EXHIBIT 209

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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In The Matter of the Petition of Geneva Steel for Approval or Determination of a New Contract for Electric Service and an Infrastructure Agreement.	DOCKET NO. 02-035-05 **Petition and Emergency Request for Expedited Resolution**

Summary of Requested Relief

Pursuant to Utah Code Ann. §§ 54-3-1, et seq., 54-54-16-101, et seq., 63-46b-3, et seq., and 63-46b-20, and applicable Public Service Commission Rules, Geneva Steel ("Geneva") hereby petitions the Commission to establish expedited procedures for approval or determination of the rates, terms and conditions of service for: (i) a contract ("New Contract") for continued interruptible electric service by PacifiCorp to Geneva's historic and future operations to be effective at the termination of Geneva's existing special contract on January 1, 2003, including service to Geneva's planned new electric arc furnace ("New Furnace"), expected to be operational in or after January 2004, sufficient to satisfy the requirements of Utah Code Ann. §§ 54-16-201(1)(a)(ii) and 54-16-203(4); and (ii) an agreement ("Infrastructure Agreement") specifying repayment terms for new industrial infrastructure charges that are properly the responsibility of Geneva sufficient to satisfy the requirements of Utah Code Ann. §§ 54-16-201(1)(a)(i) and 54-16-203(1)-(3).

Geneva and PacifiCorp are engaged in good faith negotiations on the rates, terms and conditions for the New Contract and the Infrastructure Agreement. Geneva hopes and anticipates that the parties may be able to promptly reach agreement on both contracts. However, Geneva faces severe time pressures and restrictions that necessitate completion and approval of the contracts as soon as possible. Geneva thus requests that the Commission hold a scheduling conference immediately to set discovery and testimony deadlines and procedures, and to set hearing dates as early as possible in August 2002, in order to consider and approve the terms of the two referenced contracts to the extent the parties reach prompt agreement, and to direct PacifiCorp to execute a New Contract and an Infrastructure Agreement containing just and reasonable terms and conditions as determined by the Commission to the extent the parties are unable to reach prompt agreement.

Background

Geneva operates steel production facilities in Vineyard, Utah County, Utah. Geneva historically employed, and anticipates again employing, more than 1150 skilled employees. On January 25, 2002, Geneva filed a voluntary petition with the United States Bankruptcy Court for the District of Utah seeking relief under chapter 11 of the Bankruptcy Code. Geneva's facilities are largely idled at this time as it completes negotiations for financing arrangements to enable it to resume and expand its operations.

For more than 13 years, Geneva has received electrical services for its historic operations under the terms of an Electric Supply Agreement for interruptible power and energy ("Current Agreement") dated February 10, 1989, as amended. The Current Agreement provides for up to 150 MW of interruptible power and energy under certain circumstances. The Current Agreement expires on December 31, 2002.

Geneva is in the advanced stages of obtaining financing for the construction of its New Furnace. PacifiCorp has informed Geneva that new infrastructure improvements will be necessary in order for PacifiCorp to supply the electric needs of the New Furnace. The Industrial Electric Infrastructure Act ("Act"), Utah Code Ann. §§ 54-16-101, et seq., which becomes effective on July 22, 2002, provides, among other things, for deferred accounting treatment and recovery by PacifiCorp of expenses reasonably incurred in providing new industrial electric infrastructure needed to provide electric service to a new industrial facility under the terms and requirements of the Act. Geneva's New Furnace constitutes a new industrial facility under the Act and expenses reasonably incurred by PacifiCorp in connection with new industrial electric infrastructure for the New Furnace constitute covered expenses under the Act.

New Agreement. The Act requires that PacifiCorp execute an agreement approved by the Commission for electric services to be used in the operation of the New Furnace. By this Petition, Geneva seeks approval of the terms of a New Contract to govern electric service to the New Furnace in conformity with the Act, as well as continued service to Geneva's other facilities. To the extent the parties are unable to agree on any given term(s) of a New Contract, Geneva respectfully requests the Commission to direct PacifiCorp to execute a New Contract with just and reasonable rates, terms and conditions as determined by the Commission.

Geneva anticipates that its future operations (other than the New Furnace) may require up to 110 MW of peak electric supply after January 1, 2003. Geneva expects the New Furnace will require approximately 120 MW of peak electric supply beginning in or after January 2004. Geneva requests a contract with a term of five years for continued interruptible service for all of Geneva's operations after January 1, 2003, at a rate of $26 per Mwh effective in 2003, escalating annually thereafter at 3% per annum, with reasonable terms of interruptibility and buy-through.

Geneva is aware of, and intends to participate actively in, the task force recently ordered by the Commission to study costs and benefits of interruptible service. Geneva also understands that the Commission may elect to adjust the terms and conditions of interruptible service, if necessary, following the completion of the work of the task force and appropriate hearings. Geneva respectfully asks the Commission to establish reasonable rates and terms for interruptible service to Geneva at this time in order to provide it with sufficient certainty of pricing to permit it to close its financing.

Infrastructure Agreement. The Act also requires that PacifiCorp execute an Infrastructure Agreement approved by the Commission that specifies, among other things, the new industrial electric infrastructure to be provided and the portion of the costs for such infrastructure to be paid by Geneva under applicable tariffs, rules or practices. By this Petition, Geneva seeks approval of the terms of an Infrastructure Agreement in conformity with the Act. To the extent the parties are unable to agree on any given term(s) of an Infrastructure Agreement, Geneva respectfully requests the Commission to direct PacifiCorp to execute an Infrastructure Agreement with just and reasonable rates, terms and conditions as determined by the Commission.

The new industrial electric infrastructure needed to supply the New Furnace and the portion of the covered expenses to be paid by Geneva should be reasonably estimated at this time for purposes of the Infrastructure Agreement, subject to true-up. Geneva should be permitted to repay its portion of such expenses over a period of seven years, beginning when the New Furnace begins commercial operations, and subject to reasonable carrying charges.

Timing

Geneva must quickly finalize financing arrangements to resume operations and to construct its New Furnace. Before any such financing can close, however, and before construction on the new infrastructure can begin, the terms of the New Contract and the Infrastructure Agreement must be resolved and disclosed. Geneva thus seeks expedited approval or determination of the terms of the New Contract and the Infrastructure Agreement. Moreover, given the short period of time available for resolution of these issues, Geneva respectfully invites the Division of Public Utilities and the Committee of Consumer Services to participate in ongoing discussions and negotiations, as well as in informal and formal expedited discovery.

Geneva anticipates that its financing could close as early as August 30, 2002. It is imperative that Geneva's electric supply contracts be in place prior to closing of the financing arrangements. Any additional delay in closing the financing due to unresolved electric issues would be extremely detrimental to Geneva and to its efforts to re-open and continue its operations.

Geneva respectfully requests that hearings be scheduled as soon as practicable in August 2002, and that a Commission order be entered by August 23, 2002.

Public Interest

Geneva submits that expedited consideration and resolution of its Petition is in the public interest. Failure to grant expedited consideration or failure to effect a timely and reasonable resolution of the issues presented by this Petition would cause immediate and irreparable harm to Geneva, would threaten the viability and operations of Geneva's facilities in Utah County, and would cause significant and irreparable economic damages and other injuries to Geneva and its employees and customers, as well as to the citizens and economy of Utah County and the State of Utah.

Conclusion

Geneva respectfully petitions this Commission to schedule a scheduling conference as quickly as possible, to enter a scheduling order establishing hearing dates, testimony deadlines, expedited discovery procedures and other timelines for resolution of this Petition, to determine and approve just and reasonable terms for a New Contract and an Infrastructure Agreement, and to direct PacifiCorp promptly to execute such agreements.

