Comparing the Risk Profiles of Renewable and Natural Gas Electricity Contracts:
A Summary of the California Department of Water Resources Contracts

by

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List of Abbreviations

CPUC	California Public Utilities Commission
DWR	California Department of Water Resources
EEI	Edison Electric Institute
EOB	California Electricity Oversight Board
FERC	Federal Energy Regulatory Commission
ISO	California Independent System Operator
WSPP	Western Systems Power Pool

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Executive Summary

The risks that exist in the electricity industry depend on the technologies and resources that are used to generate electricity. Renewable resources are frequently noted to benefit society by reducing certain risks relative to conventional fuels (such as natural gas). The allocation of risks in the electricity industry, in turn, influences electricity investment decisions, and thereby has a significant impact on the overall portfolio of electricity supply.

This paper compares the allocation of risks in long-term contracts for electricity generated from natural gas with the allocation of risks in long-term contracts for renewable electricity. Our contract sample consists of twenty-seven long-term (three years and longer) contracts signed by the California Department of Water Resources (DWR) on behalf of the customers of California's three investor-owned utilities during the California electricity crisis. The DWR contracts will substantially define California's electricity system over the next decade, and the California State Auditor expects the contracts to cost about $40 billion.

1. Fuel Price and Supply Risk in Electricity Contracts

Many renewable resources have a free source of fuel and can thereby mitigate fuel price risk, whereas the price of natural gas is quite volatile and thus increases fuel price risk. Contracts for natural gas-generated electricity allocate fuel price risk through the electricity pricing mechanism. Fixed-price electricity contracts allocate fuel price risk to the Seller, however the Buyer still bears some residual fuel price (i.e. bankruptcy) risk. Tolling and indexed-price agreements allocate fuel price risk to the Buyer. If a party bears fuel price risk and wishes to reduce its exposure, it must also bear the cost of hedging its risk. Renewable electricity contracts are commonly fixed-price, and provide a more complete hedge against fuel price risk than either a fixed-price or hedged tolling (or indexed-price) natural gas-generated electricity contract.

The DWR hedged its fuel price risk exposure primarily through the use of fixed-price non-renewable (primarily natural gas) electricity contracts, which provide 57% of the electricity the DWR has under contract through 2010. The DWR bears fuel price risk in the tolling agreements, which provide 41% of its electricity. Renewable electricity only provides 1.5% of the DWR's total ten-year electricity purchases; the DWR clearly did not use renewables as a significant hedge against fuel price risk. The elasticity of the total cost of the DWR contracts to natural gas prices is only about 0.2, however, the DWR's total cost could vary on the order of $2 billion based on scenarios of natural gas price forecasts.

Renewable electricity contracts and natural gas-fired electricity contracts face different challenges with regards to fuel supply risk. Natural gas-fired power plants are more vulnerable to systematic interruptions in natural gas supply (affecting many plants simultaneously), while renewable generation facilities are more vulnerable to unsystematic day-to-day variability in fuel supply. Since fuel supply interruptions are likely to be out of the Seller's control, the DWR contracts generally excuse the Seller from delivering power in the event of a fuel supply interruption.

The DWR contracts provide for the construction of a significant capacity of new natural gas-fired power plants, which will increase California's reliance on natural gas, and may have important implications for the vulnerability of California's economy to natural gas price volatility. (The DWR's recently renegotiated contracts convert some of the fixed-price natural gas contracts to tolling agreements, further increasing the DWR's fuel price risk exposure.) This increased reliance on natural gas may also make California's electricity system more susceptible to systematic and catastrophic interruptions of natural gas supply.

2. Performance Risk in Electricity Contracts

There is no inherent difference in the amount of performance risk present in renewable and non-renewable contracts, and the DWR contracts manage performance risk in the renewable contracts in a similar manner to the non-renewable non-dispatchable contracts, which the renewable contracts most resemble. Almost all of the DWR contracts allocate the risk of construction cost over-runs to the Seller. In most of the contracts, the parties share the risk that a power plant will not be built according to schedule; most contracts allow the DWR to terminate the contract with respect to any unit that does not reach operation by a specified deadline, and in some contracts the Seller must pay a financial penalty as well.

Dispatchable contracts are commonly tolling agreements, in which the Buyer pays both a capacity charge and a fuel charge. Dispatchable contracts have four primary performance concerns during operation. First, many of the dispatchable contracts require annual testing of the capacity of the power plant to determine the capacity charge. Second, many of the dispatchable contracts require periodic testing or calculation of the plant's heat rate to determine the fuel charge. Third, most of the contracts have availability requirements to ensure that the power plant is available to generate power when needed, and the contracts financially penalize the Seller if the availability requirement is not met. Finally, some of the dispatchable contracts require the Seller to pay "cover damages" (the incremental cost of replacement power) for unexcused failures to deliver power; what outages qualify as excused outages is determined by the "firmness" of the contract.

Non-dispatchable contracts have fewer performance concerns to manage than dispatchable contracts, since the contracts are almost all fixed-price. The fixed-price nature of a non-dispatchable contract provides the Seller a built-in incentive to perform – the Seller is only paid when power is delivered. All of the DWR's non-dispatchable contracts require the Seller to pay cover damages for unexcused failures to deliver power. In the DWR's two wind contracts, the DWR assumed an additional aspect of performance risk (that is particular to the wind contracts) by agreeing to bear any ISO imbalance charges that might arise.

The State Auditor expressed concern that many of the DWR contracts contain performance risk terms that are excessively lenient for the Sellers, and many of the recently renegotiated contracts strengthen the performance risk terms.

3. Demand Risk in Electricity Contracts

Renewable electricity generation technologies are more difficult to dispatch in general than natural gas-fired electricity generation technologies (particularly gas turbines); natural gas-fired electricity contracts are therefore better able to reduce demand risk (through dispatchability) than renewable contracts. Dispatchable contracts reduce the amount of demand risk faced by the

Buyer, while the Seller's demand risk is mitigated through the capacity charge. Since dispatchable contracts tend to be tolling agreements, the Buyer decreases its exposure to demand risk but increases its exposure to fuel price risk.

About one quarter of the electricity the DWR has under contract over the next decade is dispatchable. The State Auditor's review of the DWR contracts found that the DWR has purchased excess non-dispatchable power and inadequate dispatchable power. As a result, any further electricity contracting efforts in California in the near future (by the DWR or by other parties) may focus on dispatchable contracts, which would likely result in a further increase in California's reliance on natural gas rather than renewable resources. However, the DWR recently renegotiated several contracts and increased dispatch flexibility in contracts that were previously non-dispatchable.

4. Environmental Risk in Electricity Contracts

We use the phrase "environmental risk," for lack of a better concise phrase, to mean the financial risk to which parties to an electricity contract are exposed, stemming from regulations related to environmental protection. Non-renewable electricity generation technologies cause more environmental damage than renewable generation technologies, and renewable electricity contracts can therefore mitigate environmental risk. If new environmental regulations are enacted, parties to non-renewable contracts will most likely have to bear additional costs, while parties to renewable contracts may realize financial benefits.

Given the potential financial impact of a new environmental regulation, it is perhaps surprising that relatively few of the DWR's non-renewable contracts (only about one-third) explicitly allocate environmental risk in a comprehensive manner. All of the DWR contracts that explicitly allocate environmental risk allocate it to the DWR, although some of the contracts require the Seller to bear part of the cost. The DWR could face large cost increases if new environmental regulations are implemented. For example, a carbon tax could result in billions of dollars of additional costs.

When renewable electricity is generated, two commodities are created – electricity and "renewable credits" – that can be sold separately. The renewable credits represent the environmental benefit of generating electricity with renewable resources. The DWR did not acquire the renewable credits for about two-thirds of its renewable electricity, so although the DWR nominally purchased 1.5% of its electricity from renewable resources, only 0.5% of the DWR's electricity can be considered renewable from an environmental risk perspective (e.g. if a renewable portfolio standard were implemented).

Our review of the DWR contracts demonstrates that many participants in the electricity industry take environmental risk seriously, but that there is no "industry standard" way to allocate environmental risk – the contracts were highly non-uniform in how they addressed environmental risk.

5. Regulatory Risk in Electricity Contracts

There is no inherent difference in the amount of regulatory risk that parties to renewable and non-renewable contracts face. The DWR contracts contain clauses designed to both prevent regulatory action, and to mitigate and allocate the consequences of a new regulatory requirement. About half of the DWR's non-renewable contracts prevent the parties to the contract from seeking changes in the contract from a regulatory authority, and about half the contracts also state that the contract price is "just and reasonable" to try to prevent regulatory review. Most of the non-renewable contracts specify that if a regulatory authority orders a change in the contract, either the contract price will not change or the parties will use their best efforts to reform the agreement to give effect to the original intention of the parties. In contrast, none of the renewable contracts attempt to prevent regulatory review of the contracts, and only two of the renewable contracts designate a course of action that will be taken if a regulatory agency orders a change in the contract.

The treatment of regulatory risk in the DWR contract sample may not represent the standard management of regulatory risk in competitive contracts in the electricity industry; the parties selling electricity – especially high-priced non-renewable electricity – to the DWR were clearly aware that they faced an unusually sizeable amount of regulatory risk. The strength of the various clauses the DWR contracts use to address regulatory risk may soon be tested if the Federal Energy Regulatory Commission rules on requests made by the California Public Utilities Commission and the Electricity Oversight Board to either change the terms of the DWR contracts or to abrogate them completely.

Conclusions

Of the risks analyzed in this paper, renewables can provide the most value relative to natural gas by mitigating fuel price risk and environmental risk, while natural gas technologies can provide value by reducing demand risk. Renewables and natural gas face different challenges with regards to fuel supply risk, and neither natural gas nor renewables has a clear advantage with regards to regulatory risk or performance risk.

It is not clear whether utilities and other parties that procure electricity objectively analyze the trade-offs between the various risks we have discussed. Utilities appear to place a particular emphasis on demand risk, which favors investment in natural gas generation technologies, and less emphasis on fuel price risk and environmental risk, which might favor renewable technologies. Only a portion of a portfolio of electricity supplies needs to be dispatchable in order to reduce demand risk, so there are significant opportunities for investments in natural gas and renewables to complement each other within a portfolio of electricity supplies. A better understanding of the risks associated with the use of renewable and non-renewable electricity in the electricity industry may help utilities (and others that procure power) make more objective investment decisions in the future.

1. Introduction

Considerable risks exist in the electricity industry, from the perspective of industry participants as well as society as a whole; electricity is considered essential for everyday life, and sizeable capital investments are required to build electricity generation facilities. The risks that exist in the electricity industry depend on the investment decisions that are made – decisions about both the types of generation facilities to build and the resources to use to generate the electricity. Renewable resources are frequently noted to benefit society by reducing certain risks relative to conventional fuels (such as natural gas). California's recent electricity crisis highlighted some of the risk mitigation value of renewable energy; in contrast to the skyrocketing natural gas prices that contributed to steep increases in wholesale electricity prices during the crisis, renewable resources were able to generate electricity at stable and predictable prices.

The amount of risk a party bears depends on how the risks (which exist due to resource and technological choices) are allocated among various parties.[1] Electricity contracts play a central role in allocating risks among parties in the electricity industry. (Other contracts – such as financing agreements and fuel supply agreements – and regulations also play a significant role in allocating risks.[2]) The allocation of risks in the electricity industry, in turn, influences electricity investment decisions, and thereby has a significant impact on what types of power plants are built and the overall portfolio of electricity supply.

This paper compares the allocation of risks in long-term contracts for electricity generated from natural gas with the allocation of risks in long-term contracts for renewable electricity. Our comparison highlights some of the key differences between the two types of resources that decision makers must consider when making electricity industry investment decisions.

This analysis of the treatment of risk in long-term natural gas and renewable electricity contracts is drawn from our review of the contracts signed by the California Department of Water Resources (DWR) on behalf of the customers of California's three investor-owned utilities during the California electricity crisis. We reviewed the DWR's long-term contracts and summarized the provisions that allocate risks, focusing on financial risks and reliability risks from the perspectives of both parties to the contracts. In addition, we reviewed the California State Auditor's report on the DWR contracts, and we use the Auditor's calculations of the amount of energy to be provided by each contract and the contract costs as the basis for many of our calculations (California State Auditor 2001). Finally, we reviewed several other analyses of the DWR contracts, including an analysis by JBS Energy (Marcus 2002) and two filings at the Federal Energy Regulatory Commission (FERC) in protest of the DWR contracts submitted by the California Public Utilities Commission (CPUC) and the California Electricity Oversight Board (EOB) (CPUC 2002; EOB 2002).

[1] The amount of risk a party is exposed to also depends on the party's ability to mitigate the risks that it bears.
[2] This paper does not include an analysis of the various other contracts and regulations that are associated with the long-term power contracts that we analyze, and therefore does not represent a complete analysis of the allocation of risks associated with our sample of power projects. For an analysis of the allocation of risks between financial institutions and private power plant developers in loan agreements, see Kahn et al. (1992).

The DWR contracts form the basis of our analysis of the treatment of risk in electricity contracts for several reasons. First, the DWR contracts will play an important role over the next decade in determining the shape of California's electricity industry – an industry that provides an essential input to the fifth largest economy in the world. Second, the contracts represent an unusually large sample of publicly available contracts, providing a unique opportunity to analyze the treatment of risk in electricity contracts. Third, the DWR contracted with both natural gas and renewable power plants, allowing a comparison of the risk profiles of the two types of contracts. Finally, although the DWR contracts were not executed in a fully competitive market, the contracts are based on industry-standard contract templates and therefore may provide broader insights into the risk allocation practices common in competitively bid contracts.

We begin, in Section 2, by discussing our use of the term "risk" and outlining the risks in the electricity industry that we analyze further. Section 3 provides a brief overview of the context in which the DWR contracts were signed and some of the principal terms of the contracts. Section 4 examines how the long-term contracts allocate fuel price and fuel supply risk. Section 5 discusses the treatment of performance risk. Section 6 considers demand risk. Section 7 discusses environmental risk – the uncertainty due to environmental regulations – and Section 8 reviews other aspects of regulatory risk. Conclusions are discussed in Section 9.

2. Risks in Electricity Contracts

The term "risk" in everyday life is generally used to refer to the potential for future harm. Risk is used to describe a wide variety of potential negative outcomes in life, for example: the risk of getting cancer, the risk of being in a car accident, the risk of a nuclear power plant accident, etc. However, in other cases, risk simply refers to a future that is uncertain, independent of whether the future outcome will be beneficial or detrimental. For example, investing in a stock is risky, although the future value of your investment may decrease *or* increase.

In academic circles, risk is often used in a more defined manner. The states of incertitude about the future are sometimes distinguished using three different concepts: risk, uncertainty, and ignorance. Risk analysis attempts to model the future by specifying probabilities for a complete set of possible outcomes. Uncertainty is distinguished as a separate concept that is used when probabilities of outcomes are inestimable, but the complete set of possible outcomes is still assumed to be known. The final concept is ignorance about the future. Ignorance exists when one is unable to assign probabilities to future outcomes, or to specify the complete set of possible outcomes (Stirling 1994). The distinctions among these three states of incertitude become important when one attempts to quantify the value or cost of a risk.

In this paper, we adopt a broad definition of the term "risk," and we use it to mean the possibility that future events or outcomes will be uncertain. Our qualitative use of the term "risk" in this paper encompasses all three of the above defined states of incertitude.

It is ordinarily assumed that most people, and that society as a whole, are risk averse.[3] Most people place a value on being able to predict a future outcome with certainty, and they are often willing to pay to eliminate future variability or risk.

An individual's perception of a particular risk is in relation to the potential impact that it could have on his or her life; individuals may be less averse to a risk that would have only a small impact. The risks involved in long-term power agreements are important to society for several reasons. First, electricity is considered to be an essential commodity; any significant interruption in its supply would create a state of emergency in California and have serious economic repercussions. In addition, the elasticity of demand for electricity is very low,[4] so when prices increase most residents and businesses feel they have relatively little choice but to pay higher amounts, which can be a significant burden for some. Finally, Californians have spent about 2% of the gross state product on electricity in the last several years (CEC 2002b; California Technology, Trade & Commerce Agency 2002). With such a large amount of California's income going to purchase electricity, it is important that the risks present in the industry are managed efficiently and equitably.

[3] Finance textbooks define a risk-averse investor as one who would prefer to avoid fair gambles; a fair gamble is one with a zero expected return (Ross 1999).
[4] The elasticity of the demand for electricity in California is very low in part because most consumers do not receive accurate real-time price signals, and in part because electricity is considered to be an essential commodity. Even if consumers did receive accurate price signals, the demand elasticity of electricity would still be relatively low.

The Allocation and Mitigation of Risks

There are two different actions that can be taken when a risk exists: the risk can be *allocated* to a certain party, and the risk can be *mitigated*. The allocation of a risk determines who will bear the consequences of an uncertain future event. For example, the allocation of the risk of a future change in tax law determines who will pay for a tax increase or benefit from a tax decrease. Risk mitigation, on the other hand, reduces the uncertainty associated with a future event, or reduces the potential impact of the event. For example, in order to mitigate fuel price risk – the risk that future fuel prices will be uncertain – a developer can choose to build a wind-powered generation facility (that will have free fuel) rather than a natural gas-fired power plant. In his 1992 paper, Kahn cites Arrow's work that from a societal perspective, risks should be allocated either to the party best able to mitigate the risk, or the party best able to bear the costs of the risk.

Contracts play an important role in the electricity industry by legally binding two parties to an agreement and allocating risks between the parties. Contracts can also provide mechanisms, incentives, and penalties designed to mitigate risks. The long-term electricity contracts analyzed in this paper only represent one of the ways that risks are managed in the electricity industry. As noted above, many other agreements, for example financing agreements and fuel supply agreements, also play a significant role in allocating risks in the electricity industry.

Systematic risk vs. Unsystematic risk

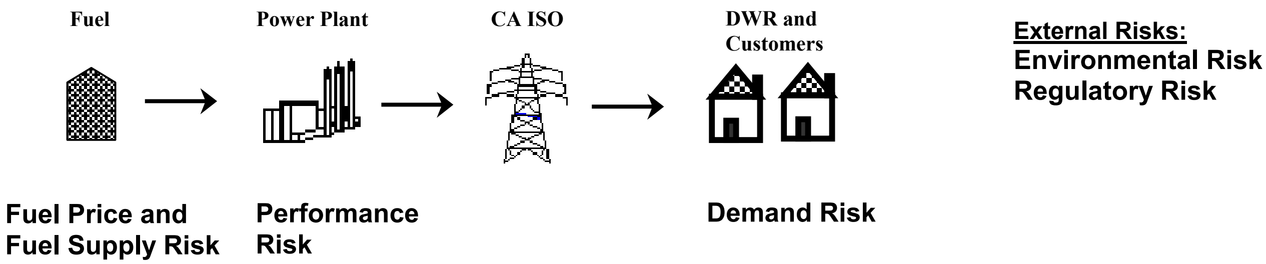
Risks can either be unsystematic or systematic in nature. An unsystematic risk affects an individual member of a group and is uncorrelated with the risk that the same event or outcome will affect other individuals. For example, the risk that one power plant will be poorly maintained and have a poor performance record generally does not affect the likelihood that another power plant will be maintained in a similarly poor manner (unless they are owned and managed by the same company).

A systematic risk, on the other hand, is a risk that affects all members of a group simultaneously; the risk that an individual member of the group faces is correlated with the risk faced by the other members of the group. For example, the risk that a major natural gas pipeline entering California might be crippled and interrupt fuel supply would affect many of the state's natural gas-fired power plants simultaneously.

2.1 Types of Risks in Electricity Contracts

Many risks exist in the process of building and operating a power plant, providing fuel to the plant, and transmitting the electricity produced by the power plant to a customer. The broad categories of risks present in the electricity system that we analyze in this paper are presented in Figure 1, mapped to the physical production and transmission of electricity in California, where applicable.

Figure 1. Categories of Risks in Electricity Contracts



The risks that long-term electricity contracts manage include:

- **Fuel Price Risk.** The risk that the price of the fuel used to generate electricity will exhibit variability (positive or negative), resulting in an uncertain cost to generate electricity.
- **Fuel Supply Risk.** The risk that the fuel supply to a power plant will be unreliable, resulting in the inability to generate electricity in a predictable and dependable manner.
- **Performance Risk.** The risk that either party to an electricity contract will not fulfill its part of the agreement in an optimal manner.
- **Demand Risk.** The risk that the electricity that has been contracted for will not be needed as anticipated.
- **Environmental Risk.** The financial risk to which parties to an electricity contract are exposed, stemming from both existing environmental regulations and possible future regulations.
- **Regulatory Risk.** The risk that future laws or regulations, or regulatory review of a contract, will alter the benefits or burdens of an electricity contract to either party.
- **Other Risks.** The parties to an electricity contract face numerous other sources of uncertainty, including the risk that the transmission system – which is necessary for the parties to complete the electricity delivery transaction – will be unreliable, and the risk that a party to the contract will default on the contract, for example by entering into bankruptcy.

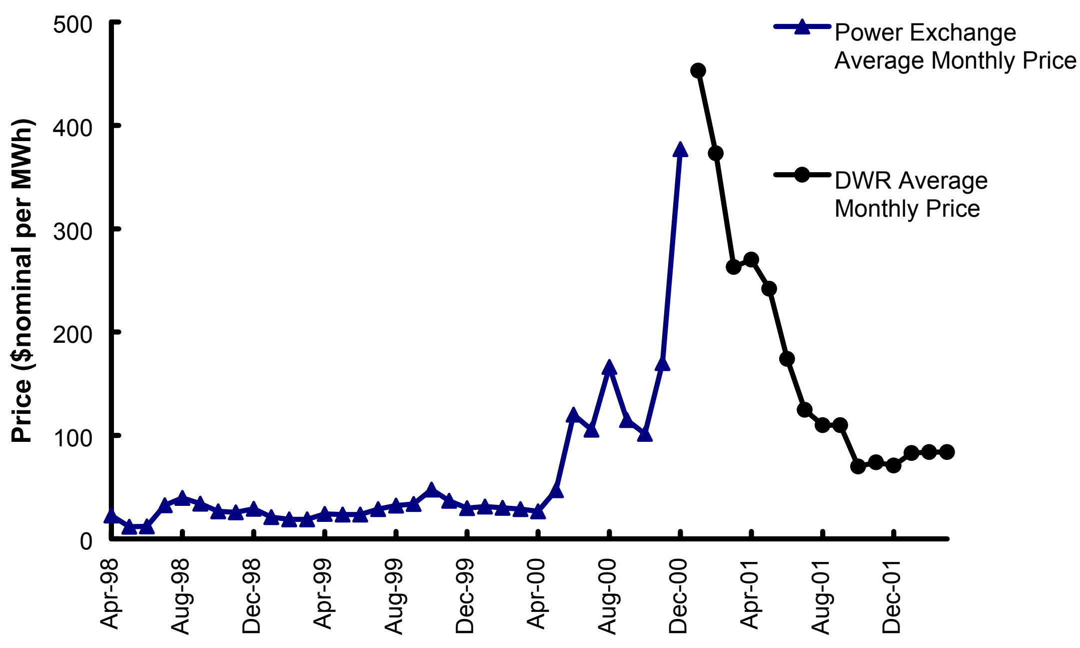
3. Background on the California Electricity Crisis and the DWR Contract Sample

3.1 The California Electricity Crisis and the DWR Contracting Context

In the middle of January 2001, the credit ratings of California's utilities were downgraded to junk status due to financial difficulties caused by extremely high wholesale market prices coupled with frozen, regulated, retail rates. Generators were unwilling to continue selling electricity to the utilities, and during the ensuing two days of rolling blackouts, the State dove into the power purchasing business in order to keep the lights on in California.

To fill the void for a creditworthy power purchaser, the State enlisted its only agency with experience buying and selling power: the DWR.[5] The DWR began spending an average of $50 million per day, using appropriations from the State's General Fund, to supply about one-third of the electricity used by the customers of California's three investor-owned utilities – the so-called "net short" – from the spot market (California State Auditor 2001).[6] As shown in Figure 2, the prices in the spot market had reached levels an order of magnitude higher than the "normal" prices the state had seen over the past several years.

Figure 2. Wholesale Price of Electricity in California



Source: UC Energy Institute (2001); DWR (2002a)

[5] The DWR had experience contracting for 2,400 MW of power for the State Water Project; its power purchasing responsibilities immediately increased by more than five fold when it began purchasing power on behalf of the customers of California's utilities (California State Auditor 2001).

[6] The "net short" is the difference between the electricity demanded by the utility customers, and the electricity supplied by utility-owned generation and qualifying facilities under contract with the utilities.

The Legislature authorized the DWR to enter into long-term contracts in Assembly Bill 1X (AB 1X), in order to decrease the State's exposure to the volatile and expensive spot market; the power purchases were quickly eating through the State's surplus. The DWR immediately began to implement this large and unprecedented power contracting effort.

There were many competitive and uncompetitive forces influencing the DWR's contracting process; these are summarized in Table 1, below. The DWR contracts are based on two contract templates that are widely accepted in the electricity industry and were already in use in the Western U.S. The Edison Electric Institute (EEI) and the National Energy Marketers Association developed the main contract used by the DWR.[7] The contract was developed over a two-year period with the collaboration of utilities, generators, marketers, and others. The DWR chose to use this contract because it was familiar and acceptable to sellers of electricity, and would thereby allow for expedited negotiations and execution of the contracts. The second contract template was developed by the Western Systems Power Pool.[8] This contract had been in use for some time, and the DWR had previous experience contracting with it. (California State Auditor 2001)

Both the DWR and the "Sellers" (the counterparties to the DWR electricity contracts) had incentives to sign long-term contracts. The DWR had intense political and financial pressure to sign contracts quickly, to slow the State's expenditures on electricity, to stabilize the market, and to prevent further blackouts. At the same time, since the DWR had become the single monopsony buyer of electricity in the market and was contracting for the majority of the power the state would need for the coming decade, the Sellers had an incentive to contract with the DWR; if a Seller did not contract with the DWR, it could be left with no one to sell its electricity to in the coming years.

The Sellers' eagerness to contract with the DWR may have been tempered by the tight supply – demand conditions in the market, which gave the Sellers more power in negotiations relative to the DWR (since the Sellers knew the DWR would need to contract with *most* of them to meet the state's needs). The Sellers were also hesitant to contract with the DWR over concerns of creditworthiness, and the State's commitment to stand by the contracts (California State Auditor 2001).

