

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672
2672 SCOMM 120 HOUSE SPEC. COMM. UTILITY RESTRUCTURING, 1999-2000

For example, in the case of a line outage, 92 percent of customers are considered to have had service restored when the substation circuit breaker is re-closed, regardless of the number of customers on the line who actually remain out of service. Therefore, the installation of a few thousand sets of line-sectionalizing disconnects or branch line fuses has drastically lowered the reported average customer minutes of interruption (ACMI) without regard for the duration of outages or the number of customers who remained out of service.

Similarly, Meter Readers are instructed to "punch the button" on their hand-held meter reading devices when they have a pleasant encounter with a customer, but not to record their unpleasant customer contacts. Thus, when the "encountered" customers are surveyed, the customer satisfaction index is artificially high.

Growth of Non-Union Utility Affiliates.

Not only are we experiencing a serious decline in the number of qualified personnel and good paying jobs in the utility industry, but we are also seeing the monies being recovered by the utilities through their CTC charges being utilized to spawn non-union utility company subsidiaries. Here again, we stood with the utilities in defending their billions of dollars in "stranded assets." We helped them gain the rights to go into non-traditional business ventures, and the right to utilize their established corporate identities (names and logos). We did this with a handshake agreement that success for them would translate into union job opportunities in the new affiliates for our members. Supposedly, the new jobs would help replace those lost to competition and down-sizing in the deregulated utilities. In spite of the strides made in protecting stranded assets through CTC and in opening up opportunities for a host of new business ventures, union workers on the Southern California Edison property have yet to see their first hour of work in any of Edison's new affiliates. (A few business ventures have been purchased where the workers were and are represented by a union.)

Workers Pensions Under Assault.

I'm sure you are aware of the move in recent years by big corporations across the United States to tap into the pension funds of their workers. I believe that any attempts to tap into, or reconfigure, workers' earned pension benefits in an effort to increase corporate profits is one of the lowest and most severe forms of attacks on our citizenry. Throughout our working years, a portion of the fruits of our labor is set aside for our use in our "golden years" when we can no longer provide for ourselves. These monies were earned by the workers, they belong to the workers, and no legitimate corporation should attempt to convert these funds into corporate "profit centers" at their workers' expense. (Although not considered a pro-labor publication, much has been written about this problem by the Wall Street Journal in recent months.) After 18 months of bargaining, we are deadlocked with the Edison Company over their attempt to adversely modify our membership's pensions.

While Edison has not indicated that they intend to attempt to "impose" (force) our members into their newly developed "cash-balance" pension plan, they do intend to force all non-represented employees into their new plan this year. This plan could result in greatly reduced pensions (and greatly reduced company funding) for younger and future employees.

Conclusion: I believe it is far from certain that real bottom-line energy cost savings will trickle down to residential and small business consumers in the state of California as deregulation unfolds, but that's a subject I am not going to address here. I can tell you that deregulation, to date, has significantly reduced the number of good paying full-time jobs in the California utility industry. These were jobs by which California residents could support, raise and educate their families. The replacement jobs within the utilities are significantly downgraded in quality from what Californians enjoyed a short while ago. Fortunately, or unfortunately (depending on our point of view), stockholder interests, executive compensation, bonuses and stock options seem to be holding up well in the deregulated marketplace. It is possible that residential and small business consumers and the workers in the electric utility industry may benefit when/if actual competition for electric services comes to California. However, we must all remain vigilant to see to it that these promises develop as deregulation and competition unfold. If we do not remain vigilant, the quality of electric service and the jobs within the electric utility industry will further erode while consumer prices climb. If this should be allowed to happen, all Californians will be losers! Thank you very much for this opportunity to share these thoughts with you. I look forward to working with you in any way I can to help make California a better place.

Addendum To Testimony Of Rae E. Sanborn Before the California Assembly Utilities And Commerce Committee

The promise of electric utility deregulation in California was to save consumers money by creating competition in pricing and by better use of fuels, customer choices of service levels, etc. It absolutely was not intended that cost savings would be obtained by reducing the quality of workers, the quality of jobs, the safety of workers, or by jeopardizing the reliability of electrical service. Near the end of the written remarks I submitted to you earlier, I stated that we must be vigilant if the promise of deregulation is to be achieved. I want to offer you a few examples of what I feel we must watch for and protect against.

TRAINING AND QUALIFICATIONS OF WORKERS.

There are a number of involves potential dangers to workers, the public and system reliability. Some of these are:

Meter Installers (Metering work has recently been "unbundled" by the PUC.) Meters are basically sealed package units which are installed on homes and buildings to measure a customer's use of electricity for the providers. These "cash registers" of the electric utility industry are usually installed or removed uneventfully. However, when a new meter socket has been improperly installed, or if the meter has been tampered with, corroded or otherwise damaged, this task can be very hazardous and result in a very serious electrical shock and/or flash burns to workers or customers. (A number of workshops have been held to develop minimum training standards for employees who will do this work.) **Steam Plant Maintenance Workers** Recently, Edison proposed a 1-year (vs. the existing 3-year) apprenticeship for training new steam plant Electricians and Instrumentation Technicians! In the past, when utilities had a long-term view of their business and a very specific obligation to serve their customers, such a proposal would never have come up. This proposal has not been implemented because we refused to allow the company to trivialize the training for these positions.

However, in the unregulated and unrepresented plants of the future, this type of get-by-quick-and-cheap mentality is likely to prevail. If so, it will definitely threaten system reliability, worker safety, and job quality.

Test Technicians, Maintenance Electricians and Power Station Operators.

Edison is now significantly understaffed in these critical positions. A hodgepodge of retired and contract workers, and employees prematurely promoted or transplanted from related classifications, are being used to supplement these positions. An electric utility system is intricately integrated, and its components must "fit" perfectly together to work properly. Faults in electric utility system protection schemes can result in major system failures. An analogy may be drawn to computer systems: there are many different kinds and most of them are good, but they cannot all be modified or repaired in the same way. Software or hardware that works well in one system may cause another to "crash." Since utilities have cut their full-time Operating, Maintenance and Test crews, outsiders are being utilized in ever greater numbers to do this work. Some may be less than qualified. Few are fully familiar with the intricacies of the local protection schemes they are being asked to work on.

Line Crew Personnel and Work Methods.

Edison now also has a significant shortage of Linemen and related classifications. They are attempting to address this problem by refilling positions and with the use of contractors and new work methods. Recently, Edison proposed to use helicopters to lift line workers on and off steel transmission towers and aerial conductors. Under the Company's proposal, the linemen would climb into a large basket suspended by rope a few hundred feet below a helicopter. The "chopper" would fly them to the work area and hang them and their basket on the top of a tower or on the mid-span of a de-energized high-voltage conductor. After the workers performed their work, the chopper would move them to another location or return them to the ground. In addition to the obvious concerns about this proposal, Edison insisted that the helicopter pilots they wanted to use, to do this portion of our work and transport our union members, must remain non-union. As such, we would have no say in their selection, qualifications, training, adherence to safety rules and procedures, etc. Obviously, we have not agreed to the Company's proposal. We are willing to work with Edison to develop new work methods. However, it is not necessary for work to be done non-union, nor for management to have unfettered control over the lives and safety of its workers, for new work methods to be feasible.

Oversight Needed.

The electric utility industry is changing under deregulation. As utility deregulation unfolds, we are beginning to see a dangerous lowering of standards in construction, maintenance and operation of our high-voltage electric systems. As we have recently seen, mistakes on high voltage systems can cause horrendous explosions and can blackout multi-state areas.

We license lawyers, real estate salespeople, hairdressers and even barbers, but we have no license or minimal training requirements for utility workers in the critical positions. Setting reasonable standards for attracting, training and retaining highly qualified utility workers should be seriously considered.

I hope that my presentation has helped to shed some light on "the California experience" to date. I also hope that you will share some of my concerns for the adverse impacts on California's citizens and workers because, in the bottom line, our assessment of how California is doing is really all about how our citizens and workers are doing.

Rae E. Sanborn, Business Manager/Financial Secretary, IBEW Local 47

TABLE 10.4
Stakeholder Identified Impacts and Views Relating to Utility Employees

Description of Stakeholder	Impact of Retail Competition Identified	Views Concerning Employees
Labor Representative	Cost-cutting measures and work force reductions are being implemented throughout the electric power industry. As a result, the existing work force and the electric systems are stressed to a point that threatens worker safety and public safety.	Public safety and worker safety must be maintained, as electric power companies cut staffing levels to enhance profitability.
Utility Consultant	As the energy utility industry becomes more competitive it is likely that the established players are going to get leaner. The work force will be reduced likely without much consideration for skill retention. Those with highly competitive skills will leave. Others will be forced out. This has been the ongoing experience in the telecommunications companies.	Part of the problem is knowing which skills the company requires and how it will communicate this to and reward those who stick with the company, as well as show to attract new talent.
Utility Consultant	The average age for most organizations in the electric utility industry is actually decreasing due to the downsizing efforts and early retirement packages being offered. This is leaving the existing workforce with a drain in technical expertise to be able to handle most situations. Since the downsizing is still fairly new, the impact on the industry has yet to be felt fully.	There are two strategies that companies facing this issue can pursue. The first is to utilize contract personnel for a short term where there is a lack of critical skills and experience. If this option is used, then it is suggested that they have plans in place for technology transfer as part of the contract. The second option to overcome the loss of experience is to establish well-structured and understood processes and procedures.
Labor Representative	Our organizations (NECA & IBEW) have anticipated workforce shortages in the industry with or without electric deregulation. Deregulation has and will continue to cause large shifts of workers from the regulated sector to the private sector. Are the private sector entities prepared to respond to the re-training needs of the older workforce and attract and train new people? Deregulation may also cause an increased demand for skilled workers, thus compounding the problem. This demand could come from the increased number of firms entering the market, the increase in energy services that will be offered to the consumer, and the overall expansion of the electrical industry.	Our apprenticeship programs are increasing their efforts to recruit more qualified applicants. We are also continually updating the training program with the latest teaching methods and industry technologies.

Description of Stakeholder	Impact of Retail Competition Identified	Views Concerning Employees
Utility Consultant	ENERGY SUPPLIERS WORKFORCE: We are seeing a lot of downsizing by utilities as they try to prepare for competition. Early retirement packages are becoming common place for all levels of the workforce. These retirement packages are being expensed and can become part of the rate base, which provides additional benefits for utilities that have been making too much money. These cost reduction measures, while reducing operating costs, are not causing a corresponding reduction in energy rates to existing customers; but will enhance cost competitiveness in the future. A lot of expertise is being shuffled out the door, leaving a younger, less costly employee base. However, this younger group, while certainly intelligent and eager, do not possess the experiential knowledge and understanding of the utilities systems of the older workforce and we have seen that customer service suffers as a result.	
Utility Consultant	CUSTOMER'S WORKFORCE: On the customers' side we are seeing large ESCOs coming to energy intensive clients with programs and offers to take over and manage the customers HVAC, lighting and other utilities. This can displace the existing workforce, although in some cases the ESCO will hire the facilities personnel to continue running the systems. There are similar issues to the utilities; a lot of site and systems specific experience is lost in the transition. Chauffage - the offering of energies and related services on a cost per square foot basis - is being considered as an option to replace on-site personnel.	The concerns are that an aging but qualified and experienced workforce is being displaced with the intent of cost reduction. It has been our experience that in most cases this workforce has the best understanding of the energy systems whether it be the utility or the customer's facility and in many cases with their experience, they are an IRREPLACEABLE source when analyzing systems for cost reduction strategies. It is our concern that cutting this experience by removing an experienced workforce that typically has 10 to 15 productive years left, in order to realize immediate savings is short sighted. Especially when this experience can be instrumental in the effective transition to a deregulated environment. We realize that there are situations where individuals may not be contributing but in our building analysis and dealings with utilities we have found the experienced and qualified workers to be an asset to developing cost reduction strategies for our clients.

Description of Stakeholder	Impact of Retail Competition Identified	Views Concerning Employees
Utility Consultant	At one of the utilities I represent, it is safe to say that the average age of linemen and substation repairmen is in the late forties. In the line dept., 56 percent of the linemen are over the age 45. In the substation repair dept., 60 percent of the people are over the age 45. At the present time there are no plans in place to replace the aging workforce. I know that some people are hoping to be able to go to the trades and be able to hire qualified journeymen, but we also see their numbers decreasing in the state.	Even if you are able to hire a qualified journeyman, it still takes time for them to become familiar with the specific utility's working practices. It has been stated that it takes 6-8 years to make a good qualified journeyman in the line and substation dept.; 4 years in apprenticeship and 2-4 years to learn the system and ojt. Taking the above into consideration, it appears we could be running into a shortage of qualified people in the next 5-10 years. In my opinion, the concentration has been on reducing numbers, not retraining and improving the skills of the workforce.
Utility Services/Consulting (General Physics Corp.)	Recent statistics state that approximately 42 percent of the technical utility workforce has been lost over the last five years. Those who left were typically the most senior (and most experienced) workers within those organizations. GP works at approximately 100 power plants each year. Our experience is that most utilities have stopped "downsizing" and are now implementing programs to attract and retain new employees with a "grow your own" philosophy. This philosophy involves providing "top quality" training and opportunities for advancement that entice the employees to remain. The more progressive companies are including "technology-based" training (e.g. CBT, Distance Learning, etc.) to meet these training needs. Finally, most (over 90 percent) of utilities are implementing cross-training or multi-skilling programs to create highly-skilled workers that can perform multiple tasks. This allows the utility to do more with less.	It is also important that utilities be proactive in preparing for the turnover of the aging workforce. Many utilities are capturing the knowledge of the aging workforce now, before they walk out the door. By proactively planning and preparing their training programs, the utilities are in a position to train new personnel quickly with high efficiency and effectiveness.
IPP – Coastal Power Corp.	We have experienced difficulty in identifying skilled professionals with experience in the domestic energy market. As the market continues to deregulate, individuals with experience in power development and marketing will be harder and harder to find.	The likely result will be a migration from other energy-related fields such as natural gas marketing, as well as unrelated fields such as finance, business development, and industrial marketing. During this phase, employers will be challenged to train and keep a skilled workforce.

TABLE 10.5
Potential Impacts of Retail Access on Utility Employees

Impact	Likely Effects	Remedial Action	Statutory Changes Required
Staffing Reductions due to cost cutting.	Reduced levels of skilled employees. Could increase productivity and reduce pressure to increase rates. Increased profits/reduced rates. If reductions reduce workforce below levels necessary to adequately maintain plant & services, increased reliance on contractor and outsource labor.	No action necessary if reliability, efficiency and emergency response not adversely impacted. Performance based standards or cost of service review could be applied to create financial incentives/penalties.	None required for jurisdictional utilities. Restructuring legislation may retain some form of regulation for distribution and transmission functions.
Staffing reductions due to mergers and acquisitions.	Staff reductions may not be geographically uniform. Efficiency and productivity benefits may be realized based on economies of scale.	Regulatory and merger approval authority should specifically include consideration of workforce impacts, and authority to impose conditions if impacts are adverse. Mergers could be used as opportunity to impose financial incentives/penalties for reliability, efficiency and emergency response performance.	Legislation may be required to strengthen authority.
Staffing reductions due to technological improvements.	Productivity, profitability and performance should increase. Risk that some players may seek to install expensive, performance enhancing technologies under regulation to prepare for competition, enhancing competitive position at ratepayer expense.	Regulatory review of jurisdictional utilities. Administrative review of stranded cost claims. Oversight through regulatory proceedings.	None required. Restructuring legislation may retain some form of regulation for distribution and transmission functions.
Staffing growth due to new services and offerings.	Creates new demand for broad range of staffing capabilities. Increased demand could lead to wage increases and worker shortages in the near term.	Enhanced cooperation between market participants and educational/training institutions. Improved in-house training and development programs.	None.

Impact	Likely Effects	Remedial Action	Statutory Changes Required
Staffing growth due to strengthened regulation of monopoly functions.	Regulation of non-competitive functions, such as transmission, distribution and metering, may result in partial reversal of any trends of staffing reduction. In turn, these could raise the costs associated with these functions, and reduce net savings associated with restructuring.	Comprehensive regulation of remaining monopoly functions can ensure efficient system operation and safety. Performance based incentives and penalties may offer opportunities for cost savings.	Regulatory responsibilities and authority must be detailed in any restructuring legislation.

TABLE 10.6
Potential Impacts of Changes in Employment Trends on Universal Service & Reliability

Impact of Workforce and Expense Reductions at Utilities	Likely Effects	Remedial Action	Statutory Changes Required
Increased emergency response and repair time.	Increase in costs associated with emergency interruptions. Delay in service restoration. Potential for allegations of discriminatory service restoration schedules.	Retain/enhance regulatory authority over T&D sectors. Establish and enforce comprehensive emergency response service quality standards. Consider performance based regulatory systems to apply incentives and penalties.	Regulatory responsibilities and authority must be detailed in any restructuring legislation.
Increased customer inquiry and complaint resolution time.	Reduced customer service personnel staffing could increase response and resolution time, while decreasing opportunities for "human" resolution of problems. Automated systems could improve response time and information, and more efficiently direct complaints and inquiries.	Establish and enforce minimum service quality standards for customer response and resolution. Consider performance based regulatory systems to apply incentives and penalties.	Regulatory responsibilities and authority must be detailed in any restructuring legislation.
Diminished service quality.	Absent clear regulatory standards or direct profitability feedback mechanisms, service providers may face an incentive to allow service quality degradation in order to enhance short-term profitability.	Establish and enforce minimum service quality standards. Consider performance based regulatory systems to apply incentives and penalties. Collect and disseminate service quality performance data to customers.	Regulatory responsibilities and authority must be detailed in any restructuring legislation.
Increased outage and incident rates.	Maintenance deferral and staffing reductions, as well as enhanced complexity associated with retail competition could lead to short and/or long-term degradation in reliability and increased incidence of service disruptions.	Establish and enforce minimum service quality standards. Consider performance based regulatory systems to apply incentives and penalties. Collect and disseminate service quality performance data to customers.	Regulatory responsibilities and authority must be detailed in any restructuring legislation.

Impact of Workforce and Expense Reductions at Utilities	Likely Effects	Remedial Action	Statutory Changes Required
Cost shifting to distribution entities could increase rates.	Absent comprehensive cost allocation process, utilities may have incentive to shift costs related to overall system reliability to distribution sector, where regulation is anticipated to remain. As a result, costs normally shared among a broad base of customers may be shifted off customers that take at transmission level.	Initiate and complete comprehensive cost allocation process to fairly assign costs prior to opening of retail access markets. Adopt and enforce affiliate transaction rules to prevent future cost shifting or unfair cross-subsidization.	Regulatory responsibilities and authority should be detailed in any restructuring legislation, with directive to complete cost allocation process and adopt affiliate rules prior to opening of markets.

TABLE 10.7
Policy Options Relating to Utility Employees

Policy Option	Method of Implementation	Advantages	Disadvantages
Resolve Market Uncertainty	Adopt clear timetable for restructuring activities, with date certain. Ensure early resolution of issues impacting employment levels.	Addresses the uncertainty about competition that has motivated labor cost cutting practices.	Has no effect on industry wide trends aimed at reducing labor costs.
Impose Staffing Requirements	Establish regulatory and/or good practice standards establishing minimal staffing levels for regulated entities (Today, regulated utilities. Under competition, regulated distribution and transmission utilities.)	Sets staff levels to ensure safety, reliability, and emergency response. Provides assurance of cost recovery for labor expenses. Removes incentive to cut labor costs to improve profitability.	Minimizes flexibility in staffing decisions. Requires administrative oversight. May remove incentives for productivity improvements. Imposes costs that are passed onto customers.
Impose Performance Standards	Establish performance mechanisms for application to regulated entities today and under retail competition.	Allows businesses maximum flexibility in retaining labor force best suited for reduced costs as well as safety, reliability, and emergency recovery.	Requires monitoring & oversight. Potential for gaming if standards not set properly.
Create Legal Liability for Losses Relating to Inadequate Staffing	Create and enhance legal mechanisms for imposing legal liability on utility service providers whose failure to maintain an adequate work force gives rise to unnecessary or unavoidable property losses or personal injury.	Allows businesses to manage risk of liability directly through staffing decisions. Creates judicial mechanism for adjudging responsibility.	Because so many system failures are related to forces beyond the control of the service provider, establishing fair rules for liability may be difficult. May encourage excessive litigation.
Market Response	Allow competitive market forces and customer response to ultimately determine staffing levels.	Allows markets to assign appropriate value to system reliability, safety, and emergency recovery. Avoids regulatory oversight.	Because electric service is deemed an essential service, discriminatory practices could result. Due to time lag in hiring and training qualified personnel, service quality and safety declines could take years to restore.