DATED this ____day of July, 2002.

HATCH, JAMES & DODGE

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Gary A. Dodge
Attorneys for Geneva

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was mailed, postage prepaid, this ____ day of ________________, 2002, to the following

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EXHIBIT 212

EXHIBIT 212 (RMA-1)

PacifiCorpRAMPP-6 Action Plan
Revised June 14, 2002

RAMPP-6 Model Issues

The Commission order in Docket 98-2035-05 requests the impacts of updating the RAMPP-6 action plan for out-of-date assumptions. The Company has updated the following assumptions:

1. Wholesale market prices were updated to the Official February 2002 forecast.
2. Natural Gas prices were updated to the Official February 2002 forecast.
3. Native loads were updated to the current SRP forecast.
4. The Wholesale Balancing Adjustment was removed.
5. The Capacity Purchase Option was converted to a super peak purchase option.
6. West Valley CTs were added as a potential resource (200 MW)
7. Gadsby CTs were added as a potential resource (120 MW)
8. The SCE Winter Capacity Purchase was canceled (433 MW)
9. The SCE Sale was restructured (200 MW)
10. The WAPA 1 Block A was suspended December 2000 (7 MW)
11. The WAPA 2 contract was suspended December 2000 (75 MW)

The model selects 115 MW and 150[1] MW of Simple Cycle CT capacity in 2002 and 2003. This represents 88% of the West Valley and Gadsby CTs capacity[2]. The model also selects 126 MW of wind[3] in 2003. Cogeneration is selected starting in 2004 and Coal, Hunter 4, is selected in 2006, the first years that they are available. The model did not select Super Peak Purchase or Combined Cycle CTs.

The modeling results and a detailed description are attached.

Resource Planning Strategy

The planning and decision making associated with meeting load requirements are a function of the Commercial and Trading Organization. This organization strives to:

- Deliver the most economic solution.
- Reduce commodity risk in the regulated business
- Serve load with both owned assets and purchases
- Reduce cost and risk with hedges and load management programs

The Commercial and Trading Organization deals with both load growth and load balancing in the short term and long term. The short-term responsibility entails estimating the Company's hourly future position by delivery point and calculations as to how to best balance the position. The long-term responsibility furthers this load balancing over the 20 year integrated resource-planning horizon. The Integrated Resource Plan is developed by the C&T Organization.

[1] Due to summer heat derating this represents 123 and 160 MW of nameplate capacity.
[2] Nameplate capacity selected by the model totals 283 MW. Gadsby and West Valley have a capacity of 320 MW.
[3] The 126 MW of wind represents the peak contribution from 350 MW of installed capacity.

Currently, load growth in the Western U.S. is higher than the rest of the U.S. The region has a surplus now, but as the economy recovers and growth levels increase the surplus is expected to diminish over the next decade in the absence of new resources. PacifiCorp has also experienced consistent load growth in portions of the service area, especially the east side of the system. For the overall period 1978-2001, the average growth rate in the West was 1.47% and 3.87% in the East. Consequently, while the system is in overall balance, there are periods where the eastern portion reserve margin is particularly close.

This update to the RAMPP-6 action plan takes into account the Company's enhanced risk mitigation strategy. This strategy balances costs associated with ownership of resources or contracts with the risks of relying on market access. One result of this strategy is the Company's decision to reinforce its owned and contracted resources in the Wasatch front area. Another result is an effort to build additional demand side capabilities including direct load control.

Near-term Planning Requirements

The Company faces 2 daily balancing problems:

1. We still must purchase in the real time to cover super peak period; and
2. We must sell in the real time surplus shoulder power back to the market.

While the Company's daily capacity/peak needs have a super peak, the products available from the wholesale market tend to be available in blocks, e.g. 16 hour/6 day (16x6) blocks. Purchasing these products subjects our customers to market risk. Power must be purchased to meet the peak; often at premium prices while surplus power on the shoulders of the peak must be sold back into the market at lower prices often below the price paid.

The Company tends to have 2 seasonal system peaks, summer in the East and winter in the West. Each peak has a different daily shape. The West peaks in the morning and evening, while the East peaks in the late afternoon. There are difficulties in supplying energy for these peaks, especially because we don't have an unlimited ability to transfer energy between our Western and Eastern regions. The summer peak on the East side is particularly difficult to fill. It presents real capacity (or peak) issues. In the winter Western peak, capacity and average energy needs are closer together. The peak capacity is needed for more than half the day, which more closely matches the products available from the market. In summer in the East, the peak capacity is needed for only a few hours each day. Serving the peak with baseload units or 6x16 power results in the surplus shoulder situation. Additionally, the large summer peak in Utah has been growing rapidly. The majority of the summer peak can be attributed to air conditioning load.[4]

Transmission Issues

Because of physical flow reasons, nameplate transmission capacity in a power grid cannot be simply numerically summed to determine actual firm physical capacity. Transmission studies,

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[4] In response the Company has issued an RFP for an air-conditioning load control program. This program will be presented to the Commission for approval later this summer if cost effective responses are received.

using forecasted load and resource balances, are used to estimate firm capacity into and within a control area, at a point in time. Consider the situation in summer of 2005:

- Approximately 1,100 MW of estimated effective firm import capability exists.
- The peak loads in the Utah region are estimated at about 4,400 MW while the peak resources are about 2,500 MW.
- This leaves an 800 MW requirement to be filled by DSM activities, new resources and non-firm transmission.[5]

Short Term Action Plan

The IRP process informs long-term direction setting and major asset choices. Short term planning (1 to 3 years) is a continuous activity undertaken within the scope of the IRP based long-term plan. Short term planning addresses the uncertainty associated with the economy, market price fluctuations, current system constraints and other exogenous events. Short-term decisions are required to:

- Balance for the normal expected variation of loads resources and events.
- Correct as short-term data corrects long-term assumptions (very dry hydro, unexpected long term outage).
- Take advantage of market opportunities.

To meet the long-term direction indicated by the IRP process the Company is taking several steps within the Action Plan time frame to ensure adequate supply and satisfy our load-serving obligation. These include:

- Re-establishment of an independent IRP organization.
- Construction of the Gadsby peaker.
- Ongoing DSM efforts.
- Release of an RFP for an air-conditioning load control program.
- Power contracts entered into as a result of an RFP for new resources.
- Establishment of a tiered rate structure for summer months in Utah.

IRP Organization

In response to the changing dynamics within the power industry the Company re-established an independent IRP organization within the Commercial and Trading organization in the summer of 2001. The director of the IRP organization is Janet Morrison. Janet reports directly to Bob Klein, Senior Vice President of the C&T organization. Janet brings a wealth of experience to the position. She has worked for Scottish Power for the past 18 years and has held a variety of positions in Generation Operations, Transmission Planning, Energy Trading and Dispatch, Contract Sales & Marketing, Business Development and Project Management. The organization is staffed with analysts experienced in generation planning, transmission planning, modeling and

[5] Power can be wheeled from the California ISO at SP15 or purchased from LADWP, however this has tended to be non-economic.

analysis, market fundamentals, risk analysis and demand-side management. By creating an independent organization the Company plans to make the IRP process more robust and real-time going forward. In addition, the placement of the IRP process within the C&T organization is intended to assure that the IRP is an integral component of the Company's business planning process.

Gadsby Peaking Units

Currently under construction is the 120 MW Gadsby Peaker, located at the site of the Company's existing Gadsby steam plant. The construction contract estimates that commercial operation will begin during the summer of 2002. The units will provide economic energy production during peak periods and ancillary services in the form of voltage support and operating reserves when needed.

