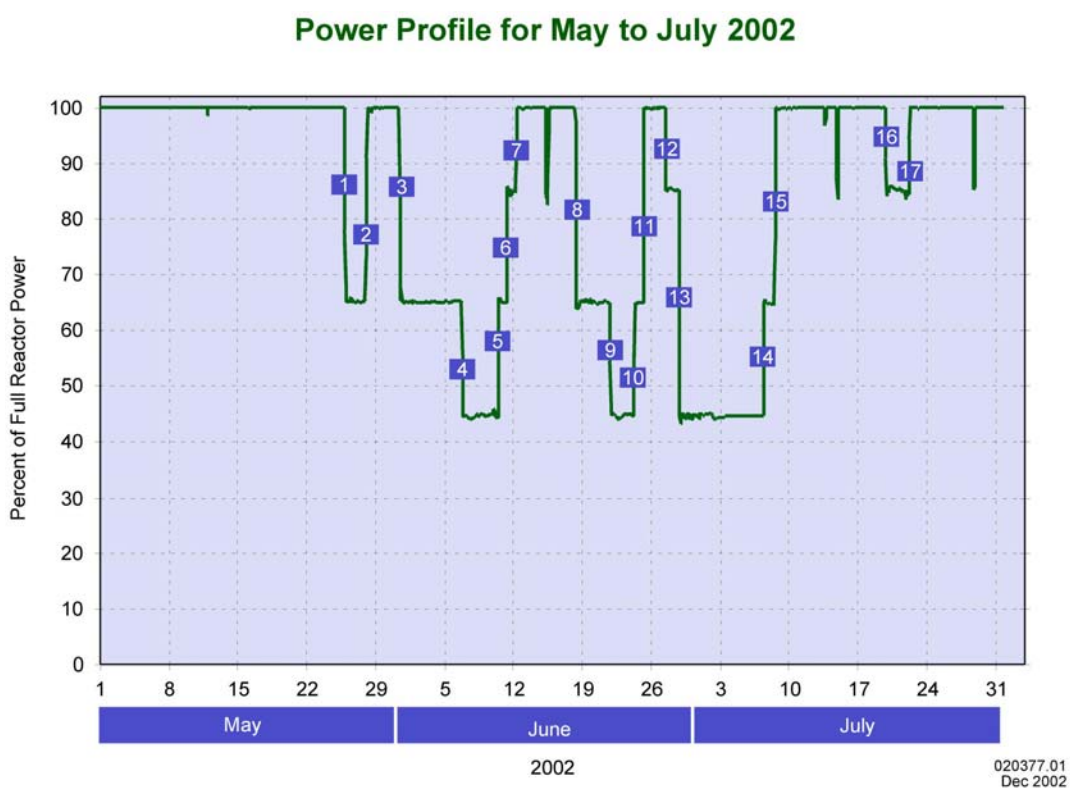
Appendix D
Generating Flexibility

Columbia is the only plant in the 103-unit U.S. nuclear fleet to regularly change power levels because of market, weather, or river conditions.

Sometimes called “load following” or “economic dispatch,” these power level changes are made at the direction of Bonneville, based on many variables that Bonneville alone can describe. However, there are a few basic themes:

- A surplus of power in the Northwest
- Voltage support for the region and the interties
- Market prices
- Gas saturation levels below dams and other fish mitigation issues

In May, June and July of 2002 alone, Columbia operators made 17 power manipulations at Bonneville’s request. Resulting power levels ranged from 100 percent to 45 percent.



This graph shows power level changes at Columbia in May, June and July of 2002. Other short spikes on the graph represent regularly scheduled brief downpowers for maintenance purposes. (Source: Energy Northwest System Engineering)

Bonneville has repeatedly said that Columbia provides flexibility and assistance in helping meet spring and early summer Biological Opinion for certain species of migrating salmon operating requirements for the Federal Columbia River Power System.

Bonneville credits Columbia for lost generation when operators reduce Columbia's output in response to Bonneville's requests. (See Appendix C.) More difficult to quantify is the resulting wear-and-tear on plant equipment and increased risk of human error. In 1996, variable speed drives for the reactor recirculation pumps were installed to reduce the stress on the piping, valves and pumps. Even so, each time power is reduced, additional wear is placed on steam plant components when they are operated in off-normal conditions. Also, each power change, depending on the level of change, introduces opportunities for operator errors.

Appendix E
Radiation Exposure

Radiation exposure is an important measure of how well a nuclear plant is operated, for several reasons:

- Radiation safety is one of three Nuclear Regulatory Commission (NRC) reactor-oversight performance areas, and occupational radiation safety is one of seven safety cornerstones in the oversight process. The cornerstone monitors the effectiveness of a plant's program to control and minimize dose.
- As low as reasonably achievable (ALARA) personal exposure and a low number of radiologically contaminated areas are indicators of a clean plant – one in which tasks can be completed quickly without donning protective clothing – thus saving time and material while improving worker efficiency.
- Low collective radiation exposure is a key indicator of a well-run commercial nuclear power station.

In 1994, Columbia was the highest-dose BWR in the nation with 866 rem. While the station was well within national standards and its own administrative standards, its collective radiation exposure was high. Collective exposure has dropped dramatically in recent years.

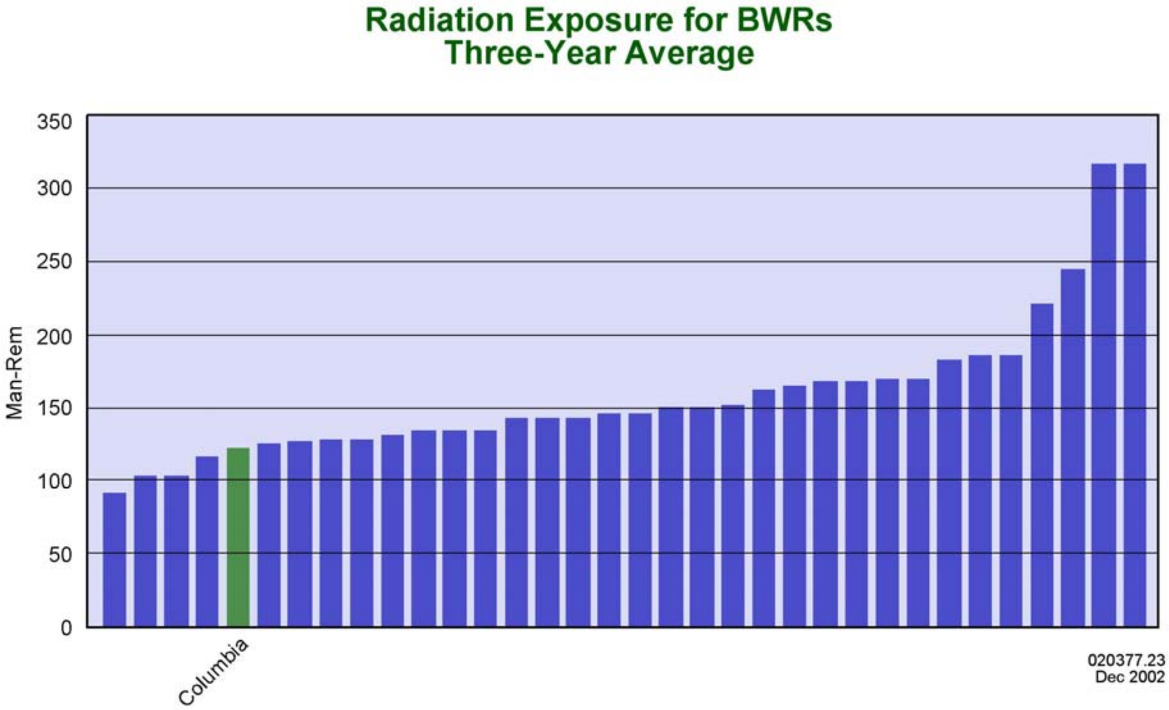
Dose rates are significantly higher during outage years. Columbia had annual refueling outages until 2000, when it began a transition to a 24-month cycle. By that time, almost every other plant was on either an 18- or 24-month refueling cycle.