MODELING

Analysis of Generation Competition in Alaska

To assist policy makers in the State of Alaska in understanding the potential impacts of electric market competition, this study was undertaken to estimate the impact on the Alaska interconnected utilities of wholesale competition. The underlying question being answered is: If Alaska establishes a competitive power market, how will it impact electric power prices and the profitability of the Alaska utilities?

Modeling competitive markets is highly dependent upon the assumptions that underlie the analysis. Projections of fuel costs, plant operating characteristics, the timing of new entrants, and load growth, as well as many other input variables, can have significant impacts on modeling outputs. To accommodate this source of uncertainty, this study utilized scenario analysis to characterize the impacts attributed to several key market and generator input variables.

This study was conducted on the heels of a central dispatch planning study completed by Black & Veatch International for the APUC in October 1998. In order to provide consistent and useful results to the APUC, this study has relied on input assumptions data, and projections developed for the Black & Veatch effort to the maximum extent possible.

Overview of Methodology

The impact of wholesale competition can be analyzed by the modeling of utility costs, generation, and sales revenues under a market environment. In this study, a market simulation model was used to simulate generation dispatch in a pool environment. The stacking model dispatches generation to meet load based on generator cost, and calculates the market prices that result when the last generator is dispatched to meet the last increment of load. A detailed description of the stacking model is included in Appendix 4, and the input assumptions used in the model are included in Appendix 5.

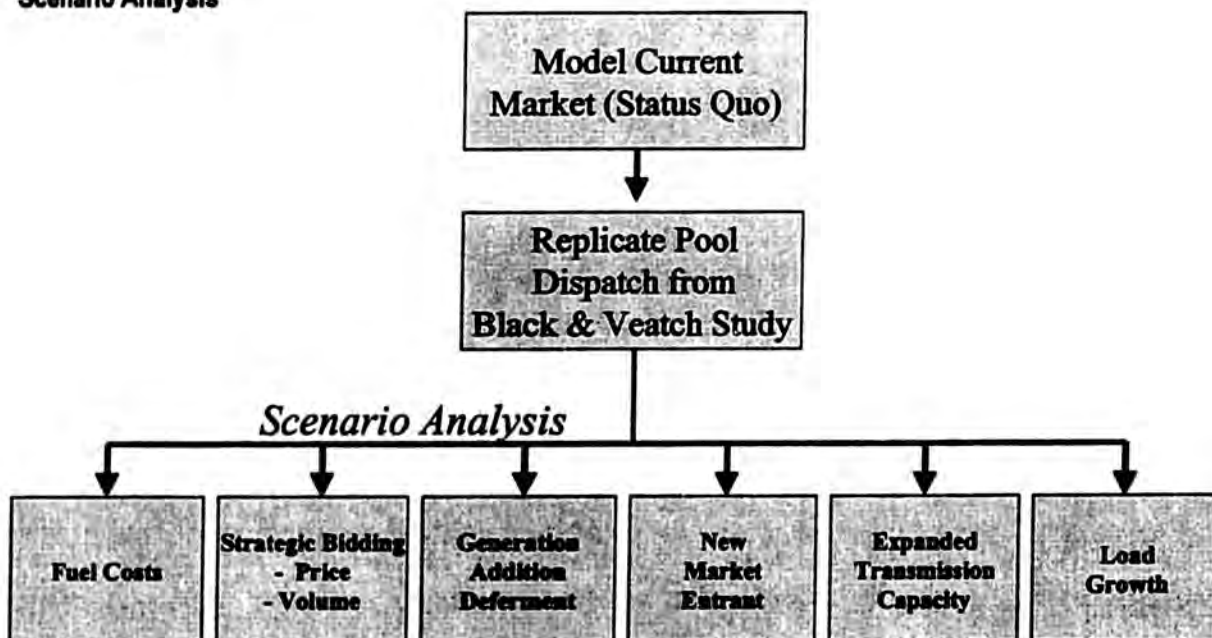
The stacking model is simple to use and easy to understand. It adequately captures the essence of a competitive market for the purposes of planning and scenario comparisons. It is not a daily operation model for real time dispatch and trading. For the purposes of estimating future market behavior, more complex optimization models that account for demand and supply uncertainties do not necessarily yield more accurate results. The accuracy afforded by more detailed production cost simulation models is irrelevant in the face of the large range of outcomes that result from input value assumptions and future

uncertainties. The simplicity of the stacking model allows it to be used for scenario analysis and estimation of market outcomes under a range of assumptions for input values and market conditions. In addition, strategic bidding behavior of market participants can be modeled through selective alteration of plant parameters and market behavior of competitors.

The development of market simulations was conducted in several steps (see Figure 1). First, the model was run to simulate current conditions of the interconnected utilities. This is the Status Quo case. Then, the model was used to simulate coordinated dispatch between the utilities. This scenario is intended to simulate the Black & Veatch analysis, and was conducted to validate that the two modeling approaches produced consistent results. Based in this scenario, the model was used to investigate the impact on utility costs, sales and total revenues of various market and input assumptions. Six different areas were addressed in the scenario analysis:

1. Fuel cost differences between the utilities;
2. Strategic bidding behavior, including increasing generation bid prices above marginal costs, and decreasing supply volume;
3. Deferring planned generation additions;
4. Allowing new market entrants;
5. Reassigning and expanding transmission capacity; and
6. Varying load growth forecasts.

FIGURE 1
Scenario Analysis



In addition, the development of stranded cost estimates from the results provided in this analysis is straightforward. A commonly used methodology for the estimation of stranded costs is the lost net revenues method. Stranded costs are estimated by calculating the net present value of the difference between the utility revenues under regulation and under competition.

For each scenario, the model simulated wholesale market competition through the year 2017.

Major Structural Issues

In the design of competitive power markets, there are a number of structural components that can have significant impacts on the resulting market prices. In addition, the behavior of market participants can also impact market outcomes. For the purposes of this study, several assumptions were made regarding the pricing and availability of transmission capacity, the pricing rules used in the power pool, participant bidding behavior, the exercise of market power, and consumer behavior.

Transmission: The market simulation in this analysis included the interconnected utilities in Alaska's rail belt. There are significant transmission constraints in this area, particularly running south to north from the Anchorage area to Fairbanks. This study assumed that dispatch in the competitive market would be based on generation cost, and that only transmission limitations and system reliability issues would alter dispatch order. Given the limits on transmission capacity, this dispatch rule results in the formation of three zonal market prices within the railbelt system.

There are a variety of transmission pricing regimes in use in the lower-48 and internationally. The most well accepted and standard transmission pricing scheme in use in the US is the postage stamp tariff form adopted by FERC in the *Pro Forma* tariff. In this analysis, we assume that an open access, postage stamp tariff is in use by the participating utilities, and that no transmission owner is able to capture differences in regional market prices through transmission pricing. In addition, the study assumed that there would be no pancaking of transmission rates. Transactions using the transmission systems of several utilities pay only once for such usage.

Determination of Market Price and Bidding Behavior: This analysis assumes that the competitive market will consist of a centrally dispatched power pool, in which the pool determines dispatch order based on generator bid prices. Except in the scenarios in which generators are assumed to exhibit strategic pricing behavior, all generators are assumed to bid their variable operating costs, which

consist of fuel costs, and fixed and variable operations and maintenance costs. The market clearing price is the bid price of the last unit dispatched to meet load.

Market Power: Beginning with the introduction of electric competition in the United Kingdom, the exercise of generation market power has proven to be a substantial problem for market restructuring efforts. This modeling exercise assumes that generators will not bid strategically, that is, that they will always bid their variable costs. In order to assess whether any generators could exercise market power, several scenarios were run to assess the impact of strategic bidding behavior. However, this study has not examined all possible sources of market power abuse.

Consumer Behavior: The model does not consider demand responsiveness to price. The analysis used the same customer load forecast in most of the scenarios. A few scenarios are included that show the impact of changes in load forecasts, but again, these scenarios do not include any strategic behavior of customers in response to market prices. Customer behavior can have an impact on market prices. For example, in the pool structure operating in California, schedule coordinators submit load forecasts that include incremental and decremental loads depending on the market price in each hour.

Estimating Market Clearing Prices

The stacking model produces market clearing prices that reflect the bid price of the last generator dispatched for that hour. For the base case, the bids match the total variable cost of fuel and operation and maintenance costs. All generators that are dispatched for that hour receive the market clearing price for their output.

Figure 2 depicts the zonal market clearing price, by hour, for base case pool dispatch in 1996. This scenario assumes coordinated dispatch among the railbelt utilities, and the position of existing transmission constraints. The price differentials between regions represent the varying costs of generation in the three regions, less economic energy exports and imports given existing transmission capabilities. The oscillation in market clearing prices shown in the top 1000 hours of the load duration curves are due to different units being able to send power North to GVEA because of variations in the native demand requirements in CEA and MLP service territories.

FIGURE 2
Zonal Market Clearing Prices for Pooled Dispatch in 1996

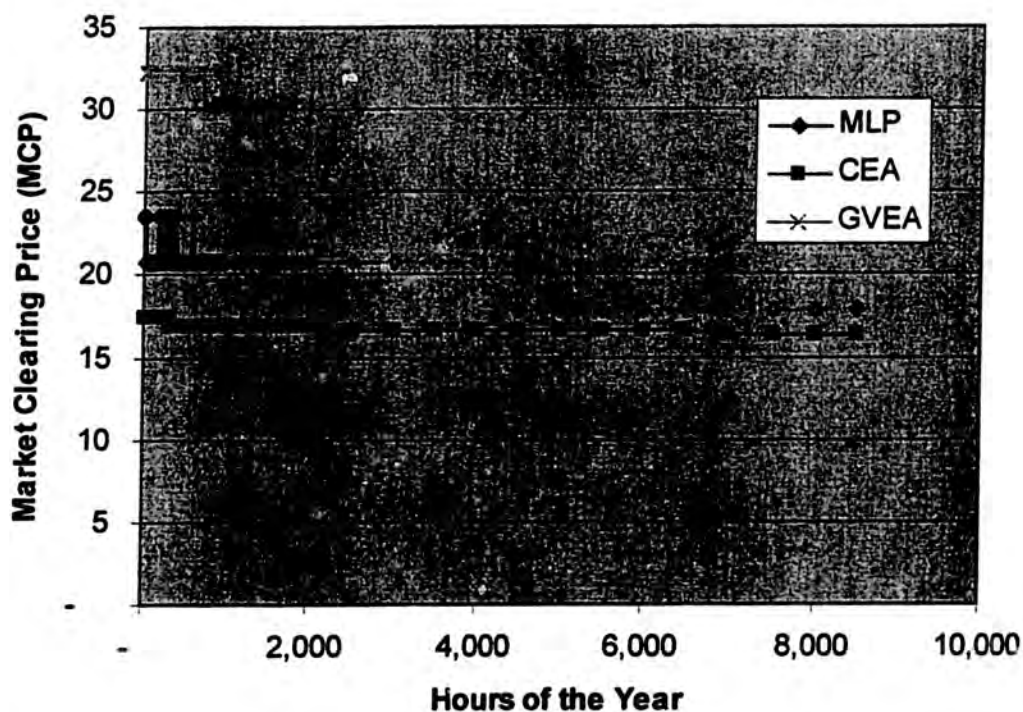


FIGURE 3
Zonal Market Prices for Study Period, Pool Dispatch

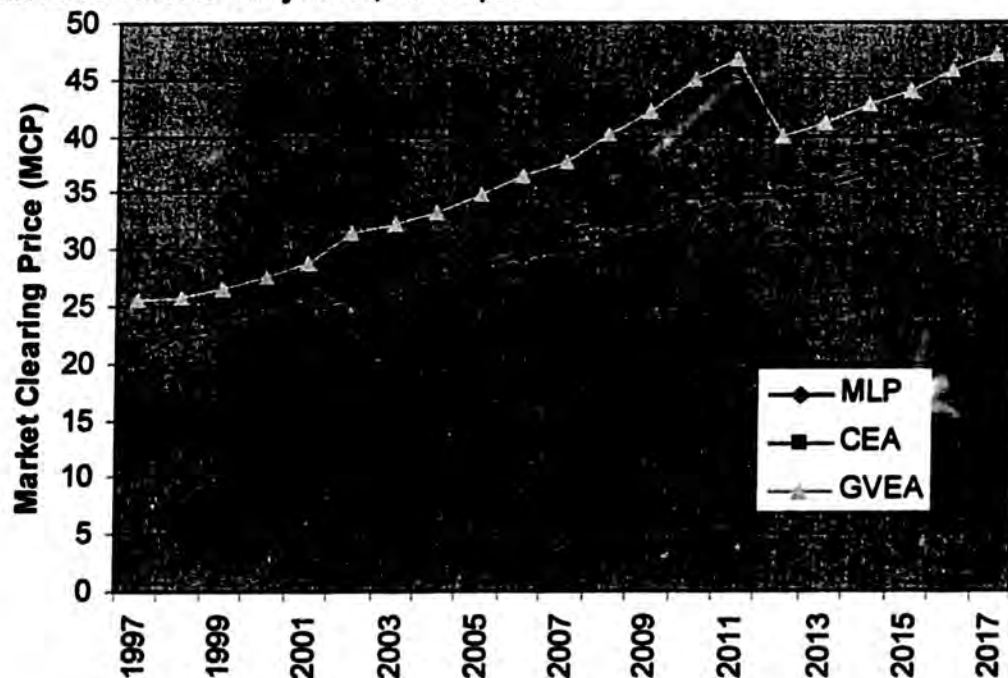


Figure 3 illustrates the difference in zonal market clearing prices over the study period. The drop in prices for GVEA corresponds to the planned addition of significant new capacity in that year.

Scenario Analyses

The following section summarizes the results of each market competition scenario. Analysis results are provided in the form of total sales (MWh) by utility and net present values of revenues, costs and profit by utility, over the study period. Scenarios are compared to a common case (Pool Dispatch Scenario) in order to compare the relative impacts of each market restructuring scenario.

Status Quo Case

The Status Quo scenario duplicates current conditions for the rail belt utilities in which each utility dispatches generation on an individual basis to serve its own loads, with only limited economy energy purchases and sales. The purpose of the case was to generate sales, revenue and cost totals for the three generating utilities before any cost savings due to market mechanisms are modeled. This case allows the quantification of the benefits of wholesale markets.

Table 1 below summarizes the major modeling assumptions for the Status Quo scenario. Unless noted otherwise, these assumptions were carried through all of the scenarios presented in this report.

TABLE 1
Modeling Assumptions

Major Modeling Assumptions	
All current generation plants in the area are dispatched	
New plants built in the GVEA service territory, per BVI Table 6-1	
All plants bid their variable cost (fuel and variable O&M)	
Total costs reflect both variable and fixed O&M costs. The costs do not include return of or on capital.	
Plant heat rates based on 100% output at summer plant capacities	
Multi-area transmission limits as follows:	
1.	Plants in the MLP service territory could dispatch up to the hourly load in the MLP service territory, plus an operating reserve margin. Max Dispatch = Load[MLP, LDC hour] * (1+OperatingReserve)
2.	Plants in the CEA service territory can exceed area needs to reflect economy energy sales of 92 MWh to MLP (BVI, section 3.2) and (637,637-406,265 MWh) to GVEA (BVI, section 4.3). This is implemented in the model through a transmission capacity of 26.42 MW Max Dispatch = Load[CEA, LDC hour] * (1 + Operating Reserve) + 26.42 MW
3.	Plants in the GVEA service territory could dispatch up to the hourly load in the GVEA service territory, plus an operating reserve margin. Max Dispatch = Load[GVEA, LDC hour] * (1+OperatingReserve)
Operating reserve is 6%. The 6% operating reserve criteria is based on reported load and generation in 1996.	
Real discount rate is 8% for all utilities.	
CEA includes AGENT, HA, MEA, and SEES.	
Fuel costs by company and plant from BVI table 3-3.	

Table 2 summarizes the results of the Status Quo scenario. Total sales are split between the three major utilities, and costs and revenues are indicated. Note that the revenues represent what each utility would receive under competitive market prices, and do not reflect current regulated revenue requirements.

TABLE 2
Total Sales, NPV Costs and Revenues for Study Period, Status Quo Case

Utility	Sales (MWh)	Total Costs (\$Millions)	Generator Revenues (\$ Millions)
MLP	26,946,946	276	302
CEA	71,492,787.2	782	911
GVEA	14,537,990	301	255
Total	112,977,724	1,359	1,468

Pooled Dispatch Case

The model was used to estimate the cost savings from employing a pool dispatch in the Railbelt area. The pool dispatch case is identical to the Status Quo case with the exception that the transmission limits were increased to allow more efficient dispatching. MLP was assigned 20MW of capacity, CEA 50MW of capacity and GVEA 70 MW (reverse flow). This scenario duplicates the coordinated dispatch analysis completed by the BVI study. Table 3 summarizes total sales by utility and the net present value of utility costs and revenues.

TABLE 3
Total Sales, NPV Costs and Revenues for Study Period, Pooled Dispatch Scenario

Utility	Sales (MWh)	Total Costs (\$Millions)	Generator Revenues (\$ Millions)
MLP	30,741,791	320	377
CEA	75,729,252	835	964
GVEA	6,506,680	163	90
Total	112,977,724	1,318	1,431

Table 4 compares the Pool Dispatch Scenario to the Status Quo scenario. As shown below, increasing the transmission allowances reduces overall system costs by \$41 million. This is largely due to the fact that GVEA expensive generation can be displaced by MLP and CEA plants.

TABLE 4
Change from Status Quo Scenario

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)	
	MWh	%	\$Millions	%
MLP	3,794,845	14%	\$ 44.26	16%
CEA	4,236,465	6%	\$ 53.17	7%
GVEA	(8,031,310)	-55%	\$(138.36)	-46%
Total	0		\$ (40.94)	

The costs savings estimate is higher than the BVI estimate, but still only represents a 3% savings in total variable costs. Moreover, given the strategic emphasis of the stacking model, the difference between a 2% (BVI study) and 3% stacking model savings is not significant.

TABLE 5
Comparison of BVI and E3 Study Results (Net Present Value \$000's)

	BVI Costs (BVI Table ES-1)	Costs w/o Capital	Costs w/ Capital for New GVEA Plants
Individual	1,433	1,359	1,421
Pooled	1,403	1,318	1,380
Savings from Pooled Dispatch	30	41	41
Percentage Savings	2.09%		2.89%

All of the remaining scenarios are variations on this Pool Dispatch Scenario.

Equalization of Fuel Costs

The purpose of the Fuel Cost Equalization scenarios was to isolate the impact of differences in natural gas fuel contracts on the wholesale market. In this scenario, fuel costs for all natural gas plants were set equal to the cost for the CEA Beluga 1-8 plants. This scenario examined the impact of fuel cost differentials on the operations of the plants in the Railbelt. Under the Status Quo transmission limits, there is little impact from changing the fuel costs. Utility costs decrease by \$41.7 million, but revenues also decrease by \$49.2 million, leaving a decrease in net utility

revenues (decrease in profit) of 7.5 million when compared to the Pool Dispatch scenario.