The project is gas-fired, and consists of three 40 MW General Electric LM-6000 units, with heat rates of 10,500 Btu/kWh. The units will be equipped with the latest in pollution control technology. Estimated costs are $80 million installed or $657/kW of capacity.

Demand-Side Management Director

A Director of Demand-Side Management, Mike Koszalka, has been added to the IRP group, reporting to Janet Morrison. Mike will be responsible for defining the strategy and coordinating all DSM activities within PacifiCorp. The responsibilities assigned to this position include, ensuring that the appropriate high-level economic decisions are coordinated, that appropriate reporting is delivered, and that there is a central focus within PacifiCorp for both internal and external purposes.

On-going DSM Programs

The Company's DSM programs will continue to be an integral component of the IRP planning process. New and existing programs will be modeled along with supply side options to determine the optimal resource portfolio. The Company's existing programs will be continued as the new IRP is developed. These programs include:

- Energy Exchange - an industrial load management program.
- Power Forward - a Utah Summer Awareness Program.
- Energy FinAnswer Program - engineering and financial assistance (varies by state) for installation of energy efficient motors, heating & cooling, refrigeration, etc.
- Retrofit Incentive Programs - engineering and incentives for energy efficiency measures (OR, WA and UT). Includes incentives for installation of Vending Mi$er (a device that turns off vending machines when not in use).
- Energy education and Awareness Campaign - Do the Bright Thing

Additional DSM programs that are either implemented or underdevelopment include compact fluorescent bulb offerings and on-site or web based home energy audits.

DSM programs that are currently being analyzed in cooperation with the Utah Energy Efficiency Advisory Group include:

- Residential and small commercial load control (RFP has been released)
- High efficiency residential AC
- Second appliance recycling
- Energy Star Appliance Promotion
- Best practices AC servicing program
- New commercial/industrial load management

The Company intends to continue to use DSM as a valuable and cost-effective load management tool.

New Resource RFP

The RFP process provides an impartial analytical process to fill our short-term resource needs. The Company issued an RFP in September of 2001 for new resources. The initial phase ("Phase I") of the RFP process focused on system needs for the summer of 2002, 2003, and 2004. Absent one negotiation that is ongoing, PacifiCorp has completed purchases it intends to make during Phase I.

PacifiCorp is currently pursuing entities who submitted proposals that PacifiCorp may find attractive in resolving system needs for the 2003, 2004, and possibly the 2005 timeframe via a second solicitation ("Phase II").

The RFP was emailed to 75 WSPP members and sent directly to large industrial customers in Utah. In addition, the RFP was posted on PacifiCorp's web site. The Company received 52 proposals from 27 suppliers that varied widely by type of product offered and availability date of resource. The proposals were "blinded" for evaluation, and an independent consultant (Cap Gemini Ernst & Young) was utilized to ensure impartial selection and consistency with best industry analytical practices. Bids received were evaluated on the following basis:

- Minimum 25 MW bid requirement
- Capability of physical delivery during summer months, 2002-2004
- Availability during super-peak or peak hours
- Optionality to take delivery
- Intra-hour or intra-day dispatchability
- Pricing structure (fixed, variable, indexed to gas, etc.)
- Location in or capability of delivery to PacifiCorp's eastern control area

Proposals received an initial screening by PacifiCorp's Credit department and several entities were eliminated for credit reasons. Proposals were sorted into tiers based on their desired attributes. The top tier was asked to refresh their bids and bid pricing specifically for the summer of 2002-2004. These bids were evaluated in December of 2001 based on consistent inputs and assumptions. Several proposals were chosen for potential negotiation based on optimal cost/risk balance. A subset of these was chosen for initial negotiation and "un-blinded".

The un-blinded counter-parties consisted of well-known market participants and PacifiCorp's affiliate (PacifiCorp Power Marketing). Non-affiliate transactions consisted of various forms of day-ahead physically settled call options delivering power into the Utah grid. The affiliate transaction consists of a very flexible multi-year lease with West Valley LLC (a special purpose company for sole purpose of leasing).

The West Valley transaction is a flexible lease with lease termination and plant purchase options. It will provide 200 MW of capacity, 80 MW will be available in June 2002, 80 MW in July and the remaining 40 MW in August. The transaction has the following operational details:

- POD: within Eastern control area.
- Dispatch: at PacifiCorp sole discretion to dispatch each of the units.
- Delivery Hours: at PacifiCorp sole discretion (no minimum run time or maximum starts).
- Operation: PacifiCorp will staff and operate the plant.
- Gas Supply: PacifiCorp's responsibility from 2 gas sources.

The transaction is unit contingent. The unit consists of five 40 MW GE LM-6000 units with heat rates of 10,000 Btu/kWh. The units are available for peaking, energy reserves and other ancillary services 24-hours a day, 365 days of the year with a 10-minute start.
The Phase II solicitation consisted of shaped physical power delivered to the East side during summers of 2003, 2004 and 2005. Six counter-parties from the original RFP, consisting of 7 bids, were un-blinded on March 12, 2002. A Phase II solicitation was e-mailed to 13 un-blinded counter-parties on March 20, 2002. Six counter-parties responded with 11 bids on March 27, 2002. Evaluation is currently underway; the next step is identification of the top 3 counter-parties. The current IRP interim results will be used in evaluating the final choices.

Summer Tiered Rates

On November 2, 2001 the Commission approved an inverted block rate structure for residential customers during the months of May through September. Beginning in May of 2002 rates are 6.3029¢ per kWh first 400 kWh and 7.0866¢ per kWh all additional kWh. This rate structure is intended to encourage efficient energy use during the peak summer months, May through September.

In addition to the inverted rate structure change, the company also redesigned the residential Time of Use rate plan, reducing the basic charge to provide a better opportunity for customers to effectively exercise the plan and to encourage greater plan participation.

To communicate these rate changes to customers, the company produced a bill insert that began appearing in customer billings in May. The insert addresses what the changes are, why they were made, and provides energy-savings tips so that customers can take full advantage of the changes. The company has provided the commission staff copies of the inserts for the purpose of answering possible customer questions surrounding the rate changes/customer communication.

EXHIBIT 213

EXHIBIT 213 (RMA-2)

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

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IN THE MATTER OF THE APPLICATION OF UTAH POWER & LIGHT COMPANY FOR APPROVAL OF PROVISIONS FOR THE SUPPLY OF ELECTRIC SERVICE TO MAGNESIUM CORPORATION OF AMERICA.	DOCKET NO. 01-035-38 REPORTER'S TRANSCRIPT OF PROCEEDINGS

Salt Lake City, Utah

Wednesday, May 8, 2002

9:10 a.m.

BEFORE:

STEPHEN F. MECHAM, Chairman, Public Service Commission of Utah; and

CONSTANCE B. WHITE, Commissioner, Public Service Commission of Utah; and

RICHARD M. CAMPBELL, Commissioner, Public Service Commission of Utah.

--oOo--

the 30 year term of that contract?

A No, I don't know the number of times that they were interrupted.

Q Presumably at that time -- well, never mind. I'll strike that. Page three in your testimony, beginning at page three at least, you talked about why you proposed two separate agreements.

A Correct.

Q One of them is to clearly define terms and conditions for interruptibility. You can do that in one contract too, correct?

A Correct.

Q The second one is, insure that the value of services reflects the cost of acquiring those services. To make sure we're following each other, you're not talking about the cost-of-service based on an analysis that may be done in traditional rate making, you're talking about the cost of acquiring what you view to be a comparable product on the market. Is that right?

A Yeah, in fact if you're going to buy the option to interrupt them, what are you avoiding by interrupting them?