Columbia's cumulative tally for fiscal year 2002 was 38.6 rem. This places Columbia third best of the 34 domestic boiling water reactors during that period of time.

The overall dose at Columbia has improved because:

- The plant is running well with fewer equipment problems in radiologically significant areas.
- The plant is radiologically cleaner, meaning fewer sources of contamination and reduced dose rates.
- Worker culture is focused on maintaining exposure as low as reasonably achievable.
- Improved worker efficiency has resulted in less time being spent on radiologically significant jobs, resulting in reduced dose.
- Fewer refueling outages reduce the frequency of performing some outage-related higher dose-rate jobs.

Columbia will continue to work to reduce collective radiation exposure and improve radiological safety. The station has a plan in place with strategies for dose reduction, contamination reduction, and personal performance improvement.

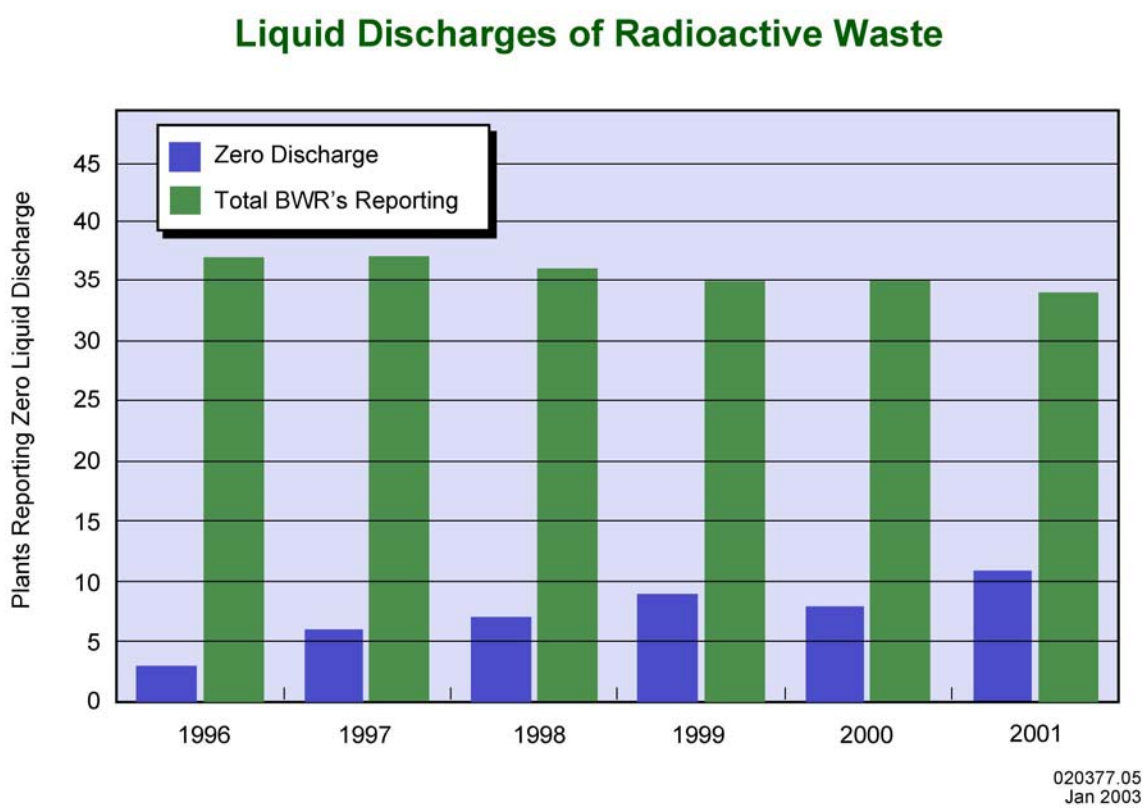


This chart shows the most recent (October 1999 through September 2002) three-year averages of dose rates at BWRs. Because refueling outages (when increased dose is incurred) do not take place each year, the best benchmarking instrument is one that compares multi-year averages. (Source: BWROG)

Appendix F
Environmental Stewardship – Liquid Discharges

One aspect of environmental stewardship is the minimization of liquid waste discharges. Process water in Columbia Generating Station is treated by filtration and ion exchange for reuse in the plant. In the past, excess water containing low levels of radioactive waste was occasionally discharged into the environment. These discharges did not exceed U.S. Nuclear Regulatory Commission standards that permit small amounts of radioactivity to be discharged to the environment.

In 1993, Columbia discharged more than 3,000,000 gallons of water containing low-level radioactivity to the river. By 1998, these discharges had been reduced to 717,000 gallons, and since then Columbia has discharged none. Columbia has not discharged any radioactive effluent into the Columbia River for over four years. It is important to note that, even when the plant was discharging excess process water, the effluents were estimated to contribute only about 1/100th of a millirem per year of radiation dose to an exposed individual. Such low numbers can only be calculated, not measured in the field. By comparison, an average individual's background exposure from normal activities is about 360 millirems per year.



This graph shows the number of BWRs reporting zero liquid discharges of radioactive waste. (Source: INPO)

As other evidence of its commitment to environmental stewardship, Energy Northwest is pursuing registration under ISO 14001, an environmental standard established by the International Organization for Standardization (ISO) that is widely applicable across businesses and industries. Part of the effort includes establishing an environmental management system to ensure environmental issues are systematically identified, controlled, and monitored, and that measures to address identified issues are coordinated to the greatest degree possible. Highly diverse environmental issues will be covered by the system, including both regulated (e.g., the handling of asbestos and reducing paint waste) and unregulated (e.g., recycling paper and conserving energy) activities.

The environmental management system is consistent with Energy Northwest's strategic objective of "public confidence, trust and stewardship". There are at least 36,765 organizations worldwide that have implemented ISO 14001, with more than 2,040 in the United States, ranging from Ford and General Motors to the Tennessee Valley Authority, IBM, and locally, the Weyerhaeuser Corporation and Pacific Northwest National Laboratory.

Appendix G
Energy/Business Services

Energy/Business Services, formerly known as Resource Development, was created in 1996. By that time the performance of Columbia had greatly improved, and the progress was being sustained.

The Business Development Fund was created to establish financial tracking and a method to carry cash reserves from year-to-year. The fund's sources of cash are net revenue from successful business units and incentive fees earned from operation and management of the net-billed projects.