The DWR and the Sellers both had experienced contract negotiators working for them. The DWR had negotiators previously from the Los Angeles Department of Water and Power and Southern California Edison, as well as the department's own experienced staff (Governor Davis 2001). The DWR also hired consultants familiar with the electricity industry and long-term contracts. However, the DWR was understaffed for the task it had at hand, especially in comparison to the resources the Sellers had available to negotiate contracts. In addition, it has

[7] The Edison Electric Institute is a U.S. trade association of investor-owned electric utilities (Edison Electric Institute 2002). The National Energy Marketers Association is a trade association representing producers, generators, transporters, and marketers of energy services (National Energy Marketers Association 2002).

[8] The Western Systems Power Pool is an association of utilities and electricity sellers in the Western U.S. that seeks to standardize terms used in electricity contracts, thereby promoting liquidity in the market (Western Systems Power Pool 2002).

been alleged that some of the negotiators and consultants working for the DWR had conflicts of interest that may have led to contracts that were more favorable to the Sellers (Vogel 2002).

The DWR's contracting effort was successful and fast; within six months, twenty-seven long-term (three years and longer) contracts had been executed to supply most of the investor-owned utilities' net short over the next ten years. Approximately 40% of the total energy now under contract to the DWR was contracted for during the first month alone. The average time to sign a contract was 7.5 days during the first month, whereas the State Auditor reported that under normal circumstances the average time to execute such a contract would be two to six months (California State Auditor 2001).

Table 1. Competitive and Uncompetitive Forces Influencing the DWR Contracting Process

Competitive Forces	Uncompetitive Forces
▪ Used industry standard contracts from EEI and WSPP. ▪ Both DWR and Sellers had incentives to sign contracts. ▪ Both sides had experienced contract negotiators.	▪ DWR had political and financial pressure to sign contracts quickly. ▪ Tight supply – demand conditions gave Sellers an advantage. ▪ Contract negotiators for the DWR may have had conflicts of interest. ▪ Some contracts were signed in a hurry.

Although the unique conditions surrounding the DWR contracting process may have yielded some contracts executed in a hurry that are more favorable to the Seller (California State Auditor 2001; Marcus 2002), as well as average prices that are higher than the "norm," as a whole the terms and conditions of the DWR contracts can provide insight into the risk allocation and mitigation practices common in the electricity industry.

3.2 Overview of the DWR Contract Sample

By October of 2001, the DWR had completed its portfolio of power contracts.[9] The DWR signed twenty-seven long-term contracts for electricity, and seven short-term contracts. We define long-term contracts as those three years in length or longer. The short-term contracts, which account for less than 3% of the total energy DWR contracted for, are not included in this analysis for two reasons. First, the terms and conditions of the short-term contracts are more likely to be unique to the DWR's situation and therefore less informative about the risk allocation and mitigation practices common in the industry as a whole. Second, short-term contracts do not provide a useful comparison between the treatment of risks in renewable and natural gas contracts – one of the central purposes of this paper – because renewable electricity facilities generally need long-term contracts in order to be constructed.

[9] In April of 2002, the DWR announced that it had renegotiated several contracts. This paper analyzes the DWR's original portfolio of contracts, but we note the general changes that were made in the renegotiated contracts throughout the paper, where applicable. For further details on the contracts that have been renegotiated to date, see Appendix A.

The frequently stated number of fifty-nine DWR contracts differs from the thirty-four short- and long-term contracts identified above because the DWR separates many contracts into multiple transactions based on numerous factors including the product (peak, baseload, etc.) and the time period that power is provided at a given price (California State Auditor 2001). While this division of contracts is useful for practical scheduling purposes, it does not help illuminate the differences among the contracts in their treatment of risks.

Some contracts contain multiple energy transactions; in these cases, the contract contains terms and conditions that pertain to all of the transactions, and the individual transactions specify details such as the amount of power to be delivered, the pricing structure, fuel supply arrangements, etc. For the purposes of this analysis, we describe each transaction with unique terms and conditions that affect the allocation of risks as an individual contract. (There are four Calpine transactions that are treated as individual contracts, for example, and the Dynegy contract has two transactions embedded in it that are also treated as individual contracts.) Conversely, multiple transactions (with the same counterparty) with identical terms and conditions are grouped into a single contract. (The seven Calpeak transactions, two Wellhead, and two Whitewater transactions are grouped into three contracts, respectively.)

Table 2 summarizes some of the principal terms of the twenty-seven long-term contracts highlighted in this report. All of the information contained in the table was taken from our review of the contracts, except the estimates of the ten-year energy purchases, price range, and ten-year power costs, which are derived from the State Auditor's report (California State Auditor 2001).[10]

The DWR contracts are expected to cost about $42.6 billion over ten years (California State Auditor 2001).[11] The contracts purchase electricity to supply most of the net short of California's three investor-owned utilities, which represents about one-third of the utility customers' power demand. The average price over ten years for the electricity is estimated to be $70 per MWh (California State Auditor 2001). This price would be high in the context of a properly functioning electricity market, but is about one fourth the price that the DWR was paying at the time the contracts were signed.

[10] The major assumptions made to calculate the Auditor's figures are that the DWR is assumed to purchase the maximum amount of energy available under each contract (including the dispatchable contracts), and that the cost of gas is assumed to start at $10.74 per million Btu in 2001 and to fall to $4.68 per million Btu in 2010 (California State Auditor 2001).

[11] The $42.6 billion includes both the short-term and long-term DWR contracts. As noted in Table 2, the long-term contracts analyzed in this paper account for $40.3 billion.

Table 2. Principal Terms of the California Department of Water Resources (DWR) Long-term Contracts

Seller	Date Contract Signed	Term (years)	Pricing Structure	Product	Dispatchable?	New Units?	Resource[§]	Delivery Point[†]	MW Range	Ten-year Energy Purchases (GWh)[‡]	Price Range ($ / MWh)[‡]	Ten-Year Power Cost ($ millions)[‡]
Allegheny	3/23/2001	11	Fixed	Base, Peak	No	No	Natural gas (CC)	SP 15	150 - 1,000	63,898	61	3,909
Alliance Colton	4/23/2001	10	Tolling	Peak	Partially	Yes	Natural gas (SC)	SP 15	80	1,468	379 - 141	253
Calpeak	8/14/2001	10	Tolling	Summer Super Peak	Yes	Yes	Natural gas (SC)	NP 15, SP 15	342	5,027	114 - 66	398
Calpine – 1*	2/6/2001	10	Fixed	Base	No	No	Unspecified	NP 15	200 - 1,000	64,596	59	3,785
Calpine – 2*	2/26/2001	10	Fixed	Peak	No	Yes	Natural gas (CC)	TBD by Seller	200 - 1,000	70,115	115 - 61	4,322
Calpine – 3*	2/26/2001	20	Fixed	Base	Yes	Yes	Natural gas (SC)	NP 15	90 - 495	8,001	174 - 154	1,337
Calpine – 4*	6/11/2001	3	Tolling	Peak	Yes	Yes	Natural gas (SC → CC)	NP 15	180 - 225	3,024	134 - 84	322
Coral Power	5/24/2001	11	Tolling > 2005	Base, Peak	Partially	Yes	Natural gas (SC)	NP 15, and TBD by Seller	275 - 850	28,677	249 - 57	2,292
Dynegy – 1	3/2/2001	4	Fixed	Base, Peak	No	No	Natural gas (CC)	SP 15	200 - 600	14,246	120	1,702
Dynegy – 2	3/2/2001	4	Tolling	Base, Peak	Partially	No	Natural gas (CC)	SP 15	200 - 1,500	21,174	145 - 79	2,008
El Paso	2/13/2001	5	Fixed	Peak	No	No	Unspecified	NP 15, SP 15	100	2,441	115 - 127	295
Fresno Cogeneration	8/3/2001	10	Tolling	Peak	Yes	Yes	Natural gas (SC)	NP 15	21	950	179 - 92	100
GWF Energy	5/11/2001	10	Tolling	Peak	Yes	Yes	Natural gas (SC and CC)	NP 15	340 - 430	23,713	295 - 44	1,689
High Desert*	3/9/2001	8	Fixed	Base	No	Yes	Natural gas (CC)	SP 15	840	51,896	58	3,010
Morgan Stanley	2/14/2001	5	Fixed	Base	No	No	Unspecified	SP 15	50	2,136	96	204
PacifiCorp	7/6/2001	10	Tolling > 2002	Base	Yes > 2002	Yes	Natural gas (CC)	NP 15	150 - 300	21,900	70**	1,533
Sempra	5/4/2001	10	Tolling > 2002	Base, Peak	No	Yes	Natural gas (SC and CC)	SP 15	400 - 1,900	93,325	160 - 57	6,238
Sunrise	6/25/2001	10	Tolling	Summer Super Peak, Base	Yes	Yes	Natural gas (SC → CC)	SP 15	325 - 560	38,888	228 - 59	2,218

Seller	Date Contract Signed	Term (years)	Pricing Structure	Product	Dispatchable?	New Units?	Resource§	Delivery Point†	MW Range	Ten-year Energy Purchases (GWh) ‡	Price Range ($ / MWh) ‡	Ten-Year Power Cost ($ millions) ‡
Wellhead	8/14/2001	10, option to extend to 20	Tolling	Peak	Yes	Yes	Natural gas (SC)	NP 15	92	4,047	142 - 78	354
Williams	2/16/2001	10	Fixed	Base, Peak	No	No	Natural gas (CC)	SP 15	175 - 1,400	56,535	63 - 87	3,779
								Total Non-Renewable		**576,059**		**39,750**
Capitol Power*	8/23/2001	5	Fixed	Base	No	Re-power	Biomass	NP 15	15	590	119 – 109♦	67
Clearwood	6/22/2001	10	Fixed	Base	No	Yes	Geothermal	NP 15	25	1,692	67	114
County of Santa Cruz	9/13/2001	5	Fixed	Base	No	Yes	Landfill Gas	NP 15	3	112	65	7
Imperial Valley	3/13/2001	3	Fixed	Base	No	No	Biomass	SP 15	16	362	100 – 90	34
PG&E Energy Trading	5/31/2001	10	Fixed	Intermittent	No	Yes	Wind	SP 15	67	2,017	59	118
Soledad¤	4/28/2001	5	Fixed	Base	No	Re-power	Biomass	NP 15	13	410	80 – 84	34
Whitewater*	7/12/2001	12	Fixed	Intermittent	No	Yes	Wind	SP 15	108	3,263	60	196
								Total Renewable		**8,448**		**570**
								TOTAL		**584,506**		**40,323**

Note: only DWR contracts with terms of three years and longer are included in this table. Totals may not equal sum of components due to independent rounding.
§ CC = combined cycle; SC = simple cycle; SC → CC = simple cycle facility to be converted to combined cycle at some point during the term of the contract.
† NP 15 is the ISO congestion zone north of Path 15; SP 15 is the ISO congestion zone south of Path 15. Path 15 is the main transmission connection between the northern and southern parts of California; it is rated to carry 3,750 MW of power, but it is often congested (Western Area Power Administration 2002).
‡ Figures derived from spreadsheets provided by the State Auditor's office that were used in the State Auditor's report on the DWR contracts (California State Auditor 2001). All dollars are in nominal dollars. Ten-year energy purchases is the amount of electricity to be provided by each contract through 2010. Ten-year power cost is the total cost of the ten-year energy purchases.
* These contracts have been renegotiated. See Appendix A for details.
** This contract is fixed price only until 2003. After 2003 the contract is tolling, but the State Auditor's report did not include a price estimate for this period.
♦ This is the price included in the State Auditor's report, although the contract states a fixed price of $89 per MWh.
¤ The Soledad contract was terminated on 27 March 2002.

Key

Pricing Structure	Fixed	The contract price per MWh of electricity is set in the contract. In some contracts the price is fixed throughout the term of the contract, and in other contracts the price varies according to a fixed schedule.
	Tolling	The DWR pays for the cost of natural gas, pays the generator a fee to reserve the use of the facility, and pays operating charges when the facility generates power.

Product	Base	Baseload products (7x24) can supply power all day every day. (Approximately 8,760 hours per year.)
	Peak	Peak products (6x16) generally can supply power from 6 am to 10 pm, Monday through Saturday. (Approximately 5,000 hours per year.)
	Summer Super Peak	Summer super peak products (5x8) generally can supply power for 8 hours per day, 5 days a week, from June through October. (Approximately 870 hours per year.)
	Intermittent	Wind power plants generate electricity only when wind is available.
Dispatchable?	No	Non-dispatchable contracts (also known as "must-take" or "take-or-pay") require the DWR to pay for, and the Seller to provide, all the electricity scheduled in the contract.
	Yes	Dispatchable contracts allow the DWR to choose the amount of electricity to be generated, within limits set in the contract.
	Partially	Partially dispatchable contracts require the DWR to take a minimum amount of electricity and allow the DWR to dispatch the facility in limited ways.

The State Auditor's report identifies a shift in the types of contracts DWR procured during the first month of its contracting effort and later periods (see Appendix B for a table of the long-term contracts in the order in which they were signed). About 40% of the total energy under contract was acquired during the first month. Seven out of the eight long-term contracts signed in the first month are fixed price, and none of the contracts generate energy from renewable resources. These contracts supply a mixture of baseload and peak power from existing generation facilities. The types of contracts DWR signed in the first month reflect the DWR's desire to reduce its costs by signing long-term contracts immediately, when only existing facilities were available. After the first month of contracting, almost all of the additional contracts signed are dispatchable tolling agreements (except for the renewable contracts) with newly constructed generating plants.

Many of the DWR's long-term contracts have terms of at least ten years. The weighted average (by the amount of electricity to be provided by each contract through 2010, or the "ten-year energy purchases") contract length of all the long-term contracts in our sample is 9.7 years. One natural gas contract has a term of twenty years, and another has an option to extend the contract from ten years to twenty. Nearly all of the contracts with terms shorter than ten years are for energy to be provided from existing units.[12]

Additional features of the DWR contracts include:

- About two-thirds of the energy contracted for will come from only the six largest contracts.[13]
- Over 60% of the energy to be supplied over the ten-year period will come from newly constructed generating plants.
- The State Auditor's analysis of the DWR contracts found that the DWR's overall portfolio includes excess baseload energy and insufficient energy during peak periods, requiring the DWR to sell energy for a loss at certain times, and to buy energy on the spot market when demand is high (California State Auditor 2001).
- Forty one percent of the electricity is supplied in "tolling" agreements, most of which give the DWR some flexibility to dispatch the facility. Fifty nine percent of the electricity is supplied at fixed prices; these contracts are mostly non-dispatchable.

Comparison of the Renewable and Non-Renewable Contracts

87% of the electricity procured by the DWR is generated using natural gas, and 1.5% of the electricity is generated from renewable resources. (Technically, only 0.5% of the energy supplied by the DWR contracts can be considered renewable because the DWR did not acquire the "renewable credits" associated with the electricity from the two wind contracts. For a further discussion of this issue, see Section 7 on Environmental Risk.) The contracts that do not specify what resources will be used to generate the electricity under contract will most likely use predominantly non-renewable resources; to simplify the discussion in the rest of this paper we group the natural gas and "unspecified" contracts as "non-renewable" contracts, unless otherwise

[12] Most of the DWR's renegotiated contracts shorten the contracts' length (see Appendix A).

[13] The six largest providers of energy to the DWR are the Sempra, Calpine – 2, Calpine – 1, Allegheny, Williams, and High Desert contracts.

noted. Thus, the non-renewable contracts are mostly fueled by natural gas, and make up 98.5% of the DWR's electricity.

The renewable contracts are slightly cheaper, on average, than the natural gas contracts, and the renewable and natural gas contracts have approximately the same average contract length (almost ten years). Table 3, below, provides a comparison of some of the key terms of the long-term contracts for electricity generated from renewable resources, natural gas, and "unspecified" resources.[14]

Table 3. Comparison of Key Contract Terms of the DWR Long-term Renewable and Non-Renewable Contracts

	Renewable	Natural Gas	Unspecified Resources	Total Contract Sample
Number of contracts (% of total)	7 (26%)	17 (63%)	3 (11%)	27 (100%)
Weighted average* contract length (Range of contract lengths)	9.8 years (3 to 12)	9.7 years (3 to 20)	9.7 years (5 to 10)	9.7 years (3 to 20)
Weighted average* contract price (dollars per MWh)	66	70 Fixed price contracts: 68 Tolling contracts: 72	62	69
Number of contracts with new units to be built	6**	13	0	19**
Ten-year energy purchases‡ (% of total)	8,448 GWh (1.5%)	506,885 GWh (86.7%)	69,174 (11.8%)	584,506 GWh (100%)
Ten-year power cost‡ (% of total)	$0.57 billion (1.4%)	$35.5 billion (88%)	$4.3 billion (10.6%)	$40.3 billion (100%)

* The weighted averages are weighted by ten-year energy purchases (or the amount of electricity to be provided by each contract through 2010).
** Includes two re-powered plants.
‡ Figures derived from spreadsheets provided by the State Auditor's office that were used in the State Auditor's report on the DWR contracts (California State Auditor 2001). All dollars are in nominal dollars.

Contracts for Renewable Energy

The DWR's seven long-term contracts for renewable energy provide a total of 247 MW of renewable electricity generating capacity. Some of the key characteristics of the different types of renewable contracts are presented in Table 4, below. The renewable capacity the DWR contracted for includes 175 MW of wind power, 44 MW of electricity from biomass, 25 MW of geothermal power, and 3 MW from landfill gas-generated electricity.

The wind power contracts have the lowest price of the renewable contracts, and will provide the majority of the DWR's energy from renewable sources over the next decade. Only three of the long-term natural gas contracts are expected by the State Auditor to have lower prices than the wind contracts.[15] The biomass contracts have the shortest contract lengths (three to five years)

[14] The Calpine – 1, El Paso, and Morgan Stanley contracts do not specify the resources that will be used to generate the electricity provided to the DWR.
[15] Only the Calpine – 1 and High Desert contracts provide power at a fixed price less than $59 per MWh. The Sunrise contract is expected to provide power at an average price of $57 per MWh, however the electricity price will depend on the price of natural gas since this contract is a tolling agreement.

and the highest prices of the renewable contracts; the wind power contracts have the longest contract lengths of the renewable contracts (ten to twelve years).

Table 4. Comparison of Key Contract Terms of the DWR Long-term Renewable Electricity Contracts

	Wind	Biomass	Geothermal	Landfill Gas	All Renewables
Total capacity (MW)	175	44	25	3	247
Number of contracts	2	3	1	1	7
Weighted average* contract length (Range of contract lengths)	11.2 years (10 to 12)	4.5 years (3 to 5)	10 years	5 years	9.8 years (3 to 12)
Weighted average* contract price‡ (dollars per MWh)	59	89	67	65	66
Ten-year energy purchases‡ (% of renewables total)	5,280 GWh (63%)	1,363 GWh (16%)	1,692 GWh (20%)	112 GWh (1%)	8,448 GWh (100%)

* The weighted averages are weighted by ten-year energy purchases (or the amount of electricity to be provided by each contract through 2010).
‡ Figures derived from spreadsheets provided by the State Auditor's office that were used in the State Auditor's report on the DWR contracts (California State Auditor 2001), except the price given in the Capitol Power biomass contract was used instead of the Auditor's figure to calculate the weighted average contract price for the biomass contracts. All dollars are in nominal dollars.

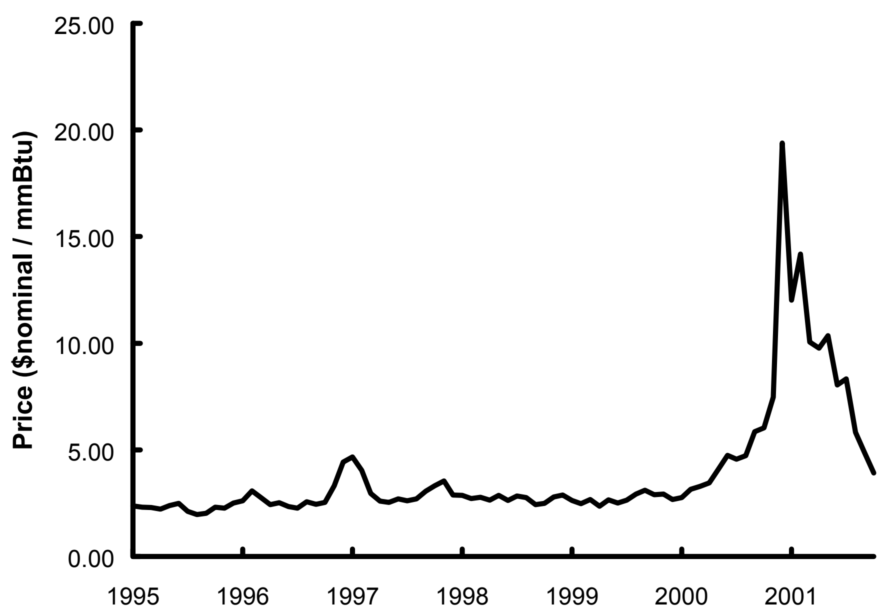
4. Fuel Price and Supply Risk in Electricity Contracts

The majority of the electricity DWR has contracted for over the next decade will come from power plants fueled by natural gas – a fuel whose price has exhibited unprecedented volatility in California over the past few years (see Figure 3, below). The volatile natural gas prices in California contributed to the extremely high wholesale electricity prices that caused California's electricity crisis. In contrast to the volatility of natural gas prices, the price of electricity generated from renewable resources is often quite stable, because the price of fuel for most renewable generating facilities is more stable than natural gas, and in many cases the fuel is free (e.g. wind and solar resources).[16]

The resource that is used to generate electricity also has important implications for a power plant's ability to operate reliably; a generating facility's reliability depends critically on the reliability of its underlying fuel supply. The value that electricity customers place on maintaining a reliable electricity system was re-emphasized by the public's dismay at the multiple days of rolling blackouts California experienced during 2001. Natural gas-fired power plants and renewable power plants face different challenges in obtaining a reliable supply of fuel to ensure that electricity is produced reliably.

In this section, we examine how the long-term (three years and longer) DWR contracts allocate and mitigate the risk that the price of fuel will exhibit variability, and the risk that fuel supply to the generating plants will be unreliable.

Figure 3. Price of Natural Gas Delivered to Electric Utility Consumers in California



Source: EIA (2002)

[16] We use the term "fuel" to describe the energy that is used to power renewable generation technologies (e.g. wind, sunlight, geothermal heat), even when such energy does not originate from a fuel in the conventional sense of the word.

4.1 Fuel Price Risk in Electricity Contracts

4.1.1 Fuel Price Risk Fundamentals

A party's exposure to fuel price risk in an electricity contract depends on three factors: (i) the variability of the fuel's price, (ii) the allocation of fuel price risk between the parties to the contract, and (iii) the ability of the party to mitigate the risk to which it is exposed.

Among the fuels most commonly used to generate electricity, natural gas is the most volatile in price. Long-term electricity contracts generally allocate natural gas price risk through one of three electricity pricing mechanisms: (i) fixed prices, (ii) indexed prices, or (iii) "tolling." Fixed-price electricity contracts allocate fuel price risk to the Seller; the Buyer presumably pays a premium for fixed-price contracts because the Seller has to manage the fuel price risk to which it is exposed, which increases the Seller's costs. If the Seller does not adequately mitigate its exposure to fuel price risk it will be more likely to default on the contract, so the Buyer is left with some "residual" fuel price risk (i.e. bankruptcy risk) with fixed-price non-renewable contracts.

Indexed-price contracts generally index the price of electricity to either inflation or to the cost of another commodity, for example, the cost of the fuel used to generate the electricity, or the price of a product produced by the Buyer (e.g. an industrial customer) (Kahn 1992). When indexed-price electricity contracts are indexed to the price of the natural gas used to generate the electricity, the fuel price risk is allocated to the Buyer. Although indexed-price contracts are common in the industry, the DWR did not sign any indexed-price contracts. The only way the DWR could have managed its fuel price risk with an indexed-price contract would have been to use financial hedging instruments. Because the DWR was unsure of its legal authority to use financial instruments at the time it contracted for power (California State Auditor 2001), the DWR chose instead to use tolling agreements (which allow the DWR to use physical gas supply contracts to hedge its fuel price risk exposure).

In tolling contracts, the Buyer pays for the cost of the natural gas used to generate the electricity, and the Buyer has the option to provide the natural gas itself. Tolling agreements allocate the natural gas price risk to the Buyer, and the Buyer then bears the cost of mitigating its fuel price risk exposure if it chooses to pursue such mitigation. The Buyer can mitigate its fuel price risk exposure through either fixed-price physical gas supply contracts or financial hedging instruments.

In contrast to natural gas, renewable resources in general have a less variable – or often free – fuel cost stream,[17] resulting in less fuel price risk for either party to an electricity contract. Hence, it is more common to have fixed-price contracts for renewable electricity than for natural gas-generated electricity.[18] Since renewable resources decrease fuel price risk for both parties to

[17] Wind, sunlight, water, geothermal heat, and landfill gas are all renewable resources that provide "free" fuel to generate electricity (fuel collection is of course costly in all cases, but once collected the fuel is effectively free). Biomass is a renewable fuel that can either be free or have a variable cost.
[18] Coal prices are also less variable than natural gas prices, and contracts for electricity from coal-fired power plants are more often fixed price than contracts for natural gas-generated electricity.

a contract, a fixed-price renewable electricity contract is a more complete hedge against fuel price risk for the Buyer than a fixed-price contract for natural gas-generated electricity (because the Buyer may still bear some residual fuel price risk in the natural gas contracts, as discussed above).[19]

4.1.2 Fuel Price Risk in the DWR Contract Sample

After experiencing first hand the damaging effects of natural gas price volatility during the California crisis, the DWR hedged its exposure to fuel price risk primarily through the use of fixed-price long-term non-renewable electricity contracts.[20] As described in more detail below, these fixed-price non-renewable electricity contracts comprise 57% of the total energy DWR has contracted for through 2010 (see Table 5, below). The DWR's long-term contracts for fixed-price renewable electricity provide only 1.5% of the energy DWR contracted for over the next decade; clearly, the DWR did not use the physical hedge provided by renewables as a large part of its strategy to mitigate fuel price risk exposure. The DWR contracted for the rest of the electricity (41% of the total) with tolling agreements.[21] These tolling agreements allow the DWR to hedge its natural gas price risk exposure through either physical fuel supply contracts or financial hedging instruments, if it so desires.