Q Even if one accepted that was legitimate, that is to insure that the value of interruptible services provided by a customer reflects the cost of acquiring those services, that could be done in one contract as opposed to two, correct?

A Correct, with a caveat that you have to be careful about the term because, as you know, the market changed quite rapidly over the last year or so and so you have to be careful to make sure that there is some flexibility to take care of those kind of conditions so that if the interruptible piece gets out of sync with what the value of interruptibility is, then what you have is a contract that's not fixable. You have to kind of take apart the whole contract to fix one component of it.

Q So basically what you're saying is if you had your preference you would have a real-time pricing basically if you will for the interruptibility portion?

A Real-time pricing from what perspective?

Q Some kind of ability to respond day-to-day, month-to-month, week-to-week to market conditions, short-term market conditions.

A Yes, it would be good to have the option to know what you were going to avoid on a short-notice basis.

Q Now you understand, do you not, that from a customer's perspective that may be optimal to the utility dealing with say a wholesale contract or whatever? You understand, do you not, from a customer's perspective that gives almost no predictability?

A I understand that, yes.

Q And understand that that's one of the reasons that Magcorp has resisted the kind of approach that the company has proposed?

A Yes.

Q You also say beginning on page three and over to four that a third reason for proposing the separate agreements is the NERC and what was the WSCC operating criteria. Your expectation is there may be changes in that, is that right?

A Correct.

Q Why does one contract have anything to do with that, one contract versus two?

A One of things that was discussed and that I mentioned earlier was the idea of looking at operating reserves, which is what this is talking about, as a product that could be purchased from Magcorp or Magcorp could supply operating reserves to PacifiCorp's system.

What we have is that there's some proposed changes that could occur over the next year to 18 months, but those changes are not fixed yet, they haven't been agreed to by the WSCC and all the parties. So in order to do something around operating reserves or something with a short-term notice and trying to take advantage of the value of the reserves, you're limited by changes occurring maybe over the term of this agreement.

Q So you're not really saying it's one or two contracts, it's the term depending on what comes out of the W -- what is it now?

A WS --

Q WECC, I think that's right. And NERC, whatever comes out of that you're saying you would like the flexibility to try and respond to that?

A Correct.

Q Are you familiar with the data response in this proceeding where PacifiCorp was asked to give a value to operating reserves?

A Yes.

Q And do you recall what that answer was?

A I think there was a couple different answers given because there's different types of operating reserves, there's spin and nonspin. I believe nonspin if I recall was $1 -- somewhere in the

EXHIBIT 214

EXHIBIT 214 (RMA-3)

DISCUSSION DOCUMENT (PacifiCorp)
MERGER OF
PACIFIC POWER & LIGHT AND UTAH POWER & LIGHT

Author – Gordon McDonald
Regulation Manager
PacifiCorp

SUMMARY

The Pacific Power/Utah Power merger was filed fourteen years ago: before direct access, before wholesale competition, at a time of surplus power in the western United States. The merger was expected to produce substantial benefits for all of the Company's customers and it did. The merger reduced the need for new generation. In 2001, PacifiCorp's peak loads were 785 MW lower than the sum of the separate peaks of the two former divisions.

PacifiCorp accepted allocation risk arising from the merger. The benefits of the merger could not have been obtained without accepting this risk, which results from the normal operation of the regulatory process. Merger conditions related to this risk were imposed in Utah and Oregon but, in every state, PacifiCorp bears the risk and shareholders have been adversely affected as a result.

PacifiCorp made commitments in every state to freeze or reduce prices and kept those commitments. Since the merger, PacifiCorp's prices have increased less than the prices of many other utilities in the region.

Parties may hold different interpretations of the terms of the merger and the benefits that followed, but to solve the present problems it is necessary to move forward. The Company is encouraged that parties are participating in the MSP process with a focus on actions that are in the public interest today.

1. Environment of the Merger

In 1987, the electricity industry was still firmly rooted in the traditional vertically integrated utility structure. Parties expected that utilities would plan and build resources for their systems as needed. There were no non-utility marketers, even at the wholesale level. Wholesale prices were stable. Retail direct access was nowhere on the horizon.

In September 1987, PacifiCorp and Utah Power and Light Company filed applications with seven state regulatory commissions for approval of the merger of their two companies. The Applicants (as they were known in those proceedings) filed direct testimony supporting the applications over the next several months. The various Commissions issued orders approving the merger in 1988.

PacifiCorp was concerned about competition, even in 1987, but competition of a different sort. The direct testimony of David F. Bolender, then President of Pacific Power, describes concerns about alternate fuels, municipalization and technology:

> "Electric utilities are not only competing with their traditional rivals—oil, wood, gas and other electric suppliers, but also cogenerators, small power producers and a whole host of new emerging technologies, including fuel cells and photovoltaics." (Page 4.)

In this environment, PacifiCorp believed that high prices would reduce sales and put further upward pressure on prices. The Company was already in surplus:

> "Competition is also intensified by the power surplus now present in many regions of the country, including Pacific Power's service territory." (Page 5)

> "Our principal concern today is power sales. We want to sell more of the resources we already have in order for the Company to grow and benefit customers. Economic growth is our number one goal, because it is good for customers, shareholders and employees. When we grow, it helps us spread our fixed costs across a larger base, resulting in lower prices for customers. Growth also allows us the opportunity to provide a reasonable return to shareholders and good career opportunities for employees." (Page 5)

Attachment 1 reproduces the principal resource planning tables from the direct testimony of Dennis Steinberg. Utah Power's resource plan without the merger showed that they were slightly in surplus. Utah Power planned additional purchases in two years and planned the construction of a steady stream of generating resources beginning in six years. Utah Power expected peak loads to increase from 2,394 MW in 1986 to 3,159 MW today. By now, Utah Power would have constructed two atmospheric fluidized-bed coal plants. Others would have been under construction so that a total of six would have been on line by 2007.

Pacific Power's resource plans without the merger showed a utility that was also in surplus, requiring additional small purchases in two years and other new resources in six. By now, Pacific Power expected to meet a peak load of 5859 MW with 510 MW from new firm energy resources and 1801 MW of purchases.

The merger was seen as an extraordinary strategic and geographic fit. Pacific Power had access to low-cost Northwest hydroelectric resources. Utah Power had access to wholesale markets in the desert Southwest. Pacific Power's transmission system was generally oriented in an east-west direction. Utah Power's was north-south. The surplus could be sold in profitable wholesale markets and provide benefits to the Company and its customers.

The merger was expected to delay the need for new resources. Pacific Power was and is a winter peaking system and Utah Power a summer peaking one. The testimony of Bruce Hutchinson showed that the merger would provide about 400 MW of diversity between the two systems. The testimony of Dennis Steinberg showed that the merged company would not need new resources for nine years. Not only would this defer costly investments but it would allow more profitable, longer term wholesale sales. Testimony pointed out additional benefits from integrated dispatch of generation, lower reserve requirements, and improved system reliability. The Applicants expected that the merger would reduce total net power costs by 5%-10%.

The Applicants initially estimated that the merger would produce total benefits of $48 million in the first year, increasing to $158 million in 1992. In Utah particularly, there was much contention regarding specific estimates of benefits. In the end, every commission found that the merger would be beneficial to the public.

The Utah Commission stated:

> "…[W]e find that the merger will result in approximately $300 million of savings in resource additions, in present value terms, over the 19-year time period examined, and that these long-run savings are the most important benefit of the merger." (Page 56)
>
> "We further find that substantial savings in net power costs will result from the merger. Even in the Committee's low estimates, these benefits will approximate $50 million during the five-year period immediately following the merger. The Commission finds that the more optimistic assumptions, which project these benefits to be in the range of $90 to $160 million, are reasonable." (Page 60)

The Washington Commission stated:

> "…[T]he Company demonstrated on this record that there are substantial economies to be gained in the first five years of the merger; it estimated total merger benefits of $48 million per year in the first year, increasing to $158 million per year in the fifth year. While recognizing that these are estimates, the Commission notes the benefits to be of substantial magnitude. The evidence establishing merger benefits was largely uncontradicted."