Energy/Business Services exists to:

- Help meet the energy and business needs of Energy Northwest members and the region
- Provide career opportunities for Energy Northwest employees, making it easier to attract and retain qualified employees and thus mitigate some of the disadvantages of Columbia being a single-unit operation
- Decrease Columbia's costs by paying a portion of corporate overhead and providing cost avoidance opportunities

Through Energy/Business Services, Energy Northwest currently operates several other electricity generating facilities that include hydro, wind and solar generation. In addition, Energy/Business Services offers operations and maintenance expertise to other power generating facilities and provides other professional services.

Energy/Business Services revenues have grown from $3.7 million in fiscal year 1999 to $16.3 million in fiscal year 2002. Bonneville has estimated the benefit to Columbia since 1998 to be $7.5 million by reducing overheads and direct charges to Columbia.

In the future, certain business units are expected to generate sufficient revenues to be sources of funds for starting new business units. Some of the business units will operate for the benefit of the public and may not show a positive margin for the foreseeable future. All business units are under constant review, and decisions regarding the future of each will be based on both its specific purpose and the revenues it produces.

Attachment A
Independent Assessment

INDEPENDENT ASSESSMENT OF COST COMPARISONS AND FUTURE COST PERFORMANCE TARGETS FOR COLUMBIA GENERATING STATION

September 24, 2002

Prepared by:

Richard M. Kacich

JANUS MANAGEMENT ASSOCIATES, INC.
208 B NEW LONDON TURNPIKE
GLASTONBURY, CT 06033

Attachment A

TABLE OF CONTENTS

EXECUTIVE SUMMARY

The Executive Board of Energy Northwest has been engaged in a comprehensive process to evaluate the operation and maintenance of the Columbia Generating Station (CGS). The Board considers it imperative that CGS's going forward cost is maintained at the lowest possible level while ensuring the objectives for safe and reliable operation are met. The Board has also directed that the cost of power be closely scrutinized with a focus on identifying opportunities for cost reductions.

Plant management utilized a variety of industry data comparative services and benchmarking information to compare CGS historical cost performance and future plans to other comparable nuclear facilities. To obtain an evaluation of the reasonableness of the above-described cost comparison, the Executive Board requested that Janus Management Associates, Inc. (Janus) perform an independent assessment of the reasonableness of the cost comparison and the ability to maintain CGS's cost of power at the lowest level possible.

The Janus assessment involved two major elements. The first was a review of the documentation provided by Energy Northwest, reviewed in light of other information sources that provide a cost comparison context. The second entailed an on-site interview process of station personnel, primarily key management individuals. While considerable objective data were utilized, the interview process included some elements of subjectivity and perception. The use of both quantitative and qualitative information was necessary to perform a more thorough analysis, given the stated overarching goals of safety and long-term, reliable operation.

The assessment of the cost comparisons and future cost performance targets gave preference to comparisons at a global level, recognizing that variations in plant design and operation, financial data reporting conventions, and other variables introduce complexities in making those comparisons.

CONCLUSION

Janus concludes the cost comparison methods and metrics selected to compare CGS to other nuclear power plants in the industry are reasonable. The benchmark plants chosen for the comparison reflect care in selecting high performance plants, which sustain that achievement over an extended period of time. The study also recognizes the limitations and imprecision in the data. The cost performance goals identified in the draft CGS Cost Study are reasonable, noting the importance of the statement that indicates they will be revisited periodically as additional data for both CGS and the industry are accumulated.

Listed below are the most significant strengths and challenges identified during the assessment. Details of these strengths and challenges and additional observations are contained in the report.

STRENGTHS

CGS has made meaningful strides in improving its performance over the past several years. Quantitative measures on cost performance, generation, person-rem, Institute of Nuclear Power Operations (INPO) indices, Nuclear Regulatory Commission (NRC) Inspection data, and other metrics provide strong evidence of the progress. CGS' most recent three-year production cost was $17.1/MW-hr, which compares favorably to the three-year rolling industry average of $17.4/MW-hr, particularly in light of the historical 12-month fuel cycle.

The CGS CEO, Mr. Vic Parrish, demonstrates a holistic, thoughtful and long-term perspective in leading the station. He lives the station's core values, embraces continuous improvement, demonstrates that he cares about the well being of the employees, and passionately pursues operational and performance excellence. His openness to and pursuit of best practices from other leading organizations are apparent. Interviewees spoke from the heart, openly, and with pride, about CGS being an excellent place to work. Equally significant, while qualitative, is the view of the workforce regarding the environment at CGS. They are justifiably proud of who they are, what they do, how well they do it, and their commitment to continuously improve.

CHALLENGES

The future cost targets were based on five, high-performing, single units, reflecting the intent by CGS to be among the best. A seven-year interval was also chosen with benchmark plants that did not exhibit cyclical cost performance. The draft CGS Cost Study used a 4% annual cost escalation rate to establish the future CGS annual cost targets. By looking over the seven year interval, the significant performance improvements that have been realized over that period are implied by the draft CGS Cost Study to be more representative of the future than a shorter, presumably higher performing period, such as the most recent three years. The earlier and lower performance is not what those facilities are likely aspiring to accomplish. The draft CGS Cost Study's approach also assumes that the five benchmark plants have reached a plateau in cost performance, rather than continuing to improve. While these plants are currently performing at high levels, and developments such as escalated security requirements provide upward cost pressures, it will be important to continue to monitor future developments to see if adjustments to the targets are in order.

The 24-month fuel cycle represents a significant challenge to cost performance as well as an opportunity for reducing costs. With comprehensive, organization-wide planning for this mode of operation, it provides a platform for improving cost performance as compared to the historical 12-month cycle. Periodic direction from the Bonneville Power Administration to reduce power represents a unique challenge in the industry. In addition to the obvious lost generation that can be statistically adjusted for in cost and performance metrics, cycling the plant increases the opportunity for error. During such maneuvers, some equipment is operating at conditions that are sub-optimal, causing additional wear and posing further equipment reliability challenges. The Station staff is challenged to anticipate these effects, and also needs to be prepared to take immediate advantage of any incremental, on-line maintenance opportunity that operation at reduced power might present.

INDEPENDENT ASSESSMENT OF COST COMPARISONS AND FUTURE COST PERFORMANCE TARGETS FOR COLUMBIA GENERATING STATION

INTRODUCTION

This independent assessment of Columbia Generating Station's cost comparisons and future cost performance targets and plans was undertaken at the direction of the Executive Board of Energy Northwest. The methodology employed included a review of various benchmarking reports, cost comparisons, performance data, the "Cost Comparison of Columbia Generating Station to Top Utilities" dated July 2002 (the draft CGS Cost Study) and related information supplied by the Executive Board or its agents. The review spawned additional information requests that further informed this assessment. Additionally, eleven, one-on-one interviews were conducted over a two-day interval. Interviews included several members of the senior leaders of the Station including the Chief Executive Officer (CEO), as well as a cross section of first line supervisory personnel. A general tour of the facility was conducted, including the recently constructed Independent Spent Fuel Storage Installation (ISFSI). The varied locations of the interviews, a free-form discussion with the Shift Manager in the Control Room, and the plant tour afforded the opportunity to observe a number of other interactions that were utilized in forming the judgments and observations included in this assessment.