Overall, the DWR is reasonably well protected from natural gas price volatility. The elasticity of the DWR's total cost for power from all contracts through 2010 relative to natural gas prices is only about 0.2 (that is, a 10% increase in natural gas prices would increase DWR's total cost by about 2%). This protects the DWR from facing large increases in costs due to natural gas price increases, but also prevents DWR from benefiting substantially if gas prices decrease. The DWR contracts were signed when natural gas prices had reached a record high, so DWR's inability to benefit substantially from gas price decreases in the fixed-price contracts may be a larger concern than DWR's exposure to gas price increases.

[19] In addition, if an increase in renewable electricity generation reduces natural gas consumption, and this reduction has even a marginal effect on natural gas prices, the overall economic benefit to society could be quite large, given the enormous volume of natural gas consumed throughout the economy (Nogee 1999).

[20] 45% of the DWR's total electricity supply is from fixed-price natural gas-generated electricity contracts, and 12% is from fixed-price contracts for power that do not specify the resources that are used to generate the electricity; these "unspecified" contracts will most likely use non-renewable resources (primarily natural gas) to generate the electricity to be provided under the contract.

[21] Several of the DWR's renegotiated contracts were converted from fixed-price to tolling contracts, increasing the DWR's fuel price risk exposure. See Appendix A for further details.

Table 5. Key Contract Terms that Allocate Fuel Price Risk in the DWR Long-term Contracts

Seller	Pricing Structure	Resource	Dispatchable?	Ten-year Energy Purchases (GWh)‡
Allegheny	Fixed	Natural gas	No	63,898
Calpine – 2*	Fixed	Natural gas	No	70,115
Calpine – 3*	Fixed	Natural gas	Yes	8,001
Dynegy – 1	Fixed	Natural gas	No	14,246
High Desert*	Fixed	Natural gas	No	51,896
Williams	Fixed	Natural gas	No	56,535
		Total Fixed-Price Natural Gas Contracts		**264,691 (45%)**
Calpine – 1*	Fixed	Unspecified	No	64,596
El Paso	Fixed	Unspecified	No	2,441
Morgan Stanley	Fixed	Unspecified	No	2,136
		Total Fixed-Price Unspecified Resource Contracts		**69,174 (12%)**
		Total Fixed-Price Non-Renewable Contracts		**333,865 (57%)**
Alliance Colton	Tolling	Natural gas	Partially	1,468
Calpeak*	Tolling	Natural gas	Yes	5,027
Calpine – 4	Tolling	Natural gas	Yes	3,024
Coral Power	Tolling > 2005	Natural gas	Partially	28,677
Dynegy – 2	Tolling	Natural gas	Partially	21,174
Fresno Cogeneration	Tolling	Natural gas	Yes	950
GWF Energy	Tolling	Natural gas	Yes	23,713
PacifiCorp	Tolling > 2002	Natural gas	Yes > 2002	21,900
Sempra	Tolling > 2002	Natural gas	No	93,325
Sunrise	Tolling	Natural gas	Yes	38,888
Wellhead	Tolling	Natural gas	Yes	4,047
		Total Natural Gas Tolling Contracts		**242,194 (41%)**
Capitol Power*	Fixed	Biomass	No	590
Clearwood	Fixed	Geothermal	No	1,692
County of Santa Cruz	Fixed	Landfill Gas	No	112
Imperial Valley	Fixed	Biomass	No	362
PG&E Energy Trading	Fixed	Wind	No	2,017
Soledad**	Fixed	Biomass	No	410
Whitewater*	Fixed	Wind	No	3,263
		Total Fixed-Price Renewable Contracts		**8,448 (<1.5%)**
			TOTAL	**584,506 (100%)**

Note: only DWR contracts with terms of three years and longer are included in this table. Totals may not equal sum of components due to independent rounding.
‡ Figures derived from spreadsheets provided by the State Auditor's office that were used in the State Auditor's report on the DWR contracts (California State Auditor 2001).
*These contracts have been renegotiated; see Appendix A for further details.
**The Soledad contract was terminated on 27 March 2002.

Although the elasticity of the DWR contracts is relatively low, the absolute amount of money at stake is quite large. The State Auditor estimates the total cost of the DWR's long-term contracts to be $40.3 billion over ten years (see Table 2, in Section 3). The Auditor used the DWR's natural gas price forecast to calculate the total cost of the DWR contracts. The DWR's natural gas price forecast anticipates gas prices that are significantly higher overall than the CEC's latest forecast (see Appendix C).[22] Using the Auditor's model of the DWR contracts with the CEC forecast of natural gas prices, the DWR long-term contracts would cost approximately $38.3 billion – $2 billion less than the Auditor's estimate, or 0.85 cents less per each kWh delivered by tolling agreements.

In recent months, natural gas prices have been quite low. If the DWR does not choose to hedge its natural gas price risk exposure through either physical fuel supply contracts or financial hedging instruments, the DWR could potentially face significant cost increases in the future. For example, if we use the CEC natural gas price forecast but assume that gas prices spike during 2006 to the levels gas prices reached in 2001, the relative increase in gas prices could cost the DWR $1.7 billion, or 0.7 cents per each kWh delivered by tolling agreements (see Appendix C).

A. Non-Renewable Fixed-Price Contracts

Fifty seven percent of the electricity DWR has contracted for over the next decade is from fixed-price contracts with non-renewable (primarily natural gas) resources. All of these fixed-price contracts allocate fuel price risk to the Seller. However, if the Seller does not adequately mitigate its exposure to fuel price risk then the Seller's bankruptcy risk may increase, leaving the DWR exposed to some "residual" fuel price risk. For example, if the Seller is exposed to extremely high natural gas prices and can no longer meet its contractual obligations, the DWR will be left to find a replacement contract at a time when gas prices are high. This paper does not assess the magnitude of the residual fuel price risk (i.e. bankruptcy risk) faced by the DWR, as we do not have access to information regarding the Sellers' management of their own fuel price risk.

B. Natural Gas Tolling Contracts

Tolling agreements and fixed-price agreements conceptualize the service and product being provided by the Seller to the Buyer in fundamentally different ways. In fixed-price contracts, the Seller clearly sells the Buyer a product: electricity. In tolling agreements the Seller is effectively providing the Buyer a service: the right to use the Seller's power plant to convert natural gas to electricity. The Seller is paid not only for the use of its facility, but also for simply being available to generate (through a reservation charge, or "capacity charge"). In addition, the Buyer pays for the natural gas used to generate the electricity. Although the physical end result of the two contracts is the same (the Buyer is provided with electricity), the risk of fuel price variability is clearly allocated to the Seller in the case of fixed-priced contracts, and to the Buyer in tolling contracts.

[22] The DWR's natural gas price forecast was created by its consultant in July 2001, when gas prices were still extremely high. The CEC forecast was published in February 2002.

Forty one percent of the electricity DWR has under contract over the next decade is expected to come from natural gas tolling agreements, which allocate the natural gas price risk to the DWR. The contract price in most of these tolling agreements consists of: (i) a capacity charge that is mostly independent of the plant's actual generation of electricity; (ii) a fuel charge based on the amount of fuel used to generate electricity (if the Seller is providing fuel); and (iii) an operations and maintenance (O&M) charge per MWh of electricity generated. Some contracts have other charges including a fixed O&M charge (independent of whether or not the plant generates power), and charges for fuel used to start-up the plant.

Tolling agreements allow the DWR to choose the level of natural gas price risk exposure it desires. The tolling contracts give the DWR the option to either supply the natural gas itself,[23] or to approve a fuel supply plan for the Seller to supply the gas. Hence, the DWR can manage its fuel price risk by either signing a long-term contract for natural gas supply, agreeing with the Seller on a fuel supply plan that meets the DWR's risk exposure needs, or else purchasing natural gas on the spot market and using financial instruments to hedge the price volatility.

If the DWR does not hedge the natural gas price risk it is exposed to through its tolling agreements, the DWR's total cost for power over ten years could vary on the order of $2 billion (or 0.85 cents per kWh delivered by the tolling agreements), as discussed above. If the DWR chooses to hedge its natural gas price risk, it will have to bear the cost of hedging. There are numerous financial hedging instruments (e.g. futures, swaps, and options) and physical hedging instruments (e.g. fixed-price gas supply contracts and storage) that the DWR could use to mitigate its fuel price risk exposure. Bolinger et al. (2002) preliminarily find that the cost of hedging on a long-term basis with these instruments is on the order of $5 per MWh.

Although the DWR bears fuel price risk in all of the tolling contracts, almost all of the tolling agreements in our sample allow the DWR to dispatch the power plant. (All but one of the tolling contracts are at least partially dispatchable, and all but one of the fixed price contracts are non-dispatchable, see Table 5, above.) In effect, under a tolling agreement with a dispatchable plant, the DWR accepts fuel price risk in exchange for a reduction in its demand risk. The link between tolling and dispatchability is consistent with the desire of a Seller to avoid excessive fuel price risk – it would be risky for a Seller to agree to provide fixed-price energy and to let the DWR dispatch the facility, because the uncertain amounts of fuel required to generate power would make it difficult for the Seller to mitigate its fuel price risk exposure.[24]

[23] The contracts in the DWR sample vary in the frequency with which the Buyer has the opportunity to choose to supply the fuel itself, but it is most commonly once per year.

[24] A more modest fuel price risk involves the allocation of fuel imbalance charges. When a power plant is dispatchable, it may draw more or less fuel from a natural gas pipeline than it was scheduled to, resulting in fuel imbalance charges. Seven of the eleven tolling agreements specify that fuel imbalance charges will be paid by the party at fault for incurring them. One tolling contract requires the Buyer to pay for all imbalance charges, while the only non-dispatchable tolling agreement requires the Seller to pay for fuel imbalance charges. Two other tolling contracts do not specify the allocation of fuel imbalance charges.

C. Renewable Fixed-Price Contracts

The DWR's contracts for renewable electricity comprise 1.5% of the energy DWR has contracted for over the next decade. All of the DWR's contracts for renewable electricity are fixed price.

Of the renewable energy DWR has under contract, 84% will be generated from *free* renewable resources (wind, geothermal heat, and landfill gas). These contracts provide the greatest possible mitigation of fuel price risk for both the DWR and the Sellers. For the DWR, the mitigation of fuel price risk provided by these renewable electricity contracts is greater than the mitigation provided by the fixed-price natural gas contracts, because of the bankruptcy risk described above. The renewable contracts are also a more complete hedge against fuel price risk than a physically or financially hedged tolling agreement, since counterparties to such financial instruments may not always honor their commitments. The renewable electricity contracts *reduce* fuel price risk for both parties, whereas hedged natural gas contracts may *shift* fuel price risk to another party.

The other 16% of the DWR's renewable electricity will be generated from biomass.[25] Unlike the other renewable fuels, biomass is not always free and can have a variable price. Since the DWR's biomass contracts are fixed price, the Sellers bear the biomass price risk. Similar to the fixed-price natural gas contracts, the DWR still bears some residual fuel price risk (i.e. bankruptcy risk) if the Seller of a biomass contract is excessively exposed to fuel price risk.

Biomass contracts have at least one advantage and one disadvantage as compared to natural gas contracts, with respect to fuel price risk. Since fuel supply for biomass power plants is local by nature (it is not economical to transport biomass fuel supply over long distances), the volatility of biomass prices is less systematic than natural gas prices – that is, a spike in biomass prices at one plant will not necessarily affect the price of biomass for all biomass generators in California simultaneously. On the other hand, there is no index price for biomass, which makes it difficult to hedge biomass price risk with financial instruments; the Seller's only option is to use physical hedges to mitigate its fuel price risk exposure.

Although renewable energy contracts can provide the most complete hedge of fuel price risk possible, the DWR did not choose to use renewables to hedge its fuel price risk to any large extent. If California has another natural gas price spike similar to the spike during 2000 and 2001, and the DWR has not adequately hedged its gas price risk, the DWR will only be partially protected from revisiting sky-high electricity prices.

[25] One of the biomass contracts included in our analysis – the Soledad contract – was terminated on 27 March 2002.

4.2 Fuel Supply Risk in Electricity Contracts

4.2.1 Fuel Supply Risk Fundamentals

The ability of a power plant to reliably generate electricity depends on the dependability of its supply of fuel. Non-renewable and renewable power plants face different challenges in obtaining reliable supplies of fuel.

The reliability of the supply of natural gas to a power plant depends on both the reliability of the supply of the gas itself, and the reliability of the transportation of the gas to the plant. The supply of natural gas to a power plant can be interrupted due to "normal" supply and transportation constraints (e.g. pipeline constraints), or due to catastrophes. The parties to an electricity contract can usually manage the risk of a "normal" natural gas supply or transportation constraint by acquiring firm fuel and transportation contracts. (In certain circumstances, however, even firm natural gas contracts may be interrupted (CEC 2000), but these events are generally foreseeable.[26]) On the other hand, the risk of a catastrophic interruption of natural gas supply to a power plant (e.g. an attack on the pipelines that bring gas into California) cannot be readily reduced through the terms of an individual contract. From the perspective of maintaining a reliable supply of electricity in California (rather than the perspective of the two parties to an individual contract), the risk of a catastrophe is much more serious than a "normal" gas supply or transportation constraint, because it is unpredictable and systematic – it affects numerous power plants simultaneously – potentially causing widespread disruptions to the electricity grid.

Contracts for electricity generated from natural gas at individual power plants cannot do much to reduce the risk of fuel supply uncertainties, other than requiring a firm gas supply and transportation contract. Consequently, contracts for electricity mostly *allocate* the remaining risk of a fuel supply interruption rather than further *reducing* the risk. Individual electricity contracts also cannot manage the more serious *systematic* risk of a natural gas supply interruption (that would affect numerous power plants at once); this risk can only be managed by the owner of a portfolio of electricity supplies, for example, through resource diversification and the use of renewable energy.

The supplies of many renewable fuels used to generate electricity are less predictable, on a day-to-day basis, than the supply of natural gas. Sun and wind resources have a significant amount of diurnal variation that is difficult to predict accurately in advance. Individual contracts for electricity from solar and wind resources cannot reduce fuel supply risk without using back-up generation.[27] Landfill gas and geothermal resources have less day-to-day variation than solar and wind resources, but their supply can be unpredictable over longer time scales. Hydroelectric power has a relatively predictable and controllable fuel supply; water for hydroelectric power varies seasonally and from year-to-year, but water can be stored behind dams to smooth out

[26] For example, in 1999 and 2000, the natural gas infrastructure in the San Diego area began to reach the limits of its capacity, and San Diego Gas and Electric petitioned the CPUC to request permission to curtail firm fuel service to several power plants (CEC 2000).
[27] It may be possible to manage this risk financially using weather derivatives, but the risk cannot be managed in terms of physical reliability.

variations.[28] Biomass power plants are the only type of renewable facilities whose fuel is not provided naturally to the plant – biomass plants have to acquire and transport fuel to the plant, which introduces an additional source of uncertainty. Biomass electricity contracts can manage fuel supply risk in a similar manner to natural gas contracts, by acquiring firm fuel and transportation contracts from biomass suppliers. In contrast to natural gas fuel supply risk, however, the risk of renewable fuel supply uncertainty is mostly unsystematic – affecting individual renewable plants – rather than systematic.

In California, most renewable electricity (other than hydroelectric power) has historically been sold on an "as-available" basis,[29] because of the way the CPUC structured the Interim Standard Offer 4 (ISO4) contracts for renewable and cogeneration "qualifying facilities." More recently, wind contracts are virtually always as-available; however, contracts for electricity from other renewable resources do not have as variable a fuel supply (e.g. biomass) and can therefore provide for a firmer supply of electricity.

4.2.2 Fuel Supply Risk in the DWR Contract Sample

The DWR bears some fuel supply risk in all of the DWR's non-renewable and renewable long-term (three years and longer) contracts. As discussed below, the DWR bears the risk of a catastrophe (e.g. a natural gas pipeline explosion) in all of the non-renewable contracts. The DWR also bears the risk of other, less dramatic, fuel supply or fuel transportation interruptions in most of the non-renewable contracts. Since the DWR contracts increase California's overall reliance on natural gas, the contracts may increase the state's systematic risk of a natural gas supply interruption – affecting numerous power plants simultaneously – making the electrical grid more vulnerable to natural gas interruptions.

In the DWR's renewable contracts, day-to-day variations in fuel supply are a larger concern than in the natural gas contracts. However, the renewable contracts may help diversify the DWR's fuel supply portfolio and thereby decrease the risk that a systematic natural gas supply interruption will disrupt California's electrical grid.[30]

We begin by examining fuel supply risk in the DWR's non-renewable fixed-price contracts, followed by the non-renewable tolling contracts, and then finally the renewable contracts.

A. Non-Renewable Fixed-Price Contracts

In the DWR's fixed-price non-renewable contracts, the Seller is responsible for procuring the fuel supply and fuel transportation necessary to generate the electricity to be provided under the contract. Almost none of the DWR's fixed-price non-renewable contracts explicitly allocate the risk of a fuel supply or transportation interruption; as such, the allocation depends primarily on

[28] It is possible to store biomass, hydro, and landfill gas resources to reduce fuel supply uncertainties. Of course, it is also possible to store natural gas.

[29] As-available contracts allow the power plant to sell electricity whenever it is able to generate it.

[30] A systematic fuel supply interruption would have large economic repercussions, so although the probability of a systematic interruption may be small, there is considerable value in reducing the risk.

the definition of "force majeure." An event of force majeure is defined in the EEI contract template as a circumstance that prevents a party from performing its obligations, that is not within the reasonable control of (or the result of negligence of) the party, and which the party cannot overcome by the exercise of due diligence. During an event of force majeure, the Seller is excused from delivering power.

Fifty-seven percent of the DWR's non-renewable energy is under fixed-price contracts. The Calpine – 2 contract is the only fixed-price non-renewable contract that explicitly allocates the risk of a fuel supply or fuel transportation interruption to the DWR. The Calpine – 2 contract provides that a fuel supply or transportation interruption is an excused outage, except if the interruption is due to curtailment under an interruptible gas transportation contract, and firm gas transportation is available.[31]

Although the other fixed-price contracts do not explicitly allocate the risk of a fuel supply or fuel transportation interruption, they presumably allocate the risk in a similar manner to the Calpine – 2 contract. The fixed-price contracts excuse the Seller from providing power – through the force majeure clause – if a fuel interruption is out of the Seller's control, and not due to negligence. If the Seller has firm fuel supply and transportation contracts that are interrupted, the outage would be excused and the Seller would face no penalty. However, if the Seller has an interruptible fuel supply or transportation contract that is interrupted, the outage would presumably *not* be excused, and the Seller would have to pay for the DWR's incremental cost of purchasing replacement power ("cover damages"), and the Seller would be penalized according to the contract's availability requirements.[32]

The three fixed-price contracts that do not specify the resources that will be used to generate the electricity[33] are also the only electricity supply contracts that do not specify what generating facilities will be used. In these cases, it would be more difficult for the Seller to claim force majeure for a fuel supply or fuel transportation interruption to an individual plant (e.g. if a gas pipeline to the plant is crippled), since the contract does not specify from what generating units the Seller will supply power.

B. Natural Gas Tolling Contracts

The firmness of both fuel supply and fuel transportation arrangements are important in determining the reliability with which a power plant can generate electricity. All of the DWR's tolling contracts give the DWR the option to either supply the natural gas needed to generate the electricity under the contract itself, or to approve a fuel supply plan for the Seller to supply the gas. Six of the eleven natural gas tolling contracts assign the Seller the responsibility of procuring natural gas transportation; three of these six contracts require the Seller to arrange for firm fuel transportation, while the other three allow the fuel transportation to be interruptible.

[31] Interruptible natural gas contracts allow the distributing company to curtail service under certain circumstances, as specified in the contract, whereas firm contracts provide continuous service.

[32] For a further discussion of cover damages and availability guarantees, see Section 5.4.2 on Performance Risk.

[33] The Calpine – 1, El Paso, and Morgan Stanley contracts do not specify the resources that are used to generate the electricity; these "unspecified" contracts will most likely use non-renewable resources (primarily natural gas) to generate the electricity to be provided under the contract, and are therefore included in this section.

The other five tolling contracts do not assign responsibility for obtaining fuel transportation. It is possible that a fuel supply plan (agreed to by the parties) would determine the fuel transportation arrangements.

The DWR's tolling contracts allocate most of the fuel supply risk to the DWR, similar to the fixed-price non-renewable contracts. Nine of the DWR's eleven natural gas tolling contracts explicitly excuse the Seller from delivering power if the fuel supply or fuel transportation to the plant is interrupted. (Some of these contracts are more lenient than others; see Table 6, below.) If a contract does not explicitly address the risk of a fuel supply or fuel transportation interruption, then the allocation of the risk is determined by the contract's force majeure clause, as discussed above for the fixed-price non-renewable contracts.

Unlike the fixed-price non-renewable contracts, only three of the tolling contracts require the Seller to pay the DWR cover damages if the Seller has an unexcused outage due to a fuel interruption.[34] However, most of the tolling agreements penalize the Seller for not meeting availability requirements; for the most part, the contracts require availabilities over 95% during the summer and over 90% during the rest of the year (see Table 6, below).[35]

[34] The Calpine – 4, Sempra, and Sunrise contracts require the Seller to pay cover damages for an unexcused outage.
[35] In dispatchable agreements, availability is generally defined as the number of hours during the period that the unit was *available* to deliver energy divided by the total possible dispatch hours during period. (See Section 5 on Performance Risk for further discussion of availability.)

Table 6. Key Contract Terms that Allocate Fuel Supply Risk in the DWR Natural Gas Tolling Contracts

Seller	Type of fuel transportation arrangement Seller must make	Is Seller excused from delivering power if fuel supply or fuel transportation is interrupted?	Availability Requirement
Alliance Colton	Not addressed explicitly	Yes	June through October: 95%
Calpeak*	Firm	Yes, if interruption is due to non-economic reasons.	June – October, December – February: 96% Otherwise: 94%
Calpine – 4*,†	Not addressed explicitly	Yes	June through October: 98% Otherwise: 92%
Coral Power	Not addressed explicitly	Not addressed explicitly	July, August, September: 97% Otherwise: 94.3%
Dynegy – 2	Firm	Yes	None
Fresno Cogeneration	May be interruptible	Yes, except if Seller has firm transportation contract and interruption is due to Seller's negligence.	June through October: 97% Otherwise: 94%
GWF Energy	May be interruptible	Yes, except if Seller has firm transportation contract and interruption is due to Seller's negligence.	June through October: 98% Otherwise: 94%
PacifiCorp	Firm	Yes, if interruption is due to force majeure in fuel supply or transportation agreement.	Approx. 88%
Sempra†	Not addressed explicitly	Yes	None
Sunrise*	Not addressed explicitly	Not addressed explicitly	June through September: 95% Annual: 91.8%
Wellhead	May be interruptible	Yes, except if Seller has firm transportation contract and interruption is due to Seller's negligence.	June through October: 97% Otherwise: 94%

*These contracts have been renegotiated; see Appendix A for further details.
† Seller pays DWR cover damages for unexcused outages.

C. Renewable Fixed-Price Contracts

The DWR contracted for electricity from four different renewable resources: wind, geothermal, landfill gas, and biomass. Each of these resources faces different challenges with regards to fuel supply variability. In all but one of the DWR's renewable contracts, the DWR bears some fuel supply risk.

The wind contracts provide the DWR with electricity "as-available," or whenever there is wind available to generate electricity. Since the contracts are fixed price and the Seller is only paid when electricity is delivered to the DWR (i.e. there is no capacity charge), the parties share the fuel supply risk – the DWR's supply of electricity is uncertain, and the Seller's revenue stream is uncertain.

Although the geothermal contract is a unit-contingent contract,[36] it has contract clauses that make it similar to an as-available contract. Problems with the geothermal wellfield are considered to be an excused outage, and inadequate or excessive geothermal reservoir pressures or temperatures constitute events of force majeure, also excusing the Seller from delivering power. Although these clauses shift some of the fuel supply risk to the DWR, the geothermal contract requires the Seller to operate the plant such that the monthly actual generation is within plus or minus 10% of the monthly scheduled generation, making it somewhat "firmer" than an as-available contract.[37] Hence, the parties share the fuel supply risk in the geothermal contract (similar to the wind contracts), but the Seller bears somewhat more of the fuel supply risk in the geothermal contract than in the wind contracts because of the requirement that the Seller operate the facility within a certain output range.

The landfill gas contract is a unit-contingent contract, and therefore excuses the Seller from delivering power whenever the plant is unavailable due to an outage. The Seller is required to generate power at the plant's "maximum capability" in every hour, and to operate the plant such that the monthly actual generation is within plus or minus 10% of the monthly scheduled generation. Generating plant "outage" and "maximum capability" are not defined in the contract, but it is likely that a fuel supply interruption would excuse the Seller from providing power while worsening the Seller's availability. The amount of fuel supply risk the DWR has to bear is constrained by the Seller's availability requirement: 75% availability during June through October, and 70% otherwise.[38] If the Seller does not meet the availability requirement for three consecutive months, the DWR can terminate the contract. (This is the DWR's only remedy with regard to the plant's availability.) The parties share the fuel supply risk in the landfill gas contract, but the DWR bears less risk than in either the wind or the geothermal contracts.

The Soledad biomass contract has a nearly identical allocation of fuel supply risk (and an identical availability requirement) as the landfill gas contract;[39] the Capitol Power biomass contract is also nearly identical, but the fuel supply risk that the DWR must bear is further reduced by a requirement that the Seller obtain firm commitments for fuel supply and fuel transportation (see Table 7, below).[40]

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[36] Unit-contingent contracts excuse the Seller from delivering scheduled power during forced outages and events of force majeure. For a further discussion of unit-contingent and firm electricity contracts, see Section 5 on Performance Risk.

[37] The geothermal contract has no availability requirement, but the contract states that the plant is expected to generate power 8,000 hours per year (91% availability).

[38] In the renewable contracts, availability is generally defined as the number of hours the plant delivered power during the period divided by the total possible number of hours the plant could have delivered power during the period.

[39] Note that the Soledad contract was terminated on 27 March 2002.

[40] The landfill gas contract and the Soledad biomass contract are expected to generate power 8,000 hours per year (91% availability). The Capitol Power biomass contract is expected to generate power 7,680 hours per year (88% availability).