TABLE 6
Fuel Cost Equalization Base Case

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	59,555	0.2%	-32.1	-11.2%	-37.8	-11.2%	-5.7
CEA	-42,983	-0.1%	-9.4	-1.1%	-11.3	-1.2%	-1.8
GVEA	-16,572	-0.3%	-0.2	-0.1%	-0.2	-0.2%	0.0
Total	0		-41.7		-49.2		-7.5

Changing the transmission rights for MLP from 20MW to 35MW increases the impact of the fuel cost equalization dramatically. The change results in an over 2,900 GWh exchange between MLP and CEA over the 22 year period. The change in operating costs and total generator revenue between the two cases is less than \$5 million. This small cost impact is due to the fact that once the fuel price differentials are eliminated, the MLP and CEA generators have essentially the same cost. Thus the replacement of CEA output with MLP output would lead to only very small cost savings. This suggests that the benefits of competition might largely come from fuel cost differentials, rather than generator stock differences.

TABLE 7
Fuel Cost Equalization with Increased MLP Transmission

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	2,950,355	8.8%	-0.9	-0.3%	14.7	3.8%	15.6
CEA	-2,926,103	-4.0%	-45.6	-5.8%	-59.6	-6.6%	-14.0
GVEA	-24,252	-0.4%	-0.2	-0.1%	-0.2	-0.3%	0.0
Total	0		-46.7		-45.1		1.6

Market Power

To assess the ability of generators to exercise market power and influence market clearing prices, several scenarios were run to test the impacts of increased bid prices and reduced bid quantities on market price. The scenarios are:

1. CEA's bid price is 20% over its marginal costs
2. CEA's bid price is 20% over its marginal costs, and MLP is assigned 35 MW of transmission capacity
3. CEA's bid price is 20% over its marginal costs, and MLP is assigned all 70 MW of transmission capacity
4. CEA's bid price is 40% over its marginal costs
5. CEA's bid price is 40% over its marginal costs, and MLP is assigned 35 MW of transmission capacity
6. CEA's bid price is 40% over its marginal costs, and MLP is assigned all 70 MW of transmission capacity.
7. CEA withholds Beluga 3 capacity
8. CEA withholds Beluga 6-8 capacity

The two Beluga units were chosen to examine the effect of withdrawing a mid-merit unit (Beluga 3) versus a more efficient large units (Beluga 6-8). A more comprehensive analysis could evaluate the impact of each generating unit in the Railbelt.

The following tables summarize the results.

As shown in Table 8 through Table 13, CEA is able to significantly increase its profits by increasing its bid price. With no reallocation of transmission, CEA is able to increase its profits by \$157 million and \$315 million if it raises prices 20 percent and 40 percent, respectively. By increasing CEA's bid price, dispatch of GVEA's units is increased and the dispatch of CEA's generator is decreased, resulting in an increase in market prices. This increase represents the higher costs of GVEA's units.

Increasing the transmission capacity allocated to MLP dilutes CEA's ability to exercise such market power and reduces the increase in overall costs imposed on the system by CEA's high bid prices. Nevertheless, the higher bid prices increase overall profit and costs in all of the cases.

TABLE 8
CEA Bids 20% Over Marginal Cost, Contract Transmission Capacity

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	51,759	0.2%	0.9	0.3%	5.2	1.4%	4.4
CEA	-4,788,948	-6.8%	-47.6	-6.0%	109.4	10.2%	157.0
GVEA	4,737,189	42.1%	53.2	24.7%	57.6	38.9%	4.3
Total	0		6.4		172.2		165.8

TABLE 9
CEA Bids 20% Over Marginal Costs, 35 MW Transmission Capacity for MLP

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	2,922,646	8.7%	36.2	10.2%	62.5	14.2%	26.3
CEA	-7,252,587	-10.6%	-80.2	-10.6%	60.8	5.9%	141.0
GVEA	4,329,941	40.0%	48.9	23.1%	53.0	36.9%	4.2
Total	0		4.9		176.3		171.4

TABLE 10
CEA Bids 20% Over Marginal Costs, 70 MW Transmission Capacity for MLP

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	14,823,013	32.5%	190.6	37.3%	245.4	39.5%	54.9
CEA	-16,268,111	-27.4%	-197.2	-30.9%	-125.3	-14.9%	71.8
GVEA	1,445,098	18.2%	8.8	5.1%	-1.5	-1.7%	-10.4
Total	0		2.2		118.6		116.3

TABLE 11
CEA Fossil Fleet bids 40% over Marginal Cost

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	59,555	0.2%	1.0	0.3%	12.0	3.1%	11.0
CEA	-6,719,276	-9.7%	-64.0	-8.3%	251.3	20.7%	315.2
GVEA	6,659,721	50.6%	73.1	31.0%	80.7	47.1%	7.5
Total	0		10.1		343.9		333.8

TABLE 12
CEA Fleet bids 40% above Marginal Cost, and MLP Transmission Capacity increases to 35MW

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	2,950,355	8.8%	36.7	10.3%	74.1	16.5%	37.4
CEA	-9,454,754	-14.3%	-98.8	-13.4%	193.7	16.7%	292.5
GVEA	6,504,399	50.0%	71.2	30.4%	78.3	46.4%	7.1
Total	0		9.1		346.1		337.0

TABLE 13
CEA Fleet bids 40% above Marginal Cost, and MLP owns 70MW Transmission Capacity

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	9,653,370	23.9%	123.6	27.9%	209.6	35.8%	86.0
CEA	-14,255,834	-23.2%	-165.7	-24.7%	83.3	8.0%	249.0
GVEA	4,602,461	41.4%	51.6	24.1%	55.9	38.2%	4.3
Total	0		9.5		348.8		339.3

The three tables below, Tables 14, 15, and 16, summarize the results of scenarios in which a utility withholds generation from the pool. Table 13 shows that the withholding of Beluga 3 can result in a relatively small increase in costs and a substantial increase in profits for CEA. In comparison, as shown in Table 14 and 15, withholding Beluga 7-8 or 6-8 from the pool has a negative impact on profits for CEA.

TABLE 14
Withholding of Beluga 3 by CEA

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	0	0.0%	0.0	0.0%	0.2	0.0%	0.2
CEA	-269,975	-0.4%	-1.3	-0.2%	24.3	2.5%	25.5
GVEA	269,975	4.0%	2.6	1.6%	2.6	2.8%	0.1
Total	0		1.3		27.1		25.8

TABLE 15
Withholding of Beluga 7-8 by CEA

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	304	0.0%	0.0	0.0%	0.3	0.1%	0.3
CEA	-541,484	-0.7%	43.8	5.0%	39.0	3.9%	-4.9
GVEA	541,180	7.7%	5.2	3.1%	5.5	5.8%	0.3
Total	0		49.0		44.8		-4.3

TABLE 16
Withholding of Beluga 6-8

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	304	0.0%	0.0	0.0%	0.3	0.1%	0.3
CEA	-541,484	-0.7%	47.3	5.4%	39.0	3.9%	-8.4
GVEA	541,180	7.7%	5.2	3.1%	5.5	5.8%	0.3
Total	0		52.6		44.8		-7.8

This empirically supports the theory that removal of mid-merit plant like Beluga 3 can artificially increase market prices and inflate generator profits. These examples also demonstrate that not all plants are able to inflate market prices (e.g. Beluga 6-8 and 7-8.) Even with compensating transmission policies, some units, if allowed to bid strategically, can have a significant impact on the level of market prices.

Canceling Generation Additions

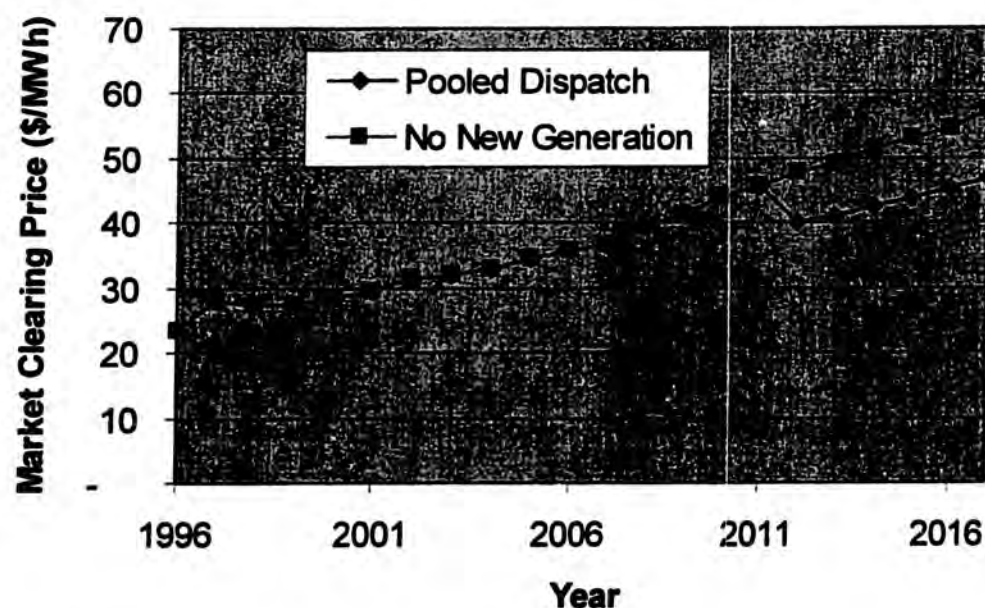
Table 16 summarizes the results of a scenario analysis in which GVEA's planned generation additions are not built. The GVEA planned additions are the only new plants included in the base case analysis, and are from BVI Table 6-1. Note that the elimination of the planned GVEA generation has some impact on the total dispatch costs, but a larger impact on the utility profit. Costs decline because GVEA avoids both the variable costs of the new generators, and also the fixed O&M costs associated with the units. Generator revenues increase because market clearing prices remain higher with no new assets in the area.

Figure 4 illustrates this impact on market prices.

TABLE 17
No New Generation Capacity Added

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	0	0.0%	0.0	0.0%	1.9	0.5%	1.9
CEA	28,914	0.0%	0.3	0.0%	6.0	0.6%	5.7
GVEA	-28,914	-0.4%	-42.6	-35.5%	5.3	5.5%	47.8
Total	0		-42.3		13.2		55.5

FIGURE 4
Impact on Market Prices of Canceling Generation Additions



Impact of New Market Entrants

This scenario examined the impact of a new market entrant on the costs and revenues that could be collected by the three major generating utilities. The scenario added a 100MW of new generation in the GVEA service territory in the year 2002, based on the cost characteristics of the GE 7EA combined cycle unit. The unit was assumed to obtain natural gas at the same cost as the CEA Beluga units.

In the Status Quo case, the efficient new unit displaced the majority of the existing GVEA generation.

TABLE 18
New Entrant in the Status Quo Case

	Sales by Company (MWh)_			Total NPV Costs (\$M's)			Total NPV Revenues (\$M's)		
	Base Case Resources	Add GE 7EA CC in 2002	Difference	Base Case Resources	Add GE 7EA CC in 2002	Difference	Base Case Resources	Add GE 7EA CC in 2002	Difference
MLP	26,946,946	30,793,550	3,846,604	275.5	320.6	45.1	301.7	378.0	76.3
CEA	71,492,787	60,770,096	(10,722,691)	782.1	672.0	(110.1)	911.4	904.0	(7.3)
GVEA	14,537,990	7,398,078	(7,139,913)	300.9	171.3	(129.6)	254.6	98.8	(155.9)
IPP	-	14,016,000	14,016,000	-	120.6	120.6	-	159.8	159.8
Total	112,977,724	112,977,724	(0)	1,358.6	1,284.5	(74.0)	1,467.7	1,540.7	72.9

In the pooled dispatch case, the largest impact of the Independent Power Producer (IPP) is to displace CEA power. While this benefits consumers in the GVEA territory, it is unlikely that this scenario would be realized. The costs of operating the IPP (which include fixed costs) are higher than the market revenues. The IPP would not be able to cover operating expenses, not to mention return of and on capital. On the other hand, if the IPP were to drive the market price in the GVEA territory higher through strategic bidding in order to cover return of an on capital, then consumers in the area would pay significantly higher rates.

TABLE 19
New Entrant in the Pooled Dispatch Base Case

	Sales by Company (MWh)_			Total NPV Costs (\$000's)			Total NPV Revenues (\$000's)		
	Base Case Resources	Add GE 7EA CC in 2002	Difference	Base Case Resources	Add GE 7EA CC in 2002	Difference	Base Case Resources	Add GE 7EA CC in 2002	Difference
MLP	30,741,791	29,475,134	(996,658)	319.8	308.9	(10.9)	376.5	350.3	(26.2)
CEA	75,729,252	66,200,801	(9,528,452)	835.3	730.5	(104.8)	964.0	826.8	(137.2)
GVEA	6,506,680	3,015,790	(3,490,891)	162.6	120.0	(42.6)	90.5	36.7	(53.8)
IPP	-	14,016,000	14,016,000	-	120.6	120.6	-	111.8	111.8
Total	112,977,724	112,977,724	-	1,317.6	1,280.0	(37.6)	1,431.1	1,325.7	(105.4)

Table 20 shows the impact of the IPP on CEA's market power. The IPP's introduction does reduce the revenues that CEA can collect from the market.

TABLE 20
New Entrant when the CEA Fleet Bids 40% above Dispatch Cost

	Sales by Company (MWh)_			Total NPV Costs (\$000's)			Total NPV Revenues (\$000's)		
	Base Case Resources	Add GE 7EA CC in 2002	Difference	Base Case Resources	Add GE 7EA CC in 2002	Difference	Base Case Resources	Add GE 7EA CC in 2002	Difference
MLP	30,801,346	30,801,346	-	320.8	320.8	-	388.5	386.2	(2.3)
CEA	69,009,976	59,225,746	(9,784,231)	771.3	658.9	(112.4)	1,215.3	1,030.5	(184.8)
GVEA	13,166,401	8,934,632	(4,231,769)	235.7	187.6	(48.1)	171.2	124.2	(47.0)
IPP	-	14,016,000	14,016,000	-	120.6	120.6	-	168.9	168.9
Total	112,977,724	112,977,724	0	1,327.8	1,287.9	(39.9)	1,775.0	1,709.7	(65.3)

The reduction, however, is far from sufficient to avoid the exercise of market power. Table 21 shows that even with the IPP in place, CEA could increase profits by \$275 million (relative to the status quo with the IPP in 2002) through strategic bidding. The IPP is already running at full capacity in the base case with IPP scenario, so the IPP cannot increase sales in response to CEA's strategic behavior.

TABLE 21
Impact of CEA Bidding 40% above Dispatch Cost (with IPP in 2002)

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	1,056,213	3.4%	11.9	3.7%	35.9	9.3%	24.0
CEA	-6,975,055	-11.8%	-71.6	-10.9%	203.6	19.8%	275.3
GVEA	5,918,842	66.2%	67.6	36.0%	87.5	70.5%	19.9
IPP	0	0.0%	0.0	0.0%	57.0	0.0%	57.0
Total	0		7.8		384.1		376.2

Like the 40% bidding strategy case above, the introduction of an IPP in 2002 reduces CEA's profit from withdrawing Beluga 3 from service. CEA's profit increase drops from \$25 million to \$18 million, but the reward for strategic bidding behavior remains.

TABLE 22
Impact of IPP on CEA's Withdrawal of Beluga Unit 3

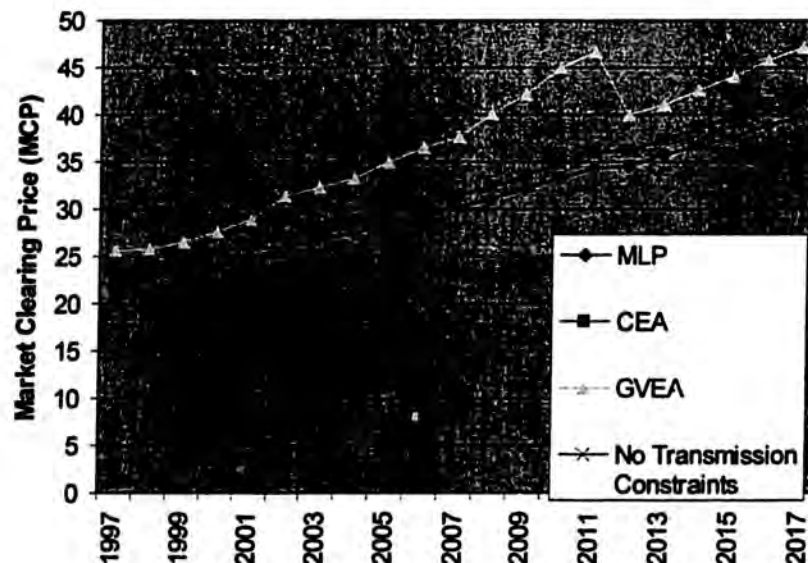
	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	458,812	1.5%	4.8	1.5%	9.5	2.7%	4.7
CEA	-992,736	-1.5%	-11.1	-1.5%	6.9	0.8%	18.0
GVEA	533,925	15.0%	4.9	3.9%	5.8	13.6%	0.9
IPP	0	0.0%	0.0	0.0%	0.0	0.0%	0.0
Total	0		-1.3		22.2		23.6

Impact of Additional Transmission Capacity

The Market Power section of this report explored some of the ways that transmission transfer capability can attempt to discipline the generation market. These scenarios examine the value of increased transmission, even if generation owners do not attempt to capitalize on market power.

Increased transmission capacity would remove the differences between zonal market prices. The new total region market price with no transmission capacity constraint is shown below in Figure 5. As illustrated, the market prices are generally higher than the MLP market prices, but lower than the prices for CEA and GVEA.

FIGURE 5
MCP with no Transmission Constraints



As shown in Table 23, the impact of removing the transmission capacity constraint is a decrease in total dispatch costs of only \$10 million over

the 22 year period. The impact on market clearing prices, however, results in an almost \$72 million decrease in customer bills. Partial relief of the transmission constraint, modeled by assigning 35 MW of transmission capacity to MLP, has a similar impact on costs and revenues, but to a smaller degree. Cost savings are only \$1million, and utility revenues (consumer costs) decrease by \$5.8 million.

TABLE 23
No Transmission Capacity Constraint

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	4,561,801	12.9%	45.9	12.6%	38.5	9.3%	-7.4
CEA	-898,542	-1.2%	-5.8	-0.7%	-32.4	-3.5%	-26.5
GVEA	-3,663,260	-128.8%	-50.6	-45.2%	-77.7	-606.4%	-27.1
Total	0		-10.5		-71.6		-61.1

TABLE 24
MLP Receives 35 MW of Transmission Capacity

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	2,868,609	8.5%	35.3	9.9%	53.9	12.5%	18.6
CEA	-2,870,399	-3.9%	-36.5	-4.6%	-48.3	-5.3%	-11.8
GVEA	1,790	0.0%	0.2	0.1%	0.2	0.2%	0.0
Total	0		-1.0		5.8		6.8

Load Growth

The load growth scenarios illustrate the impact that varying load growth forecasts have on utility costs and revenues. The market clearing prices for several load growth forecasts are illustrated in Figure 6. Table 19 below summarizes the impact of increasing the load forecast by 2% each year.