OVERVIEW

CGS has made meaningful strides in improving its performance over the past several years. Quantitative measures on cost performance, generation, person-rem, Institute of Nuclear Power Operations (INPO) indices, Nuclear Regulatory Commission (NRC) Inspection data, and other metrics provide strong evidence of the substantial progress. Equally significant, while qualitative, is the view of the workforce regarding the environment at CGS. They are justifiably proud of who they are, what they do, how well they do it, and their commitment to continuously improve.

The cost comparison methods and metrics selected to compare CGS to others in the industry, and the future cost performance targets and plans, are reasonable. The benchmark plants chosen for the comparison reflect care in selecting high performance plants, which sustain that achievement over an extended period of time. The study also recognizes the limitations and imprecision in the data. Multiple sources, such as the Electric Utility Cost Group, the Federal Energy Regulatory Commission, INPO, and the Nuclear Energy Institute (NEI), were used to provide higher confidence of the validity of the comparisons and to take advantage of the strengths of the various data sources. The cost performance goals identified in the draft CGS Cost Study are reasonable, are in the process of being refined in the near term, and noting the importance of the statement that indicates they will be revisited periodically as additional data for both CGS and the industry are accumulated.

That said, some further analysis of the available industry data is offered in this assessment to provide further context in forming judgments about current and future cost performance targets. Additionally, several areas of focus that promise to accelerate the rate of performance improvement at CGS are identified. Finally, a number of other observations and insights that may contribute to the stated objectives of safe, reliable, long-term operation at the lowest possible level of costs are also provided for consideration.

ASSESSMENT

This assessment starts with a discussion of the most important dimension of what is required to achieve the performance objectives stated above, abbreviated to safe, reliable, low-cost operation. That concerns leadership's performance in establishing a healthy work environment. In that regard, CGS enjoys what appears to be an excellent circumstance that should continue to be nurtured with great care.

The CGS CEO, Mr. Vic Parrish, demonstrates a holistic, thoughtful and long-term perspective in leading the station. He lives the station's core values, embraces continuous improvement, demonstrates that he cares about the well being of the employees, and passionately pursues operational and performance excellence. His openness to and pursuit of best practices from other leading organizations are apparent. While these values and behaviors revealed themselves in both interviews and conversation, they are even more evident in listening to others, and most evident by observing how people behave.

Virtually all interviewees spoke from the heart, openly, and with pride, about CGS being an excellent place to work. The work environment and culture reflected a safety-conscious foundation. Use of the Problem Evaluation Report System, had been transformed from being described as equivalent to “a police officer writing a traffic citation” to a vehicle for learning. The value of the Leadership Academy was repeatedly characterized as surpassing expectations. Plant challenges, such as fuel corrosion and Control Rod Drive pump maintenance, are addressed with high standards and expectations. When a challenge to safe and reliable operation emerges, individuals and plant organizations rally to evaluate and respond in a collaborative fashion. This is not to suggest that CGS employees believe they are the best in the industry. All interviewees acknowledged that they learn - usually a lot - when they visit other nuclear facilities. No one had difficulty enumerating several improvement opportunities. In fact, when one interviewee was asked to describe one, the initial response was, "I have so many!" Two interviewees had gaps in their employment history at CGS. Both were very pleased to return to the Station and remarked very favorably about the extent of improvement during their absence.

The current culture and work environment are healthy and are very valuable assets. Regulatory margin appears to be ample. The benefit of this environment cannot be calculated in dollars, but far surpasses any costs associated with initiatives such as the Leadership Academy. It is far and away the most favorable platform from which to launch a more aggressive cost performance campaign.

One other observation is imperative to this discussion. It is important to establish cost performance targets to avoid any potential for short-term success at the expense of long-term reliability. Said differently, an organization could "make the numbers" in the near-term by ceasing to pay attention to the longer-term consequences. An extreme, purely hypothetical example would be the organization that avoids spending the tens of millions necessary to build a dry cask storage facility, only to one day be unable to offload the reactor core. Other examples are much subtler, as explained below.

The aging workforce phenomenon at CGS is unlikely to be problematic in 2003. That is not to suggest that steps shouldn't be taken in 2003 to deal with it. The pipeline for licensed reactor operators can be ignored for a period of time without immediate, adverse consequences, but that is not a viable, long-term approach. Several nuclear plants have been operating with capital investments running less than $5 million annually for several years. While this may be workable or even optimum for a period of time, it is unlikely to be optimal over the long haul. In some scenarios, the pace of spending can simply be picked up and plant performance may not be particularly cyclical or eventful. Conversely, if a period of limited spending happens to coincide with several human performance errors, the development of a new degradation phenomenon, an increase in employee concerns, and intensifying regulatory scrutiny, the resulting requirements for costly programs and capital additions can become very high. As a whole, while industry-wide improvements have been impressive over the past several years, there has never been a time when there was no nuclear facility on this "slippery slope", proving time and again that recovery is a very expensive undertaking. As a single operating unit, CGS is well advised to maintain the current healthy margin that exists between CGS's performance today and the performance of plants that have little or no regulatory margin.

THE 24-MONTH FUEL CYCLE

CGS is currently in the midst of its first two-year operating cycle, planning for the next outage in late spring 2003. The transition from the prior 12-month cycle is of central importance to achieving the desired top cost performance. The reasons for this are well documented in the analyses performed by CGS to justify this change. This analysis includes both hard financial data and qualitative factors such as employee morale and adequacy of outage planning time. Absent a change from the current expectation that CGS will periodically be a load follower, the 24-month cycle is the best approach. Use of the term "best approach" is in the context of the CGS asset as a generating resource for the Bonneville Power Administration (BPA), which is not necessarily the same as the cycle length that would result in the lowest cost performance if CGS were a conventional, baseload plant. While beyond the scope of this assessment, a cycle length of 18 months may very well be optimum from a pure, cost performance perspective, and this is one of many factors that need to be considered in evaluating CGS's cost performance and targets compared to others in the industry. With comprehensive, organization-wide planning, the 24-month cycle offers the best potential for strong cost performance, largely because generation is maximized and scheduled outage days (and their attendant costs) are minimized over the 24-month period. At the same time, there are some economic offsets compared to the prior 12-month cycle. These include poorer nuclear fuel economy and the resultant higher nuclear fuel costs, a greater number of discharged assemblies that need to be stored either at the ISFSI or the spent fuel pool, and a greater equipment reliability challenge to maintain a low forced outage rate.

As is well understood by CGS staff, periodic direction from BPA to reduce power represents a unique challenge in the industry. In addition to the obvious lost generation that can be statistically adjusted for in cost and performance metrics, cycling the plant increases the opportunity for error. During such maneuvers, some equipment is operating at conditions that are sub-optimal, causing additional wear and posing further equipment reliability challenges. The Station staff is challenged to anticipate these effects, and also needs to be prepared to take immediate advantage of any incremental, on-line maintenance opportunity that operation at reduced power might present. Performance during the current cycle has been quite respectable and most interviewees believed that the prospects for a solid operating run for the remainder of the cycle are good. At the same time, most interviewees observed that they did not feel fully prepared for this operational change and, in some respects, it "sneaked up on them." At the appropriate time, perhaps following completion of this cycle, it may be a candidate topic for a cross-discipline self-assessment.

THE METRICS

CGS has identified five high performing, single-unit plants to help establish future cost performance targets. This approach is reasonable, and performance at the targeted levels would yield very satisfactory results. In the interest of further informing the judgments that are reached about achieving the goal of low cost performance, the following observations are offered.