The availability requirement in these three renewable contracts (the landfill gas, and two biomass contracts) does not reflect the availability the plants are capable of, or the availability they are expected to achieve. Instead, the availability requirement represents the "last straw" – the point where DWR can terminate the contract. This is in contrast to the non-renewable contracts discussed above, which penalize the Seller monetarily for not meeting an availability requirement (that the plant is expected to achieve), but do not set a minimum level of availability beyond which the DWR can terminate the contract.

The Imperial Valley biomass contract is the firmest of the renewable contracts. In fact, the contract may even be firmer than most of the non-renewable contracts, because the contract explicitly excludes the loss of fuel supply from the definition of force majeure. (An event of force majeure is the only excused outage under the contract.) Similar to the fixed-price non-renewable contracts, the Imperial Valley biomass contract requires the Seller to pay cover damages to the DWR if the Seller fails to deliver power due to an unexcused outage.

As a whole, the DWR's renewable electricity contracts allocate a significant amount of fuel supply risk to the DWR. Although some types of renewable resources face variability in fuel supplies that are difficult to control, the Imperial Valley contract makes it clear that in some cases it is possible to contract for firmer supplies of renewable electricity than the DWR chose to.

Table 7. Key Contract Terms that Allocate Fuel Supply Risk in the DWR Renewable Electricity Contracts

Seller	Renewable Resource	Contract clauses relevant to fuel supply risk	Firmness	Availability Requirement
Capitol Power*	Biomass	▪ Seller must have firm commitments for fuel supplies and transportation. ▪ DWR must take (Seller must deliver) plant's maximum capability in all hours, not to exceed 105% of contract capacity. ▪ Seller must operate the plant such that monthly actual generation is within plus or minus 10% of monthly scheduled generation.	Unit-Contingent	▪ June through October: 75% Otherwise: 70% ▪ If plant doesn't meet availability guarantee for 3 consecutive months, DWR can terminate. ▪ (Plant expected to deliver 7,680 hours per year; 88% availability)
Clearwood	Geothermal	▪ DWR must take (Seller must deliver) plant's maximum capability in all hours, not to exceed 120% of contract capacity. ▪ Seller must operate the plant such that monthly actual generation is within plus or minus 10% of monthly scheduled generation.	Unit-Contingent (Force majeure includes inadequate or excessive geothermal reservoir pressures or temperatures)	▪ None (Plant expected to deliver 8,000 hours per year; 91.3% availability)
County of Santa Cruz	Landfill gas	▪ DWR must take (Seller must deliver) plant's maximum capability in all hours, not to exceed 105% of contract capacity. ▪ Seller must operate the plant such that monthly actual generation is within plus or minus 10% of monthly scheduled generation.	Unit-Contingent	▪ June through October: 75% Otherwise: 70% ▪ If plant doesn't meet availability guarantee for 3 consecutive months, DWR can terminate. ▪ (Plant expected to deliver 8,000 hours per year; 91.3% availability)
Imperial Valley	Biomass	▪ DWR must take (Seller must deliver) quantity of energy set in contract.	Firm (Force majeure does not include loss of fuel supply.)	▪ None (Seller pays cover damages to DWR if Seller fails to deliver.)
PG&E Energy Trading	Wind	▪ Electricity is generated when sufficient wind is available.	As-available	▪ None
Soledad*	Biomass	▪ DWR must take (Seller must deliver) plant's maximum capability in all hours. ▪ Seller must operate the plant such that monthly actual generation is within plus or minus 10% of monthly scheduled generation.	Unit-Contingent	▪ June through October: 75% Otherwise: 70% ▪ If plant doesn't meet availability guarantee for 3 consecutive months, DWR can terminate. ▪ (Plant expected to deliver 8,000 hours per year; 91.3% availability)
Whitewater*	Wind	▪ Electricity is generated when sufficient wind is available.	As-available	▪ None

*These contracts have been renegotiated; see Appendix A for further details. The Soledad contract was terminated on 27 March 2002.

4.3 Summary of Fuel Price and Supply Risk

The volatility of natural gas prices was one of the root causes of California's electricity crisis. The DWR has protected itself from fuel price risk primarily through the use of fixed-price non-renewable contracts, which will provide about 57% of the energy DWR has contracted for over the next decade. If the DWR wants to further mitigate potentially large increases in costs due to future natural gas price spikes, the DWR will have to bear the cost of hedging its fuel price risk in the natural gas tolling contracts as well.

In contrast to the volatility of natural gas prices, most of the renewable energy DWR contracted for has a free source of fuel. The DWR's renewable contracts shield the DWR from fuel price risk, and provide the DWR with a more complete hedge against fuel price risk than the non-renewable contracts (due to residual fuel price – or bankruptcy – risk in the natural gas contracts).[41] However, the DWR did not take advantage of the opportunity to use renewable electricity contracts to stabilize its costs to any significant extent.

The DWR's contracting decisions undoubtedly involved trade-offs between fuel price risk and fuel supply risk. Natural gas-fired power plants and renewable generation facilities face different challenges in maintaining a reliable supply of fuel to ensure the reliable production of electricity. Natural gas-fired power plants are more vulnerable to systematic interruptions in natural gas supply (affecting many plants simultaneously), while renewable generating facilities are more vulnerable to unsystematic day-to-day variability in fuel supply. Individual electricity contracts cannot mitigate systematic risks effectively; the owner of a portfolio of electricity supplies must manage systematic fuel supply risks through the design of their portfolio of fuel supplies.

The DWR's electricity contracts provide for the construction of a significant amount of new natural gas-fired generation capacity in California, thereby increasing the state's reliance on natural gas. This increased reliance on natural gas may make California's economy more vulnerable to natural gas price volatility,[42] and may make California's electricity system more susceptible to systematic and catastrophic interruptions of natural gas supply. The DWR's renewable contracts, in contrast, reduce fuel price risk and have fuel supply uncertainties that are uncorrelated with the uncertainties in natural gas supply, and may thereby increase the reliability of California's electricity system by diversifying the state's fuel supply mix.

[41] There may be a risk of bankruptcy among renewable providers, however, in most cases it would be unrelated to fuel price risk.

[42] Several of the DWR's renegotiated contracts were converted from fixed-price to tolling contracts, further increasing the DWR's fuel price risk exposure. See Appendix A for further details.

5. Performance Risk in Electricity Contracts

Contracts create a set of requirements that each party to a contract agrees to adhere to; for example, an electricity contract may stipulate that the Seller will build a new power plant that will be operational by a certain deadline. But what happens if a party does not meet a requirement that is set in the contract?

This section on performance risk addresses the uncertainty in each party's ability or willingness to fulfill their part of the agreement to provide or receive a certain quantity of energy, or to make available a certain capacity of generation facilities. Of all the risks addressed in this paper, the parties to an electricity contract are most able to control performance risk. As a result, contracts contain numerous clauses designed to manage performance risk. There is no inherent difference in the amount of performance risk present in renewable and non-renewable contracts, and the DWR contracts manage performance risk in the renewable contracts in a similar manner to the non-renewable non-dispatchable contracts.

5.1 Performance Risk Fundamentals

Our analysis of performance risk is divided into two time periods: (i) during the construction of a power plant, and (ii) during the operation of a power plant. The major sources of uncertainty during the construction of a power plant are whether the plant will be built on time, and whether the plant will be built within the budget that has been allocated for its construction.[43] The major sources of uncertainty during the delivery period of an electricity contract (once a power plant is operational) are how efficiently the power plant will be operated, and how reliably the generator will supply the amount of energy or capacity that was contracted for.

Electricity contracts attempt to both *reduce* performance risk, and to *allocate* whatever performance risk remains between the parties to the contract. Since many elements of performance risk are within the control of the generator, electricity contracts contain numerous penalties and incentives to reduce performance risk – that is, to ensure that a plant is constructed and operated in a desirable fashion, and to ensure that the generator performs according to the terms of the contract. If a contract does not contain various remedies to address non-performance, and one party to a contract does not perform according to the terms of the contract, the only remedy of the other party would be to declare the non-performing party in default and to terminate the contract;[44] this rather drastic action might be appropriate if the non-performing party's transgression is serious, but would not provide a very satisfactory remedy for minor transgressions.

[43] Power plants developers have experienced large cost over-runs and construction delays in the past; possibly the most notorious example in California is PG&E's Diablo Canyon nuclear power plant, which was expected to cost $300 million to build, but ended up finally reaching commercial operation more than 10 years behind schedule at a total cost of over $5 billion (Hirsch 1999).
[44] The EEI template contract provides that a party defaults on a contract if the party fails to perform a material covenant contained in the contract. The defaulting party is required to pay the non-defaulting party a termination payment, equal to the difference between the present value of the existing contract and a replacement contract.

The allocation of performance risk during the delivery period of a contract is managed in large part by the firmness of the contract, which determines under what circumstances the Seller is excused from delivering electricity. In the DWR sample, all contracts are for either "unit-contingent" or "firm" electricity products. Unit-contingent contracts excuse the Seller from performing in more situations than firm contracts, which only excuse the Seller during events of force majeure.

A unit-contingent contract, as defined in the EEI contract template, excuses the Seller from delivering power when the Seller's specified generating facilities are unavailable either due to a forced outage,[45] or to an event that was not anticipated as of the date the contract was executed, and that is not within the reasonable control of (or due to the negligence of) the Seller. Both unit-contingent and firm contracts excuse the Seller's performance during an event of "force majeure." An event of force majeure is defined in the EEI contract template as a circumstance that prevents a party from performing its obligations, that is not within the reasonable control of (or the result of negligence of) the party, and which the party cannot overcome by the exercise of due diligence. Force majeure is commonly used in legal contracts to absolve parties of responsibility during catastrophes, which are usually defined as acts of God, natural disasters, and other "unforeseeable and irresistible" events (Tepper 1995); however, some contracts expand on the definition of force majeure. The definition and interpretation of force majeure clauses can strongly influence the amount of performance risk that each party to a contract bears.

5.2 Performance Risk in the DWR Contract Sample

The DWR's long-term electricity contracts provide for the construction of a significant amount of new generation capacity in California, while exposing the DWR to only a minimal amount of the risk of construction cost over-runs, as shown below. Although the Sellers of the contracts bear nearly all of the risk of construction cost over-runs, the DWR bears some of the risk that the new power plants will not be built on schedule or completed.

One of the principal ways the DWR has reduced its exposure to performance risk is through relatively high contract prices; the high prices give the Sellers an inherent incentive to deliver power in order to earn the profitable payments. However, high prices are most likely not the lowest cost way for the DWR to create appropriate incentives for the Sellers to perform. The DWR contracts also contain numerous other provisions to reduce performance risk during the delivery period of the contracts. Availability guarantees and penalties are the primary ways that performance risk is managed in the DWR's dispatchable contracts, whereas the non-dispatchable contracts primarily use "cover damages" – a penalty equal to the incremental cost of replacement power for undelivered energy – to reduce performance risk. Most contracts also require the Sellers to maintain the power plants in accordance with "prudent industry practices."

The California State Auditor (2001) expressed concern that many of the DWR contracts contain performance risk terms that are excessively lenient for the Sellers, as noted below. Partly in response to the Auditor's report, many of the DWR's recently renegotiated contracts contain

[45] A forced outage is defined in the NERC Generating Unit Availability Data System (GADS) Forced Outage reporting guidelines as an outage resulting from an immediate mechanical, electrical, or hydraulic control system trip or an operator-initiated trip in response to an alarm.

stronger performance risk terms. (See Appendix A for further details on the renegotiated contracts.)

5.2.1 Performance Risk During Construction of a Power Plant

A. Non-Renewable Contracts

Over half of the DWR's non-renewable contracts provide for the construction of new power plants, and all but one of these contracts allocate the risk of construction costs to the Seller. The Sunrise contract is the only contract that requires the parties to share the construction cost risk, by increasing the DWR's capacity charge if the actual construction costs exceed the estimated costs, and vice versa.

In all of the DWR's non-renewable contracts, the parties share the risk that a new power plant will not be built on schedule; if a power plant's operation is delayed, the Seller's revenue stream will be delayed and the DWR may have to procure replacement energy. In most of the non-renewable contracts, the DWR may terminate the contract (i.e. relieve both parties of any further obligation) with respect to any unit that does not reach commercial operation by a specified deadline (see Table 8, below). Some contracts also financially penalize the Seller for not meeting the construction deadline,[46] and a few contracts provide the Seller with a financial incentive to reach commercial operation before the deadline. The contracts that allocate the most risk of delayed construction to the DWR simply relieve the Seller of any liability to provide electricity to the DWR if the power plants that were to provide the power do not reach commercial operation (as long as the Seller used commercially reasonable effort to achieve operation). In the State Auditor's report on the DWR contracts, the Auditor expressed concern that although the construction of new power plants was a priority for the DWR, many of the DWR's contracts lack terms that would ensure that the new power plants will reach commercial operation (California State Auditor 2001).[47]

[46] The non-renewable contracts do not have a standard penalty if a commercial operation deadline is not met. Some contracts have a one-time penalty of about $3,000 to $6,000 per MW if a Seller misses the deadline, while other contracts have a penalty of about $500 per MW for each day the unit is late in reaching operation.
[47] Some of the DWR's renegotiated contracts contain stronger terms to ensure that new power plants will reach commercial operation (see Appendix A).

Table 8. Power Plant Construction Deadline Penalties and Incentives in the DWR Non-Renewable Contracts

Seller	If unit does not reach operation despite Seller's reasonable effort, Seller is not liable to provide electricity	DWR can terminate with respect to any unit that does not reach operation by deadline	Seller pays DWR penalty for not reaching operation by deadline	Seller receives incentive if unit reaches commercial operation before deadline
Alliance Colton		✓		✓
Calpeak*		✓	✓	
Calpine – 2*	✓			
Calpine – 3*	✓			
Calpine – 4*	✓	✓		
Coral Power		✓	✓	
Fresno Cogeneration		✓	✓	
GWF Energy		✓		✓
High Desert*		✓	✓	
PacifiCorp**				
Sempra	✓			
Sunrise		✓	✓	
Wellhead		✓	✓	

* These contracts have been renegotiated; see Appendix A for further details
**The PacifiCorp contract says that the Seller may build a new plant, but the Seller is not required to do so under the contract.

B. Renewable Contracts

Six of the DWR's seven renewable contracts provide for the construction of new power plants or the re-powering of existing power plants. The Seller pays for the construction in all of these contracts, and bears the construction cost risk. The parties to the renewable contracts share the risk that a new power plant will not be built (or an existing plant will not be re-powered) on schedule. All of the renewable contracts allow the DWR to terminate the contract with respect to any unit that does not reach commercial operation by a deadline, and none of the contracts otherwise penalize the Seller if a deadline is not met.

5.2.2 Performance Risk During Operations

Dispatchable and non-dispatchable contracts provide different products and services to the DWR, who therefore must manage different types of performance risk. A non-dispatchable contract usually delivers electricity according to a schedule specified in the contract, whereas a dispatchable contract allows the DWR to decide when it wants the Seller's power plant to produce power (within some limitations).[48] (Dispatchability is discussed further in Section 6 on Demand Risk.) Consequently, dispatchable contracts have more dimensions of performance risk to manage than non-dispatchable contracts; we therefore separate our discussion of performance risk based on dispatchability and will look specifically at the DWR's non-renewable dispatchable contracts, the non-renewable non-dispatchable contracts, and finally the renewable contracts.

A. Dispatchable, Non-Renewable Contracts

Just over half of the DWR's non-renewable contracts are at least partially dispatchable; these dispatchable contracts are expected to provide about 27% of the DWR's non-renewable energy over the next decade. In all of the dispatchable contracts, the DWR pays the Seller both a "capacity charge" for making the power plant available to the DWR (regardless of whether or not the DWR requests that the plant generate power), and an energy charge for the electricity that is actually delivered. There are four primary performance concerns in dispatchable natural gas-fired electricity contracts: (i) the actual generation capacity of the Seller's power plant, (ii) the power plant's efficiency in generating electricity, (iii) the availability of the power plant to generate electricity, and (iv) the reliability with which the Seller delivers, and the DWR receives, electricity that has been dispatched by the DWR.

The actual capacity of a dispatchable power plant is important because the DWR pays the Seller a capacity charge to have a certain amount of generating capacity available. Many of the dispatchable contracts require annual testing of the capacity of the power plant in order to determine the capacity charge, while other contracts simply fix the capacity charge in the contract (see Table 9, below). When the capacity charge is not adjusted based on the actual capacity of the power plant, the DWR bears the risk that the capacity of the power plant will differ from the capacity that is stated in the contract.

Since all but one of the dispatchable contracts are tolling contracts that require the DWR to pay for the natural gas used to generate the electricity, the DWR's fuel costs will often depend on how efficiently the power plant can produce electricity from natural gas – the plant's "heat rate." As shown in Table 9, many of the dispatchable contracts require periodic testing or calculation of the plant's heat rate, and the DWR's fuel payments are adjusted accordingly. Several of the contracts that do not require heat rate testing simply calculate the fuel charge using a fixed heat rate if the Seller is providing the fuel, thereby shifting the risk that the power plant will operate inefficiently to the Seller; however, if the DWR provides the fuel needed to generate the electricity – as is allowed in these tolling agreements – and the contract does not provide a mechanism to adjust the DWR's fuel costs based on the actual heat rate of the plant, then the DWR bears the risk that the power plant will operate inefficiently.

[48] Dispatchable contracts are frequently tolling agreements, which require the DWR to pay for the natural gas used to generate the electricity and allow the DWR to supply the natural gas itself, as discussed in Section 4 on Fuel Price and Supply Risk.

Table 9. Power Plant Performance Testing in the DWR Dispatchable, Non-Renewable Contracts

Seller	Capacity Test	Heat Rate Test
Alliance Colton	Annual Seller may re-test at any time, but no more than once a month.	Annual Seller has the right to re-test at any time, but no more than once a month.
Calpeak‡	At Seller's discretion or DWR's request (not more than once a year).	Annual
Calpine – 3‡	None	None*
Calpine – 4‡	Annual Each party may request two additional tests per year.	Monthly
Coral Power	None	None**
Dynegy – 2	None†	None**
Fresno Cogeneration	Annual	Monthly
GWF Energy	Annual Each party may request two additional tests per year.	Monthly
PacifiCorp	None	None**
Sunrise	Annual Seller may schedule two additional tests per year.	Biannually
Wellhead	Annual	Monthly

‡ These contracts have been renegotiated; see Appendix A for further details.
* The Calpine – 3 contract is a fixed-price contract (not a tolling contract), so heat rate testing would be unnecessary.
** If the Seller is providing the fuel in these contracts, the contract's fuel charge is simply calculated using a fixed heat rate, rather than based on the actual amount of fuel consumed, making a heat rate test unnecessary. However, if the DWR provides the fuel, then the DWR bears the risk that the power plant will operate inefficiently.
† The Dynegy – 2 contract's capacity charge is based on the amount of electricity delivered rather than the capacity available, so capacity testing would be unnecessary.

Since the DWR pays the Sellers of the dispatchable contracts to have the power plants *available* to generate power (whether or not the DWR calls upon the Seller to actually deliver power), the actual availability of the generation units is another aspect of performance uncertainty that the DWR faces. The DWR reduces its exposure to this facet of performance risk by requiring the Sellers to meet guaranteed levels of availability.

The general definition of availability in dispatchable contracts is the number of hours that the generation unit was *available* to generate power during a period, divided by the total possible number of hours the unit could have been dispatched during the period as specified in the contract (adjusted for force majeure events and scheduled outages).[49] Most of the DWR's dispatchable contracts require the Seller to meet a guaranteed level of availability, and the Seller is penalized for failing to meet the guarantee, primarily through a reduction in the capacity charge (see Table 10, below). Two contracts also provide the Seller an incentive to surpass the

[49] Some dispatchable contracts allow the unit to be dispatched in any hour of any day, whereas others restrict the possible dispatch, for example, to only peak hours.

guaranteed level of availability. Most of the dispatchable contracts guarantee availabilities over 95% during the summer and over 90% during the rest of the year. Several contracts also set absolute minimum levels of availability after which the DWR may terminate the agreements.

Table 10. Availability Requirements in the DWR Dispatchable, Non-Renewable Contracts

Seller	Guaranteed Availability	Availability Penalties and Incentives		
		Capacity Charge Penalty	Capacity Charge Incentive	Other
Alliance Colton	June through October: 95% Annual: 95%	✓		
Calpeak*	June through October, December through February: 96% All other months: 94%	✓		DWR may terminate if annual average availability is less than 60% for any two out of three years. If Seller fails to meet availability guarantee intentionally, then Seller defaults.
Calpine – 3*	None			
Calpine – 4*	June through October: 98% All other months: 92%	✓		
Coral Power	July through September: 97% All other months: 94.3%	✓		
Dynegy – 2**	None			
Fresno Cogeneration	June through October: 97% All other months: 94%	✓		DWR can terminate or suspend performance if the availability is less than 60% for one year.
GWF Energy	June through October: 98% All other months: 94%	✓	✓	DWR may terminate if the availability is less than 60% for one year.
PacifiCorp	Annual: 88%	✓		
Sunrise	June through September: 95% Annual: 91.8%	✓	✓	
Wellhead	June through October: 97% All other months: 94%	✓		DWR can terminate if the availability is less than 60% for one year.

* These contracts have been renegotiated; see Appendix A for further details.
** The Dynegy – 2 contract's capacity charge is based on the amount of electricity delivered rather than the capacity available.

The final primary performance concern in dispatchable natural gas contracts is the reliability with which the Seller will deliver, and the DWR will receive, electricity that has been dispatched by the DWR. The dispatchable contracts use "cover damages" to reduce this aspect of performance risk – if the Seller fails to deliver scheduled energy and the failure is unexcused, then the Seller pays for the DWR's incremental cost of replacement energy, and if the DWR fails to receive scheduled energy, then the DWR pays the Seller the difference between the contract price and the amount the Seller was able to sell the energy for. What events qualify as excused outages depends on the firmness of the contract. As discussed above, unit-contingent contracts excuse the Seller from delivering power during generator outages and events of force majeure, while firm contracts only excuse the Seller during events of force majeure.

Eight of the DWR's eleven dispatchable contracts require the Seller to pay cover damages, however some of these contracts only require cover damages if the Seller willfully fails to deliver the scheduled energy (see Table 11, below). A few contracts further penalize the Seller (in addition to cover damages) for willfully failing to deliver scheduled energy.[50] If a contract does not require the Seller to pay the DWR cover damages for a failure to deliver energy, then the Seller is only penalized through the availability requirements discussed above.

Table 11. Remedy for Failure to Deliver or Receive Scheduled Energy in the DWR Dispatchable, Non-Renewable Contracts

Seller	Firmness	Seller pays cover damages?	DWR pays cover damages?
Alliance Colton	Unit-Contingent	Yes, if failure is willful or due to negligence	Yes
Calpeak‡	Firm	No	No
Calpine – 3‡	Firm	Yes	Yes
Calpine – 4‡	Unit-Contingent	Yes	Yes
Coral Power	Unit-Contingent	Yes*	Yes
Dynegy – 2	Unit-Contingent	No**	No
Fresno Cogeneration	Firm	Yes, if failure is willful	No
GWF Energy	Firm	Yes, if failure is willful	No
PacifiCorp	Firm	No	No
Sunrise	Unit-Contingent	Yes	No
Wellhead	Firm	Yes, if failure is willful	No

‡ These contracts have been renegotiated; see Appendix A for further details.
* The Coral Power contract only requires the Seller to pay the DWR cover damages once the Seller has fallen below the availability guarantee.
** The Dynegy – 2 contract capacity charge is calculated based on the number of MWh's delivered, so the Seller is penalized for failure to deliver through a reduction in the capacity charge.

Against the backdrop of the California electricity crisis and accusations that generators were exerting market power by withholding electricity, the State Auditor expressed concern that cover damages are not sufficient to protect the DWR against Sellers that repeatedly or intentionally fail to deliver power. The Auditor expressed concerned that the DWR contracts do not allow the DWR to terminate a contract if a Seller repeatedly or intentionally fails to deliver power, or to inspect generation facilities to verify a generator's claims of an excused outage. The Auditor argues that cover damages cannot fully protect the DWR if a Seller is withholding electricity to

[50] The Fresno Cogeneration, GWF Energy, and Wellhead contracts require the Seller to pay a penalty equal to two times the capacity charge for any hour in which the Seller willfully fails to deliver energy. The Sunrise contracts stipulates that the Seller defaults if the Seller willfully fails to deliver power to the DWR.

exert market power in the spot market, because all of the DWR's purchases in the spot market would be at an increased price – not just the electricity the DWR purchases to replace the power withheld by the Seller (for which the Seller pays cover damages) (California State Auditor 2001).[51]

B. Non-Dispatchable, Non-Renewable Contracts

Almost half of the DWR's non-renewable contracts are non-dispatchable; these non-dispatchable contracts are expected to provide about 73% of the DWR's non-renewable energy over the next decade. In all but one of the non-dispatchable contracts, the Seller delivers power according to a schedule that is fixed in the contract; the only exception is the High Desert contract, in which the Seller delivers the actual output of electricity from the Seller's power plant, as it is available. Since almost all of the non-dispatchable contracts are fixed price (the Seller is paid only when electricity is delivered), the contracts have a built-in incentive to reduce performance risk.[52] Accordingly, the non-dispatchable contracts have fewer contract clauses designed to manage performance risk than the dispatchable contracts.

None of the non-dispatchable contracts provide for capacity tests, and the Sellers bear the risk that the power plants will not be able to operate at the desired capacity, since the contracts require the Sellers to deliver electricity according to a fixed schedule. (The High Desert contract shifts some of the risk that the plant will not operate at full capacity to the DWR, since the Seller only delivers electricity as it is available.) In addition, none of the non-dispatchable contracts provide for heat rate tests, and the Sellers therefore bear the risk that the power plants will operate inefficiently (since the Sellers are paid per MWh of electricity delivered and not based on the amount of fuel consumed).

If a Seller fails to deliver the electricity scheduled in a non-dispatchable contract, the firmness of the contract (and the circumstances surrounding the failure to deliver) will determine if the Seller is excused from delivering the energy (see Table 12, below). If the Seller is not excused from delivering power and fails to deliver (or if the DWR fails to receive) scheduled energy, the party at fault is required to pay the other party cover damages. As noted above, the State Auditor expressed concern that cover damages are not sufficient to protect the DWR against Sellers that repeatedly or intentionally fail to deliver power (California State Auditor 2001).