TABLE 25
Load Growth Forecast Increased by 2%

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	7,542,987	19.7%	79.8	20.0%	118.5	23.9%	38.7
CEA	16,710,445	18.1%	188.9	18.4%	290.6	23.2%	101.7
GVEA	7,542,842	53.7%	97.1	37.4%	120.2	57.0%	23.1
Total	31,796,274		365.7		529.3		163.5

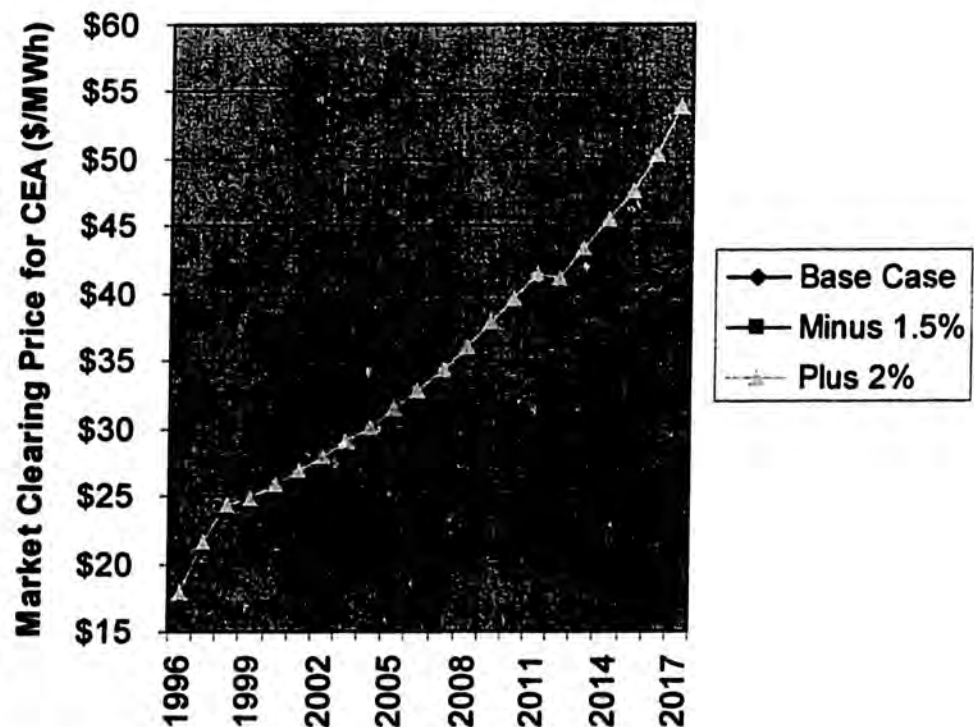
Note that under this high growth scenario, the increase in generator revenues is far greater than the increase in utility costs. This occurs because market clearing prices increase due to more expensive units being dispatched increases revenues for all generators.

TABLE 26
Load Growth Forecast Decreased by 1.5%

	Increase in Sales between 1996 and 2017		Increase in Costs (\$M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	\$Millions	%	\$ Millions	%	\$ Millions
MLP	-4,448,137	-16.9%	-44.1	-16.0%	-66.8	-21.6%	-22.7
CEA	-11,416,719	-17.8%	-121.9	-17.1%	-146.4	-17.9%	-24.5
GVEA	-2,751,412	-73.3%	-33.7	-26.2%	-44.0	-94.4%	-10.2
Total	-18,616,268		-199.7		-257.1		-57.5

Table 20 reports the impacts of reducing the load growth forecast by 1.5% each year. Similar to the high growth scenario, the change in generator revenues outpaces the decrease in utility costs.

FIGURE 6
Annual MCP for CEA under Alternate Growth Forecasts



Plant Capacity Adequacy

This report analysis did not independently analyze the need for capacity under the individual or joint dispatch case. The base case used the GVEA generation plant scheduled additions from the BVI study.

Stranded Costs

Stranded costs are the reduction in generator revenues due to the introduction of competition into the Railbelt. E3 has estimated stranded costs as the difference between 1) the net generation revenues the utility would have received under rate of return regulation and 2) the net generation revenue the utility would receive under competition.

$$[1] \text{ Stranded Cost} = \text{NPV}(\text{Net Generation Revenue}[R,y]) - \text{NPV}(\text{Net Generation Revenue}[C,y])$$

where R is the regulated environment, and C is the competitive environment, y is the year

Net generator revenue is the total revenue from customers for generation services less 1) variable fuel costs, 2) variable O&M costs, and 3) fixed O&M costs.

$$[2] \text{ Net Generation Revenue}[x,y] = \text{Revenue}[x,y] - \text{Cost}[x,y]$$

where $\text{Cost}[x,y]$ is the sum of variable fuel, variable O&M, and fixed O&M costs,
 $\text{Revenue}[x,y]$ is the generation revenue collected from customers
 x is either R or C

Combining Equations 1 and 2 and rearranging terms results in the following simplified stranded cost formula:

$$[3] \text{ Stranded Cost} = - \text{NPV}(\text{Revenue}[C,y] - \text{Revenue}[R,y]) + \text{NPV}(\text{Cost}[C,y] - \text{Cost}[R,y])$$

where $\text{NPV}(\text{Cost}[C,y] - \text{Cost}[R,y])$ is the increase in costs shown in Table 4 through Table 26 above.

The potential stranded costs are calculated for the period from 1996 to 2017. The 1996 starting point was chosen for consistency with the BVI study. The estimates of stranded costs vary between \$34 million and almost \$500 million. These estimates are provided as an indication of the potential magnitude of these costs. As is discussed in the following section, the generation revenue requirement ($\text{Revenue}[R,y]$) has been extrapolated from a single year of data, and merits further work and input from the respective utilities.

TABLE 27
Stranded Costs by Scenario (\$Millions)

Scenario		Increase in NPV Revenue	Increase in NPV Costs	Stranded Cost
Table 5	Base Case	(\$414)	(\$41)	\$373
Table 6	Fuel Cost Equalization	(\$463)	(\$83)	\$380
Table 7	Fuel Cost Equalization with Increases MLP Transmission	(\$459)	(\$88)	\$371
Table 8	CEA Bids 20% over Marginal Cost, Contract Transmission Capacity	(\$242)	(\$35)	\$207
Table 9	CEA Bids 20% Over Marginal Costs, 35 MW Transmission Capacity for MLP	(\$238)	(\$36)	\$202
Table 10	CEA Bids 20% Over Marginal Costs, 70 MW Transmission Capacity for MLP	(\$295)	(\$39)	\$257
Table 11	CEA Fossil Fleet bids 40% over Marginal Cost	(\$70)	(\$31)	\$39
Table 12	CEA Fleet bids 40% above Marginal Cost, and MLP T Capacity 35MW	(\$68)	(\$32)	\$36
Table 13	CEA Fleet bids 40% above Marginal Cost, and MLP owns 70MW T Capacity	(\$65)	(\$31)	\$34
Table 14	Withholding of Beluga 3 by CEA	(\$387)	(\$40)	\$347
Table 15	Withholding of Beluga 7-8 by CEA	(\$369)	\$8	\$377
Table 16	Withholding of Beluga 6-8	(\$369)	\$12	\$381
Table 17	No New Generation Capacity Added	(\$401)	(\$83)	\$317
Table 23	No Transmission Capacity Constraint	(\$485)	(\$51)	\$434
Table 24	MLP Receives 35 MW of Transmission Capacity	(\$408)	(\$42)	\$366
Table 25	Load Growth Forecast Increased by 2%	\$115	\$325	\$209
Table 26	Load Growth Forecast Decreased by 1.5%	(\$671)	(\$241)	\$430
Table 18	New Entrant in the Status Quo Case	(\$501)	(\$195)	\$306
Table 19	New Entrant in the Pooled Dispatch Base Case	(\$631)	(\$158)	\$473
Table 20	New Entrant when the CEA Fleet Bids 40% above Dispatch Cost	(\$648)	(\$161)	\$488
Table 21	Impact of CEA Bidding 40% above Dispatch Cost (with IPP in 2002)	(\$304)	(\$158)	\$146
Table 22	Impact of IPP on CEA's Withdrawal of Beluga Unit 3	(\$609)	(\$158)	\$451

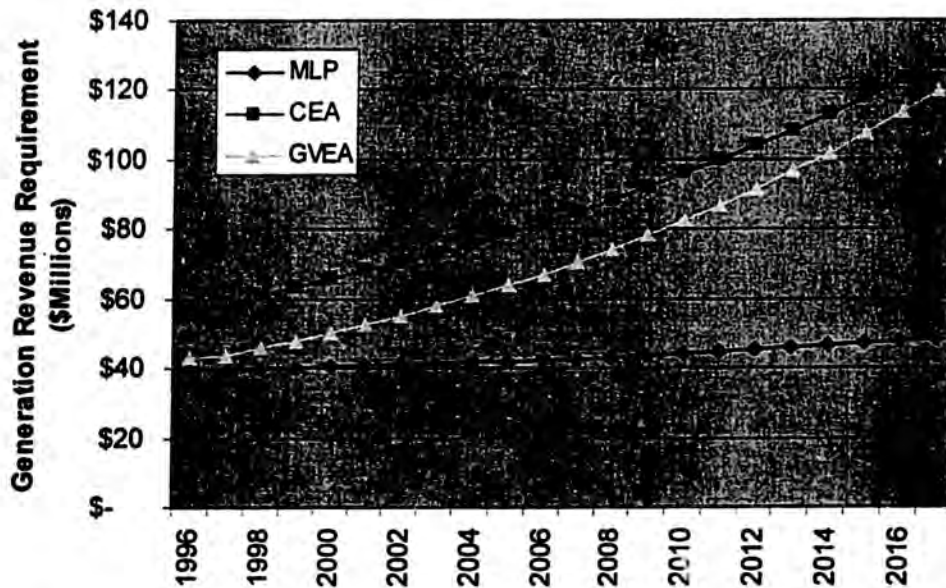
Generation Revenue

Generation revenue requirements under regulation are estimated for each utility. The generation revenue requirement excludes transmission and distribution, so those costs are separated out from the total utility revenues. The separation is based on 1997 FERC Form 1 information filed with FERC and the Alaska PUC. The 1997 revenues are extrapolated out to 2017 using the following simple assumptions:

1. Generation plant depreciation remains constant and reduces the annual generation return on investment
2. Generation operating costs increase in proportion to load growth
3. Generation operating costs increase in proportion to fuel cost increases
4. All other generation costs remain constant

These assumptions result in generation revenues that are projected to increase annually, as shown in Figure 7.

FIGURE 7
Generation Revenue Requirements



These generation revenue requirements are based on the assumption that the utilities remain under cost of service regulation. The streams also do not reflect the impact of GVEA adding generation capacity. These generation revenue requirements provide a reasonable estimate of stranded cost magnitudes, but are not intended to be the "final word" on the matter.

The net present values of these streams (1996 to 2017) are shown below for each of the three utilities.

TABLE 28
NPV Generation Revenues Under Regulation

Company	NPV Revenue under Regulation (\$Millions)
MLP	\$427
CEA	\$775
GVEA	\$642
Total	\$1,845

Effect on Power Cost Equalization

Sufficient data was not available to single out the stranded investment exposure of the Four Dam Pool. However, it is important to note that the Blue Ribbon Panel study on the Power Cost Equalization program recommended that the funding level for PCE coming from the annual

debt service from the Pool be increased from its current level of 40 percent to 60 percent in the future – from \$4.4 million to \$6.0 million. The implication is that if the value of the Pool is significantly reduced as a result of restructuring, and the debt service paid to the State is correspondingly reduced, the revenues to the PCE could be negatively impacted.

Conclusions

- The efficiency gains reported in the BVI study from coordinated dispatch are supported by the results of this analysis.
- Due to existing transmission capabilities, there will be regionally market price differences between the major railbelt utilities.
- Equalizing the differences in fuel costs between the railbelt utilities can result in over \$40 million in cost savings, but this savings is met by decreases in utility revenue, resulting in a net loss the utilities. Expanding MLPs access to transmission capacity practically removes the net loss to the utilities from fuel price equalization.
- Certain generation units may have the ability to exercise market power through strategic bidding behavior, including bidding above marginal cost and withholding generation from the market.
- Canceling GVEA's planned generation additions results in an increase in long-term market prices, and results in higher overall profits for the utilities.
- The introduction of new generation into the Railbelt can reduce utility gains from strategic behavior, but additional analysis would be required to determine the amount and location of that generation to fully mitigate market power issues.
- Removing transmission constraints results in the elimination of zonal market price differences. However, the reduction in transmission constraints must be large for the price differential to be completely eroded.
- Higher load growth forecasts increase utility revenues to a greater degree than utility costs, resulting in increased profits for the utilities. Likewise, lower load growth forecasts decrease utility revenues to a greater extent than utility costs, resulting in a decrease in utility profit.
- Competition in the Railbelt would likely result in stranded costs. The magnitude of the stranded cost problem could be in the range of \$34 million to almost \$500 million.

APPENDICES

Glossary ⁽¹⁾

Acid Rain: Also called acid precipitation or acid deposition, acid rain is precipitation containing harmful amounts of nitric and sulfuric acids formed primarily by nitrogen oxides and sulfur oxides released into the atmosphere when fossil fuels are burned. It can be wet precipitation (rain, snow, or fog) or dry precipitation (absorbed gaseous and particulate matter, aerosol particles or dust). Acid rain has a pH below 5.6. Normal rain has a pH of about 5.6, which is slightly acidic. The term pH is a measure of acidity or alkalinity and ranges from 0 to 14. A pH measurement of 7 is regarded as neutral. Measurements below 7 indicate increased acidity, while those above indicate increased alkalinity.

Ampere: The unit of measurement of electrical current produced in a circuit by 1 volt acting through a resistance of 1 ohm.

Anthracite: A hard, black lustrous coal, often referred to as hard coal, containing a high percentage of fixed carbon and a low percentage of volatile matter. Comprises three groups classified according to the following ASTM Specification D388-84, on a dry mineral-matter-free basis:

Coal	Fixed Carbon Limits		Volatile Matter	
	GE	LT	GT	LE
Meta-Anthracite	98	-	-	2
Anthracite	92	98	2	8
Semianthracite	86	92	8	14

Ash: Impurities consisting of silica, iron, alumina, and other noncombustible matter that are contained in coal. Ash increases the weight of coal, adds to the cost of handling, and can affect its burning characteristics. Ash content is measured as a percent by weight of coal on an "as received" or a "dry" (moisture-free, usually part of a laboratory analysis) basis.

Available but not Needed Capability: Net capability of main generating units that are operable but not considered necessary to carry load, and cannot be connected to load within 30 minutes.

Average Revenue per Kilowatthour: The average revenue per kilowatthour of electricity sold by sector (residential, commercial, industrial, or other) and geographic area (State, Census division, and national), is calculated by dividing the total monthly revenue by the corresponding total monthly sales for each sector and geographic area.

(1) Source: Energy Information Administration, U.S. Department of Energy, Electric Power Annual, 1997.

Barrel: A volumetric unit of measure for crude oil and petroleum products equivalent to 42 U.S. gallons.

Base Bill: A charge calculated through multiplication of the rate from the appropriate electric rate schedule by the level of consumption.

Baseload: The minimum amount of electric power delivered or required over a given period of time at a steady rate.

Baseload Capacity: The generating equipment normally operated to serve loads on an around-the-clock basis.

Baseload Plant: A plant, usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously. These units are operated to maximize system mechanical and thermal efficiency and minimize system operating costs.

Bbl: The abbreviation for barrel.

Bcf: The abbreviation for 1 billion cubic feet.

Bituminous Coal: The most common coal. It is dense and black (often with well-defined bands of bright and dull material). Its moisture content usually is less than 20 percent. It is used for generating electricity, making coke, and space heating. Comprises five groups classified according to the following ASTM Specification D388-84, on a dry mineral-matter-free (mmf) basis for fixed-carbon and volatile matter and a moist mmf basis for calorific value.

	Fixed Carbon Limits		Volatile Matter Limits		Calorific Value Limits Btu/lb	
	GE	LT	GT	LT	GE	LE
LV	78	86	14	22	-	-
MV	69	78	22	31	-	-
HVA	-	69	31	-	14000	-
HVB	-	-	-	-	13000	14000
HVC	-	-	-	-	10500	13000

- LV = Low-volatile bituminous coal
- MV = Medium-volatile bituminous coal
- HVA = High-volatile A bituminous coal
- HVB = High-volatile B bituminous coal
- HVC = High-volatile C bituminous coal

Boiler: A device for generating steam for power, processing, or heating purposes or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a

fluid contained within the tubes in the boiler shell. This fluid is delivered to an end-use at a desired pressure, temperature, and quality.

Btu (British Thermal Unit): A standard unit for measuring the quantity of heat energy equal to the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit.

Capability: The maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress.

Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer.

Capacity (Purchased): The amount of energy and capacity available for purchase from outside the system.

Capacity Charge: An element in a two-part pricing method used in capacity transactions (energy charge is the other element). The capacity charge, sometimes called Demand Charge, is assessed on the amount of capacity being purchased.

Census Divisions: The nine geographic divisions of the United States established by the Bureau of the Census, U.S. Department of Commerce, for the purpose of statistical analysis. The boundaries of Census divisions coincide with State boundaries. The Pacific Division is subdivided into the Pacific Contiguous and Pacific Noncontiguous areas.

Circuit: A conductor or a system of conductors through which electric current flows.

Coal: A black or brownish-black solid combustible substance formed by the partial decomposition of vegetable matter without access to air. The rank of coal, which includes anthracite, bituminous coal, subbituminous coal, and lignite, is based on fixed carbon, volatile matter, and heating value. Coal rank indicates the progressive alteration from lignite to anthracite. Lignite contains approximately 9 to 17 million Btu per ton. The contents of subbituminous and bituminous coal range from 16 to 24 million Btu per ton and from 19 to 30 million Btu per ton, respectively. Anthracite contains approximately 22 to 28 million Btu per ton.

Cogenerator: A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes. To receive status as a qualifying facility (QF) under the Public Utility Regulatory Policies Act (PURPA), the facility must produce electric energy and another form of useful thermal energy through the sequential use of energy, and meet certain ownership, operating, and efficiency criteria.

established by the Federal Energy Regulatory Commission (FERC). (See the Code of Federal Regulations, Title 18, Part 292.)

Coincidental Demand: The sum of two or more demands that occur in the same time interval.

Coincidental Peak Load: The sum of two or more peakloads that occur in the same time interval.

Coke (Petroleum): A residue high in carbon content and low in hydrogen that is the final product of thermal decomposition in the condensation process in cracking. This product is reported as marketable coke or catalyst coke. The conversion factor is 5 barrels (42 U.S. gallons each) per short ton.

Combined Cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Combined Cycle Unit: An electric generating unit that consists of one or more combustion turbines and one or more boilers with a portion of the required energy input to the boiler(s) provided by the exhaust gas of the combustion turbine(s).

Combined Pumped-Storage Plant: A pumped-storage hydroelectric power plant that uses both pumped water and natural streamflow to produce electricity.

Commercial: The commercial sector is generally defined as nonmanufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions. The utility may classify commercial service as all consumers whose demand or annual use exceeds some specified limit. The limit may be set by the utility based on the rate schedule of the utility.

Commercial Operation: Commercial operation begins when control of the loading of the generator is turned over to the system dispatcher.

Consumption (Fuel): The amount of fuel used for gross generation, providing standby service, start-up and/or flame stabilization.

Contract Price: Price of fuels marketed on a contract basis covering a period of 1 or more years. Contract prices reflect market conditions at the time the contract was negotiated and therefore remain constant throughout the life of the contract or are adjusted through escalation clauses. Generally, contract prices do not fluctuate widely.

Contract Receipts: Purchases based on a negotiated agreement that generally covers a period of 1 or more years.

Cooperative Electric Utility: An electric utility legally established to be owned by and operated for the benefit of those using its service. The utility company will generate, transmit, and/or distribute supplies of electric energy to a specified area not being serviced by another utility. Such ventures are generally exempt from Federal income tax laws. Most electric cooperatives have been initially financed by the Rural Electrification Administration, U.S. Department of Agriculture.

Cost: The amount paid to acquire resources, such as plant and equipment, fuel, or labor services.

Current (Electric): A flow of electrons in an electrical conductor. The strength or rate of movement of the electricity is measured in amperes.

Demand (Electric): The rate at which electric energy is delivered to or by a system, part of a system, or piece of equipment, at a given instant or averaged over any designated period of time.

Demand-Side Management: The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers only to energy and load-shape modifying activities that are undertaken in response to utility-administered programs. It does not refer to energy and load-shape changes arising from the normal operation of the marketplace or from government-mandated energy-efficiency standards. Demand-Side Management (DSM) covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.