Expand the current comparative profile of "cost of power without fuel" to include the additional views of operations and maintenance expenses ("O&M") only, production costs (O&M and fuel) and total costs of power with fuel.

One of the CGS-sponsored benchmarking studies explains the exclusion of fuel costs from the comparison "because of the differences in procurement practices." This is not a persuasive explanation. Those differences may, in fact, speak to the capability of the nuclear fuel procurement staff in minimizing the cost of fuel. Particularly for CGS, the transition to a two-year cycle introduces an expected increase in fuel costs compared to prior benchmark years. Further, production costs (O&M and fuel) are widely reported in various industry publications and afford multiple opportunities for cost comparisons. Looking at this information can be instructive.

In and amongst all the various performance metrics and all the uncertainties and variations in how data are presented, the ultimate figure of merit is the total cost of producing electricity, in $/MW-hr or ¢/kw-hr. Separating the various components of O&M, fuel, administrative and general expenses, and capital, the resulting total is comprehensive without introducing excessive complexity.

To establish the basis for the selection of the target costs, as presented in the draft CGS Cost Study, five, high-performing, single units were chosen, reflecting the intent to be among the best. A seven-year interval was also chosen with the benchmark plants that did not exhibit cyclical cost performance. Having established the average, the authors of the draft CGS Cost Study used a 4% annual cost escalation rate to establish the future CGS annual cost targets.

By looking over the seven year interval, the significant performance improvements that have been realized over that period are implied by the draft CGS Cost Study to be more representative of the future than a shorter, presumably higher performing period, such as the most recent three years.

The earlier and lower performance is not what those facilities are likely aspiring to accomplish. The draft CGS Cost Study's approach also assumes that the five benchmark plants have reached a plateau in cost performance, rather than continuing to improve. While these plants are currently performing at a very high level and developments such as escalated security requirements provide upward cost pressures, it will be important to monitor future developments to see if adjustments to the targets are in order. The 4% escalation rate is recognized to be an estimate, but is probably on the high side of the range of assumptions in use in the industry.

NEI provides an annualized estimate of fleet-wide production costs. The most recent value is $17.6/MW-hr for the year 2000. (See Figure 1.) A separate tabulation reports the three-year rolling industry average is $17.4/MW-hr. Entergy Nuclear, Inc. (Entergy) has reported the three-year rolling average production costs at its nuclear power plants, Arkansas Nuclear One, Grand Gulf, River Bend and Waterford, as $17, $14, $19, and $16/MW-hr, respectively. Entergy also reported the industry average as $18/MW-hr based on Utility Data Institute and its own internal analysis. CGS' most recent three-year production cost was $17.1/MW-hr. As a large unit, CGS should be capable of maintaining its production costs below industry averages.

IMPROVEMENT OPPORTUNITIES

1. **Establish and publicize the long-term steady-state outage duration goal, and align the organizational priorities accordingly. The concept that "everyone on site has an outage job" should be implemented to improve outage performance and execution.**

   Neither various station publications nor the interviews revealed the existence of a universally shared, normal outage duration target, supported by information on why that target is appropriate, and whether that target can be achieved incrementally or in one step. The power uprate study identifies 30 days for all outages. The fuel cycle assumptions indicate 35 days in 2003 and 30 days in each outage year thereafter. The long-range forecast has 34 days in 2003, 45 days in 2005, and 28 days each subsequent outage year. Interview results revealed a greater diversity of views about what CGS should be targeting, with durations ranging from less than twenty days to the mid-thirties, and achieved at various paces.

   Since excellence in outage planning and execution requires a station-wide effort, further clarity of the outage duration target would be beneficial. For perspective on what other plants are achieving, Entergy conducted seven refueling outages in 2001 and the first half of 2002 with an average duration of 23 days.

   Because the possible load-following directives from BPA could complicate the outage duration optimization process, it may be best to start out by ignoring that potential and striving for the shortest possible outage that will yield a breaker-to-breaker operating run. For a 24-month or 730-day period, an approximate 695 to 700 days on-line and 30 to 35 days of outage may be the optimum goal. Plant management and staff recognize the goal is not merely the shortest possible outage; it is the maximizing generation over the two year period, cycle after cycle.

   The CGS fuel cycle assumptions provide for Effective Full Power Days per cycle ranging from 660 to 672 for the next five cycles. Taking into account some BPA-directed down-powers, allowing for unplanned outages, and recognizing some coastdown capability, the fuel cycle assumptions are reasonable.

The concept that "everyone on site" has an outage job has not been implemented as fully at CGS as at some other nuclear stations, and may represent one of the many steps that can be taken to improve outage performance and execution. It has the added advantage of allowing more employees periodic diversity of job assignments and the experience of " walking in someone else's shoes" to enhance collaboration and teamwork down the road.

NEI has also tabulated the average and median duration of refueling outages across the industry on an annual basis for the years 1990 to 2001. The results demonstrate the dramatic improvements realized during the past decade. (See Figure 2.) For 2001, the average and median values were 37 and 34 days, respectively. Because CGS has historically not experienced as much organizational learning in outage proficiency as others, and having never entered into a refueling outage after nearly two years of operation, CGS is encouraged to avail itself of the methods employed at other successful plants.

2. Improve the processes used for long term planning, capital investment decision making and improving equipment reliability.

There is an enormous variation in capital spending histories across the U.S. nuclear power plant fleet, with recent three-year averages ranging from less than $4 million to more than $45 million. While there are numerous reasons for these differences, one important reason is significant differences in plant needs. It is beyond the scope of this assessment to recommend a plant capital investment spending profile for CGS. However, the interviews did reveal that the CGS organization has further work ahead to specify what capital investments are necessary to achieve the desired level of reliability for the 24-month fuel cycle. Enhancing these processes is integrally connected to the outage duration goal and includes many other optimization efforts, such as more on-line maintenance, completion of the preventive maintenance (PM) optimization program, and other improvement initiatives.

3. Over the long term, look for opportunities to reduce full time equivalent (FTE) staff working at CGS, but not to the detriment of maintaining safety and maximizing generation as higher priorities.

Numerous industry studies are available regarding staffing at nuclear power plants. A recent industry publication reported average staffing levels for all single-unit plants were approximately 850 FTEs (defined as employees, not including authorized vacancies, and long term contractors such as Security). Larger single-unit plants understandably tend to have higher staffing, on the order of 900 FTEs. While there are imperfections in the comparisons and the CGS total appears to be truly all-inclusive, the staffing level at CGS is on the high side of the industry spectrum.

Based upon interview responses and other observations at the facility, CGS has a highly motivated and talented staff. It is fair to say that the organization will be more successful in meeting the cost targets with some modest staff reduction, if properly sequenced with other improvement initiatives.

However, staff reductions are not the recommended immediate priority. Maximizing generation has the potential to yield much greater cost performance improvement. Across the U.S. nuclear fleet, improvements in this area have been very impressive. NEI reported the capacity factor for U.S. nuclear power plants in 2001, including outages, as 90.7%. For the first six months of 2002, the figure is 91.4%. Entergy reported a 98% capacity factor for its five-unit "Southern" fleet in 2001, while its four acquired Northeastern units had a 94% capacity factor, including outages. While such results are by no means easy to achieve year after year, this level of performance is a worthy goal for CGS.