The only other performance penalty contained in the DWR's non-dispatchable, non-renewable contracts is an availability guarantee (contained in only two contracts). In the non-dispatchable contracts, the definition of availability is the percent of the scheduled energy that is actually delivered by the Seller, which differs from the definition of availability in the dispatchable contracts. The Allegheny contract requires the Seller to deliver at least 90% of the scheduled energy (or else the DWR could declare the Seller in default of the contract), and the Williams

[51] Some of the DWR's renegotiated contracts contain stronger terms to address the Auditor's concerns regarding Sellers that repeatedly or intentionally fail to deliver power (see Appendix A for further details).

[52] The Sempra contract is the only non-dispatchable contract that is also a tolling agreement. Although the DWR pays for the cost of gas in the Sempra contract, there is no capacity charge and the pricing structure is designed such that the DWR only pays Sempra when electricity is delivered.

contract requires the Seller to deliver at least 70% of the scheduled energy and provides performance penalties and incentives based on the availability requirement.

Table 12. Firmness of the DWR's Non-Dispatchable, Non-Renewable Contracts

Seller	Firmness
Allegheny	Unit-Contingent
Calpine – 1*	Firm
Calpine – 2*	Unit-Contingent
Dynegy – 1	Firm
El Paso	Firm
High Desert*	Unit-Contingent
Morgan Stanley	Firm
Sempra	Firm
Williams	Unit-Contingent

* These contracts have been renegotiated; see Appendix A for further details.

C. Renewable Contracts

All of the DWR's renewable contracts are fixed-price, non-dispatchable contracts. The primary mechanism the renewable contracts use to manage performance risk is built-in to the fixed-price nature of the contracts – the Seller is only paid for electricity that is delivered. There is some variation in how the renewable contracts manage performance risk, and we consider each of the variations in turn.

Out of all the renewable contracts, the DWR bears the most performance risk in the two wind contracts. The wind contracts deliver electricity as-available, and have no availability requirement. If the wind plants do not deliver as much energy as they might be capable of delivering, the Sellers are not penalized. However, the wind contracts require the Sellers to pay cover damages if they fail to deliver scheduled energy and the failure is unexcused (changes in wind resource conditions would be an excused outage). The primary incentive for the Sellers of the wind contracts to perform well is the fixed-price nature of the contracts.

At the time the DWR contracts were signed, the California ISO heavily penalized electricity suppliers who delivered less electricity than they had scheduled with the ISO (through "imbalance charges"); this rule was intended to prevent gaming of the market, however it represented a uniquely large financial burden for wind power generators, since future wind supply cannot be predicted with extreme accuracy. In both of the DWR's wind contracts, the DWR agreed to accept this aspect of performance risk, and to pay any ISO imbalance charges that might arise. The ISO recently revised its rules to facilitate the use of intermittent energy sources, which will reduce the DWR's potential cost exposure (FERC 2002a).

The landfill gas and two of the three biomass contracts require the Sellers to deliver energy at the plant's maximum capability in every hour, instead of requiring the Sellers to deliver energy according to a schedule set in the contract (as most of the non-renewable, non-dispatchable contracts require). None of these renewable contracts require capacity tests, thereby shifting this aspect of performance risk to the DWR. However, the Sellers bear the risk that their power plants will operate inefficiently, since they are only paid based on how much electricity is delivered.

If the Seller in either the landfill gas or the two biomass contracts discussed above fails to deliver scheduled power (and they are not excused from delivering based on the contracts' firmness provisions), they are not required to pay the DWR cover damages. However, the Sellers are obliged to meet two other requirements designed to reduce the amount of performance risk the DWR bears. First, the Sellers are required to deliver within plus or minus 10% of the monthly schedules that they submit to the DWR (or else default on the contract and pay a sizeable termination payment).[53] Second, the Sellers are required to deliver over 70% to 75% of the total potential electricity that could be generated by the unit, based on the plant's capacity given in the contract; if a Seller fails to meet this availability guarantee for three consecutive months, the DWR can terminate the contract (see Table 13, below).

The geothermal contract is very similar to the landfill gas and two biomass contracts discussed above, except the geothermal contract has no availability requirement, and instead is required to pay the DWR cover damages for failing to deliver scheduled energy.

The Imperial Valley biomass contract is nearly identical to a non-dispatchable, non-renewable contract in how it manages performance risk. The energy delivery schedule is set in the contract, and the Seller has no availability requirement and instead pays cover damages for failing to deliver scheduled energy.

[53] The termination payment is equal to the difference between the present value of the existing contract and a replacement contract.

Table 13. Key Contract Terms that Allocate Performance Risk in the DWR Renewable Electricity Contracts

Seller	Renewable Resource	Firmness	Contract clauses relevant to performance risk	Availability Requirement and Penalties	Seller pays cover damages?	DWR pays cover damages?
Capitol Power*	Biomass	Unit-Contingent	▪ DWR must take (Seller must deliver) plant's maximum capability in all hours, not to exceed 105% of contract capacity. ▪ Seller must operate the plant such that monthly actual generation is within plus or minus 10% of monthly scheduled generation.	▪ June through October: 75% Otherwise: 70% ▪ If plant doesn't meet availability guarantee for 3 consecutive months, DWR can terminate.	No	Yes
Clearwood	Geothermal	Unit-Contingent	▪ DWR must take (Seller must deliver) plant's maximum capability in all hours, not to exceed 120% of contract capacity. ▪ Seller must operate the plant such that monthly actual generation is within plus or minus 10% of monthly scheduled generation.	▪ None	Yes	Yes
County of Santa Cruz	Landfill gas	Unit-Contingent	▪ DWR must take (Seller must deliver) plant's maximum capability in all hours, not to exceed 105% of contract capacity. ▪ Seller must operate the plant such that monthly actual generation is within plus or minus 10% of monthly scheduled generation.	▪ June through October: 75% Otherwise: 70% ▪ If plant doesn't meet availability guarantee for 3 consecutive months, DWR can terminate.	No	Yes
Imperial Valley	Biomass	Firm	▪ DWR must take (Seller must deliver) quantity of energy set in contract.	▪ None	Yes	Yes
PG&E Energy Trading	Wind	As-available	▪ Electricity is generated when sufficient wind is available.	▪ None	Yes	Yes
Soledad**	Biomass	Unit-Contingent	▪ DWR must take (Seller must deliver) plant's maximum capability in all hours. ▪ Seller must operate the plant such that monthly actual generation is within plus or minus 10% of monthly scheduled generation.	▪ June through October: 75% Otherwise: 70% ▪ If plant doesn't meet availability guarantee for 3 consecutive months, DWR can terminate.	No	Yes
Whitewater*	Wind	As-available	▪ Electricity is generated when sufficient wind is available.	▪ If no energy is generated and delivered for a period of six months for reasons other than weather related conditions, DWR may terminate.	Yes	Yes

* These contracts have been renegotiated; see Appendix A for further details.
** The Soledad contract was terminated on 27 March 2002.

5.3 Summary of Performance Risk

The parties to an electricity contract are able to control and manage performance risk more than any other risk discussed in this paper. Ideally, contracts should allocate a risk to the party best able to manage the risk. In general, since the Seller builds and operates the power plant that provides the electricity sold under a contract, the Seller is best able to control the performance of the power plant. Contracts therefore allocate a substantial amount of performance risk to the Seller, and provide incentives for the Seller to perform in a way that reduces the uncertainties faced by the DWR.

There is no inherent difference in the amount of performance risk present in renewable and non-renewable contracts, and the DWR contracts manage performance risk in the two types of contracts in a similar manner.[54] The treatment of performance risk in the renewable contracts is similar to the treatment in the non-renewable, non-dispatchable contracts, since both are non-dispatchable and mostly fixed-price contracts. Perhaps the largest difference between the performance risk clauses in the renewable and non-renewable contracts is that the renewable contracts do not penalize the Seller if a power plant is delayed in reaching commercial operation (other than allowing the DWR to terminate the contract), whereas most of the non-renewable contracts contain penalties in addition to the DWR's termination rights. The DWR also assumed additional performance risk in the two wind contracts by agreeing to bear any ISO imbalance charges that might arise, which is an aspect of performance risk that is not a significant concern in the other DWR contracts.

Overall, the California State Auditor (2001) expressed concern that many of the DWR contracts contain performance risk terms that are excessively lenient for the Sellers; many of the DWR's recently renegotiated contracts contain stronger performance risk terms (see Appendix A, for further details).

[54] To the extent that renewable generation is based on a variable underlying fuel stream (for example, wind), a renewable contract clearly cannot have the same requirements for performance as a contract for natural gas-fired generation or other kinds of renewable generation.

6. Demand Risk in Electricity Contracts

The amount of electricity that the DWR or any other utility is responsible for supplying to its customers can vary on very short time scales (minute-to-minute) and on longer time scales (year-to-year). Electricity demand varies based on population, the economy, and weather and temperature, among other factors. The variability of electricity demand can make predicting electricity demand, and contracting to satisfy that demand, a difficult task. The DWR's ability to supply the California utilities' net short also depends on the availability of the utilities' retained generation – which the DWR does not control – thereby further complicating the DWR's task.[55]

Since electricity demand is variable, instantaneously supplying enough electricity to meet the demand requires significant coordination of power plants. Disptatchable power plants allow electricity supply to follow the varying load; renewable electricity generation technologies are more difficult to dispatch in general than natural gas-fired generation technologies (particularly gas turbines). In addition, during California's electricity crisis, the state recognized the need to reinstate coordination of power plant maintenance schedules, after blackouts and high prices were due in part to numerous power plants simultaneously shutting down for maintenance.[56]

6.1 Demand Risk Fundamentals

Since the demand for electricity in the future is uncertain, the parties to an electricity contract face "demand risk" – uncertainty over whether the electricity that has been contracted for will be needed and therefore valuable.[57] Electricity is a unique commodity because it cannot be stored (to any significant extent) and it must be simultaneously produced by the supplier and utilized by the customer.

In order to reliably provide customers with electricity, the owner of a portfolio of electricity supplies must design the portfolio to be able to supply electricity to follow the customers' load; this requires the use of dispatchable contracts.[58] A dispatchable contract allows the party purchasing the power to tell the Seller when to generate electricity, and how much electricity to generate (within limitations).[59] Non-dispatchable contracts, in contrast, generally deliver "blocks" of power (fixed amounts of electricity) during hours that are set in the contract (for example, baseload or peak hours). Renewable electricity generation technologies are more difficult to dispatch in general than natural gas-fired electricity generation technologies (particularly gas turbines). Although some dispatchable contracts are valuable as part of a

[55] The utilities' retained generation includes utility-owned generation (e.g. nuclear and hydropower) and the qualifying facilities under contract to the utilities.
[56] Whether some power plants were not generating electricity in order to exert market power and increase the market price rather than to perform maintenance remains an open question.
[57] Of course, the owner of a portfolio of electricity supplies also faces uncertainty in whether adequate electricity has been contracted for (i.e. if demand for electricity turns out to be higher than was expected).
[58] Renewable generation facilities may also be able to reduce demand risk by providing increased flexibility due to short construction lead-times and the modular nature of certain technologies (Hoff 1997); certain natural gas-fired generation facilities (e.g. peakers) also have these characteristics.
[59] Electricity providers can also use dispatchable demand contracts (i.e. contracts with customers that agree to decrease demand upon request) in place of dispatchable supply contracts in order to maintain the necessary supply-demand balance.

utility's portfolio, utilities only need enough dispatchable power to "top-off" the electricity provided by non-dispatchable plants (i.e. only a portion of the load varies).

Since generators are often not required to deliver electricity when their power plant is undergoing routine maintenance, the timing of maintenance can introduce uncertainty into an otherwise relatively certain electricity delivery (or potential dispatch) schedule. In order to reduce this uncertainty, electricity contracts often constrain when the Seller can do maintenance.

6.2 Demand Risk in the DWR Contract Sample

Only about one-quarter of the total energy the DWR has under contract for the next decade is dispatchable. All of these dispatchable contracts are for electricity from power plants fueled by natural gas (see Table 14, below). Since almost three-quarters of the DWR's energy is non-dispatchable, the DWR bears a significant amount of demand risk. The State Auditor's analysis of the DWR contracts found that the DWR's overall portfolio of electricity contracts includes excess deliveries of baseload energy and insufficient deliveries of (or dispatchable deliveries of) peak energy (Auditor 2001, pg. 23). Evidence of the amount of demand risk that the DWR bears has materialized, as the DWR has been forced to sell large quantities of "must-take" (non-dispatchable) power at a loss (Marcus 2002). Some of the recently renegotiated contracts decrease the DWR's demand risk by increasing the DWR's dispatch flexibility in contracts that were previously non-dispatchable (see Appendix A).

For the purpose of analyzing demand risk, the DWR non-renewable electricity contracts can be divided into three groups: (i) non-dispatchable contracts, (ii) dispatchable contracts, and (iii) partially dispatchable contracts. We consider each of these groups in turn, followed by the renewable contracts.

Table 14. Dispatchability of the DWR Long-term Contracts

Seller	Dispatchable?	Resource	Ten-year Energy Purchases (GWh)‡
Allegheny	No	Natural gas	63,898
Calpine – 1*	No	Unspecified	64,596
Calpine – 2*	No	Natural gas	70,115
Dynegy – 1	No	Natural gas	14,246
El Paso	No	Unspecified	2,441
High Desert*	No	Natural gas	51,896
Morgan Stanley	No	Unspecified	2,136
Sempra	No	Natural gas	93,325
Williams	No	Natural gas	56,535
	Total Non-Dispatchable, Non-Renewable Contracts		**419,189 (72%)**
Alliance Colton	Partially	Natural gas	1,468
Calpeak*	Yes	Natural gas	5,027
Calpine – 3*	Yes	Natural gas	8,001
Calpine – 4*	Yes	Natural gas	3,024
Coral Power	Partially	Natural gas	28,677
Dynegy – 2	Partially	Natural gas	21,174
Fresno Cogeneration	Yes	Natural gas	950
GWF Energy	Yes	Natural gas	23,713
PacifiCorp	Yes > 2002	Natural gas	21,900
Sunrise	Yes	Natural gas	38,888
Wellhead	Yes	Natural gas	4,047
	Total Dispatchable, Non-Renewable Contracts		**156,870 (27%)**
Capitol Power*	No	Biomass	590
Clearwood	No	Geothermal	1,692
County of Santa Cruz	No	Landfill Gas	112
Imperial Valley	No	Biomass	362
PG&E Energy Trading	No	Wind	2,017
Soledad**	No	Biomass	410
Whitewater*	No	Wind	3,263
		Total Renewable Contracts	**8,448 (<2%)**
		TOTAL	**584,506 (100%)**

Note: only DWR contracts with terms of three years and longer are included in this table.
* These contracts have been renegotiated; see Appendix A for further details.
** The Soledad contract was terminated on 27 March 2002.
‡ Figures derived from spreadsheets provided by the State Auditor's office that were used in the State Auditor's report on the DWR contracts (California State Auditor 2001).

A. Non-Dispatchable, Non-Renewable Contracts

All but two of the non-dispatchable, non-renewable contracts specify in the contract how much electricity the Seller will deliver and when (the delivery schedule).[60] Since the DWR cannot choose when to have electricity delivered in the non-dispatchable contracts (after a contract is finalized), and the DWR must pay the Seller a fixed amount for every MWh of electricity that is delivered (whether or not the DWR needs the electricity), the DWR bears demand risk in the non-dispatchable contracts.[61] The Williams contract increases the amount of demand risk that the DWR bears above the other non-dispatchable contracts because the Williams contract allows the Seller to provide the DWR with a significant amount of must-take energy each month, at the *Seller's* option. To somewhat decrease the amount of demand risk born by the DWR, half of the non-dispatchable, non-renewable contracts restrict the timing of when the Seller can do routine maintenance (excluding the contracts that provide electricity from unspecified "market" sources that would presumably not need to do maintenance and would provide power continuously) as shown in Table 15, below.

Table 15. Maintenance Restrictions in the DWR Non-Dispatchable, Non-Renewable Contracts

Seller	Resource	Maintenance Restrictions
Allegheny	Natural gas	None
Calpine – 1*	Unspecified	N/A**
Calpine – 2*	Natural gas	None
Dynegy – 1	Natural gas	Seller will avoid peak hours
El Paso	Unspecified	N/A**
High Desert*	Natural gas	Seller will avoid July, August and September, and schedule maintenance with DWR
Morgan Stanley	Unspecified	N/A**
Sempra	Natural gas	None
Williams	Natural gas	Scheduled maintenance will occur November through April, and will not exceed 14 days per unit per year.

* These contracts have been renegotiated; see Appendix A for further details.
** The contracts that provide electricity from unspecified "market" sources would presumably not need to do maintenance and would provide power continuously

B. Dispatchable, Non-Renewable Contracts

In contrast to the non-dispatchable contracts, the DWR's dispatchable contracts do not require the DWR to take any minimum quantity of energy. Rather, the dispatchable contracts define the parameters within which the DWR can request the Seller to deliver power. In all of the

[60] The Williams and High Desert contracts do not specify the precise delivery schedule in the contract. However, the High Desert contract's delivery schedule is relatively certain – the Seller is required to deliver the actual output of its power plant to the DWR in all hours.
[61] These non-dispatchable contracts are also known as "take-or-pay" or "must-take" contracts.

dispatchable contracts, the DWR pays the Seller both a capacity charge for making the power plant available to the DWR (regardless of whether or not the DWR requests that the plant generate power), and an energy charge for the electricity that is actually delivered. Dispatchable contracts reduce the DWR's demand risk by allowing the DWR to schedule electricity to match its changing load. The amount of demand risk faced by the electricity generator under a dispatchable contract is mitigated through revenue collection from their capacity charge.

The DWR's dispatchable contracts allow the DWR to dispatch power plants the day before the electricity is needed, or on a real-time basis, or both (see Table 16, below). The contracts contain numerous other constraints with regard to how the DWR can dispatch the power plants. (Many contracts supply power from multiple power plants, but the dispatch constraints are usually with regard to each individual power plant or generating "unit.") The primary constraints on the DWR's dispatch flexibility are:

- the maximum number of times the generating units can be started each day, (commonly two times per day),
- the minimum number of consecutive hours that a dispatched unit must run, (commonly four hours), and
- the smallest increment of capacity that can be dispatched if the DWR wants the Seller to deliver any power (ranges from 21 MW to 195 MW).

Some contracts also explicitly state that the DWR's dispatch must be within the operating specifications of the units (e.g. the unit's ramp rate), but this would implicitly have to be true for any unit.

In order to further reduce the amount of demand risk that the DWR bears, most of the DWR's dispatchable contracts also restrict the timing of when the Seller can do routine maintenance, as shown in Table 16, below. In general, the contracts have the Sellers avoid performing maintenance during the summer months and during peak hours – times when the demand for electricity in California is the highest and when it may be the most difficult for the DWR to procure replacement energy.

As mentioned previously in Section 4, it is interesting to note that all but one of the DWR's dispatchable contracts are also tolling agreements.[62] Since a generator with a dispatchable contract does not know in advance when it will generate electricity, it would be difficult for the generator to reduce its fuel price risk using physical or financial fuel supply contracts; hence, dispatchable contracts are frequently tolling or indexed-price agreements which allocate the fuel price risk to the purchaser of the electricity.

[62] The Calpine – 3 contract is the only fixed-price dispatchable contract.

Table 16. Dispatch Flexibility and Maintenance Restrictions in the DWR Dispatchable, Non-Renewable Contracts

	Timeframe of Allowed Dispatches		Dispatch Constraints			Maintenance Restrictions
Seller	**Day-Ahead**	**Real-time**	**Maximum number of start-ups per day**	**Number of consecutive hours unit must run if dispatched**	**Smallest increment of capacity that can be dispatched if the DWR wants power delivered***	
Calpeak‡	✓	✓	2	4	Unspecified	Seller will schedule maintenance during November, March, April and May.
Calpine – 3‡	✓	✓	Unspecified	4	36 MW (>80% of unit)	None
Calpine – 4‡	✓	✓	Unspecified	4	36 MW (>80% of each unit)	None
Fresno Cogeneration	✓		2	4†	21.3 MW (100% of unit)	Seller will avoid summer months and peak hours
GWF Energy	✓	✓	1	Unspecified	44 MW (100% of each unit)	Seller will avoid peak hours, and provide DWR notice
PacifiCorp**		✓	Unspecified	Unspecified	25 MW	Seller provides DWR 30 days non-binding advance notice of scheduled maintenance
Sunrise		✓	Unspecified	2 to 6	195 MW (>60% of full output)	Seller will avoid June through September
Wellhead		✓	2	4†	42 MW (100% of each unit)	Seller will avoid summer months and peak hours

*Some contracts have more than one unit with different capacities.
‡ These contracts have been renegotiated; see Appendix A for further details.
**The PacifiCorp contract is dispatchable after 2002
† With three hours of non-operation between dispatches.

C. Partially Dispatchable, Non-Renewable Contracts

The DWR's three partially dispatchable contracts lie somewhere in between the dispatchable and non-dispatchable contracts in the amount of flexibility the contracts provide the DWR to decide when electricity will be delivered. All of the partially dispatchable contracts require the DWR to receive a minimum quantity of electricity, and allow the DWR to dispatch an additional quantity of energy. The Coral Power contract provides the DWR with the least amount of flexibility of the partially dispatchable contracts, and is unusual because it provides the Seller with flexibility to change the amount of power to be delivered (see Table 17, below). The partially dispatchable contracts also have similar maintenance restrictions to the dispatchable contracts.

Table 17. Dispatch Flexibility and Maintenance Restrictions in the DWR Partially Dispatchable, Non-Renewable Contracts

	Timeframe of Allowed Dispatches		Dispatch Constraints				Maintenance Restrictions
Seller	Day-Ahead	Real-time	Maximum number of start-ups per day	Number of consecutive hours unit must run if dispatched	Smallest increment of capacity that can be dispatched if the DWR wants power delivered	Other constraints	
Alliance Colton	✓	✓	2	8	10 MW (100% of each unit)	DWR must choose number of dispatchable hours (for most of the dispatchable energy under contract) annually. Once chosen, these hours are take-or-pay.	Seller will avoid June through October and peak hours.
Coral Power	✓		Unspecified	10	25 MW	Most of the energy to be delivered under the contract is non-dispatchable. Seller has option to cancel about half the energy under contract by 2003, and to pay DWR a penalty. Beginning on January 1, 2006, DWR may reduce the baseload deliveries for a given quarter, in increments of 25 MW, however DWR must still pay Seller $25.16 per MWh not delivered. Prior to each calendar year, Seller may increase or decrease the quantities to be delivered for the coming year by 10% (except baseload deliveries may not be increased).	None
Dynegy – 2	✓		Unspecified	Unspecified	50 MW	Two-thirds of the contract capacity during peak hours is non-dispatchable.	Seller will avoid peak hours, and provide DWR notice.

D. Renewable Contracts

All of the DWR's renewable contracts are non-dispatchable, and therefore all demand risk is allocated to the DWR. The Imperial Valley biomass contract is similar to a non-dispatchable natural gas contract – electricity is supplied according to a schedule fixed in the contract. The DWR bears slightly more demand risk in the landfill gas, geothermal, and the other two biomass contracts, which all supply electricity at the power plants' maximum capability (with some restrictions);[63] this is similar to the High Desert natural gas contract, however the renewable plants may have more uncertain fuel supplies on a day-to-day basis than the natural gas plant, increasing the DWR's demand risk relative to the High Desert contract. The DWR bears the most demand risk with the two wind power contracts, which supply energy as-available, because the electricity deliveries are neither dispatchable nor predictable significantly in advance of delivery.

As with the non-renewable contracts, almost all of the renewable contracts restrict the timing of when the Seller can do routine maintenance so as to reduce the amount of demand risk born by the DWR (see Table 18, below). In general, the renewable contracts require the Sellers to avoid performing maintenance during peak months, and require the Sellers to provide advance notice of the maintenance schedule to the DWR. Four of the seven renewable contracts also limit the number of days each year the Seller can have outages to perform maintenance.

Table 18. Maintenance Restrictions in the DWR Renewable Contracts

Seller	Maintenance Restrictions
Capitol Power*	Seller will avoid June through October, and provide DWR 30 days notice. Maintenance outages allowed for 40 days per year.
Clearwood	Seller will avoid peak months, coordinate schedule with DWR, and provide DWR with list of scheduled maintenance periods each year.
County of Santa Cruz	Seller will avoid June through October, and provide DWR 30 days notice. Maintenance outages allowed for 20 days per year.
Imperial Valley	Seller will avoid peak hours, and provide DWR with 14 days notice. Four maintenance outages, lasting an aggregate of 15 days, per year.
PG&E Energy Trading	None
Soledad**	Seller will avoid June through October, and provide DWR 30 days notice. Maintenance outages allowed for 20 days per year.
Whitewater*	Seller will schedule maintenance during November, March, April and May.

* These contracts have been renegotiated; see Appendix A for further details.
** The Soledad contract was terminated on 27 March 2002.

[63] The Capitol Power, Clearwood, County of Santa Cruz, and Soledad contracts require the Sellers to deliver within plus or minus 10% of the monthly schedules that they submit to the DWR. In addition, if the Seller makes a same-day change in its schedule that results in an increase to its output, the DWR has the right, but not the obligation, to purchase the increase at the contract price.

6.3 Summary of Demand Risk

The DWR reduced its exposure to demand risk by purchasing about one quarter of its total electricity using non-renewable dispatchable contracts, which allow the DWR to decide when power should be generated and in what quantities, and thereby enables the DWR to purchase electricity to follow its varying load. (It is not necessary or valuable to have all contracts in an electricity portfolio be dispatchable, it is only valuable to have dispatchable contracts provide electricity for the variable part of the load.) In general, contracts for electricity generated from natural gas are better able to reduce demand risk than renewable electricity contracts, because certain natural gas technologies are dispatchable.

All of the DWR's renewable contracts and the majority of the non-renewable contracts are non-dispatchable. The non-renewable dispatchable contracts provide the only mechanism for the DWR to significantly reduce its exposure to demand risk. While the dispatchable contracts reduce the DWR's demand risk, they also increase the DWR's exposure to fuel price risk (since almost all of the dispatchable contracts are natural gas tolling agreements). The DWR further reduced its exposure to demand risk in most of the contracts by restricting power plant maintenance to off-peak hours and non-summer months.