The Montana Commission found that:

> "The record is replete with potential benefits resulting from the proposed merger."(Page 30)

2. Developments Since the Merger

For a number of years, PacifiCorp produced estimates of actual savings from the merger. Through 1992, actual savings were estimated to have been $277 million, 75 percent above the estimate offered in direct testimony.

The diversity benefits of the merger are still present today. The following table is based on hourly system loads for the year 2001. "Pacific Division" refers to PacifiCorp's combined loads of Oregon, Washington, California and Eastern Wyoming. "Utah Division" refers to the combined loads of Idaho, Utah and Western Wyoming.

Native Load Including Requirements Sales for Resale
(Megawatts)

Time	Pacific Division Load	Utah Division Load	System Load
Pacific Division Peak 1/17/01 @ 08:00	4,495	3,198	7,693
Utah Division Peak 7/03/01 @ 15:00	3,664	4,198	7,854
System Peak 8/07/01 @ 14:00	3,808	4,091	7,899

Considered separately, the two divisions had peak loads of 4,495 MW and 4,198 MW for a total of 8,684 MW. The actual peak load was 7,899 MW or 785 MW lower. In the present tight power supply environment, each division would have to have in place additional power supply arrangements costing many millions of dollars if the merger had not occurred. The divisions would have had to purchase peak power or build additional resources, both of which carry substantial risks. Consumer prices have been lower as a result of the diversity of the divisions.

The policy environment of the industry has changed substantially since the merger application was filed in 1988. FERC issued Order 436 the following year, encouraging unbundling and open access in the natural gas transportation. FERC would signal for the first time its encouragement of open access electricity transmission in its order approving this very merger. FERC issued Order 636 in 1992, requiring unbundling and open access in natural gas. That same year, the Energy Policy Act was enacted, establishing the category of exempt wholesale generators and paving the way for independent development of major generating projects and increased competition in wholesale power markets. FERC issued Order 888 in 1996, requiring open and nondiscriminatory transmission tariffs. The first states enacted retail direct access legislation in

1996, including New Jersey, Massachusetts, Pennsylvania, Ohio, Texas and California. Power supplies are much tighter now than they were then and the volatility of market prices is correspondingly higher. Marketers and other competitive participants are sponsoring much of the planned new capacity.

3. Prices Since the Merger

Attachment 2 shows PacifiCorp's average retail base rates for each state since the merger. Prices in Attachment 2 do not reflect the benefits of the BPA residential exchange credit, which affects prices in Northwest states. Generally, prices have fallen in Utah and Idaho, modestly increased in Oregon and Eastern Wyoming, and remained roughly unchanged in Western Wyoming, Washington and California.

Attachment 3 reproduces an article appearing recently in the Oregonian that compares utility prices in the Pacific Northwest. Prices of many utilities that have historically benefited from inexpensive power from the Bonneville Power Administration are now higher than PacifiCorp's prices.

4. The Issue of Allocations

The Applicants did not propose an allocation method as part of their merger applications. The Applicants highlighted and explained this decision in direct testimony. Fredric D. Reed, then Senior Vice President of Pacific Power, stated that developing an allocation method would require the Companies to better understand how the merged company would operate and would involve lengthy consultations with commissions. "It may well take several years of discussions and actual experience before all affected parties understand the issues involved and a consensus emerges."(Page 2.)

A delay of several years would have placed the merger, and its associated benefits, in substantial jeopardy. The Merger Agreement allowed either party to abandon the transaction for any reason if it had not closed by August 12, 1988. As time passed after that date, it would have been increasingly likely that circumstances would change leading one party or the other to terminate the Agreement.

The Company acknowledged from the beginning that it had a risk associated with inconsistent allocation methods. In direct testimony filed with most or all state commissions, Fredric Reed stated:

> Question
> Do you think this Commission can properly evaluate the merger without knowing how cost savings will be allocated?

> Answer
> Yes. It is this Commission, not the Company, that will be the ultimate judge of what allocation methodologies are reasonable. It is clear that there are substantial total savings available from the merger and undisputed that a substantial portion of those savings should flow to … customers. If either Utah Power or Pacific Power were to propose unreasonable allocation methods in future rate proceedings, it is the PacifiCorp stockholder, not utility customers, who would be at risk.
>
> Furthermore, it should be noted that while interjurisdictional and interclass allocations will prove to be complex, it may well be that any number of potential reasonable allocation methods would produce generally the same result. This is not to say that allocation is not an important issue, but rather that the issue of how benefits will be allocated should not be permitted to overshadow the fact that there will be substantial benefits to … customers independent of what particular allocation methodology is adopted.(Page 3.)

There is room for parties to differ regarding the interpretation of the Company's testimony on allocation risk. Applicants' direct testimony acknowledged allocation risk but did not propose merger conditions which would specify or increase it.

The merger created a new allocation issue: how to deal with the benefits and costs created by the merger, amounts that were not logically related to either division alone. It is clear from Mr. Reed's testimony that the Company related the allocation issue to the new benefits and costs. The allocation risk of the merger should then have been proportionate to the benefits. A variety of allocation methods would have led to similar conclusions, further reducing the apparent risk. Mr. Reed's testimony goes on to state:

> "…[E]ven if one were to assume that only one index were used to allocate all cost savings and new revenues, the outcome may not materially differ. It is interesting to note, for example, that if one combines the operations of Pacific Power and Utah Power, Utah Power accounts for approximately 41.3 percent of the coincidental peak, 42.0 percent of total energy generation, 41.5 percent of megawatt hour sales, 41.9 percent of customers and 43.0 percent of assets.
> … [V]arious indices track each other quite closely and differences in allocation methods may not produce significantly different outcomes."(Page 4.)

State commissions treated allocation risks in a variety of ways in their merger orders. Here is a summary of the allocation issue in the various state dockets:

California. The PUC expressed concern that rate decreases promised to the state of Utah not be funded by California ratepayers. The Commission's order requires that PacifiCorp reconvene the Allocation Committee within six months after the merger is approved.

Idaho. The Idaho PUC related the allocation issue to its requirement that there be no rate increases as a result of the merger. It stated:

> PPC recommends that the merger be subject to the understanding that future jurisdictional allocations will not result in rate increases beyond what there would have been without the merger. This recommendation is a corollary of the previous one [that there be no merger-related rate increases], and it likewise is a statutory requirement. As Pacific's Mr. Reed noted, the risk of inconsistent allocations, including those required in Idaho by statute, is borne by the company's shareholders.
>
> Also, the merged utility will now be operating in seven states. Idaho is prepared to participate in formalized proceedings to consider jurisdictional allocations. (Page 26)

The Idaho Commission also treated as an instance of the "no merger-related price increases" rule, a Staff condition that the division to which newly built plant is allocated must show savings to that division exceeding the cost of the plant allocated to the division.

Montana. The PSC discussed the issue of allocations and found that it was not necessary to address it in the merger approval docket. The Commission imposed no specific conditions related to allocations.

Oregon. A number of parties raised issues in the Oregon merger proceeding. On March 3, 1988, the Applicants signed a global stipulation with the Staff containing specific provisions related to rate issues, reporting requirements and other matters in addition to allocation issues. The stipulation contains lengthy guidelines for allocating merger costs and benefits. It includes the provision:

> Pacific agrees that its shareholders shall assume all risks that may result from less than full system cost recovery if inter-divisional allocation methods differ among the merged company's various jurisdictions.(Page 13.)