It is logical and necessary to first focus on achieving organizational effectiveness and finding ways to do less work before embarking upon a staff reduction campaign. Reducing rework rates results in less work. Optimizing PMs will reduce the amount of work scheduled. Identifying ways to simplify processes, require fewer organizational "handoffs", and take increasing advantage of technology will require fewer personnel to accomplish the same work. With improved equipment reliability, fewer emerging issues, and improved long range planning, the organization will increase its control over its destiny versus reacting to the challenge of the day. Conducting half the number of refueling outages is also less total work. The United Services Alliance should yield other best practice and resource-sharing opportunities to improve cost performance. After a period of time to pursue these initiatives, a more concerted effort on staffing may be appropriate.

Further to CGS's overall high performance philosophy, consideration should be given to pursuing certification for environmental performance by the International Organization for Standardization (ISO). The ISO is made up of different international standards groups that set management standards to drive quality. ISO-14001 establishes environmental standards. Given the work already accomplished in this area, and to further demonstrate that CGS aspires to be among the best, ISO-14001 certification would provide a capstone to the plant's environmental stewardship initiatives.

OTHER OBSERVATIONS

1. **The Quality organization is perceived by some staff to be lagging in adding value to CGS performance compared to other departments in the organization.**

   Most interviewees expressed the view that the Quality organization had a tough job, and although it was trying hard and getting better, the organization could improve on the value-add of its work products. There was no indication of not fulfilling all regulatory requirements, and the QC function was thought by one interviewee to be very effective. In the aggregate, considering performance-based and not just compliance-based quality functions, most interviewees believe this area to be an improvement opportunity.

2. **There may be an opportunity to establish an enhancement to the existing Incentive Program that is "win-win".**

   Generation is one of the parameters for which incentive payment is earned. Under the current scheme, maximum payout is realized at a 97% capacity factor. There is no further financial reward for performance above 97%. Also, there is no apparent reward for under spending the budget, unless established at the local level.

As noted previously, the ultimate figure of merit is $/MW-hr, over the long term. To the extent costs and/or generation performance are better than the current maximum, BPA enjoys the financial benefit. To say that incentive compensation cannot be awarded because no O&M dollars were set aside is not persuasive logic. It is axiomatic that one should incent the desired result. Since a desired result is strong cost performance, incent the employees to deliver it. To provide an order of magnitude example, a 3% capacity factor opportunity on an annual basis is:

11 days X 24 hours/day X 1150 MW X $30/MW-hr = $9.1 million

Budget under runs represent a similar opportunity. If the staff delivers a result better than the current maximum payout (and, of course, meets safety, reliability, quality and regulatory requirements) why not share 20%-25% of the result with them in the form of incentive pay?

It is beyond the scope of this assessment to design a program, and of course, the appropriate safeguards must be employed to avoid rewarding unintended outcomes (such as underspending the capital program by deferring projects), but there does appear to be a win-win opportunity. Such a modification to the program also may encourage more innovation within the workforce when staff reduction opportunities present themselves.

3. The internal participation on the Corporate Nuclear Safety Review Board ("CNSRB") could be enhanced.

It became apparent during interviews that the CNSRB function is an example of the station's core values. The CNSRB goes well beyond regulatory minimums. Its composition includes very knowledgeable outside members who are considered to add real value. The CNSRB demonstrates the continuous improvement philosophy in action. However, the inside members do not appear to view their participation on the CNSRB as prestigious, nor do they seem to engage in self-critical dialogue to the same degree as the outside members. Appointment to the CNSRB could be changed to something to be sought after, a dimension of career development, something to which others in the CGS organization would aspire. This way of thinking could then be brought into the workplace as a more mature, holistic critique of organizational performance.

4. Consider institutionalizing some enhancements to the process used to develop and utilize performance indicators across the Station.

During the course of the assessment process, information in the form of performance indicators was made available. In general, the information was comprehensive, easily interpreted, and tended to reflect strong performance given the percentage of "green" indicators. Without having a complete appreciation for the entire suite of indicators and their use at CGS, the following possible enhancements are offered:

- Station personnel frequently indicated that their goals are derived from top quartile, or even top decile performance. By just looking at the indicators, this is not apparent. Consider adding a basis section to the indicator page or elsewhere that explains how it is determined that a particular level of performance is worthy of a green designation.

- Another expectation at CGS is continuous improvement. As it relates to performance indicators, one would expect the indicator owner to periodically (perhaps annually) assess whether the performance bar should be raised and by how much. If the indicator page were enhanced to provide 3 or 4 prior period actuals, trends in performance would be readily apparent. As an example, annual person-rem totals for the past 3 years could be provided along with the monthly actuals and projections for the current year.

- For those relatively few instances where performance was not in the green, the indicator page did not detail what the indicator owner was doing to restore performance to the targeted level. This expectation could be established along with the date by which green performance could be expected.

- As a companion step to the above point, accountability on delivering green performance is important. While there is no doubt that CGS has high expectations, it may be beneficial to establish a site-wide, periodic accountability and mutual assistance process to provide a forum for discussing current performance and the actions, barriers and resources required to restore green performance on a schedule consistent with management expectations.

5. The business initiatives beyond the operating nuclear facility are simultaneously a threat and an opportunity.

The direction established for the organization includes dimensions beyond the safe, reliable operation of the nuclear unit, and also involves a diversified portfolio of generating resources and the delivery of other professional services. On the one hand, the growth opportunity and diversity of job assignments is a plus for the organization, both in terms of financial performance and intellectual stimulus. On the other hand, any activity that has the potential to de-focus the organization from its number one priority represents an incremental challenge for leadership. For example, when a portion of the organization is working on the supply of services to another facility, leadership is challenged to do both extremely well. On balance, the advantages appear to outweigh the disadvantages. It would be advisable to periodically assess this issue and confirm that the nuclear priority is not being short-changed in any respect.

6. Periodically look at the composition of the senior leaders to ensure there is an adequate supply of "new blood."

With its attractive work environment and committed workforce, CGS enjoys the substantial benefits of a stable team that is very knowledgeable of the facility and fully committed to its long-term success. While a detailed profile was not compiled, the interviews indicated that the majority of the station's senior leaders (executive team and department managers) were long-term CGS employees. As with many strengths, at some point this may become a weakness. While CGS's succession planning may address this point, it is recommended that when vacancies at this level arise, a conscious decision be made to determine if the vacancy is best filled by a capable "outsider." Fresh perspectives and new dynamics in organizational interactions can rejuvenate the pursuit of performance excellence. Any successful organization must be driving towards some previously unattained goal to be at its best. CGS is encouraged to be mindful of the stimulus that "new blood" may provide, and factor that into personnel decision-making.

APPENDICES

INTERVIEW GUIDE

Columbia Generating Station Management Interview Guide

1. What is the mission and vision of the organization? How is that mission and vision communicated to the organization?

2. How do you use benchmarking? How do you achieve continuous improvement? Will your peers continue to improve cost performance or will they plateau? How do your future targets take this into account?