Distillate Fuel Oil: A general classification for one of the petroleum fractions produced in conventional distillation operations. It is used primarily for space heating, on-and-off-highway diesel engine fuel (including railroad engine fuel and fuel for agriculture machinery), and electric power generation. Included are Fuel Oils No. 1, No. 2, and No. 4; and Diesel Fuels No. 1, No. 2, and No. 4.

Distribution System: The portion of an electric system that is dedicated to delivering electric energy to an end user.

Electric Plant (Physical): A facility containing prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or fission energy into electric energy.

Electric Rate Schedule: A statement of the electric rate and the terms and conditions governing its application, including attendant contract terms and conditions that have been accepted by a regulatory body with appropriate oversight authority.

Electric Utility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and files forms listed in the Code of Federal Regulations, Title 18, Part 141. Facilities that qualify as cogenerators or small power producers under the Public Utility Regulatory Policies Act (PURPA) are not considered electric utilities.

Energy: The capacity for doing work as measured by the capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatthours, while heat energy is usually measured in British thermal units.

Energy Charge: That portion of the charge for electric service based upon the electric energy (kWh) consumed or billed.

Energy Deliveries: Energy generated by one electric utility system and delivered to another system through one or more transmission lines.

Energy Efficiency: Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatthours), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.

Energy Receipts: Energy generated by one electric utility system and received by another system through one or more transmission lines.

Energy Source: The primary source that provides the power that is converted to electricity through chemical, mechanical, or other means. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

Facility: An existing or planned location or site at which prime movers, electric generators, and/or equipment for converting mechanical, chemical, and/or nuclear energy into electric energy are situated, or will be situated. A facility may contain more than one generator of

either the same or different prime mover type. For a cogenerator, the facility includes the industrial or commercial process.

Federal Energy Regulatory Commission (FERC): A quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification.

Federal Power Act: Enacted in 1920, and amended in 1935, the Act consists of three parts. The first part incorporated the Federal Water Power Act administered by the former Federal Power Commission, whose activities were confined almost entirely to licensing non-Federal hydroelectric projects. Parts II and III were added with the passage of the Public Utility Act. These parts extended the Act's jurisdiction to include regulating the interstate transmission of electrical energy and rates for its sale as wholesale in interstate commerce. The Federal Energy Regulatory Commission is now charged with the administration of this law.

Federal Power Commission: The predecessor agency of the Federal Energy Regulatory Commission. The Federal Power Commission (FPC) was created by an Act of Congress under the Federal Water Power Act on June 10, 1920. It was charged originally with regulating the electric power and natural gas industries. The FPC was abolished on September 20, 1977, when the Department of Energy was created. The functions of the FPC were divided between the Department of Energy and the Federal Energy Regulatory Commission.

FERC: The Federal Energy Regulatory Commission.

Firm Gas: Gas sold on a continuous and generally long-term contract.

Firm Power: Power or power-producing capacity intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.

Flue Gas Desulfurization Unit (Scrubber): Equipment used to remove sulfur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals, such as lime, are used as the scrubbing media.

Flue Gas Particulate Collectors: Equipment used to remove fly ash from the combustion gases of a boiler plant before discharge to the atmosphere. Particulate collectors include electrostatic precipitators, mechanical collectors (cyclones), fabric filters (baghouses), and wet scrubbers.

Fly Ash: Particulate matter from coal ash in which the particle diameter is less than 1×10^{-4} meter. This is removed from the flue gas using flue gas particulate collectors such as fabric filters and electrostatic precipitators.

Forced Outage: The shutdown of a generating unit, transmission line or other facility, for emergency reasons or a condition in which the generating equipment is unavailable for load due to unanticipated breakdown.

Fossil Fuel: Any naturally occurring organic fuel, such as petroleum, coal, and natural gas.

Fossil-Fuel Plant: A plant using coal, petroleum, or gas as its source of energy.

Fuel: Any substance that can be burned to produce heat; also, materials that can be fissioned in a chain reaction to produce heat.

Fuel Expenses: These costs include the fuel used in the production of steam or driving another prime mover for the generation of electricity. Other associated expenses include unloading the shipped fuel and all handling of the fuel up to the point where it enters the first bunker, hopper, bucket, tank, or holder in the boiler-house structure.

Full-Forced Outage: The net capability of main generating units that is unavailable for load for emergency reasons.

Gas: A fuel burned under boilers and by internal combustion engines for electric generation. These include natural, manufactured and waste gas.

Gas Turbine Plant: A plant in which the prime mover is a gas turbine. A gas turbine consists typically of an axial-flow air compressor, one or more combustion chambers, where liquid or gaseous fuel is burned and the hot gases are passed to the turbine and where the hot gases expand to drive the generator and are then used to run the compressor.

Generating Unit: Any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

Generation (Electricity): The process of producing electric energy by transforming other forms of energy; also, the amount of electric energy produced, expressed in watthours (Wh).

Gross Generation: The total amount of electric energy produced by the generating units at a generating station or stations, measured at the generator terminals.

Net Generation: Gross generation less the electric energy consumed at the generating station for station use.

Generator: A machine that converts mechanical energy into electrical energy.

Generator Nameplate Capacity: The full-load continuous rating of a generator, prime mover, or other electric power production equipment under specific conditions as designated by the manufacturer. Installed generator nameplate rating is usually indicated on a nameplate physically attached to the generator.

Geothermal Plant: A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

Gigawatt (GW): One billion watts.

Gigawatthour (GWh): One billion watthours.

Greenhouse Effect: The increasing mean global surface temperature of the earth caused by gases in the atmosphere (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon). The greenhouse effect allows solar radiation to penetrate but absorbs the infrared radiation returning to space.

Grid: The layout of an electrical distribution system.

Gross Generation: The total amount of electric energy produced by a generating facility, as measured at the generator terminals.

Heavy Oil: The fuel oils remaining after the lighter oils have been distilled off during the refining process. Except for start-up and flame stabilization, virtually all petroleum used in steam plants is heavy oil.

Hydroelectric Plant: A plant in which the turbine generators are driven by falling water.

Industrial: The industrial sector is generally defined as manufacturing, construction, mining agriculture, fishing and forestry establishments Standard Industrial Classification (SIC) codes 01-39. The utility may classify industrial service using the SIC codes, or based on demand or annual usage exceeding some specified limit. The limit may be set by the utility based on the rate schedule of the utility.

Intermediate Load (Electric System): The range from base load to a point between base load and peak. This point may be the midpoint, a percent of the peakload, or the load over a specified time period.

Internal Combustion Plant: A plant in which the prime mover is an internal combustion engine. An internal combustion engine has one or more cylinders in which the process of combustion takes place, converting energy released from the rapid burning of a fuel-air mixture into mechanical energy. Diesel or gas-fired engines are the principal

types used in electric plants. The plant is usually operated during periods of high demand for electricity.

Interruptible Gas: Gas sold to customers with a provision that permits curtailment or cessation of service at the discretion of the distributing company under certain circumstances, as specified in the service contract.

Interruptible Load: Refers to program activities that, in accordance with contractual arrangements, can interrupt consumer load at times of seasonal peak load by direct control of the utility system operator or by action of the consumer at the direct request of the system operator. It usually involves commercial and industrial consumers. In some instances the load reduction may be affected by direct action of the system operator (remote tripping) after notice to the consumer in accordance with contractual provisions. For example, loads that can be interrupted to fulfill planning or operation reserve requirements should be reported as Interruptible Load. Interruptible Load as defined here excludes Direct Load Control and Other Load Management.

(Interruptible Load, as reported here, is synonymous with Interruptible Demand reported to the North American Electric Reliability Council on the voluntary Office of Energy Emergency Operations Form OE-411, "Coordinated Regional Bulk Power Supply Program Report," with the exception that annual peakload effects are reported on the Form EIA-861 and seasonal (i.e., summer and winter) peakload effects are reported on the OE-411).

Kilowatt (kW): One thousand watts.

Kilowatthour (kWh): One thousand watthours.

Light Oil: Lighter fuel oils distilled off during the refining process. Virtually all petroleum used in internal combustion and gas-turbine engines is light oil.

Lignite: A brownish-black coal of low rank with high inherent moisture and volatile matter (used almost exclusively for electric power generation). It is also referred to as brown coal. Comprises two groups classified according to the following ASTM Specification D388-84 for calorific values on a moist material-matter-free basis

Limits Btu/lb.

	GE	LT
Lignite A	6300	8300
Lignite B	-	6300

Load (Electric): The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

Maximum Demand: The greatest of all demands of the load that has occurred within a specified period of time.

Mcf: One thousand cubic feet.

Megawatt (MW): One million watts.

Megawatthour (MWh): One million watthours.

MMcf: One million cubic feet.

Natural Gas: A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

Net Capability: The maximum load-carrying ability of the equipment, exclusive of station use, under specified conditions for a given time interval, independent of the characteristics of the load. (Capability is determined by design characteristics, physical conditions, adequacy of prime mover, energy supply, and operating limitations such as cooling and circulating water supply and temperature, headwater and tailwater elevations, and electrical use.)

Net Generation: Gross generation minus plant use from all electric utility owned plants. The energy required for pumping at a pumped-storage plant is regarded as plant use and must be deducted from the gross generation.

Net Summer Capability: The steady hourly output, which generating equipment is expected to supply to system load exclusive of auxiliary power, as demonstrated by tests at the time of summer peak demand.

Net Winter Capability: The steady hourly output which generating equipment is expected to supply to system load exclusive of auxiliary power, as demonstrated by tests at the time of winter peak demand.

Noncoincidental Peak Load: The sum of two or more peakloads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, week, month, a heating or cooling season, and usually for not more than 1 year.

Non-Firm Power: Power or power-producing capacity supplied or available under a commitment having limited or no assured availability.

Nonutility Power Producer: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers)

without a designated franchised service area, and which do not file forms listed in the Code of Federal Regulations, Title 18, Part 141.

Nuclear Fuel: Fissionable materials that have been enriched to such a composition that, when placed in a nuclear reactor, will support a self-sustaining fission chain reaction, producing heat in a controlled manner for process use.

Nuclear Power Plant: A facility in which heat produced in a reactor by the fissioning of nuclear fuel is used to drive a steam turbine.

Off-Peak Gas: Gas that is to be delivered and taken on demand when demand is not at its peak.

Ohm: The unit of measurement of electrical resistance. The resistance of a circuit in which a potential difference of 1 volt produces a current of 1 ampere.

Operable Nuclear Unit: A nuclear unit is :q.operable:eq. after it completes low-power testing and is granted authorization to operate at full power. This occurs when it receives its full power amendment to its operating license from the Nuclear Regulatory Commission.

Outage: The period during which a generating unit, transmission line, or other facility is out of service.

Peak Demand: The maximum load during a specified period of time.

Peak Load Plant: A plant usually housing old, low-efficiency steam units; gas turbines; diesels; or pumped-storage hydroelectric equipment normally used during the peak-load periods.

Peaking Capacity: Capacity of generating equipment normally reserved for operation during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on an around-the-clock basis.

Percent Difference: The relative change in a quantity over a specified time period. It is calculated as follows: the current value has the previous value subtracted from it; this new number is divided by the absolute value of the previous value; then this new number is multiplied by 100.

Petroleum: A mixture of hydrocarbons existing in the liquid state found in natural underground reservoirs, often associated with gas. Petroleum includes fuel oil No. 2, No. 4, No. 5, No. 6; topped crude; Kerosene; and jet fuel.

Petroleum Coke: See Coke (Petroleum).

Petroleum (Crude Oil): A naturally occurring, oily, flammable liquid composed principally of hydrocarbons. Crude oil is occasionally found in springs or pools but usually is drilled from wells beneath the earth's surface.

Planned Generator: A proposal by a company to install electric generating equipment at an existing or planned facility or site. The proposal is based on the owner having obtained (1) all environmental and regulatory approvals, (2) a signed contract for the electric energy, or (3) financial closure for the facility.

Plant: A facility at which are located prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or nuclear energy into electric energy. A plant may contain more than one type of prime mover. Electric utility plants exclude facilities that satisfy the definition of a qualifying facility under the Public Utility Regulatory Policies Act of 1978.

Plant Use: The electric energy used in the operation of a plant. Included in this definition is the energy required for pumping at pumped-storage plants.

Plant-Use Electricity: The electric energy used in the operation of a plant. This energy total is subtracted from the gross energy production of the plant; for reporting purposes the plant energy production is then reported as a net figure. The energy required for pumping at pumped-storage plants is, by definition, subtracted, and the energy production for these plants is then reported as a net figure.

Power: The rate at which energy is transferred. Electrical energy is usually measured in watts. Also used for a measurement of capacity.

Power Pool: An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies.

Price: The amount of money or consideration-in-kind for which a service is bought, sold, or offered for sale.

Prime Mover: The engine, turbine, water wheel, or similar machine that drives an electric generator; or, for reporting purposes, a device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cell(s)).

Profit: The income remaining after all business expenses are paid.

Public Authority Service to Public Authorities: Public authority service includes electricity supplied and services rendered to municipalities or divisions or agencies of State or Federal governments, under special contracts or agreements or service classifications applicable only to public authorities.

Public Street and Highway Lighting: Public street and highway lighting includes electricity supplied and services rendered for the purposes of lighting streets, highways, parks, and other public places; or for traffic or other signal system service, for municipalities, or other divisions or agencies of State or Federal governments.

Pumped-Storage Hydroelectric Plant: A plant that usually generates electric energy during peak-load periods by using water previously pumped into an elevated storage reservoir during off-peak periods when excess generating capacity is available to do so. When additional generating capacity is needed, the water can be released from the reservoir through a conduit to turbine generators located in a power plant at a lower level.

Purchased Power Adjustment: A clause in a rate schedule that provides for adjustments to the bill when energy from another electric system is acquired and it varies from a specified unit base amount.

Pure Pumped-Storage Hydroelectric Plant: A plant that produces power only from water that has previously been pumped to an upper reservoir.

Qualifying Facility (QF): A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act (PURPA). (See the Code of Federal Regulations, Title 18, Part 292.) Part 292.

Railroad and Railway Services: Railroad and railway services include electricity supplied and services rendered to railroads and interurban and street railways, for general railroad use, including the propulsion of cars or locomotives, where such electricity is supplied under separate and distinct rate schedules.

Rate Base: The value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost. Depending on which method is used, the rate base includes cash, working capital, materials and supplies, and deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Ratemaking Authority: A utility commission's legal authority to fix, modify, approve, or disapprove rates, as determined by the powers given the commission by a State or Federal legislature.

Receipts: Purchases of fuel.

Regulation: The governmental function of controlling or directing economic entities through the process of rulemaking and adjudication.

Reserve Margin (Operating): The amount of unused available capability of an electric power system at peakload for a utility system as a percentage of total capability.

Residential: The residential sector is defined as private household establishments which consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking and clothes drying. The classification of an individual consumer's account, where the use is both residential and commercial, is based on principal use. For the residential class, do not duplicate consumer accounts due to multiple metering for special services (water, heating, etc.). Apartment houses are also included.

Residual Fuel Oil: The topped crude of refinery operation, includes No. 5 and No. 6 fuel oils as defined in ASTM Specification D396 and Federal Specification VV-F-815C; Navy Special fuel oil as defined in Military Specification MIL-F-859E including Amendment 2 (NATO Symbol F-77); and Bunker C fuel oil. Residual fuel oil is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes. Imports of residual fuel oil include imported crude oil burned as fuel.

Restricted-Universe Census: This is the complete enumeration of data from a specifically defined subset of entities including, for example, those that exceed a given level of sales or generator nameplate capacity.

Retail: Sales covering electrical energy supplied for residential, commercial, and industrial end-use purposes. Other small classes, such as agriculture and street lighting, also are included in this category.

Revenue: The total amount of money received by a firm from sales of its products and/or services, gains from the sales or exchange of assets, interest and dividends earned on investments, and other increases in the owner's equity except those arising from capital adjustments.

Running and Quick-Start Capability: The net capability of generating units that carry load or have quick-start capability. In general, quick-start capability refers to generating units that can be available for load within a 30-minute period.

Sales: The amount of kilowatthours sold in a given period of time; usually grouped by classes of service, such as residential, commercial, industrial, and other. Other sales include public street and highway lighting, other sales to public authorities and railways, and interdepartmental sales.

Sales for Resale: Energy supplied to other electric utilities, cooperatives, municipalities, and Federal and State electric agencies for resale to ultimate consumers.

Scheduled Outage: The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

Short Ton: A unit of weight equal to 2,000 pounds.

Small Power Producer (SPP): Under the Public Utility Regulatory Policies Act (PURPA), a small power production facility (or small power producer) generates electricity using waste, renewable (water, wind and solar), or geothermal energy as a primary energy source. Fossil fuels can be used, but renewable resource must provide at least 75 percent of the total energy input. (See Code of Federal Regulations, Title 18, Part 292.)

Spinning Reserve: That reserve generating capacity running at a zero load and synchronized to the electric system.

Spot Purchases: A single shipment of fuel or volumes of fuel, purchased for delivery within 1 year. Spot purchases are often made by a user to fulfill a certain portion of energy requirements, to meet unanticipated energy needs, or to take advantage of low-fuel prices.

Stability: The property of a system or element by virtue of which its output will ultimately attain a steady state. The amount of power that can be transferred from one machine to another following a disturbance. The stability of a power system is its ability to develop restoring forces equal to or greater than the disturbing forces so as to maintain a state of equilibrium.

Standard Industrial Classification (SIC): A set of codes developed by the Office of Management and Budget, which categorizes business into groups with similar economic activities.

Standby Facility: A facility that supports a utility system and is generally running under no-load. It is available to replace or supplement a facility normally in service.

Standby Service: Support service that is available, as needed, to supplement a consumer, a utility system, or to another utility if a schedule or an agreement authorizes the transaction. The service is not regularly used.

Steam-Electric Plant (Conventional): A plant in which the prime mover is a steam turbine. The steam used to drive the turbine is produced in a boiler where fossil fuels are burned.

Stocks: A supply of fuel accumulated for future use. This includes coal and fuel oil stocks at the plant site, in coal cars, tanks, or barges at the plant site, or at separate storage sites.

Subbituminous Coal: Subbituminous coal, or black lignite, is dull black and generally contains 20 to 30 percent moisture. The heat content of subbituminous coal ranges from 16 to 24 million Btu per ton as received and averages about 18 million Btu per ton. Sub bituminous coal, mined in the western coal fields, is used for generating electricity and space heating.

Substation: Facility equipment that switches, changes, or regulates electric voltage.

Sulfur: One of the elements present in varying quantities in coal which contributes to environmental degradation when coal is burned. In terms of sulfur content by weight, coal is generally classified as low (less than or equal to 1 percent), medium (greater than 1 percent and less than or equal to 3 percent), and high (greater than 3 percent). Sulfur content is measured as a percent by weight of coal on an "as received" or a "dry" (moisture-free, usually part of a laboratory analysis) basis.

Switching Station: Facility equipment used to tie together two or more electric circuits through switches. The switches are selectively arranged to permit a circuit to be disconnected, or to change the electric connection between the circuits.

System (Electric): Physically connected generation, transmission, and distribution facilities operated as an integrated unit under one central management, or operating supervision.

Transformer: An electrical device for changing the voltage of alternating current.

Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Transmission System (Electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

Turbine: A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction, or a mixture of the two.

Uniform System of Accounts: Prescribed financial rules and regulations established by the Federal Energy Regulatory Commission for utilities subject to its jurisdiction under the authority granted by the Federal Power Act.

Useful Thermal Output: The thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical generation.

Voltage Reduction: Any intentional reduction of system voltage by 3 percent or greater for reasons of maintaining the continuity of service of the bulk electric power supply system.

Watt: The electrical unit of power. The rate of energy transfer equivalent to 1 ampere flowing under a pressure of 1 volt at unity power factor.