This provision was effective for five years following the closing of the merger. (Page 17.)

In approving the stipulation and ruling on issues raised by other parties, the OPUC stated:

> The Commission does not believe that significant problems will be encountered in resolving interjurisdictional allocation matters. Pacific currently operates within a six-state service territory and has not experienced difficulty establishing allocation methods consistent with sound regulatory principles.

Utah. The Utah PSC seemed to agree that the allocation issue was related to the allocation of the benefits of the merger:

> In summary, we find that net positive benefits will result from the merger and that a reasonable allocation plan can be worked out after the merger to assure that Utah ratepayers

receive their appropriate share of these benefits. (Order dated September 28, 1988, docket 87-035-27, page 67)

The Utah merger order itself does not discuss a move to rolled-in allocation although parties testified regarding it. The Commission propounded three general principles to guide the Applicants in formulating an allocation method, none of which mentioned rolled-in allocation:

> First, the proposed allocation methods should avoid total reliance on stand-alone modeling. Second, the proposed methods should embody a consistent and equitable method of allocating the benefits derived from the uniquely valuable assets of each division, in particular, the strategically located Utah Power transmission system and the low-cost power production of Pacific Power. Third, an allocation model should be verifiable against actual data. (Page 67.)

The Utah PSC seemed to disagree that the Company would, in fact, bear all the risk, particularly in the long term:

> Applicants assert that developing detailed allocations prior to the merger is not essential because the Merged Company's shareholders will assume the risk that differing allocation methods employed by the various jurisdictions could result in less than full cost recovery. The Division testified that this risk of dollars "falling through the cracks" exists currently within the present inter-state allocation process, wherein Applicants' shareholders fully assume the risk of less than full cost recovery. But should there be less than full cost recovery, the Merged Company will earn less than that allowed by regulators. In such a case, we expect the Merged Company would request additional revenues to increase earnings, or its cost of capital will increase. Neither the Applicants nor the Division state how this risk of less than full cost recovery due to jurisdictional allocation methods can be identified, quantified and assigned to shareholders. It is clear that in the short term it will be the shareholder who bears this risk, but ultimately in the longer term the ratepayer shares in this risk. (Pages 62-63)

In a separate section of the Order titled "Other Proposed Conditions," the Utah PSC ordered the following:

> The Merged Company shall agree that PacifiCorp shareholders shall assume all risks that may result from less than full system cost recovery if inter-divisional allocations methods differ among the Merged Company's various jurisdictions. (Page 97)

The Company stipulated again to this requirement in the Utah proceedings regarding the PacifiCorp/ScottishPower merger. In return, the DPU pledged to assist the Company to resolve allocation issues among the states:

> ScottishPower and PacifiCorp agree that they shall assume all risks that may result from less than full system cost recovery if interjurisdictional allocation methods differ among

PacifiCorp's various state jurisdictions. The DPU agrees to use its reasonable best efforts to reach agreement with the other state regulators as to the interjurisdiction cost allocation methodology to be recommended to the respective state commissions. In the event the state regulators are unable to reach agreement or the DPU concludes that the methodology supported by any of the other U.S. regulatory states would cause actual or perceived financial harm or inequity (on the basis of projections at that time) to the ratepayers in Utah, the DPU may support or recommend such allocation methodology to the Commission as it determines to be appropriate. ScottishPower and PacifiCorp assume the risk of whatever allocation methodologies or decisions the Commission may adopt. In addition, ScottishPower and PacifiCorp assume all risks that may result from any difference among PacifiCorp's various state jurisdictions in respect of the conditions imposed by the different state commissions relating to this merger transaction. (Stipulation, Docket No. 98-2035-04, paragraph 45.)

Washington. The Staff and other parties objected to the merger and raised concerns that the merger would yield no benefits to Washington customers. The Company agreed, in its Supplemental Brief, to make a rate filing that passed through to Washington customers their allocated share of $59 million in merger benefits. The method by which the benefits would be allocated was not resolved in the merger proceeding. The Washington UTC rejected a condition proposed by the Public Power Council that would have prevented future changes in jurisdictional allocation from increasing prices. The Commission stated, "The Commission finds this [rate decrease] filing, as detailed earlier in this order, to be an appropriate method for the equitable sharing [of] the merger benefits with Washington ratepayers."(Page 15)

Wyoming. The PSC did not discuss the allocation issue and imposed no conditions related to it.

5. Merger Conditions Related to Price

The Applicants made commitments related to price in every state. The Applicants clearly committed that prices would never be higher as a result of the merger. The following summarizes additional commitments and the commissions' findings.

California. The Applicants committed to seek no increase in price through 1989. In approving the merger, the Commission ordered that there be no increase in Pacific Power's Electric Revenue Adjustment Mechanism (ERAM) and no attrition price increase for four years, through 1991.

Idaho. The Applicants proposed the same price decrease in Utah Power's Idaho service territory as they proposed in Utah: 2% within sixty days, followed by an additional 3-8% over four years. The Applicants also pledged that prices in the Pacific Power portion of the service territory would not increase for four years. The Idaho PUC imposed a condition that prices charged in neither the Pacific nor the Utah portions of the service territory could increase as a result of the merger.

Montana. The Applicants committed to maintain stable prices in Montana for five years.

Oregon. As part of a global stipulation with Staff, Applicants committed not to increase prices through 1992. PacifiCorp had already committed not to increase prices in Oregon through 1989 so this merger commitment represented a 3-year extension. In addition, Applicants agreed to file a general rate case by mid-1989. The 1989 rate filing was to include a pro forma adjustment to reflect \$48 million of systemwide merger benefits estimated to occur in 1988. That amount translated to approximately \$17 million or 2.8 percent in Oregon. The Company also agreed to hold Oregon customers harmless if the merger resulted in increased costs. The Commission summarized provisions in the stipulation and associated testimony when it stated:

> "Applicants have committed indefinitely that Pacific's customers will not be harmed by the merger and will not subsidize benefits to Utah Power customers. Applicants recognize that if the merger results in higher costs, those costs will be borne by the merged company's shareholders. Applicants further agree that shareholders will assume all risks that may result from less than full system cost recovery if interdivisional allocation methods differ among the various jurisdictions." (Page 22.)

The Commission approved the stipulation and rejected a price condition proposed by BPA to 'guarantee' 5 years of estimated merger benefits

Utah. In the Applicants' initial testimony, David Bolender committed the Company to reduce prices in Utah by a total of between 5 and 10 percent over four years. Also in initial testimony, Fredric Reed testified that the Company would file tariffs reducing overall prices by two percent within sixty days of the effective date of the merger. The Commission approved the Company's proposed price decreases with additional provisions governing the distribution of the decreases among customer classes. The Utah commission also ordered that, "the Merged Company shall certify that firm retail rates will never be raised as a result of the merger." (Page 96.)

Washington. The Applicants agreed in their supplemental brief to make a rate filing in April 1989 that would pass through Washington's allocated share of \$59 million of estimated merger benefits along with three other identified cost changes. The merger portion of the decrease was expected to be slightly less than \$5 million in the jurisdiction or about 3.6 percent. The Commission imposed additional reporting requirements but did not impose additional price conditions.

Wyoming. Applicants made several price commitments as part of the merger. For the Utah Power portion of the service territory, Applicants committed to reduce prices by 2% within sixty days, followed by an additional 3-8% over five years. In the Pacific Power portion of the service territory, Applicants committed to maintain stable prices over the next five years. Applicants also committed that no price increases would occur as a result of the merger.