3. In your experience, what are the major influences on plant performance and thus, cost performance?
   - Leadership
   - The safety culture of management and the workforce
   - Plant material condition
   - Organization adequacy and responsiveness
   - Quality of engineering and design documentation and processes
   - Regulatory environment
   - BWR-specific and industry issues/events

   What major influences do you think affected CGS's costs over the past 3-4 years? What major challenges do you expect to encounter in pursuit of your cost reduction goals? How will you meet the challenges?

4. Why do you think CGS was typically higher than the average of the comparison plants for Direct O&M, Indirect O&M, and Total Costs? (Reference EUCG 2002 Report) Are these opportunities for you? Do you have confidence in your ability to meet the targets?

5. In setting cost targets and emphasizing cost control, what do you anticipate the impact on the workforce's safety culture will be? How are/will you ensure that safety remains the first priority?

6. Describe the health of your relationship with the NRC. Do you anticipate they will have any concerns with escalating focus on cost performance? Do you plan any proactive communications with the NRC?

7. One of CGS's major challenges appears to be both the retention of existing staff and the attraction of qualified and experienced personnel. Do the cost performance targets exacerbate this challenge?

8. How do you generate the capital budget, justify projects, and set priorities? What has driven the capital budget in the past five years? Have you invested sufficiently in the facility? What do you see driving the capital spending requirements next year and in the next five years? (Reliability projects, power uprate, equipment replacements due to wearing out, breakdown or obsolescence, reactor internals)

9. Please comment on your recent, scheduled outage performance, both in terms of duration and subsequent reliability. How much does a "load follower" operating regime affect this goal?

10. Is the station aligned in its priorities cross functionally, and top to bottom?

11. What do you do very well, and how do you know?

12. What is your biggest improvement opportunity?

13. Do you respect the Oversight Organization? Does the organization? How about the Offsite Safety Review Committee?

14. Has the Leadership Academy made an impact? How do you know?

15. Is your incentive plan well structured?

16. Are you prepared for the transition to a two-year cycle?

INTERVIEWEES

Managers and staff holding the following positions were interviewed:

- CEO/CNO
- VP Technical Services
- Engineering Manager
- Maintenance Manager
- Plant General Manager
- Design Engineering Manager
- Operations Manager
- Reactor Operator, Operations
- Craft Supervisor, Maintenance
- Control Room Supervisor, Operations
- Maintenance Employee

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16. *Nuclear News*, Excerpt, July 2002
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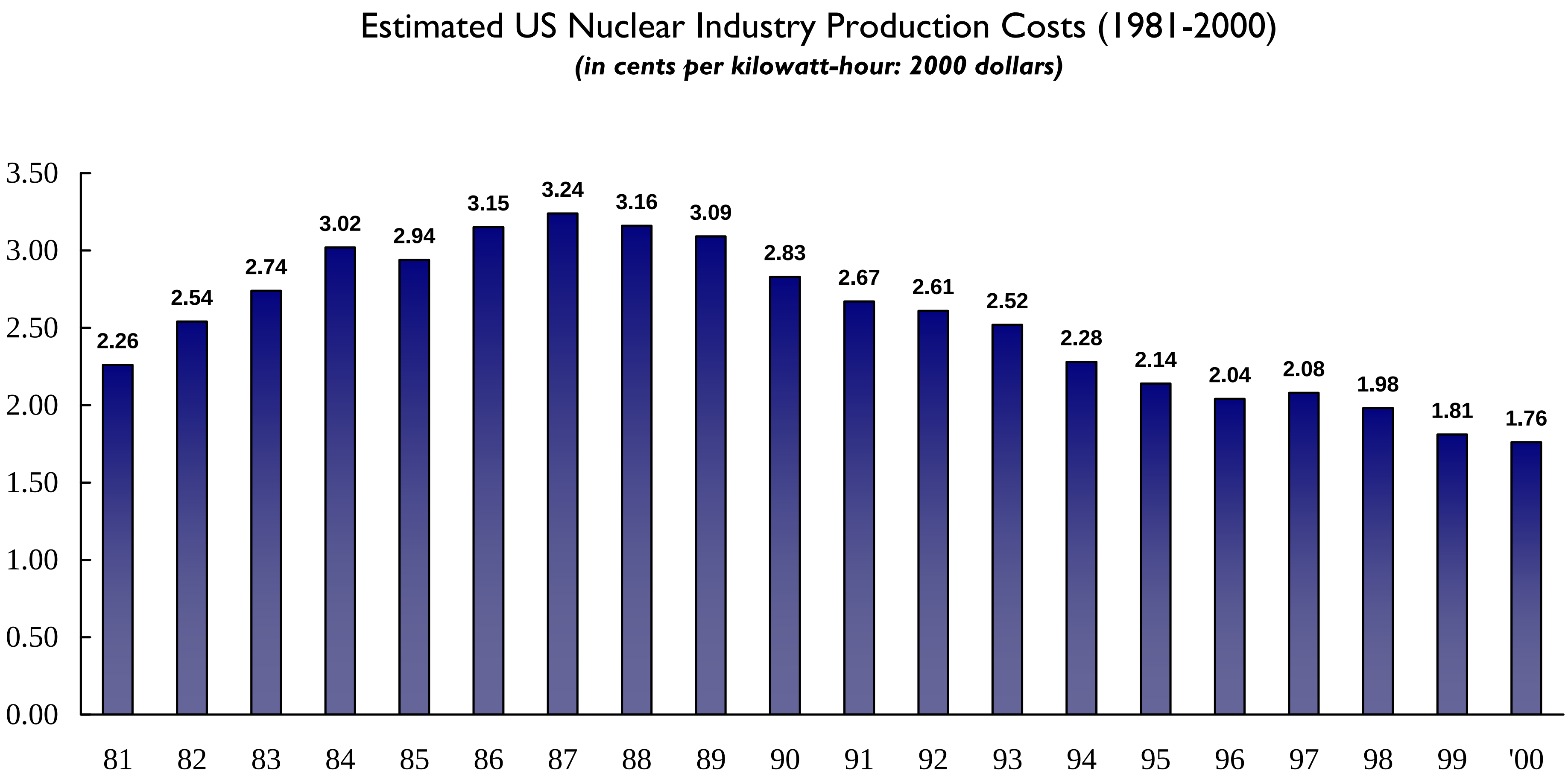
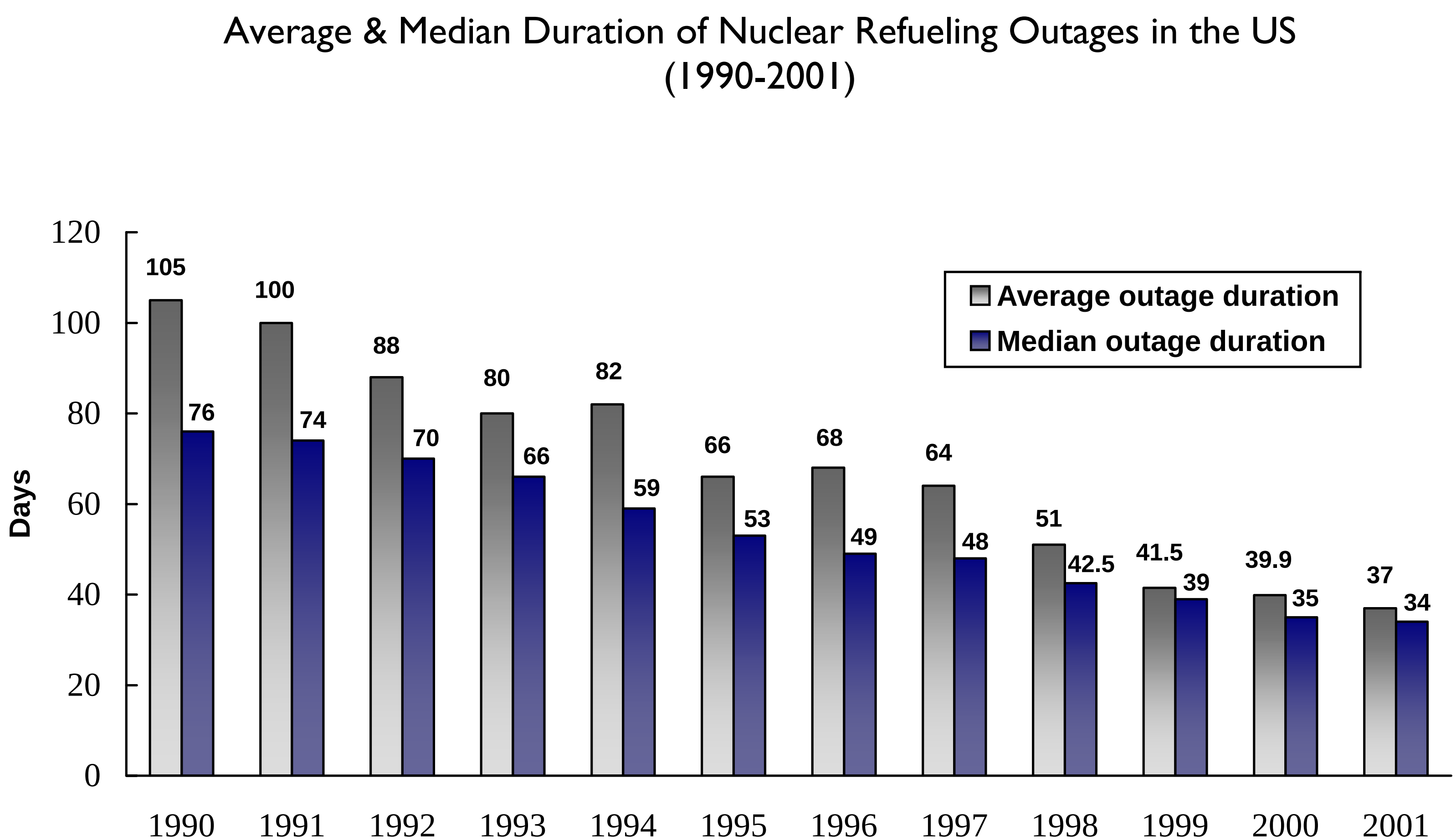
19. *Power, Business and Technology For The Global Generation Industry*, Excerpt, Volume 146, Number 5, August 2002
20. Various Staffing Benchmark Analyses