As noted above, the State Auditor's report on the DWR contracts found that the DWR's portfolio of contracts includes insufficient dispatchable contracts. The DWR did not take full advantage of the dispatchability that natural gas-fired electricity contracts can provide, and partly as a consequence, the DWR has been forced to sell large quantities of non-dispatchable power at a loss.[64] As a result, any further electricity contracting efforts in California in the near future (by the DWR or by other parties) may focus on dispatchable contracts, which would likely result in a further increase in California's reliance on natural gas rather than renewable resources.[65]

[64] The DWR's exposure to demand risk raises concerns about the effect it may have on the state's energy efficiency and conservation programs. The DWR is a state agency, and the state also allocates money for and administers most of California's energy efficiency programs. Since the DWR is already selling excess power at a loss, what incentive will it create for the state to aggressively pursue conservation and efficiency programs that can produce energy savings at costs cheaper than the DWR is purchasing energy? Regulated utilities may face similar predicaments if regulatory incentives are designed to punish over-procurement of power, and the utility is both procuring power supplies and administering demand reduction programs.

[65] However, the DWR recently renegotiated several contracts and increased dispatch flexibility in contracts that were previously non-dispatchable (see Appendix A).

7. Environmental Risk in Electricity Contracts

The laws and regulations governing the environmental impacts of electricity generation change relatively frequently, as does the cost of compliance with existing environmental regulations; it is likely that further changes will occur within the term of most of the DWR's contracts. In this section, we examine how the DWR contracts manage the risk related to compliance with environmental requirements, and the risk that future environmental regulations will affect the cost or legal ability to generate electricity.

We use the phrase "environmental risk," for lack of a better concise phrase, to mean the financial risk to which parties to an electricity contract are exposed, stemming from regulations related to environmental protection. (Environmental risk is a subset of regulatory risk; we consider other aspects of regulatory risk in Section 8). Our definition of environmental risk is different from the common societal use of the phrase "environmental risk." For example, the possibility of a future carbon tax is an environmental risk (in our definition) from the perspective of the parties to an electricity contract. However, from a societal standpoint, clearly the true danger (or "risk") is that nothing will be done to prevent global climate change, and the earth's climate will change and dramatically disrupt life on the planet.

Contracts for renewable electricity mitigate environmental risk for both parties to a contract, because renewable generation technologies cause less environmental damage than non-renewable generation technologies.

7.1 Environmental Risk Fundamentals

Parties to an electricity contract face a significant amount of uncertainty due to current environmental regulations and the possibility of future changes in environmental regulations. These environmental risks – as we call them – can impose potentially large costs on the parties to an electricity contract. Some possible future environmental regulations include a carbon tax, a renewable portfolio standard, and further regulation of sulfur dioxide, nitrogen oxides, and mercury emissions from power plants (EIA 2001a), all of which could impose significant financial burdens on electricity industry participants.

The allocation of environmental risks in the electricity industry can play an important role in determining what types of power plants get built, and thereby the overall environmental performance of the electricity system. For example, if the U.S. Congress had not passed the Price-Anderson Act – which allocates most of the risk of a nuclear power plant catastrophe to the public – it would be very unlikely that a private company would have been willing to build a nuclear power plant (Cohn 1997).

In an electricity contract, a party's exposure to environmental risk depends on three factors: (i) the technological characteristics and the environmental impact of the power plant(s) used to generate the electricity, (ii) the allocation of environmental risk in the electricity contract, and (iii) in the case of a new environmental regulation, the details of how the new regulation is implemented.

Power plants fueled by non-renewable fuels damage the environment more than renewable generation facilities. Hence, parties to a contract for electricity generated from non-renewable fuels are more exposed to environmental risks (by nature of the technology used to generate the electricity) than parties to a contract for renewable electricity. The decision about what type of power plant to build – which determines, to a large extent, the parties' environmental risk exposure – is generally made by the Seller before an electricity contract is negotiated.[66] Contracts may contain requirements for environmental performance and equipment upgrades to mitigate environmental risk exposure, however, the type of power plant that is built is the primary determinant of the parties' environmental risk exposure.

An electricity contract can allocate environmental risk to either the Buyer or the Seller, or the contract can split the risk between the parties. Since there are numerous sources of environmental risk, it is very unlikely that a contract could allocate *all* environmental risk to one party or the other; rather, the allocation of environmental risk is multi-dimensional – different environmental risks are allocated between the parties in different ways.

Environmental risk can arise from both existing environmental regulations, and the possibility of future environmental regulations. When environmental risk is due to a possible future environmental regulation, the amount of risk a party is exposed to is determined in part by the details of how the new regulation is implemented. For example, if a new carbon tax were levied on the use of natural gas, by default the Seller would bear the cost in most contracts; however, if the carbon tax were levied on the use of electricity, the Buyer would bear the cost. Contract clauses not intended to allocate environmental risk might nevertheless play a role depending on how a new regulation is implemented. For example, if a carbon tax were levied on the use of natural gas, in a fixed-price natural gas contract (in which the Seller purchases the gas used to generate the electricity) the Seller would bear the cost of the tax, but in a tolling contract (in which the Buyer can purchase the gas) the Buyer might bear the cost of the tax. Of course, new regulations might also "grandfather" existing power plants and excuse them from being subject to the new regulation altogether.

When a party to an electricity contract accepts an environmental risk, it implies something about their conception of the severity of the risk and the likelihood that a regulation will be implemented (as well as the party's risk aversion). The common practice of grandfathering undoubtedly influences perceptions regarding the likelihood that new environmental regulations will impact the parties to an electricity contract. The purchaser of electricity contracts must account for the possible cost of environmental risks that it would be exposed to in deciding what types of contracts to sign. Likewise, when sellers of electricity contracts are exposed to environmental risks, they will presumably increase the contract price to account for the cost of bearing the risks.

7.2 Environmental Risk in the DWR Contract Sample

The DWR contracts mostly allocate the risk of compliance with current environmental regulations (e.g. pollution permits) to the Seller, either explicitly or by default. However, there

[66] Of course, a purchaser of electricity contracts can demand contracts for electricity generated from particular technologies if it wishes to mitigate environmental risk.

are some notable exceptions; three non-renewable contracts allocate the risk (and cost) of acquiring pollution permits to the DWR, resulting in a potential cost exposure for the DWR on the order of a billion dollars, as discussed in further detail below.

Only thirty-five percent of the DWR's non-renewable contracts (representing 45% of the DWR's non-renewable energy under contract) allocate the risk of future environmental regulations in a comprehensive manner.[67] (All of these contracts allocate the risk of future environmental regulations predominantly to the DWR.) The fact that relatively few of the DWR's contracts allocate this risk comprehensively can be attributed to either a lack of concern about the cost of future environmental regulations or a lack of awareness of their potential cost. If future environmental regulations are enacted, the DWR may be exposed to sizeable costs, and new regulations may result in costly legal battles for the DWR in the contracts that do not explicitly allocate environmental risk. For example, as illustrated below, if a carbon tax is levied with a carbon allowance price between $10 per metric ton of carbon equivalent and $100 per metric ton, the DWR could face additional costs through 2010 ranging from $12 million to $8.5 billion (0.005 cents per kWh to 1.5 cents per kWh).

Contracts for renewable energy significantly reduce exposure to environmental risk because the technologies used to generate the renewable electricity are less environmentally damaging than non-renewable technologies. However, the purchaser of a renewable electricity contract may not benefit from the environmental risk mitigation that the contract can provide, unless the benefit is allocated to the purchaser in the contract; in both of the DWR's wind contracts, the Sellers retain the rights to the "renewable-ness" of the electricity. Consequently, as discussed in further detail below, although the DWR is nominally purchasing 1.5% of its electricity from renewable resources, from the perspective of mitigating environmental risk the DWR is only purchasing about 0.5% of its electricity from renewable resources. If the renewable portfolio standard (RPS) that is currently being debated in California is implemented, the DWR could be exposed to approximately $300 million in additional costs.

7.2.1 Risk of Compliance with Current Environmental Regulations

The construction and operation of power plants is heavily regulated, in large part because power plants have a significant impact on the environment. Environmental regulations can create significant sources of uncertainty for a power plant developer's legal ability and cost to build and operate a power plant. The risk that a power plant owner faces due to existing environmental regulations can be divided into two categories: pre-operation, and post-operation.

Prior to reaching commercial operation, a power plant usually must go through an extensive siting process and acquire a number of environmental permits. This process can be quite lengthy – on the order of a year or more – and power plants sometimes encounter intense public opposition (for example, the recent Calpine Metcalf power plant siting process in San Jose). Once a power plant reaches commercial operation, the plant must maintain permits (particularly

[67] The Calpine – 1, Calpine – 2, Calpine – 3, Dynegy – 1, Dynegy – 2, GWF Energy, and Williams contracts allocate the risk of a new environmental regulation passed by any governmental authority. All other contracts only allocate the risk of regulations passed by either the federal or state government, or regulations that are targeted at energy services.

air pollution permits) in order to operate. Pollution permit prices can be volatile, and power plants can run out of the permits they need in order to continue operating; both of these factors were blamed in part for the extremely high electricity prices during California's crisis.

A. Non-Renewable Contracts

In all of the DWR's non-renewable contracts that provide for the construction of new generating facilities, both parties share the risk that a unit may not reach commercial operation. In order to reach commercial operation, a power plant must pass an environmental review and permitting process. If a unit does not reach commercial operation by a deadline, most of the DWR's contracts simply allow the DWR to terminate the portion of the contract pertaining to the unit, and some contracts require the Seller to pay a penalty. (This is discussed in Section 5 on Performance Risk.) Three of the DWR's non-renewable contracts address the risk that the failure to reach commercial operation will be due specifically to the Seller's inability to acquire the environmental permits necessary to construct the facility. The Alliance Colton, Coral Power, and High Desert contracts allow the Seller to terminate the relevant portion of the contract, with no further liability, if they are unable to obtain the necessary permits.

Once a power plant has been built, the plant must acquire environmental permits on an ongoing basis in order to operate. Half of the DWR's non-renewable contracts assign responsibility for acquiring or paying for the permits necessary to produce electricity; most of these contracts allocate the responsibility of acquiring permits to the Seller (see Table 19, below). (By default, in contracts that do not explicitly allocate this risk, the responsibility is presumed to rest with the Seller.) Two of the non-renewable contracts that allocate the responsibility of acquiring permits to the Seller also contain clauses that address the Seller's performance at acquiring the permits; the Sunrise contract rewards the Seller for obtaining permits beyond those required to generate the maximum amount of energy in the contract, and the Alliance Colton contract does not penalize the Seller if the Seller is unable to obtain some of the permits necessary to deliver the amount of energy specified in the contract (and instead simply reduces the energy deliveries).

Three of the non-renewable contracts require the DWR to pay for the operational environmental permits required to generate electricity. The Williams contract requires the DWR to pay for the cost of emission credits, while the two Dynegy contracts require the DWR to pay for both the cost of the permits and for the cost of exceeding the power plants' applicable emission limits (to the extent necessary to supply the electricity under contract). The State Auditor's report presents a thorough analysis of these unusual contract clauses, and estimates that the Williams contract alone could expose the DWR to between $400 million and $688 million in additional costs over the lifetime of the contract, or between 0.7 and 1.2 cents per kWh in addition to the contract price (California State Auditor 2001).[68] Similarly, the Dynegy contracts could expose the DWR to additional costs on the order of $300 million for the emission credits alone, not including the cost of exceeding the power plants' emission limits.

[68] These contract clauses were chosen by the California State Auditor as among the most "troubling" contract provisions in the DWR's contracts (California State Auditor 2001). The Auditor assumes that emission credit prices will remain capped at $15,000 per ton.

Table 19. Explicit Allocation of the Risk of Acquiring the Environmental Operational Permits Required to Generate Electricity in the DWR Non-Renewable Contracts

Seller	Seller responsible for operating permits.	DWR pays for operating permits
Allegheny		
Alliance Colton	✓	
Calpeak*	✓	
Calpine – 1*		
Calpine – 2*		
Calpine – 3*		
Calpine – 4*		
Coral Power	✓	
Dynegy – 1		✓
Dynegy – 2		✓
El Paso		
Fresno Cogeneration	✓	
GWF Energy	✓	
High Desert*		
Morgan Stanley		
PacifiCorp		
Sempra		
Sunrise	✓	
Wellhead	✓	
Williams		✓

* These contracts have been renegotiated; see Appendix A for further details.

B. Renewable Contracts

In the process of constructing a new electricity generation facility, renewable facilities may face less uncertainty due to existing environmental regulations than non-renewable power plants. For example, wind turbines often do not need to go through the same stringent siting and environmental review process as natural gas-fired power plants. However, renewable facilities can be difficult to site, often due to local opposition. All of the DWR's renewable contracts that provide for the construction of new generating facilities allow the DWR to terminate the contract if the units do not reach commercial operation by a deadline (discussed in Section 5 on Performance Risk). The Clearwood geothermal contract, however, allows the Seller to claim force majeure if the Seller is unable to acquire the necessary environmental permits to construct the facility.

Not all renewable electricity generation facilities are required to obtain permits in order to operate; for example, wind, solar, and geothermal facilities have a minimal impact on the environment once the plants are built, and these types of facilities are not required to obtain ongoing environmental permits. Other renewable facilities have environmental impacts during operation; for example, biomass and landfill gas plants emit air pollutants, and are therefore required to obtain operational permits. Accordingly, the DWR's landfill gas contract, and two of the three biomass contracts explicitly allocate responsibility for acquiring operational environmental permits to the Seller; similar to the non-renewable contracts, the third biomass contract is presumed to allocate the responsibility by default to the Seller.[69]

7.2.2 Risk of Future Changes in Environmental Regulations

The laws and regulations that affect electricity contracts change frequently. Over the last few years, significant changes have been made to the regulations governing California's electricity system at both the state and federal levels. Further changes are being debated today. In this section, we examine how the DWR contracts allocate the risk of future changes in environmental regulations.[70] While the next section discusses regulatory risk more broadly, here we discuss regulatory changes specifically affecting environmental risk, which are perhaps among the most likely future regulatory changes and which could impose significant financial burdens on the parties to an electricity contract.

A. Non-Renewable Contracts

Seventeen of the DWR's twenty non-renewable contracts allocate some of the risk of a future change in regulations to the DWR. However, there are numerous differences in the ways the contracts allocate this risk; there does not appear to be an "industry standard" way to allocate the risk of a future change in regulations. The non-renewable contracts can be divided into two broad categories: contracts that only allocate the risk of a future change in regulation that is targeted at energy services, and contracts that allocate the risk of a future change in regulation more generally.[71]

Seven of these seventeen contracts (representing 27 % of the non-renewable energy under contract) only explicitly allocate the risk of a future change in regulation in a limited way – the allocation only applies to regulatory changes that are targeted at energy services, and most of the clauses only apply to changes implemented by the State of California. For example, the Wellhead contract states:

> [Wellhead] shall be entitled to pass through to [the DWR] any liability, loss, cost, damage and expense, including gross-up, arising out of a tax or other imposition enacted by the California state legislature after the date of this Agreement that is not of general applicability and is instead directed at the generation, sale, purchase, ownership and/or transmission of electric power, natural gas and/or other utility or energy goods and services. [DWR] shall be entitled to the benefit or reduction of or credit with respect to

[69] The Capitol Power and Soledad biomass plants require the Seller to acquire environmental permits, while the Imperial Valley contract does not address the issue explicitly. (Note that the Soledad contract was terminated 27 March 2002.)

[70] The contracts in the DWR sample may not represent the normal allocation of environmental risk in competitive contracts in the electricity industry, because the DWR is part of the government of the state of California. Since governments create environmental risks (as we have defined them), the Sellers' perceptions about DWR's ability to influence policymakers may have influenced the allocation of environmental risks in our contract sample.

[71] Appendix D outlines the allocation of environmental risk in all of the DWR contracts.

> any such tax or other imposition enacted by the California state legislature after the date of this Agreement. (Wellhead contract 2001, §9.2)

It is unclear whether the contract clauses that allocate the risk of changes in regulations targeted at energy services would apply (or were intended to apply) to new environmental regulations, or whether they were simply intended to shield the Sellers from windfall profits taxes or other such impositions arising from the political dissatisfaction with the electricity industry at the time the contracts were signed.[72] However, it is clear that the contracts that only allocate the risk of a future change in regulation that is targeted at energy services do not comprehensively allocate environmental risk.[73]

The other ten of the seventeen non-renewable contracts that allocate some of the risk of a future change in regulations to the DWR (representing 63% of the non-renewable energy under contract) allocate the risk of a *general* change in regulations, rather than only the risk of regulatory changes that are targeted at energy services. As presented in Table 20, below, these contracts can be grouped into two broad categories based on the treatment of environmental risk: contracts that allocate the cost (sometimes above a threshold) of a new regulation to the DWR, and contracts that require the parties to the contract to negotiate how to share the costs (sometimes above a threshold) of a new regulation. Some of the contracts restrict the applicability of an environmental risk clause based on the governmental authority that implements the new regulation (e.g. a federal authority versus a state authority).

[72] Sellers of electricity were clearly mindful of the possibility that the state might impose a windfall profits tax on the sale of electricity. Two bills were introduced in the Legislature in April 2001 to impose a windfall profits tax, and one bill came within one vote of passing in May (SB 1xx).

[73] The Calpeak, Calpine – 4, Coral Power, Fresno Cogeneration, PacifiCorp, Sempra, and Wellhead contracts only explicitly allocate the risk of a future change in regulation in the limited manner discussed here.

Table 20. Explicit Allocation of the Risk of Future Environmental Regulations in the DWR Non-Renewable Contracts

(Only Applicable to Regulations Imposed by the Governmental Authority in Parenthesis, if Specified)

Seller	Any cost above threshold born by the DWR	Parties will negotiate how to share costs above threshold
Allegheny	No threshold (State)	
Alliance Colton	Unclear*	
Calpeak**		
Calpine – 1**	Threshold = $5 / MWh	
Calpine – 2**	Threshold = 50¢ / MWh	
Calpine – 3**	Threshold = 50¢ / MWh	
Calpine – 4**		
Coral Power		
Dynegy – 1	No threshold	
Dynegy – 2	No threshold	
El Paso		
Fresno Cogeneration		
GWF Energy		Threshold = $2.5 M / yr; If parties do not successfully negotiate, Seller may terminate.
High Desert**		
Morgan Stanley		
PacifiCorp		
Sempra		
Sunrise		No threshold; Parties will negotiate in good faith to leave Seller whole.
Wellhead		
Williams	No threshold (State) $5 / MWh (Federal)	

Note: Blank cells are contracts that do not explicitly allocate the risk of a general future environmental regulation.
* The Alliance Colton contract states that it is standard practice for contracts to allocate environmental risk in this manner, but it is unclear if the contract itself actually does.
** These contracts have been renegotiated; see Appendix A for further details.

As shown in the first column of Table 20, eight of the DWR's twenty non-renewable contracts allocate the cost of a new regulation to the DWR. There are numerous differences among these contracts:

- The Allegheny contract passes on an increase or decrease in costs only due to actions of a state governmental authority to the DWR.
- Three of the Calpine contracts and the Williams contract pass on any cost increase (above thresholds of either $0.50 or $5.00 per MWh) due to actions by any governmental entity to

the DWR.[74] The Williams contract provides an example of this comprehensive treatment of environmental risk:

> If [Williams] can demonstrate that its cost of service for this Agreement has been increased by an aggregate amount of $5 per MWh or more since the [date the contract was executed] as a result of any governmental action or inaction *other than by* a [political subdivision or public entity of the State of California], [DWR] shall pay all such increased costs of services in excess of $5 per MWh in the aggregate for the remainder of the delivery term. (emphasis added)
>
> If [Williams] can demonstrate that its cost of service for this Agreement has been increased since the [date the contract was executed] as a result of any governmental action or inaction by a [political subdivision or public entity of the State of California], [DWR] shall pay all such increased costs of services for the remainder of the delivery term.
>
> For the purpose of the preceding two sentences, governmental action that increases the cost of service for this Agreement shall include (a) new taxes (including the imposition or increase in rate or amount thereof) or (b) the imposition of other unanticipated costs and charges caused by governmental action. (Williams contract 2001, §9.2)

The Williams contract shifts more of the burden of a regulatory change to the DWR if the change is implemented at the State level than if it is implemented by a non-State entity. This differentiation may be due to the Seller's perceptions about the DWR's ability to influence policymakers in California.

- The Dynegy contracts simply state that Dynegy "shall not suffer the effects of any costs or restrictions imposed by environmental agencies whenever incurred that are associated with providing" energy under the contracts (Dynegy contracts 2001, §4C). The contracts do not define "environmental agencies."
- The Alliance Colton contract claims that it is standard practice for Sellers to pass regulatory risk on to the purchasers of electricity contracts. The contract states:

> [Alliance Colton] represents and warrants to [DWR] that (a) it is standard business practice in jurisdictions where sellers in power sales transactions believe there to be political risk, to provide in transactions with non-government entities that future changes in taxes are generally borne by the customer in a power sales transaction; (b) no change in tax law has been included in [Alliance Colton's] Contract Price; and (c) if the taxes that would be paid by [Alliance Colton], other than income taxes, are reduced, then [Alliance Colton] shall pass all of such tax reduction on to [DWR]. (Alliance Colton contract 2001, §10.2 (xiii))

However, it is unclear whether this contract actually allocates the risk of a tax increase to the DWR.

Two of the DWR's non-renewable contracts provide that the parties to the contract will negotiate how to share the costs of a new regulation rather than specifying how the costs will be shared in the contract; both of these contracts allocate the risk of a new regulation in large part to the DWR. The GWF Energy contract provides that if regulatory changes increase the Seller's costs by more than $2.5 million in any year (or approximately $1.00 per MWh) after August 31, 2003, then the Seller can propose to adjust the contract price; if the two parties cannot agree on an adjustment to the contract price, then the Seller can terminate the contract. The Sunrise contract also requires the parties to negotiate how to share the costs of a new regulation. The Sunrise

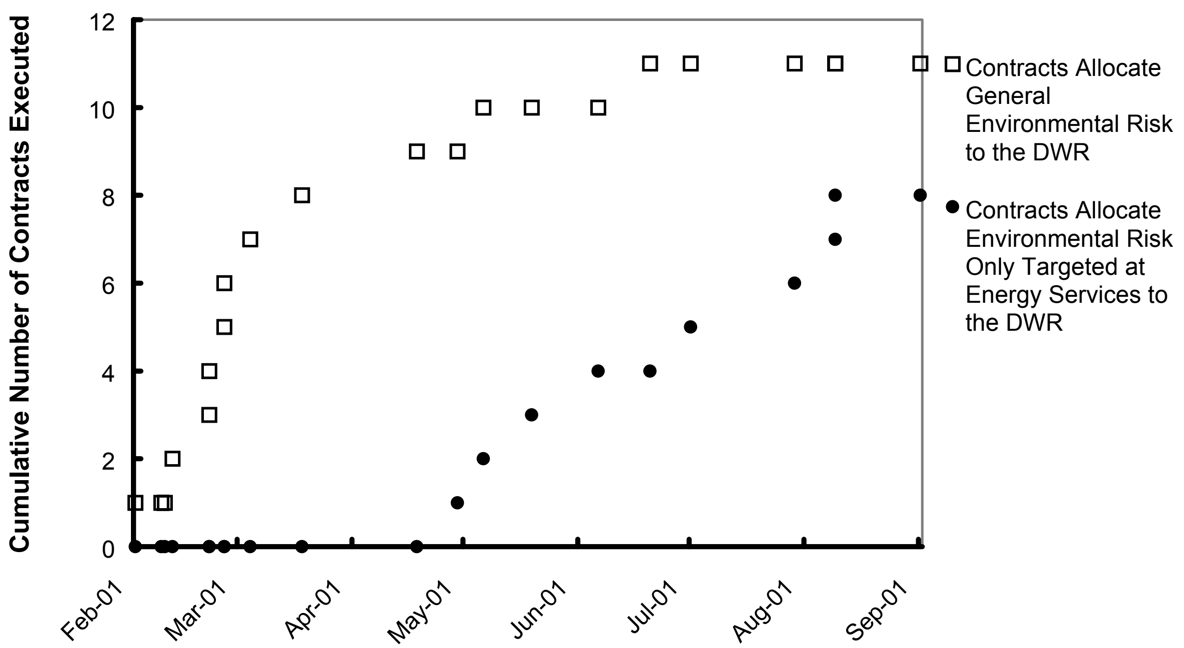
[74] These three Calpine contracts have been renegotiated (see Appendix A). In the renegotiated contracts, the DWR only bears the risk of a new regulation targeted at energy goods and services implemented by the California Legislature.

contract's environmental risk clause is only applicable to new state regulations, and it fully allocates the risk of a new state regulation to the DWR:

> In the event that a change in California Law subsequent to the date of this Agreement has the effect of imposing additional costs on [Sunrise] beyond those that would have been imposed prior to such change in California Law, the [DWR] and [Sunrise] shall in good faith negotiate and make changes to this Agreement and/or the payments contemplated hereunder that will have the effect of leaving [Sunrise] no worse off than if the change in California Law had not occurred. (Sunrise contract 2001, §13.04)

It appears that the difference between which contracts allocate only the risk of a future change in regulation that is targeted at energy services compared to which contracts allocate environmental risk more generally can be explained in part by the date the contract was executed (see Figure 4, below). The contracts that allocate the risk of any general change in regulations to the DWR were mostly signed by May of 2001, while the contracts that are less favorable to the Seller and only allocate the risk of regulatory changes targeted at energy services to the DWR were signed primarily after May. Hence, the allocation of environmental regulatory risk in the DWR contract sample may be explained in part by the relative strength of the DWR's bargaining position over time.[75]

Figure 4. Allocation of Environmental Risk in the DWR Non-Renewable Contracts by Date of Contract Execution

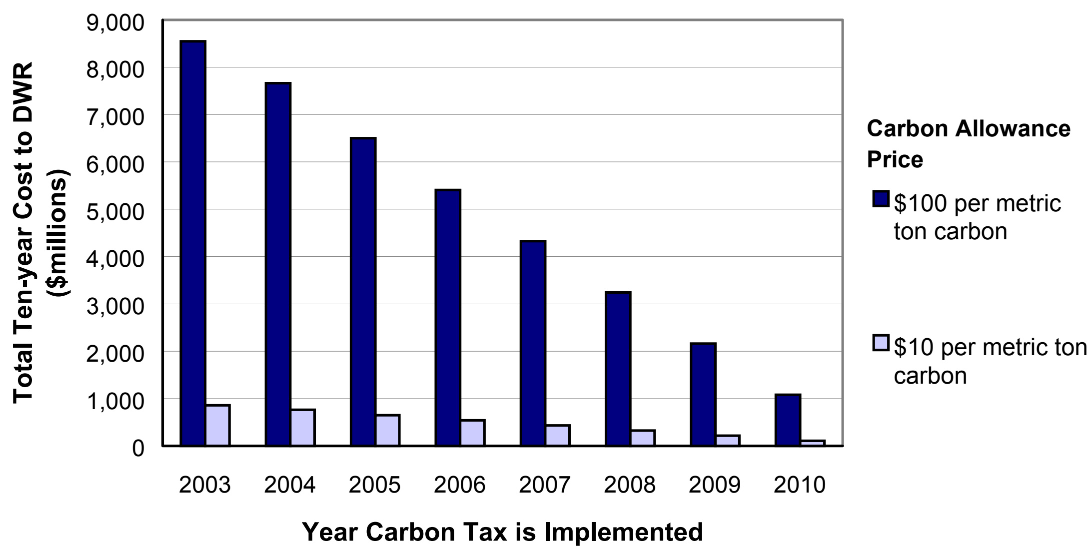


[75] Upon renegotiation, the Calpine – 1, Calpine – 2, and Calpine – 3 contracts were changed from allocating the risk of any general change in regulations to the DWR to only allocating regulatory changes targeted at energy services to the DWR, perhaps reflecting the DWR's strengthened bargaining position during renegotiations relative to when the Calpine contracts were originally signed.