Watthour (Wh): An electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Wheeling Service: The movement of electricity from one system to another over transmission facilities of intervening systems. Wheeling service contracts can be established between two or more systems.

Wholesale Sales: Energy supplied to other electric utilities, cooperatives, municipals, and Federal and State electric agencies for resale to ultimate consumers.

APPENDIX 2

Comparison of Selected State Restructuring Legislation

Start Date of Retail Competition		
Nevada	A.B. 366; 7/16/97	Customers may begin obtaining generation, aggregation, and any other potentially competitive services from an alternative seller no later than 12/31/99, unless the PUC determines that a different date is necessary to protect the public interest. (Section 39, p. 12)
California	H.B. 1890; 8/31/96	3/31/98 (p. 30, 42)
Maine	H-568, (LD 1804); 5/23/97	Beginning on 3/1/00, all consumers have the right to purchase generation services from competitive providers. (p. 1)
Montana	S.B. 390; 5/2/97	On or before 7/1/98, customers with loads greater than 1000 kW must have opportunity to choose an electric supplier. Co-ops may file notice with PSC, within one year after effective date of Act, electing not to participate in retail access. (p. 4, 11)
New Hampshire	H.B. 1392; 5/21/97	PUC to implement in most expeditious manner and no later than 1/1/98. PUC may delay to 7/1/98 but not longer without legislative approval. (p. 9)
Oklahoma	S.B. 500; 4/25/97	All retail customers are permitted to choose their retail electric energy suppliers by 7/1/02. (p. 3-4)
Pennsylvania	H.B. 1509; 11/26/98	Transition period to begin on 1/1/97. All customers to have retail access by 1/1/01. (p. 39, 84)
Rhode Island	96-H8124 (Sub. B); 8/7/96	By 1/1/97 each distribution company shall file with PUC a plan for transferring ownership of generation, transmission, and distribution facilities into separate affiliates. Company shall implement plan within 3 months after retail access is available to 40 percent of kWh sales in New England. PUC may extend time if necessary. (p. 17-18)
Massachusetts	H.B. 5117	3/1/98 for all customers
Connecticut	H.B. 5005, 4/29/98	35% of each companies' peak load, consisting of customers in distressed municipalities will be able to choose their electric supplier by January 1, 2000. The remainder will be able to choose starting July 1, 2000.
Illinois	H.B. 362	10/99 All large industrial customers, 33% of nonresidential customers. 12/00 - remaining 66% of non-residentials. 5/02 - all residentials.

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Phase-In of Retail Competition

Nevada	A.B. 366	PUC may establish different dates for different services and different geographic areas and authorize retail competition in gradual phases. Utilities shall submit to PUC plan for compliance with Act, including information PUC needs to: set rates (e.g., utilities' cost to provide service and estimate of required revenue), allocate costs of service among customers, and adopt regulations for potentially competitive services. PUC may exempt sellers from certain portions of Act if necessary to achieve effective competition. (Section 39, p. 12; Section 49, p. 20)
California	H.B. 1890	Full retail access for all customers no later than 1/1/02; phase-in to be equitable to all classes as determined by PUC. (p. 5, 42, 91)
Maine	H-568, (LD 1804)	Beginning 3/1/02, electric billing and metering services are subject to competition. The PUC may establish an earlier date except in no case may the date be prior to 3/1/00. (p. 3)
Montana	S.B. 390	Transition period begins 7/1/98 for customers with loads greater than 1000 kW; all customers eligible by 7/1/02, unless the PSC determines added time is needed because workable competition does not exist. Full implementation may not be delayed beyond 7/1/04, however, for customers with loads greater than 1000 kW and not beyond 7/1/06 for all other customers. Participating co-ops must adopt transition plans on or before 7/1/01, and the transition period may not extend beyond 7/1/02, although the transition plan may be altered under certain circumstances. (p. 3-5, 9, 12-13)
New Hampshire	H.B. 1392	On the effective date of the Act, PUC shall undertake a generic proceeding to develop a statewide industry restructuring plan in accordance with the legislative principles in the bill. Final order is due by 2/28/97. PUC shall require all utilities to submit compliance filings. No utility shall be required, however, to commence implementation until filings representing 70 percent of retail sales have been implemented. (p. 9-10)
Oklahoma	S.B. 500	Legislature directs Corporation Commission to study all relevant issues relating to restructuring and develop a proposed industry restructuring framework under the direction of the legislative Task force. Commission shall address appropriate steps to achieve an orderly transition and may include, in addition to the directives in this Act, other provisions Commission deems necessary and appropriate. However, Commission is expressly prohibited from promulgating rules or orders relating to restructuring without prior express legislative authorization. A defined period for transition shall be established. (p. 4)
Pennsylvania	H.B. 1509	As of 1/1/99, maximum of 33 percent of peak load in each customer class will have direct access; 66 percent by 1/1/00; 100 percent by 1/1/01. PUC may extend 1/1/99 implementation date for 6 months. PUC to conduct milestone reviews to ensure technically workable and equitable transition. (p. 35, 39-41)
Rhode Island	96-H 8124, Sub. B	On 7/1/97, distribution companies required to offer retail access from non-regulated power producers to all new commercial and industrial customers with anticipated annual demand of 200 kW or more, all existing manufacturing customers over 1500 kW, and all state accounts, not to exceed 10 percent of total kW sales. On 1/1/98 access to include all existing manufacturers over 200 kW and all towns in state, not to exceed 20 percent of total kW sales. Access for all customers within 3 months after access is available to 40 percent or more of the kW sales in all New England states, but not later than 7/1/98. PUC may extend final deadline up to 6 months. (p. 24-25)
Massachusetts	H.B.5117	No phase-in

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Phase-In of Retail Competition (cont.)		
Connecticut	H.B. 5005	(see above start date info)
Illinois	H.B. 362	(see above start date info)

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Pilot Program		
Nevada	A.B. 366	
California	H.B. 1890	
Maine	H-568, (LD 1804)	
Montana	S.B. 390	Beginning 7/1/98, utilities shall conduct pilot programs using samples of residential and small commercial customers. Utilities must file a report with the PSC and the transition advisory committee on or before 7/1/00 analyzing the results of the pilot programs. Co-ops may also establish pilot programs for customers with loads less than 1000 kW. (p. 3-4, 9)
New Hampshire	H.B. 1392	
Oklahoma	S.B. 500	
Pennsylvania	H.B. 1509	PUC has authority to require utilities to submit proposals for pilots to begin 4/1/97. Program must commit 5 percent of peak load for each customer class. Minimum period for pilot is 1 year and shall include an evaluation process as directed by PUC. (p. 42-45)
Rhode Island	96-H 8124, Sub. B	
Massachusetts	H.B. 5117	
Connecticut	H.B. 5005	
Illinois	H.B. 362	

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Primary Responsibility for Implementation of Retail Competition		
Nevada	A.B. 366	PUC shall promulgate regulations to implement Act and shall determine which electric services are potentially competitive. Such services are defined as ones that: will not harm one or more customer classes; will decrease cost; increase quality or innovation, where effective competition is likely to develop; will advance competitive position of state; and won't jeopardize safety or reliability. If PUC determines that market for potentially competitive service does not include effective competition, it shall establish method for determining prices, terms, and conditions of service. Effective competition means an individual seller can't significantly influence the price of service. (Sections 39-52, p. 12-22; Section 337, p. 149)
California	H.B. 1890	PUC. (p. 42)
Maine	H-568, (LD 1804)	PUC. PUC may impose by rule any additional requirements necessary to carry out the purposes of the Act, except PUC may not regulate the rates of competitive providers. (p. 5)
Montana	S.B. 390	All public utilities shall submit a transition plan to the PSC not later than 1 year before retail choice is offered. PSC shall develop a procedural schedule for considering transition plans and issue a final order within 9 months after the plan is filed. On approval of plan, PSC shall enforce the plan in its final order. PSC may extend the transition period if workable competition does not exist. Workable competition exists if competition is sufficient to inhibit monopoly pricing or anti-competitive price leadership. (p. 5, 12-13)
New Hampshire	H. 1392	PUC authorized to order such charges and other service provisions and to take such other actions substantially consistent with the legislative principles in the bill that are necessary to implement restructuring. (p. 3, 11)
Oklahoma	S.B. 500	Legislature directs Corporation Commission to study all relevant issues relating to restructuring and develop a proposed industry restructuring framework under the direction of the legislative task force. Commission shall address appropriate steps to achieve an orderly transition and may include, in addition to the directives in this Act, other provisions Commission deems necessary and appropriate. However, Commission is expressly prohibited from promulgating rules or orders relating to restructuring without prior express legislative authorization. (p. 4)
Pennsylvania	H.B. 1509	PUC. (p. 28-29)
Rhode Island	96-H 8124 Sub. B	PUC and the Division of Public Utilities and Carriers. (p. 2)
Massachusetts	H.B. 5117	Department of Telecommunications and Energy (DTE), Division of Energy Resources (DOER)
Connecticut	H.B. 5005	Department of Public Utility Control (DPUC)
Illinois	H.B. 362	Public Utility Commission

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Independent System Operator (ISO)		
Nevada	A.B. 366	
California	H.B. 1890	Control of transmission system given to ISO. Utilities cannot collect CTC unless they commit control of their transmission assets to ISO. ISO governed by Oversight Board selected by governor and legislature. (p. 30, 36-39, 87, 90)
Maine	H-566, (LD 1804)	The governance of any ISO with responsibility for operations of the regional transmission system must be fully independent of influence by market participants. The PUC shall use all means within its authority and resources to advocate for and promote the interests of Maine ratepayers in any FERC proceeding involving the development, governance, operations, or conduct of an ISO. PUC shall monitor events in the region pertaining to the development of an ISO, the management of competitive access to the regional transmission system, and rights to negotiate potential contracts between buyers and sellers. If the PUC determines that there is insufficient independence on the part of the ISO, the PUC shall provide a report to the joint standing committee of the legislature with recommendations to remedy the problem. (p. 20, 22-23)
Montana	S.B. 390	
New Hampshire	H.B. 1392	
Oklahoma	S.B. 500	
Pennsylvania	H.B. 1509	All participants encouraged to coordinate plans and transactions through ISO or functional equivalent. ISO should, and PUC shall, set and enforce inspection, maintenance, and repair standards. (p. 23)
Rhode Island	96-H 8124 Sub. B	By 1/1/97, electric licensing committee to submit recommendations to legislature for changes to regional power pool that would facilitate creation of ISO. (p. 22)
Massachusetts	H.B.5117	Established as of 3/1/98. Monitored and analyzed by DOER.
Connecticut	H.B. 5005	The licensing process for sellers of electricity begins April 1, 1999 and requires that the seller be registered with or certified by the regional ISO, ISO-New England, or have a contractual relationship with an entity that is so registered or certified. The seller must be in compliance with all ISO-New England rules and standards and must own or purchase such capacity and reserves as ISO-New England may require.
Illinois	H.B. 362	As of enactment of bill, each electric utility company will file a request to join an ISO. If by 3/31/99, FERC has not approved the ISO application; or if by 6/30/99, all utilities have not applied to be a part of the ISO, an Oversight Board will be formed to oversee creation of ISO.

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Power Pool		
Nevada	A.B. 366	
California	H.B. 1890	Power Exchange established to operate an efficient, competitive auction for electricity open to all suppliers on a nondiscriminatory basis.(p. 5, 39)
Maine	H-568, (LD 1804)	
Montana	S.B. 390	
New Hampshire	H.B. 1392	New England Power Pool should be reformed to compliment restructuring on a regional basis. Any pool structure should not preclude bilateral contracts and should not preclude ancillary pool services from being obtained from non-pool sources. (p. 8)
Oklahoma	S.B. 500	Legislative task force is authorized to retain consultants to study the benefits of establishing a Power Exchange which would operate as a power pool allowing power producers to compete on common ground in the state. (p. 9)
Pennsylvania	H.B. 1509	PUC to take all necessary steps to encourage interstate power pools. PUC and utilities to work with federal and state governments, regional reliability councils, and interstate power pools to ensure reliable service. (p. 37)
Rhode Island	96-H 8124 Sub. B	By 1/1/97, electric licensing committee to submit recommendations to legislature for changes to regional power pool that would facilitate creation of voluntary power exchange. PUC shall establish regulations for non-regulated power producers selling into state that are necessary to meet operating and reliability standards of regional power pool. (p. 22)
Massachusetts	H.B.5117	New England Power Pool should be used to provide strong coordination and enforceable protocols for all users of the power grid and to promote the use of the interconnected regional transmission systems.
Connecticut	H.B. 5005	(see text above for Massachusetts)
Illinois	H.B. 362	

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Mandatory Rate Reductions or Rate Caps		
Nevada	A.B. 366	Rates charged for residential services must not exceed the rate charged for the service on 7/1/97. The rate cap remains in effect until 2 years after the date the PUC repeals the regulations that established the pricing method for the service. The PUC may approve an increase in the rate for residential service in an amount that does not exceed the increase necessitated to ensure the recovery by the utility of just and reasonable costs. (Section 45, p. 18)
California	H.B. 1890	Small customers receive at least 10 percent reduction on 1/1/98 and no less than 20 percent by 4/1/02. Can be financed with rate reduction bonds. (p. 5, 28, 49)
Maine	H-568, (LD 1804)	When retail access begins, PUC shall ensure that standard-offer service is available to all consumers of electricity. By 2/15/98, PUC shall provisionally adopt rules establishing terms and conditions for standard-offer service. If qualifying bids for standard-offer service in any service territory, when combined with the regulated rates of transmission and distribution service and any stranded costs charge exceed, on average, the total rate for electricity immediately before the implementation of retail access, PUC shall investigate whether implementation of retail access remains in the public interest or whether other mechanisms to achieve the public interest and to adequately protect consumer interests need to be put in place. PUC shall notify legislature of results of its investigation and its determination. (p. 17-18)
Montana	S.B. 390	Rate moratorium during transition period: 7/1/98 thru 6/30/00, utilities may not charge more than rates in effect on 7/1/98; 7/1/00 thru 6/30/02, utilities may not increase the increment of rates normally allocated to electric supply-related costs above those associated with such costs in effect on 7/1/98. From 7/1/00, utilities may propose increases to rate increments normally allocated to T&D costs. Increased costs related to universal system benefit programs greater than those in effect on passage are exempt from rate caps, as are increased costs necessary to implement full customer choice including metering, billing, and technology. Certain other exemptions are allowed in extraordinary cases. (p. 6-8)
New Hampshire	H.B. 1392	
Oklahoma	S.B. 500	
Pennsylvania	H.B. 1509	Rates capped at 1/1/97 levels for 54 months or until stranded costs are recovered and all customers have retail access, whichever is shorter. Additionally, generation component of rates is capped for 9 years or until distribution utility has collected stranded costs and all customers have direct access, whichever is shorter. (p. 30-31)
Rhode Island	96-H 8124 Sub. B	Within 3 months after retail access is available to 40 percent of the kW sales in New England and extending through 2009, distribution companies must arrange power contracts for their customers who have not contracted for their own power supply such that the average revenue per kWh received from the customer shall equal the price for the 12-month period ending 9/30/96, with certain inflationary adjustments. No customer who chooses this standard offer and subsequently contracts with their own supplier shall be required to pay an exit fee. (p. 26)
Massachusetts	H.B.5117	2.8 cent/kWh standard offer charge for generation offered by energy producers affiliated with established distribution companies. 10% rate reduction for all customers off rates in effect 8/97. Proceeds from securitization, if chosen and approved, can be used toward further reducing rates by additional 5%.
Connecticut	H.B. 5005	From 7/1/98 until 1/1/00, rates are capped at their 12/31/96 levels. Starting 1/1/00, each distribution company must provide service under a "standard offer" to those customers who do not arrange for service from an alternate supplier. The standard offer, provides for a 10% reduction (off rates effective 12/31/98). This requirement runs for 4 years. DPUC must adjust rates under the standard offer to reflect changes in taxes and fuel costs. Starting 1/4/04, distribution companies must procure power for consumers who do not obtain service from competitive suppliers, but can charge market rates for this power.
Illinois	H.B. 362	ComEd and IP residential rate reductions: 8/98 - 15%; 10/02 - 0%. Other suppliers except CILCO's residential rate reductions: 8/98 - 5% (2% CILCO); 5/02 - Max 5%, 10/02 - reflective of Midwest avg. (CILCO has had historically low rates compared to the Midwest avg, therefore, it doesn't have to offer as substantial rate reductions as ComEd and IP. Non-residential customers get no rate reduction.)

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Financing Rate Reductions and Stranded Costs		
Nevada	A.B. 366	
California	H.B. 1890	Provides for rate reduction bonds to finance rate reductions and stranded ("transition") costs. (p. 5-6, 75-87)
Maine	H-588, (LD 1804)	
Montana	S.B. 390	PSC may authorize the imposition and collection of fixed transition amounts and the issuance of transition bonds. After 7/1/97, a utility may apply to the PSC for a determination that certain transition costs may be recovered through the issuance of transition bonds. If such bonds are not issued within 4 years of the PSC order, the order must terminate. A utility may apply for an extension or renewal of the order. Order must set forth the term over which transition bonds are to be paid—not to exceed 20 years. Upon issuance of transition bonds, the financing orders and fixed transition amounts must be irrevocable. Cost savings associated with and resulting from the bonds must benefit customers. Proceeds from bonds must be used to recover, reimburse, finance or refinance transition costs, and to acquire transition property. Bonds may not constitute an indebtedness or loan of credit against the state or a political subdivision thereof. Co-ops may fully recover transition costs approved by local governing body. (p. 2-3, 6-7, 10, 16-21)
New Hampshire	H.B. 1392	
Oklahoma	S.B. 500	All transition costs shall be recovered by virtue of savings generated by increased efficiency in markets brought about by restructuring. All classes of consumers shall share in the transition costs. No later than 1/1/99, Commission shall commence study of financial issues related to restructuring. Study shall include but is not limited to examination of IOU financing and any other financial issues Commission deems appropriate. Final report shall be provided to legislative task force no later than 12/31/99. (p. 6-7)
Pennsylvania	H.B. 1509	PUC may approve utility request for issuance of transition bonds for some or all of its stranded costs. If approved, the utility's rates or its CTC must be reduced by an amount equal to the revenue requirement of the stranded costs for which transition bonds have been issued. (p. 52-53, 69-84)
Rhode Island	96-H 8124 Sub. B	
Massachusetts	H.B. 5117	As of 7/1/98, DTE will review purchase power contracts to determine if utility companies have made efforts to reduce or renegotiate them in order to reduce stranded costs. Non-mitigable stranded costs can be collected through a transition charge. Customers can only bypass transition charge if they have already notified utility company of intention to cogenerate. No exit fee would be charged that customer in that case.
Connecticut	H.B. 5005	Certain stranded costs resulting from generation-related regulatory assets and above-market long-term contracts are eligible to be refinanced through the issuance of rate reduction bonds. The bonds will mature no later than 12/31/11. Beginning 1/1/00, all utility customers will be charged a new competitive transition assessment to pay the debt service on the rate reduction bonds and approved stranded costs that are not eligible to be funded with the proceeds of the rate reduction bonds. The assessment will be charged until the bonds are paid in full and stranded costs are fully recovered by the utilities.
Illinois	H.B. 362	Utilities may use securitization to finance transitional costs or stranded costs. Commission must approve of securitization as long as the proceeds of sale will be used to: 1) refinance debt, equity or both reducing capital; 2) retire fuel contracts for nukes; or 3) fund debt services to pay for costs associated with above. Funding charges for securitization can only be collected until 12/31/08.