6. Conclusion

The Pacific Power/Utah Power merger delivered substantial benefits to all of PacifiCorp's customers. The Company is encouraged that parties are participating in the MSP process with a focus on actions that are in the public interest today.

EXHIBIT 215

EXHIBIT 215 (RMA-4)

New Power Sources in WECC
MW's

	WECC	Arizona	California	Colorado	Idaho	Montana	New Mexico	Nevada	Oregon	Utah	Washington	Wyoming
Planned	**37,575**	12,905	7,554	83	1,800	2,770	240	5,060	1,485	248	4,930	500
Under Construction	**10,768**	4,230	3,858		270		135	310	540		1,375	50
Under Development	**3,920**	2,350	1,322								248	

Source: Energy InfoSource Plant Construction Rapid Report, June 20, 2002

Company	Project Name	Type of Plant	Capacity (MW)	City	Status	Target Production Date	Cost
Arizona							
NRG Energy/SRP/Dynegy		Gas	825	Tempe	Delayed		$ 400,000,000
Calpine/Pinnacle West	West Phoenix Power Plant	Gas	545	Phoenix	In Commercial Operation		$ 220,000,000
Calpine Corp.	South Point Power Plant	Gas	526	Bullhead City	In Commercial Operation		$ 275,000,000
Salt River Project		Gas	825	Gilbert	Planned		$ 400,000,000
Pinnacle West Energy		Gas	2120	Arlington Valley	Planned	2003	$ 1,000,000,000
Duke Energy		Gas	550	Arlington Valley	Planned	late-03	$ 250,000,000
Power Development Enterprises/Industrial Power Technology		Gas	750	Gila Bend	Planned	early-04	$ 400,000,000
Allegheny Energy		Gas	1080	La Paz County	Planned	2005	$ 540,000,000
Reliant Resources	Reliant Resources Arrow Canyon	Gas	500	Las Vegas	Planned	Jun-03	$ 270,000,000
Southwestern Power	Toltec Power Station	Gas	1800	Eloy	Planned	2004	$ 1,000,000,000
PPL Global		Gas	600	Pinal County	Planned	2002	$ -
Sempra	Mesquite Power	Gas	1000	Maricopa County	Planned	2003	$ 600,000,000
Unisource/Bechtel	Springerville Generating Station	Coal	760		Planned	2005	$ -
Southwestern Power	Bowie Power Station	Gas	1000	Cochise County	Planned	2004	$ -
Reliant Resources	Signal Peak Phase I	Gas	580	Pinal County	Planned	2004	$ -
Reliant Resources	Signal Peak Phase II	Gas	580	Pinal County	Planned	2009	$ -
Salt River Project/UniSource	Springerville Units 3 & 4	Coal	760	Springerville	Planned	2005	$ -
PP&L Global/Duke Energy	Griffith	Gas	520	Kingman	Under Construction		$ 275,000,000
Reliant Resources		Gas	550	Casa Grande	Under Construction		$ 263,000,000
Pinnacle West Energy	Redhawk Power Plant	Gas	2120	Palo Verde	Under Construction	2002	$ -
PG&E Generating		Gas	1040	Harquahala Valley	Under Construction	mid-03	$ 400,000,000
Panda Energy/TECO	Gila River Project	Gas	2350	Gila Bend	Under Development	2002	$ 1,000,000,000
		Total Delayed	**825**				
		Total Planned	**12905**				
	Total Under Construction		**4230**				
	Total Under Development		**2350**				
	Total In Commercial Operation		**1071**				
		Total Plants	**21381**				**$ 7,293,000,000**
California							
Calpine		Gas	180	San Jose	Delayed		$ 250,000,000
Calpine Corp	Russell City Energy Center	Gas	600	Hayward	Delayed		$ -
Calpine Corp.	Metcalf Energy Center	Gas	600	San Jose	Delayed		$ 300,000,000
Calpine Corp.	Teayawa Energy Center	Gas	600	Thermal	Delayed		$ 275,000,000
Calpine Corp.	East Altamont Energy Center	Gas	1100	Tracy	Delayed		$ 550,000,000
Calpine Corp.	Inland Empire Energy Center	Gas	600	Riverside County	Delayed		$ 325,000,000
Calpine Corp.	Sutter Power Plant	Gas	545	Yuba City	In Commercial Operation		$ 300,000,000
Edison Mission Energy	Sunrise Power Project	Gas	320	Kern County	In Commercial Operation		$ 200,000,000
Calpine Corp.	Los Medanos Energy Center	Gas	500	Pittsburg	In Commercial Operation		$ -
InterGen	Larkspur Energy Facility	Gas	90	San Diego	In Commercial Operation		$ -
Black Hills	Harbour Plant	Gas	30	Long Beach	In Commercial Operation		$ -
InterGen	Indigo Energy Facility	Gas	135	Palm Springs	In Commercial Operation		$ -
Calpine Corp.	Delta Energy Center	Gas	880	Pittsburg	In Commerical Operation		$ 350,000,000
Ogden Pacific Power		Gas	550	Burney	Planned		$ 300,000,000
Wisvest	Blythe Energy Power Plan	Gas	520	Blythe	Planned		$ 250,000,000
Modesto Irrigation District		Gas	80	Modesto	Planned		$ 60,000,000
Enron	Antelope Project	Gas	1000	California City	Planned	2003	$ 500,000,000
Enron	Long Beach District Energy Facility	Gas	500	Long Beach	Planned		$ 300,000,000
Mirant	Contra Costa Project	Gas	530	Antioch	Planned	early-03	$ 250,000,000
Thermo Ecotek	Mountainview Project	Gas	1056	San Bernardino	Planned		$ 550,000,000
InterGen	Ocotillo Energy Facility	Gas	900	Palm Springs	Planned	2004	$ 500,000,000
Enron		Gas	750	Roseville	Planned	2005	$ -
Southern California Public Power Authority	Magnolia Power Project	Gas	240	Burbank	Planned	2004	$ 200,000,000
FPL Energy		Gas	517	Blythe	Planned	early-03	$ -
California Power Partners		Gas	90	Lancaster	Planned	mid-02	$ 75,000,000