In the non-renewable contracts that do not explicitly allocate the risk of a general change in regulations, it is implicitly allocated based on the point of delivery of the power (i.e. the transmission system in the relevant ISO congestion zone); all costs up to the delivery point are born by the Seller, and all costs after the delivery point are born by the DWR (California State Auditor 2001). Thus, as discussed above, the details of the implementation of a new regulation could have a large effect on which party bears the cost. Of course, if a contract does not explicitly allocate the risk of a new regulation, and one is enacted, it is likely that the parties will litigate the matter.[76] Finally, as with fuel price risk, even if the Seller clearly bears the environmental risk in a contract, the DWR may still bear some "residual" environmental risk (i.e. bankruptcy risk) if the Seller is excessively exposed to the risk.

Based on the preceding discussion, it is clear that the DWR could be exposed to significant financial costs if new environmental regulations – such as regulations of carbon dioxide, nitrogen oxides, sulfur dioxide, and mercury emissions – are implemented. For example, as illustrated in Figure 5, if the DWR is assumed to bear the cost of a carbon tax for *all* of its non-renewable contracts, a carbon allowance price of $10 per metric ton would result in additional costs for the DWR ranging from $855 million (0.15 cents per kWh) if the tax were implemented in 2003 to $108 million (0.02 cents per kWh) if the tax were implemented in 2010.[77] Similarly, with a carbon allowance price of $100 per metric ton the DWR's exposure could range from $8.5 billion (1.5 cents per kWh) if the tax were implemented in 2003 to $1 billion (0.2 cents per kWh) if the tax were implemented in 2010.

Figure 5. DWR's Potential Exposure to Carbon Emission Regulations (for all Non-Renewable Contracts)

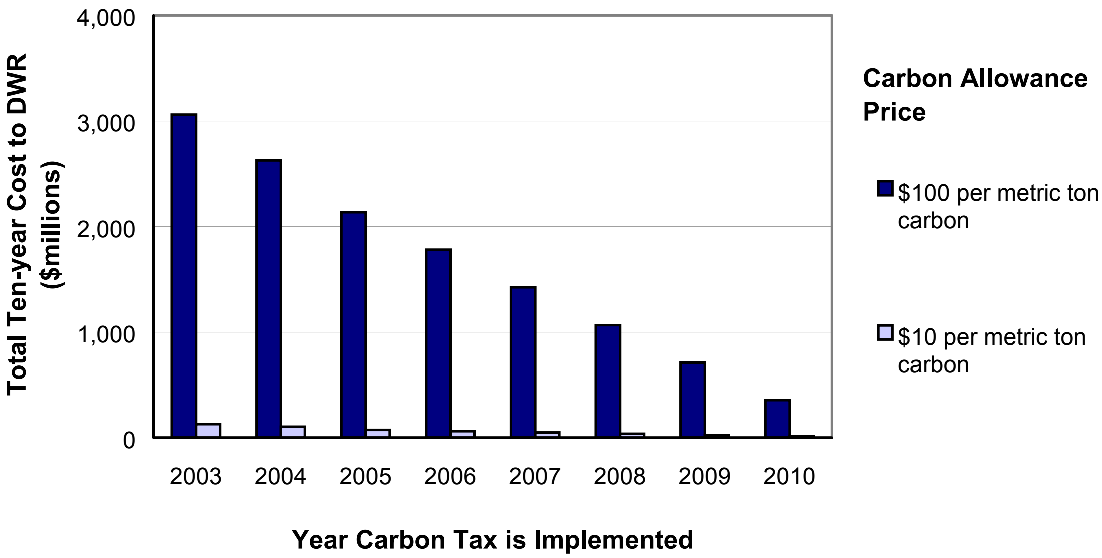


[76] A party might try to claim force majeure to avoid the cost of a burdensome new regulation, however force majeure clauses generally exclude economic considerations and would probably only apply to a new regulation that prevents a power plant from operating.

[77] Carbon emissions are calculated for all of the non-renewable contracts assuming an average emission rate for natural gas generation of 160.79 metric tons of carbon per GWh (DOE and EPA 2000). For various estimates of carbon allowance prices, see EIA (2001a and 2001b), Weyant (2000), and Interlaboratory Working Group (2000).

If the DWR is assumed to bear the cost of a carbon tax only for the non-renewable contracts that *explicitly* allocate the risk to the DWR (see Figure 6),[78] the DWR's cost exposure could range from $128 million to $12 million (0.05 to 0.005 cents per kWh) if a $10 per metric ton carbon allowance price were implemented in 2003 and 2010, respectively, and $3.1 billion to $356 million (1.2 to 0.14 cents per kWh) if a $100 per metric ton carbon allowance price were implemented in 2003 and 2010, respectively. If the Sellers of the non-renewable contracts that do not explicitly allocate the risk to the DWR are unable to bear the new cost of a carbon tax, the DWR might also be faced with numerous contract defaults.

Figure 6. DWR's Potential Exposure to Carbon Emission Regulations (Only for Non-Renewable Contracts that Explicitly Allocate the Risk to the DWR)



Although more stringent national regulation of sulfur dioxide, nitrogen oxides, and mercury emissions from power plants is likely, a 'back-of-the-envelope' calculation suggests that it may not expose the DWR to significant costs. Using a scenario developed by the U.S. Energy Information Administration (EIA) of federal legislation to decrease emissions of the three pollutants from power plants by 75% by 2012 (EIA 2001b), the potential cost to the DWR from all non-renewable contracts is approximately $100 million (or 0.02 cents per kWh) through 2010.[79] However, it is unclear how additional regulation of nitrogen oxides would affect current programs in California, which already have emission allowance prices that can be higher than the EIA predicts in its scenario.

[78] Since a carbon tax would most likely be implemented by a federal governmental authority, only the Calpine – 1, Calpine – 2, Calpine – 3, Dynegy – 1, Dynegy – 2, GWF Energy, and Williams contracts allocate the risk to the DWR. (Some of these contracts require both parties to share the cost.) If a carbon tax were considered to be 'targeted at energy services' then Calpeak, Coral Power, and Pacificorp contracts would allow the Sellers to terminate the contracts.

[79] Sulfur dioxide and mercury emissions are not a large concern from natural gas-fired power plants. We assumed emission rates of 0.45 lbs of nitrogen oxides per MWh for existing power plants, 0.31 lbs per MWh for new simple cycle plants, and 0.06 lbs per MWh for new combined cycle plants (CEC 2001). We linearly extrapolated EIA's nitrogen oxides emission allowance price for each year through 2010.

B. Renewable Contracts

Only one of the DWR's seven contracts for renewable energy explicitly allocates the risk of a future change in regulations. (The Soledad biomass contract allocates the risk of any state-implemented change in regulation to the DWR.[80]) Since generating electricity from renewable resources considerably mitigates environmental risk, the parties to the DWR contracts may not have considered future environmental risk to be a significant enough concern to warrant allocation in the contracts.

However, if future environmental regulations are enacted, the question of which party to a renewable electricity contract receives the benefits of the renewable plant's environmental performance may arise. For example, if a renewable portfolio standard (RPS) were adopted – requiring all providers of electricity to provide a minimum percentage of renewable electricity – which party would receive credit for the "renewable-ness" of the DWR contracts? This question is usually answered by creating two commodities from the generation of electricity from renewable resources: the electricity itself, and the "renewable credits" associated with the electricity. The electricity commodity is considered to be equivalent to electricity generated from any other source, while the renewable credit contains the value of having generated the electricity from renewable sources rather than non-renewable sources.

Generators of renewable electricity can unbundle the electricity and renewable credit commodities and sell them separately. If the purchaser of electricity from a renewable power plant does not take ownership of the renewable credits, then the purchaser cannot claim to be buying renewable energy; the renewable credits can be sold to a third party who is then considered to be the purchaser of the renewable energy (even if they are not receiving physical delivery of electricity from the renewable facility).

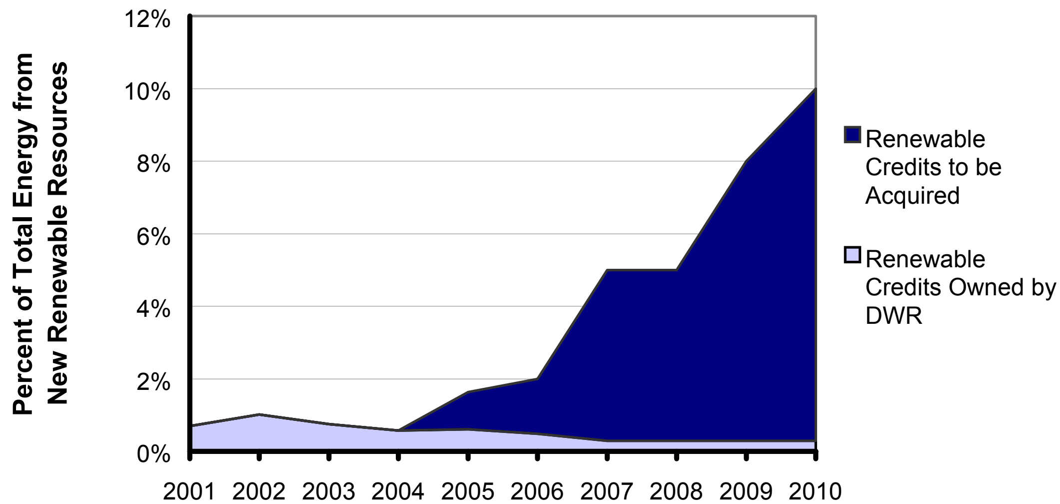
Only two of the DWR's renewable contracts explicitly allocate the renewable credits created by the generation of electricity under the contract; in the two wind contracts, the Sellers retain all rights to "the renewable attributes, emission reductions or credits (offsets) relating to the project" (PG&E Energy Trading 2001). PG&E National Energy Group has announced plans to market the renewable credits that are created from the wind energy it sells to the DWR, clearly illustrating that the DWR will not be able to benefit from the renewable nature of its contract with PG&E unless it acquires the renewable credits (Green Power Network 2001). It is likely that by default the DWR would receive the renewable credits in the contracts that do not explicitly allocate them, however the issue might be subject to litigation if the renewable credits gain significant value due to a new environmental regulation.

Although the DWR signed a total of seven contracts with producers of renewable energy, since the DWR does not own the renewable credits in the two wind contracts (which provide the majority of the renewable electricity under contract), the DWR can only purport to have five contracts for renewable electricity, supplying 0.5% of the total energy under contract in the coming decade. If a RPS is implemented either in California or nationally, it is likely that the DWR (or the three investor-owned utilities in California) would need to acquire significant amounts of additional renewable electricity or renewable credits to satisfy the RPS requirement.

[80] The Soledad contract was terminated on 27 March 2002.

For example, if the RPS currently being debated in the California Legislature as part of Senate Bill 532 (SB 532) were implemented, the DWR would need to acquire additional renewable credits (see Figure 7) and could be liable for $150 million to $300 million in additional costs through 2010.[81] (The investor-owned utilities could be responsible for meeting the RPS requirement instead of the DWR, but either way the ratepayers would most likely have to bear the additional cost.[82]) In this SB 532 scenario, the DWR would have forfeited $40 to $80 million because the Sellers of the two wind contracts retained their renewable credits, and would have gained $21 to $42 million in value from the other renewable contracts.

Figure 7. Renewable Credits Required by the DWR in a Renewable Portfolio Standard Scenario
(SB 532 scenario, with banking)



7.1 Summary of Environmental Risk

Non-renewable and renewable electricity contracts have very different environmental risk profiles by nature of the technologies and fuel sources used to generate the electricity. If new environmental regulations are enacted, parties to non-renewable contracts will most likely have to bear additional costs, while parties to renewable contracts may realize financial benefits.

[81] SB 532 would require retail electricity providers to sell a minimum percentage of electricity from new renewable generation facilities (SB 532 amended 4 Sept. 2001). The requirement would increase from 1% of electricity to be supplied from new renewable facilities in 2003 to 10% in 2010. The Imperial Valley contract would not qualify as a new renewable resource. SB 532 allows retailers to bank renewable credits, and caps the renewable credit price at 1.5 ¢ per kWh. We use the State Auditor's model of the DWR contracts and assume a renewable credit price of 0.75 to 1.5 ¢ per kWh to calculate the DWR's potential cost exposures.

[82] It is possible that an increase in renewable electricity generation could reduce natural gas consumption and thereby reduce natural gas prices, and provide a net economic benefit to ratepayers (Nogee 1999).

Given the potential financial impact of a new environmental regulation, it is perhaps surprising that relatively few of the DWR contracts explicitly address environmental risk in a comprehensive way. This lack of attention to environmental risk in many of the non-renewable contracts can be attributed to either a lack of concern about the cost of future environmental regulations or a lack of awareness of their potential cost. The DWR contracts demonstrate that environmental risk is a risk that many participants in the electricity industry take seriously, but that there is no "industry standard" way to allocate environmental risk. Future environmental regulations may result in costly legal battles in the DWR contracts that do not explicitly allocate environmental risk.

As a whole, the DWR is significantly exposed to environmental risk in its long-term electricity contracts. Not only do most of the non-renewable contracts that explicitly address environmental risk allocate it to the DWR, but the DWR also did not acquire the environmental *benefit* of purchasing renewable energy in either of the wind contracts (which provide the majority of the DWR's renewable energy).[83]

[83] Since the DWR is a state agency, its exposure to environmental risk calls into question the influence it may have on the creation of new environmental regulations in California. For example, will the California Legislature be more reluctant to create a renewable portfolio standard that would highlight the fact that the DWR procured only a small amount of renewable energy? Although this is an interesting and important issue in California, in general, the parties to electricity contracts are not as closely associated with the policymakers creating new environmental regulations.

8. Regulatory Risk in Electricity Contracts

California's electricity industry is regulated by agencies at both the state and federal levels. Over the past decade, California's electricity industry has been subject to a great deal of regulatory uncertainty – from the roots of the movement to restructure the electricity industry, to the crisis of 2000 and 2001, to the industry's current state of limbo. Both renewable and non-renewable contracts face similar regulatory uncertainties.

Given California's particularly tumultuous recent history, the contracts in the DWR sample may not represent the standard allocation of regulatory risk in competitive contracts in the electricity industry. The parties selling electricity to the DWR were clearly aware that they faced a substantial amount of regulatory risk for at least three reasons: (i) the contracts were signed at the height of California's crisis, (ii) the contract prices are relatively high, and (iii) the DWR is a government agency and therefore might be able to influence regulatory decisions more than a "regular" counterparty to an electricity contract would be able to.

8.1 Regulatory Risk Fundamentals

We define regulatory risk as the possibility that future laws and regulations will alter the benefits or burdens of an electricity contract. Excessive regulatory risk can have dire consequences on an electricity market. For example, many have blamed the tight supply - demand conditions that existed in California's electricity market during the crisis on the utilities' decisions not to build significant amounts of new generation capacity during the 1990s because the utilities faced excessive regulatory uncertainty.

Regulatory risk can be divided into two broad categories: (i) the possibility of changes in general regulations or laws that would affect an electricity contract, for example, a nationwide carbon tax, and (ii) regulatory requirements targeted at a specific contract, for example, a FERC ruling to modify the contract price of a given contract. The first category of broad regulatory changes that would affect – but not be targeted at – electricity contracts is discussed in Section 7 on Environmental Risk, because changes in environmental regulations are among the most likely future regulatory changes, and are potentially among the most costly for the parties to an electricity contract. In this section we discuss only the second category of regulatory risk: regulatory requirements targeted at specific contracts.

Parties to an electricity contract can take two approaches to manage regulatory risk. First, contracts can try to prevent regulatory action. Regulatory agencies have both rule-making authority to create new regulations, and adjudicatory authority to rule on existing regulations and electricity contracts. Electricity contracts can contain clauses to try to prevent regulatory agencies from exercising this latter, adjudicatory, role. Second, if a regulatory authority requires a change in a contract, the contract can try to mitigate and allocate the consequences of the regulatory requirement.

Two regulatory authorities regulate California's electricity industry: the Federal Energy Regulatory Commission (FERC) at the federal level, and the California Public Utilities Commission (CPUC) at the state level. The FERC has regulatory jurisdiction over the wholesale electricity market in California and the contracts signed by the DWR. The FERC is required by Section 206 of the Federal Power Act (FPA) to ensure that wholesale rates are "just and reasonable" (16 U.S.C. 824e); FERC has the authority to change contract prices or terms it determines to be unjust or unreasonable, and to abrogate contracts entirely. The California Public Utilities Commission has regulatory authority over retail electricity rates and the investor-owned utilities in California; at the time the DWR contracts were signed, it was unclear what regulatory oversight the CPUC would have over the DWR's contracts.

8.2 Regulatory Risk in the DWR Contract Sample

Regulatory challenges to the DWR contracts have already begun. Both the CPUC and the Electricity Oversight Board have filed complaints with the FERC, asking the agency to modify or abrogate the DWR contracts (CPUC 2002; EOB 2002), and FERC has agreed to hear the complaints (FERC 2002).[84] About half of the DWR's non-renewable (i.e. primarily natural gas) contracts prevent the parties to the contract from seeking changes in the contract from a regulatory authority. Almost all of the non-renewable contracts designate a course of action that the parties will take if a regulatory agency orders a change in the contract. In contrast, none of the renewable contracts attempt to prevent regulatory review of the contracts, and only two of the renewable contracts designate a course of action that will be taken if a regulatory agency orders a change in the contract.

A. Non-Renewable Contracts

Undoubtedly, the best way parties to an electricity contract can mitigate regulatory risk is to ensure that the contract price and terms are just and reasonable. This may not have been the primary strategy used by some of the Sellers of the DWR contracts, as demonstrated by the extremely high prices in some of the non-renewable contracts. Instead, the contracts' terms try to prevent regulatory review of the contracts and to mitigate and allocate the consequences of a regulatory requirement.

The DWR's non-renewable contracts use two strategies to attempt to prevent regulatory review of the contracts. Thirteen of the twenty non-renewable contracts explicitly prevent the parties to the contract from seeking a change in the contract from a regulatory authority (see Table 21, below), and eleven of the twenty non-renewable contracts state that the parties to the contract agree that the contract is "just and reasonable."

[84] The CPUC dropped its complaint with regards to the Sellers that have renegotiated contracts with the DWR (see Appendix A).

Table 21. Contract Clauses to Prevent Regulatory Review in the DWR Non-Renewable Contracts

Seller	Party prevented from seeking change in contract from a regulatory authority (given in parentheses, if specified in contract)	Contract states that the price is just and reasonable (for purposes of regulatory authority in parentheses, if specified in contract)
Allegheny	Both parties	✓ (FERC)
Alliance Colton		
Calpeak*	Both parties (FERC)	✓ (FERC)
Calpine – 1*	Both parties (FERC)	✓ (FERC)
Calpine – 2*	Both parties (FERC)	✓ (FERC)
Calpine – 3*	Both parties (FERC)	✓ (FERC)
Calpine – 4*	Both parties (FERC)	✓ (FERC)
Coral Power	Both parties (FERC)	
Dynegy – 1	DWR (CPUC)	✓ (CPUC)
Dynegy – 2	DWR (CPUC)	✓ (CPUC)
El Paso		
Fresno Cogeneration	Both parties	
GWF Energy	Both parties	
High Desert*		
Morgan Stanley		
PacifiCorp		✓ (CPUC)
Sempra		✓ (FERC)
Sunrise		
Wellhead	Both parties	
Williams	Both parties (FERC)	✓

* These contracts have been renegotiated; see Appendix A for further details.

All but three of the non-renewable contracts specify a course of action for the parties to take if a regulatory authority orders a change in the contract; many contracts specify different courses of action depending on who instigated the regulatory change (e.g. one of the parties to the contract, the State of California, etc.). Most of the DWR's non-renewable contracts try to mitigate the effect of a regulatory authority's requirement to modify the contract, and some contracts allocate this regulatory risk by shifting the burden to one party or the other.

Eight of the twenty non-renewable contracts try to mitigate the effect of a change in the contract required by a regulatory authority by stipulating that the contract price will not change, even if the regulatory authority orders that it change (see Table 22, below).[85] Thirteen of the twenty non-renewable contracts stipulate that, in the face of a required regulatory change to the contract, the parties will use their best efforts to reform the agreement in order to give effect to the original

[85] The CPUC's Section 206 complaint to the FERC challenges the notion that a contract can circumvent a regulatory order by requiring the contract price to stay the same regardless of regulatory action (CPUC 2002).

intention of the parties; this clause is contained in the EEI contract template.

Five of the DWR's non-renewable contracts allocate the risk of a required change in the contract by shifting the burden primarily to one party (see Table 22, below). The two most extreme contracts stipulate that the DWR will default on the contract (requiring a large upfront termination payment to the Seller)[86] if an agency of the State of California, in one case, or the California Legislature, in another case, instigates a regulatory review of the contract that results in a requirement to change the contract.

Table 22. Courses of Action to be Taken by Parties to a Contract if a Regulatory Authority Orders a Change in the Contract

(Only Applies to Regulatory Review Instigated by Party in Parentheses, if Specified)

Seller	Contract price will not change	Parties use best efforts to reform agreement to give effect to original intention of parties.	DWR defaults	Seller can terminate (with no termination payment)	Adversely affected party may terminate or re-negotiate contract
Allegheny	✓ (either party)	✓			✓
Alliance Colton		✓			
Calpeak*	✓				
Calpine – 1*	✓ (State of CA)	✓			
Calpine – 2*	✓	✓			
Calpine – 3*					
Calpine – 4*	✓	✓			
Coral Power		✓	✓ (CA Legislature)	✓ (non-State)	
Dynegy – 1		✓			
Dynegy – 2		✓			
El Paso		✓			
Fresno Cogeneration					
GWF Energy	✓ (State of CA)			✓ (non-State)	
High Desert*	✓ (CA Legislature)	✓			
Morgan Stanley		✓			
PacifiCorp			✓ (State of CA)	✓ (non-State)	
Sempra					✓
Sunrise		✓			
Wellhead					
Williams	✓ (State of CA)	✓			

* These contracts have been renegotiated; see Appendix A for further details.

[86] The termination payment is equal to the difference between the present value of the remaining term of the existing contract and a replacement contract.

B. Renewable Contracts

Almost none of the DWR's renewable contracts contain clauses related to regulatory risk. However, renewable contracts are certainly not immune to regulatory risk. For example, in the mid-1990's, FERC excused the three California investor-owned utilities from entering into contracts for approximately 1,400 MW of power from renewable and cogeneration facilities that were required by California's Biennial Resource Planning process (FERC 1995).

None of the renewable contracts seek to prevent regulatory review of the contracts, and only two renewable contracts outline a course of action if a regulatory authority requires a change in the contract. The two wind contracts contain the regulatory risk clause from the EEI template, which requires the parties to use their best effort to reform the agreement to give effect to the original intention of the parties if a regulatory authority has ordered a change in the contract. The renewable contracts' lack of attention to regulatory risk can be attributed to either a lack of awareness about the potential risk, or else confidence in the "just and reasonable" nature of the contract terms.

8.3 Summary of Regulatory Risk

A contract legally binds two parties to an agreement and provides certainty about the future. Thus, it is expected that parties to an agreement will try to minimize the ability of outside parties to change the terms of the contract. In the electricity industry, regulatory agencies have some authority to change the terms of an electricity contract.

The DWR's non-renewable contracts contain many provisions to try to decrease exposure to regulatory risk by both seeking to prevent regulatory review of a contract, and by specifying a course of action if a regulatory agency requires a change in a contract. In contrast, very few of the DWR's renewable contracts contain provisions related to regulatory risk. The treatment of regulatory risk in the DWR contract sample, however, may not represent the standard management of regulatory risk in competitive contracts in the electricity industry; the parties selling electricity – especially high-priced non-renewable electricity – to the DWR were clearly aware that they faced an unusually sizeable amount of regulatory risk.

The strength of the various clauses the DWR contracts use to address regulatory risk may soon be tested if the FERC rules on requests made by the CPUC and the EOB to either change the terms of the DWR contracts or to abrogate them completely.

9. Conclusions

Natural gas-fired electricity generation technologies and renewable electricity generation technologies have inherently different risk profiles; the allocation of these risks in electricity contracts results in substantially different risk burdens for each party to a contract. Of the risks analyzed in this paper, renewables can provide the most value relative to natural gas by mitigating fuel price risk and environmental risk, while natural gas technologies can provide value by reducing demand risk. Renewables and natural gas face different challenges with regards to fuel supply risk. Natural gas-fired power plants are more vulnerable to systematic interruptions in natural gas supply (affecting many plants simultaneously), while renewable generation facilities are more vulnerable to unsystematic day-to-day variability in fuel supply; prioritizing the relative importance of these systematic and unsystematic risks is subjective and will depend on the overall portfolio of fuel supplies that is used to generate electricity. Neither natural gas nor renewables has a clear advantage with regards to regulatory risk or performance risk.