FIGURE 1 – PRODUCTION COST HISTORY



Source: RDI for 1995 forward; UDI for years prior to 1995

FIGURE 2 – OUTAGE DURATION HISTORY



Source: Institute of Nuclear Power Operators (INPO)
Note: Values do not include data from shutdown units

RESUME OF RICHARD M. KACICH

Richard M. Kacich is a Management Consultant at Janus Management Associates, Inc., which has provided management, economic, and technical consulting services to the nuclear electric utility industry since 1992. Rick is also the Director of Special Projects, reporting to Bruce Kenyon, President of the Generation Group at Northeast Utilities (NU). He was appointed to this position effective April 1, 2001, immediately following the closing of the Millstone sale to Dominion. In this newly created position, Rick is involved in a variety of business activities, including close-out of the auction work associated with the Millstone sale, and the sale of Seabrook Station which commenced in 2001. With respect to Seabrook, he serves as the Seller Representative on the Transition Executive Committee. Rick is involved in the oversight of the various nuclear facilities in which NU has an ownership interest. This includes serving on the Board of Directors for Connecticut Yankee Atomic Power Company (CYAPCO), Maine Yankee Atomic Power Company (MYAPCO) and Yankee Atomic Electric Company (YAEC), as well as Chairing the Connecticut Yankee Oversight Committee and Co-Chairing the CYAPCO and MYAPCO Joint Oversight Committee. He also serves as the Chairman of the Seabrook Nuclear Safety Audit & Review Committee (NSARC).

From November 1998 through March 2001, Rick was the director of the Business Services organization at NU. He was responsible for managing performance and financial affairs for Millstone Station, and managed consolidated business functions for the nuclear group. He oversaw the bidding of Millstone output to the grid, and managed interfaces with ISO-New England and the entitlement contract customers for Millstone's output. He served as the controller for Millstone Station, provided internal business reports to senior management and to the NU Trustees, provided expert testimony on nuclear prudence and restructuring issues, and coordinated the interface with numerous external groups. In March 1999, he was appointed to the Connecticut Yankee Board of Directors. He served as the on-site lead for the Millstone divestiture process, including the coordination of on-site due diligence, was the lead presenter during the management presentations, and served in the role of co-chair of the Dominion/Millstone Integration Team. He also served in the Station Emergency Response Organization in the capacity of Executive Spokesperson at the Hartford Armory.

Born in St. Louis, Missouri, he earned a bachelor of engineering degree in nuclear engineering from Rensselaer Polytechnic Institute (RPI) in Troy, NY in 1974. The following year he received a master of engineering degree in nuclear engineering from RPI. While at RPI, he was an instructor at the RPI Critical Facility, wrote A Manual of Experiments for the Rensselaer Reactor Facility, and held a senior reactor operator's license. In July 1992, he earned an Executive MBA from the University of Hartford.

He joined NU in 1975 as an assistant engineer. He participated in the initial core loading and start-up testing of Millstone Unit 2 during his assignment to Millstone Station in 1975-1976. He subsequently served in various positions in the licensing organization and was promoted to licensing supervisor in 1982. In 1987, he assumed the role of manager, Generation Facilities Licensing, which involved coordination of all licensing activities for NU's fossil, hydroelectric, and nuclear generating facilities. In March 1992, he was promoted to director, Nuclear Licensing. From December 1993 to February 1996, his duties expanded as director to include Nuclear Planning, Budgeting and Financial Analysis and Nuclear Safety Engineering, as well as Licensing. For seven months beginning in February 1996, he assumed the new position of director, Nuclear Operational Standards, responsible for all financial analysis and budgeting functions, and the Nuclear Excellence Plan designed to recover Millstone Station. In September 1996, he was appointed director, Special Projects, responsible for coordinating the interface with numerous external groups, for preparing responses to PUC interrogatories, providing expert testimony on nuclear restructuring and prudence issues, and administering and upgrading the Nuclear Group Policies and Millstone Station Administrative procedures.

He is a member of the American Nuclear Society and is a registered professional engineer in the state of Connecticut.

Kacich has participated in numerous owners groups and industry activities, including the INPO APOC for Millstone Station, the SEP Owners Group (chairman), the BWR Owners Group, the Nuclear Utility Fire Protection Group, the Nuclear Utility Group on Environmental Qualification, the Nuclear Utility Backfitting and Reform Group, and various Atomic Industrial Forum and NEI activities.