Source: <http://www.ncsl.org/programs/esnr/compare.htm>

Updated: July, 1998

Divestiture of Generation Assets		
Nevada	A.B. 386	A vertically integrated electric utility shall not provide a potentially competitive service except through an affiliate. The PUC shall establish limitations on ownership, operation, and control of the assets of a provider of an electric service to prevent anti-competitive conduct and ensure the development of effective competition. Such conditions and limitations may include limitations on the ownership, operation, and control of transmission facilities and any generation necessary to the reliable and economic operation of such transmission facilities. An affiliate may provide a potentially competitive service if PUC finds there is an arm's length transaction that will not adversely affect effective competition and the risk of anti-competitive behavior, and the regulatory expense to prevent such behavior, is minimal; PUC shall adopt procedure to process an affiliate request to provide potentially competitive service and shall make any required findings no later than 6 months before authorizing retail competition. (Section 39, p. 12; Sections 41-43, p. 15-16)
California	H.B. 1890	Essential to separate monopoly transmission function from competitive generation operations by use of ISO. PUC must approve retention of generation assets in same corporation with distribution assets after market valuation. (p. 29, 61)
Maine	H-568, (LD 1804)	On or before 3/1/00, each investor-owned utility shall divest all generation assets and generation-related business activities other than contracts with QFs or demand side management providers, facilities located outside the U.S., or generation assets PUC determines necessary for the utility to perform its transmission and distribution obligations. No later than 1/1/99, each utility shall submit to the PUC a plan to accomplish divestiture. PUC shall review the plans and, by 7/1/99, issue an order approving or modifying the plan. Utility may apply for an extension beyond 3/1/00. PUC shall grant an extension if the extension would improve the sale value of the assets. If extension is granted, utility shall transfer generation assets to a distinct corporate entity by 3/1/00. After 2/28/00, each utility shall sell rights to capacity and energy from all generation assets except those necessary to perform its transmission and distribution obligations. PUC shall adopt rules governing the procedure for divestiture. PUC shall require distribution utility to divest an affiliated competitive provider if the utility or the affiliate has knowingly violated provisions of the Act and the violation resulted in or had the potential to result in substantial injury to retail consumers. If, after the effective date of the Act, 10 percent or more of the stock of a distribution utility is purchased by an entity, the purchasing entity and any affiliate may not sell or offer generation service to any retail customer and, if the PUC determines that an affiliated provider obtains an unfair market advantage as the result of such a purchase, the PUC shall order the distribution utility to divest the affiliate. If PUC orders a distribution utility to divest an affiliate, the distribution utility may not have an affiliated interest in a competitive provider after the divestiture. (p. 2, 7, 11-12)
Montana	S.B. 390	To the extent a utility is vertically integrated, it shall functionally separate electricity supply, retail transmission, and distribution. PSC may approve functional separation but may not order divestiture or prohibit it. Utilities shall prevent undue discrimination in favor of own power supply and prevent any form of self-dealing that could result in noncompetitive electricity prices. Utilities must grant customers and suppliers access to the utilities' retail transmission and distribution systems on a nondiscriminatory, comparable basis. Utilities may satisfy these provisions if they adopt a code of conduct consistent with the FERC-approved code of conduct. Similar provisions apply to co-ops. (p. 2, 5, 9)
New Hampshire	H.B. 1392	Restructuring should require at least functional separation of generation from transmission and distribution services. However, distribution companies should not be entirely precluded from owning small-scale distributed generation resources. PUC authorized to require that distribution and power supply services be provided by separate affiliates. (p. 2, 4, 11)
Oklahoma	S.B. 500	A primary goal of a restructured electric industry is to encourage development of competition through separation of generation services from transmission and distribution services. Entities that own both transmission and distribution, as well as generation facilities, shall not be allowed to use any monopoly position in these services as a barrier to competition. Generation services shall be functionally separated from transmission and distribution services. No later than 1/1/98, Commission shall commence study of technical issues related to restructuring, which shall include but not be limited to examination of unbundling of generation, transmission and distribution services, and market power. (p. 2-4, 6)
Pennsylvania	H.B. 1509	PUC may permit but cannot require a utility to divest facilities or reorganize its corporate structure. (p. 33-34)

Source: <http://www.ncsl.org/programs/esnr/compare.htm>

Updated: July, 1998

Divestiture of Generation Assets (cont.)		
Rhode Island	96-H 8124 Sub. B	By 1/1/97, distribution companies must file plan with PUC to transfer ownership of generation facilities to separate affiliates. Every wholesale power supplier receiving contract termination fees must subject its generating facilities to market valuation through lease, sale, spin-off or other method. At least 15 percent of such facilities must be disposed of through this process. If company is subject to a higher requirement in another state's restructuring proceeding, same amount will apply in Rhode Island. Implementation methodology must be filed with PUC by 7/1/97. Employees of distribution company must function independently of affiliated non-regulated power company under detailed standards of conduct. (p. 17, 31-32, 35-38)
Massachusetts	H.B.5117	Optional divestiture, although encouraged by DTE as a good way for utility to rid itself of nuclear related stranded costs. Non-nukes must be sold at auction or sale. Proceeds from sale of generation, net of tax effects, should be applied to reduce amount of transition costs. Affiliates must be separate entities.
Connecticut	H.B. 5005	The state's electric companies must unbundle and separate their power generation assets from their transmission and distribution assets. Utilities must divest their nonnuclear generation by 1/1/00, sell their nuclear generation assets and mitigate their costs in order to be eligible to claim any stranded costs. By 1/1/00, DPUC must establish a competitive transition assessment (CTA) for each distrib co. to recover DPUC-approved stranded costs. The CTA will be applied to all customers.
Illinois	H.B. 362	

Source: <http://www.ncsl.org/programs/esnr/compare.htm>

Updated: July, 1998

Treatment of Stranded Costs		
Nevada	A.B. 366	When PUC determines an electric utility providing noncompetitive service cannot meet the conditions to also provide a potentially competitive service, utility has reasonable opportunity to recover previously incurred costs of those services it elects not to provide in future. The PUC shall determine the recoverable costs associated with assets and obligations documented in the accounting records of a vertically integrated electric utility that are properly allocable to a particular potentially competitive service as of the date alternative sellers begin providing such service in this state. Shareholders of the utility must be fully compensated for all such costs determined by the PUC. In determining the recoverable costs, the PUC shall take into account extent utility was legally required to incur cost; extent market value exceeds costs for assets and obligations; mitigation efforts; extent to which previous rates have already compensated shareholders for risk of non-recovery; tax effects; and, where utility had discretion to incur costs, its performance relative to similar utilities. PUC may impose a non-bypassable mechanism for recovery and determine time period for recovery. Such determinations and procedures must not discriminate against a market participant. (Section 43, p. 16; Section 46, p. 18)
California	H.B. 1890	Fair opportunity to fully recover costs of PUC approved generation-related assets, including work force realignments and buyouts of certain existing power contracts. PUC to identify and determine costs and categories that may become uneconomic. Such costs are recoverable from all customers on a non-bypassable basis. Calculation based on book cost net against market value. Departing customers pay a severance fee; remaining customers pay a competitive transition charge (CTC) based on customer usage. CTC ends for most costs on 12/31/01; employee related cost recovery extends to 12/31/06. "Firewall" protects customers in one class from absorbing CTC exemptions granted in other classes. If local publicly owned utility elects not to allow retail competition, it cannot recover stranded costs. (p. 5, 31, 45-53, 60, 89-90)

Source: <http://www.ncsl.org/programs/esnr/compare.htm>

Updated: July, 1998

Treatment of Stranded Costs (cont.)		
Maine	H-568, (LD 1804)	Stranded costs: a utility's legitimate, verifiable, and unmitigable costs made unrecoverable as a result of restructuring and determined by the PUC. For each utility, PUC shall determine the sum of the following to the extent they qualify as stranded costs: costs of utility's regulatory assets related to generation; difference between net plant investment associated with generation assets, and the market value of generation assets; difference between future contract payments and market value of the utility's purchased power contracts. When determining market value of generation assets and purchased power contracts, PUC shall rely to the greatest extent possible on market information. PUC may not include any costs for obligations incurred on or after 4/1/95, except: regulatory assets created after 4/1/95 and prior to 3/1/00, for amortization of costs associated with restructuring a QF contract; costs deferred pursuant to rate plans; energy conservation costs; obligations incurred after 4/1/95, and prior to 3/1/00, that are beyond the control of the utility; and obligations incurred after 4/1/95, to reduce potential stranded costs. Utility must pursue all reasonable means to reduce potential stranded costs and to receive highest possible value for assets and contracts. PUC shall consider utility's efforts to mitigate when determining amount of stranded costs. PUC shall provide utility a reasonable opportunity to recover stranded costs through rates of transmission and distribution. Nothing in the Act may be construed to give a utility a greater or lesser opportunity to recover stranded costs than existed prior to retail access. Before retail access begins, PUC shall estimate stranded costs of each utility. PUC shall use these estimates as the basis for a stranded costs charge to be charged by each transmission and distribution utility when retail access begins. In 2003, and every 3 years thereafter until utility is no longer recovering adjustable stranded costs, PUC shall correct any substantial inaccuracies in the estimates and adjust the charges to reflect the correction. Any change will be prospective only and may not reconcile past estimates to reflect actual values. PUC shall set an amount of recoverable, stranded costs after calculating the net aggregate value of all divested assets that had proceeds exceeding book costs against the aggregate value of all other stranded generation assets. Commission may not shift cost recovery among customer classes in a manner inconsistent with existing law. PUC shall conduct separate adjudicatory proceedings to determine stranded costs for each utility. In the same proceeding, PUC shall establish stranded cost charges for each utility. Customer who significantly reduces or eliminates consumption due to self-generation, conversion to alternative fuel or DSM, may not be assessed an exit or entry fee in any form. Absent other just cause, a layoff after 3/1/00 is deemed to be a result of retail competition. Each utility must file a plan with the PUC prior to the beginning of retail access providing transition services and benefits for eligible employees. Such benefits include programs to assist employees in maintaining fringe benefits, up to 2 years of retraining and out-placement services, full tuition for 2 years at the University of Maine or a comparable technical school at the discretion of the employee, 24 months of continued health care insurance, and severance pay equal to 2 weeks of base pay for each year of full-time employment. The plan may include provisions for early retirement benefits. PUC shall allocate the reasonable accrual incremental cost of such benefits to ratepayers through charges collected by the transmission and distribution utility. All charges must be transferred to a system benefits administrator in the transmission and distribution utility and used to provide the benefits and services provided for in the Act. (p. 13-15, 21-22)
Montana	S.B. 390	PSC shall allow recovery of transition costs including unmitigatable costs of QFs such as reasonable buyout or buy down, unmitigatable costs of energy supply-related regulatory assets and deferred charges, unmitigatable transmission costs related to generation and other power purchase contracts, except recovery of those costs is limited to the amount accruing during the first 4 years after the PSC approves a transition plan. Value of generation-related assets must be reasonably demonstrable and considered on a net basis. Methods for determining value include estimating future market values, independent third-party appraisal, and competitive bid sale. Transition charges must be imposed within a transition cost recovery period approved by the PSC on a case-by-case basis. Certain transition costs may have varying transition cost recovery periods. (p. 3, 6-7, 10)

Source: <http://www.ncsl.org/programs/esnr/compare.htm>

Updated: July, 1998

Treatment of Stranded Costs (cont.)		
New Hampshire	H.B. 1392	Defined: costs, liabilities, and investments utilities would reasonably expect to recover under existing regulatory scheme but which they will not recover in a competitive market. Limited to existing, PUC-approved renegotiated, or new PUC-mandated, commitments. Legislative intent to give PUC appropriate tools and guidance to address stranded costs. PUC shall balance interests of ratepayers and utilities. Nothing is intended to provide greater recovery than present law provides. Utilities should recover net nonmitigatable costs of environmental mandates and federally mandated QF contracts. Costs should be on net basis, verifiable, exclusive of transmission and distribution assets, periodically trued up. Recovery should be by nondiscriminatory, appropriately structured charge, fair to all customer classes, limited in duration, consistent with promotion of competitive markets, applied only to customers within the distribution utility's service territory. Entry and exit fees are not preferred mechanisms. PUC may establish interim recovery charge good for 2 years after compliance filing, to be netted against final recovery charges. Interim charge sets no precedent for amount of final recovery charge.(p. 4, 7-8, 10-11)
Oklahoma	S.B. 500	A procedure shall be established for identifying and quantifying stranded costs and for allocating such costs. Mechanisms shall be proposed for recovery of an appropriate amount of prudently incurred, unmitigatable, verifiable stranded costs. Each entity must propose a recovery plan that establishes its unmitigatable, verifiable stranded costs and a limited recovery period designed to recover costs expeditiously, provided that the recovery period and amount of transition costs shall yield a transition charge that shall not cause total price, including transmission and distribution services, for any consumer to exceed the cost per kW hour paid on the date of this Act during the transition period. Transition charge shall be applied to all consumers including direct access consumers, shall not disadvantage one class or supplier over another, shall not impede competition, and shall be allocated over a period of not less than 3 nor more than 7 years. No later than 1/1/99, Commission shall commence a study of financial issues related to restructuring, which shall include but not be limited to the examination of stranded costs and their recovery, and a final report shall be provided to the legislative task force no later than 12/31/99. (p. 6-7)
Pennsylvania	H.B. 1509	Fair opportunity to fully recover amount of stranded costs PUC determines to be just and reasonable. PUC determines level of each utility's stranded costs to be collected through a non-bypassable CTC applied to all customers accessing transmission and distribution systems. PUC must adhere to specifically enumerated principles in determining amount. Calculation based on utility's known and measurable net generation-related cost determined on net present value basis over life of asset that may become uneconomic despite mitigation efforts. Includes prudently incurred costs of work force realignments and power contract buyouts and excludes any costs previously disallowed by PUC as imprudent. (p. 21-22, 24, 26-27, 35-36, 49-52)
Rhode Island	96-H 8124 Sub. B	Utilities should have a reasonable opportunity to recover prudently incurred transition costs. Distribution companies who purchase wholesale power under an all-requirements contract are authorized to terminate the contract and pay a termination fee. Such payments are recoverable from all customers through a non-bypassable transition charge. Charge may include costs of regulatory assets, nuclear obligations, buyout of above market power contracts, net unrecovered commitments, and capital costs of generating plants. Charge continues until liabilities are satisfied, with true up calculations. Recovery time for certain specified components is limited to period from 7/1/97 to 12/31/00. From 7/1/97 to 12/31/00, charge shall recover 2.8¢/kWh, thereafter in an amount set by PUC.(p. 3, 20, 28-30)
Massachusetts	H.B.5117	Use of securitization by distribution company would require approval by DTE and is subject to achievement of mitigation efforts satisfactory to DTE. But, use of securitization may only be used if distrib. co. demonstrated that rate reductions stemming from securitization would not be financially viable without securitization.

Source: <http://www.ncsl.org/programs/esnr/compare.htm>

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Treatment of Stranded Costs (cont.)

Connecticut	H.B. 5005	To have stranded costs approved, the utility must take reasonable steps to mitigate the costs, including seeking to have the purchasers of generation assets offer employment to those employed by the divested generating facility and making good faith efforts to negotiate the buyout, buydown or renegotiation of power contracts. An electric company is eligible to claim stranded costs in connection with its nonnuclear generation assets only if it divests them. The DPUC will calculate the stranded costs for generation-related regulatory assets to be their book value as of 1/1/00. Stranded costs for long-term contract costs that have been reduced to a fixed present value through the buyout, buydown, or renegotiation of independent power producer contracts and purchased power contracts approved by FERC will be calculated at their present value and the DPUC will then net purchased power contracts approved by the FERC that are below market value against any contracts that are above market value. Stranded costs for nonnuclear generation assets will be calculated by the DPUC to be the difference between the book value and the market value of an efficiently managed, comparable nonnuclear generating facility in a competitive market. A distrib co. can apply to DPUC to retire Millstone I for economic reasons. DPUC must allow any recovery ordered to be recovered through a CTA. Other nuclear power plants must be operating for recovery of the stranded costs associated with them. Companies must put plants up for auction by 1/1/04 if they want to continue recovery of associated stranded costs.
Illinois	H.B. 362	Residential: Graduated transition chg. decreases annually during the period 2002-2006. Non-Residential: .05 cents/kWh in '99 increases to .9 cents/kWh in 2006. Intangible transition assets can be securitized. Collection of transition costs can continue to 2008, 2010, if determined to be in public interest. The amt. Securitized cannot exceed 50% of total capitalization (\$7 billion for ComEd, \$1.8 billion for IP)

Source: <http://www.ncsl.org/programs/esnr/compare.htm>

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Reciprocity		
Nevada	A.B. 366	PUC to issue a quarterly report to legislature evaluating, among other issues, opportunities to cooperate, formally or informally, with other states or with the Federal Government in the implementation of competition. (Section 53, p. 23)
California	H.B. 1890	For a utility to sell to another utility's customers, it must allow access to its own customers. Out-of-state utilities must enter into a compact to adhere to enforceable reliability protocols to be allowed to sell to California retail customers. (p. 29, 90-91)
Maine	H-568, (LD 1804)	
Montana	S.B. 390	All suppliers must be afforded open, fair, and nondiscriminatory access to customers and a comparable opportunity to compete. Distribution service providers or affiliates may not use another distribution service provider's facilities unless the first provider offers comparable, nondiscriminatory access to its distribution facilities. Co-ops that elect not to participate in retail access may not use utilities' distribution systems unless there is a pre-existing contract. (p. 11, 14)
New Hampshire	H.B. 1392	
Oklahoma	S.B. 500	Any municipal corporation may voluntarily become subject to the provisions of the Act through a non-revocable election. Any municipal corporation that elects not to participate shall be prohibited from extending retail electric distribution service beyond its corporate limits with the exception that it may continue to offer retail distribution service from lines owned on the Act's effective date. (p. 4, 9)
Pennsylvania	H.B. 1509	No entity regulated by the PUC may use the transmission or distribution system of another PUC regulated entity to supply electricity to an end-use customer unless the first entity allows the other entity to sell to its customers. (p. 38-39)
Rhode Island	96-H 8124 Sub. B	
Massachusetts	H.B.5117	All suppliers must be given open access to customers and the ability to compete. The Commonwealth should enter into compact with other New England state and N.Y. that provides incentives to sell electricity to MA retail customers. But protects reliability of regional transmission and distribution
Connecticut	H.B. 5005	Municipal companies cannot restructure unless they want to sell outside their service territories. If they decide to do this, they must open their markets to competitors. Municipals account for only 4% of the market in CT.
Illinois	H.B. 362	Alternative suppliers may not: 1) deny service or offer different terms, rates, etc. to anyone or group; 2) deny service based on locality or change rates etc. based on locality. Electric Co. may serve customer outside service territory as long as customer is eligible for service from alternative and has expressed desire for alt. Service. They may also sell to customers previously served by municipal company. Municipal CO's are exempt from state jurisdiction.

Source: <http://www.ncsl.org/programs/esnr/compare.htm>

Updated: July, 1998

Customer Aggregation		
Nevada	A.B. 366	Customers may begin obtaining aggregation services from an alternative seller no later than 12/31/99, unless the PUC determines that a different date is necessary to protect the public interest. (Section 29, p. 11; Section 39, p. 12)
California	H.B. 1890	All customer classes are entitled to aggregation on a voluntary basis. Can be done by private parties, or governmental entities. Public bodies acting as residential aggregators must offer to include everyone within the jurisdiction. (p. 43)
Maine	H-568, (LD 1804)	When retail access begins, consumers may aggregate in any manner they choose. If a public entity serves as an aggregator, it may not require consumers within its jurisdiction to purchase generation service from that entity. (p. 2-3)
Montana	S.B. 390	Aggregators may be licensed by the PSC to aggregate retail customer purchases. Aggregators take title to electric energy as an intermediary for sale to retail customers. (p. 2)
New Hampshire	H.B. 1392	
Oklahoma	S.B. 500	
Pennsylvania	H.B. 1509	Permits PUC licensing of aggregators, brokers and marketers as suppliers of electric energy, including municipal corporations selling outside their municipal limits, to serve all customer classes. (p. 24, 53-56)
Rhode Island	96-H 8124 Sub. B	
Massachusetts	H.B.5117	Municipalities can aggregate, but cannot solicit customers of municipal companies. Cities and towns can aggregate on behalf of citizens.
Connecticut	H.B. 5005	By 1/1/00, the DPUC must propose standards and procedures to facilitate the aggregation of electricity loads and the aggregation of end use customers into buying groups.
Illinois	H.B. 362	Groups of customers can aggregate power needs and purchase electricity at bulk rates. However, customers included in aggregation must have become eligible for choice.