The DWR's long-term electricity contracts, upon which we base our analysis of the treatment of risk in electricity contracts, will largely define California's electricity system over the coming decade. The DWR contracts provide for the construction of a significant capacity of new natural gas-fired power plants, which will increase California's reliance on natural gas, and may have important implications for the vulnerability of California's economy to natural gas price volatility and possible systematic interruptions in natural gas supply. In addition, the State Auditor expressed concern that the DWR's contract portfolio includes excessive non-dispatchable contracts and insufficient dispatchable contracts; consequently, any further electricity contracting efforts in California in the near future (by the DWR or by other parties) may focus on dispatchable contracts, which would likely result in a further increase in California's reliance on natural gas and would hinder further development of renewable generation facilities. Some of the contracts that the DWR recently renegotiated address the Auditor's concerns regarding dispatchability by increasing the DWR's dispatch flexibility in contracts that were previously non-dispatchable.

Our analysis of the allocation of risks in the DWR contracts also illuminates the risks that the DWR – and thereby the ratepayers of California's three utilities or California taxpayers – will bear over the next decade. The DWR bears fuel price risk for about 40% of the electricity under contract, and the DWR bears most of the fuel supply risk in the contracts. The contracts contain numerous penalties and incentives to try to reduce performance risk, and although the parties share performance risk, a substantial amount is allocated to the Sellers because many elements of performance risk are within the Sellers' control. Demand risk is primarily allocated to the DWR, however the dispatchable natural gas contracts reduce the DWR's demand risk. Environmental risk is not uniformly addressed in the contracts, however the contracts that do explicitly allocate environmental risk predominantly allocate it to the DWR. Finally, the DWR and the Sellers generally share regulatory risk, although a few contracts allocate the risk to the DWR. As we have shown in Sections 4 and 7, the DWR could be exposed to billions of dollars in additional costs due to its exposure to fuel price risk and environmental risk.

As we have noted throughout this paper, certain aspects of the DWR contract sample may not be representative of competitively bid long-term electricity contracts. The DWR recently renegotiated several contracts and primarily strengthened terms and conditions related to performance risk, in addition to shortening contract lengths and reducing contract prices (see Appendix A). This finding increases our confidence that the DWR contracts' treatment of the risks that are most relevant to our comparison of natural gas-fired and renewable electricity contracts (that is, fuel price and supply risk, demand risk, and environmental risk) may not have been influenced as strongly by the particular circumstances of the crisis period in which the contracts were executed, and can thereby provide insight into the risk allocation and mitigation practices common in the electricity industry.

It is not clear whether utilities and other parties that procure electricity objectively analyze the trade-offs between the various risks we have discussed. Utilities appear to place a particular emphasis on demand risk, which favors investment in natural gas generation technologies, and less emphasis on fuel price risk and environmental risk, which might favor renewable technologies. As we discussed in Section 6, only a portion of a portfolio of electricity supplies must be dispatchable in order to reduce demand risk, so there are significant opportunities for investments in natural gas and renewables to complement each other within a portfolio of electricity supplies. A better understanding of the risks associated with the use of renewable and non-renewable electricity in the electricity industry may help utilities (and others that procure power) make more objective investment decisions in the future.

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11. Glossary

Allocate The allocation of a risk determines who will bear the consequences of an uncertain future event.

As-available As-available contracts allow the power plant to sell electricity whenever it is able to generate.

Availability Availability is generally used in dispatchable contracts to mean the number of hours that the generation unit was available to generate power during a period, divided by the total possible number of hours the unit could have been dispatched during the period as specified in the contract (adjusted for force majeure events and scheduled outages).

Baseload Baseload contracts (7x24) can supply power all day every day.

Capacity charge The amount a Seller of a dispatchable contract is paid to be available to generate electricity (separate from a fuel or energy charge for the electricity that is actually generated).

Commercial operation deadline The deadline for a Seller to complete construction of a power plant, after which penalties may be assessed.

Cover damages If a Seller fails to deliver scheduled energy and the failure is unexcused, then the Seller pays for the DWR's incremental cost of replacement energy; if the DWR fails to receive scheduled energy, then the DWR pays the Seller the difference between the contract price and the amount the Seller was able to sell the energy for. (What events qualify as excused outages depends on the firmness of the contract.)

Default Contracts define under what conditions a party has defaulted on the contract; these conditions usually include failure to perform any material obligation in the contract or entering into bankruptcy. When a party defaults on a contract, the contract is terminated and the defaulting party must pay the non-defaulting party a termination payment.

Demand risk The risk that the electricity that has been contracted for will not be needed as anticipated.

Dispatchable Dispatchable contracts allow the DWR to choose the amount of electricity to be generated, within limits set in the contract.

Environmental risk The financial risk to which parties to an electricity contract are exposed, stemming from both existing environmental regulations and possible future regulations.

Excused outage During an excused outage, the Seller is not required to deliver scheduled electricity and is not penalized for failing to deliver.

Firm Firm electricity contracts generally only excuse the Seller from delivering scheduled electricity during events of force majeure.

Firm gas contracts Firm natural gas contracts provide continuous service, whereas interruptible gas contracts allow the distributing company to curtail service under certain circumstances, as specified in the contract.

Firmness The firmness of an electricity contract determines what events qualify as excused outages. In the DWR contract sample, all contracts are either firm or unit-contingent.

Fixed-price In a fixed-price contract, the price per MWh of electricity is set in the contract. In some contracts the price is fixed throughout the term of the contract, and in other contracts the price varies according to a fixed schedule.

Force majeure An event of force majeure is defined in the EEI contract template as a circumstance that prevents a party from performing its obligations, that is not within the reasonable control of (or the result of negligence of) the party, and which the party cannot overcome by the exercise of due diligence. Force majeure is commonly used in legal contracts to absolve parties of responsibility during catastrophes, however, some contracts expand on the definition of force majeure. During an event of force majeure, the Seller is excused from delivering power.

Forced outage A forced outage is defined in the NERC Generating Unit Availability Data System (GADS) Forced Outage reporting guidelines as an outage resulting from an immediate mechanical, electrical, or hydraulic control system trip or an operator-initiated trip in response to an alarm.

Fuel price risk The risk that the price of the fuel used to generate electricity will exhibit variability (positive or negative), resulting in an uncertain cost to generate electricity.

Fuel supply risk The risk that the fuel supply to a power plant will be unreliable, resulting in the inability to generate electricity in a predictable and dependable manner.

Heat rate A measure of how efficiently a power plant generates electricity. (Usually measured in Btu per kWh.)

Imbalance charge Penalties assessed by the California ISO on electricity suppliers who deliver less electricity than they had scheduled.

Intermittent Some electricity generation technologies can only generate electricity intermittently, when the fuel resource is available (e.g. wind and solar).

Interruptible gas contracts Interruptible natural gas contracts allow the distributing company to curtail service under certain circumstances, as specified in the contract, whereas firm contracts provide continuous service.

Long-term contract We define long-term contracts to be three years in length and longer.

Mitigate Risk mitigation reduces the uncertainty associated with a future event, or reduces the potential impact of the event.

Must-take Electricity that is sold in non-dispatchable contracts, in which the DWR must take and pay for the electricity specified in the contract whether or not it is actually needed.

Net short The "net short" in California is the difference between the electricity demanded by the utility customers, and the electricity supplied by utility-owned generation and qualifying facilities under contract with the utilities.

Non-dispatchable Non-dispatchable contracts (also known as "must-take" or "take-or-pay") require the DWR to pay for, and the Seller to provide, all the electricity scheduled in the contract.

Non-renewable In this paper, non-renewable contracts include contracts for electricity generated from natural gas and contracts that do not specify what resources will be used to generate the electricity under contract (but that will most likely use predominantly non-renewable resources). The non-renewable contracts analyzed in this paper are fueled primarily by natural gas.

O&M charge The amount a Seller of a dispatchable contract is paid for the operations and maintenance associated with generating electricity.

Partially dispatchable Partially dispatchable contracts require the DWR to take a minimum amount of electricity and allow the DWR to dispatch the generation facility in limited ways.

Peak Peak products (6x16) generally can supply power from 6 am to 10 pm, Monday through Saturday.

Performance risk The risk that either party to an electricity contract will not fulfill its part of the agreement in an optimal manner.

Regulatory risk The risk that future laws or regulations, or regulatory review of a contract, will alter the benefits or burdens of an electricity contract to either party.

Renewable credit Renewable credits contain the value of having generated electricity from renewable sources rather than non-renewable sources. Renewable credits can be traded separately from electricity.

Renewable portfolio standard (RPS) A policy that requires providers of electricity to sell a minimum percentage of electricity generated from renewable resources.

"Residual" fuel price risk The risk of a Seller's bankruptcy that the DWR still bears due to fuel price risk in fixed-price natural gas-generated electricity contracts.

Risk The possibility that future events or outcomes will be uncertain.

Summer super peak Summer super peak products (5x8) generally can supply power for 8 hours per day, 5 days a week, from June through October.

Systematic A systematic risk is a risk that affects all members of a group simultaneously; the risk that an individual member of the group faces is correlated with the risk faced by the other members of the group.

Take-or-pay See Must-take.

Termination payment In an event of default, the defaulting party pays a termination payment to the non-defaulting party. The termination payment is equal to the difference between the present value of the existing contract and a replacement contract.

Tolling In a tolling agreement, the DWR pays for the cost of natural gas, pays the generator a fee to reserve the use of the generation facility, and pays operating charges when the facility generates power.

Unit A single generation unit or power plant. Contracts often provide electricity from a group of generating units.

Unit-contingent Unit-contingent electricity contracts generally excuse the Seller from delivering power when the Seller's generating facilities are unavailable either due to a forced outage, or to an event that was not anticipated as of the date the contract was executed, and that is not within the reasonable control of (or due to the negligence of) the Seller. Unit-contingent contracts also excuse the Seller's performance during an event of force majeure.

Un-systematic An unsystematic risk affects an individual member of a group and is uncorrelated with the risk that the same event or outcome will affect other individuals.

12. Appendices

Appendix A. DWR's Renegotiated Contracts

By the middle of May 2002, the DWR had renegotiated eight (six non-renewable and two renewable) of the twenty-seven long-term electricity contracts analyzed in this paper, and terminated the Soledad biomass contract. The CPUC agreed to drop its complaint at FERC with regards to the Sellers that renegotiated with the DWR. Highlights of the changes in the renegotiated contracts are provided below. These highlights are drawn primarily from information provided by the DWR and the Governor's office, rather than a detailed review of the renegotiated contracts (Governor Davis 2002; DWR 2002b).

Calpeak
- Shortens contract term from 10 to 9 years.
- Reduces capacity charge.
- Terminates one of the contract's seven peaker units, relocates another peaker to a Northern California location free from transmission constraints and extends its commercial operation deadline.
- Enhances dispatch flexibility for the DWR.
- Strengthens performance guarantees, termination and power plant inspection rights.

Calpine – 1
- Shortens contract term from 10 to 8 years.
- Allows DWR to acquire additional dispatchable (and tolling) power during 2002 and 2003.
- Requires Seller to pay cover damages for unexcused failures to deliver power.
- Restricts Seller's ability to provide replacement energy from the ISO imbalance energy market.
- Reduces DWR's environmental and regulatory risk by only requiring the DWR to bear the risk of a tax or other imposition enacted by the California Legislature that is targeted at energy goods and services.

Calpine – 2
- Shortens contract term from 10 to 8 years.
- Reduces contract price from $61 per MWh to $59.60 per MWh.
- Allows DWR to acquire additional dispatchable (and tolling) power during 2002 and 2003.
- Strengthens provisions to ensure that new power plants are built and meet commercial operation deadlines. Provisions include performance penalties for the Seller if a plant is not constructed, and the State may takeover the site and permit from Seller and complete the plant itself.
- Delivers power to NP 15.
- Requires Seller to pay cover damages for unexcused failures to deliver power.
- Restricts Seller's ability to provide replacement energy from the ISO imbalance energy market.
- Reduces DWR's environmental and regulatory risk by only requiring the DWR to bear the risk of a tax or other imposition enacted by the California Legislature that is targeted at energy goods and services.

Calpine – 3

- Shortens contract term from 20 to 10 years.
- Converts contract from fixed-price to tolling.
- Enhances dispatch flexibility for the DWR.
- Strengthens provisions to ensure that new power plants are built and meet commercial operation deadlines, including performance penalties for the Seller if plants are not constructed and capacity charge penalties if deadlines are not met.
- Requires availability of 98% in summer and 92% in winter, with capacity charge penalties if availability requirement is not met.
- Requires annual capacity test with capacity charge penalty.
- Requires Seller to pay cover damages for unexcused failures to deliver power.
- Adds "anti-gaming" provisions to address the Auditor's performance risk concerns, and restricts Seller's ability to provide replacement energy from the ISO imbalance energy market.
- Reduces DWR's environmental and regulatory risk by only requiring the DWR to bear the risk of a tax or other imposition enacted by the California Legislature that is targeted at energy goods and services.

Calpine – 4

- Enhances dispatch flexibility for the DWR.
- Strengthens provisions to ensure that new power plants are built and meet commercial operation deadlines, including performance penalties for the Seller if plants are not constructed.
- Requires Seller to build a plant in San Jose. If Seller does not construct the plant, DWR may terminate.
- Requires availability of 98% in summer and 92% in winter, with capacity charge penalties if availability requirement is not met.
- Requires annual capacity test with capacity charge penalty.
- Requires Seller to pay cover damages for unexcused failures to deliver power.
- Adds "anti-gaming" provisions to address the Auditor's performance risk concerns, and restricts Seller's ability to provide replacement energy from the ISO imbalance energy market.

High Desert

- Shortens contract term from by 6 months.
- Increases power deliveries during summer 2002 and 2003.
- Converts contract from non-dispatchable to dispatchable, and from fixed-price to tolling.
- Strengthens provisions to ensure that new power plants are built and meet commercial operation deadlines, including performance penalties for the Seller if plants are not constructed.
- Allows DWR to terminate for inappropriate unexcused failures to deliver power, and provides additional financial penalties if Seller fails to deliver for economic reasons.
- Requires availability of 95%, with capacity charge penalties if availability requirement is not met.
- Requires annual capacity test with capacity charge penalty.

- Restricts Seller's ability to provide replacement energy from the ISO imbalance energy market.

Capitol Power
- Shortens contract term from by 6 months.
- Reduces contract price from $89 per MWh to $87 per MWh, and caps the total net income the generator will receive. If the costs of running the plant are lower than projected, then the costs to DWR will be reduced.
- Extends the commercial operation deadline.
- Requires parties to share some of the construction cost risk.

Whitewater
- Shortens contract term from by 6 months.
- Reduces contract price from $60 per MWh to either $54/MWh if the units are online by August 31, 2002 or $ 40 per MWh if the units reach operation after August 31, 2002.
- Extends the commercial operation deadline.
- Strengthens performance penalties for Seller's willful failure to deliver.

Appendix B. Principal Terms of the DWR Long-term Contracts, Listed by Date of Execution

Seller	Date Contract Signed	Term (years)	Pricing Structure	Product	Dispatchable?	New Units?	Resource[§]	Delivery Point[†]	MW Range	Ten-year Energy Purchases (GWh)[‡]	Price Range ($ / MWh)[‡]	Ten-Year Power Cost ($ millions)[‡]
Calpine – 1*	2/6/2001	10	Fixed	Base	No	No	Unspecified	NP 15	200 - 1,000	64,596	59	3,785
El Paso	2/13/2001	5	Fixed	Peak	No	No	Unspecified	NP 15, SP 15	100	2,441	115 - 127	295
Morgan Stanley	2/14/2001	5	Fixed	Base	No	No	Unspecified	SP 15	50	2,136	96	204
Williams	2/16/2001	10	Fixed	Base, Peak	No	No	Natural gas (CC)	SP 15	175 - 1,400	56,535	63 - 87	3,779
Calpine – 2*	2/26/2001	10	Fixed	Peak	No	Yes	Natural gas (CC)	TBD by Seller	200 - 1,000	70,115	115 - 61	4,322
Calpine – 3*	2/26/2001	20	Fixed	Base	Yes	Yes	Natural gas (SC)	NP 15	90 - 495	8,001	174 - 154	1,337
Dynegy – 1	3/2/2001	4	Fixed	Base, Peak	No	No	Natural gas (CC)	SP 15	200 - 600	14,246	120	1,702
Dynegy – 2	3/2/2001	4	Tolling	Base, Peak	Partially	No	Natural gas (CC)	SP 15	200 - 1,500	21,174	145 - 79	2,008
High Desert*	3/9/2001	8	Fixed	Base	No	Yes	Natural gas (CC)	SP 15	840	51,896	58	3,010
Imperial Valley	3/13/2001	3	Fixed	Base	No	No	Biomass	SP 15	16	362	100 – 90	34
Allegheny	3/23/2001	11	Fixed	Base, Peak	No	No	Natural gas (CC)	SP 15	150 - 1,000	63,898	61	3,909
Alliance Colton	4/23/2001	10	Tolling	Peak	Partially	Yes	Natural gas (SC)	SP 15	80	1,468	379 - 141	253
Soledad[¤]	4/28/2001	5	Fixed	Base	No	Re-power	Biomass	NP 15	13	410	80 – 84	34
Sempra	5/4/2001	10	Tolling > 2002	Base, Peak	No	Yes	Natural gas (SC and CC)	SP 15	400 - 1,900	93,325	160 - 57	6,238
GWF Energy	5/11/2001	10	Tolling	Peak	Yes	Yes	Natural gas (SC and CC)	NP 15	340 - 430	23,713	295 - 44	1,689
Coral Power	5/24/2001	11	Tolling > 2005	Base, Peak	Partially	Yes	Natural gas (SC)	NP 15, and TBD by Seller	275 - 850	28,677	249 - 57	2,292
PG&E Energy Trading	5/31/2001	10	Fixed	Intermittent	No	Yes	Wind	SP 15	67	2,017	59	118
Calpine – 4*	6/11/2001	3	Tolling	Peak	Yes	Yes	Natural gas (SC → CC)	NP 15	180 - 225	3,024	134 - 84	322
Clearwood	6/22/2001	10	Fixed	Base	No	Yes	Geothermal	NP 15	25	1,692	67	114
Sunrise	6/25/2001	10	Tolling	Summer Super Peak, Base	Yes	Yes	Natural gas (SC → CC)	SP 15	325 - 560	38,888	228 - 59	2,218

Seller	Date Contract Signed	Term (years)	Pricing Structure	Product	Dispatchable?	New Units?	Resource[§]	Delivery Point[†]	MW Range	Ten-year Energy Purchases (GWh)[‡]	Price Range ($ / MWh)[‡]	Ten-Year Power Cost ($ millions)[‡]
PacifiCorp	7/6/2001	10	Tolling > 2002	Base	Yes > 2002	Yes	Natural gas (CC)	NP 15	150 - 300	21,900	70**	1,533
Whitewater*	7/12/2001	12	Fixed	Intermittent	No	Yes	Wind	SP 15	108	3,263	60	196
Fresno Cogeneration	8/3/2001	10	Tolling	Peak	Yes	Yes	Natural gas (SC)	NP 15	21	950	179 - 92	100
Calpeak	8/14/2001	10	Tolling	Summer Super Peak	Yes	Yes	Natural gas (SC)	NP 15, SP 15	342	5,027	114 - 66	398
Wellhead	8/14/2001	10, option to extend to 20	Tolling	Peak	Yes	Yes	Natural gas (SC)	NP 15	92	4,047	142 - 78	354
Capitol Power*	8/23/2001	5	Fixed	Base	No	Re-power	Biomass	NP 15	15	590	119 – 109♦	67
County of Santa Cruz	9/13/2001	5	Fixed	Base	No	Yes	Landfill Gas	NP 15	3	112	65	7
									TOTAL	**584,506**		**40,323**

Note: only DWR contracts with terms of three years and longer are included in this table. Totals may not equal sum of components due to independent rounding.
§ CC = combined cycle; SC = simple cycle; SC → CC = simple cycle facility to be converted to combined cycle at some point during the term of the contract.
† NP 15 is the ISO congestion zone north of Path 15; SP 15 is the ISO congestion zone south of Path 15. Path 15 is the main transmission connection between the northern and southern parts of California; it is rated to carry 3,750 MW of power, but it is often congested (Western Area Power Administration 2002).
‡ Figures derived from spreadsheets provided by the State Auditor's office that were used in the State Auditor's report on the DWR contracts (California State Auditor 2001). All dollars are in nominal dollars. Ten-year energy purchases is the amount of electricity to be provided by each contract through 2010. Ten-year power cost is the total cost of the ten-year energy purchases.
* These contracts have been renegotiated. See Appendix A for details.
** This contract is fixed price only until 2003. After 2003 the contract is tolling, but the State Auditor's report did not include a price estimate for this period.
♦ This is the price included in the State Auditor's report, although the contract states a fixed price of $89 per MWh.
◘ The Soledad contract was terminated on 27 March 2002.

Appendix C. California Natural Gas Price Forecast Scenarios

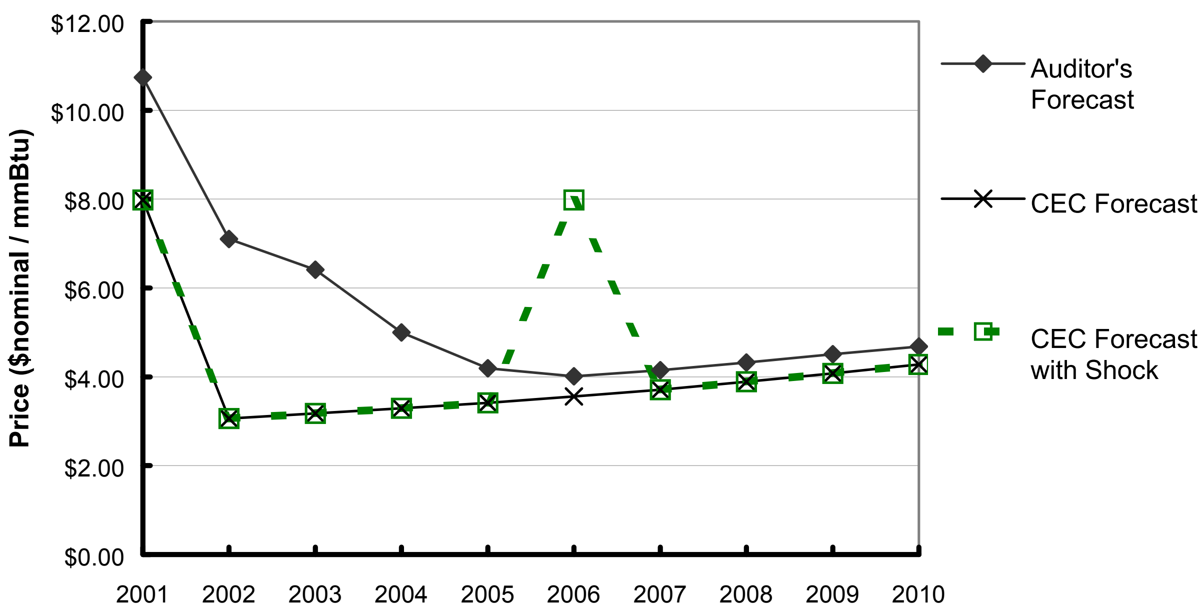
California Natural Gas Price Forecast Scenarios and Total Cost to the DWR
($nominal / mmBtu)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	DWR Ten-year Power Cost ($millions)
Auditor's Forecast[1]	10.74	7.10	6.41	5.00	4.19	4.01	4.15	4.32	4.51	4.68	40,323
CEC Forecast[2]	7.98*	3.06	3.18	3.29	3.42	3.56	3.71	3.89	4.08	4.28	38,270
CEC Forecast with Shock[3]	7.98*	3.06	3.18	3.29	3.42	7.98	3.71	3.89	4.08	4.28	39,977

1. Forecast used by the California State Auditor (2001). Forecast created by DWR's consultant, Navigant Consulting, 25 July 2001.
2. California Energy Commission Forecast (CEC 2002a) published in February 2002; Forecast for PG&E territory.
3. California Energy Commission Forecast, with 2006 gas price equal to the average gas price in 2001.

*actual 2001 average natural gas price in California (EIA 2002) with the missing November and December prices estimated using the proportional price changes of US natural gas wellhead prices.

California Natural Gas Price Forecast Scenarios



Appendix D. Allocation of the Risk of a Future Environmental Regulation in the DWR Contracts

	General New Regulations Implemented by:							New Regulations Targeted to Energy Services Implemented By:		
	Any Governmental Authority			Federal	State			Federal	State	
Seller	Parties can negotiate how to share costs above threshold, or Seller can terminate with no liability.	Seller passes on to DWR any cost increases above threshold	Seller shall not suffer the effects of any costs or restrictions imposed by environmental agencies.	Seller passes on to DWR any cost increases above threshold of $5.00 per MWh.	Any increase in cost for Seller passed on to DWR.	Any increase *or* decrease in cost for Seller passed on to DWR.	Parties will negotiate in good faith to leave Seller whole.	Seller can terminate with no termination payment	Any increase *or* decrease in cost for Seller (due to Legislature only) passed on to DWR.	DWR pays for increased cost or else defaults.
Non-Renewable Contracts										
Allegheny						✓				
Alliance Colton		Unclear**								
Calpeak*								✓	Due to any agency of State	
Calpine – 1*		$5 / MWh								
Calpine – 2*		50¢ / MWh								
Calpine – 3*		50¢ / MWh								
Calpine – 4*									✓	
Coral Power								✓		✓
Dynegy – 1			✓							
Dynegy – 2			✓							
El Paso										
Fresno Cogeneration									✓	
GWF Energy	$2.5 M / yr								✓	
High Desert*										
Morgan Stanley										
PacifiCorp									✓	
Sempra								✓		
Sunrise							✓			
Wellhead									✓	
Williams				✓	✓					
Renewable Contracts										
Capitol Power*										
Clearwood										
County of Santa Cruz										
Imperial Valley										
PG&E Energy Trading										
Soledad*						✓				
Whitewater*										

* These contracts have been renegotiated; see Appendix A for further details. The Soledad contract was terminated on 27 March 2002.
** The Alliance Colton contract claims that it is standard practice for contracts to allocate environmental risk in this manner, but it is unclear if the contract itself actually does.