Company	Project Name	Type of Plant	Capacity (MW)	City	Status	Target Production Date	Cost
Sempra	Palomar Energy	Gas	550	Escondido	Planned		$ -
NRG Energy	El Segundo Expansion	Gas	271	El Segundo	Planned	2005	$ -
PG&E Generating		Gas	1048	McKittrick	Under Construction		$ 730,000,000
Duke Energy	Moss Landing	Gas	1060	Monterey Bay	Under Construction	mid-02	$ 525,000,000
Calpine Corp.	Otay Mesa Generating Project	Gas	500	Otay Mesa	Under Construction	mid-03	$ 350,000,000
Sempra/Occidental	Elk Hill Project	Gas	500	Kern County	Under Construction	2003	$ 300,000,000
Calpine Corp.	Pastoria Plant	Gas	750	Kern County	Under Construction	2003	$ 400,000,000
Constellation Power/Inland Energy	High Desert Project	Gas	720	Victorville	Under Development	early-03	$ 350,000,000
Covanta	Three Mountain Power Project	Gas	500	Burney	Under Development	late-03	$ -
Valero Energy		Gas	102	Benicia	Under Development	2002	$ 100,000,000
		Total Delayed	**3680**				
		Total Planned	**7554**				
		Total Under Construction	**3858**				
		Total Under Development	**1322**				
		Total In Commercial Operation	**2500**				
		Total Plants	**18914**				**$ 8,290,000,000**
Colorado							
Calpine Corp.	Colorado Energy Center (Blue Spruce)	Gas	336	Aurora	Delayed		$ 100,000,000
Calpine Corp.	Rocky Mountain Energy Center	Gas	600	Hudson	Delayed		$ 360,000,000
Coastal Power/New Century Energies		Gas	265	Brush	In Commercial Operation		$ 115,000,000
KN Energy		Gas	160	Ft. Lupton	In Commercial Operation		$ -
Black Hills/Indeck		Gas	111	Metro Denver	In Commerical Operation		$ 80,000,000
Black Hills		Gas	240	Colorado Springs	In Commerical Operation		$ 100,000,000
PG&E Generating	Plains End	Gas	111	Arvada	In Commerical Operation		$ -
Wilexco		Refuse	83	Colorado Springs	Planned	2003	$ 90,000,000
		Total Delayed	**936**				
		Total Planned	**83**				
		Total In Commercial Operation	**887**				
		Total Plants	**1906**				**$ 845,000,000**
Idaho							
Ida-West		Gas	250	Canyon County	Planned		$ -
Ida-West		Gas	250	Middleton	Planned	2004	$ 200,000,000
Newport Generation	Kootenai Power Project	Gas	1300	Rathdrum	Planned	2004	$ 550,000,000
Avista Power/Cogentrix		Gas	270	Rathdrum	Under Construction		$ 150,000,000
		Total Planned	**1800**				
		Total Under Construction	**270**				
		Total Plants	**2070**				**$ 900,000,000**
Montana							
Panda Energy		Gas	1000	Montgomery County	Planned	late-03	$ 300,000,000
Great Plains Power		Coal	900	Weston	Planned		$ -
Ameren		Hydro	770	Reynolds County	Planned	2009	$ -
Empire District Electric		Gas	100	Sarcoxie	Planned	2003	$ -
Duke Energy/Associated Electric Coop	St. Francis Energy Facility	Gas	250	Glennonville	In Commercial Operation		$ 100,000,000
Aquila Energy/Calpine	Aries Energy Center	Gas	600	Pleasant Hill	In Commercial Operation		$ 280,000,000
NRG Energy	Audrain Generating Station	Gas	640	Audrain County	In Commerical Operation		$ 250,000,000
		Total Planned	**2770**				
		Total In Commercial Operation	**1490**				
		Total Plants	**4260**				**$ 930,000,000**
New Mexico							
PNM		Gas	80	Lordsburg	Planned	Jul-02	$ -
Energy Development Group	Cambray Energy Center	Gas	160	Deming	Planned	2005	$ -

Company	Project Name	Type of Plant	Capacity (MW)	City	Status	Target Production Date	Cost
PNM	Afton Generating Station	Gas	135	Las Cruces	Under Construction	Oct-02	$ -
Avista Power		Gas	120	Lordsburg	In Commercial Operation		$ 70,000,000
MCN Energy		Gas	140	Bernalillo County	In Commercial Operation		$ -
		Total Planned	**240**				
		Total Under Construction	**135**				
		Total In Commercial Operation	**260**				
		Total Plants	**635**				**$ 70,000,000**
Nevada							
Composite Power Corp.		Solar/Wind	1000	Nye County	Planned		$ 1,800,000,000
NTS Development Corp.		Sludge	30	Clark County	Planned		$ 25,000,000
Mirant		Gas	1000	Las Vegas	Planned		$ -
PG&E Generating	Meadow Valley Generating Project	Gas	1000	Clark County	Planned	2004	$ -
M&N Wind Power		Wind	260		Planned	2004	$ -
Williams		Gas	125	Las Vegas	Planned	mid-02	$ -
Reliant Resources		Gas	575	Clark County	Planned	Jun-03	$ -
Pinnacle West	Silverhawk Power Station	Gas	570	Las Vegas	Planned	early-04	$ -
Diamond Generating	Ivanpah Energy Center	Gas	500	Goodsprings	Planned	Mar-05	$ 350,000,000
Reliant Resources	Reliant Resources Bighorn	Gas	310	Clark County	Under Construction	Jun-02	$ -
		Total Planned	**5060**				
		Total Under Construction	**310**				
		Total Plants	**5370**				**$ 2,175,000,000**
Oregon							
PG&E Generating	Umatilla Generating Plant	Gas	550	Hermiston	Delayed		$ -
Pacificorp		Gas	500	Klamath Falls	In Commercial Operation		$ -
Avista Power	Coyote Springs 2	Gas	280	Boardman	Planned	Jun-02	$ -
Enron		Gas	605	Coburg	Planned		$ -
Coburg Power		Gas	600	Coburg	Planned	mid-03	$ 350,000,000
Calpine Corp.	Hermiston Energy Center	Gas	540	Hermiston	Under Construction	mid-02	$ 270,000,000
		Total Delayed	**550**				
		Total Planned	**1485**				
		Total Under Construction	**540**				
		Total in Commercial Operation	**500**				
		Total Plants	**3075**				**$ 620,000,000**
Utah							
Questar/UAMPS		Gas	128	Payson	Planned	2004	$ -
Utah Power	Gadsby Power Plant	Gas	120	Salt Lake City	Planned		$ 80,000,000
		Total Planned	**248**				
		Total Plants	**248**				**$ 80,000,000**
Washington							
PPL Global	PPL Starbuck	Gas	1200	Columbia County	Cancelled		$ -
NESCO		Gas	660	Sumas	Planned	2003	$ 400,000,000
FPL Energy	Stateline	Wind	300	Walla Walla	Planned		$ -
Cogentrix		Gas	850	Benton County	Planned	2004	$ 275,000,000
U.S. Electric Power		Coal	249	Whatcom County	Planned	2004	$ -
Newport Generation	Wallula Power Project	Gas	1300	Wallula	Planned	2004	$ 550,000,000
Washington Winds	Maiden Wind Farm	Wind	150	Benton County	Planned	late-02	$ -
Mirant/Avista		Gas	286	Longview	Planned	mid-03	$ -
Tractebel Power	Chehalis Power Project	Gas	505	Lewis County	Planned	late-03	$ 360,000,000
Duke Energy	Satsop 2	Gas	630	Grays Harbor County	Planned		$ -
Westcoast Power/EPCOR		Gas	249	Frederickson	Under Construction	mid-02	$ 160,000,000

Company	Project Name	Type of Plant	Capacity (MW)	City	Status	Target Production Date	Cost
TransAlta		Gas	248	Centralia	Under Construction	Jul-02	$ 210,000,000
Calpine Corp.		Gas	248	Goldendale	Under Construction	Jul-02	$ -
Duke Energy	Satsop	Gas	630	Grays Harbor County	Under Construction	mid-04	$ 300,000,000
FPL Energy		Gas	248	Everett	Under Development		$ -
		Total Canceled	**1200**				
		Total Planned	**4930**				
		Total Under Construction	**1375**				
		Total Under Development	**248**				
		Total Plants	**7753**				**$ 2,255,000,000**
Wyoming							
Independent Energy (Black Hills)	Wygen #1	Coal	80	Gillette	In Commerical Operation		$ -
Black Hills		Coal	500	Gillette	Planned	mid-05	$ -
Shell Wind Energy	Rock River I	Wind	50	Carbon County	Under Construction		$ -
		Total Planned	**500**				
		Total Under Construction	**50**				
		Total In Commercial Operation	**80**				
		Total Plants	**630**				**$ -**
WSCC							
		Total Delayed	5991				
		Total Canceled	1200				
		Total Planned	37575				
		Total Under Construction	10768				
		Total Under Development	3920				
		Total In Commercial Operation	6788				
		Total Plants	**66242**				**23,458,000,000**