Source: <http://www.ncsl.org/programs/esnr/compare.htm>

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Unbundling		
Nevada	A.B. 366	PUC to determine which electric services are potentially competitive using a set of specified criteria. Retail customers will have direct access to such services. (Section 39, p. 12-13)
California	H.B. 1890	Each electric corporation shall propose a stranded cost recovery plan to the PUC, which must provide identification and separation of individual rate components. Bills shall disclose each component of the total charge. (p. 49, 62, 71)
Maine	H-568, (LD 1804)	Beginning 1/1/99, utility shall issue bills that state the current cost of electric capacity and energy separately from transmission and distribution charges and other charges for electric service. By 1/31/98, each utility shall file an unbundling proposal with PUC. Beginning 3/1/02, billing and metering services are subject to competition. PUC may establish an earlier date for competitive billing and metering services, but beginning date may not be prior to 3/1/00. (p. 3, 19)
Montana	S.B. 390	Electrical bills must disclose each component of the electrical bill in accordance with the rules promulgated by PSC. Bills must disclose distribution and transmission charges, electricity supply charges, competitive transition charges, and universal system benefits charges. (p. 14)
New Hampshire	H.B. 1392	Restructuring should require unbundling of prices and services. Customers should be able to choose options such as levels of reliability, real time pricing, and generation source. There should be clear price information on generation, transmission, distribution, and ancillary services. (p. 2, 4)
Oklahoma	S.B. 500	A primary goal of a restructured industry is to encourage unbundling of prices. Consumer choice means retail consumers shall be allowed to purchase different levels and quality of electric supply. When consumer choice is introduced, rates shall be unbundled to provide clear price information on generation, transmission, distribution, and ancillary charges. Bills for all classes shall be unbundled, utilizing line itemization to reveal various component costs of services. Charges for public benefit programs shall be unbundled and appear in line item format for all classes of consumers. (p. 3-5)
Pennsylvania	H.B. 1509	PUC must require unbundling of electric services, tariffs, and bills to separate charges for generation, transmission and distribution, and may require unbundling of other services. Customer bills must contain unbundled charges sufficient to enable consumer to determine basis for the charges. (p. 29-30, 47)
Rhode Island	96-H 8124 Sub. B	On or before 1/1/97, and effective 7/1/97, distribution companies shall file unbundled rates separately stating transmission, distribution and transition charges. Customer bills shall conspicuously display specified information, including transition and conservation charges, taxes, number of kWh consumed, cost of power, cost of distribution, and other costs. (p. 27, 49)
Massachusetts	H.B. 5117	As of 1/1/98, unbundled bills were sent to customers.
Connecticut	H.B. 5005	By 10/1/98, each electric company must submit a plan to the DPUC to unbundle and separate by 10/1/99, all of the utility's generation assets. Any nonnuclear generation assets that the utility does not intend to divest by 1/1/00 must be unbundled and separated by transferring them to one or more separate affiliates. Any nuclear generation assets that the utility does not intend to sell by 1/1/00 must be unbundled and separated by divesting them by 1/1/04, transferring them to one or more separate affiliates or to one or more divisions.
Illinois	H.B. 362	Three years from effective date of this Act, Commission will investigate the need for unbundling.

Source: <http://www.ncsl.org/programs/esnr/compare.htm>

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Consumer Education		
Nevada	A.B. 366	The PUC shall establish minimum standards for the form and content of all disclosures, explanations, or sales information disseminated by sellers of competitive services to ensure that consumers receive adequate, accurate, and understandable information about the service that enables them to make an informed decision relating to the source and type of electric service purchased. Such standards must not be unduly burdensome, must not unnecessarily delay or inhibit competition, and may establish different requirements for disclosures, explanations, or sales information relating to different services or similar services to different classes of customers wherever appropriate. Before commencement of direct access, the PUC shall carry out an educational program for consumers to inform them of changes in the provision of electric service, inform them of the requirements relating to disclosures, explanations, or sales information, and provide assistance in understanding and using the information to make reasonably informed choices. The PUC shall expend up to \$500,000 from its reserve account to provide education and informational services to educate and inform residents. The PUC shall contract with an independent person to provide such services. (Section 48, p. 19; Section 57, p. 24)
California	H.B. 1890	Electric corporations, in conjunction with PUC, shall devise and implement a customer education program. (p. 72)
Maine	H-568, (LD 1804)	PUC shall establish standards for publishing and disseminating, through any means considered appropriate, information that enhances consumers' ability to effectively make choices in a competitive market. PUC shall adopt rules implementing a consumer education program including the immediate organization of a consumer education advisory board to investigate and recommend methods to educate the public about retail access and its impact on consumers. PUC shall ensure broad representation from all customer classes including public agencies on the advisory board. Members serve without compensation. The advisory board must address level of funding for adequate educational efforts and source of such funding; aspects of retail access on which consumers need education; most effective means of accomplishing education of consumers; appropriate entities to conduct education efforts; and any other relevant issue regarding education of consumers. PUC shall consider the recommendations of the advisory board when adopting rules to implement a consumer education program. (p. 5, 19)
Montana	S. B. 390	Public utilities shall educate customers about choice so customers can make informed choices. The education process must give special emphasis to efforts during the transition period.
New Hampshire	H.B. 1392	PUC should ensure customer confusion is minimized and consumers will be well informed about changes. (p. 4)
Oklahoma	S.B. 500	Commission shall ensure that consumer confusion will be minimized and consumers will be well informed about changes resulting from restructuring and increased choice. (p. 4)
Pennsylvania	H.B. 1509	Each distribution company, in conjunction with PUC, must implement a consumer education program. PUC shall establish regulations to ensure suppliers provide adequate and accurate information to enable consumers to make informed choices. Information must be in an understandable format that enables comparison of price and service on a uniform basis. (p. 47-48)
Rhode Island		Distribution companies to notify customers of retail options at least 90 days prior to eligibility for retail access. (p. 25)
Massachusetts	H.B. 5117	DOER will be primary agency in charge of consumer ed. DOER will provide a toll free hot-line for customers, and provide educational materials. Educational services will be approved by DTE to ensure they're not duplicative of educational/protection services provided by DTE's Consumer Division. Portfolio standards and disclosure of fuel sources, emissions etc. will be provided in standardized form for consumers to make supplier choices.
Connecticut	H.B. 5005	DPUC must establish a comprehensive education program. The cost of this program is covered by a systems benefits charge.
Illinois	H.B. 362	

Source: <http://www.ncsl.org/programs/esnr/compare.htm>

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Consumer Protection		
Nevada	A.B. 386	Any alternative seller must have a PUC license, which may be limited, suspended, or revoked to protect the public interest. By 1/1/99, PUC to establish conditions alternative sellers must satisfy before selling to retail customers. Conditions relate to safety, electric reliability, financial reliability, fitness to serve customers, billing practices, and terms for establishing and terminating service. PUC to establish and implement standards of conduct related to activities inconsistent with goals of Act, including appropriate penalties for violation and procedures for imposing such penalties and referring potential violations to Attorney General or Justice Department. PUC shall establish procedures to ensure no customer is switched to another seller without reliable confirmation. (Section 40, p. 14; Section 42, p. 15-16; Section 48, p. 19)
California	H.B. 1890	Every entity offering power to small customers must register with PUC. All offers of service must include written notice of price and terms, including amount of CTC and right to rescind contract. Consumers can recover actual and punitive damages, including attorney's fees, for violations. No residential or small commercial customer's account can be switched to another provider without confirmation by an independent third party verification company. (p. 8, 43-44, 72-73)
Maine	H-568, (LD 1804)	PUC shall establish minimum standards to protect consumers. PUC shall license competitive electric providers. To issue a license, PUC must receive evidence of financial capability, ability to enter into binding interconnection arrangements with transmission and distribution utilities, disclosure of all pending legal actions and customer complaints filed during the prior 12 months, evidence of ability to satisfy the renewable resource portfolio standards, and disclosure of names and corporate addresses of all affiliates. PUC may also require a bond as evidence of financial ability to withstand market disturbances. PUC shall establish rules governing information disclosure for competitive providers. As a condition of licensure, provider supplying customers with a demand of 100 kW or less may not terminate generation service without 30 days' prior notice, must offer service for a minimum period of 30 days, must allow customer to rescind selection of competitive provider within 5 days of initial selection, may not telemarketing services to a customer who has filed a written request not to receive such services, and must provide a customer with specified disclosure information within 30 days of contracting. PUC may limit the duration and scope of a license or may revoke a license in the public interest. PUC shall establish by rule consumer protection standards to protect and promote market competition and to prevent fraud or other unfair and deceptive business practices. PUC may impose a penalty of up to \$5,000 for each violation of any consumer protection rule. Each day of a violation constitutes a separate offense. If PUC has reason to believe that utility has violated any provision of law for which a criminal prosecution is provided or has violated any antitrust law of the state or the US, PUC shall notify the attorney general. Attorney general shall promptly institute any appropriate actions. A distribution utility may not release any proprietary customer information without the prior written authorization of the customer. Employees of a distribution utility may not state or provide any customer or potential customer opinion regarding reliability, experience, qualifications, financial capability, managerial capability, operations capability, customer service record, consumer practices, or market share of any affiliated competitive provider or nonaffiliated competitive provider. (p. 4-6, 9-10, 12)
Montana	S.B. 390	Public interest requires continued protection of consumers through licensure, provision of information, and a process for investigating and resolving complaints. Utilities shall maintain standards of safety and reliability of the electric delivery system. PSC may require proof of financial integrity, adequate reserves, and a license bond. PSC may revoke or suspend a license of an electric supplier or impose a penalty or both. If the supplier intentionally provided false information to PSC, switched electricity customer without written permission, failed to provide reasonably adequate supply of electricity, committed fraud, or engaged in deceptive practices, fine is not less than \$100 or more than \$1,000 for each violation. Each day of each violation constitutes a separate violation. PSC shall promulgate rules establishing procedures to prevent unauthorized switching of customers. Transitional advisory committee shall file annual report in 2000 that addresses the need, if any, for additional consumer protection including protection from abusive or anti-competitive practices. (p. 1, 11, 13-14, 16)
New Hampshire	H.B. 1392	Retail suppliers who do not own transmission and distribution facilities should at a minimum be registered with PUC. (p. 5)

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Consumer Protection (cont.)		
Oklahoma	S.B. 500	Appropriate rules shall be promulgated ensuring that reliable and safe electric service is maintained. Minimum residential consumer service safeguards and protections shall be ensured. No later than 1/1/98, Commission shall commence study of technical issues related to restructuring including but not limited to reliability and safety. Final report shall be provided to legislative task force no later than 12/31/98. No later than 7/1/99, Commission shall commence study of consumer issues related to restructuring including but not limited to examination of consumer safeguards and licensing of retail suppliers. Final report shall be provided to legislative task force no later than 8/31/00. All retail suppliers shall be required to meet certain minimum standards designed to ensure reliability and financial integrity and be registered with Commission. There shall be no customer switching between distribution providers from the date of this Act until 7/1/02, except by mutual consent of all affected parties. (p. 4-7, 9)
Pennsylvania	H.B. 15	Each generation supplier required to obtain PUC license and post bond or other security to ensure financial responsibility. PUC to establish regulations to prevent customer account transfer without direct oral confirmation or written consent. PUC to monitor market for anti-competitive conduct; investigate complaints or potential violations and refer them as necessary to the appropriate state or federal prosecutors; deny proposed mergers, acquisitions, dispositions, or other transactions that are anti-competitive or discriminatory. (p. 21, 47, 53, 67-69)
Rhode Island	96-H 8124 Sub. B	By 1/1/97, electric licensing committee to submit proposals to legislature for consumer protection. All non-regulated power producers must file registration application with division listing specified information and showing evidence of financial soundness such as surety bonds or other mechanisms specified by division. On request, distribution company must release names and addresses of customers to power producers who will be eligible for retail access within next 60 days, unless customer has requested in writing that information not be released. (p. 22, 24, 26)
Massachusetts	H.B.5117	DTE's Consumer Division will continue to protect consumers and ensure that distribution companies adhere to rules and regulations concerning billing and termination procedures. Alternative supplier can only serve customers after receiving a Letter of Affirmation stating that the customer desires the alternative supplier.
Connecticut	H.B. 5005	By 1/1/99, the DPUC is required to develop licensing procedures for sellers of electricity using the transmission and distribution facilities of an electric company. Suppliers must demonstrate their technical and managerial competence and meet a variety of environmental, consumer protection and labor provisions.
Illinois	H.B. 362	Utility companies retain obligation to serve residential and small commercial customers. If a customer leaves and returns to be served by initial utility company, that company must serve the customer at the market price and guarantee service for up to 24 months. Supplemental low-income Energy Assistance Fund will be established from surcharge on bills (\$.40/mo for residents, \$.40/mo for non-residents and \$300/mo for large industrials). Energy Assistance Program Design Group will design low-income energy efficiency programs.

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Universal Service/Low-Income Assistance Program		
Nevada	A.B. 366	An electric distribution utility shall provide all noncompetitive services within its territory unless the PUC authorizes another entity to provide the noncompetitive service. PUC to establish minimum terms and conditions under which any customer not using an alternate seller will receive electric service. PUC shall designate utility to provide service to customers who do not elect or are unable to obtain alternative seller. Procedures may include, but are not limited to, requiring utility to serve such customers, requiring each alternative seller to serve a share of such customers, competitive bidding to select one or more providers. If the provider is an electric utility, the service shall be provided through an affiliate whose sole business is provision of basic service. (Section 44, p. 17; Section 45, p. 18)
California	H.B. 1890	Such programs must continue to be funded at not less than the 1996 authorized levels. (p. 6, 65-67)
Maine	H-568	The policy of the state is to ensure adequate provision of financial assistance. In order to continue existing levels of financial assistance for low-income households and to meet future increases in need, PUC shall receive funds collected by all transmission and distribution utilities at a rate set by the commission in periodic rate cases and set initial funding for programs based on an assessment of aggregate customer need. If legislature appropriates financial support for households and individuals receiving assistance from the general fund, PUC may not terminate the assistance provided by transmission and distribution utilities unless the general fund source has completely replaced such assistance. On or before 1/1/98, PUC and state planning office shall provide the legislature with recommendations to fund assistance to low-income consumers through the general fund or through a tax on all energy sources in the state. (p. 19-20, 26)
Montana	S.B. 390	Universal system benefits programs include cost effective local energy conservation, low-income customer weatherization, renewables and low income energy assistance. Programs are paid for by a non-bypassable universal system benefits charge assessed at the meter. Programs are established to ensure continued funding of, and new expenditures for, conservation, renewables, and low-income assistance during the transition period and into the future. From 1/1/99 through 7/1/03, 2.4 percent of each utility's annual retail sales revenue for the calendar year ending 12/31/95 establishes the minimum annual funding level. Utilities receive credit for internal programs or activities that support renewables, conservation, or low energy assistance. Credits can be carried forward to future years. Minimum annual funding for low-income and weatherization is established at 17 percent of the utility's annual universal system benefits funding level. The utility's transition plan must describe proposals for benefit programs, including methodologies such as cost effectiveness and need determination used to measure the utility's level of contribution to each program. Customers with loads greater than 1000 kW pay a charge equal to the lesser of \$500,000, less credits, or .9 mills per kWh x the customer's kWh purchases, less credits. Utilities must submit an annual summary report relating to system benefit programs to the PSC and the transition advisory committee. Co-ops may collectively pool statewide credits to satisfy annual funding requirements. On or before 7/1/02, transition advisory committee and PSC shall reevaluate system benefits programs and make recommendations to the legislature regarding future need for such programs. On or before 11/1/98, the transition advisory committee shall make recommendations to the governor and legislature regarding low-income assistance programs. Recommendations may include assignment of agency or private nonprofit entity to administer fund. (p. 2-4, 11-12, 16)
New Hampshire	H.B. 1392	Distribution utility has obligation to connect all customers and to maintain minimum residential service safeguards, including low income assistance. A non-bypassable, competitively neutral system benefits charge applied to distribution may be used to fund low income programs. (p. 5)

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Universal Service/Low-income Assistance Program (cont.)		
Oklahoma	S.B. 500	"Public benefit programs" means all social, economic, and environmental programs currently funded through rates charged to consumers. Entities providing distribution services shall be relieved of their traditional obligation to provide electric supply but shall have a continuing obligation to provide distribution service to all consumers within existing service territories. Firm service territories shall be fixed by a date certain if not currently established in law. Minimum residential consumer service safeguards and protections shall be insured including programs and mechanisms that enable residential consumers with limited incomes to obtain affordable essential electric service and the establishment of a default provider for any distribution customer who has not chosen an alternative supplier. Commission shall consider establishment of a distribution access fee assessed to all consumers to cover social costs, capital costs, and operating costs. No later than 1/1/99, Commission shall commence study of financial issues related to restructuring including but not limited to stranded benefits and their funding. Final report shall be provided to legislative task force no later than 12/31/99. No later than 7/1/99, Commission shall commence study of consumer issues related to restructuring including but not limited to examination of service territories, obligation to serve, and obligation to connect. Final report shall be provided to legislative task force no later than 8/31/00. (p. 3, 5, 7)
Pennsylvania	H.B. 1509	State must at a minimum continue current protections and policies to assist low-income customers. PUC shall ensure that universal service is appropriately funded in each distribution territory and shall encourage the use of community-based organizations with necessary experience to be direct providers of programs that assist low-income customers. PUC shall establish an appropriate cost recovery mechanism for each utility to fully recover universal service costs. Distribution company remains provider of last resort unless PUC approves alternative. While distribution company collects CTC, or until there is 100 percent direct access, company has full obligation to serve, including connection, delivery, and acquisition of power. After transition period, PUC shall adopt regulations defining obligation to serve. (p. 20, 22, 28, 34-35, 48-49)
Rhode Island	98-H 8124 Sub. B	Current special rates and protections shall continue. Within 3 months after 40 percent of kWh sales in New England are available for retail access, distribution company shall arrange a last resort power supply for customers unable to receive power under the standard offer or elsewhere. Company shall periodically solicit bids for power at market prices plus a fixed contribution from the company, subject to PUC approval. Company's fixed contribution is recoverable in rates charged all other customers. Company can terminate for nonpayment pursuant to PUC regulations. Authorized performance-based rate increases for distribution companies between 1/1/97 to 12/31/98 cannot be applied to low-income customers. (p. 3, 27-28, 35, 43)
Massachusetts	H.B.5117	Default service will ensure that customer will be served by incumbent supplier. Rate shall never exceed the avg. monthly market price of electricity. Payment options and rates charged for default service will remain uniform for up to 6 months. Ratepayer Parity Trust Fund will be established to subsidize low-income rates from monthly benefits surcharge on customers' bills.
Connecticut	H.B. 5005	Universal Service: Default and back-up service is required of distrib co's. Standard offer rate is available to all customers. Low-income: Include bars on discrimination on basis of income and redlining, a requirement that the state budget agency open the state electricity purchasing pool to people on public assistance. The ban is extended to include preventing winter shut-offs. The low-income programs, studies and other efforts are funded through a systems benefits charge. Utility companies retain obligation to serve residential and small commercial customers.
Illinois	H.B. 362	If a customer leaves and returns to be served by initial utility company, that company must serve the customer at the market price and guarantee service for up to 24 months. Supplemental low-income Energy Assistance Fund will be established from surcharge on bills (\$.40/mo for residential, \$.40/mo for non-residential and \$300/mo for large industrials). Energy Assistance Program Design Group will design low-income energy efficiency programs.

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